Landowners' Guide to Oil and Gas Development

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Section 8

Potential Environmental Impacts During Oil and Gas Operations

photo: Roberta Franchuk, Pembina Institute

8. Potential Environmental Impacts During Oil and Gas Operations

As a landowner or occupant you can play a valuable role by keeping a lookout and documenting any problems with operations. This chapter examines in depth some of the potential impacts that oil and gas operations may have on air, water and land. Additionally, it outlines the process for conservation and reclamation before and after development occurs (further expanded upon in Section 9).

What's in this chapter

As the regulatory system is fundamentally based on industry self-reporting, the Alberta Energy Regulator (AER) inspects a small proportion of all wells, pipelines and other facilities each year, focusing on those operations where the company has a poor record, the site is sensitive, or there is a high inherent risk to the operation.[1] Given the AER's limited resources relative to the size of the industry, as a *landowner* or *occupant* you can play a valuable role by keeping a lookout and documenting any problems with operations.

8.1 Oil and gas facilities

If you have a well, pipeline or facility on your land, it is advisable to regularly inspect the land around the site, especially if livestock are in the area, to ensure there are no spills or leaks and that gates are closed and fences are intact.

> Unless it is an emergency situation you should first discuss any concerns you have with the company, and then register your issue with AER. In an emergency situation you should contact the company operator through its 24-hour emergency number[2] and the AER energy and environmental emergency 24-hour response line (as soon as you can do so safely).

If the company fails to promptly resolve any issue to your satisfaction, then you should ask for help from the AER. The AER (Section A.2) deal with complaints related to the operation of a company on the lease site, problems that directly affect the environment and issues related to seismic activity or activity on *public lands*. The Farmers' Advocate will also provide advice (Section A.4).

8.1.1 Complaints and field inspections

The last field inspections report was issued by the Energy Resources Conservation Board (ERCB) in 2013 based on inspections undertaken in 2012. The Alberta Energy Regulator (AER) assumed the ERCB's responsibilities in 2013 along with all legislation and regulation of the oil and gas industry. In 2012, the ERCB received 754 public complaints,

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[1] Energy Resources Conservation Board, *Field Operations Provincial Summary 2012,* ST57-2013, 2. http://www.aer.ca/documents/sts/ST57-2013.pdf

[2] Companies are required to provide their 24-hour licensee emergency number in their emergency response plan, as well as on an obvious sign at the entrance of the well or facility site.

relating to a total of 963 issues.[3] There were over 27,800 oil and crude bitumen and satellite installations in Alberta and the ERCB inspected about 15% of them.[4] They designated 1.7% of the oil *batteries* as high risk non-compliant, indicating these facilities had violated regulations to the extent that they could potentially cause an adverse or significant impact on the public and/or the environment.[5] Problems were due to off-lease odour emissions of *hydrogen sulphide* (H_2S), inadequate reporting of *flared* and *vented* gas volumes, and inadequate immediate emergency response capacity.

There were over 9,800 gas batteries in the province in 2012. Inadequate reporting of flared and vented gas volumes, inadequate testing of underground tanks, and inadequate flaring programs were the main cause of unsatisfactory inspections for gas batteries.[6]

If a problem is reported to the AER, the Regulator may require the company to fix it within a specified timeframe. The AER should be informed if the company does not comply within the given time period. The AER may impose a penalty according to an escalating scale of consequences, with higher penalties for serious offences and repeat offenders. Penalties can include temporary or long-term suspension of operations, the refusal of applications, closure or *abandonment* of wells, and prosecution.

The AER maintains its Compliance Dashboard,[7] which replaces its Monthly Enforcement Action Summary. On the AER website you can find summaries of incidents, investigations, and enforcement activities.

8.1.2 Pipelines

If a company does not clear away debris from a pipeline *right-of-way* or fails to restore the *topsoil*, cultivate and seed the land properly, or deal with drainage problems, the landowner or occupant should contact the company. The company should also be contacted if soil sinks in the pipeline trench or if the pipeline becomes exposed or if there are any other observable impacts.

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[3] *Field Operations Provincial Summary 2012*, 2–3.

[4] *Field Operations Provincial Summary 2012*, 7.

[5] *Field Operations Provincial Summary 2012*, 7.

[6] *Field Operations Provincial Summary 2012*, 9.

[7] Alberta Energy Regulator, "Compliance Dashboard." http://www1.aer.ca/ComplianceDashboard/index.html

You should also register your complaint with the AER. If the company fails to take suitable action, the landowner or occupant should contact the regional inspector at the Alberta Energy Regulator (Section A.2) . The Farmers' Advocate office (Section A.4) may also be able to help.

If there is a dispute about damages on the pipeline right-of-way, it is possible to go to *arbitration*. The arbitration process is governed by the Alberta Arbitration Act. If the damage occurs off the right-of-way line, the problem can be brought before the Surface Rights Board (Section A.3.1). It is advisable to have this process defined in the pipeline agreement, so that if issues occur you have a process that is agreed upon by both parties.

If you suspect a pipeline leak, call the company and the AER immediately. The first sign of a leak might be odour but a slow leak might be indicated by a change in the growth of plants close to the leak. A company must report a pipeline leak to the AER. Failure to report or unsatisfactory performance may result in the AER ordering the pipeline to be shut in or replaced.

In 2012 there were 567 pipeline incidents (leaks and ruptures, not including other damage dealt to pipelines that did not result in loss) in Alberta, with 40% being caused by internal corrosion and a further 13% by external corrosion. The number of corrosion failures has remained relatively consistent since 2009. The ratio of pipeline failures to line length has also remained consistent since 2009, at approximately 1.5 per year per 1,000 km. The majority of failures were in small-diameter gathering lines (mainly 2–6 inch diameter).[8] Stress corrosion cracking is one kind of failure that can occur as a result of external corrosion in buried pipelines. While it is a factor in only a small percentage of pipeline failures, it is of particular concern because a leak in a high-pressure gas pipeline may lead to an explosion.

8.1.3 Oil and gas wells

The AER requires companies to test new oil and gas wells for surface *casing* vent flows/gas migration and to repair or monitor those with any leaks. A well must also be tested before it is abandoned.[9] These requirements are important because if wells are

[8] AER, *Pipeline Performance in Alberta 1990-2012*, Report 2013-B (2013). https://www.aer.ca/documents/reports/R2013-B.pdf

[9] AER, Interim Directive ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Venting Flow/Gas Migration Testing, Reporting, and Repair

not properly cased or abandoned, gas, oil or *saline water* from deeper formations may escape from the well bore and contaminate shallow potable water aquifers. Gas migration — the leakage of gas outside an oil or gas well — can occur if well bore casings are not properly cemented or if earth tremors from activity in the area have damaged the casing.

8.2 Air emissions

Flaring and venting from wells, *gas plants* and other facilities and the associated smoke, odour, and potential exposure to hazardous air pollutants have long been a source of concern for those living and working near oil and gas operations.

8.2.1 Flaring and venting

There are several types of flaring:

- **Well test flaring** occurs during the initial tests to find out a well's capability (see Section 8.2.3).
- ***Coalbed methane* flaring** takes place when coal seams that contain water are *dewatered* to reduce the pressure and release the methane gas. During this dewatering phase it may not be economic to pipe small volumes of gas, especially if an exploratory well is at some distance from an existing pipeline, so a company may want to flare it for several weeks or months.
- ***Hydraulic fracture* flaring** occurs during well testing of hydraulically fractured wells. Similar to conventional well test flaring, the rate of oil and gas production is measured to infer future oil and gas production. The gas that is produced during testing must be managed either through flaring or venting. As with conventional wells, it is possible to use an *incinerator* instead of a flare stack at a hydraulically fractured well. More discussion on hydraulic fracturing operations is provided in Section 4.7.

Requirements; 3) Casing Failure Reporting and Repair Requirements (2003). AER Directives are available at AER, "Directives." http://www.aer.ca/rules-and-regulations/directives/

- ***Solution gas*** **flaring** (and venting) occurs at batteries, where oil from one or more wells is processed and stored. The solution gas is a by-product in oil production, separating out from the oil at the lower pressures present at the Earth's surface. These flares burn constantly. In some cases where there is insufficient gas to sustain a flare, the AER may allow direct venting of the solution gas. However, if an operation is within 500 m of a residence and solution gas volume produced is more than 900 m^3 a day, the *operator* must *conserve* solution gas.[10]
- **Gas processing plants** use flares to burn off by-products for which there is no market. They also burn off gas during emergency conditions.
- **Temporary flares** are sometimes used at facilities and wells during pipeline maintenance operations and servicing.
- **Continuous flares,** although not preferred, may be permitted by the AER if an operator demonstrates that is not economically feasible to capture solution gas. Continuous flaring may also be permitted if the operation will flare less than 900 m^3 a day, but the AER still has the discretion to require a company to assess the economic viability of conserving the solution gas.
- **Emergency flares** are used when a well or facility faces operational challenges, and pressures reach potentially dangerous levels. In these cases, excess gas is flared to drop equipment pressures.

Background information on flaring is given in *Flaring: Questions + Answers*.[11]

Research done by the former Alberta Research Council showed that a flare can release a large number of air pollutants, including unburned hydrocarbons and other harmful substances that result from incomplete combustion. The products of incomplete combustion depend on the constituents in the gas that is burned but can include *BTEX* aromatics,[12] polycyclic aromatic hydrocarbon compounds and, if the gas is *sour,*

[10] AER, Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting (2015), section 2.6.

[11] Robert D. Bott, *Flaring: Questions + Answers* (Canadian Centre for Energy Information, 2007). http://www.ccacoalition.org/en/resources/flaring-questions-answers-2nd-edition-canadian-centre-energy-information

[12] Mel Strosher, *Investigations of Flare Gas Emissions in Alberta,* Special Report 005 (1996). http://ags.aer.ca/publications/SPE_005.html

hydrogen sulphide (H_2S). When H_2S is burned, it produces sulphur dioxide, which is also harmful (Section 4.6.2).

If problems are occurring with flares, you should first contact the company and make them aware of the situation. You can also call the AER's emergency and complaint line to register your complaint, asking them to investigate and take action.[13] Signs of problems with flaring include visible black smoke or plumes, frequent or long-lasting flares, continuous flaring for projects that have not been approved for such, or abnormally intense flames. If you experience health issues that seem to be correlated with flaring activity, take detailed notes about flaring activity nearby.

You should document issues, especially if they are ongoing: take photographs of flares and smoke, and keep records of the date, nature of the occurrence and length of time that the problem persists. Be sure to include something in the photograph to provide scale and to identify the location where it was taken — such as the company sign adjacent to the site. Ideally, you should use a camera that includes a date and time stamp on the image. This is especially important in cases where the flaring event may conclude before a field inspector can come to the site to investigate.

> Ensure you document any issue you have with an operation, including the time you spent investigating the problem, associated damages, and other relevant details. See the example in Appendix D at the end of the guide for ideas of what you should document.

Venting of gases can also pose problems. Venting occurs when solution gases from oil wells, batteries or tanks are released unburned to the air. Some venting may also occur from *compressor* vents, instrument gas stations, pneumatic devices, *dehydrators* and storage tanks. This release of unburned hydrocarbons to the atmosphere creates odours and exposure to potentially harmful substances. Vented gas also contributes to global climate change and wastes a non-renewable resource. Current AER regulations set standards for venting and allow venting of small volumes of gas where it is not considered practical to recover or flare it. For example, continuous venting of gas containing H_2S must not exceed *Alberta Ambient Air Quality Guidelines*[14] for H_2S or result

[13] The AER's Energy and Environmental Emergency 24-Hour Response Line is 1-800-222-6514. You can report an energy or environmental emergency or complaint, and the each call is triaged and forwarded to the appropriate filed centre for a response.

[14] Alberta Environment and Parks, *Alberta Ambient Air Quality Objectives and Guidelines Summary* (2016). http://environment.gov.ab.ca/info/library/5726.pdf

in odours outside the lease boundary. There are also limits on the total amount of benzene that may legally be released.[15]

Venting of natural gas or methane from oil and gas operations is a significant contributor to climate change. Methane is 86 times more potent as a greenhouse gas than carbon dioxide, over a 20-year period. The Government of Alberta has announced as part of its Climate Leadership plan that methane emissions will be reduced by 45% below 2014 levels by 2025.

Flaring and venting can be eliminated in various ways, such as by piping the gases for other processing, using the gas on-site to drive equipment or provide heat, or pooling gas from several small sources and sending via pipeline to processing plants. When deciding about flare reductions, a company must consider economic, social and environmental factors, including the proximity of nearby *residents*.

While emissions from solution gas flares and gas plant flaring have received most of the attention, there is also concern about flaring and venting from pipeline maintenance. Pipeline maintenance is often preceded by purging the line and flaring or venting the gas directly to the atmosphere. To inspect the condition of pipeline walls, a cylindrical device known as a “smart pig” is sent along the pipe; it detects and sends back data on cracking and corrosion.

Background: Flaring in Alberta

The Alberta Research Council study led to a review of flaring and subsequent efforts to reduce flare emissions. At the request of the oil and gas industry, a multi-*stakeholder* project team of Alberta’s Clean Air Strategic Alliance (CASA)[16] was formed to develop recommendations to manage solution gas flaring in the province. The initial recommendations adopted were successful in substantially reducing emissions, but due to a lack of consensus over measures that would generate further reductions, the CASA team was disbanded in 2010.

[15] AER, Directive 060, section 8.3.

[16] The Clean Air Strategic Alliance (CASA) is a multi-stakeholder partnership of industry, government and non-government organizations. CASA’s mandate is to bring together diverse stakeholder groups to solve air quality problems on a consensus, rather than adversarial, basis. See Section B.3.5.

Flared volumes reached an all-time low in 2009 but have subsequently returned to early 2000s levels due to lower natural gas prices and increasing pipeline and compression costs.[17]

Despite the initial success, the regulations related to solution gas flaring were never intended to remain static over the long term. It was recognized that alterations may be necessary to account for new technologies, new production methods, and new economic conditions. The approach has not been comprehensively reviewed since 2010 when the CASA team provided their final report.

8.2.2 Incinerators

In some circumstances using an incinerator may be preferable to flaring. Some types of incinerator can burn with high efficiency and thus minimize odour and air pollution, including greenhouse gas emissions.[18] Unlike flares, the efficiency of well-designed incinerators is not affected by cross-winds. Additionally, an incinerator reduces the noise and eliminates the light associated with flare.

A company will consider a variety of factors when determining whether to use a flare or incinerator, including cost, volume of gas flow, proximity of houses and land topography. Although the emissions from an incinerator may be less than a flare, they are released closer to the ground and may not disperse as effectively. Thus, if a well is close to a dwelling located in a hollow, a flare stack may be considered preferable to an incinerator.

8.2.3 Well testing

After a company has *drilled* a well, it must be tested to determine characteristics about the oil or gas being produced, rate of production, and other factors for production. During this testing, *reservoir fluids* and gas can be produced and must be managed accordingly. The reservoir fluids can be stored on site before being transported for waste management. The produced gas, after it is separated from the fluids (see Section 8.3),

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[17] AER, *Upstream Petroleum Industry Flaring and Venting Report*, ST60B-2015, 4, 6. http://www.aer.ca/data-and-publications/statistical-reports/st60b

[18] See, for example, Questor Technology Inc. at http://www.questortech.com/ Some so-called incinerators are similar to low-level shielded flares and do not achieve the high combustion efficiency of refractory incinerators. An efficient, well-designed incinerator should not require the addition of propane to the gas to ensure continuous burning.

can be transported in a pipeline for processing or can be flared or vented at a well site. If flaring or venting is used, air quality might be affected.

The recommendation for producers is to first try to avoid any gas emissions at all. If they cannot be avoided, the emissions should be minimized, and any emissions that do occur should meet the performance requirements. Gas capture is preferred to flaring, and flaring is preferred to venting.

The AER allows 21 days to complete well testing. Although a company can apply to the AER for a longer test period under specific circumstances, any flaring and venting during well testing must not exceed 72 non-consecutive hours.[19] Flaring approved by the AER must conform to Alberta Ambient Air Quality Objectives and Guidelines.[20] The challenge is that there are no requirements for ongoing air monitoring at wells that do not contain H_2S, and in some instances it will not be known if these guidelines are exceeded. If you believe these operations are exceeding these standards, it is important to inform the AER immediately so that they may be able to respond to the complaint in time to measure the air quality event. Even in an instance where the individual project may still be in compliance, it can be helpful to register your complaints with the AER so they can see over time that this may be an area of concern.

> Flaring intensity during oil and gas well testing has increased consistently since 2005; in 2014 well test flaring per well drilled was over 90% greater than in 2005. This is related to the increasing number of *horizontal*, multistage-fractured wells being drilled.[21]

Well test flaring may emit pollutants that can damage vegetation and affect human and animal health. As explained in Section 4.4, *setbacks* are intended to protect people from exposure, but people may wish to be alerted during well tests. The AER requires a company to notify its local field centre, the local municipality, and rural residents before testing an oil well or sour gas well using a flare that will last more than four hours in a 24-hour period.[22] The requirements are different for oil wells and gas wells, but the minimum notification radius ranges from 0.5 km to 3 km depending on the

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[19] AER, Directive 060, section 3.2.

[20] Alberta Environment and Parks, “Ambient Air Quality Objectives.” http://aep.alberta.ca/air/legislation/ambient-air-quality-objectives/default.aspx

[21] *Upstream Petroleum Industry Flaring and Venting Report*, 10.

[22] AER, Directive 060, table 2.

composition of the gas being flared, duration of the flare and the gas volume discharged.[23]

Companies are not automatically required to notify adjacent landowners or occupants when they test flare for a shorter duration. However, the AER suggests that companies conduct "good neighbour" operations, where residents have identified themselves as being sensitive to or interested in emissions from a facility.

You may want to arrange for livestock to be located upwind or away from the flare. If you or others suffer from respiratory illness, you can *negotiate* with the company to ensure that it notifies you when it plans to carry out its well-test flaring so you can leave the area at that time. You may want to make arrangements for the company to delay the start of a well test or to stop a test if meteorological conditions are unfavourable and would result in pollution concentrating at ground level. Although regulations require companies to ensure ground level concentrations do not exceed maximum allowable levels, general ambient monitoring is not always required.

In an established area where pipelines are already nearby, a company may be able to greatly reduce well test flaring by conducting an in-line test through a pipeline to a processing facility. However, a short period of flaring will probably be required to remove any remaining fluids from the well after it is drilled, since the fluids could cause corrosion if released into the pipeline.

If small quantities of solution gas are measured in an oil well, it may not be economic for the company to collect and pipe the gas. Instead, a company may want to install a permanent flare stack or incinerator for production from such a well. Operators with continuous solution gas flares, incinerators or vents are expected to provide public information packages with the following information:[24]

- the definition of solution gas, and information on its conservation and use
- an explanation of solution gas flaring, incineration, and venting management options and the decision process
- a summary of analysis completed to determine that flaring, incineration, or venting is needed
- information on general flare/vent performance requirements and reduction targets

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[23] AER, Directive 060, table 2.

[24] AER, Directive 060, section 2.10.1.

- descriptions of specific actions the licensee or operator will take to eliminate or reduce flaring, incineration, or venting or improve the efficiency of the flare, incinerator, or vent source based on the evaluation
- a list of industry, AER, and government contacts that are related to public consultation and relevant to the project.

Total solution gas flared and vented reached an all-time low in 2009, while the overall conservation rate has remained relatively stable at 95 percent through this period.[25]

> Air emission issues at compressor stations are described in Section 6.2. Dehydrators, which may be located at well sites, are described in Section 6.3.1.

8.2.4 Odour

In most years, odour is the most frequent cause of complaints to the AER.[26] Venting of gases (especially from crude oil and bitumen batteries), tank venting, leaking tank seals or ineffective vapour recovery units on storage tanks can cause odours. If there is an odour it is important to notify the company and AER at once and ask that action be taken to locate and stop the source. If the odour is caused by H_2S see Section 7.2 for information on evacuation in emergency situations. If you are concerned that you or individuals in your household might be affected by the emissions, you may wish to leave the area. If you leave because of odours when there is no general emergency, you should notify the AER as to the reason that you left.

If you are troubled by a recurring odour, notify the AER of each event or on a regular basis. Keep a record of when events occur, noting the wind direction, wind strength, ambient temperature, and any other weather conditions that may be present during the event. You should also document your description of the odour during each event, as that may reveal details to assist finding the cause of the odour.

As indicated in Section 4.6.2, Alberta Health has reviewed the health effects associated with short-term exposure to low levels of H_2S.[27] There are still many gaps in our knowledge about the long-term effects of exposure, but "there is evidence that

[25] *Upstream Petroleum Industry Flaring and Venting Report*, 3.

[26] *Field Operations Provincial Summary 2012*, 3.

[27] Alberta Health and Wellness, *Health Effects Associated with Short-term Exposure to Low Levels of Hydrogen Sulphide — A Technical Review* (2002). http://www.health.alberta.ca/documents/Health-HS2-Exposure-2002.pdf

cumulative health effects of repeated low-level H_2S exposure exist."[28] The specific risk of low-level exposure to H_2S for the general population or sensitive people is not known.

The AER has two mobile monitoring units to measure H_2S and sulphur dioxide, as well as infrared cameras that detect leaks of hydrocarbons.[29] The AER uses these units to monitor locations where there have been odour complaints. If you have a problem, ask the AER to set up the monitoring unit in your area. Sometimes the AER will require a company to conduct its own air monitoring when they have received a complaint, or the AER may work with Alberta Environment and Parks and partner airshed organizations to conduct further monitoring, as they may have mobile monitoring equipment that can measure for more substances at lower concentrations.[30]

It is important that any monitoring equipment is properly located in an area where the air pollution is high and where conditions lead to bad air. Thus, the equipment should be downwind, where the emissions seem to be the worst when the wind speed is low or during air inversion conditions. Landowners or occupants can suggest what they consider to be the best monitoring location based on their experiences.

8.3 Drilling wastes

Well drilling generates large volumes of waste in the form of *drilling mud*, drill cuttings and *flowback fluids*, which require storage and disposal. Spills and leaks of drilling fluid, hydrocarbons or water produced during drilling operations must be carefully cleaned up, as required by the regulations, to minimize any contamination of soil and water.

Drilling mud is circulated down the drill pipe to cool the drill bit and maintain the desired pressure in the well. The mud is prepared and stored in tanks on or near the well site and circulated into the well bore as needed. The mud is then returned to the surface, carrying the drill cuttings with it. The mud may be a water-based clay mixture,

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[28] S. Roth and V. Goodwin, *Health Effects of Hydrogen Sulphide: Knowledge Gaps*, prepared for Alberta Environment (2003), vi. http://aep.alberta.ca/air/state-of-the-environment/condition-indicators/documents/HealthEffectsHydrogenSulphide-2003.pdf

[29] *Field Operations Provincial Summary 2012*, 2.

[30] The former Alberta Environmental Monitoring, Evaluation and Reporting Agency (AEMERA) was disbanded in 2016, and Alberta Environment has reassumed the roles of environmental monitoring and reporting.

but if there is a risk of encountering a water-sensitive subsurface rock formation, hydrocarbon-based muds are used. These hydrocarbon-based drilling muds have historically had a diesel fuel base. Mineral oil and canola oil are less toxic alternatives to diesel fuel but are typically more expensive and may have other operational challenges. Rock cuttings from the active drilling zone are normally separated from the drilling mud and collected in a *pit* (commonly referred to as a “sump”) or in large tanks. They ultimately form part of the drilling mud waste when the drilling project is complete.

The chemical composition of drilling muds varies, depending on the products that must be added to address the challenges at each well. Potentially toxic products include bactericides, emulsifiers, lubricants, shale control inhibitors and surfactants.[31] Drilling muds may also become contaminated with hydrocarbons or salts that are brought to the surface from deep underground formations.

Drilling muds, flowback and wastewater associated with hydraulic fracturing activities may also contain higher concentrations of naturally occurring radioactive materials (NORM). This may include uranium, thorium, radium (and their decay products); potassium-40; and lead-210/polonium-210.[32] As the name suggests, deposits of NORM occur naturally in different concentrations at different depths, depending on the underlying geology. Specifically, NORMs may be concentrated in shale or clay-rich layers, and therefore are often associated with unconventional oil and gas activities.[33] These activities and the storage or transportation of these materials can increase concentrations of NORMs above their natural background levels, when they are called technologically enhanced natural occurring radioactive material (TENORM).[34]

Reserve pits of hydraulic fracturing wastes present a potentially heightened risk of exposure, such as by animals drinking pit water, wind distributing dust particles onto nearby soil and crops, and waste water breaching the berms.

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[31] For a review of the composition and function of drilling fluid, see Don Williamson, “Drilling Fluid Basics,” *Oilfield Review* 25 (2013). http://www.slb.com/resources/oilfield_review/or_en_intro_article.aspx

[32] U.S. Environmental Protection Agency, “TENORM: Oil and Gas Production Wastes.” https://www.epa.gov/radiation/tenorm-oil-and-gas-production-wastes

[33] Ibid.

[34] Alisa Rich, Ernest Crosby, “Analysis of Reserve Pit Sludge From Unconventional Natural Gas Hydraulic Fracturing and Drilling Operations for the Presence of Technologically Enhanced Naturally Occurring Radioactive Material,” *New Solutions,* 23 (2013).

8.3.1 Drilling waste disposal

Current regulations allow a company to dispose of non-hydrocarbon-based drilling wastes on the lease site or access road, or to seek written permission to use public or private land in the area. As described in more detail below, landowners have the right to withhold their consent for many types of waste disposal methods, and have the ability to influence the management of waste on-site through their surface agreements and the negotiating process.

The AER sets out its requirements for drilling waste disposal in Directive 050: Drilling Waste Management. It specifies that the company must provide landowners with a copy of Information for Landowners on Consent for the Disposal, Treatment, or Storage of Drilling Wastes.[35] The Directive identifies several management methods of drilling waste disposal:

- management on a well site or remote site — includes storage, mixed-bury-cover, landspread, disposal onto forested public lands, biodegradation, mobile thermal treatment, landspray, landspray-while-drilling, and pump-off
- management on pipeline right-of-way — includes storage, mixed-bury-cover, landspread, landspray, landspray-while-drilling, and pump-off
- management on fields and vegetated lands — includes landspray, landspray-while-drilling, and pump-off
- use of approved waste management facilities — includes landfill, waste processing biodegradation, waste cavern, and waste disposal well
- subsurface disposal of drilling waste while drilling
- alternative management methods (as approved by AER).

These practices are described in the AER's FAQs about Directive 050.[36]

Drilling waste may contain heavy metals, sodium, chloride, hydrocarbons, nitrogen or TENORMs, which can degrade the quality of or be harmful to the soil. Contaminants may also be transported from the disposal location into *ground* and *surface waters*. Since these methods have the potential to pollute soils and surface waters, the AER Directive 050 specifies maximum loading or application rates (even nitrogen loadings should not be exceeded).

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[35] AER, Directive 050: Drilling Waste Management (2016)., section 1.5.

[36] AER, "Directive 050 FAQs." https://www.aer.ca/rules-and-regulations/directives/directive-050-faqs

Companies are required to sample and test the wastes prior to disposal for all options. Drilling wastes are not treated prior to land application unless these tests indicate the presence of toxicants in the waste. If this testing identifies that hydrocarbons are a likely source of toxicity however, disposal may still proceed provided that all criteria for the chosen disposal method are met.[37] Companies are also required to collect samples to assess the pre-soil conditions at the disposal site; in some cases, post-soil sampling is also required.[38] Landowners should ask to see the laboratory results and review the disposal method criteria that the company must adhere to. If, during drilling, a company later adds new substances to the mud that change its chemistry, they will have to revise their disposal plan. However, they do not have to take into account any changes they may cause in the level of salts from the rock formations or produced water when disposal is underway.

Landowners have the right to withhold their consent for any disposal that goes beyond the well site or pipeline right-of-way boundaries for any landspray, landspray-while-drilling, or pump-off methods, or a remote site for storage, mix-bury-cover, landspread or biodegrade wastes. The company does not have to secure consent if the drilling waste will be managed on the site where it was created.[39] Off-site waste disposal requires the approval of the landowner over and above the approval given for the well site itself, or of a nearby landowner who consents to the disposal process on their land. This approval should be in writing and attached to the surface lease or *right-of-entry* agreement, from which it should remain a separate agreement.

As a landowner, before giving permission for any drilling mud to be spread on your land, you should ask what type of drilling mud is being used and the level of compensation offered. If you agree to disposal on your land, ask to receive copies of the lab work on the mud sampling and the pre-disposal soil conditions, so you can ensure that the mud meets the criteria and the baseline condition of the disposal site is documented. If you are engaged in organic farming you will require the wastes to be taken off-site to maintain your organic status. Neighbours of organic farmers should also be aware that organic beekeepers can lose their organic status if sump fluids are spread within range of their hives.

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[37] AER, Directive 050, section 4.3.19.

[38] AER, Directive 050, section 9.2.2.

[39] AER, Directive 050, section 1.5.

The AER conducted 155 drilling waste inspections in 2012, and determined that 10 were high-risk noncompliant. The primary reasons for noncompliance were inadequate disposal practices resulting in pooling, clumping, or erosion; inadequate sump location; and failure to get landowner approval for off-site disposal of drilling wastes.[40]

8.3.2 Drilling waste treatment

There are environmentally preferable methods of treating and disposing of some wastes, particularly for invert and hydrocarbon-contaminated muds. These methods include oilfield waste treatment facilities, thermal destruction, or disposal in hazardous waste landfills. Companies should be encouraged to dispose of their waste in the way that minimizes environmental impacts.

8.3.3 Spills, leaks and contamination

You may have concerns that an oil or gas well or pipeline is contaminating soil or water. You may see a leak or spill, or it may be indicated by a change in vegetation growth in a certain place. Unless it is an emergency situation, you should first ask the company to deal with the problem, although you should report the issue to the AER as well. If you are not satisfied that the problem has been adequately resolved, you will need to contact the AER again. Occasionally a leak or spill will contaminate the property of a neighbour. The *owner* or leaseholder of the affected land should notify the AER as soon as possible, and ensure that they require the company to complete a thorough clean-up and *remediation* of any affected land. If staff from the AER find evidence of spills, leaks or improper conservation, they can take various enforcement actions (Section C.2.1).

If you find a spill or leak you should contact the AER on the Energy and Environmental 24-hour Response line: 1-800-222-6514.

8.3.4 Land sales and contamination

Despite the fact that a company is liable for any contamination that results from its activities, as the landowner you are required by law to disclose any known contamination or "latent defects" when you sell your property. A landowner can be sued

[40] *Field Operations Provincial Summary 2012*, 11.

for deceit or fraud if they have intentionally or recklessly misled a buyer, and the buyer has been harmed as a result.

Despite this: buyer beware. Recent court cases have suggested that "the burden of thoroughly investigating a site remains firmly on the purchaser's shoulders".[41] Much of the time, land contracts may transfer land "as is" and exclude a warranty outside of the scope of the contract, such as the condition of the soil. Therefore if an engineering report recommends that further investigation is necessary, or there are other indications that investigation needs to be done, if you do not do your due diligence the liability may fall on you as a buyer.[42] In some cases the purchaser's bank has asked for an environmental assessment if a *reclamation certificate* has not been issued (Section 9) and it is possible they may want an environmental audit before they grant a mortgage. The current landowner would normally have to pay for this audit. Also, some lenders may ask for an environmental assessment of sumps or sites used for drilling waste disposal before allowing a person to use their property as security for borrowing, although this is not universally asked. These sites may or may not be identified specifically on resources like the Environmental Site Assessment Repository (ESAR), so you may have to dig into the approval of past projects to determine if these sites existed in the past. The Farmers' Advocate's Office may be able to give advice in these situations.

8.4 Water

Water is required for all oil and gas operations. Water is used in drilling muds, and is also commonly injected into oil or gas wells to enhance production through water-flood or hydraulic fracture operations. Any operation that plans on using water must receive approval from the AER for their proposed source.

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[41] See Motkoski Holdings Ltd. v. Yellowhead (County), 2008 ABQB 454 (Q.B.). http://www.albertacourts.ab.ca/jdb/2003-/qb/civil/2008/2008abqb0454.pdf; and Motkoski Holdings Ltd. v. Yellowhead (County), 2010 ABCA 72 (C.A.). http://www.albertacourts.ab.ca/jdb/2003-/ca/civil/2010/2010abca0072.cor1.pdf

[42] Rob Omura, "Fraud and Concealment of Contaminated Land: Do Your Due Diligence, Purchaser," *ABLawg,* June 2, 2010. http://ablawg.ca/2010/06/02/fraud-and-concealment-of-contaminated-land-do-your-due-diligence-purchaser/

8.4.1 Water wells

Two separate issues need to be considered with respect to water wells: the effect that water wells drilled by an oil and gas company can have on groundwater, and the impacts that may be caused by oil and gas wells.

Historically, companies have drilled water wells to get water for drilling muds, but in some areas water is also used for "waterflood" operations, where it is injected into an older reservoir to enhance oil recovery. Hydraulic fracturing water use for extracting oil and gas has also exponentially grown (see Section 4.7 for more on hydraulic fracturing). While a properly constructed oil and gas water well should not allow pollutants to reach groundwater, these wells may draw from aquifers needed to supply water for domestic and agricultural operations.

Water wells can only be drilled by someone who has a current approval from Alberta Environment and Parks to drill water wells; they must follow the construction standards set out in the Water Regulations under the Water Act. A company must apply for and receive a well licence from the AER only if a water well is drilled deeper than 150 metres.[43] Before a company withdraws water from a water well for drilling operations they must apply for a temporary diversion licence. Companies must obtain a term licence under the Water Act prior to any large-scale or long-term diversions of *non-saline groundwater* (Section C.3.4).

Baseline water well testing

Many landowners ask the company to pay for the testing of their water well when they negotiate a lease agreement. This is to ensure that there is a baseline study against which to compare any future changes in well water quality that might result from oil- and gas-related operations. You should ensure that the laboratory carrying out the tests is accredited by the Canadian Association of Environmental Analytical Laboratories (Section B.1.3). Be sure to ask for a copy of the test results and keep it for future reference.

The test should be thorough and cover both water volume and water quality. A basic flow test should involve pumping a well at a constant rate for at least 60 minutes, although in some cases, pumping for 120 minutes or for a day or more may be necessary. While the pumping rate is maintained, the water levels should be recorded in the well to measure the draw down. The well should then be allowed to recover for the

[43] AER, Directive 056: Energy Development Applications and Schedules (2014), section 7.

same length of time that it was pumped, and again the depth should be measured to calculate the recovery rate of the well. In situations where the top of the well is inaccessible, it may not be possible to calculate the draw down and recovery rate, but the well should still be pumped to determine the yield. Alberta Agriculture has a great resource regarding water wells and how to determine yield.[44]

A routine water quality test measures about ten parameters, including total dissolved solids, total hardness, alkalinity, pH, chlorides, sulphates, nitrates and nitrites, and sodium. You should ask for the test to include total extractable hydrocarbons, to establish that there are no hydrocarbons in the water before drilling starts. A test for metals, including arsenic, cadmium, copper, lead, manganese, and zinc, may also be a good idea. A test for gas content may be advisable if there is a risk of gas migration from an oil and gas operation, such as shallow coalbed methane or hydraulic fracturing operations. You can ask the company to pay for these tests, and negotiate it as a condition in your surface access lease.

If a company is unwilling to pay for a routine water quality test by an independent company before it constructs an oil or gas well, you may want to ask the AER to facilitate your negotiations. While the water is being tested, you may also want to get a test done for total fecal coliforms, as these organisms can cause acute illness. However, a company may not want to pay for this part of a test, as it does not relate directly to oil and gas activities. You may want to contact the local health unit regarding bacterial tests as many health units in Alberta will cover all or part of testing costs for routine and bacterial analyses of domestic water wells.

A water test that includes the testing according to the Canadian Drinking Water Quality Guidelines as well as comprehensive parameters frequently required for drinking water approvals can cost up to $2000.

Health Canada sets standards for the acceptable level of substances in drinking water.[45]

Water well drillers submit their drilling reports to the Alberta government and this information is stored in the publicly available Alberta Water Well Information Database.

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[44] Alberta Agriculture, Food and Rural Development; Alberta Environment; and Agriculture and Agri-Food Canada, *Water Wells that Last,* eighth edition (2013), 69. http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404/$file/waterwells.pdf

[45] Health Canada, *Guidelines for Canadian Drinking Water Quality – Summary Table* (2014). http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/sum_guide-res_recom/index-eng.php

Chemical analysis data after 1986 is not stored on the database; you must contact the landowner if the land is not your own.[46]

Water well quality concerns

The Alberta Energy Regulator is responsible for concerns that relate to water well contamination if thought to be caused by oil and gas activity (see Figure 6). If it finds that oil or gas industry activity could have caused the contamination, they will investigate. If you have a complaint about a water well that may be affected by the oil and gas industry or groundwater contamination, you should call the AER's Energy and Environmental 24-hr Response line at 1-800-222-6514.

If you suspect your well has been contaminated by hydrocarbons from oil or that gas may have leaked into the groundwater, you should get your well tested by an independent laboratory (you can find a directory of private laboratories in Section B.1.3). All tests that were conducted before the oil or gas well was drilled should be repeated and, in addition to the test for total extractable hydrocarbons, you should also request a BTEX test (for benzene, toluene, ethylbenzene and xylenes). If you find gas in your well, a carbon isotope of each gas detected may help identify the source. You may want to negotiate with the company to arrange for them to pay for the costs of testing the well. If you need help, contact the Farmers' Advocate Office and inquire about their Water Well Restoration or Replacement Program (Section A.4).

[46] Alberta Environment and Parks, "Alberta Water Well Information Database." http://aep.alberta.ca/water/reports-data/alberta-water-well-information-database/default.aspx

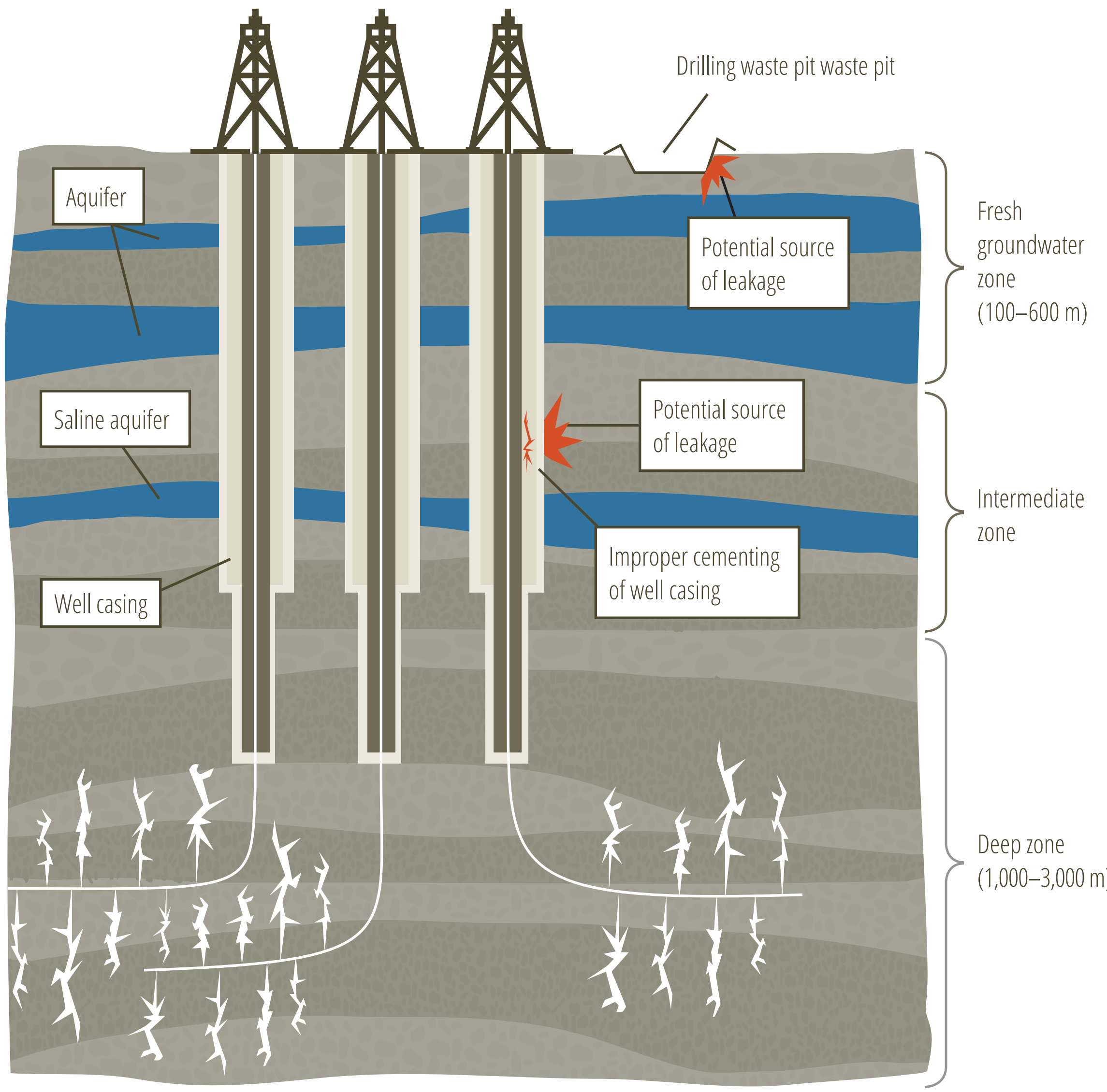

Figure 6. Schematic of well with groundwater layers and potential sources of leakage[47]

[47] The illustration reflects an idealized geology. Geoogical formations can have very different characteristics that can result in the layers not being straight, predictable and uniform (as illustrated).

8.4.2 Surface water

Surface water can also be used to supply the necessary water at an oil and gas operation. Surface water is collected by water trucks and transported to the development site. Due to the intermittent supply, surface water is not suited for continuous operations. Instead, surface water tends to be used for drilling muds, well testing, and hydraulic fracturing where water is only required for a temporary period.

If surface water is proposed to be used, the operational requirements to withdraw the water will be stipulated in an operator's water licence. It is standard for these licences to require use of a fish screen in water courses or bodies that are known to contain fish populations, and to limit withdrawals from watercourses to 10% of the instantaneous flow rate. These requirements ensure that fish populations and the aquatic ecosystem are not significantly affected by withdrawal of the water. If a company is observed withdrawing water from a waterbody or watercourse on your property, they are required to show you their licence upon request. If you believe water licence requirements are being contravened, you should notify the AER and provide any supporting evidence.

8.4.3 Coalbed methane water issues

Coalbed methane (CBM) is an unconventional natural gas formed in coal seams, also known as natural gas in coal or natural gas from coal. Coal seams can be found across the southern half of Alberta.

If a coal formation contains water, it will be necessary to remove some of the water to reduce the pressure and allow the gas to be released. In some coal seams in central Alberta (for example, those in the Horseshoe Canyon formation) the coal is "dry" and no dewatering is necessary; however, deep coal formations (such as those in the Mannville group) usually contain saline groundwater.[48] This water will usually be pumped out and piped to a central injection well, where it will be re-injected deep underground, in the same way that saline water from a conventional natural gas well is re-injected. If the saline zone is close below the non-saline zone, a company should not produce any gas from the non-saline zone, since this could result in the mixing of water of different qualities.

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[48] Saline groundwater is defined as water with more than 4,000 milligrams per litre of total dissolved solids (Alberta, Water (Ministerial) Regulation, 205/98, s 1(1)(z)). The depth at which water becomes saline varies widely, but the transition may occur at between 400–600 metres in Alberta.

It is mandatory for an operator of a coalbed methane well to conduct baseline water testing for a new well or *complete* or recomplete wells if the wells are shallow and above the *base of groundwater protection* (BGWP).[49] Since these are being drilled into shallow non-saline aquifers and these aquifers require dewatering to release the gas, their operations have the potential to impact the flow to other water wells.

> A conventional gas or oil well will sometimes produce saline water, and the quantity will probably increase as the well ages. This water is pumped out with the oil or gas, separated and injected back deep underground. If a CBM well contains water, it will need dewatering at the start of operations so that the gas can be released.

You should get your water wells tested prior to any CBM development in a shallow, non-saline aquifer in the vicinity of your water well. The AER requires that developers offer to test all active water wells within a minimum 600-metre radius of a proposed CBM well prior to drilling or recompleting the well.[50] Companies are required to provide detailed reports before the AER will consider an application for the diversion of groundwater. This is because dewatering of the coal seams could lower the water level in domestic wells, if the coal is near the surface or there is hydraulic connectivity with shallow aquifers. This data will provide a baseline against which to measure any future changes.

If, after drilling, a company finds they need to divert non-saline water from the coal seam, they must submit a technical report to the AER together with their application. The technical report must include detailed information about the hydrogeology, aquifers and water wells. The AER administers Alberta Environment and Parks water standards that require a company to test water wells for gas and, if gas is detected, to test for the carbon isotopes of each gas.[51] This will help identify the source of any gas

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[49] The base of groundwater protection is the term the AER uses to define the approximate depth where non-saline groundwater changes to saline. AER, Directive 035: Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection (2013), 1. AER Directives are available at AER, "Directives." http://www.aer.ca/rules-and-regulations/directives/

[50] If there is no well within 600 m, the operator is required to offer to test all wells within 800 m. AER, Directive 035.

[51] Alberta Environment, *Gas Sampling Requirements for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations* (2006). http://esrd.alberta.ca/water/inspections-and-

and serve as a baseline, in case the CBM development leads to any gas migration in the future. The Alberta Energy Regulator also publishes a public notice about the proposed water withdrawal and must respond to any statements of concern from the public. The Regulator is required to consider all statements from those who are directly and adversely affected, before they decide whether to authorize the diversion of water from the aquifer.

If a CBM well is drilled into a non-saline aquifer, you should ask about plans to dewater the coal seams, any potential impacts on groundwater, and how the water will be handled.

While saline water must be re-injected deep underground, there may be different ways of handling non-saline water. If the Alberta Energy Regulator issues a licence or approval for diversion of non-saline aquifers, it will indicate how the water must be handled. Even water that is defined as non-saline must be managed carefully, since the level of salts may be sufficient to damage soils and crops. Depending on the level of salts, non-saline water — that may still contain more than the standards of dissolved salts for potable water — may be used for watering livestock. Whether the water is suitable for irrigation will depend not only on the salt content and the crops grown, but also on the sodium adsorption ratio of the receiving soil. Alternatively, the water may be discharged or re-injected into a compatible aquifer underground. Since the quality of the water may change during the dewatering process, regular testing of the salinity level should be requested.

> While guidelines are designed to prevent damage to a non-saline aquifer, it is still advisable to ensure that a company will provide an alternate water supply should your water well be adversely affected by CBM drilling. You should include a clause in your surface lease agreement to this effect.

Licences issued by the Alberta Energy Regulator for groundwater diversions typically include “investigation and mitigation” requirements that may include alternative water supply arrangements if needed. You typically would need to provide a written complaint to the Alberta Energy Regulator to initiate an investigation.

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compliance/baseline-water-well-testing-for-coalbed-methane-development/documents/GasSamplingRequirementsWaterWellTesting.pdf

8.5 Noise

Compressor stations, processing plants, well batteries, well drilling and servicing operations can all cause noise, which is especially noticeable in quiet rural areas. If you have a complaint, you should first contact the company, but if you have a problem locating the company or if you are not satisfied with their response, contact the AER 24-hour Emergency and Operational Complaint number, 1-800-222-6514, and ask them to help (Section A.2).

Noise is measured in decibels, which is a logarithmic scale; an increase in ten decibels is perceived as a doubling in noise level. Examples of the sound levels of familiar noises[52] are given in Table 6.

Table 6. Examples of noise levels

Source	Sound level (dBA[53])
Soft whisper at 1.5 metres	30
Quiet office or living room **AER target[54] nighttime sound level at low density housing with dwellings more than 500 m from heavily travelled roads[55]**	40
Inside average urban home, quiet street, refrigerator	50
Noisy office, conversation at 1 m	60
Highway traffic at 15 m	75
Jackhammer	88–98
Loud shout	90
Modified motor cycle	95
Amplified rock music	110

[52] AER, Directive 038: Noise Control (2007), appendix 2.

[53] As explained in AER Directive 038, appendix 3, sound is measured in decibels, but, to approximate the human hearing response at low frequencies, the decibel sound is filtered through the A filtering network and the sound is measured as dBA. The AER uses dBA Leq, which represent energy equivalent sound levels.

[54] AER, Directive 038, 3. This is a target and does not establish compliance should infringement occur.

[55] AER, Directive 038, table 1.

The AER policy on noise is summarized in Directive 038: Noise Control. This directive also sets out noise requirements for all facilities approved by the AER, including drilling and service rigs. The directive aims to keep sound levels to an acceptable minimum so that the quality of life for neighbours of a facility is not impaired and their sleep is not affected. The directive regards noise from the "receptor viewpoint" rather than considering sound levels at the property line.

A person can make a complaint about noise in different ways — in person or by phone, fax, email or letter. Once the company has been informed, it must contact the complainant directly to try to understand the concerns and work out reasonable expectations and a time frame for action. Section 2 of Directive 038 sets out what the AER considers permissible sound levels. Section 4 provides more detail about dealing with complaints and Appendix 5 includes a noise complaint investigation form that the company and the complainant will need to complete. If a company conducts a sound survey, it must ensure it is carried out under representative conditions that would affect the person complaining.

A noise impact assessment is required for a new facility, or for modifications to an existing facility, to identify and deal with aspects that might later cause problems. For these facilities, a company commits to the AER in its application[56] that it will comply with noise requirements set out in Directive 038. If the company does not comply, it has two options: satisfy the complainant or do what it takes to meet the noise guideline. This includes shutdown of the facility if necessary.

Although Directive 038 does not cover construction operations, the AER expects construction companies to keep noise to acceptable levels and take reasonable mitigating measures, such as only undertaking noisy operations between 7 a.m. and 10 p.m. The AER also asks operators to advise nearby residents of noise-causing activities and to schedule them to cause the least disruption.[57]

[56] AER, Directive 056.

[57] AER, Directive 038: Noise Control (2007), 13.

8.6 Conservation and reclamation

A company is required by law to pay attention to conservation and to minimize damage to the environment during the development and operation of an oil or gas well. Alberta Environment sets guidelines for soil conditions for *reclamation*[58] (Section 9.2) but you may want to discuss issues relating to your specific site.

8.6.1 Pre-development

Landowners should discuss and outline in an agreement with the company how they will preserve topsoil so that it can be used later to help restore the site. It is important that the topsoil be stripped and stored carefully; it must not be used for the construction of berms or dykes. It may also be advisable to have a layer of *subsoil* under roads and well sites stripped and stored separately, since years of compaction can cause permanent damage to the soil structure. In some situations it may be advisable to ask that an elevation survey of the site be completed along with the basic survey, to ensure that the surface of the land is later restored to the same elevation and that drainage is not affected.

Paying attention to the way in which a company deals with its drilling wastes may also prevent problems when the site is eventually closed down and the leased land reverts to the landowner. As remote sumps and disposal sites are often difficult to identify, a landowner should require the company to clearly identify their locations in their surface lease agreement. This ensures that when a site is abandoned the company can reclaim any site where disposal or remote sumps were located, prior to applying to AER for a reclamation certificate.

After the lease is signed, but before the company starts operations, a pre-construction site assessment report should be completed and provided to a landowner. This report provides a baseline against which to measure any future changes. Alberta Environment and Parks provide a recommendation on what should be included in this report.[59]

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[58] Alberta Environment and Parks, "Reclamation Criteria for Wellsites and Associated Facilities Application Process." http://aep.alberta.ca/lands-forests/land-industrial/programs-and-services/reclamation-and-remediation/upstream-oil-and-gas-reclamation-and-remediation-program/wellsite-reclamation-certificate-application-process.aspx

[59] Alberta Environment and Parks, *Pre-construction Assessment Report for Wellsites,* C&R/IL/00-8 (2000). https://extranet.gov.ab.ca/env/infocentre/info/library/6889.pdf. As this information letter indicates, the assessment should include a description of the land use, the type of surface

In areas of native pasture and parkland, a company should avoid or minimize its impacts on native vegetation.[60]

8.6.2 Post-development

Problems can arise during work to abandon and reclaim a well site. The AER is responsible for *down-hole* well closure, and in 2014 assumed responsibility for the regulation of reclamation and remediation activities resulting from oil, gas, and coal operations. Complaints about surface reclamation on both public and private lands should be made to the AER 24-hour Emergency and Operational Complaint number, 1-800-222-6514.

The process for reclamation is explained in Section 9. The fact that a reclamation certificate has been issued does not guarantee that work has been done well, as problems may not become evident until later. At the time of writing, a company is responsible for 25 years for surface reclamation issues such as vegetation, soil texture, drainage etc; and it has a lifetime liability for contamination.[61] If landowners or occupants have problems with the reclaimed land they should contact the company first and then notify the AER. An AER inspector may inspect the site and may require the company to conduct further work in response to the notification.

8.7 Animal health

Problems can arise if animals eat contaminated vegetation or come into contact with contaminated soil, or spills such as oil, condensate, or hydraulic fracturing fluids. Animals may also be affected by air emissions. If you believe that activity may have an impact on your livestock, you can negotiate precautionary elements into your surface lease agreement such as fencing to ensure your animals don't come into close contact

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soil salvage, the average depth of surface soil, the location of salvaged stockpiles, and drainage. It should detail any evidence of erosion or salinity, areas with poor vegetation, and weed patches, and ideally would include photographs. You may want to take your own photographs of the site before work starts, to augment the information provided in the pre-construction assessment report, in case there is any later damage that is not satisfactorily reclaimed. The information letter tells you who to contact if the company does not agree to provide this report.

[60] AER, Principles for Minimizing Surface Disturbance in Native Prairie and Parkland Areas (April 2014) https://www.aer.ca/documents/manuals/Manual007.pdf

[61] AER, *Closure – Abandonment, Reclamation, and Remediation Fact sheet* (2014). http://www.energy.alberta.ca/LandAccess/pdfs/ERSfsAERclosure.pdf

with the well site. Landowners concerned about the impact that air pollution might have on their animals should request assessments of the project's emissions and the location of where they are released in relation to active pasture lands. You can also include clauses in your agreement that cover the costs of a necropsy in cases where you suspect nearby development may have played a role in an animal death. It would be helpful to have an ongoing relationship with a veterinarian to establish a herd health baseline, so that you can monitor changes in health and behavior to compare to the health of the herd prior to development.

If you believe that oil or gas activity is affecting the health of your livestock, contact your local veterinarian and the AER's 24-hour Emergency and Operational Complaint number at 1-800-222-6514. An independent animal health investigator may be called in. Be sure to keep a record of events and take photographs to aid any investigation.

The Clean Air Strategic Alliance Animal Health Project Team was set up in 1999 to prevent short- and long-term animal health impacts due to air contaminants. Their report includes a bibliography of research studies conducted to investigate these impacts.[62] The team conducted a survey of air quality impacts on animal health and designed the Herd and Environmental Record System, to enable livestock owners to address livestock health issues potentially associated with air emissions.[63] In 2001, the Western Interprovincial Scientific Studies Association was founded to study the impacts of air emissions from the oil and gas sector on animal health in Alberta, British Columbia, Manitoba and Saskatchewan.[64] The study, only available for purchase from the Alberta Energy Regulator, broadly concluded that "there were no associations between the measured exposures and most of the health outcomes" they investigated.[65]

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[62] Clear Air Strategic Alliance, *Animal Health Project Team Final Report and Recommendations* (2003), 24.
http://casahome.org/PastProjectsAwards/PastProjects/AnimalHealth.aspx?EntryId=493

[63] Clean Air Strategic Alliance, "Herd Environmental Record System."
http://casahome.org/PastProjectsAwards/PastProjects/AnimalHealth/HerdEnvironmentalRecordSystem.aspx

[64] Manitoba Innovation, Energy and Mines, "Western Canada Study on Animal and Human Health Effect Associated with Exposure to Emissions from Oil and Natural Gas Field Facilities", news release, November 19, 2001.
http://www.gov.mb.ca/iem/petroleum/air_quality/western_canada_study.html

[65] Western Interprovincial Scientific Studies Association, *Western Canada study of animal health effects associated with exposure to emissions from oil and natural gas field facilities: a study of 33,000 cattle in British Columbia, Alberta, and Saskatchewan* (2006), 13.

However, there were some statistically significant correlations between hydrogen sulphide, sulphur dioxide, and VOC exposures and the risk of calf mortality and calf medical treatment.[66] Additionally, there is little research that has measured herd health in respect to newer unconventional practices and their associated potential contaminants.

[66] Ibid., 14.

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