CAPP

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

GUIDELINE

H_2S Release Rate Assessment and Audit Forms

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The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce more than 90 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues of about $100 billion a year. CAPP's mission is to enhance the economic sustainability of the Canadian upstream petroleum industry in a safe and environmentally and socially responsible manner, through constructive engagement and communication with governments, the public and stakeholders in the communities in which we operate.

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1 Introduction

The protection of the public through the development of safe drilling and well operation plans is the primary objective of the H_2S release rate determination process. Regulators in Western Canada mandate the preparation of an H_2S release rate before an application to drill a well can be submitted. H_2S release rates are prepared for drilling, completion and producing operations. They are used to determine the following:

- the emergency planning zone (EPZ) for each operation type,
- the classification of the well (i.e. critical [special] or non-critical [non-special]),
- the facility level designation for land-use setback requirements.

This document provides guidance for

- capturing offset H_2S concentration and AOF data,
- applying geological considerations to the vetting of the offset H_2S and AOF data,
- applying engineering adjustments to the offset AOF data.

Although the industry often uses the term “Absolute Open Flow” (AOF) in the context of gas wells, references to the term “AOF” in this document shall apply to both oil wells and gas wells, unless specific reference is made to the well type.

The original H_2S Release Rate Assessment Guidelines were published by CAPP in 1998. As with the original guidelines, the intent of this revised edition is to provide a methodology and standard for the industry to calculate the potential H_2S release rate of a well. Furthermore, the guidelines provide the industry with forms that facilitate the capture of appropriate data for assessing the H_2S release rate potential of a well, and provide a consistent format for the documentation and retention of data that is also helpful for the audit process.

Starting in 2010, a review of the guidelines was undertaken for the purpose of clarifying the requirements, streamlining the methodology, and updating the procedures in light of changes both in field operations and available information. Changes include:

- removal of maps that were intended to provide exemptions for wells that would not encounter H_2S concentrations above 500 ppm. (The industry is now required to determine the H_2S release rate potential for all wells, regardless of the H_2S concentration. Consequently, the maps no longer apply.),
- elaboration of search area requirements,
- removal of the outdated EPZ calculations and provision of guidance for using the ERCBH2S program for calculating the EPZ based on the maximum H_2S release rate as determined from the guidelines in this document,
- clarification of when net pay adjustments are necessary,
- streamlining of the calculation procedure,
- updates to horizontal well calculations to account for multiple stimulations,
- addition of commingling guidelines,

- inclusion of newer best-practice procedures that were not documented in the previous guidelines,
- addition of acid gas injection guidelines,
- addition of guidelines for producing wells (post-testing phase),
- alignment with Alberta ERCB regulations and British Columbia OGC regulations.

It is the user's responsibility to determine the appropriate level of analysis required for each specific application; note that the user should use sound engineering judgment and due diligence in the calculation decisions. More rigorous analysis, to ensure the most appropriate geological analogues are selected and the appropriate engineering adjustments have been applied, should be conducted for wells that meet the following criteria:

- the emergency planning zone includes residents or areas with high public usage,
- the well is located within 5.0 km of an urban density development (with 50 or more dwellings),
- the well is a critical or special sour well.

When conducting an H_2S release rate evaluation, the user of this guide is expected to make every effort to obtain all available information, including the operator's internal confidential or proprietary data. Regulators expect that the documentation package will be prepared under the supervision of a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) or other technical designation.

This document does not supplant any regulations designed for the protection of individuals such as those defined by Occupational Health and Safety and it does not address the mechanical integrity of components when subjected to H_2S.

2 Maximum H_2S Release Rate

2.1 Maximum H_2S Release Rate Determination

The following excerpt is from Directive 56.

The H_2S release rate for each potential zone that may contain H_2S gas is determined by multiplying the maximum H_2S content and AOF rate as determined by the geological and engineering review of the available data. The paired data points need not be from the same well. The sum of the release rates from each zone becomes the cumulative release rate for the drilling, completion/servicing, and suspended/producing release rate, as applicable to the project.

The H_2S release rate is expressed in units of m^3/s and can be calculated using Equation 2.1 as follows:

Equation 2.1

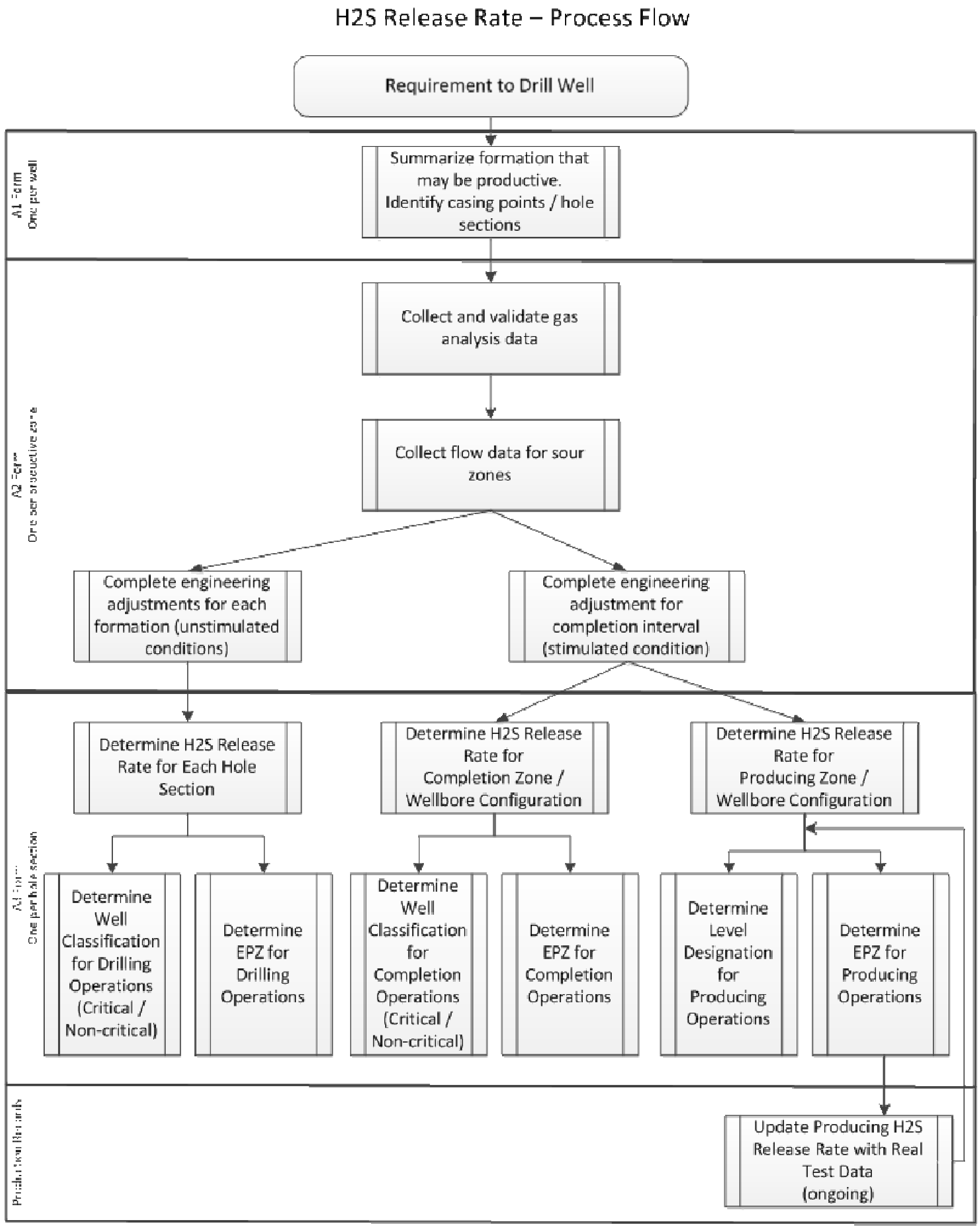
$$H_2S_{RR} = H_2S\% * 0.01 * \left(\frac{AOF}{86{,}400}\right)$$

Where

H_2S_{RR}	= <u>Surface</u> H_2S release rate (m^3/s)
$H_2S\%$	= Maximum H_2S concentration measured as a percentage of the total gas stream
AOF	= <u>Surface</u> absolute open flow potential (m^3/d)

The H_2S release rate is used as an input to calculate an EPZ. The EPZ is calculated using the ERCBH2S plume dispersion modelling software; nomographs, however, may also be used to determine an EPZ. The analyst is advised to be informed of the specific EPZ calculation requirements in each jurisdiction.

2.2 H_2S Release Rate Assessment



Note:

Examples of completed A1, A2 and A3 forms can be found in Appendix B.

2.3 Release Rate Cases

Release rate scenarios can be divided into three operational phases: drilling, completion/servicing and producing operations. A separate H_2S release rate estimate is needed to determine the emergency planning zone for each of the respective cases. H_2S release rate calculations are based on the wellhead (or surface) maximum flow rate. Adjustments to the maximum wellhead flow rate may be made to account for the changes in wellbore configuration including the size of wellbore tubulars, number of formations open to the wellbore, stimulation, etc.

2.3.1 Drilling Case

If multiple casing strings are cemented in place during a drilling operation, then separate release rates can be determined for each hole section (such as the intermediate hole or main hole). Only those sour formations that would be open to the wellbore, while drilling a given hole section, would be included in that section's separate release rate calculation.

An assessment of shallow formations (above the top of the Mannville) is generally not necessary if deeper zones will contribute to the H_2S release rate of the well, unless it is known that the shallower zones may significantly impact the H_2S release rate. Note, however, that the zones above the Mannville must be evaluated if zones deeper than the top of the Mannville will not be penetrated by the proposed well or if the deeper zones are determined to be sweet.

During drilling operations, the formations are considered to be unstimulated. Therefore, flow adjustments to a skin value of zero may be made to offset data from a stimulated zone. In cases where there is evidence of formation damage on the test data, the drilling AOF should be appropriately adjusted upward to reflect an undamaged zone. Vertical flow analysis may be conducted to further adjust from sandface AOF to surface AOF using the appropriate combination of open-hole sections of the wellbore and cased sections of the wellbore.

2.3.2 Completion/Servicing Case

H_2S release rates during completion or well servicing operations are usually based on stimulated flow from a single zone. Most often, the primary target represents the highest H_2S release rate potential. However, in some cases, a secondary zone may represent the highest stimulated H_2S release rate and should generally be referenced for the H_2S release rate estimate for completion operations. Exceptions may apply such as the situation wherein the operating company stipulates that the secondary horizon will not be completed during the proposed operations for reasons such as:

- The company does not have the rights to the formation.
- Another well in the same spacing unit is already producing.

- The company will amend the well licence and emergency response plan and revisit stakeholders such as affected residents before moving to the secondary horizon.

Vertical flow analysis may be conducted to further adjust from sandface AOF to surface AOF. If completion operations are restricted to “wellhead on” techniques (i.e. where the flow path will be confined inside the tubing string and the annulus is protected with a packer or other isolation device), then the wellhead AOF can be adjusted to account for the friction and hydrostatic pressure losses associated with the tubing diameter. If, however, the wellhead will not be in place (“wellhead off”) at any time after the formation is opened to flow into the wellbore, then the wellhead AOF shall be calculated based on flow up the wellbore using the configuration of the pipe cemented in the hole (i.e. casing, liner, open hole or any combination thereof).

When classifying a well and determining the emergency planning zone on the basis of “wellhead on” H_2S release rates, operators are advised to also determine the “wellhead off” H_2S release rate and incorporate appropriate design considerations that would correspond to the “wellhead off” H_2S release rate. For example, if the “wellhead on” H_2S release rate results in a noncritical well classification, but the “wellhead off” release rate would be a critical sour well, then the wellhead design and selection of casing and tubing materials should correspond to industry recommended practices for a critical sour well.

2.3.3 Producing Case

The same issues identified for completion H_2S release rate calculations apply to producing H_2S release rate calculations. However, the producing H_2S release rate estimate is also used to set the “level” designation of the well, which in turn defines the development restrictions surrounding the well. Companies must be careful to appropriately characterize the potential level status of the well for any completion configuration that may be contemplated. If a secondary horizon creates a larger emergency planning zone or a higher level designation, then reference to the secondary horizon is recommended in the pre-drilling or pre-completion estimates.

For wells completed with packers, the producing H_2S release rate can be estimated using the appropriate tubing string configuration. However, if a packer is not in place, the H_2S release rate should represent a combination of tubing flow and flow up the tubing/casing annulus.

Once the well has been tested, offset well references are no longer required and the H_2S release rate potential should be based on actual H_2S data and actual flow data. The H_2S release rate must be adjusted if either the actual H_2S concentration or the actual AOF creates a greater H_2S release rate value than originally used in the well licence. It is recommended that the operator adjusts the H_2S release rate if test data supports a lower H_2S release rate that results in any of the following:

- a material difference in emergency response planning requirements,

- a change in the category of the well (e.g. critical to non-critical, or sour to sweet),
- a change in the facility level status.

As a well produces, and reservoir pressure and reservoir conditions change, the producing AOF should be revised to reflect the current capability of the well.

2.3.4 Commingling

For any of the drilling, completion/servicing and producing cases, situations may arise where more than one sour formation is open to flow into the wellbore. Vertical flow analysis may be conducted to further adjust from sandface AOF estimates to surface AOF estimates. However, depending on the distribution of H_2S concentrations and flow capability of the potentially productive formations, the highest H_2S release rate potential may exist for scenarios that do not have all of the formations contributing. For example, a low-H_2S-concentration, high-rate formation may create enough downhole backpressure to back production out of a high-H_2S-concentration formation. The surface AOF is intended to represent the combination of contributing formations that generate the highest H_2S release rate potential.

If one or more of the offset analogue wells has only multi-zone AOF data, and the proposed well will be completed in only one of those zones, then the analogue AOF test may be adjusted as follows:

- For sandstones, the AOF of the proposed well may be calculated by multiplying the analogue AOF by the ratio of the net pay of the proposed well to the total net pay of the analogue well, provided the net pay adjustment is not used to reduce the AOF potential of the analogue.
- For carbonates, the analogue AOF should be applied without a net pay adjustment.

3 Data Sampling

3.1 Search Area

H_2S concentrations tend to vary, not only from well to well, but even within a single well from sample to sample. As such, it is important for the analyst to reference valid sample points that represent the maximum valid H_2S concentration. A better understanding of the geological analogue allows the analyst to restrict data to more representative samples and gain confidence in the quality of the analysis. In addition, as the number of data points in a representative sample set increase, the confidence of the data quality also increases.

Directive 56 recommends beginning with a three-by-three township study area to examine the well penetrations for the prospective zone, and to define the appropriate geological analogies from which representative H_2S and AOF samples can be obtained. However, although the regulatory agencies would generally like to see the geological trends and related mapping for this area, smaller review areas may be used if sufficient data can be obtained. Conversely, the best geological analogues may be more distant and outside the perimeter of a three-by-three-township grid. Similarly, larger review areas may be needed in sparsely drilled areas.

Both Directive 56 and these guidelines recommend a minimum of five representative analogous samples for each of the H_2S concentration and AOF. However, in sparsely drilled areas, the search area may become so large that it extends beyond any reasonable geological correlation, and only in this case would a data set of less than five samples be warranted.

For clarification, the recommendation is a minimum of five representative H_2S samples <u>for each zone</u> that may contain H_2S in the prospective well. Only the highest H_2S concentration may be selected from each potential zone in any one well.

Data points are representative if they cannot be discounted for technical reasons. If samples that have a higher H_2S concentration than the sample selected are discounted, then the applicant must support the decision with geological or engineering reasoning. Conversely, a potentially sour formation must not be excluded from a release rate calculation simply because there is no data to prove that the formation is sour. It should be excluded only if there is data to prove that it is sweet.

Analysts may find some samples show “trace” H_2S concentrations that are not quantified or show very low concentrations in areas that are typically considered to be sweet. These analyses may be the result of contamination of sampling cylinders or measurement devices or contamination of drilling or completion fluids. Operators who are confident that the area is sweet, may choose to license these wells as such, provided that all of the following conditions are met:

- All samples with H_2S concentrations either just have "trace" indications or show H_2S values at less than 50 ppm concentration
- Over 80% of the representative samples are indicated to be sweet (i.e. with no trace H_2S concentrations)
- The Operator believes the samples showing the trace concentrations are erroneous.

This document provides guidelines for such technical vetting of the data.

3.1.1 Wells To Be Drilled Inside an Existing Pool

- The data sampling may be restricted to the single pool.
- There is no minimum recommendation for the number of valid gas analysis samples for wells drilled inside of a pool. Generally, the highest valid H_2S sample from the pool will apply. However, if the proposed well is drilled in a larger pool where trends in the H_2S concentration are apparent, the analyst should use sufficient data in reasonable proximity to the well and, as a minimum, should consider the five closest wells.
- If gas analysis samples from the pool are poor in quality, then the data must be augmented with five valid samples from outside of the pool.
- If flow data samples from the existing pool are less than five, or are poor in quality, then the data set must be augmented with addition samples from outside of the pool.

3.1.2 Wells To Be Drilled Outside an Existing Pool:

- Generally, a minimum of five data samples is required; however, the search area should extend a minimum of five kilometers from the proposed well location, and all representative samples within the minimum search radius should be included in the analysis unless they can be discounted as invalid for geotechnical reasons. Furthermore, a minimum of three pools in the data set of five samples is preferable if reasonable analogues exist. However, fewer pools may be appropriate if it is geologically supported.
- The highest valid data point from a multi-well pool represents the true H_2S concentration of the pool and should be considered as one data sample. However, for search areas that intersect a portion of extensively developed pools, the data search for that pool may be restricted to the closest five valid samples.
- The analyst may consider accepting fewer data points for formations where geologically analogous data is limited, the data that is available is of good quality, and it is apparent that the formation in question is not a significant

contributor to the overall H_2S release rate of the well, or if the well is in a remote area and there are no site-specific emergency planning requirements.

3.2 H_2S Sampling Procedures and Data Quality

For accurate measurement, it is desirable to sample the gas during steady-state conditions. There are several techniques to measure the H_2S concentration in a gas sample. The measurement technique, the type of sample container, the time lapse between sample collection, and the actual measurement are all important. Usually it is best to measure the H_2S concentration immediately upon sampling, which favours on-site measurement techniques. Electronic meters tend to be the most accurate, but are not often used due to the cost, calibration requirements, etc. Common field practice has been to use on-site Tutwiler measurements for H_2S concentrations greater than 2 to 3%, and length of stain detection tubes are used for measurements where H_2S concentrations are less than 2 to 3%. For more details, refer to Appendix A, "H_2S Concentration Measurement Techniques."

H_2S will adsorb on metal surfaces and, therefore, the accuracy of the H_2S concentration in a gas sample may deteriorate depending on both the container metallurgy and the time lapse in sending the container for lab analysis. The order of accuracy, from highest to lowest, in sampling points for H_2S concentration follows.

1) Gas sample from a first stage separator or a recombined gas analysis

   H_2S concentration measurements from the gas of second- and third-stage separation are inaccurate and will be higher than the H_2S concentration of the first-stage separation. This is primarily because of the high solubility of H_2S, in comparison to most natural gases, in oil or water.

   H_2S samples from second-stage separators, or downstream of second-stage separators, should be used only if they are incorporated into a recombined analysis along with samples from the first-stage separator.

2) Gas from a wellhead sample or gas from meter runs close to the wellhead
3) Downhole gas samples taken after the well is on production
4) Open-hole samples taken from samplers, i.e. repeat formation testers (RFTs) or modular dynamic testers (MDTs): these samples are often contaminated with drilling fluid and yield low values of H_2S concentration

Solution gas samples may be excluded if the flow rate data is based on flow rates from the gas cap. Conversely, gas cap samples should not be considered if the flow rate data is based on liquid flow data.

4 Geologic and Engineering Analysis

This step provides instruction in the use of geologic analogues, data editing and wellbore design to further refine the cumulative H_2S release rate from Section 2.

4.1 Geologic Interpretation of Potentially Sour Formations

A well's geologic setting must be clearly defined to more accurately estimate potential H_2S release rates. Since the objective of the H_2S release rate calculation is to determine the potentially highest H_2S release rate from a well, all prospective formations and their corresponding H_2S concentrations must be assessed individually.

It may be appropriate to exclude a formation from a release rate determination if it is wet, non-porous, eroded, or absent due to non-deposition. Criteria for exclusion must be based on sound geologic and geophysical interpretation of features such as hydrocarbon/water contacts, sub-crop edges, depositional edges, and porosity distribution. For example, isolated reefs, which are located basin-ward of a shelf margin, often have reservoir characteristics and H_2S concentrations that differ from the more regionally extensive shelf margin. If geologic and seismic data indicate that a proposed well is going to encounter an isolated reef, then a database consisting of analogous isolated reefs should be used to determine the H_2S release rate. Data from the shelf margin should be excluded from the assessment.

Factors such as poor seismic data quality or ambiguous geologic interpretations may lead to uncertainty in the geologic assessment. In these circumstances, the operator must utilize their interpreted scenario that will err on the side of caution and yield a higher H_2S release rate.

4.2 Gas Cap Versus Oil Leg Flow Rates

Since H_2S is very soluble in hydrocarbon liquids, solution gas H_2S concentrations are generally higher than those found in an associated gas cap. Consequently, if solution gas H_2S concentrations were combined with a gas cap release rate, the resulting calculated release rate would be unrealistically high and unreasonable.

When there is uncertainty in the position of the gas/oil contact in the proposed well, then the H_2S release rate should be assessed for both the gas cap and the oil leg. The greater of the two release rates would be used in this case.

4.3 Wellbore Design Considerations and Slant Wells

A drilling program's wellbore design may have a direct impact on the well's potential H_2S release rate, since only those formations that are exposed to the open wellbore are included in the rate determination calculation. For example, if intermediate casing is run over any potential H_2S-bearing formation, the H_2S release rate calculation for formations penetrated below the casing shoe are summed separately from those formations above the shoe. Conversely, if an operator of a well receives a waiver for intermediate casing, a recalculation of the H_2S release rate for the entire open-hole section is required.

When planning a well, careful consideration should be given to selecting the depth of the surface and intermediate casing and also to determining the deepest possible H_2S-bearing formation to be tested. Adjusting the terminating formation to a deeper horizon after drilling has commenced may require a recalculation of the H_2S release rate and the initiation or modification of an emergency response plan.

Wellbores that penetrate potential H_2S-bearing formations at angles less than 30°C can be considered to be equivalent to a vertical well for release rate calculation purposes. See Section 5.4.2 for calculations for slant wells.

5 Engineering Adjustments

Section 5 provides guidance on the calculations necessary to adjust the maximum AOF from the analogue well to the proposed well, while accounting for differences between vertical, slant (>30ºC) and horizontal wells (>85ºC).

Some, or all, of the following adjustments may be applied to the analogue well data in order to appropriately model the expected maximum AOF rate from the proposed well.

- Calculate sandface AOF for analogue well at reservoir pressure existing at time of test.
- Adjust sandface AOF to expected reservoir pressure of proposed well.
- Incorporate appropriate adjustments for differences in the expected net pay of the proposed well and the net pay of the analogue well (refer to net pay adjustment guidelines).
- Adjust for differences between the skin in the analogue well and the expected skin for the proposed well for the drilling, completion or production cases. (Note: A mechanical skin of zero should be used for the drilling case.)
- For a proposed slant well or horizontal well, adjust analogue sandface AOF to account for difference in well type and contacted reservoir length.
- Adjust final calculated sandface AOF of proposed well to wellhead AOF.

The order in which the above sandface adjustments are made will not affect the result. However, the wellhead AOF adjustment should always be the final adjustment. Input/output analysis should be retained for audit purposes.

Note:

1) *Existing horizontal wells should be used as the primary analogues for proposed horizontal wells if five or more representative horizontal wells are available for reference. If fewer than five representative horizontal wells are available, then the data set should be supported with vertical well data. Furthermore, if vertical wells in the review area have higher unadjusted AOFs than any of the top five horizontal well AOFs, then those vertical wells should be included in the data set and the appropriate vertical-to-horizontal-well engineering adjustments should be applied.*
2) *All of the following equations are based on single-phase flow (either gas or oil as applicable). Use of an analogue that is based on two-phase flow may result in an underestimation of the AOF of the proposed well if single-phase flow is expected.*

5.1 Calculate AOF

5.1.1 Guideline for Application of Oil Equations

Oil wells may produce from reservoirs that are above or below the bubble point pressure. Reservoirs at a static pressure above the bubble point are undersaturated and do not have a gas cap. Conversely, reservoirs with a pressure below the bubble point pressure typically have a gas cap.

Wells that concurrently produce gas from the gas cap usually have relatively low oil rates because of the high mobility of gas in comparison to oil. Nonetheless, oil wells that cone gas can exhibit high gas rates. Because the H_2S release rate potential is a function of the maximum produced gas rate, it is important to analyze the gas flow rates (or gas/oil ratios) for each offsetting well rather than focusing on the oil flow data only. Assigning a single arbitrary gas/oil ratio to calculated oil rates will usually result in inappropriate gas rate estimates, as the gas/oil ratios will vary from well to well.

When analyzing the potential H_2S release rate of the proposed oil well, the analyst must indicate whether a gas cap may exist. Any well which may potentially encounter a gas cap (for example, during drilling operations) must incorporate an assessment of the gas flow capability of the gas cap when determining the H_2S release rate potential of the well. Conversely, if it can be established that the proposed well will not penetrate the gas cap, then flow rate calculations may be restricted to the solution gas rates of analogue wells producing from the oil leg. The applicable equations are presented in the remainder of Section 5 below.

Flowing or pumping pressure data at the sandface or wellhead is generally not publicly available. Therefore, it is difficult to estimate the maximum production potential of non-operated, analogue oil wells. Good engineering practice must therefore prevail to conservatively estimate the inflow pressure corresponding to the test oil rate. For example, an analyst may be familiar with an area and may know that wells typically produce with near “pumped off” conditions with 90% or more drawdown. In this case, the analyst may choose to cut the drawdown in half and use a 45% drawdown for the purpose of determining a conservative (or high-side) estimate of the maximum flow potential of each well. Using Vogel’s formula, the analyst would then estimate a maximum flow potential (using a 45% drawdown) that is 50% higher than maximum flow potential corresponding to a 90% drawdown.

5.1.2 AOF of Analogue Oil Wells — Undersaturated Reservoirs (No Gas Cap)

The maximum inflow performance rate for oil wells in undersaturated reservoirs can be determined if the reservoir pressure, bubble point pressure, test rate, and flowing pressure are known. The following sets of equations can be used to predict the maximum inflow rate.

Equation 5.1

for test conditions above the bubble point
$q_b = q_t (P_r - P_{bp})/(P_r - P_{wf})$

Equation 5.2

the relationship at the bubble point
$q_b/q_c = 1.8 (P_r - P_{bp})/P_{bp}$

Equation 5.3

for test conditions below the bubble point
$q_t/q_c = 1.8 (P_r/P_{bp}) - 0.8 - 0.2 (P_{wf}/P_{bp}) - 0.8 (P_{wf}/P_{bp})^2$

Equation 5.4

for determination of AOF_{oil}
$AOF_{oil} = q_b + q_c$

Where

P_r = static reservoir pressure

P_{bp} = bubble point pressure

P_{wf} = flowing wellbore pressure at test rate q_t

q_t = test rate

q_b = theoretical flow rate at a flowing wellbore pressure equal to the bubble point pressure

q_c = incremental flow rate, in addition to q_b, that occurs at 100% drawdown

AOF_{oil} = maximum flow rate at 100% drawdown

If the production test rate is above the bubble point pressure, solve for AOF_{oil} using Equation 5.1, Equation 5.2 and Equation 5.4 in sequence. If the production test rate is below the bubble point pressure, solve for AOF_{oil} using Equation 5.3, Equation 5.2 and Equation 5.4 in sequence.

5.1.3 AOF of Analogue Oil Wells – Saturated Reservoirs (Gas Cap)

For saturated reservoirs with pressures equal to or below the bubble point, the above equations can be simplified using Vogel's relationship for a solution gas reservoir in one equation as follows:

Equation 5.5

$$AOF_{oil} = \frac{q_t}{1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2}$$

Note:

1) *Vogel's equation is applicable to wells with zero skin.*
2) *For very high gas/oil ratios (GOR >2000 m^3/m^3) or production tests that are conducted in the gas cap, use the equation in section 5.1.4 for AOF calculations.*

5.1.4 Sandface AOF of Analogue Gas Wells and High GOR Oil Wells

For gas wells or oil wells with GORs above 2000 m^3/m^3, a test on an analogue well may have flowing and shut-in pressures recorded at either the sandface or the wellhead. If the pressures are recorded at the sandface, Equation 5.6 may be used directly to calculate the sandface AOF. If the pressures were recorded at the wellhead, a number of correlations (i.e. Cullender and Smith, Beggs and Brill, Hagedorn and Brown, etc.) are available in various software programs to first convert the wellhead pressures to sandface conditions.

Equation 5.6

$$AOF_{gas} = \frac{Gas\ Test\ Rate * \left(P_r^2\right)^n}{\left(P_r^2 - P_{wf}^2\right)^n}$$

Where

AOF_{gas} = absolute open flow potential for gas at sandface conditions

P_r = reservoir pressure

P_{wf} = flowing bottomhole pressure

n = inverse slope of AOF plot

An "n" value of 1.0 should be used in Equation 5.6 unless a multi-point AOF test analysis is available which supports the justification for a lower value of "n."

Equation 5.6 is applicable to any analogue well, regardless of whether it is vertical, slant or horizontal.

Note: The pressure-squared formulation in Equation 5.6 is generally applicable for formation pressures less than 14,000 kPa. For higher pressured reservoirs, it is recommended that pseudo-pressure be substituted for pressure-squared in Equation 5.6 (see Section 5.7.2).

5.2 Adjustment for Reservoir Pressure

Well test data from well analogues may be based on different pressures than the pressure expected in a proposed well. This section provides guidelines for pressure adjustments. For wells that have multiple tests from the same interval, the test that most closely approximates the expected pressure should be used as the reference test for that analogue well.

5.2.1 Oil Wells

If the reservoir pressure of the proposed well is different from the reservoir pressure of the analogue well, then an adjustment should be made to AOF_{oil} as per Equation 5.7.

Equation 5.7

$$AOF_{oil\ (proposed)} = \left(\frac{P_{r\ (proposed)}}{P_{r\ (analog)}}\right) AOF_{oil\ (analog)}$$

Where

AOF$_{oil\ (proposed)}$ = maximum oil rate of proposed well

AOF$_{oil\ (analogue)}$ = maximum oil rate of proposed well

P$_{r\ (proposed)}$ = expected reservoir pressure of proposed well

P$_{r\ (analogue)}$ = reservoir pressure at which AOF$_{oil\ (analogue)}$ was calculated for the analogue well

5.2.2 Gas Wells

If the reservoir pressure of the proposed well is different from the analogue well's reservoir pressure, then an adjustment can be made to the inflow. One method is shown below:

Equation 5.8

$$AOF_{proposed} = AOF_{analog}\left(\frac{z_{analog}}{z_{proposed}}\right)\left(\frac{\mu_{analog}}{\mu_{proposed}}\right)\left(\frac{\left(P_{r\ (proposed)}\right)^{2n}}{\left(P_{r\ (analog)}\right)^{2n}}\right)$$

Where

AOF$_{proposed}$ = adjusted AOF potential at the proposed reservoir conditions

AOF$_{analogue}$ = AOF of analogue well

$z_{analogue}$ = gas supercompressibility – analogue well

$z_{proposed}$ = gas supercompressibility – proposed well

$\mu_{analogue}$ = gas viscosity – analogue well

$\mu_{proposed}$ = gas viscosity – proposed well

P$_{r\ (proposed)}$ = reservoir pressure expected in proposed well

P$_{r\ (analogue)}$ = original reservoir pressure

n = inverse slope of AOF plot

Note:

1) assume n = 1.0 unless the reference AOF data is based on a lower n value

5.3 Adjustment to Zero Skin

The following equation is used to adjust an analogue well AOF with a positive or negative skin to an AOF with a skin value of zero.

Equation 5.9

$$AOF_{zero\ skin} = \left(\frac{\ln\left(\frac{r_e}{r_w} \right)_{ana\log} + s_{ana\log}}{\ln\left(\frac{r_e}{r_w} \right)_{ana\log}} \right) AOF_{ana\log}$$

Where

$AOF_{zero\ skin}$ = AOF of the analogue well adjusted for zero skin conditions

$AOF_{analogue}$ = AOF of the analogue well (with skin)

r_e = drainage radius

r_w = wellbore radius

$s_{analogue}$ = skin in the analogue well

5.4 Adjustment for Net Pay or Contacted Reservoir Length

Companies are expected to provide regional mapping that demonstrates the geological trends for the primary and secondary zones that will be identified as the “well purpose” on Schedule 4 (for Alberta) of the well licence application. Secondary zones on the geologist’s prognosis may be low probability or low productivity zones that are not necessarily supported with detailed mapping. Well deliverability is a function of the permeability height. Because permeability information is not available in an undrilled well, and often not analyzed in producing wells, it is impractical to make permeability height adjustments. For certain formation types, it may be reasonable to adjust flow rate expectations as a function of the net pay. The net pay discussion below applies to the “well purpose” formations.

1) Net pay maps should be supported with interpretation including log cutoffs for shale content, porosity and water saturation.
2) Generally, net pay adjustments should be made to sandstone formations.
3) Net pay adjustments in carbonates are generally not appropriate as well deliverability is often unrelated to the net pay.
4) Net pay adjustments in thick shales or tight gas reservoirs are often not appropriate as deliverability is generally a function of fracture height, from stimulation treatments, or a function of natural fracturing. Generally, the fracture treatments in these thick reservoirs will not grow to the full height of the reservoir.

If formations that are not identified as “well purpose” formations contribute more than 20% of the release rate, it is recommended that the net pay guidelines described above be applied to these formations.

5.4.1 Vertical Wells

For sandstone formations, the deliverability of the well is a function of the net pay in vertical wells. If the analogue well has a different net pay (h) than the proposed well, then the AOF should be adjusted (either increased or decreased) by the ratio of the net pay values:

Equation 5.10

$$AOF_{proposed} = \left(\frac{h_{proposed}}{h_{ana\log}} \right) AOF_{ana\log}$$

Where

$AOF_{proposed}$ = AOF of the proposed well adjusted to the expect net pay

$AOF_{analogue}$ = AOF of the analogue well

$h_{proposed}$ = net pay of the proposed well

$h_{analogue}$ = net pay of the analogue well

For vertical wells in carbonate formations, well deliverability is often not a function of net pay. Wells with thinner pay sections may produce at greater rates due to fracturing, vugular porosity etc. Net pay adjustment, therefore, is not recommended for carbonates. In particular, Equation 5.10 should not be used to reduce the AOF of a proposed carbonate well. The analyst can choose to use Equation 5.10 to increase the AOF of the proposed well if deemed prudent.

5.5 Adjustment for Contacted Reservoir Length

5.5.1 Slant Wells

By having a reservoir exposure greater than a vertical well, a slant well will result in a higher inflow. However, this increase in inflow is not directly proportional to the increased contacted reservoir length. The approach is appropriate for deviation angles between 30°C and 85°C. For wells with an inclination less than 30°C in reference to the bedding plane, the calculated pseudo-skin is <-0.5 and can be ignored. Wells with an inclination greater than 85°C in reference to the bedding plane can be treated as horizontal wells.

This section details the pseudo-skin approach to adjust the AOF of an analogue vertical well to a proposed slant well. If the analogue well is also a slant well, the analogue AOF can generally be used directly with no further adjustment (given that the difference in inclination between the two wells is minimal).

Mathematically, the production from a slant well is equivalent to that of a vertical well with a pseudo-skin (s_{pseudo}) as shown in Equation 5.11 and Equation 5.12.

Equation 5.11

$$AOF_{deviated} = \left(\frac{\ln\left(r_e / r_w \right)_{vertical} + 0}{\ln\left(r_e / r_w \right)_{deviated} + s_{pseudo}} \right) \times AOF_{vertical}$$

Where

$AOF_{deviated}$	= AOF of proposed (deviated) well (m^3/d)
$AOF_{vertical}$	= AOF of analogue (vertical) well (m^3/d)
r_e	= drainage radius for vertical and deviated wells (m)
r_w	= wellbore radius for vertical and deviated wells (m)
s_{pseudo}	= skin effect due to wellbore deviation

and

Equation 5.12

$$S_{pseudo} = \ln\left[\frac{4r_w}{LaY} \right] + \frac{h}{YL} * \ln\left[\frac{2a\sqrt{LhY}}{4r_w \, (Y+1)/Y} \right]$$

where

a	= $\sqrt{kh/kv}$ (anisotropy ratio)
h	= reservoir thickness (m)
k_h	= permeability in the horizontal direction (md)
k_v	= permeability in the vertical direction (md)
L	= producing length of the well (m)
r_w	= wellbore radius of deviated well (m)
Y	= $\sqrt{\frac{k_v}{k_h} + \frac{\left(\frac{h}{L} \right)^2 (k_v - k_h)}{k_h}}$

Note:

1) *Rogers and Economides (1996), Besson (1990), and Chen, et al. (1995) outline the details of this approach. Equation 5.12 is referenced from Besson and is applicable for slanted wellbore that fully penetrates the target formation.*

5.5.2 Horizontal Wells with Matrix Flow

Mathematically, the matrix flow production from a horizontal well is equivalent to that of a vertical well stimulated by an infinite conductivity fracture with a half-length equal to half the length of the horizontal section (i.e. $x_f = L/2$). Therefore, the mechanical skin value can be replaced with s_{pseudo} as shown in Equation 5.13.

Equation 5.13

$$AOF_{horizontal} = \left(\frac{\ln\left(r_{ev} / r_{wv} \right)_{vertical} + 0}{\ln\left(r_{eh} / r_{wh} \right)_{horizontal} + s_{pseudo}} \right) \times AOF_{vertical}$$

Where

$AOF_{horizontal}$ = AOF of proposed (horizontal) well (m^3/d)

$AOF_{vertical}$ = AOF of analogue (vertical) well (m^3/d)

r_{ev} = drainage radius of vertical well (m)

r_{eh} = drainage radius of horizontal well (= ½ L + r_{ev})

r_{wv} = wellbore radius of vertical well (m)

r_{wh} = wellbore radius of horizontal well (m)

s_{pseudo} = skin effect due to horizontal wellbore

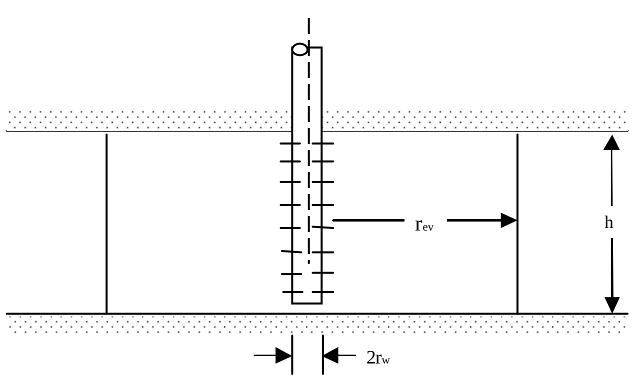


Figure 1: Vertical well drainage area

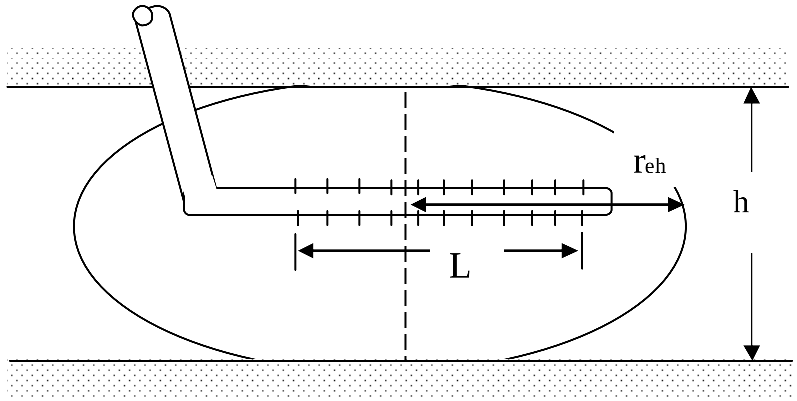


Figure 2: Horizontal well drainage area

Equation 5.13 is only applicable for comparing the productivity of a vertical well that is undamaged/unstimulated to the corresponding productivity index of a horizontal well. Hence $s_{analogue}$ is zero in Equation 5.13.

s_{pseudo} can be determined by the following equation developed by Besson (1990).

Equation 5.14

$$s = \ln\left(\frac{4r_{wh}}{L}\right) + \frac{ah}{L}\ln\left(\frac{2ah}{2\pi r_{wh}(1+a)Cos\left(\frac{\pi e}{h}\right)}\right) - \left(\frac{ah}{L}\right)^2\left(0.167 + 2\left(\frac{e}{h}\right)^2\right)$$

Where

r_{wh} = wellbore radius of the horizontal well

a = $\sqrt{kh/kv}$ (anisotropy ratio)

e = eccentricity of the horizontal well (m) (vertical distance between middle of the reservoir and well axis; it is recommended not to use e values greater than 0.25h)

h = reservoir thickness (m)

k_h = permeability in the horizontal direction (md)

k_v = permeability in the vertical direction (md)

L = producing length of the well (m)

Note:

1) *There are a number of variations on Equation 5.14 with the differences being attributable to how the drainage area of the horizontal well is modelled (i.e. circular, ellipsoid, rectangle with semi-circular ends.). Equation 5.14 was proposed by Besson (1990). Other variations have been proposed by Giger (1983); Giger, Reiss, and Jourdan (1984); Renard and Dupuy (1990); and Joshi (1991). The differences between the equations, on the resulting calculated rate, are minor.*

2) *In most cases, a horizontal well will be targeted along the centre axis and the eccentricity (e) will be zero.*

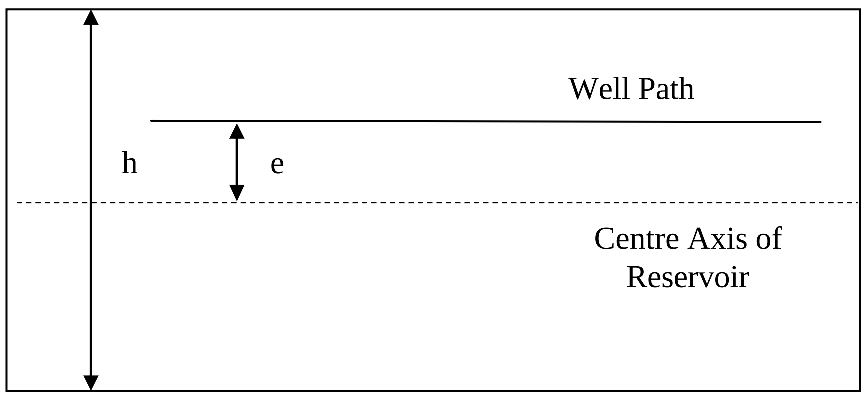


Figure 3: Eccentricity Diagram

3) *For situations in which the horizontal length is much greater than the pay thickness (i.e. L > 100 times h), and eccentricity is zero, the second and third terms in Equation 5.14 become insignificantly small, and Equation 5.14 reduces to:*

Equation 5.15

$$s = \ln\left[4r_w / L\right]$$

and Equation 5.14 reduces to:

Equation 5.16

$$AOF_{horizontal} = \left(\frac{\ln\left(r_{ev} / r_{wv}\right)_{vertical}}{\ln\left(4r_{eh} / L\right)_{horizontal}} \right) AOF_{vertical}$$

4) *If the proposed well is to be an unfrac'd horizontal well, and if the analogue is also an unfrac'd horizontal well, then the AOF of the proposed well may*

simply be calculated as the ratio of the length of the proposed well over the length of the analogue well multiplied by the AOF of the analogue well.

5.5.3 Horizontal Wells with Multiple Stimulations

Horizontal wells in low permeability formations (including shales) are often completed with multi-stage fracture stimulations spaced along the horizontal portion of the wellbore.

Generally the prestimulation rates are very low in shales and tight-gas reservoirs. Available prestimulation test data should be used for the drilling case even to the point that a value of zero can be used if supported by historical analogue data. In absence of supporting data, the unstimulated case can be estimated by determining the unstimulated vertical well flow capability and applying horizontal well adjustments. The unstimulated vertical well capability may be estimated using the following steps:

1) dividing the stimulated horizontal well AOF by the number of frac stages, and
2) adjusting the stimulated skin to zero. (Note: The use of fracture stimulated skin values of -7 to -8 is appropriate for tight reservoirs. Use Equation 5.9 to adjust to zero skin.)

Equations 5.13 and 5.14 would then be applied to the unstimulated vertical well flow rate to determine the unstimulated horizontal well capability.

Good comparative data now exists to conclude that the post-stimulation productivity of stimulated horizontal wells is directly proportional to the number of fracs. Generally public databases do not include the fracture stimulation details; however, it is reasonable to assume that the proposed horizontal well will be stimulated using similar procedures and the resulting AOF will be proportional to the ratio of the horizontal length of the analogue well to that of the proposed well (i.e. frac spacing will be similar).

For such wells, the completion/production AOF can be estimated by multiplying the AOF of the analogue vertical well by the number of fracs proposed in the horizontal well. If the analogue well is also a horizontal well with multiple fracs, then the AOF of the proposed well can be calculated as the ratio of the number of fracs in the proposed well to the number of fracs in the analogue well. Note that horizontal length does not enter directly into this calculation, other than to predict the number of fracs that may be staged in the proposed well.

5.6 Adjustment for Stimulation of Wells

The AOF of a well should be reflective of whether it has been stimulated or not. If stimulated data is being referenced to determine unstimulated flow capability, then the data should be adjusted to reflect zero skin. Alternatively, if unstimulated data is referenced to estimate the flow capability of a proposed well that will be stimulated, the impact of the stimulation must be reflected in the estimated AOF capability.

Equation 5.17

$$AOF_{proposed} = \left(\frac{\ln\left(r_{e\,(ana\log\,)} / r_{w\,(ana\log\,)}\right) + s_{ana\log}}{\ln\left(r_{e\,(propose\,d)} / r_{w\,(propose\,d)}\right) + s_{pseudo}} \right) \times AOF_{ana\log}$$

Where

$AOF_{analogue}$ = absolute open flow of the analogue or reference well

$AOF_{proposed}$ = absolute open flow of the proposed well with the skin adjustment

$r_{e\ (analogue)}$ = drainage radius of the analogue well

$r_{e\ (proposed)}$ = drainage radius of the proposed well with the skin adjustment

$r_{w\ (analogue)}$ = wellbore radius of the analogue well

$r_{w\ (proposed)}$ = wellbore radius of the proposed well with the skin adjustment

$s_{proposed}$ = 0 for the drilling case (both overbalanced and underbalanced)

For stimulated wells, adjustments should be based on skin data from well test analysis when available. If skin data is not available, the following rules of thumb may be applied:

-1 for the matrix sandstone acidizing in both the completion/servicing and production cases,

-2 for matrix carbonate acidizing in both the completion/servicing and production cases,

-4 for fracture stimulations in both sandstone and carbonates in completion/servicing and production cases (higher skin values or up to -8 may be appropriate for fracture stimulation of shales and other tight-gas reservoirs).

5.7 Adjustment From Sandface AOF to Wellhead AOF

After applying some, or all of the above adjustments for gas wells, the sandface AOF of the proposed well will have been calculated. The last step is to then calculate the corresponding surface AOF by overlaying a tubing performance curve on top of the sandface AOF curve. The process of modelling of tubing performance curves, and the resulting wellhead AOF, is most often conducted using nodal analysis software that calculates the pressure differences resulting from hydrostatic and friction pressure losses between the sandface and wellhead. The choice of the appropriate model should be based on the type of fluid expected (oil, dry gas, gas with water, etc.). The user must have sufficient knowledge of the software used and its limitations.

- For the drilling case, calculate the wellhead AOF based on flow up the casing/open hole using the configuration of the well when the maximum flow rate is expected.

- For the completion/servicing case when the wellhead is not installed, calculate the wellhead AOF based on flow up casing, using the casing configuration of the well. If the wellhead is installed, the same adjustments described for the producing case below may be applied.
- For the production case, calculate the wellhead AOF based on flow as follows:
  - Where the wellhead is installed and there is a packer in place, flow up tubing using the tubing configuration of the well when the maximum flow rate is expected.
  - Where a packer is not in place, combine both tubing and annulus flow rates to determine the maximum expected flow rate.

Adjustments from sandface AOF conditions to wellhead AOF conditions are recommended if the adjustment would result in any of the following:

- a significant reduction in the emergency planning requirements,
- a reduction in the well category used for well licensing requirements (for example from a critical to a non-critical designation),
- a reduction in the level designation of the well (which is based on the producing case and is used for setback restrictions).

Note: In order to simulate the maximum wellhead AOF, do not include any water or drilling mud in the wellbore pressure profile calculations. It is appropriate to incorporate condensate if the condensate/gas ratio is known from offset well data, and provided that this ratio is corrected to the reservoir conditions for the proposed well.

5.8 Acid Gas Injection Wells

While the same guidelines described above apply to acid gas injection wells, particular attention is required due to the potential for critically high H_2S release rates under blowout conditions. Acid gases (particularly those with high H_2S concentration) may be in either the gaseous or dense phases at reservoir conditions (a liquid phase is also possible, but unlikely, and hence is not addressed here). In the event of a blowout, dense phase fluids will undergo a phase change either in the reservoir or in the wellbore.

This section first addresses the sandface AOF calculation and then addresses the tubing performance curve calculation. The combination of the two calculations yields the wellhead AOF.

For reference, Equation 5.8 is repeated below as Equation 5.18

Equation 5.18

$$AOF_{proposed} = AOF_{analog}\left(\frac{z_{analog}}{z_{proposed}}\right)\left(\frac{\mu_{analog}}{\mu_{proposed}}\right)\left(\frac{\left(P_{r\,(proposed)}\right)^{2n}}{\left(P_{r\,(analog)}\right)^{2n}}\right)$$

Where

$AOF_{proposed}$	= adjusted AOF potential at the proposed reservoir conditions
$AOF_{analogue}$	= AOF of analogue well
$z_{analogue}$	= gas supercompressibility – analogue well
$z_{proposed}$	= gas supercompressibility – proposed well
$\mu_{analogue}$	= gas viscosity – analogue well
$\mu_{proposed}$	= gas viscosity – proposed well
$P_{r\ (proposed)}$	= reservoir pressure expected in proposed well
$P_{r\ (analogue)}$	= original reservoir pressure
n	= inverse slope of AOF plot

5.8.1 Gas Properties

The pressure-squared formulation of Equation 5.6 assumes that μ*z is constant for a given well/gas composition across the range of pressures. As discussed above, the assumption is generally valid for sweet gases, at pressures less than 14,000 kPa. For higher pressured reservoirs, it is recommended that pseudo-pressure be substituted for pressure-squared in Equation 5.6

For acid gases, particularly H_2S, the important observation is that while both the viscosity and supercompressibility each change much more significantly than sweet gases, the two factors vary in opposite directions such that the resulting μ*z value can be considered to be constant at pressures less than 14,000 kPa and reservoir temperatures above 60°C. Therefore, the pressure-squared formulation used in all equations to this point is also applicable for acid gases below 14,000 kPa and reservoir temperatures above 60°C.

5.8.2 Pseudo-Pressure

Above 14,000 kPa, for both sweet and acid gases, it is recommended that the pressure-squared formulation be replaced by pseudo-pressure. Pseudo-pressure rigorously accounts for the changes in viscosity and supercompressibility. Pseudo-pressure is defined as:

Equation 5.19

$$\psi(p) = 2\int_0^p \frac{p}{\mu Z}\, dp$$

and the Rawlins Schellhardt AOF equation, in terms of pseudo-pressure, becomes:

Equation 5.20

$$q = C\,[\bullet_{(Pi)} - \bullet_{(Pwf)}]^n$$

It is recommended that pseudo-pressure be used for all acid gas calculations and for sweet gas calculations above 14 MPa. A number of software programs are capable of calculating pseudo-pressure when plotting AOFs.

5.8.3 AOF

When the viscosity and supercompressibility factors are inserted into Equation 5.18 above, the adjusted sandface AOF will generally be less than the produced (sweet or slightly sour) gas situation due to higher μ*z values for acid gases. An example is shown in Figure 4 below; however, the reader is cautioned to run the calculations based on the PVT properties of the specific gas composition being investigated.

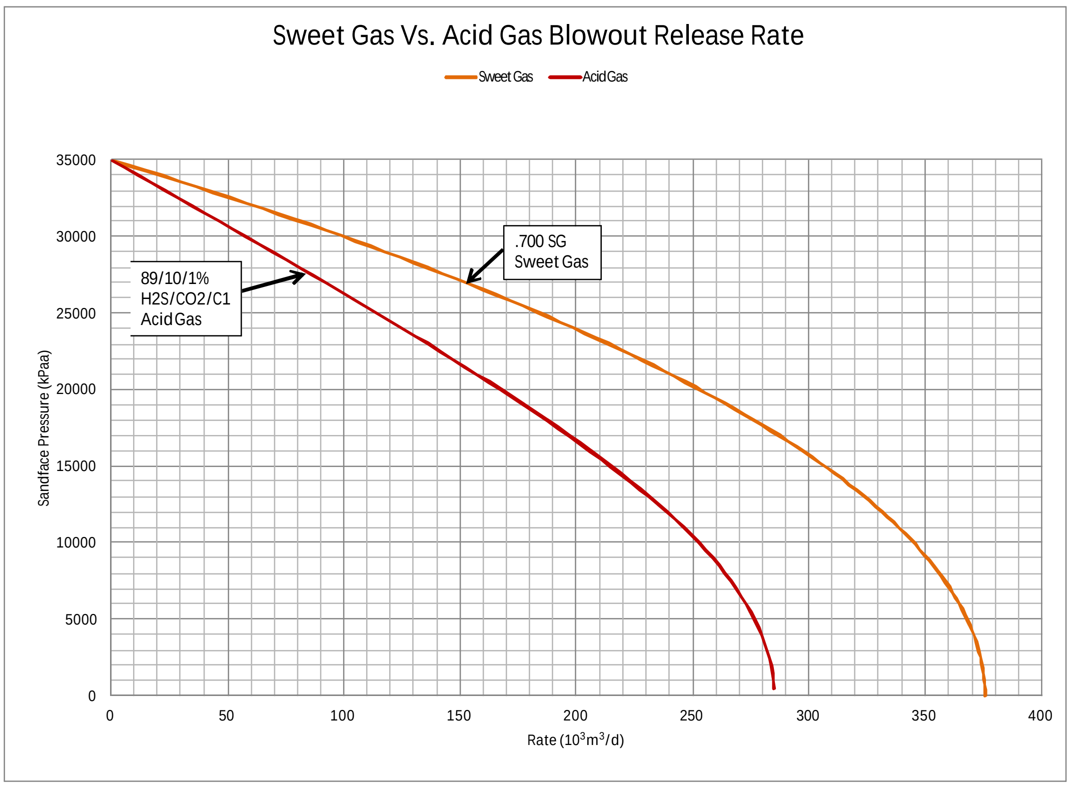


Figure 4 Sweet Gas Vs. Acid Gas Blowout Release Rate

Note that the calculations in Figure 4 range up to a maximum rate of 375 10^3m^3, which is the largest acid gas injection well in western Canada.

The maximum H_2S release rate should be calculated at the highest reservoir pressure expected over the life of the acid gas disposal well (typically at the end of the injection period).

5.8.4 Adjustments from Sandface AOF to Wellhead AOF

Section 5.6 above discusses the process of generating a tubing performance curve to adjust sandface AOF to wellhead AOF. Software programs typically require input values for the sandface temperature and surface temperature. A value of approximately 4°C can be assumed for a typical surface temperature and most software programs will use a linear temperature profile between the sandface and surface temperatures. However, the high flow rate during a blowout means that there is little time for the gas in the wellbore to equilibrate to the geothermal gradient; the process is closer to being adiabatic. The gas will be warmer than the geothermal gradient in the lower parts of the well but, under adiabatic expansion, will cool at low pressures near the wellhead. The high compressibility of acid gases (particularly H_2S) results in a significant cooling effect and the phenomenon is supported by reported instances of blowouts in which the released acid gas was well below 0°C.

For acid gases, the calculation of tubing performance curves based on adiabatic flow is recommended, especially in situations where dense phase acid gas may exist at the sandface. The calculations require software that employs equation-of-state modelling and accounts for complex changes in phase, viscosity, density and supercompressibility.

If the sandface flowing conditions are below the critical point for H_2S (i.e. below 9250 kPa and above 55°C) such that the fluid is in the gaseous phase, then use of empirical flow calculations, based on a geothermal gradient, is permitted. The resulting calculations can yield an over-estimation of the wellhead AOF; however, if the analyst deems the resulting EPZ to be manageable, then the approach is acceptable. The analyst is cautioned, however, that the actual gas release temperature will be colder than estimated and the dispersion modelling must account for the heavier-than-air acid gas.

In the case of acid gas injection into an aquifer, the tubing performance curves must be calculated on the basis of dry gas flow (i.e. the calculations cannot assume that the wellbore will load up with water).

6 EPZ Modelling

6.1 ERCBH2S Model

The model for EPZ determination is ERCBH2S. Operators are encouraged to review the supporting technical documentation which is available on the ERCB website.

Models should be run for each of the three phases of operations

1) drilling,
2) completion/servicing/workover,
3) producing/injection.

The default time to ignition or stoppage of flow, if mitigation is not available, is 720 minutes for all three scenarios. If mitigation is chosen, the mitigation timeframe is dependent on the operation, the equipment and operator preferences. The minimum timeframe that may be input for ignition or stoppage of flow for drilling, completion, servicing, and workovers is 15 minutes. Operators should ensure that crews are trained in implementing the intended ignition procedures, and have run drills to demonstrate they can achieve ignition within the modelled timeframe, before drilling into the sour formation.

For producing operations, the minimum mitigation timeframe is dependent on whether a surface-controlled subsurface safety valve (SCSSSV) is in place. If a SCSSSV is in place, the mitigation timeframe to stoppage of flow defaults to 3 minutes. If a SCSSSV is not in place, the timeframe to ignition or stoppage of flow may range from 60 minutes to 720 minutes. Again, the operator should be able to demonstrate that the mitigation timeframes can be met on all days, at all times.

For any of the phases of operation, if the mitigation timeframe is not lowered below 180 minutes, the emergency planning zone is not significantly different from the unmitigated case.

The ERCBH2S model is not run for wells with H_2S concentrations less than 100 ppm (0.01%). For sour wells with concentrations below 100 ppm, a default emergency planning zone of 0.01 km should be used.

6.2 Nomograph

Nomographs may also be used, based upon the following formulas, to determine the EPZ:

Equation 6.1

$$\text{If } H_2S_{RR} < 0.3\frac{m^3}{s} \quad \text{then } EPZ = 2.0(H_2S_{RR})^{0.58}$$

Equation 6.2

$$\text{If } 0.3 \le H_2S_{RR} < 8.6\,\frac{m^3}{s} \quad \text{then } EPZ = 2.3(H_2S_{RR})^{0.68}$$

Equation 6.3

$$\text{If } H_2S_{RR} \ge 8.6\,\frac{m^3}{s} \quad \text{then } EPZ = 1.9(H_2S_{RR})^{0.81}$$

Appendix A H_2S Concentration Measurement Techniques

A.1 H_2S Concentration Measurement Techniques

Technique	Accuracy	Comments
On-site Analysis: **Electronic meter**	± 10%	1. Some models are far more accurate than ± 10%. 2. Not often used in conjunction with well tests due to cost, robustness; continued calibration checks needed.
On-site Analysis: **Tutwiler** For 100 mL Burrette Size: H_2S % — Iodine Normality 0.5 — 0.01345 1.0 — 0.01345 1.5 — 0.01345 2.0 — 0.01345 1.5 — 0.0269 2.0 — 0.0269 2.5 — 0.0269 3.0 — 0.0269 0.5 — 0.1 1.0 — 0.1 1.5 — 0.1 2.0 — 0.1 4.0 — 0.1 6.0 — 0.1 8.0 — 0.1 10.0 — 0.1	 ± 15% ± 8% ± 5% ± 4% ± 10% ± 8% ± 6% ± 5% ± 120% ± 58% ± 39% ± 29% ± 15% ± 10% ± 7% ± 6%	1. Accuracy depends on: a) Condition of chemicals. Iodine has a relatively short shelf life, cannot be exposed to sunlight and cannot be frozen. Starch solution must be made accurately. b) Normality of the iodine solution compared to the H_2S concentration • 0.01345 N recommended for H_2S less than 1.6%. The minimum measurable volume of iodine that can be titrated is 0.5 mL, which represents 0.08% H_2S concentration increments using a 100 mL burette. • 0.0269 N recommended for H_2S greater than 1.6%. The minimum measurable volume of iodine that can be titrated is 0.5 mL, which represents 0.16% H_2S concentration increments using a 100 mL burette. • **0.1 N is the most commonly used iodine solution in the field.** The minimum measurable volume of iodine that can be titrated is 0.5 mL, which represents 0.6% H_2S concentration increments using a 100 mL burette. ***c)*** Size of the gas burette • Recommend 500 mL burette for H_2S concentrations less than 0.16%, or when more accuracy is desired. • **Most commonly used burette in the field is 100 mL.** ***d)*** To reduce measurement error, the iodine normality should be selected so that no more than 10 mL of iodine is needed (the size of the titration cylinder). 2. For the above accuracy reasons, **the common industry practice has been to use Tutwiler measurements for H_2S concentrations down to as low as 2 to 3%. Below this value, length of stain detector tubes are commonly used.**
On-Site Analysis: **Length of Stain Detector Tubes**	± 25%	***1.*** Most often used for H_2S levels less than 2% to 3% ***2.*** ± 25% is from Reference 4. Reference 3 indicates better accuracy is obtainable under certain circumstances. ***3.*** Accuracy more questionable with high H_2S concentrations (due to the large scale range of concentration on the tube, especially the older tubes). ***4.*** Reading should be corrected for gas temperature and ambient pressure, but this has not been a common field practice. ***5.*** Single pull plunger type pumps are considered slightly more accurate than the bellows type pump when multiple inflation of the bellows is required.
Lab Analysis: Transport Technique:		***1.*** Accuracy depends upon the type of pressure container that the gas sample is transported to the lab in. The H_2S will react with the walls of normal carbon steel containers and so the subsequent H_2S measurement will be low. Silianized glass

		containers and high nickel steel alloy containers are the best. ***2.*** Even with silianized glass containers and high nickel steel alloy containers, the concentration of H_2S will decrease with time. See Reference 5 for details. ***3.*** Tedlar bags are sometimes used to transport a gas sample to the lab. These are not recommended for high H_2S concentrations, as testing has shown that the H_2S measurements may be 20% too low after 20 days
Lab Analysis: ***1.*** Tutwiler or Length of Stain Detector Tubes. ***2.*** Gas Chromatograph.		***1.*** Not recommended because of accuracy of measurement and loss of accuracy when transporting the gas in a pressure cylinder to the lab. ***2.*** Very accurate. Measures all sulfur compounds. Accuracy is limited by the transportation method and time delay as mentioned above.

References:

1. *"Hydrogen Sulfide in Gases by the Tutweiler Method", UOP Method 9-59, Universal Oil Products Company, Des Plaines, Illinois, USA, 1959.*

2. *"Test for Hydrogen Sulfide in LPG and Gases (Tutweiler Method)", Plant Operations Test Manual, Gas Processor's Association (GPA), 1812 First Place, Tulsa, Oklahoma.*

3. *"Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes", Adopted as a tentative standard in 1997 by the Gas Processors Association, GPA publication 2377-77.*

4. *"Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes", ASTM Designation D 4810-88 (re-approved 1994).*

5. *"Influence of Containers on Sour Gas Samples", J.G.W. Price & D.K. Cromer, Petroleum Engineer International, March, 1980.*

Appendix B Example of Completed Audit Forms

B.1 Example of a Completed Audit Form

The following example shows how the audit forms are to be used to document potential H_2S release rates. The hypothetical example used is a horizontal Leduc well, which, in addition to the Leduc, has three potentially sour formations in the overlying section. These three formations, Viking, Glauconite and Basal Quartz, will be penetrated in the vertical section of the well. Intermediate casing will be run prior to drilling the Leduc horizontal section.

Form A1 (B.1.1) is used to summarize all of the well's geologic and basic information. Potentially productive formations are listed along with the intermediate casing point and the well's total depth. Because the Viking is above the top of the Mannville, and the remaining formations are sour, the Viking is exempt from further analysis as it would not materially affect the release rate potential of the well.

A typical analysis was performed on the Glauconite Formation and documented on Form A2 (B.1.2). In this analysis, a minimum five-kilometre data search radius is required. Within a given search radius a minimum of five AOF and five H_2S data points are required. The search radius is expanded until the required number of data points is achieved. In the example sheet, the required data was obtained with a five-kilometre data search and Form A2 was used to document **all of the data** obtained in the data search.

The Basal Quartz Formation (B.1.3) underwent a more detailed analysis because some of the H_2S concentration data was edited to differentiate between updip gas cap and solution gas H_2S concentrations. Since representative gas cap H_2S concentrations were sought in the data search, the operator was able to cull the solution gas H_2S concentration data. Both the culled and utilized AOF and H_2S concentration data are documented on Form A2.

The example well has intermediate casing set prior to penetrating the Leduc Formation. To evaluate the potential H_2S release rate for the vertical section of this well, the individual release rates for the Glauconite and Basal Quartz Formations were determined, summed and documented on Form A3 (B.1.4).

The Leduc AOF and H_2S concentration data was documented on Form A2 (B.1.5). However, since a 400 m horizontal section is planned for this well, methodology was used to adjust the release rate to reflect a 400 m Leduc horizontal wellbore. The release rate was then documented on Form A3 (B.1.6).

The operator **must keep a record of all calculations** used to determine the adjusted H_2S release rate. In addition, records of the referenced gas analysis used on the A3 forms must be retained.

Because this is an Alberta-based well, ERCBH2S is used to estimate the emergency planning zone size. Model inputs require knowledge of the surface-casing size for the intermediate-hole section, the intermediate-casing size for the main-hole section and the tubing size for the producing case. In addition, information about mitigation is needed for the drilling, servicing cases, and producing cases, and whether a subsurface safety valve is in place for the producing case. In the scenario shown, 15-minute mitigation was used for the drilling and completion scenario, and a subsurface safety valve was in place for the producing scenario.

The following samples of forms A1, A2 and A3 include:

- B.1.1 is an example of Form A1 summarizing all of the well's geologic and basic information
- B.1.2 is an example of Form A2 documenting the Glauconite Formation's AOF and H_2S concentration data
- B.1.3 is an example of Form A2 documenting the Basal Quartz Formation's AOF and H_2S concentration data
- B.1.4 is an example of Form A3 based on the information in B.1.2 and B.1.3
- B.1.5 is example of Form A2 documenting the Leduc Formation's AOF and H_2S concentration data
- B.1.6 is an example of Form A3 based on B.1.5

B.1.1 Sample Form A1

MAXIMUM POTENTIAL H_2S RELEASE RATE DETERMINATION - AUDIT FORM (A1)

GEOLOGICAL INFORMATION

Operator Name:	Fictional Resources		**Prepared by:**	Ng Giner (Engineer)
Well Location:	4-5-44-22 W4M			Row Cound (Geologist)
Type of Well (Vertical, Directional, Horizontal):	Horizontal		**Date:**	2011 10 01
			Page:	1

GEOLOGICAL SUMMARY

	Name of Potentially Productive Formation (also list intermediate casing points in geological sequence)	Common Name for Same Formation (for use in data search)	Estimated Top Depths m KB (MD)	Estimated Top Depths m KB (TVD)	Fluid Type (Gas, Oi)	Gas Cap Present? (Yes, No)	Exempt Zone (Yes/No)	Search Area for Analogous Data (Indicate either the search radius around the proposed well or the names of analogous fields and pools.)	Footnotes
**	Viking		1150.0	1150.0	Gas	Yes	Yes	Not required	1
**	Glauconitic	Upper Manville	1200.0	1200.0	Gas	No	No	Regional 5 km search radius	2
**	Basal Quartz	Lower Manville, Ellerslie	1250.0	1250.0	Oil	Yes	No	Regional 10 km search radius	2
	Wabamun		1350.0	1320.0	Wet			Not productive	3
	Nisku		1480.0	1420.0	Wet			Not productive	3
	Intermediate Casing Point		1650.0	1550.0					
	Leduc		2010.0	1550.0	Oil	No	No	Malmo D3A, D3B and D3C pools	4
		Total Depth	2010.0	1550.0					

Footnotes:

1. The Viking is above the top of the Manville. An H2S release rate assessment is not required.
2 The Glauconitic and Basal Quartz will be contacted in the Vertical Section of the well, above the kickoff point
3. The Wabamun and Nisku formations are regionally present but are have excellent well control to show these zones are water bearing with no potential for hydrocarbon production.
4. Intermediate casing will be set before entering the Leduc reef.

* Primary Formation
** Secondary Formation

Supplemental Instructions:

A. For oil wells where a gas cap is not expected to be present, include supporting information indicating why a gas cap is not present (e.g. undersaturated reservoir; top below gas/oil contact)

B. In Alberta, formations above the top of the Mannville may be exempt from analysis if lower formations are productive and confirmed to be sour.

C. Separate H_2S release rate potentials may be determined for drilling operations in the intermediate and main-hole sections of the well. Therefore, the intermediate casing points should be listed in the above table in geological sequence. Also include the measured and true vertical setting depths of the intermediate casing points.

D. Formations that are expected to be nonproductive, but are productive in offsetting lands, should be listed with an explanation why they are nonproductive (e.g. low and wet).

B.1.2 Sample Form A2

MAXIMUM POTENTIAL H_2S RELEASE RATE DETERMINATION - AUDIT FORM (A2)

H_2S CONCENTRATION AND FLOW DATA

Operator Name:	Fictional Resources	**Prepared by:**	Ng Giner (Engineer)
Well Location:	4-5-44-22 W4M		Row Cound (Geologist)
Formation Name:	Glauconitic	**Date:**	2011 10 01
		Page:	2

POTENTIAL H_2S CONCENTRATION DATA

Unique Well I.D. (5 or more samples with H_2S recommended for analysis of sour zones)	Sample Date	Sample Interval From m KB	Sample Interval To m KB	Sample Point	Sample Pressure kPa	H_2S Conc. %	Footnotes
00/13-22-043-22W4/0	77 12 04	1199.1	1210.1	H.P Sep.	2000	0.09	
00/16-30-043-22W4/0	79 10 10	1198	1200	H.P Sep.	1210	0.18	
00/01-32-043-22W4/2	66 06 06	1201	1201	DST 1	600	0.12	
00/01-34-043-22W4/0	97 12 25	1210	1210	DST 2	1500	0.1	
02/11-12-044-23W4/0	92 01 01	1209	1209	Wellhead	2800	0.07	
00/01-13-044-23W4/0	92 06 30	1198	1208	H.P Sep.	1234	0.16	
02/16-13-044-23W4/2	95 05 31	1205	1207	DST 2	909	0.01	

POTENTIAL FLOW RATE DATA

Unique Well I.D. (5 or more flow rates recommended for analysis)	Test Type and Number	Start Test Date	Test Interval From m KB	Test Interval To m KB	Static Reservoir Pressure kPa	Flowing Bottomhole Pressure kPa	Test Gas Rate $10^3 m^3/d$	"n" or name of correlation[c]	Sandface AOFP $10^3 m^3/d$	Foot-notes
00/12-23-043-22W4/0	AOF	77 11 18	1191.1	1210.1	14000	5000	100.0	0.95	113.8	1
00/14-31-043-22W4/0	AOF	79 10 01	1198.0	1200.0	13350	7980	335.0	0.75	466.7	1
00/01-32-043-22W4/2	DST 1	66 06 06	1201.0	1205.0	12202	9009	303.0	1.00	666.1	2
00/01-34-043-22W4/0	DST 2	97 12 25	1210.0	1212.0	11009	8000	220.0	1.00	466.2	
02/10-12-044-23W4/0	AOF	91 12 27	1209.0	1214.0	13700	3000	55.0	1.00	57.8	1
00/01-13-044-23W4/0	AOF	92 03 03	1205.0	1207.0	13700	6000	28.5	1.00	35.3	1
00/12-23-043-22W4/0	AOF	77 11 18	1191.1	1210.1	14000	5000	100.0	0.95	113.8	1

Footnotes:

1. Multipoint AOF Test Data
2. A net pay adjustment was not applied as this is not a primary target for the well.

Supplemental Instructions:

A. Refer to data sampling guidelines in the CAPP H2S Release Rate Assessment Guidelines for the minimum number of required samples. Data from wells that is not considered to be representative, but would otherwise increase the H_2S release potential, should also be included in the list along with a footnote explaining the reason the data is not representative.
B. Formations that are confirmed to be sweet do not require completion of the potential flow rate data.
C. If the AOF is determined using a correlation other than Schellardt and Rawlins equation (AOF = $C(Pr^2 - Pwf^2)^n$), state the name of the correlation used (e.g. Vogel's).
D. Include supporting documentation if bottomhole pressures are estimated from surface pressures or production data. Also include documentation supporting the use of an "n" value less than 1.0 for DSTs or single-point test data. Generally, n = 1 for DSTs.

B.1.3 Sample Form A2

MAXIMUM POTENTIAL H_2S RELEASE RATE DETERMINATION - AUDIT FORM (A2)
H_2S CONCENTRATION AND FLOW DATA

Operator Name:	Fictional Resources	**Prepared by:**	Ng Giner (Engineer)
Well Location:	4-5-44-22 W4M		Row Cound (Geologist)
Formation Name:	Basal Quartz	**Date:**	2011 10 01
		Page:	3

POTENTIAL H_2S CONCENTRATION DATA

Unique Well I.D. (5 or more samples with H_2S recommended for analysis of sour zones)	Sample Date	Sample Interval		Sample Point	Sample Pressure kPa	H_2S Conc. %	Footnotes
		From m KB	To m KB				
00/08-08-043-22W4/0	75 11 04	1249.1	1254.1	H.P Sep.	200.0	0.50	1
00/09-09-043-22W4/0	79 10 31	1248.0	1250.0	H.P Sep.	150.0	0.35	1
00/12-11-043-22W4/2	76 06 06	1251.0	1255.0	DST 1	80.0	0.12	
00/13-32-043-22W4/2	90 12 25	1260.0	1262.0	DST 2	1500.0	0.19	
02/11-12-044-22W4/0	92 02 29	1269.0	1274.0	Wellhead	7000.0	0.16	
00/16-19-044-22W4/0	55 11 18	1225.0	1230.0	H.P Sep.	3800.0	0.18	
00/01-26-044-22W4/0	78 03 02	1230.0	1235.0	Separator	5000.0	0.13	

POTENTIAL FLOW RATE DATA

Unique Well I.D. (5 or more flow rates recommended for analysis)	Test Type and Number	Start Test Date	Test Interval		Static Reservoir Pressure kPa	Flowing Bottomhole Pressure kPa	Test Gas Rate $10^3 m^3/d$	"n" or name of correlation[C]	Sandface AOFP $10^3 m^3/d$	Foot-notes
			From m KB	To m KB						
00/08-08-043-22W4/0	IPR	75 11 04	1249.1	1254.1	14000	700	9.0	Vogel's	9.1	
00/09-10-043-22W4/0	AOF	79 10 31	1248.0	1250.0	15125	7980	8.0	1.00	11.1	
00/12-11-043-22W4/2	AOF	76 06 06	1251.0	1255.0	14111	12111	14.0	1.00	53.2	
00/13-32-043-22W4/2	AOF	90 12 25	1260.0	1262.0	12222	10900	220.0	1.00	1075.1	3
02/11-12-044-22W4/0	AOF	92 02 29	1269.0	1274.0	13700	8000	182.0	0.90	264.9	2
00/16-19-044-22W4/0	AOF	55 11 18	1225.0	1230.0	14200	13000	72.0	1.00	444.8	2
00/01-26-044-22W4/0	AOF	78 03 02	1230.0	1235.0	10900	3000	310.0	0.70	327.6	2

Footnotes:
1. The identified samples are analysis of solution gas from oil wells. The wells were producing with gas/oil ratios between 80 m3/m3 and 90 m3/m3 when the samples were taken. Therefore, these analysis are not considered to be representative of gas cap gas and should not be used when determining the H2S release rate potential of the gas cap.
2. Data taken from multipoint test
3. A net pay adjustment was not applied as this is not a primary target for the well.

Supplemental Instructions:
A. Refer to data sampling guidelines in the CAPP H2S Release Rate Assessment Guidelines for the minimum number of required samples. Data from wells that is not considered to be representative, but would otherwise increase the H_2S release potential, should also be included in the list along with a footnote explaining the reason the data is not representative.
B. Formations that are confirmed to be sweet do not require completion of the potential flow rate data.
C. If the AOF is determined using a correlation other than Schellardt and Rawlins equation ($AOF = C(Pr^2 - Pwf^2)^n$), state the name of the correlation used (e.g. Vogel's).
D. Include supporting documentation if bottomhole pressures are estimated from surface pressures or production data. Also include documentation supporting the use of an "n" value less than 1.0 for DSTs or single-point test data. Generally, n = 1 for DSTs.

B.1.4 Sample Form A3

Note: This example of form A3 is based on the previous two samples of form A2.

MAXIMUM POTENTIAL H_2S RELEASE RATE DETERMINATION - AUDIT FORM (A3)
POTENTIAL H2S RELEASE RATE SUMMARY SHEET - MAIN HOLE

Operator Name:	Fictional Resources	**Prepared by:**	Ng Giner (Engineer)
Well Location:	4-5-44-22 W4M		Row Cound (Geologist)
Wellbore Section:	Intermediate	**Date:**	2011 10 01
Nearest Urban Centre:	Wetaskiwin	**Page:**	4
Distance from well:	25.0 km		

H_2S RELEASE RATE SUMMARY

Formation Name	H_2S Concentration		AOF Potential		H_2S Release Rate m^3/s	Adjusted H_2S Release Rates[B]			Foot-notes
	Reference Well Unique ID	H_2S Conc. %	Reference Well Unique ID	Sandface AOF $10^3m^3/d$		Drilling m^3/s	Servicing[A] m^3/s	Susp/Prod[A] m^3/s	
Glauconitic	00/16-30-043-22W4/0	0.18	00/01-32-043-22W4/2	666.1	0.0139	0.0139	0.0000	0.0000	1
Basal Quartz	00/13-32-043-22W4/2	0.19	00/13-32-043-22W4/2	1075.1	0.0236	0.0236	0.0000	0.0000	1
					Total	0.0375	0.0000	0.0000	

EMERGENCY PLANNING ZONE SUMMARY

Operation Type	Adjusted H_2S Release Rate - m^3/s	Calculated EPZ km	Footnotes
Drilling	0.038	0.05	
Completion/Servicing	0.000	n/appl.	1
Suspended/Producing	0.000	n/appl.	1

LEVEL DESIGNATION SUMMARY

Operation Type	Adjusted H_2S Release Rate - m^3/s	Facility Level (1,2,3 or 4)	Foot-notes
Suspended/Producing			

Refer to the appropriate provincial guidelines for land-use setback requirements corresponding to each facility level.

Footnotes:
1. Servicing and Suspended Producing Release rates are not shown for the intermediate hole because the largest Servicing and Producing release rates occur in the main-hole section of the well.

Supplemental Instructions:
A. All formations may not be open to the wellbore during servicing and producing operations. Therefore, the potential H_2S release rate for servicing may be limited to the formation or formations that are anticipated to be open to the wellbore during the planned operations. Similarly, the potential H2S release rate for producing operations should be based on the formation or formations that contribute the maximum producing H2S release rate throughout the life of the well. The H2S release rate potential for formations not open to the wellbore for the servicing or producing calculations may be shown as 0 m3/s.
B. Any adjustments to the H_2S release rates must be supported with appropriate calculations and assumptions.
C. All critical (special) sour wells require a full ERP and a detailed drilling program. Refer to Alberta Guide G-56 (or BC Oil and Gas Handbook) for definitions of critical (special) sour wells.
D. Complete one sheet for each grouping of formations that may be simultaneously produced.

B.1.5 Sample Form A2

MAXIMUM POTENTIAL H_2S RELEASE RATE DETERMINATION - AUDIT FORM (A2)

<u>H_2S CONCENTRATION AND FLOW DATA</u>

Operator Name:	Fictional Resources	**Prepared by:**	Ng Giner (Engineer)
Well Location:	4-5-44-22 W4M		Row Cound (Geologist)
Formation Name:	Leduc	**Date:**	2011 10 01
		Page:	5

POTENTIAL H_2S CONCENTRATION DATA

Unique Well I.D. (5 or more samples with H_2S recommended for analysis of sour zones)	Sample Date	Sample Interval		Sample Point	Sample Pressure kPa	H_2S Conc. %	Footnotes
		From m KB	To m KB				
00/07-08-043-22W4/0	76 12 04	1549.0	1554.0	H.P. Sep	4500.0	19.00	
00/08-09-043-22W4/0	80 08 31	1548.0	1550.0	H.P. Sep	6200.0	21.00	
00/10-11-043-22W4/2	77 06 06	1551.0	1555.0	H.P. Sep	3100.0	13.00	
00/14-32-043-22W4/2	91 12 25	1560.0	1562.0	DST 2	1500.0	16.00	
02/13-12-044-22W4/0	93 02 29	1569.0	1574.0	Wellhead	7000.0	22.00	
00/10-19-044-22W4/0	66 11 18	1525.0	1530.0	B.H. Sam.	3800.0	8.00	
00/08-26-044-22W4/0	72 03 02	1530.0	1535.0	H.P. Sep	5000.0	18.00	

POTENTIAL FLOW RATE DATA

Unique Well I.D. (5 or more flow rates recommended for analysis)	Test Type and Number	Start Test Date	Test Interval		Static Reservoir Pressure kPa	Flowing Bottomhole Pressure kPa	Test Gas Rate $10^3 m^3/d$	"n" or name of correlation[c]	Sandface AOFP $10^3 m^3/d$	Foot-notes
			From m KB	To m KB						
00/07-08-043-22W4/0	IPR	76 12 04	1549.0	1554.0	17000	16010	25.0	Vogel's	244.8	1, 2
00/08-09-043-22W4/0	DST 1	80 08 31	1548.0	1550.0	16800	12000	6.0	Vogel's	13.4	
00/10-11-043-22W4/2	DST 1	77 06 06	1551.0	1555.0	17200	10800	28.0	Vogel's	50.1	
00/14-32-043-22W4/2	DST 2	91 12 25	1560.0	1562.0	16100	10900	16.0	Vogel's	32.1	
02/13-12-044-22W4/0	IPR	93 02 29	1569.0	1574.0	15800	8000	9.0	Vogel's	13.0	
00/10-19-044-22W4/0	IPR	66 11 18	1525.0	1530.0	17050	15000	24.0	Vogel's	117.2	
00/08-26-044-22W4/0	IPR	72 03 02	1530.0	1535.0	16900	3000	7.0	Vogel's	7.5	

Footnotes:

1. The oil test rate for the well in LS 7-8-43-22 W4 was 125 m3/d with a GOR of 200 m3/m3. The resulting test gas rate was 25.0 103m3/d.

The calculated maximum inflow performance at 0 kPa sandface pressure is 1224 m3/d oil and 244.8 103m3/d gas (with a 200 m3/m3 GOR).

Net pay adjustments were not applied as this well is in a carbonate formation.

Supplemental Instructions:

A. Refer to data sampling guidelines in the CAPP H2S Release Rate Assessment Guidelines for the minimum number of required samples. Data from wells that is not considered to be representative, but would otherwise increase the H2S release potential, should also be included in the list along with a footnote explaining the reason the data is not representative.

B. Formations that are confirmed to be sweet do not require completion of the potential flow rate data.

C. If the AOF is determined using a correlation other than Schellardt and Rawlins equation (AOF = C(Pr2 - Pwf2)n), state the name of the correlation used (e.g. Vogel's).

D. Include supporting documentation if bottomhole pressures are estimated from surface pressures or production data. Also include documentation supporting the use of an "n" value less than 1.0 for DSTs or single-point test data. Generally, n = 1 for DSTs.

B.1.6 Sample Form A3

Note: This is an example of form A3 based on form A2 in B.1.5.

MAXIMUM POTENTIAL H_2S RELEASE RATE DETERMINATION - AUDIT FORM (A3)
POTENTIAL H2S RELEASE RATE SUMMARY SHEET - MAIN HOLE

Operator Name:	Fictional Resources	**Prepared by:**	Ng Giner (Engineer)
Well Location:	4-5-44-22 W4M		Row Cound (Geologist)
Wellbore Section:	Intermediate	**Date:**	2011 10 01
Nearest Urban Centre:	Wetaskiwin	**Page:**	6
Distance from well:	25.0 km		

H_2S RELEASE RATE SUMMARY

Formation Name	H_2S Concentration		AOF Potential		H_2S Release Rate m^3/s	Adjusted H_2S Release Rates[B]			Foot-notes
	Reference Well Unique ID	H_2S Conc. %	Reference Well Unique ID	Sandface AOF $10^3m^3/d$		Drilling m^3/s	Servicing[A] m^3/s	Susp/Prod[A] m^3/s	
Leduc	02/13-12-044-22W4/0	22.00	00/07-08-043-22W4/0	244.8	0.6234	2.5600	2.5600	0.6400	1
					Total	2.5600	2.5600	0.6400	

EMERGENCY PLANNING ZONE SUMMARY

Operation Type	Adjusted H_2S Release Rate - m^3/s	Calculated EPZ km	Footnotes
Drilling	2.560	1.33	1
Completion/Servicing	2.560	1.33	1
Suspended/Producing	0.640	0.39	1

LEVEL DESIGNATION SUMMARY

Operation Type	Adjusted H_2S Release Rate - m^3/s	Facility Level (1,2,3 or 4)	Foot-notes
Suspended/Producing	0.640	2	

Refer to the appropriate provincial guidelines for land-use setback requirements corresponding to each facility level.

Footnotes:
1. The adjusted H2S release rate for the drilling and servicing operations incorporates the flow adjustments for a 400-m horizontal wellbore. The flow adjustment for the suspended producing configuration incorporates adjustments for vertical multiphase flow losses. Refer to the attachments for the related calculations.

Supplemental Instructions:
A. All formations may not be open to the wellbore during servicing and producing operations. Therefore, the potential H2S release rate for servicing may be limited to the formation or formations that are anticipated to be open to the wellbore during the planned operations. Similarly, the potential H2S release rate for producing operations should be based on the formation or formations that contribute the maximum producing H2S release rate throughout the life of the well. The H2S release rate potential for formations not open to the wellbore for the servicing or producing calculations may be shown as 0 m3/s.
B. Any adjustments to the H_2S release rates must be supported with appropriate calculations and assumptions.
C. All critical (special) sour wells require a full ERP and a detailed drilling program. Refer to Alberta Guide G-56 (or BC Oil and Gas Handbook) for definitions of critical (special) sour wells.
D. Complete one sheet for each grouping of formations that may be simultaneously produced.

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