Directive 040

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Pressure and Deliverability Testing Oil and Gas Wells

Contents

1 Introduction

Well test information is second only to production data in importance for the prudent management of oil or gas reservoirs. As such, well testing is an integral part of the overall production and depletion strategy of a reservoir. The lowest costs and the most benefit are realized when an appropriate number of high-quality tests are run throughout the producing life of the reservoir.

The requirements detailed in this directive are AER regulations, as enacted under sections 3, 7, 11, and 14 of the *Oil and Gas Conservation Rules* (*OGCR*). This directive addresses pressure and deliverability tests, drillstem tests, and fluid sampling and analysis. The well testing requirements defined in this directive are minimum requirements, and the AER may require testing that exceeds these requirements where it identifies such a need.

This new version of *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* is intended to serve as a handbook for testing oil and gas wells. Test quality will improve if licensees and operators use properly trained personnel, and take care in designing, conducting, analyzing, and reporting their tests. The contents of this directive should be useful to anyone involved in testing oil and gas wells, regardless of their level of experience.

1.1 AER Requirements

Following AER requirements is mandatory for the responsible duty holder as specified in legislation (e.g., licensee, operator, company, applicant, approval holder, or permit holder). The term “must” indicates a requirement, while terms such as “should,” “recommends,” and “expects” indicate a recommended practice.

Each AER requirement is numbered.

Information on compliance and enforcement can be found on the AER website.

1.2 What's New in This Edition

As part of its contributions towards the Government of Alberta's *Red Tape Reduction Act* and in an effort to modernize the directive, the AER has revised this directive as follows:

- reduced the initial pressure testing requirements
- rescinded annual pressure testing requirements for primary wells
- rescinded gas well AOF deliverability testing requirements
- included a minifrac testing and submission requirement
- updated to reflect modern practices and removed unnecessary information

2 Regulations Pertinent to Well Testing

Regulations pertinent to well testing are contained in the *OGCR*. Section 11.102 provides the authority to set requirements for well testing within this directive. Sections 11.005 and 11.120 require that all tests be submitted.

This section contains the condensed version of the basic minimum requirements for testing oil and gas wells and references the appropriate section for further clarification and explanation. The AER may require surveys that exceed these minimum requirements, as it deems necessary.

2.1 Initial Pressure Testing Requirements

(See sections 3.1, 3.5.1, and 3.5.5 of this directive for additional information.)

Initial pressures are not required on step-out wells to existing oil pools if *all* of the conditions are met as explained in section 3.1.1.

Initial pressures are not required on wells in which production is occurring from a development entity in accordance with section 3.051(1) of the *OGCR*.

1) Initial pressures for wells in which production is occurring under self-declared commingling in accordance with section 3.051(2) of the *OGCR* must conform to the requirements laid out in section 3.5.5 of this directive.

Initial pressures are not required for wells with production commingled under Southeastern Alberta Order No. MU 7490 or any successor orders.

Other testing methods that may be acceptable are addressed in section 4.

2.2 Deliverability Testing Requirements

(See sections 3.3, 3.5.5, and 6.1 of this directive for additional information.)

Bottomhole deliverability relationships are not required on wells in which production is occurring from a development entity in accordance with section 3.051(1) of the *OGCR*.

2) Bottomhole deliverability relationships for wells in which production is occurring under self-declared commingling in accordance with section 3.051(2) of the *OGCR* must conform to the requirements laid out in section 3.5.5 of this directive.

Bottomhole deliverability relationships are not required for wells with production commingled under Southeastern Alberta Order No. MU 7490 or any successor orders.

Any flaring or venting in conjunction with well testing must be conducted in accordance with *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*.

2.3 Annual Pressure Survey Requirements

(See sections 3.4 and 3.5.5 of this directive for additional information.)

3) Annual pressure surveys must be conducted by year end (December 31) for oil and gas pools, as specified in the Annual Pool Pressure Survey Schedule (aer.ca > Providing Information > Data and Reports > Activity and Data > Well Testing Schedules).

Annual pressure surveys are not required on wells in which production is occurring from a development entity in accordance with section 3.051(1) of the *OGCR*.

4) Annual pressure surveys for wells in which production is occurring under self-declared commingling in accordance with section 3.051(2) of the *OGCR* must conform to the requirements laid out in section 3.5.5 of this directive.

Annual pressure surveys are not required for wells with production commingled under Southeastern Alberta Order No. MU 7490 or any successor orders.

2.4 Fluid Analyses

(See section 3.6 of this directive for additional information.)

All fluid analyses conducted on samples gathered at a well which are representative of the formation (not mixed stream), must be submitted in accordance with section 11.070(1) of the *OGCR*.

3 Clarification of the Minimum Requirements

Sections 3 through 6 of this directive provide additional interpretation of the basic testing requirements, guidelines for meeting or modifying the basic requirements, and examples of situations where the AER may require special testing that exceeds these minimums. Together they represent the minimum requirements for well testing that are considered essential for prudent reservoir management. Recommended practices directly related to submission requirements are also included under many of the sections to assist well testers in meeting their submission requirements and obtaining the best data possible.

3.1 Initial Pressure Testing

5) Initial subsurface pressure tests must be collected on new productive oil and gas wells, and reported in electronic format (PAS), as follows:

    a) Oil wells – on all exploratory, discovery, development, or step-out oil wells; prior to any sales or production, other than test production (one well per pool per section from the bottomhole completion) for wells in pools with an oil density less than or equal to 925 kg/m^3

    b) Gas wells – on all new gas wells drilled, within the first three months of production (one well per pool per section and its adjoining sections from the bottomhole completion; see figure 1)

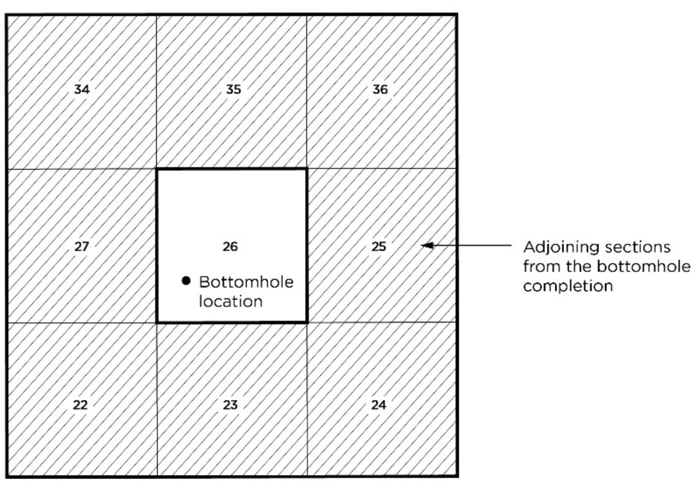

Figure 1. Diagram of which sections must be tested for new gas wells drilled

An accurate initial pressure is probably the most important pressure taken in a well. It determines the initial pool pressure in exploratory wells, it helps delineate pools in development wells, and it can show the drainage and recovery efficiency in infill wells. Without this pressure, subsequent pressures may be of limited value.

The AER maintains a list of wells for which we do not yet have initial pressure test results on the AER website, aer.ca > Providing Information > Data and Reports > Activity and Data > Well Testing Schedules. This list is updated weekly and displays the unique well identifier, the licensee, and the type of test required.

3.1.1 Step-out Oil Wells

Initial pressures are not required on step-out wells to existing oil pools if *all* of the following conditions are met:

- the well is drilled where step-out does not exceed one quarter section
- there is already at least one well drilled and completed in the pool
- all initial survey requirements have been fulfilled
- the licensee or operator can provide evidence, upon request, indicating the well is completed in the existing pool

Any further development in the section, outside of the one-quarter-section buffer zone, requires an initial pressure survey (one well per pool per section).

Important note: If you do not survey a step-out well, any further development drilling in that section requires testing, even if that quarter section gets added to the AER pool order (one initial survey must be conducted per section).

The initial survey requirement can be waived for wells drilled outside of an existing pool boundary (using the AER's current pool order *at time of drilling*, as per figure 2), where the step-out is within the quarter-section buffer zone and there is a high probability of extending the existing pool. The conditions listed above permit the waiver of the initial pressure survey requirement, while ensuring that only pools with an established pressure history and areal extent receive waiver. Also, they ensure that wells between two same formation pools have adequate initial pressure data to allow determination of pools.

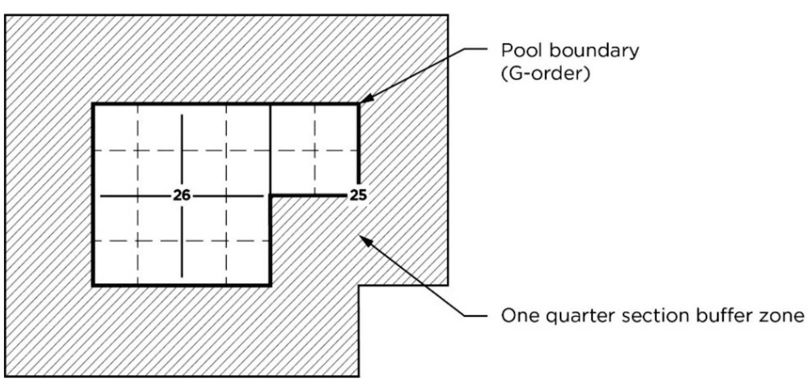

Figure 2. Pool order with buffer zone

6) The AER does not currently have an automated process to administer the waiver for these step-out wells. Therefore, the licensee must respond to the notice letter and advise AER staff that the well qualifies for exemption due to the step-out rule. AER staff will then review the situation and determine the requirement accordingly.

7) Similar problems are often experienced with wells drilled within an AER pool order that do not initially get coded into the pool, or into the Southeastern Alberta Shallow Gas System. In these cases, the licensee is also required to respond to any notice letters and advise AER staff of the criteria for exemption.

3.1.2 Recommended Practices for Initial Pressure Tests

The initial stabilized pressure should be taken before any significant production or depletion of the reservoir occurs. Taking the initial pressure after a reasonable cleanup flow period is acceptable provided that the test shows that a stabilized reservoir pressure has been reached.

Using a static gradient for an initial pressure test without sufficient shut-in may not indicate a stabilized pressure.

Initial pressure is not required for infill oil wells.

Under certain conditions, an acceptable initial pressure can be obtained from alternative methods as addressed in section 4 of this directive.

3.2 Gas Well Deliverability Testing

8) There is no requirement that a licensee or operator determine the sandface deliverability relationship for gas wells; however, where such results are determined for a producing gas well, the licensee or operator must submit them in the TRG.PAS format before the end of the first three months of production.

The AER uses this information in reserves determination, provincial forecasts of gas deliverability, and in processing applications for gas plants, pipelines, batteries, etc. In addition, these data are made available to the public for multiple purposes, including drilling release rate calculations and property evaluation

There is no deliverability test requirement for oil wells, but where such tests are run, the results must be filed with the AER, as per sections 11.005 and 11.120 of the *OGCR*.

3.2.1 Types of Deliverability Tests

It is recommended that licensee or operator consult the general practices and methodologies as described in *Directive 034* when conducting deliverability tests.

3.2.2 Surface Testing Dry Gas Wells

In order to estimate a stabilized pressure or the productivity or absolute open flow potential of a gas well, it is necessary to determine the bottomhole pressures at static and flowing conditions, either by actual measurement with a bottomhole pressure gauge or by calculation from wellhead pressure measurements. Because it is often not cost effective to measure static and flowing pressures by downhole gauge in lower productivity gas wells, estimations may be made from wellhead data gathered by an accurately calibrated deadweight gauge.

9) The calculation of a bottomhole pressure from data measured at the wellhead involves the solution of the energy balance equation as applied to both static and moving columns of gas. There are several methods available for this solution, and reference should be made to *Directive 034*. This pressure must be reported in the GRD.PAS format to meet the initial pressure requirement.

The calculation for a single-phase fluid (gas) in the wellbore requires knowledge of the wellhead pressures, the properties of the natural gas, the depth of the well, flow rates, formation and wellhead temperatures, and the size of the flow lines. Appendix B of *Directive 034* introduces the theory and basic equations relating these quantities. Methods using the basic equations and simplifying assumptions to make them practical are outlined. The recommended procedure is discussed in detail and is illustrated by appropriate examples.

Also included in *Directive 034* is a simple method for the estimation of bottomhole pressures for gas-condensate wells.

3.2.3 Reporting Deliverability Tests

10) All deliverability tests conducted must be submitted in the TRG.PAS electronic format, as defined in appendix A. A PRD.PAS file must be submitted for all tests involving flaring, incineration, or venting and any other test where production testers have been used.

The initial deliverability requirement will not be considered fulfilled until production rate data files have been submitted and accepted by the AER, as indicated above (in-line production information is to be provided in the DTINRPR - Data Table – Inline Rate and Pressure Summary - portion of the TRG.PAS file). The most current version of all PAS formats is available from the links in appendix A.

11) You must submit volumetric data for a well that has produced any fluid (crude oil, crude bitumen, condensate, gas, or water) as outlined in *Directive 007: Volumetric and Infrastructure Requirements*.

12) These volumes and the method of production (flared, incinerated, vented, or in line) must also be reported in the AOF.PAS electronic report

3.3 Flaring and Emissions During Well Testing

Flaring must always be kept to a minimum.

All flaring, incinerating, or venting during well testing must be conducted in accordance with *Directive 060*.

3.4 Annual Pool Pressure Surveys Under Special Circumstances

13) Annual surveys are required on oil and gas pools and wells that have been determined as special circumstance in accordance with section 3.4.2. All pressure surveys must be filed with the AER.
14) Tests intended to fulfil survey requirements must meet the standards set for “acceptable tests” as defined in section 4 of this directive.

It is the responsibility of the coordinating operator to ensure the requirements are met, or to address any inaccuracies with AER staff (e.g., change of licensee responsibility due to sale of property). Full details on licensee and operator responsibility are found in section 3.4.3 of this directive.

3.4.1 Developing the Survey Schedules

Pressure data are considered most important in the initial and developing years of oil or gas pools, to assist in determining pool delineation, reserves, recovery mechanism, waterdrive or influx activity, and optimum depletion strategy.

Special circumstances are identified and pools are added through the application process to monitor equity issues, enhanced recovery feasibility, progress of enhanced recovery schemes, concurrent production, special allowables, etc. These special circumstances will be a condition of the approval or the letter of disposition.

Once the survey schedule has been published for the year, the AER will not add a pool survey without notifying the coordinating operator (see section 3.4.3) or pertinent well licensee. The next update of the schedule on the AER website will include that pool.

3.4.2 Special Circumstances

Some oil and gas pools and wells have special circumstances defined and will be identified with a survey frequency of “SPECIAL CIRC” on the survey schedule. These circumstances are usually defined through the approval process and the letter of disposition, but the particulars will be identified in appendix attached to the survey schedule.

Situations which may result in special circumstances being assessed include the following:

- oil pools
  - approval clauses for enhanced recovery, concurrent production, etc.
  - partial pool requirement
  - special areal coverage requirement
  - specific wells that require monitoring
  - observation wells
  - disposal wells
  - self declared (SD) commingled wells
- gas pools
  - off-target wells
  - acid gas disposal wells
  - gas cycling schemes
  - gas storage wells
  - observation wells
  - disposal wells
  - self declared (SD) commingled wells

The survey schedules are published in February of each year. The survey schedules for oil and gas pools are posted on the AER website (aer.ca > Providing Information > Data and Reports > Activity and Data > Well Testing Schedules), complete with current status (e.g., fulfilled, outstanding, partially fulfilled, not required, etc.). This file is updated weekly.

It is the coordinating operator's responsibility to determine the pools for which they are responsible, and contact the other operators in the pool to coordinate the survey. There is a sample letter included at the end of this directive that can be used for this purpose (see appendix C). See section 3.4.3 for more information on the responsibilities of the coordinating operator.

3.4.3 Licensee and Operator Responsibilities

15) Where more than one licensee or operator produces from the same pool:

    a) A coordinating operator will be designated by the AER and deemed responsible for coordinating the surveys for the pool and ensuring the pool's survey requirements are fulfilled as required by this directive.

b) All licensee and operators in a pool must cooperate with the coordinating operator in planning, conducting, and submission of pressure survey data sufficient in quantity and quality to fulfil the pool's survey requirements as required by this directive.

All parties that obtain revenue from a pool are expected to share the burden of testing. A cooperative approach to pressure testing should result in the best well selection and the lowest costs, therefore, every effort should be made to develop a single coordinated program.

A coordinating operator will be designated for each pool on the survey schedule. The AER program selects the coordinating operator automatically as the operator who produced the largest total volume of oil or gas from the pool in the previous year. The coordinating operator is the AER's primary contact for testing in a pool, as well as being deemed responsible for ensuring the pool's survey requirements are fulfilled.

The main duty of the coordinating operator is to develop and coordinate pool pressure survey programs with the input and assistance of the other licensees and operators in the pool. The coordinating operator should always be cognizant of opportunities that permit timely pool pressure surveys to be conducted during scheduled shutdowns and plant turnarounds.

An example of the procedure for developing a pressure survey program for a pool is given in section 3.5.6.

If a coordinating operator has fulfilled their part of the requirements, but their efforts to coordinate the survey with the other licensees and operators have been to no avail, they may provide the AER with documentation of communications (e.g., copies of letters, e-mails, documentation of telephone calls, etc.). The responsibility will then shift to the uncooperative licensees and operators. Again, the survey schedule and the current status for each pool is on the AER website to assist the licensees and operators in ensuring the survey requirements are fulfilled, as referenced in section 3.4.3.

3.4.4 Licensees' Responsibilities when Buying/Selling Wells

It is the responsibility of the licensees, both the seller and the buyer, to ensure a proper well licence transfer is filed with and approved by the AER. If the seller of the property is the coordinating operator, it is their responsibility to advise the AER (see appendix B) of the change of responsibility to avoid assessment of noncompliance fees. The AER considers the original licensee responsible until this process is complete (see *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process* for more information).

16) If the AER deemed the previous licensee responsible during the first three months of consecutive production, they must contact the AER within the timeframe specified on the AER Outstanding Initial Well Testing Requirements list available on the AER website (aer.ca >

Providing Information > Data and Reports > Activity and Data > Well Testing Schedules). Failure to do so, will result in the assessment of a $1000 noncompliance fee.

3.4.5 Determining the Number of Surveys Required

17) Having regard for testing costs and adequate pressure coverage, the minimum number of pressure surveys required for a special circumstance approval should equal 25 per cent of an approval's producing well count within the approval boundary area. However, if there is a specific condition within the approval, the condition prevails over the testing requirements listed below.

18) For gas pools, one survey per four productive sections is required within the scheme boundary. This does not necessarily mean that only productive wells should be surveyed, or that a well must be surveyed in every productive section.

19) For oil pools, one survey per four production quarter sections is required within the scheme boundary. This does not necessarily mean that only productive wells should be surveyed or that a well must be surveyed in every quarter section.

It is important to remember that the initial pressure requirement would still apply to any new wells drilled into these pools. It should also be noted that initial pressures can be used to meet the annual pool pressure survey requirement provided that areal coverage is satisfactory.

3.4.6 Selecting Scheme Approval Wells to be Surveyed

It is usually considered impractical to shut in an entire pool to conduct a pressure survey. However, if interference is a problem, it may be advisable to shut in offset wells for the duration of the test.

Costs are significantly reduced if some pressures from new or shut-in wells are used to meet the requirements, provided they are representative of the producing portion of the reservoir. For example: if the well is shut in because it was in poor communication with the reservoir, it will not provide a representative pressure measurement for this pool. The practice of using opportunities to survey at reduced costs is encouraged, where adequate areal coverage is not sacrificed and some producing wells are included in the survey.

3.4.7 Observation Wells

Shut-in wells can be candidates for testing and reduce the cost of a required pressure survey, provided they are representative of the producing portion of the pool, as described above. It is unacceptable to use a well that was shut in because of poor communication with the pool. A good example of using a shut-in well for observation purposes is to monitor the pressure of an aquifer where water disposal could result in over-pressuring.

20) All requests for "observation well" status must be sent to WellTest-Helpline@aer.ca for approval. Applicants will be required to provide information regarding the type and need of the data being gathered. This information will be considered in conjunction with requirements for that well/pool, data reported to the AER, and long-term implications regarding the AER's requirements for the administration of inactive wells. If approved, the licensee must change the well status in Petrinex to "observation."

Once an observation well is approved, the AER will conduct random audits to monitor the ongoing use of the well for observation purposes. If the intent of the observation well was to monitor pressure data, the pool will be added to the special circumstances survey schedule, with full compliance administration. The pool will remain on the survey schedule until the licensee requests exemption and the well reverts back to the inactive well administration system.

3.5 Modifying the Basic Requirements

When a licensee believes that a pool or well scheme approval should qualify for relaxation or exemption, a request for relief should be made to the AER, including supporting data.

A pool or well scheme approval may qualify for waiver of survey requirements for a specific year if an extensive test was conducted in the previous year, if withdrawals have been negligible since the last survey, or if the entire pool must be shut in to obtain quality data.

Described in the following sections are situations where licensees or operators should consider requesting either relaxation or exemption from the basic requirements. This provides more flexibility for the licensee or operator to conduct the tests needed for their own use but not at scheduled intervals tracked by the AER. While each situation must be considered on its own merits, some general guidelines are provided to streamline the process and to show how requests for relief may be approved. All requests should be directed to WellTest-Helpline@aer.ca.

The need for the data should always be the main reason for testing.

Please note that applications for waiver or exemption of the survey requirements received after November 1 of the current year may result in two surveys being required in the following year, if the application is denied.

Also described below are the requirements for testing wells that are commingling production from two or more pools in the wellbore, where such requirements vary from the standard requirements stated elsewhere in this directive.

3.5.1 Heavy Oil Pools

The pressure response of a reservoir fluid is a function of the fluid's viscosity. The heavier the density of the crude oil at reservoir conditions, the more viscous the fluid. Pools with an oil density over 925 kg/m^3 may be added to the special circumstances schedule (e.g., waterflood). In general, the initial pressure requirement would still apply for oil wells in pools with an oil density less than or equal to 925 kg/m^3, and a request is needed to make a case for relief.

The licensee or operator is expected to provide supporting evidence in a request for relief from pressure testing. This evidence should include field data and analyses that show that stabilized reservoir pressures cannot be obtained using conventional survey methods.

There are no standard survey requirements for bitumen wells within designated oil sands areas, although any surveys conducted must be submitted to the AER.

3.5.2 Low-Permeability Pools

The time required for pressure buildup is inversely proportionate to permeability. In general, whenever a reasonable estimate of the stabilized reservoir pressure can be obtained within a 14-day shut-in period (using buildup or static pressure measurements), the basic pressure requirements apply. A measured or extrapolated pressure that is at least 95 per cent of the fully built-up pressure is considered adequate for most reservoir management/ development applications.

Where it takes more than 28 days to estimate a stabilized pressure, exemption from pool pressure surveys may be granted upon application. Between 15 and 28 days, relaxation may be granted upon application, depending upon the need for the data. For example, where a 21-day shut-in period is needed to gather sufficient data for a transient pressure test, the number of pressure surveys may be halved. These applications require supporting evidence including interpretation of previous pressure buildup tests, establishing the reservoir parameters pertinent to the application. For further information on time to stabilization see AER *Directive 034*.

3.5.3 Pools with Enhanced Recovery

Generally, survey requirements in a pool with enhanced recovery may exceed the minimum requirements in order to monitor the effects of injection. In addition, survey coverage in patterned floods generally requires a representative pressure test on a producing well in each pattern. These special requirements, along with time lines for submission of test results, will be outlined in AER correspondence.

It is recommended that sufficient pressure data be taken to determine the pressure for all recovery mechanisms in pools where both primary depletion and enhanced recovery schemes are operating.

Pressure sinks or highs in pressure maintenance schemes should be monitored each year until the problem is corrected. Shut-in wells within the producing area of a pool may be good candidates for pressure observation, provided they are in good communication with the productive area of the pool. However, if a well is suspended because it is in a very tight portion of the reservoir, or an area that has watered out (the flood front has passed), it would likely not provide any useful data in determining the pressures and trends of the producing area. In general, pressures from shut-in wells and new wells (initial pressures) should be used together with pressures from producing wells to satisfy a pool's pressure survey requirement.

The use of injection wells as candidates for pressure testing usually results in a higher pressure and would not be acceptable for determining the pressure in the producing zone, or assessing whether producing wells comply with a minimum operating pressure (MOP). In unique circumstances, where it has been shown by previously correlated data that a pressure from an injector is representative of the producing area of the pool, this may be deemed acceptable. This will usually occur when injection fluid is taken on vacuum (e.g., reef type pools).

When an enhanced recovery scheme, with an MOP, is in its latter stages of depletion, the MOP may be reduced to the bubble point pressure, or some other applicable pressure. Requests to amend the operating pressure should be directed to WellTest-Helpline@aer.ca and contain discussions on the suitability of the existing MOP and the proposed operating pressure along with future plans for the scheme.

21) Static gradient tests with short shut-ins (less than 14 days and below the stabilized conditions) but with pressures above the MOP or other approved operating pressure may satisfy survey requirements. However, prior approval must be obtained from the AER.

22) Relaxation of pressure testing requirements in pools with enhanced recovery, occur mainly by application. Any requests for relief from pressure testing in pools with enhanced recovery must still be submitted to WellTest-Helpline@aer.ca to ensure a temporary change in status for compliance purposes.

3.5.4 Pools with Active Waterdrives

Once sufficient pressure data has been gathered to establish that a pool has an active waterdrive, the survey requirements can usually be reduced. While further development may change the ability of the waterdrive to maintain the pool pressure, surveying 25 per cent of the wells is not necessary. Approval for reduction of requirements in these situations should be requested.

3.5.5 Pools with Commingled Production

In pools where approval has been granted by an AER order to commingle production in a small number of wellbores in a pool, generally no change would be made to the survey requirements on the basis of the commingling.

In situations where most or all of the wells in two or more pools are approved for commingled production by an AER order, the usefulness of the commingled pressure data for individual pool analysis is diminished. In these cases, the pressure measured in the wellbore reflects an unknown combination of pressures from the different pools, often complicated by the effects of crossflow. However, pressures taken on commingled pools in a wellbore can be useful for evaluating the potentially complex, multipool commingled system as a whole.

There are special cases where segregated individual pool pressure data is still required for commingled pools (e.g., enhanced recovery schemes), and specialized equipment may be required to obtain this information (e.g., sliding sleeves). For all other commingled pool cases, pressure and deliverability measurements on the composite "commingled pool" in the wellbore replace segregated individual pool test requirements.

The AER made significant changes to its management of commingled production in the wellbore in 2006. These changes acknowledged the shift to lower productivity resources, the prevalence of commingled production to achieve optimum resource recovery, and a shift in reservoir management and reserves evaluation and administration towards commingled reservoir situations. As part of these changes, well testing requirements for wells commingled under processes introduced in 2006 were modified. Specifically, wells that are producing from a development entity or under the self-declared commingling process in accordance with section 3.051 of the *OGCR* must be tested in accordance with the requirements specified below.

3.5.5.1 Gas Wells Producing From a Development Entity

23) Wells producing from a development entity in accordance with section 3.051(1) of the *OGCR* do not require any initial or ongoing pressure or deliverability testing. However, if any such tests are conducted on wells producing from a development entity, the test data and analyses must be electronically submitted to the AER via the Well Test Capture system within the Digital Data Submission (DDS) system.

An analysis of each fluid produced from the commingled well must be performed and submitted electronically via the Well Test Capture system, in accordance with section 11.070 of the *OGCR*.

3.5.5.2 Gas Wells Producing Under the Self-Declared Commingling Process

Gas wells producing under self-declared commingling in accordance with section 3.051(2) of the *OGCR* require produced fluid analyses for the commingled production stream, and pressure and productivity testing. These testing requirements must be met for each well.

The type and extent of the pressure and productivity testing for these wells is dependent upon the average operating day flow rate of the commingled well for the first three calendar months with production immediately following the well being commingled under the self-declared process

(Total production during the 3 months ÷ Total hours on production during those 3 months × 24 hours/day).

If the gas well's average operating day flow rate for the first three calendar months with production immediately following the well being commingled under the self-declared process is less than or equal to 50 10^3 m^3/operating day, then only an initial pressure and fluid analysis for the commingled production interval is required. No individual pool pressures or subsequent pressures are required, nor is any deliverability testing required. However, if any such tests are conducted on wells producing under the self-declared commingling process, the test data and analyses must be submitted to the AER via the Well Test Capture system in accordance with sections 11.005 and 11.120 of the *OGCR* and section 3.7.2 of this directive.

If the gas well's average operating day flow rate for the first three calendar months with production immediately following the well being commingled under the self-declared process is greater than 50 10^3 m^3/operating day, then some form of production testing must be conducted or be available from previous tests on the well to identify the pools or zones contributing to flow from the well. This production testing may take the form of historic production from the pool, traditional segregated pool flow or deliverability testing, or flow meter testing where such testing can be used to reliably determine the contribution to flow of the individual pools under the flow conditions present in the wellbore. Where flow meter logs are used, both the log data and an interpretation of the data must be filed together with the AER. For each pool or zone contributing 35 10^3 m^3/operating day or more to the three-month average rate, an initial segregated pressure and fluid analyses must be submitted. If the well producing more than 50 10^3 m^3/operating day has no pool or zone contributing 35 10^3 m^3/operating day or more, then the major contributing zone, regardless of flow rate, requires an initial segregated pressure and fluid analyses to be submitted. Beyond the production testing required, conducted to identify the dominant productive pools or zones, there is no further deliverability testing required for these wells commingled in accordance with the self-declared process.

Ongoing annual pressures on the commingled well are required for all self-declared commingled gas wells that initially produced more than 50 10^3 m^3/operating day. This requirement does not change when the total well rate drops to or below 50 10^3 m^3/operating day.

3.5.5.3 Oil Wells Producing Under the Self-Declared Commingling Process

Oil wells commingling under the self-declared process are subject to the commingled oil well testing requirements outlined in section 3.1.6.2 of *Directive 065: Resources Applications for Oil and Gas Reservoirs*.

3.5.6 Recommended Practices for Pressure Survey Design

Some additional practices that should be considered when designing (coordinating) a pool pressure survey are listed below. However, it is always important to keep in mind what this pressure data will be used for; what we are trying to find out about this pool.

- Whenever possible, pressure surveys should be scheduled to coincide with planned well down time.
- It is important to return the well as close to producing conditions as possible or wait until the transient introduced has dissipated; or, when fluid is used to “kill” a well in preparation for testing, that fluid should be swabbed back prior to commencement of the test.
- In pools where both primary and enhanced recovery schemes are operating, sufficient pressure data should be taken to determine the pressure for both recovery mechanisms, until enhanced recovery has been deemed “not feasible” for the primary area.
- The use of injection wells as candidates for pressure testing usually results in a higher pressure and would not be acceptable for determining the pressure in the producing zone or assessing whether producing wells are in compliance with minimum operating pressures. However, if pressure transient analysis or previously correlated data, indicates a pressure from an injector is representative of the producing area of the pool, this may be deemed acceptable. This will usually occur when injection fluid is taken on vacuum (e.g., reef type pools).
- Survey coverage early in the life of an enhanced recovery scheme with a patterned flood generally requires a representative pressure test on a producing well in each pattern. Later in the life of the scheme, selection should be based on performance and previous pressure information.
- Pressure sinks or highs in pressure maintenance schemes should be monitored each year until the problem is corrected.
- Shut-in wells within the producing area of a pool, may be good candidates for pressure observation providing they are in good communication with the productive area of the pool.
- An initial pressure is often relatively simple and inexpensive to obtain; therefore, it should be taken for all wells, including infill wells, whenever practical.
- Pressure buildup data should be taken as early as possible in the producing life of a well. However, it is important to ensure that sufficient drawdown has occurred to establish an effective (practical) time to stabilization, as detailed in section 4.1.

3.6 Fluid Analyses

24) All fluid analyses on samples gathered at a well, which are representative of the formation (not mixed stream), must be submitted electronically in the appropriate PAS file. If multiple samples/analyses are done, all must be submitted. In addition, fluid analyses on each mixed stream (commingled) fluid that is produced from each well commingling within a development entity or under the self-declared commingling process in accordance with section 3.051 of the *OGCR* must be submitted electronically in the appropriate PAS file format.

25) Further, all gas and fluid samples analyzed in conjunction with the following tests must be submitted:

   a) Drillstem tests conducted on wells outside of existing pools, as per the current AER pool order:

      - fluid analysis is required if fluid is recovered during the test
      - gas analysis is required if gas to surface during the test

   b) All deliverability tests require gas analysis for the fluid analysis correlation on all wells drilled outside of exiting pools, as per the current AER pool order.

   c) Initial pressure tests conducted on wells outside of existing pools, as per the current AER pool order:

      - gas analysis is required for oil and gas wells
      - fluid analysis is required for oil wells, and gas wells producing liquids OR, provide details regarding the source of analysis used in the correlation.

   d) Acoustic well sounder tests require analysis information when calculating acoustic pressures:

      - gas analysis is required for all acoustic tests,
      - fluid analysis is required when fluids are present in the wellbore OR, provide details regarding the source of analysis used in the correlation.

   e) Pressure transient analysis requires gas and fluid properties for calculations. OR, provide details regarding the source of analysis used in the correlation.

   f) Each well producing from a development entity or commingling under the self-declared process must have fluid analyses on each mixed stream (commingled) fluid that is produced from the well submitted to the AER in accordance with section 11.070(2) of the *OGCR*. These analyses are required, among other reasons, to verify that the well production contains no H_2S and thereby qualifies for commingling under these processes, and must be conducted within 30 days of the well commencing commingled production under section 3.051 of the *OGCR*.

Wells producing under the self-declared process in which the well's average operating day flow rate for the first three calendar months with production immediately following the well being commingled under the self-declared process is greater than or equal to 50 10^3 m^3/operating day requires some individual pool fluid analyses. Analyses of each produced fluid from each individual pool contributing greater than 35 10^3 m^3/operating day to the total flow, or the major contributing pool if no individual pool is contributing greater than 35 10^3 m^3/operating day, must be submitted to the AER.

26) Any analyses required by this section must be conducted within 30 days of the well commencing production.

3.7 Submission Requirements

27) Licensees and operators must submit to the AER, in the appropriate electronic PAS format, all pressure and deliverability tests, drillstem tests (DSTs), and fluid analyses, including those not required by this directive, as per sections 11.005 and 11.120 of the *OGCR*, and in appendix A.

This includes tests conducted within designated oil sands areas. Only those tests conducted under controlled conditions need be filed, including drawdown tests, interference tests, two-rate tests, segregation tests, reservoir limits tests, injection or fall-off tests, and so on. A casual reading of a wellhead pressure with a portable dial gauge or a pumping fluid level need not be reported. Likewise, if you have conducted a test that failed and has no useful information, it need not be submitted.

Where the AER determines that a test has been conducted and not submitted, the matter becomes a noncompliance issue, subject to the measures detailed in section 6 of this directive.

If an application has been submitted, referencing a pressure that has not been submitted, the licensee will receive a notice letter starting the compliance process. The application will be considered deficient, and processing will be delayed until all data is available.

If test data pertinent to a land sale has not been submitted:

- if the sale is pending, sale of the property in question may be deferred until all data is available, or
- if the sale has occurred, the results may be reversed and the property re-issued for sale when all data is available.

For gas, oil, or water analysis, only those samples gathered from a well need be submitted.

3.7.1 Timing of Submissions

28) All pressure and deliverability tests, including reporting of volumes and methods produced during cleanup and testing, must be submitted within 90 days of completing the fieldwork.

29) All DSTs must be submitted within 30 days of the finished drilling date.

30) All gas and fluid analysis must be submitted within 45 days of completing the test.

31) All volumes produced, whether flared, vented, or collected (in line), must also be reported through Petrinex.

Notwithstanding the above, a test that failed and provides no useful data, especially where the use of this information might be misleading, does not have to be submitted. This does not include drillstem tests, as detailed in section 4.5.

This time is provided for the licensee or operator to complete an analysis and review the results. Compliance follow-up on initial pressure and deliverability tests will begin after production has been reported in three consecutive calendar months. Although the mechanism for AER to administer initial tests is the first three consecutive months of production reported, the 90-day rule is still in effect. If documentation is provided that indicates a well was tested and the data is not in the AER records, you will be required to submit that test even though the well has not commenced production.

Any annual tests not received by 31 March of the following year, will be deemed in noncompliance and have consequences assessed. This ensures that tests conducted in November or December have the full 3 months to compile and submit the test results.

Compliance follow-up on DSTs will commence 30 days from the finished drilling date for each individual well.

3.7.2 Reporting Formats

32) All reports must be submitted electronically in the current version of the PAS format as defined in appendix A.

The most current version is always available from the links in appendix A.

33) An electronic report must include an image file, with any charts and graphs, dialogue, explanations, and any parameters used in the analysis and results that have not been included in the PAS file.

Test/survey reports should contain a complete record of any event that may have affected the quality or interpretation of the data. The objective is to provide sufficient information for anyone using the data to be able to assess its reliability. All test results should be compared with the results of previous tests, if applicable, and both should be reported. Where anomalous data is encountered, explanations should be provided, or the well should be re-tested.

When tests have been run only for the licensee's use, and are not intended to fulfil survey requirements, within the ~Test Data Section of the appropriate PAS file, setting the [PRPS] = (O)ther, will turn off the "acceptable survey" edits and therefore only be recognized as "information only." This will ensure that quality requirements are not applied and the licensee or operator not requested to provide further validation and analysis of data. It is further recommended that whenever possible the reason for a test being submitted as "information only," be documented in the [PRGC] (Comment on Pressure) filed of the PAS file.

34) Although there are no standard requirements for bitumen wells in designated oil sands areas, all tests conducted on these wells must still be submitted to the AER.

All of the gas well testing requirements and provisions of this directive apply to gas wells in the designated oil sands areas.

4 Acceptable Test Standards

The manner in which tests or surveys are conducted and reported is always critical to the value of the data obtained. This section defines the quality standards required for tests to fulfil survey requirements.

The "Acceptable Survey Standards" for required tests have been translated into edits which are defined in appendix A.

Some business rules and edits in appendix A are critical, which will result in the file being rejected. Other edits have been identified as noncritical and will not cause the file to be rejected. The noncritical edits are more subjective and require some interpretation. These edits will be administered by an audit process. Tests not meant to fulfil any requirement should be clearly indicated in the Test Data section of the appropriate PAS file. Setting the [PRPS] = (O)ther will turn off the "acceptable survey" edits and only be recognized as "information only" data. Whenever possible, the reason for a test being submitted as "information only" should be documented in the "[PRGC] (Comment on Pressure)" field of the PAS file.

- PRPS (**I**)nitial – to be used for initial test requirement fulfillment.
- PRPS (**A**)nnual – to be used for annual survey requirement fulfillment.
- PRPS (**O**)ther – submitted only in accordance with section 11.120 of the *OGCR*.

All tests conducted must still be submitted to the AER, as per sections 11.005 and 11.120 of the *OGCR*, as defined in section 2 of this directive. All submissions must be made electronically as defined in appendix A.

4.1 Obtaining a Stabilized Reservoir Pressure

A major problem with pressure data is determining whether or not the pressure is representative of a stabilized reservoir pressure. If a transient pressure test is being submitted to fulfil requirements, the PAS file must either include analysis or the raw data must reflect a stabilized reservoir pressure. For most purposes, a “stabilized reservoir pressure” is defined as a pressure that does not build over 2 kPa/hour during a six-hour period.

The following four methods are acceptable for obtaining pressures that are representative of stabilized shut-in reservoir pressures, from most preferred to least:

- Measure sufficient transient data to reliably extrapolate to a stabilized reservoir pressure (P_R). See AER *Directive 034* for more information. Transient tests must be submitted with analysis or they will be rejected as deficient—for example, a common deficiency is a flow and buildup test with a shut in less than four times the flow period.
- Measure pressure buildup until the change in pressure is less than or equal to 2 kPa/hour over a six-hour period.
- Measure a static pressure after a shut-in sufficiently long to reach a stabilized pressure, as determined from previous data from this well (relief from testing requirements may be considered as discussed in section 3.5.1).
- Measure a static pressure after a shut-in time of at least 14 days where no transient data is available.

Ensuring that a stabilized pressure is obtained for low-permeability or commingled pools may be challenging even when these four methods are used. In that case, even though improvements to testing methods for such reservoir situations may be required, the use of the above methods will still help ensure that reasonably stabilized measurements are obtained.

4.1.1 Transient Pressure Tests with Analysis

The first method involves gathering and extrapolating transient data. This is considered the most efficient method of determining a stabilized shut-in reservoir pressure. Transient data can be costly to obtain; but it has the added advantage of providing estimates of reservoir rock properties and completion effectiveness.

With electronic submission, a critical edit will check for an average reservoir pressure (P_R).

The false pressure from a Horner plot (P*) is not representative of the average reservoir pressure (P_R). P* should be corrected to average reservoir pressure P_R using the Matthews, Brons, Hazebroek (MBH) techniques as described in AER *Directive 034*.

4.1.2 Transient Pressure Tests Without Analysis

The second method involves conducting a transient test (extended measurement of buildup) that has reached pressure stabilization. The acceptable pressure change rate indicating stability would be less than 2 kPa per hour. However, this rate of change may not indicate stabilization in systems with dual porosity/permeability, fractures, stratified layers, or phase separation in the wellbore. If these circumstances exist, 2 kPa per hour should not be used.

The following critical edits determine if a stabilized reservoir pressure has been reached. Tests submitted without analysis that do not meet the criteria will be rejected:

- Get the values reported as
  - RESULTS SUMMARY [PMPP] (representative bottomhole pressure at midpoint of perforations) for acoustic well sounder (AWS) tests or
  - RESULTS SUMMARY [PRGA] (last measured or representative pressure at stop depth) for transient pressure and deliverability (TRG) tests.
- Match these values to the acoustic data table or the gauge 1 (source gauge) data table.
- The difference in pressure over the six hours before this value must be equal to or less than 12 kPa (2 kPa per hour as defined in section 4.1 of this directive).
- If a pressure reading cannot be found at the six-hour interval prior to [PMPP] or [PRGA], the edit will look for the next previous reading and determine if the 2 kPa/hr limit has been met.

If DDS cannot match the value reported in RESULTS SUMMARY [PMPP] or [PRGA] in the raw data table, the file will be rejected.

4.1.3 Static Pressure Tests

The final two methods involve static pressure measurements, which can be the most cost-effective method of survey, but they are of little value if the shut-in period is too short and the well buildup character is unknown. It should be recognized that a meaningful estimate of reservoir pressure for a shale (or low-permeability well) may require a shut-in of months or a year.

For the third method, the time required to obtain a stabilized reservoir pressure must be determined from previous transient data conducted on the same well. It is not required that the well be shut in for the full time calculated as needed to reach theoretic stabilization. For most reservoir management or development applications, an effective time to stabilization of at least 95 per cent of the true (fully built up) stabilized pressure is satisfactory. The effective time to stabilization can be determined by taking 95 per cent of the extrapolated pressure and determining the time it took to reach that point. This time may change during the life of the well and may need to be re-established, depending upon depletion, recompletions, well treatments, etc. An initial pressure transient test does not usually provide a basis for an establishing buildup time to a stable pressure after the well has produced for several months. The initial test time is very short (small radius of investigation) in relation to the long production time on subsequent tests after the well has produced commercially. Consequently, the time to reach a stable pressure can be much greater than observed on an initial test.

In some cases, the shut-in time needed to reach stabilization can be estimated from offset wells and applied to the current test as a guide to determine a necessary shut-in time or when to terminate the test. However, this is only applicable where reservoir characteristics are very similar and the expected time to stabilization would be the same. In general, it would not be acceptable to use only the shut-in time from an offset well to determine the length of time to conduct a static pressure test.

The fourth method also involves a static measurement, but in this case there is no supporting analysis. Therefore, a minimum shut-in time of 14 days was selected because it should provide adequate pressure buildup for most reservoirs except shale or low-permeability reservoirs. Another exception to this would be in enhanced recovery schemes with a minimum operating pressure. In these instances, a static test may be accepted if it indicated the well or scheme was operating above minimum operating pressure, regardless of the length of shut-in time. However, this method must be approved by AER staff, and these pressures should not be used for reservoir calculations or modelling as they are not representative of the reservoir pressure (this is an example of designing a test for a specific purpose).

When conducting an initial static pressure test, remember that drilling, completion, and cleanup operations create some drawdown or may be overbalanced. However, since production from the well has been minimal, a 14-day shut-in is probably not required for an initial static pressure survey. Please indicate that the pressure is stable on the report in the “RESULTS-SUMMARY” section, under “[PRGC] (Comment on Pressure)” element. Also, an initial static gradient with a longer stop at bottom (minimum two hours) would be acceptable, providing it indicates pressure stabilization.

4.1.3.1 Surface Indication of Static Pressure

In certain circumstances, a stabilized pressure can also be obtained by monitoring the surface pressure until it stabilizes then measures or calculates the downhole pressure. See section 4.3 of this directive for further information.

4.2 Acoustic Testing

The most accurate way to measure subsurface pressure is direct measurement, by subsurface gauge. However, this method is very costly where pump and rods have been installed. In some cases it is acceptable to determine the bottomhole pressure indirectly using an acoustic method, providing the conditions detailed in this section of this directive are met.

Currently, about one quarter of all pressure surveys on oil wells are acoustic surveys. Unfortunately, the quality of acoustic surveys has varied considerably in the past, which has given them a poor reputation, and has limited their use in reservoir studies. *Directive 005: Calculating Subsurface Pressure via Fluid-Level Recorders* states “Experience has shown that the accuracy of subsurface pressures obtained from fluid-level measurements has, at times, proved questionable. Although the producing characteristics of many wells preclude great accuracy, the lack of accuracy can be attributed in many cases to improper data-gathering procedures, interpretation, and pressure calculation techniques.”

There are practical ways to address these problems. First, the acoustic method should not be used where it is reasonable to run bottomhole gauges. Acoustics should be used for wells or circumstances where there is the best chance of obtaining meaningful pressure data. Second, the data gathering and field measurement procedures in *Directive 005* should be followed at all times. Finally, every effort should be made to improve the accuracy of the calculations of subsurface pressures.

4.2.1 Verification of Acoustic Methods

Acoustic pressure surveys may be accepted if the following conditions are met:

- the pressure being taken is not an initial pressure,
- the fluid properties used for the calculation must be accurate and appropriately derived or confirmed by comparison to static gradient tests or pressure-volume-temperature (PVT) study data,
- the well does not produce water, OR
- the well produces water, but there is a 15 per cent or less difference between bottomhole pressures as measured by one of the following methods
  a) calculated by the acoustic method, assuming the influxed liquid column is all oil, compared to all water, or
  b) calculated by the acoustic method and measured simultaneously using a bottomhole gauge.

When the acoustic method has been verified by method (a) or (b) above, it may be accepted for subsequent pressures in the well providing the same acoustic testing procedures are repeated. Method (a) is an effort to minimize the margin for error in situations where the well produces water. When verification is by (a), the submission should contain some discussion regarding the changing water influx. *Directive 005* addresses the fact that producing watercuts are seldom representative of water within the fluid column in the annulus, and should not be used when making calculations, as the watercut in the annular column will change over time. There are now models available in industry that take this factor into consideration. Another factor to consider is gas influx, which lowers the liquid level, thus driving water back into the formation.

When verification is by method (b), the submission should compare liquid levels between the acoustic and gauge tests, oil/water contacts at the end of the test, gradients used and their origin, and procedures used to control conditions to ensure consistent data for future tests. Although at first a gauge/acoustic validation may not appear to be within acceptable limits, once the above items have been addressed and final wellbore liquid content determined, a process can often be developed to calculate representative pressures for future use in that well. However, if subsequent tests are submitted where data does not appear reasonable, the verification will be considered invalid.

The verification results from wells in one pool cannot be used for wells in other pools; however, these results may be applied to other wells in the same pool that have similar reservoir characteristics. The acoustic method must be verified in a representative sample of wells before it will be routinely accepted in large multiwell pools. Again, it is important to follow the practices established in the verification process in future acoustic testing.

When conducting an acoustic test on a suspended well that experienced high watercut during production, it is important to determine if any water still exists in the wellbore. The length of time the well has been shut in and the reservoir characteristics can affect this determination. If the well is to remain suspended, but is a good representative pressure source, it may be advisable to remove the pump and rods and use the well for observation purposes, with subsurface gauge surveys.

Acoustic pressures should always be compared with the last pressure or pressure trend. Where anomalous results are indicated, the acoustic pressure may not be accepted, and further verification of the acoustic method may be required.

4.2.2 Acoustic Test Design

When designing and running an acoustic survey:

- A buildup survey is preferred over a static survey because it monitors the movement of the gas-liquid interface and wellhead pressures and provides a better understanding of reservoir and wellbore dynamics. A buildup survey also provides additional information such as permeability and skin.
- Before conducting any acoustic survey on a producing well, the pumping fluid level must be determined. This practice significantly improves the chance of obtaining acceptable acoustic data. If the well is suspended or has been shut in for some time this may not be possible.
- The presence or absence of foam should be established via a foam depression test.

- A sensible shot schedule should be used for buildup surveys. Typically a minimum of 20 to 30 points are required. They should be spaced logarithmically.
- When the pumping fluid level is high, depressing the gas-liquid interface prior to shut-in may be considered. In wells with a high gas-oil ratio, this can be done using the well's back pressure. In wells with low gas-oil ratio, forced fluid depression can be achieved by pumping nitrogen downhole.
- When an acoustic survey is to be conducted on a static well, more than one shot should be taken especially when single-channel equipment is used.
- The input data for the bottomhole calculation (fluid properties, average joint length, etc.) must be current and accurate.
- The practices in AER *Directive 005* must be followed.

It is a much more complicated engineering problem to calculate acoustic bottomhole pressures than to measure them with downhole recorders. It is important to have representative fluid compositions and final production rates. Also, the wellbore schematic, tubing tally, and directional survey data should be up-to-date. Finally, the casing pressures and fluid levels should be measured by experienced field personnel, using accurately calibrated and well-maintained equipment. This is just as important as ensuring the integrity of subsurface gauges.

In extenuating circumstances, where a pressure minimum is involved, the AER may consider a pressure that would be above minimum operating pressure if the calculation assumed the wellbore liquid was all oil.

However, prior approval would be required for use of this method, and these pressures should not be included in determining an average scheme pressure.

4.3 Surface Pressure Tests

The method of monitoring surface pressures with memory digital surface recorders has been used by some companies recently, as a means of determining reservoir pressure stabilization. This method assumes that stabilization of pressure at surface is indicative of stabilization downhole. The bottomhole reservoir pressure is then determined using acoustic fluid-level data obtained once stabilization at surface has occurred. As in section 4.2.2, the integrity of the equipment used to measure surface pressure is paramount to the success of your test.

This method of monitoring reservoir pressure stabilization is acceptable in many cases, providing

- it is not an initial pressure survey,
- the minimum of an initial and final fluid-level shot is conducted and reported, including all parameters required for an acoustic survey, and

- the test meets all criteria defined for an acoustic test in section 4.2.

4.4 Permanent Downhole Gauges

In instances where it is necessary to monitor the pressure in a particular well on a frequent basis, it may be desirable to install a permanent type of gauge downhole. There are a number of these gauges on the market, but problems are often experienced if a maintenance program is not followed. Further information on maintenance of these gauges can be obtained from their respective manufacturers. See section 7 for calibration requirements of these gauges. Pressure data obtained from these gauges must be reported in the appropriate electronic format defined in appendix A.

4.5 Drillstem Tests (DSTs)

35) There are no regulations requiring the conducting of drillstem tests, but the results of any drillstem tests that are conducted must be submitted in the DST.PAS electronic format.

All DSTs conducted, including misruns, must be submitted in the DST.PAS format as defined in appendix A. This includes reporting the closed chamber portion of a test. To submit a DST to fulfil the initial pressure survey requirement, set "[PRPS] = (**I**)nitial" in the TEST DATA section.

The licensee or operator may determine the type of DST to run based on the information it needs. See section 6 for further information on compliance administration.

4.5.1 DSTs Submitted as Initial Pressures

36) All of the following conditions must be met if a DST pressure is used to satisfy the initial pressure requirement:

   a) The test must be mechanically sound (no skidding, plugging, or loss of packer seat).

   b) The last measured pressure and the extrapolated pressure (P*) from the final shut-in period must be within five per cent of each other.

   c) Within the ~TEST DATA section of the DST.PAS file, you must set [PRPS] = (**I**)nitial. If you have already submitted the file with [PRPS] = (**O**)ther, you can resubmit the same DST.PAS file by changing the [PRPS] = (**I**)nitial. It will not be rejected as a duplicate, but more edits will be activated by this flag.

The extrapolated pressures (P*) from any two shut-in periods should be within one per cent of each other and clearly different from the hydrostatic pressure.

Further a properly conducted DST meeting the requirements for an initial pressure can also count towards an annual pressure requirement if the pool is listed in the annual survey schedule.

4.6 Wireline Formation Tests (WFTs)

Consider the following when using a WFT to obtain an initial pressure:

- Special considerations exist with WFT interpretations and interpretation techniques applicable to the measured data. General Horner/Derivative techniques can be used, but the unique near-wellbore nature of these tests tends to invalidate basic Horner flow criteria.
- An on-record master calibration certificate for each transducer used should be available.
- The wide variability in test quality and pressure response between individual tests makes it critical to have at least two good quality pressures that fall within the repeatability specification of the WFT.

Reports for WFTs intended to fulfil a pressure requirement must be submitted in the electronic DST.PAS format, as per appendix A.

The near-wellbore nature of this kind of test needs special consideration in two main areas:

Depletion: Since the pressure distribution within a single zone very often differs significantly from test to test, due to preferential depletion in a developed reservoir, it is not practical to assign a single pressure to such a zone. While it is accepted that the requirements pertain to new pools where this should not be seen, more variation is observed across a single zone than is historically seen from a conventional single test that straddles the entire zone that provides a single average pressure value. A single zone with the presence of gas, oil, and water will yield a pressure profile that does not lend itself to an easy mathematical function which describes a single, average pressure. A general technique to convert several pressures to a single value needs to be defined.

Supercharging: The near-wellbore nature of these tests often yields pressures which are obviously too high when compared to other nearby pressures obtained through conventional means. The discerning factor is near-wellbore permeability. Experience has shown that near the one millidarcy permeability level, as measured by WFT/MDT type tools, measured pressures are very likely to be affected by the excess pressure of mud filtrate invasion that has not had sufficient time to re-stabilize because of low permeability. Pressure tests with this problem will appear and interpret completely normal. However, due to the very shallow depth of investigation and the excess pressure from mud filtrate invasion, the pressure will not be representative of the formation, but some value higher than formation pressure.

Proper interpretive techniques are available to recognize but not correct for pressures that appear too high. This further emphasizes the need for experienced personnel.

4.7 Fall-Off Tests (Minifrac, Data Frac, Hydraulic Fracture)

In the development of tight or unconventional reservoirs, industry moved towards predominantly horizontal wells with multistage fracture treatments using significant volumes of treating fluids. As a result, post-completion buildup tests would not provide a representative reservoir pressure within a reasonable shut-in time. Therefore, a fracture-injection/fall-off test, or minifrac (also referred to as DFIT™ or diagnostic fracture injection test), became the more common well test in determining initial reservoir pressure.

A minifrac test is conducted without proppant prior to the main hydraulic fracture treatment. These tests are performed by injecting small volumes (typically less than 15 m^3) of fluid (most often water) at low rates. The injection is often conducted over less than 15 minutes with the fall-off completed over approximately a two-week period. Pressure data is collected throughout both the injection and fall-off periods for analysis purposes.

In early 2020 the TRG.PAS file was revised to allow licensees and operators to electronically submit minifrac data and results to the AER. The following conditions should be met when using minifrac data to fulfil initial pressure requirements:

- An appropriate analysis must be conducted and submitted to the AER with charts and graphs recognized for the interpretation of a minifrac.
- It should be noted that either surface or bottomhole pressure-gauge data is acceptable for the minifrac. If using surface pressure gauges, only incompressible fluids such as water should be used. The calculated bottomhole pressure requires the correct density of the fluid injected. It is also critical that the well does not go on vacuum (hydrostatic pressure remains less than the reservoir pressure).
- The pressure data and results are submitted in the TRG.PAS file. The various data entries also include pre-closure geomechanical properties.
- Unlike other well tests (buildups and fall-offs), the minifrac will not fulfil initial pressure requirements if the final fall-off pressure is declining at 2 kPa/hr in the last six hours of the test. An interpretation is still required with the appropriate charts and graphs.

5 Special Testing Situations

Listed below are examples of situations where special testing may be required by the AER. The need for special testing may be determined through the AER’s application and approval process. However, the AER also reserves the right to require special testing where it considers it appropriate and reasonable to do so. Special testing would usually be a temporary increase in the number of tests and may involve specific procedures. However, in some cases, where there are environmental concerns, reduced testing and more operational restrictions may apply.

- Pool definition and development
  - reserves assignment
  - enhanced recovery evaluation
  - equity issues
  - well spacing
- Facilities approval
- Production rate controls
  - conservation concerns
  - equity issues
  - concurrent production
  - off-target wells
- Anticipated enhanced recovery schemes
  - oil pools above the bubble point
  - retrograde gas pools (above the dew point)
- Operating enhanced recovery schemes
  - gas cycling
  - solvent floods
  - immiscible gas floods
  - CO_2 and N_2 floods
  - polymer floods
  - waterfloods
- Enhanced recovery schemes
  - representation in pattern floods
  - representation in areas of concern (pressures below/near minimum operating pressure, high voidage)
- Other gas or water injection circumstances that may require more extensive testing
  - gas storage schemes
  - acid gas disposal schemes

  - waste fluid disposal
- Wellbore configurations
  - multilateral wells
  - dual completions
- Environmental concerns
  - safety
  - odours, noise, visual
  - flaring sour gas
- Oil sands
  - equity issues (gas/bitumen and offset oil sands lease holders)
  - mini-frac tests
- Special requirements/relaxation that has been granted following application

6 Compliance Assurance

The AER posts the following files weekly on its website (aer.ca > Providing Information > Data and Reports > Activity and Data > Well Testing Schedules):

- A list of all wells for which initial pressure, production tests, or fluid analysis has not been received, including the following:
  - licensee
  - UWI
  - notice date
  - due date
  - interval top
  - interval base
  - type of test required (initial pressure, production tests, or fluid analysis)
  - well licence number
- The annual survey schedules for oil and gas pools, which includes the following:
  - field and pool names and codes
  - coordinating operators

- survey frequency
- year survey due
- status (fulfilled, outstanding, partially fulfilled, etc.)

Information on initial and annual schedule survey requirements and the current status are available on the well testing section of the AER website.

6.1 Exemptions, Waivers, and Extensions

37) Requests for exemptions and waivers will be considered and must include detailed rationale and supporting documentation. Extensions will also be considered and will be approved on a case-by-case basis. All requests must be made before the deadline of the test in question. Missing the deadline may result in fees being assessed (see section 6.2). Requesting an extension after the deadline has passed will not change or defer a fee assessment.

6.2 Fees

Part 17 of the *OGCR* gives a schedule of fees. A licensee who fails to fulfil or submit a test by the AER filing deadline may receive an invoice for fees.

38) If a licensee wants to appeal an invoice, the AER must receive the request within 15 calendar days of the invoice date. The licensee should send the request to the AER by email to WellTest-Helpline@aer.ca.

The AER will notify the submitting licensee with the results of the review in writing within 10 calendar days of receiving it. If the request is granted, the AER will issue a refund or a credit note.

7 Measurement

This section provides a general discussion of certain practices to be considered in the running and maintenance of pressure measurement devices.

7.1 Gauge Information

- A gauge should be chosen so that the expected maximum value of the pressure to be measured is between 60 and 90 per cent of the gauge's rated pressure range.
- Gauges should be run in tandem to track the performance of both gauges and improve the reliability of the measurements. The differences in pressure and temperature between the two gauges should always be compared.
- When the gauge is returned to the surface, it should be set at the depth reference elevations again, at the top of the casing flange where the wireline counter was initially zeroed. This gives

a check on the accuracy of the depth measuring device. The discrepancy in counter readings at this point should not be substantially greater than indicated in the following table (in metres):

Discrepancy	0.3	0.6	1.2	2.1	4.2	7.5
Run depth	600	1200	1800	2400	3000	3600

- Where a greater discrepancy is observed, any conditions that may have caused slip and elastic deformation of the wireline should be reported.
- When gauges cannot be run down to the midpoint of the producing interval, the gauges should be run as low in the well as is safely possible. Under such conditions, the determination of the wellbore gradient at run depth is critical to the extrapolation of run-depth pressure to bottomhole pressure (at midpoint of perforation). Making stops at 30 metre intervals over the last 150 metres can help to get an accurate gradient. However, be sure the gradient you use for this extrapolation makes sense (e.g., if the gauges have not encountered fluid in the wellbore of an oil well, it may not be appropriate to assume a gas gradient to MPP).

7.2 Surface Pressure Readings

The casing and tubing pressures should always be read with a recently calibrated pressure gauge and recorded. The deadweight testers must be calibrated in accordance with section 11.110 of the *OGCR*.

7.3 Gauge Calibrations

In order to maintain accuracy and a comparative baseline in the measurement of subsurface pressures, section 11.110 of the *OGCR* requires that all gauges be calibrated annually. Licensees and operators are referred to the manufacturers' manuals for assistance in understanding the details of calibrations.

39) The service companies are required to maintain adequate calibration history on each gauge and be prepared to submit this data to the AER upon request.

40) The date of last calibration is required on every pressure test report.

7.3.1 Calibration of Permanent Gauges

In instances where a permanent gauge is installed downhole, the three-month calibration requirement defeats the purpose of a permanent gauge. These gauges can provide good data. However, problems are often experienced over time if a maintenance program is not followed, with periodic checks to ensure the ongoing accuracy of the gauge.

41) When a procedure is planned that requires pulling a permanent gauge, the duty holder must take that opportunity to calibrate the gauge.

Further information on maintenance of these gauges can be obtained from their respective manufacturers.

7.3.2 Special Calibration Notes

The following comments are offered as further clarification of AER's policy with regard to pressure-gauge calibration:

- It is desirable to calibrate a gauge in, as nearly as possible, the same conditions as prevail in the field.
- At least two sets of readings should be obtained for each calibration. If consistency between the two is not evident, the gauge should be closely examined for damage.
- Sets of calibration steps should be spread out across the chart so that any damage to the chart carrier will become apparent.

Appendix A WTC PAS File Submission Formats, Business Rules, and Implications for Noncompliance

A1 Background

The AER needs to ensure that the quality and usefulness of the data that it requires is maintained. Industry has previously voiced concerns about the quality of well tests submitted to the AER, the inconsistency in engineering practices used to meet testing and submission requirements, and the need for improved enforcement of such requirements.

The discussion in this appendix addresses a number of areas where well testing often fails to meet the intent of the requirements. The PAS file formats that must be used for all well test data submission covered by this directive are available on the AER website by following the links at the end of this appendix.

A2 General Well Testing References

This directive cites AER *Directive 034* and *Directive 005* in many places for the accepted engineering practices to follow when designing, conducting, and interpreting gas and oil well deliverability and subsurface pressure tests.

Industry is reminded that these guides continue to be the main technical documents for testing procedures when conducting AER-required well tests, including the calculation of subsurface pressure measurements using fluid-level recorders.

A3 Multipoint Deliverability Testing

Deliverability tests are left to the licensee or operator to design and conduct in accordance with *Directive 034*.

The AER recognizes that there may be instances where the data obtained from conducting gas well deliverability tests on new wells might be of limited value in relationship to the productivity of those wells or the stage of development and depletion of the reservoirs in which they are completed.

Industry must be proactive in applying for well testing relaxations or exemptions if deemed reasonable.

A proactive view to an identified need for well test data can be very effective and cost efficient rather than doing the bare minimum of providing a test that is incomplete, inaccurate, and of no value just to meet an AER requirement.

A4 Inflow Performance Relationships for Flowing Oil Wells

There is no deliverability test requirement for oil wells, but where an Inflow Performance Relationship (IPR) is determined for an oil well, the test data and its interpretation must be filed with the AER, as directed by section 11.120(1) of the *OGCR*.

Because flowing oil well IPRs provide essential oil well flow capacity information, it is vital that these data be available for the public record. IPR or any other oil well test data and analysis must be submitted to the AER.

The WTC system accepts IPR data for oil wells both in PAS and image file format. IPR data taken but not submitted would place the licensee or operator in noncompliance.

A5 Well Fluid Analysis Requirements

Section 3.6 provides specific requirements for the collection and submission of fluid analyses, including both gases and liquids. Fluid analyses are particularly important, as they are the source of sour gas concentrations that are used in many initiatives and in business processes related to the public safety of Albertans.

The AER requires that samples of all fluids (gas, oil, bitumen, and water) be collected, analyzed, and submitted in accordance with the requirements stated in this directive, section 3.6, as well as in clause 11.070(2) of the *OGCR*. In particular, note that a gas analysis must be submitted to the AER within 90 days of placing a well on production for all wells that, when completed, are not within an existing pool as defined by an AER pool order. In addition, if a well produces both gas and condensate, a recombination analysis must be submitted.

The AER does not expect the submission of fluid analyses taken on a frequent basis (monthly) for metering/measurement calibrations for monthly production reporting volumes unless the composition of the reservoir fluids has changed. However, it is good practice to conduct and provide at least two fluid samples, which could provide a better compositional average than just one analysis.

A6 Current PAS File Formats

All companies are required to submit well test data electronically in the appropriate PAS formats. PAS files submitted for drillstem test, transient gauge and acoustic tests, and gradient tests require an attached image file to include plots, charts, graphs, and discussion. An image or PDF file can be attached to any PAS file to include dialogue/discussion or any information not covered in the PAS format, including the information listed below.

- Deliverability tests are to be submitted in TRG.PAS format
  - Operations and procedure summaries

  - Summary description, discussions, and conclusions
  - Gas well sandface and wellhead deliverability analysis and graphs
  - All theoretical parameters and calculations and any supplementary data and calculations related to a proper interpretation of the test
  - Daily rate table (i.e., gas, condensate, oil and water volumes and rates, tubing and casing pressures) of situations during in-line testing
- Production test data is to be submitted in PRD.PAS format
  - Fieldnotes and flowback data in PDF format
  - Any graphs pertinent to operations
  - Wellbore and completions schematics (for complex wellbore)
- Static gradient tests and 1-shot acoustic well sounder tests are to be submitted in GRD.PAS format
  - Pressure vs. depth chart
  - Wellbore and completion schematics (for complex wellbore)
- Transient gauge tests (buildups or fall-offs) and transient acoustic well sounder tests (buildups or fall-offs) are to be submitted in TRG.PAS format
  - Operations and procedures summaries
  - Summary description, discussions, and conclusions
  - Wellbore and completion schematics
  - Field charts and graphs
  - All theoretical parameters and calculations and any supplementary data and calculations related to the test
  - Parameters used to substantiate final results
  - All plots including pressure vs. time, log-log derivative, semilog, and other plots showing diagnostic and reservoir model results
  - Section 11.120(1)(a) of the *OGCR* requires that licensees submit to the AER the data and results of each bottomhole sample analysis or other pressure-volume-temperature analysis (PVT), in duplicate. PVT studies can be submitted by attaching a PDF of the report to the TRG.PAS file.

- Drillstem tests are to be submitted in DST.PAS format
  - Summary description, discussions, and conclusions
  - Drilling dimensions
  - Pressure/time charts
  - Tool diagrams, full blow descriptions with rates
  - Graphs indicating the pressure buildup or fall-off
  - All field charts, graphs, plots, and text pertinent to the test
- Gas analyses are to be submitted in GAN.PAS format
  - Laboratory report of detailed component breakdown or recombination analysis
- Oil analyses are to be submitted in OAN.PAS format
  - Laboratory report of detailed component breakdown or recombination analysis
- Water analyses are to be submitted in WAN.PAS format

Current PAS file formats spreadsheet with business rules and edits are available from the *Directive 040* webpage.

Appendix B Well Test Contact List

AER Website Links:

Well Test Capture System:

AER Home > System and Tools > Digital Data Submission (DDS) > Submissions > Well Test Data.

Annual Subsurface Pressure Survey Schedules and Outstanding Initial Pressure, Deliverability, DST, Gas and Fluid Analysis Listings:

AER Home > Providing Information: Data and Reports > Activity and Data > Well Testing Schedules

Contact Phone and Email:

All well testing enquiries, including initial or annual requirements, PAS file submission error tracking, questions, problems, or concerns:

WellTest-Helpline@aer.ca

403-355-5742 (well test help line)

Digital Data Submission system support, such as system error tracking, creating initial company accounts, or changing corporate administrator access:

ddsadministrator@aer.ca

403-297-8311 or 1-855-297-8311 (toll free, option 3 then 1)

Information Distribution Services:

InformationRequest@aer.ca

403-297-8311 or 1-855-297-8311 (toll free; option 0)

Appendix C Sample Letter for Coordinating Operators

(Date)

(Company Name and Address)

OR

To All Operators of the _____________ Pool

Dear Operators:

20XX Subsurface Pressure Survey Requirements

____ Pool

The Alberta Energy Regulator (AER) has designated ________________________________ (*company name*) the responsibility of coordinating pressure survey requirements for the above pool, as listed in the current annual survey schedule. In accordance with AER *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*, __________________ (*number*) wells must be surveyed this year.

To determine the best plan for this pool considering survey quality, areal coverage, and cost, we are requesting all pool operators to review their operations and submit possible candidates, acceptable methods and timing for surveying. We hope that this will enable us to gather quality data for reservoir evaluation and management at a reasonable cost while minimizing production losses.

Please contact the undersigned at ___________________ by __________ (*date)* with your information.

Yours truly,