NEW PARADIGM ENGINEERING LTD.

what if
why not

Appendix B
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Environment Canada Contract #3000624798

"Information on Venting Emissions Quantification and Control Options at Upstream Crude Oil Facilities"

Task 2 – Review of Current Measurement and Control Actions

1. **AER Directive 017 *<u>"Measurement Requirements for Oil and Gas Operations" (March 31, 2016 release)</u>***

    1.1. **Purpose of Directive 017 –** This Directive is to address acceptable levels of accuracy of measuring oil and gas streams for a number of purposes and has been evolving since they were first issued after a 1972 ERCB hearing that set accuracy targets of 2% for oil, 3% for gas and 5% for water. The greatest focus and most rigorous standards are applied to delivery/sales or custody transfer points, because those points have the greatest impact on royalty determination for the crown, or other Petroleum & Natural Gas Rights owners. As stated in the Directive's Introduction: *"Other measurement points that play a role in the overall accounting process are subject to less stringent accuracy standards to accommodate physical limitations and/or economics."* As a result this Directive does not place a high value on the accuracy of measuring vent streams, which attract no royalty or tax and are not part of some other "accounting process". Further there are provisions in section 1.2 for licensees to *"deviate from the minimum requirements without specific AER approval if no royalty, equity, or reservoir engineering concerns is associated with the volumes being measured and the licensee is able to demonstrate that the alternative measurement equipment and/or procedures will provide measurement accuracy within the applicable uncertainties."* Since gas venting is mainly an environmental issue, it is not clear to what degree Directive 017 is applicable to direct vent measurement for site produced gas volumes under 2,000 m^3/d or venting under 900 m^3/d. The main area the Directive does focus on is volumetric reporting of total oil, gas and water which can impact reservoir engineering analysis of well performance. So, for heavy oil, this would require ensuring that individual well GORs are accurately determined for each well, as that is a key factor in assessing heavy oil well performance under foamy flow or CHOPS conditions.

    1.2. **Major Overall Concern for Directive 017 – Determination of a Representative GOR** – Since the majority of cold heavy oil batteries do not currently appear to require continuous gas measurement, a key factor in estimating site vent volumes is in the proper determination of the Gas to Oil Ratio (GOR). The basis for this practice is based on sound reservoir engineering experience that the GOR is an inherent property of in-situ oil or bitumen in a given reservoir formation, so should stay relatively constant over time. If this were not true then estimating gas production by this method would not be appropriate. The determination of GOR is important for two purposes.

        1.2.1.1. **Determine if Associated Gas is Being Produced** – Producers, especially if oil and gas rights are separate for a formation, must ensure that large volumes of gas from a gas cap overlying the oil/bitumen formation are not being produced which would result in loss of resources. Generally in heavy oil operations a GOR over 150 m^3/m^3 might indicate potential for associated gas production and require additional testing.

        1.2.1.2. **Estimation of Total Solution Gas Production** – Knowing total solution gas production can assist in understanding oil production through foamy flow and other mechanisms so should be of value to measure, even if it is for future use for evaluating follow-up recovery processes. It is also the starting value in balancing the volumes of gas being vented, flared, sold or used as fuel on the lease.

1.3. **Sections Impacting Heavy Oil** – Since Directive 017 is intended to cover a large range of oil and gas operations and has been in use and evolving for many years, reviewing and commenting on all aspects of 427 page document was not practical. For this report the main focus is on Section 12 – Heavy Oil Measurement and other sections referred to in section 12. The following are some areas of concern identified in this section:

1.3.1. **Section 12.2.2.1 Single-Well Batteries – Initial GOR Determination** – This section starts off by saying *"For initial well startup, in the absence of suitable reservoir information, monthly tests must be conducted to determine the GOR factor or the hourly rate if gas volumes are not dependent upon oil production volumes for 6 months or until gas production stabilizes and measurement is require if over 2.0 10^3 m^3/d.…"*. **Concern:** The ***"absence of suitable reservoir information"*** is not defined as to what is "suitable". Most measured conventional, oil sands and heavy oil formations can be seen to have relatively consistent GORs over time, for oil from the same formation in the same area and depth, so should have relatively predictable GORs. If producers have confidence in predicting oil production from a new well based on a formation or area type curve, then they should also have a good handle on the GOR, and therefore gas volumes, which could be expected from that type of well, assuming quality GOR determinations are being made. Taking 6 months or more to determine a GOR delays the assessment of the site's total gas production and consideration of conservation actions until the well has already been on production for 6-14 months, by which time oil and gas volumes will be declining and potentially over half the solution gas could already have been produced from a well. **Recommendation:** Define ***"suitable reservoir information"*** to require use of an estimated reservoir GOR, to proactively assess the need to measure and conserve gas, after a given formation has at least an average of 0.5 to 1 producing wells/section/township in that formation (i.e. 18 to 36 producing wells per township producing from a formation), or some other metric.

1.3.2. **Section 12.2.2.1 Single-Well Batteries (and other single well tests) – Use of Monthly Total Oil Trucked Volume for GOR Determination** – For royalty purposes oil/bitumen in the tanks can be considered as still in the reservoir, so monthly truck volumes are suitable for accounting purposes, however, their use for GOR determination is extremely questionable for matching with a 24-hour gas rate test. Also pump speeds and run times are not always accurately tracked and reported. However, Section 12.2.2.1 states that: *"For single well oil batteries the oil volume used in determination of the GOR factor can be based on the monthly total oil production (monthly total volume/hours produced in a month x test duration)."* **Concern:** Since most primary/secondary heavy oil wells are equipped with Progressing Cavity Pumps (PCPs), which are variable-speed positive displacement pumps, it is very easy for operators to change pump speeds and often they are encouraged to make daily or weekly speed adjustments to try and optimize the pumping rate to maximize production. As a result the average volume produced per operating hour in any given month can vary widely, and with low oil rate wells it may take weeks to fill a lease tank enough to trigger a truck load, so the trucked volume per month may not be at all representative of the oil rate produced during the 24-hour gas rate test to determine GOR. Also, GORs could be biased if they are intentionally taken when pump speeds are reduced, which will result in less gas production during the 24-hour test than would be produced on average during the month. Section 6.4.4.1 Well Test Consideration requires that *"If there is a change in operating conditions during a test, such as due to a power failure or a change in choke setting, the test must be rejected and a new test must be conducted."* Section 12.2.4 Well Test Measurement with Tank Gauging or Metering also requires that: *"Wells in primary/secondary production of heavy oil must be tested at the frequency stated in 6.4.4. The tests must be conducted in a consistent manner throughout the month and a test must be conducted when there is a change in well parameters (pump speed, work-over, reactivation, flush-by, etc. as soon as possible."* **Recommendation:** Because of the high variability in monthly oil flows, the GOR determination for a test should only be based on a sufficiently accurate tank inventory change, measured over a period where the pump rate is verified as being held constant, no upsets occur, and over a long enough period to achieve a representative oil volume of +/-2%. (Section 12.2.4 provides guidelines for tank measurement accuracy) Ideally the gas flow measurement would be taken over the same time as the oil measurement by tank gauging with a minimum 22-24 hour test.

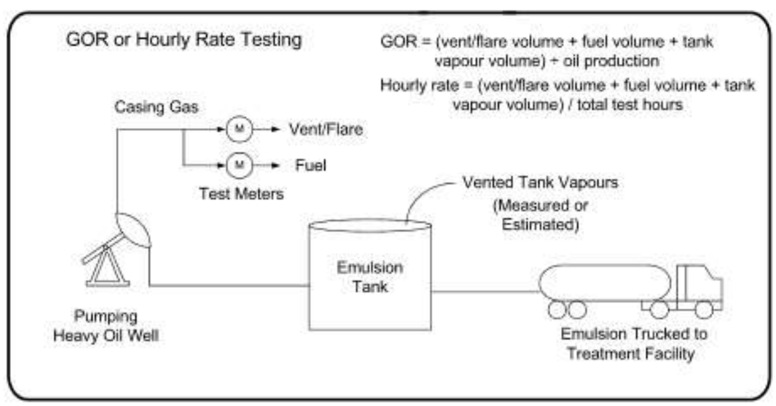

Figure 12.1 GOR or hourly rate testing schematic

GOR or hourly rate test frequencies are detailed in the table below.

Table 12.1 GOR or hourly rate test frequency requirements

Gas rate (10^3 m^3/d)	Test frequency
≤ 0.1	Once every 3 years
> 0.1 but ≤ 1.0	Annually
> 1.0 but < 2.0	Semiannually

Figure 1 – Single Well Test Measurements and Frequency Requirements

1.3.3. **Section 12.2.1.2 Crude Bitumen Administrative Grouping – Petrinex Subgroup 343 –** States that *"It is acceptable to move fluids between locations within the same crude bitumen administrative battery. These volume movements are not reported to Petrinex but must be managed in a field data capture system"*. However later it states that *"No flaring, venting, or fuel can be reported at the crude bitumen administrative battery level. Flaring, venting and fuel activity must be reported at the location where it physically occurred, i.e. at the well site."* **Concern** – Moving oil/bitumen within the "paper battery", without formal reporting, might result in use of incorrect data for calculation of GORs on a well basis, or result in incorrect or different GORs being reported through Petrinex than are actually being encountered in the field. It is not clear if GORs will be calculated from Petrinex or a "field data capture" system to ensure each well is assigned the correct GOR. **Recommendation:** Clarify that no transfers between wells in a paper battery should be made while a well is undergoing testing to determine GOR, and that the corrected "field data capture" number should be used to estimate produced GOR. Alternatively the Directive could be changed to require reporting of interwell movement of fluids in Petrinex, since they impact well assessments even though they would not impact royalties.

1.3.4. **Section 12.2.1.3 Multiwell Group Battery – Petrinex Subgroup 341** - States *"Each well must have its own separation and measurement equipment, similar to a single-well battery."* **Concern:** Issue of potential for "cascading" tanks where a number of wells are set up to flow through a series of tanks to improve separation through more efficient heating. It is uncertain if this is routinely being done or how many sites this might effect, but it is not suitable for well measurement or GOR determination and gas rate estimation. **Recommendation:** Audits to ensure this practice is not being used.

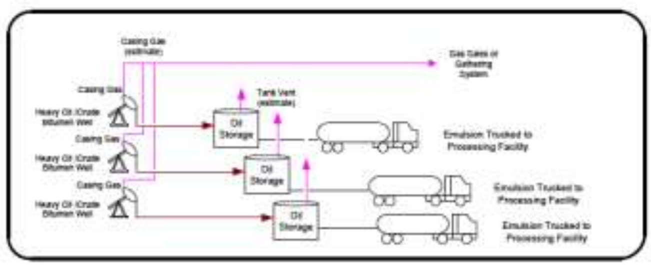

Figure 8.16 Heavy oil/crude bitumen multiwell group battery

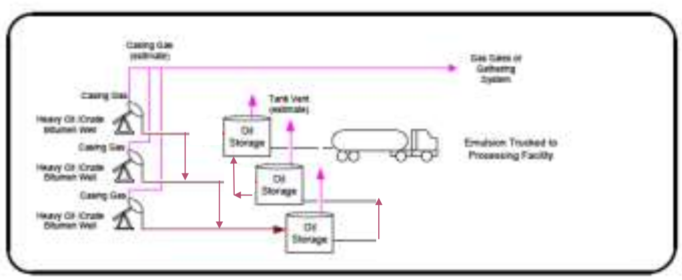

Figure 2 – Multi-well Group Battery Configuration from Directive 17 and Assumed Arrangement for "Cascading" Tanks to Enhance Separation

1.3.5. **Section 12.2.1.4 Multiwell Group Battery Proration Batteries – Petrinex Subgroup 342** – Where all oil and water production is comingled and well tests are used to allocate oil and water to individual producing wells. Using a proration factor allows allocation of production each month based on tests on each well. The proration factor is the sum of the individual well tests at the proration battery, divided by the total measured production from the battery. **Concerns:** 1) Gas should also be allocated by prorationing in the same manner as for oil and water. This requires that: a) the total gas stream be measured, and b) that the gas from a well on test is measured at the same time to ensure proper allocation. 2) Tests of oil and gas must be compared against prior and following tests to ensure that the results are consistent with what should be expected from previous tests to avoid “spikey” type curves discussed in the review of 2004 Proposed Vent Quantification Standards. Test rates for oil and water should be assessed based on the pump speed recorded for the test to ensure consistency to avoid errors in reporting. **Recommendation:** 1) All multiwell batteries should be equipped to measure the total gas flow on a continuous basis even if the gas is not being sold or used off the lease, independent of battery gas production volume; and gas from each well should be tested at the same time and duration as the well test for oil and water. 2) Any well test which deviates by more than +/-15% (limits for prorationing) from the expected liquid flowrate based on the pump rated capacity at the recorded pump speed should be reviewed and the well should be retested.

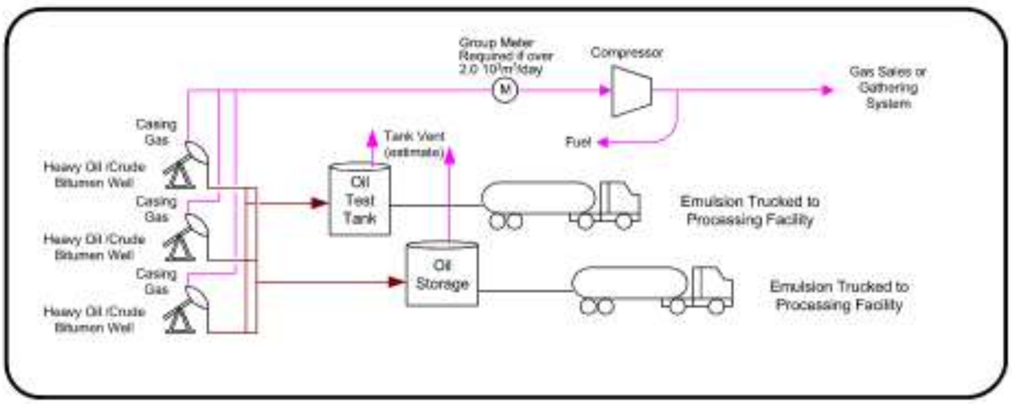

Figure 8.17 Heavy oil/crude bitumen multiwell proration battery

Figure 3 – Multi-well Proration Battery Configuration from Directive 17 Assuming Gas Sales from the Lease

1.3.6. **Section 12.2.2.2 Gas Measurement at Multiwell Batteries** – States that: *“If gas disposition is metered at a multiwall proration battery and is sold or used at a point further on, gas production volumes for each well over 2.0 10^3 m^3/d must be tested, unless metered, on a per stream basis at the same frequency as the emulsion testing, or if not more than 2.0 10^3 m^3/d, calculated using the well GOR or hourly rate at the same initial frequency as a single-well battery, and then in accordance with table 12.1 after stabilization.”* It further states that: *“If associated gas is flow lined to a central facility or collection point and gas production rates at the point of collection or emission are less than 2.0 10^3 m^3/d and not metered, a battery or facility GOR may be determined, but gas production reporting must be at the individual well level. Initial and updated factors may be determined by any of the applicable tests or procedures described in section 4.3.5.2 and at the same frequency as a single-well battery.”* **Concern:** Given that larger pads should be more likely to produce sufficient gas per pad initially to make capture necessary, based on Directive 060, and since it is more economic to install metering equipment for pads, the standard of measurement and determination of GORs should be higher for multiwell pads than for single-well pads. **Recommendation:** Require continuous measurement of total gas on all multiwell pads.

2. AER Directive 060 ***"Upstream Petroleum Industry Flaring, Incinerating and Venting" (March 22, 2016 release)***

2.1. **Purpose of Directive 060 and General Requirements –** The stated overall goal of the solution gas management framework of the Directive is to ***"Eliminate flaring, incinerating and venting"*** and is based on adopting the recommendations of two multi-stakeholder Clean Air Strategic Alliance (CASA) teams. It is intended to force licensees to evaluate three options: a) Can flaring, incineration, and venting be eliminated? b) Can flaring, incineration, and venting be reduced? c) Will flaring, incineration and venting meet performance standards? The Directive applies to all flaring and venting of more than 900 m^3/d/site. As with Directive 017 the main focus of this review will be on Conservation at Crude Bitumen Batteries and Conventional Heavy Oil Batteries which are currently venting solution gas mainly composed of methane. There are a number of aspects of the general Directive which are key issues from the point of view of reducing methane emissions from these sites.

2.1.1. **Solution Gas Flaring/Venting Reduction Targets** – Section 2.1 sets a flaring limit of 670 million m^3/yr which if exceeded in any one year would result in AER imposing reductions to reduce flaring. In contrast there is no stated limit or target for venting of solution gas, however, Section 2.2 states that: ***"The AER does not consider venting an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustion the gas must be burned (or conserved). If venting is the only feasible alternative, the requirements in section 8 must be met."*** Presumably if vent gas is combusted it would add to the flared gas volumes which would then exceed the stated flaring target[1], so by not combusting vent gas there is no requirement to constrain flaring. **Concern:** Given the extremely low number of primary/secondary heavy oil and crude bitumen sites in eastern Alberta that are flaring anything, and the large number of options available to combust methane, this statement does not appear to be applied to many sites unless odours are present or there are public complaints. There are numerous methods of combusting gas (flares, fuel, enclosed flares, auxiliary stack burners, and catalytic converters) and some of these such as auxiliary stack burners and catalytic converters can handle highly variable flows at relatively low costs and sustain combustion even with highly variable flows. **Recommendation:** To be meaningful the target should apply to (flare + vent) volumes as the original target would have been based on no routine venting being permitted, converting vents to combustion would force greater restrictions on flaring. The Directive cited continuous improvement, but the target for flaring has not been reduce below 50% of the 1996 baseline, so consideration should be given to reducing this target as well as including vent gas volumes.

2.1.2. **Directive 60 Decision Tree Tests –** The existing Directive bases decisions in the solution gas flaring/venting decision tree (Section 2.3 adapted from CASA) on whether there is: a) Public concern; b) Safety concern; c) Economic alternatives; or d) Environmental impacts/alternatives. In most heavy oil areas where venting is occurring: a) there is little local public concern unless odours are present (as in Peace River) but the public might express concern about any visible flaring, b) venting of methane is considered safe if it is vented outside of any building, c) combustion of

[1] From ST-60B-2015 - For 2014 Solution gas flared + vented was 920 million m^3 so exceeded the flaring target by almost 40% if vented gas was flared.

vent gas is not often economic (without credits for GHG reduction or acceptance of a negative present value) and at low gas prices conservation, except for on-site fuel use is not often economic; and d) generally there are no acute environmental impacts of venting. As a result the decision tree would rarely require action, since there is no point in the decision tree to test if combustion of vent streams can be sustained. **Concerns:** 1) GHG emissions were not specified in the Directive as an Environmental impact and have not in the past been generally considered in the Directive, nor are GHG credits or offsets included in economic decision process to require conservation or combustion. 2) Basic objective of requiring combustion rather than venting is not used as a test. **Recommendation:** Decision tree test should specifically have a statement that *"Venting is not an acceptable alternative to conservation or flaring"* and require a combustion test, however, flaring should clearly include all types of combustion. This criteria needs to be more stringently enforced by requiring sites to demonstrate that combustion cannot be achieved in any type of combustion device. On a higher level the GHG emissions should added to the test by setting a maximum GHG emission level by township.

2.1.3. **Conservation at Crude Bitumen Batteries –** Section 2.4 includes a number of items that should be considered for revision.

2.1.3.1. **Measurement –** Section 2.4 requires that: *"The licensee or operator of a multiwell bitumen site must build solution gas conservation lines to one common point on the lease as part of initial construction."* **Recommendation:** If this requirement is routinely enforced, then continuous measurement of solution gas and its disposition, should be relatively easy to implement, to more directly and accurately determine total gas production, fuel use and vent volumes and to establish if the solution and vent gas flow rates are sufficient to sustain combustion to avoid venting. While gas emissions from a single well may vary, a combination of multiple wells should experience less day to day and month to month flow variation.

2.1.3.2. **Test Period on Initial Start-up** – New wells are allowed to operate for six months or until *"flared and vented volumes at the site exceed a rolling average of 900 m^3/d for any consecutive three month period"*. In contrast Conventional Crude Oil batteries tests, in general, flaring for testing must not exceed 72 hours. Total gas stream measurement is required if any stream on the lease exceeds 2.0 10^3 m^3/d. **Concern:** As with single well batteries after operating in a formation for a period of time GORs, if properly determined, should reasonably be as predictable as oil production performance, so sites can be proactively assessed, before they go into operation, to determine if vent/flare volumes are likely to exceed 900 m^3/d or if produced gas volumes will likely exceed 2.0 10^3 m^3/d. By waiting 6 months to evaluate the new wells and potentially another 6-8 months to evaluate economics and order and install capture equipment and flow lines, over 40-50% or more of the produced gas may be lost before conservation can be installed. Delaying installation then makes conservation uneconomic, when it may have been economic if equipment was installed from initial construction. Also Section 2.5 for Conventional Crude Oil Batteries require the wells to be shut-in during evaluation until conservation is assessed, yet this requirement is not applied to Crude Bitumen Batteries under 2.4. **Recommendation:** All multi-well sites should be assessed proactively based on measured data from other sites in the same area and formation to determine if solution gas and/or vent gas volume limits are likely to be exceeded so that conservation equipment and metering is installed prior to start-up, including facilities to ensure maximum use of produced solution gas to fuel tank heaters and pump drive engines and to combust any surplus gas.

2.1.3.3. **Low Volume Gas Sites** – Point 3) in Section 2.4 states that *"if testing shows that combined flaring and venting volumes at the site do not exceed 900 m^3/d, economic evaluation of solution gas conservation is not required and the well may proceed to produce without conserving the solution gas. The AER, however, still recommends economic evaluation of gas conservation, even when volumes are less than 900 m^3/d."* **Concern:** Action is not proactive and is only focused on conservation. A gas flow of <900 m^3/d, if not economic to conserve, is definitely a high enough rate to combust, and many sites use less gas than this as fuel, so obviously combustion is supported. **Recommendation:** If proactive assessment of potential gas vent/flare volumes shows the estimated future gas rate will be too low to make conservation economic, then it should be required that the sites be designed to maximize solution gas consumption as an energy source on a year-round basis for pumping and tank heating, and that any surplus volume should be combusted by some method.

2.1.4. **Section 2.7 Clustering –** Sharing of gas conservation facilities must be assessed within 3 km of each other. **Concern:** The clustering assumption for distance and economics is that gas must be collected by gathering lines. **Recommendation:** There could be a specific requirement to assess "virtual pipelines" for any area where surplus gas can be captured, compressed and transported through use of trailer mounted compressors and pressurized gas cylinders rather than construction of expensive permanent pipelines.

2.2. **Focus on High Vent Areas** – One critical issue to consider is that the venting is clearly coming from one area and from township scale areas, controlled mainly by three large operators (CNRL, Husky and Devon) and mainly on Cold Lake oil sands leases. The distribution shown in Figure 4 demonstrates that the majority of the vent gas is coming from 10-15 townships and is following development of new resources so most venting is happening before current testing and mitigation options must be applied based on Directive 60. **Concern:** Lack of proactive action on township scale developments is the main driver of venting as expressed in earlier portions of this report. **Recommendation:** As was the case for the Peace River Oil Sands Area (PROSA) to eliminate odours from heavy oil operations, the Cold Lake Oil Sands Area (CLOSA) should be treated as a special case to reduce methane venting. Potentially a township limit could be set to cap venting from any township to some value less than 1 million m^3/yr, to be comparable with operations in the rest of the province. Enhanced regulation of the PROSA area did not appear to result in any significant slowdown in development activity, and reduction of high density venting in CLOSA, should not be expected to have significant impacts.

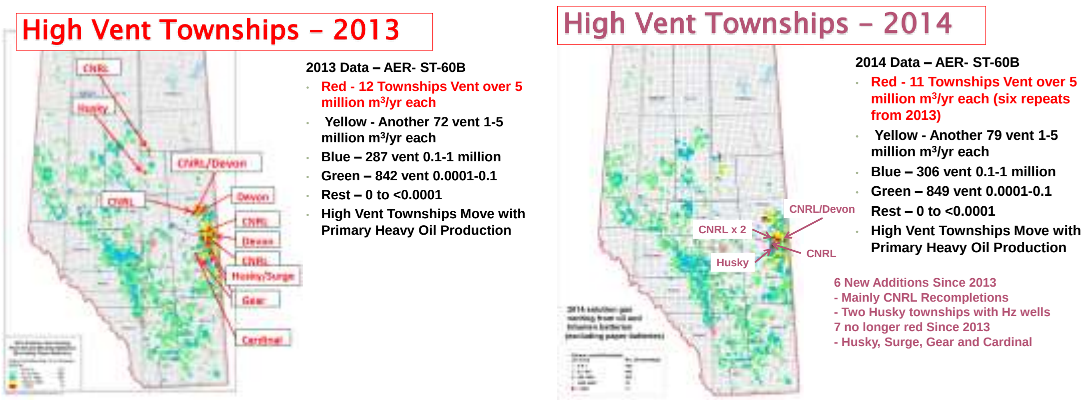

Figure 4 – Distribution of High Vent Townships in Alberta
(ST-60B reports with data from 2013 and 2014)

2.3. **Requirement to Maximize On-site Use of Vent Gas as Fuel** – Section 2.9 1) states that: *"Methods of conservation must include pipeline to sales, fuel, power generation, pressure maintenance, or any other method that may become available."* So producers should be preferentially using solution gas as to provide energy for operations. **Concern:** The most economic use for solution gas, and primary conservation practice, on any heavy oil site is to provide energy for operating the site. While every site requires an alternative source of energy (propane, natural gas or power), to allow the site to start-up and potentially to operate through periods where severe foaming may make use of solution gas more challenging, most sites produce more than enough solution gas to provide production energy for normal operation, and solution gas production is generally proportional to energy demand. Yet, based on monthly ST-60 reports, some sites show no produced gas used for fuel and no gas receipts, indicating they are relying on expensive power and propane to run the sites for pumping and heating, while venting solution gas. Other sites show all fuel being supplied by gas receipts indicating there is a gas line to the site, yet solution gas is still being vented. **Recommendation:** Use of solution gas should be more economic than other energy options and designing or retrofitting sites to use it for onsite energy, whenever possible, should be mandatory. If producers are using gas wells in an area to supply heavy oil or bitumen sites, while still venting solution gas from those sites, then that imported gas should not be royalty free, to discourage use of gas well gas when solution gas is available. Royalty free use of gas for production operations was originally intended to encourage gas conservation, not to encourage venting.

2.4. **Economic Basis for Conservation** – As indicated above the economic basis for conservation is to include a range of methods for a "solution gas conservation project" and uses for conserved gas, including use as fuel, and has other provisions which impact the disposition of vent gas, and economics, including the cost of flaring options avoided by conservation or revenues generated. Areas of concern or potential to change the economic assessments are discussed below.

2.4.1. **Gas volumes included in economics** - Section 2.9 2) states that: *"Licensees or operators must update the conservation economics for any sites that are flaring or venting combined volumes over 900 m³/d and that are not conserving every 12 months."* And Section 2.9.1 7)a) indicates that: *"The economic evaluation must account for any cost savings, such as reduced trucking, equipment rental, and the* *licensee's or operator's costs that may result from the conservation project."* **Concern:** Based on the focus on vent/flare volumes only, it makes it seem like the economics are to be based only on conserving the surplus vent and flare volumes, whereas section 2.9.1 indicates the economics are to be done for the "solution gas conservation project" which should include the total solution gas produced on the site. Focusing only on the gas being flared or vented for incremental capture decisions ignores consideration for use of solution gas as lease fuel, which should be highly economic if displacing propane or power. Given the economic hurdle of enforcing conservation even with a negative $55k present value only looking at increments for flaring and venting does not result in the true economic value of solution gas conservation for the entire lease. **Recommendation:** The economic basis calculations should include ALL solution gas conservation on a site, including mandatory use as lease fuel. This would average out the true economic cost of conservation or combustion and likely result in a greater number of sites showing economics above -$55k PV for the combined conservation of solution gas project. Savings related to reduced use of external power, propane or off-lease gas would be based on what alternative energy sources are available, but should generally be backing out propane purchases as otherwise there would either be a power line or gas line to the venting site, which would allow for lower cost export of the energy in the vent/flare gas off-site.

2.4.2. **Cost of Vent Gas Combustion Equipment to be included in Economic Assessments** – Section 2.9.1 sub-sections 6)a) and 6b) indicate that avoided costs for flaring (combustion) equipment must be subtracted from the capital cost of conservation equipment and the salvage value based on reasonable market value of equipment used for conservation must be shown as revenue at the time it is available for salvage. **Concern:** Some operators have indicated extremely high costs for flaring equipment (up to $1M/site) as a reason for avoiding combustion of vent gas, yet these high costs should then make conservation options much more economic. The AER's assertion that flaring is required over venting should mean that the producers should be installing the flaring or combustion equipment if the gas is not conserved, yet this does not seem to be happening, so it is uncertain if producers are accounting for this in their economics. i.e. if the alternative to conservation is venting, the economics for conservation are lower, than if the alternative is combustion. Since the vent gas volumes generated on most sites mainly occur in the first 2-3 years of operation there should also be significant opportunities to salvage and relocate compressor or other conservation, high volume flare or combustion equipment after only a few years operation so it should not be greatly reduced in salvage value. **Recommendation:** Better enforcement of requirement to flare or combust vs. venting to ensure that companies not conserving properly account for the negative cost of combustion and properly provide credits for being able to relocate equipment with a significant salvage value, as they already do with other equipment such as tanks, pump engines and well pumping systems. Handling of sweet methane streams would not be expected to degrade the conservation or conversion equipment as it would be for the case of this type of equipment in sour service.

2.5. **Variations in Saskatchewan Directive S-10 –** Generally this directive is a shorter version of Alberta's Directive S-10. However there are a few differences that should be noted between the two provinces and the vent/flare regulations.

2.5.1. Generally sites in Saskatchewan tend to be conventional heavy oil areas, are older and with more of them being drilled from single well sites with vertical wells, so there is less concern with multi-well site issues.

2.5.2. Volumes per lease may be higher if associated gas is allowed to be vented which is not normally the case in Alberta. Associated gas is gas found in oil pools which is not dissolved in the oil but instead is found as a separate phase on top of the oil in a formation. In some areas there may be differences in ownership between solution and associated gas, so usually venting or flaring it would not be allowed. However, in Saskatchewan, there are not as many facilities for gathering, processing and compressing this gas so the province may allow small amounts of associated gas to be flared or vented.

2.5.3. Fewer leases are tied into sales gas lines but many may be using shallow gas wells for fuel, as is being done in the oil sands so it is necessary to ensure that solution gas is used first for fuel.

2.5.4. While there are fewer gas plants in Saskatchewan in the southeast where shale oil is being produced and flared, this is not a significant factor in heavy oil operations as gas plants are not required since the gas is sweet, contains few liquids and just required dehydration and compression to be sent to sales.

2.5.5. Many sites are controlled by a single operator. Husky controls a large percentage of the leases in central Saskatchewan where heavy oil production dominates. However, unlike in the oil sands leases in Alberta, many of these leases will border on leases held by other productions or be broken up into smaller groupings with common ownership. These discontinuous leases tend to discourage development using large multi-well pads.

2.5.6. A higher percentage of the sites are on farmland and may be near residences. Generally the public is concerned about any flaring due to concerns from flaring rich gas streams. Streams of methane should not be a concern but the province prefers to avoid flaring to avoid upsetting residents.

3. Response to Questions

3.1. **What Changes could be made to these two documents to better address venting at crude oil facilities? –** The main suggested changes are covered by the recommendations provided in the above review, as they vary depending on the situation and the Section of the Directive which applies. In many, or even most, areas the changes are not necessarily in the intent, or even the wording of the Directive, but in the interpretation and enforcement of the statements made in the Directives, such as the assertion that venting is not an acceptable alternative to flaring (combustion) of surplus gas. In the past the Alberta Energy Regulator did not have a mandate to reduce GHG emissions, whereas that is now part of their mandate and the subject of new provincial and federal targets specifically focusing on reducing the volume of methane being emitted and other GHG emissions. So a key change would be to make the level of GHG emissions from a township a discrete test for gas management action and to shift assessment of potential gas volumes from a reactive process to one that is more proactive in anticipating emissions from new developments.

3.2. **In addition to the required improvements to the heavy oil measurement protocols referenced in the 2004 Standard, what other measurement provisions in Directive 017 are most in need of change/improvement?** – For Directive 017, the main focus is on changes intended to increase the quality and reliability of produced oil, gas, fuel and vent volumes being reported, mainly by ensuring “accurate and consistent GORs” and that those GORs are representative of the actual volumes being produced, conserved or flared/vented by implementing defined and tougher standards for acceptance of test results and increased auditing of methods being used. The 2004 Standard focused on ensuring the quality of the 24-hour produced gas tests that are one component of the GOR, but these must be supplemented to with changes in Directive 17 to also ensure that the oil volumes matched with the gas rates are also accurate, representative of the flow at the time of the gas test, and representative of the normal volumes of oil which should be produced by a given well at the time the gas rate is obtained. Normally there would be no incentive for producers to not accurately determine oil rates per well as there would be no savings over the longer term as the volumes must balance out, and in jointly owned operations, representatives of other producers with interest in the wells would be closely monitoring well production, testing and reporting to look for errors or deviations. On the township sized oil sands leases with common ownership, common royalty treatment and leases, the main driving force for potential deviations from quality and consistent reporting of oil volumes would be to avoid installing gas conservation equipment by under-estimating produced gas volumes. Since the 2004 Standard is not in use, and there are areas where oil rates may not be accurately reported to match with the gas volumes, the current data available on reported vent volumes is highly suspect.

3.3. Similarly, in relation to the emission control requirements described in Directive 060, what changes should be made to best control emission from crude oil production? – As with Directive 017 it is not necessarily changes that are required but clearer and more transparent interpretations of the existing requirements and how they have been used in the past, versus how they could be reinterpreted to force actions to reduce methane venting. More, and more specific, targets for total emissions and defining what accuracy requirements apply to GOR would help to ensure the intent of the Directive will be met. Having a single target for combined flare and vent emissions, along with a clearly stated quantitative target for greater reduction of these emissions over time would also greatly increase the application of mitigation actions. To maximize effectiveness of any changes the main focus of any changes should be on the CLOSA townships with the highest total vent rates, which also present the greatest opportunity for conservation and reduction of methane emissions, by a small number of large producers. It is also the area where the existing application of Directive 060 provides the greatest potential for non-compliance with the intent, and rigourous enforcement, of the Directive.

3.3.1. **Taking into account the current conservation threshold of 900 cubic meters per day with a net present value of -$55,000, what reduction targets would be achievable and reasonably cost effective?** – As discussed in 2.4 of this review, a reinterpretation of the economic basis for the economic calculations and an audit/review of how the economics have actually been done to date for “solution gas conservation projects” is likely required. Recommendations to include the economics of conservation of all the solution gas including mandatory on-site use of solution gas for fueling pumps and tank heaters to back out propane fuel costs, and properly accounting for avoided expenditures in flare/combustion equipment to avoid venting, and recovering the salvage value of relocatable equipment, could help to make much more of the vent gas reductions achievable and cost effective to reduce. Since most of the solution gas in the rest of the industry, including PROSA, is already being conserved or flared/combusted without making those operations uneconomic, it might be assumed that similar results could be attained, particularly in the high vent townships of CLOSA, by being proactive and setting tighter restrictions on venting in those areas, as is the stated intent of Directive 060.

Achievable Reduction Targets - In 2013/14 there were 11-12 townships venting over 5 million m^3/yr of methane and 72-79 venting between 1-5 million m^3/yr, if it is assumed that a target was put in place to reduce all per township methane emissions to below 1 million m^3/yr (-5 and -2.5 million m^3/yr respectively) that would reduce Alberta methane emissions by about 250 million m^3/yr or over 50% of the total vent volume being reported in ST-60B for 2014. However, given the unreliability of the vent gas volumes being reported due to the lack of quality standards on gas measurement (which could be remedied by forcing implementation of the 2004 Standard) and apparent discrepancies in oil volumes used to calculate GORs, the actual reductions could be 2-3 times higher, but would be hidden unless any incorrect historic vent volumes were to be retroactively adjusted to reflect new estimates and standards.

3.4. **Are there existing conditions in Saskatchewan that would render similar facilities unable to comply with comparable requirements?** The author does not have access to data on Saskatchewan, which is comparable to that available in Alberta through the ST-60 and ST-60B reports, but it is unlikely that there are as many multiwell heavy oil batteries in Saskatchewan. Most of the heavy oil fields in that province, are licensed to Husky Energy who, up until quite recently, preferred single well development to allow sequential access to multiple formations from the same well, and who have only recently begun development of multiwell pads for horizontal wells in a limited number of fields where they are targeting a single formation. Most Saskatchewan heavy oil operations tend to be single well batteries which are very similar to those which were being assessed for the 2004 Vent Quantification Standard. Single well batteries represent less potential for errors or misreporting of oil production volumes, which are possible in Alberta’s multiwell group and proration batteries. All the requirements of the proposed 2004 Standard should be applicable to Saskatchewan wells. And some recommendations: such as requiring maximum use of solution gas for on lease fuel, and economic assessments for conservation, or requirements to flare or combust gas, rather than venting, should be applicable in Saskatchewan.