UPSTREAM OIL AND GAS (CONVENTIONAL)

BASE LEVEL INDUSTRIAL EMISSION REQUIREMENTS (BLIERS) SECTOR SUBGROUP REPORT

The views expressed in this Sector Subgroup Report are those of the participants and do not necessarily reflect the views or policies of any organization (federal, provincial, corporate or non-governmental) within or outside the sector subgroup participants.

Further, any policy implications derived from the material herein cannot be considered to be endorsed by the participants of the Sector Subgroup Reports.

Recommended BLIERS from this sector sub-group apply to all onshore upstream oil and gas facilities. Offshore oil and gas has been excluded from the current recommendations but have been included as recommendations for future work.

November 13, 2009

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1. CRITERIA AIR CONTAMINANTS CONSIDERED FOR BASE LEVEL INDUSTRIAL EMISSION REQUIREMENTS (BLIERS)

Summary of BLIERS recommended for each criteria air contaminant (quantitative or qualitative) and proposed emission sources to be managed

CAC	Relative contribution in 2006	Sources	Qualitative / Quantitative	Recommended BLIER
NOx	48% of Total Industrial Emissions 18% of Total Canadian Emissions without Open and Natural Sources	Natural Gas-Fired Reciprocating Engines (85% of sector emissions)	Quantitative	Emission performance standard for both new and existing natural gas-fired reciprocating engines
		Boilers and Heaters (7% of sector emissions)	Quantitative	To be addressed through the Non-Utility Boilers and Heaters Equipment Sub-Group and as future work
		Natural Gas Turbines (2% of sector emissions)	Quantitative	New turbines to be addressed through the Combustion Turbine Equipment Sub-group.
SO_2	11% of Total Industrial Emissions 10% of Total Canadian Emissions without Open and Natural Sources	Sour Gas Processing (82% of sector emissions)	Quantitative	Adoption of Alberta Sulphur Recovery Requirements - some members would like special consideration for low H2S acid gas consideration
		Flaring (16% of sector emissions)	Quantitative / Qualitative	Adoption of Alberta Directive 60 flaring minimization framework
VOCs	66% of Total Industrial Emissions 19% of Total Canadian Emissions without Open and Natural Sources	Fugitive Equipment Leaks (25% of sector emissions)	Qualitative (Quantitative BLIER to be considered in future)	Development of a regulated code of practice mandating:1) detection and repair of VOC leaks from equipment and 2) operating practices at upstream oil and gas facilities
		Storage Tanks (33% of sector emissions)	Qualitative	A regulated code of practice mandating technologies and operating practices to reduce VOC emissions from new and existing storage tanks and loading operations
		Venting (23% of sector emissions)	Quantitative / Qualitative	Adoption of Alberta Directive 60 venting minimization framework

CACs or other substances, namely particulate matter and benzene, for which a BLIER may be considered or developed at a later date have been identified in Future Work and Appendix F.

2. RECOMMENDED BLIERS FOR NITROGEN OXIDES (NO_X) – (SPECIFIC STAKEHOLDER VIEWS IN APPENDIX A)

Source	Form/Scope/Basis	Recommended BLIER (Range reflecting differing stakeholder views)	Caveats, Considerations and Area(s) of Non-consensus
Natural Gas-Fired Reciprocating Engines	• Quantitative BLIER • Emission standards for new and existing engines	New Engines ≥ 600 kW: 1.3 - 2.7 g/kWh • Industry members and Environment Canada will consider lowering the standard to 1.3 g/kWh but will need to consider: ○ Greenhouse gas tradeoffs of a lower NOx threshold ○ Availability of engines and discussion with manufacturers Existing Rich Burn Engines ≥ 600 kW : 2.7 - 6.0 g/kWh • More work is needed to consider the cost implications and emission reduction achievements possible for each of the proposed ranges	Threshold for Engine Size • Some members feel that greater reductions in emissions are possible by lowering threshold for existing engines to ≥100 kW for both new and existing engines • CAPP will look at feasibility of lowering size threshold (≥ 100 kW) for new engines with its members Existing Lean Burn Engines • Some members agree that there should not be a BLIER as emissions are already much lower than rich-burn engines (average emission standard of 2.6 g/kWh (CAPP 2004)) and cost-effective retrofits are not available • Some members would like to see what emission reductions are achievable from an emissions standard for lean burn engines, and feel that further reductions are possible from this engine type. Existing Rich Burn Engines • Industry notes that there are significant economic and resource recovery impacts to retrofitting the existing engine fleet; neither of which have been fully explored (see Timelines discussion) • Environment Canada will consider the impacts of going to the proposed lower range emission standard to 2.7 g/kWh with the same considerations as for new engines. ○ Greenhouse gas tradeoffs of a lower NOx threshold

			○ Availability of engines and discussion with manufacturers
Boilers and Heaters	• Quantitative BLIER • Standards for new and existing boilers and heaters	• BLIER for boilers and heaters > 10.5 GJ/hr to be developed by the Non-Utility Boilers and heaters Equipment Sub-Group • Most heaters and boilers in UOG are < 10.5 GJ/hr. Consideration of an emission standard for boilers and heaters < 10.5 GJ/hr is recommended for future work under CAMS.	
New Natural Gas-Fired Turbines	• Quantitative BLIER	• BLIER for new gas-fired turbines to be developed by the Combustion Turbine Equipment Sub-Group • Existing turbines are a small component of the total NOx emissions from the UOG. A BLIER for existing turbines was not contemplated.	

TIMELINES FOR IMPLEMENTATION OF THE BLIER

New Engines

- New engines manufactured and imported will be expected to meet the BLIER standards by 2012, or as soon as regulatory requirements are in force and equipment meeting the standard are available.

Existing Engines

- Members agree that a phased-in approach is needed for retrofitting existing engines however there is a lack of consensus on the exact timelines for this BLIER.
  - Industry and Saskatchewan do not feel that an exact timeframe for phase-in can be estimated at this time since further analysis is needed to determine a feasible and achievable timeline (Comments in Appendix A).
  - Some members feel that significant reductions in emissions are needed and a significant proportion of engines should be retrofitted before 2015 (Comments in Appendix A).

RATIONALE & HOW PROPOSED BLIER MEETS THE OBJECTIVE OF A BLIER

NOx emissions from natural gas-fired reciprocating engines (used as compressor drivers) are the largest source of NOx emissions from the upstream oil and gas sector, comprising 85% of total sector NOx emissions (CAPP 2004). Over 75% of NOx emissions from these reciprocating engines are from engines with power ratings greater than 600 kW (AENV, 2002, AMEC 2008).

The proposed emission standards for new engines meet the objective of a BLIER as they are aligned with British Columbia's Oil & Gas Waste Regulation (for engines installed after January 1, 2006), and the current U.S. EPA Standards (Appendix B). The U.S. EPA performance standard for new natural gas-fired internal combustion engines will be decreasing to 1.3 g/kWh in 2011, which will make it the leading jurisdiction for new engines. However more information is required before some members agree to the lower 2011 limits being recommended as a BLIER (more details in Future Work and Appendix F).

Action of proposed emission standards for existing engines meets the definition of a BLIER as no other jurisdictions in attainment areas have requirements for retrofitting existing engines to reduce NOx. Other jurisdictions only require low NOx emission standards for engines that are new, moved, modified or reconstructed. Industry and Saskatchewan believe that the higher limit for the BLIER for existing engines applied to all rich burn engines above a specified power rating (≥ 600 kW) will lead to significant reductions in NOx emissions from the sector.

EMISSIONS PERFORMANCE LEVELS IN COMPARABLE JURISDICTIONS (U.S. EPA) AND ADJUSTMENT FOR CANADIAN CONTEXT

The SSG considers the U.S. EPA to be a leading jurisdiction for emissions standards for reciprocating engines. The final rule for emission standards for reciprocating engines is entitled *Standards for Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule*[1] (40 CFR Parts 60, 63, 85 *et al*.) (Appendix B). The U.S. EPA does not impose NOx standards for existing engines, unless they are modified or reconstructed (Appendix B). The U.S. EPA does have emission standards for existing engines for hazardous air pollutants[2].

The SSG has also reviewed the emissions standards from reciprocating engines in British Columbia which are the most stringent in Canada. The BC *Oil and Gas Waste Regulation* outlines the emission standards for reciprocating engines and is applicable to natural gas-fired reciprocating engines, based on date of installation rather then specifying requirements for new or existing equipment (Appendix A). As requirements are based on installation date, there are no standards for existing engines unless they were installed after a specific date. Existing engines must be examined if there is a facility modification or new drivers are added.

UNCERTAINTIES, UNKNOWNS AND FUTURE WORK

Outlined in the Future Work (Section 6) and Appendix F

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[1] Available at: http://www.epa.gov/fedrgstr/EPA-AIR/2008/January/Day-18/a25394.pdf

[2] Available at: http://www.epa.gov/ttn/oarpg/t3/fr_notices/rice_neshap_prop_022509.pdf

3. RECOMMENDED BLIER FOR SULPHUR DIOXIDE (SO_2) - (SPECIFIC STAKEHOLDER VIEWS IN APPENDIX C)

<table>
<tr><th>Source</th><th>Form/Scope/Basis</th><th>Recommended BLIER (Range)</th><th>Caveats, Considerations and Area(s) of Non-consensus</th></tr>
<tr>
<td>Sour Gas Processing</td>
<td>• Quantitative BLIER</td>
<td>Adoption of Alberta Energy Resources Conservation Board (ERCB) ID2001-3: Sulphur Recovery Guidelines For The Province Of Alberta[3] (Table 1 and section on non-proliferation)

Alberta Sulphur Recovery Requirements: ERCB ID2001-03
<table>
<tr><th>Sulphur inlet rate (tonnes/day)</th><th>Design sulphur recovery (% inlet sulphur)</th><th>Calendar quarter-year sulphur recovery guidelines (% inlet sulphur)</th></tr>
<tr><td>>2000</td><td>99.8%</td><td>99.5%</td></tr>
<tr><td>>50-2000</td><td>98.5% - 98.8%</td><td>98.2% - 98.5%</td></tr>
<tr><td>>10-50</td><td>96.2%</td><td>95.9%</td></tr>
<tr><td>>5-10</td><td>90%</td><td>89.7%</td></tr>
<tr><td>1-5</td><td>70%</td><td>69.7%</td></tr>
</table>
Non-proliferation: Development of a new sour gas processing plant for the specific purpose of avoiding higher sulphur recovery requirements at an existing facility is unacceptable (full requirements in Appendix C).</td>
<td>Spectra Energy does not accept the quantitative BLIER for SO2 emissions proposed by the Upstream Oil and Gas working group, due to the concerns (outlined in Appendix C), and the absence of an in-depth assessment of impacts of such a regulation on the operations of the Fort Nelson Gas Plant or other large-scale sour gas processing facilities in British Columbia, some of the largest sour gas processing facilities in North America. We are concerned that the timing associated with the development of this report as well as the lack of an opportunity to complete an in-depth analysis and review of potential recommendations, makes it virtually impossible for Spectra Energy to reach a consensus on this matter.

• Some members do not feel that a caveat or special consideration should be granted to a specific company based on concerns from the potential closure of a single facility.

Acid Gas Injection
• Some members believe that the BLIER proposed is a best standard for sulphur recovery – but not necessarily the best policy for managing sulphur emissions at sour gas processing plants. Some members would like to evaluate the potential of setting a BLIER that drives increased use of acid gas injection where it is technically possible to do so. Higher rates of emission reduction may be possible using this approach. The final BLIER should consider both GHG and AP emission impacts.</td>
</tr>
<tr>
<td>Flaring Sources</td>
<td>• Quantitative / Qualitative BLIER</td>
<td>Adoption of flare reduction requirements found in Alberta ERCB Directive 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting.[4]
Types of flares expected to be covered will include:
○ Solution gas flares
○ Non-routine flares</td>
<td>• SK Ministry of Energy and Resources has been working with the Upstream Oil and Gas Industry Flaring and Venting Reduction Steering Committee to revise the requirements of ERCB Directive 60.
• Saskatchewan Energy and Resources Guide S-10: *Flaring, Incinerating, and Venting Emission Reduction Requirements,* provides interim regulatory requirements</td>
</tr>
</table>

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[3] Available at : http://www.ercb.ca/docs/ils/ids/pdf/id2001-03.pdf

[4] Available at: http://www.ercb.ca/docs/Documents/directives/Directive060.pdf

		o Well test flaring and incineration o Gas battery, dehydrator, and compressor station flaring and incinerating o Gas plant flaring and incinerating • Provincial infrastructure and/or operational characteristics will need to be considered in development and application of the BLIER • Some flare reduction or minimization requirements will be quantitative while others will be qualitative (air quality management plans, well testing programs) • The SSG recognizes that provincial flaring regulations change periodically, and the national BLIER will need to be reviewed/ updated accordingly or be sufficiently flexible to prevent conflicts, inconsistencies, or administrative complications.	for reducing flaring, incinerating, and venting of associated gas in Saskatchewan. Anticipated start date is January 2011.

TIMELINES FOR IMPLEMENTATION OF THE BLIER

Sour Gas Processing

New Facilities

- Already applies to any newly proposed Alberta facility
- Application in other provinces by 2015

Existing Facilities

- Alberta Facilities: 2015 – 2017 (range),
    - Some members propose that the timeline be consistent with the current Alberta requirements (ERCB ID2001-3) with the grandfathering clause ending in 2017, as an acceleration in the schedule to 2015 is likely to have significant cost and operational implications
    - Some members want to have the BLIER come into force for all facilities by 2015

- Other Provinces and Territories – Application in 2015 or upon consultation with provincial regulators
    - Some members suggest that the provincial regulators (SK and BC primarily) be consulted on timelines for retrofit of existing facilities prior to making a timeline commitment, given the cost and resource recovery implications of this BLIER
    - Some members would like to have the BLIER come into force for all facilities by 2015

Flaring Sources

New and Existing Facilities

- The recommended BLIER would apply to all facilities when the BLIER comes into force (2015)

RATIONALE & HOW PROPOSED BLIER MEETS THE OBJECTIVE OF A BLIER

Sulphur Recovery Requirements for Sour Gas Processing Facilities

Emissions from sour gas processing plants comprise 82% of the sector's total SO_2 emissions (CAPP 2004). Alberta ERCB ID 2001-3 Sulphur Recovery Standards for sour gas processing facilities are standards equivalent to standards enforced in a leading jurisdiction in an attainment area, as shown in the jurisdictional scan in Appendix D. The Alberta requirements were also recognized by Environment Canada to be world leading (from Turning the Corner Framework 2007). Implementation of the Alberta requirements has lead to a 57% reduction in SO_2 emissions from 2000 – 2008 (ERCB, 2009). Continual improvement in Alberta and implementation of these standards in other jurisdictions will lead to further reductions in SO_2 emissions from the UOG sector.

Flaring

Other flared sources comprise 16% of the sectors total SO_2 emissions (CAPP 2004). Other applicable jurisdictions focus on reduction of flare volumes through greenhouse gas emissions trading which is not being considered in the CAMS process (Appendix D). Alberta ERCB Directive 60 is considered to be a world leading requirement and has been recognized by the World Bank Global Flaring Reduction Partnership.[5]

EMISSIONS PERFORMANCE LEVELS IN COMPARABLE JURISDICTIONS AND ADJUSTMENT FOR CANADIAN CONTEXT

Sulphur Recovery Requirements for Sour Gas Processing Facilities

A review of the regulatory benchmarking study has shown that several jurisdictions have sulphur recovery standards for sour gas processing facilities: Alberta, British Columbia, U.S. EPA, Colorado, Florida, Mississippi, Oklahoma, and New Mexico (Cheminfo and Clearstone 2007). A detailed review of these jurisdictions' regulatory regimes is shown in Appendix D. Applying the U.S. EPA sulphur recovery standards to Alberta's sulphur recovery facilities (with full degrandfathering in place), SO_2 emissions from these facilities would increase by 32%. While some state requirements are more stringent for some sulphur inlet rates, Alberta's requirements are generally more stringent across the full range of sulphur inlets than other jurisdictions in attainment areas.

Flaring

Flaring regulations from jurisdictions reviewed within the regulatory benchmarking study are summarized in Appendix D (Cheminfo and Clearstone 2007). Other applicable jurisdictions reviewed focus on reduction of flared volumes through greenhouse gas emissions trading or a carbon tax which is not considered in the CAMS process.

UNCERTAINTIES, UNKNOWNS AND FUTURE WORK NEEDED REGARDING THIS BLIER

Future work is needed to determine how the Alberta ERCB Directive 60 flare minimization requirements, which are periodically updated, could be made into a national standard (Future Work and Appendix F).

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[5] Available at: http://go.worldbank.org/425VOGDYS0

4. RECOMMENDED BLIER FOR VOLATILE ORGANIC COMPOUNDS (VOCs)

Source	Form/Scope/Basis	Recommended BLIER	Considerations / Caveats and Areas of non-Consensus
Fugitive Equipment Leaks	• Qualitative BLIER	A regulated code of practice mandating 1) detection and repair of VOC leaks from equipment and 2) operating practices at upstream oil and gas facilities. The code of practice should be developed or updated to include (but be not limited to) the following elements: • coverage • phase in period: facility types and timing • leak detection methods • leak definition/identification by method/ • consideration of leak quantification • components-scope, tagging • leak detection/monitoring-timing/frequency • repair-timing • operating practices and technologies for leak prevention and control • compliance (e.g. reporting, monitoring, inspection, maintenance, verification and record-keeping) • consideration of quantification of emission reductions of these activities (accuracy/methodologies improving over time) Identification of specific requirements in a regulated code of practice is included as future work	While there is consensus on the form of BLIER and elements to be include in a regulated code of practice (CoP) for fugitive equipment leaks there is a lack of consensus on whether the document will be a new regulated code of practice or a revised version of the CAPP Best Management Practice (BMP) for Management of Fugitive Emissions at Upstream Oil and Gas Facilities. • Some industry and provincial members prefer to have the CAPP BMP updated with the additional elements (with the following rationale) o The CAPP BMP is currently regulated by the AB ERCB and BC OGC. o The CAPP BMP is considered to be a standard required by a leading jurisdiction (Alberta) in an attainment area. o The CAPP BMP, as currently written, was developed in 2007 when fugitive emissions management at upstream oil and gas facilities was not a common practice. The BMP was written with a step-wise, continuous improvement approach in mind; allowing companies the flexibility to implement a program with evolving technologies, and measurement techniques using estimated leak rates and emissions factors. o CAPP is amenable to revising the BMP to capture the industry's experience with fugitive emissions management systems over the past two years since the program's inception. o To avoid regulatory duplication or contradictions, the CAPP BMP should be considered as the basis for the BLIER. • Some members prefer a new CoP regulated under the under the *Canadian Environmental Protection Act* or some other national requirement and do not consider the current BMP to meet the intent of a BLIER (with the following rationale)

			○ The current requirements in the CAPP BMP are not prescriptive enough for regulation under the *Canadian Environmental Protection Act*
Storage Losses	• Qualitative BLIER	A regulated code of practice mandating technologies and operating practices to reduce VOC emissions from new and existing storage tanks and loading operations. The code of practice should be developed/updated to include (but be not limited to) the following elements: • coverage • substances stored/vapour pressure • size ranges • specification of tank characteristics (internal floating roofs, external floating roofs, vapour recovery/control systems) • treatment of new tanks (with consideration of improving technologies) • treatment of existing tanks • phase-in period for existing tanks • best operating practices for emission prevention and control • technology recommendations for emission prevention and control • incorporate current research to improve assessment of UOG sector specific-emissions (flashing losses, unintentional carry-through to tanks) and estimation of breathing & working losses in current models • compliance (e.g. monitoring, inspection, maintenance, verification and record-keeping) • reporting/quantification of emission reduction (consideration of need for metering requirements, accuracy/methodologies improving over time) • fugitive emissions from storage losses to be addressed by requirements for fugitive equipment leaks Identification of specific requirements in a	

		regulated code of practice is included as future work	
Venting Sources	- Quantitative BLIER	Adoption of venting reduction requirements found in Alberta ERCB Directive 60. Types of venting expected to be covered will include: ○ Solution gas venting ○ Non-routine venting ○ Well test venting ○ Gas battery, dehydrator, and compressor station venting ○ Gas plant venting - Provincial jurisdiction and or operational characteristics will need to be considered in development and application of the BLIER - Some venting reduction or minimization requirements may be quantitative or qualitative (air quality management plans, well testing programs) - The SSG recognizes that provincial venting regulations change periodically, and the national BLIER will need to change accordingly or be sufficiently flexible to prevent conflicts, inconsistencies, or administrative complications.	- SK Ministry of Energy and Resources has been working with the Upstream Oil and Gas Industry Flaring and Venting Reduction Steering Committee to revise the requirements of ERCB Directive 60. - Saskatchewan Energy and Resources Guide S-10: *Flaring, Incinerating, and Venting Emission Reduction Requirements,* provides interim regulatory requirements for reducing flaring, incinerating, and venting of associated gas in Saskatchewan. Anticipated start date is January 2011.

TIMELINES FOR IMPLEMENTATION OF THE BLIER

Fugitive Equipment Leaks

- Further work is needed to develop a new regulated code of practice, or to revise the current CAPP BMP.

Storage Losses

- Further work is needed to develop a regulated code of practice for storage losses.

Vented Sources

New and Existing Facilities

- The venting BLIER would apply to all facilities when the BLIER comes into force (2015)

RATIONALE & HOW PROPOSED BLIER MEETS THE OBJECTIVE OF A BLIER

Fugitive Equipment Leaks and Storage Losses

The two main sources of VOC emissions from the UOG sector are from fugitive equipment leaks (25%), and storage losses (33%) (CAPP 2004). Qualitative BLIERS were chosen for fugitive equipment leaks and storage losses as the emissions are difficult to measure on a facility or equipment level. Although the BLIER is qualitative, the proposed elements for a code of practice will lead to significant reductions in emissions from the sector. Currently there are no requirements in other jurisdictions for upstream oil and gas facilities in attainment areas for leak detection and repair or for storage tanks (with the exception of the CCME code of practice for larger tanks installed after a specific date)[6].

Venting

VOC emissions from venting are responsible for 23% of the sector's total VOC emissions (CAPP 2004). Considering other jurisdictions' venting programs the venting minimization requirements required within the Alberta ERCB Directive 60 are world-leading requirements for facilities in an attainment area.

EMISSIONS PERFORMANCE LEVELS IN COMPARABLE JURISDICTIONS AND ADJUSTMENT FOR CANADIAN CONTEXT

Fugitive Equipment Leaks

Regulations covering VOC emissions from fugitive equipment leaks in jurisdictions reviewed within the regulatory benchmarking study are summarized in Appendix E (Cheminfo and Clearstone 2007). No other jurisdictions require upstream oil and gas facilities in attainment areas to implement fugitive emissions management plans to control VOCs.

Storage Losses

Regulations covering VOC emissions from storage tanks from jurisdictions reviewed within the regulatory benchmarking study shows that regulations exist for storage losses from upstream oil and gas facilities in some regions in California, in non-attainment areas. Texas regulations for storage losses only cover pipelines (Cheminfo and Clearstone 2007) (Appendix E).

Venting

Venting regulations from jurisdictions reviewed within the Cheminfo and Clearstone regulatory benchmarking study are summarized in Appendix E. Other applicable jurisdictions reviewed focus on reduction of venting volumes through emissions trading or a carbon tax which is not considered in the CAMS process. Alberta ERCB Directive 60 is considered to be a world leading requirements.

UNCERTAINTIES, UNKNOWNS AND FUTURE WORK NEEDED REGARDING THIS BLIER

Outlined in the Future Work (Section 6) and Appendix F

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[6] Available at: http://www.ccme.ca/assets/pdf/pn_1180_e.pdf

5. EXPECTED EMISSIONS REDUCTIONS FROM RECOMMENDED BLIERS

Expected emission reductions for the sector from recommended BLIERS. Reductions of projected BAU have not been calculated. Further work is needed to validate the estimated reductions and to estimate reductions for the projected BAU.

<table>
<tr><th>CAC</th><th>Emission Reductions with Proposed BLIER</th></tr>
<tr><td>NOx</td><td>The range of emission limits for rich burn engines are estimated to result in 38 – 57% NOx emission reductions from the sector based on current emissions
<i>Reductions from total sector NOx emissions*</i>
<table>
<tr><th rowspan="2">Emission Limits</th><th colspan="2">Engine Size Range</th></tr>
<tr><th>≥ 100 kW</th><th>≥ 600 kW</th></tr>
<tr><td>6.0 g/kWh</td><td>45%</td><td>38%</td></tr>
<tr><td>4.0 g/kWh</td><td>52%</td><td>43%</td></tr>
<tr><td>2.7 g/kWh</td><td>57%</td><td>48%</td></tr>
</table>
<i>* Further analysis is needed to determine the cost-effectiveness and technological achievability of full scale fleet retrofits for all engine sizes*</i></td></tr>
<tr><td>SO_2</td><td>The proposed BLIER would expand the existing Alberta sulphur recovery requirements to other jurisdictions in Canada. Preliminary estimates indicate about a 35% reduction in upstream oil and gas sectors emissions in Alberta from the ongoing implementation of Alberta’s sulphur recovery requirements. This emission reduction may be indicative of what is expected in other jurisdictions such as BC and SK, however further work is needed to estimate the incremental reductions in other jurisdictions subject to the BLIER and the overall resulting reduction in emissions on a national basis.</td></tr>
<tr><td>VOCs</td><td>Preliminary EC analysis estimates a potential 40-60% reduction in VOC emissions from the application of the recommended BLIERS.</td></tr>
</table>

6. FUTURE WORK (DETAILED IN APPENDIX F)

FUTURE WORK NEEDED TO DEVELOP BLIERS OR TO CONVERGE ON CONSENSUS RECOMMENDATIONS

- Offshore Oil and Gas: Implication of recommended BLIERS for onshore upstream oil and gas and consideration of BLIERS unique to offshore applications

- Compliance costs, cost effectiveness and regional differences for all recommended BLIERS.

- BLIERs for NOx emissions from reciprocating engines: timelines, cost-effectiveness, collateral GHG impacts, and technological achievability.

- Most heaters and boilers in UOG are < 10.5 GJ/hr. Consideration of an emission standard for boilers and heaters < 10.5 GJ/hr is recommended for future work under CAMS.

- Some members believe that future work is needed for consideration for a sulphur recovery standard for facilities with low concentrations of H_2S in inlet acid gas and for facilities that combine acid injection and sulphur recovery. Some members do not feel that a caveat should be granted based on the potential closure of one facility (Appendix C).

- Determine how Alberta ERCB Directive 60 flaring and venting minimization requirements, which are periodically updated, could be made into a national standard for flaring and venting.

- Utilization of the CAPP Best Management Practices for Facility Flare Reduction as part of a BLIER for flaring and/or venting

- Development of regulated code of practice for managing VOCs from equipment leaks and storage losses and timelines for implementation.

FUTURE WORK FOR POSSIBLE ADDITIONAL BLIERS

- Benzene

- Work to address additional substances for example: total reduced sulphur (TRS), hydrogen sulphide (H_2S), carbonyl sulphides (COS), carbon disulphide (CS_2), n-hexane and cyclohexane have been identified as priorities by a member of the sub-group.

- Work to address PM emissions from the sector has been identified as a priority by several stakeholders. Stakeholder positions on PM are included in Appendix G.

7. REFERENCES

Alberta Environment, 2002. *Inventory of Nitrogen Dioxide Emissions and Control Technologies in Alberta's Upstream Oil and Gas Industry*

AMEC, 2008. *Emission Control Technology for New and Existing Stationary Reciprocating Internal Combustion Engines Used in the Upstream Oil and Gas Sector*. Prepared for Environment Canada

British Columbia, July 2006. *Oil and Gas Waste Regulation*.

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CAPP, 2004. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2) Emissions by the Upstream Oil and Gas Industry, Volume 2.*

Cheminfo and Clearstone, 2007. *Regulatory Benchmarking Study – Benchmarking of Regulatory Regimes Affecting Air Emissions from the Upstream Oil and Gas Industry*. Prepared for Environment Canada.

Environmental Protection Agency, 1985. Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants. 50 FR 26124.

Environmental Protection Agency, 1984. Subpart V—National Emission Standard for Equipment Leaks (Fugitive Emission Sources). 49 FR 23513.

Environmental Protection Agency, January 18, 2008. *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule*. 40 CFR Parts 60, 63, 85 et al.

Environmental Protection Agency, 2009. *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*. 40 CFR Part 63

ERCB, 2001. *Sulphur Recovery Guidelines for The Province Of Alberta* (ID2001-3).

ERCB, November 16, 2006. *Upstream Petroleum Industry Flaring, Incinerating, and Venting*. (Directive 60).

ERCB, 2009. *Sulphur Recovery and Sulphur Emissions at Alberta Sour Gas Plants – Annual Report for the 2008 Operating Year (ST101-2009)*

APPENDIX A – MEMBER RECOMMENDATIONS FOR NOx

Summary of Member Recommendations and Rationale for NOx BLIERS for new and existing reciprocating engines

Member	Applicability (engine size)	BLIER Standard	Rationale / Estimated Reductions
CAPP (onshore engines)	> 600 kW	New: 2.7 g/kWh Existing (rich burn): 6.0 g/kWh to be phased-in with prioritization based on air quality and other criteria over a to-be-determined timeline. Existing (lean burn): As is	Estimated 43% reductions from Total Sector NOx emissions from retrofit of existing rich-burn engines to proposed standard (6.0 g/kWh)
Alberta Environment	> 100 kW	New: 2.7 g/kWh Existing (rich burn): 2.7 g/kWh Existing (lean burn): As is	We can get significant NOx reductions by lowering the threshold. The reductions here are likely to be the lowest cost options available for NOx reduction in the country.
Health Canada	> 100 kW	New: 1.3 g/kWh Existing: 2.7 g/kW	We should be matching leading jurisdictions.
Environment Canada	> 100 kW	New: 1.3 g/kWh Existing (rich burn): 4.0 g/kWh – potentially lowering to 2.7 Existing (lean burn): As is	Match U.S. EPA standards for new engines after research is completed to determine the tradeoff with greenhouse gas emissions Match U.S. EPA standards for modified and reconstructed. Technology is available to achieve 4 g/kWh. Potentially lowering to 2.7 after further research
Environmental NGOs	>100 kW	New: 1.3 g/kWh Existing: 2.7 g/kWh for existing	We do need to consider GHG tradeoffs when setting these requirements.

SPECIFIC MEMBER COMMENTS – NOX FROM RECIPROCATING ENGINES

Canadian Association of Petroleum Producers (CAPP)

- A size threshold of 600 kW is proposed, as the majority (75%) of sectoral NOx emissions are attributed to reciprocating engines above this size (AENV, 2002).
- For new reciprocating engines a 2.7 g/kWh standard is proposed.
  - This standard meets the objective of a BLIER as a standard equivalent to leading jurisdiction in an attainment area, as it aligns with British Columbia's Oil & Gas Waste Regulation (for engines installed after January 1, 2006), and the U.S. EPA Standards shown in Table 3.
  - In 2011, the U.S. EPA's standard for reciprocating engines will be decreasing to 1.3 g/kWh; however, CAPP is uncertain whether technologies to meet this standard will be widely

    - available and economically achievable, and whether engines will be able to consistently meet this standard in a wide range of operating conditions.
    - Modified, reconstructed and/or moved engines should not be considered to be "new" engines since the 2.7 g/kWh standard may be unachievable. This is recognized by the U.S. EPA which requires modified or reconstructed engines to meet a 4.0 g/kWh standard.
    - If the BLIER discussion were to continue past the December 2009 deadline, CAPP proposes that the SSG (or equivalent) meet with American manufacturers to understand better the achievability of a 1.3 g/kWh standard in the 2012 to 2015 timeframe.
- For existing rich burn engines, a standard of 6.0 g/kWh is proposed.
    - By retrofitting rich burn engines >600kW to 6.0 g/kWh, there is an expected reduction of the sector's **total** NOx emissions by 43%, which by itself meets the Turning the Corner emissions reductions.
    - The proposed BLIER for rich burn engines at 6.0 g/kWh for > 600kW engines is significantly lower than the current range of emission factors 18 to 30 g/kWh and will lead to significant reductions in NOx emissions from the sector.
    - This proposal meets the definition of a BLIER since no other leading jurisdiction has a requirement for retrofits to an entire fleet of rich burn engine. The U.S. EPA has a requirement to retrofit only modified or reconstructed engines.
    - Technologies available to retrofit existing rich burn engines are air-fuel ratio controllers and catalytic converters. Air-fuel ratio controllers have a demonstrated performance levels to 6.7 g/kWh, but may be able to meet 4.0 g/kWh on certain engine makes/models with precise control. Catalytic convertors have a demonstrated output of < 2.7 g/kWh, but lower an engine's efficiency and concurrently increase greenhouse gas emissions (AMEC, 2008).
    - CAPP feels that 6.0 g/kWh allows companies the flexibility to choose a retrofit technology best designed to each engine's specific operating needs and conditions.
    - Since it may not be technically or economically feasible to retrofit some compressors, work will need to be done with the provincial energy and natural resource regulators to consider the associated resource recovery implications.
- Existing lean burn engines as installed are considered to be BLIER equivalent.
    - Lean burn engines cannot easily be retrofitted to meet a lower standard.
    - Many existing lean burn engines achieve 2.7 g/kWh, but some models achieve a somewhat higher but still low level (i.e., 6 g/kW-h) which meets the standard proposed for new engines
    - Existing lean burn engines in Alberta have been installed to comply with existing provincial requirements (Code of Practice) for new engines, in place since 1996.

Timelines

- There are thousands of reciprocating engines currently operating in the UOG. CAPP estimates that retrofitting all existing rich burn engines to meet the proposed standard of 6.0 g/kWh will take many years, beyond the 2015 Turning the Corner timeline availability of capital and labour for retrofitting and other constraints, such as capital stock turnover.
- CAPP proposes a phased-in approach for retrofits of existing rich burn engines to the 6.0 g/kWh standard. This phase approach will prioritize engine retrofits based on:
    - Air quality – regions with air quality pressures would be top priority
    - Reservoirs with nearing end of life – compressor engines operating with a short remaining operating timeframe should not be required to be retrofitted.
    - Manufacturers should be consulted to determine the timing and availability of retrofit technologies.
    - Capital and labour availability – requires an industry survey.
- An exact timeframe for phase-in cannot be estimated at this time. CAPP proposes further analysis to determine a feasible and achievable timeline.

Environment Canada

New Reciprocating Engines (Manufactured and Imported) ≥ 100 kW: 2.7 g/kWh

- Lowering to 1.3 g/kWh to match the U.S. EPA standards
    - Further work is needed to determine the availability of engines and the emissions tradeoff with greenhouse gas emissions

Existing Rich Reciprocating Engines (including existing, modified and reconstructed) ≥100 kW: 4.0 g/kWh

- Technology is available to achieve 4.0 g/kWh

- Can phase-in requirements, addressing larger engines (>600 kW) first
- Need to gather info from manufacturers and contractors who carry out retro-fits
- Lowering standard to 2.7 g/kWh after research is completed to determine the tradeoff with greenhouse gas emissions and the magnitude of emission reductions from 4 to 2.7 g/kWh

Timelines

- A phase in approach for existing engines is necessary but there should be a significant percentage of engines meeting the requirements by 2015. Phase in beyond 2015 will depend on availability of labour and units.
    - Further information is needed to determine the availability of retrofit technologies from engine manufacturers to determine phase in for existing engines.

Environmental Non-governmental Organizations

New Reciprocating Engines (Manufactured and Imported) ≥ 100 kW: 2.7 g/kWh

- Lowering to 1.3 g/kWh to match the U.S. EPA standards

Existing Reciprocating Engines (including existing, modified and reconstructed) ≥100 kW: 2.7 g/kWh

- technology is available to achieve 2.7 g/kWh
- can phase-in requirements, addressing larger engines (>600 kW) first
- need to gather info from manufacturers and contractors who carry out retro-fits
- raising the standard to 4.0 g/kWh if appropriate after research is completed to determine the tradeoff with greenhouse gas emissions and the magnitude of NOx emission reductions.

- U.S. EPA is the leading jurisdiction and as such BLIER should closely follow U.S. EPA implementation timing and limits.
- 100 kW threshold – closer to USEPA.

Timelines

– More information is needed before a delay in full implementation by 2015 can be fully considered.

APPENDIX B – NOx RECIPROCATING ENGINE EMISSION STANDARDS - JURISDICTIONAL REVIEW

U.S. EPA: For the purposes of the U.S. EPA performance standard, a stationary engine that has been overhauled as part of a maintenance program is not considered to have been modified if there is no increase in the engine's emissions.

Table 1 Summary of U.S. EPA's Standards for Natural Gas Fired Reciprocating Engines

Engine Power	Engine Type	Manufacture Date	NOx Standard
<= 73 kW and > 370 kW	New	July 1, 2008	2.7 g/kWh
		January 1, 2011	1.3 g/kWh
	Modified or Reconstructed after June 12, 2006	Prior to July 1, 2008	4.0 g/kWh
>= 370 kW	New	January 1, 2008	2.7 g/kWh
		July 1, 2010	1.3 g/kWh
	Modified or Reconstructed after June 12, 2006	Prior to July 1, 2008	4.0 g/kWh
The U.S. EPA does not have standards in place for existing engines of any size, except for those engines modified or reconstructed.			

British Columbia*:* The British Columbia emission standards are considered to be leading of Canadian jurisdictions. These standards apply to engines installed after a specific date regardless of the type of engine. B.C. does not have emission standards for existing engines unless they are moved, modified or reconstructed.

Table 4: Summary of British Columbia Standards for Natural Gas Fired Reciprocating Engines (BC Ministry of the Environment 2006)[7]

Fuel Used for Power Driver	Maximum Nitrogen Oxide Emitted
Natural Gas	2.7 g/kWh
Natural Gas / Liquid Fuel Combination	6.7 g/kWh
Liquid Fuel	10.7 g/kWh

NOx emission standards are applicable to individual drivers that are:

- operated for more than 200 hours per calendar year, and that have
- rated power greater than 600 kilowatts if installed after February 26, 1997 or
- rated power greater than 100 kilowatts, if installed after January 1, 2006
- rated power greater than 100 kilowatts, regardless of installation date, when any drivers
- at a facility are added or modified (BC Ministry of the Environment 2007)

Alberta: Alberta Environment, Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants (1996, as amended) pursuant to *Environmental Protection and Enhancement Act*. The Alberta Code of Practice requires that new or additional natural gas-driven reciprocating engines of a size greater than 600 kW at full load, at a facility that emits more than 16 kilograms per our of oxides of nitrogen, shall emit less than 6 grams NOx/kW/h.. Facilities must not exceed ambient air quality objectives on a design basis as predicted by dispersion modelling.

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[7] Available at: http://www.env.gov.bc.ca/epd/industrial/regs/oil_gas/

APPENDIX C – MEMBER COMMENTS FOR SO2

Sour Gas Processing

Spectra Energy

Spectra Energy does not accept the quantitative BLIER for SO2 emissions proposed by the Upstream Oil and Gas working group, due to the concerns (outlined in Appendix C), and the absence of an in-depth assessment of impacts of such a regulation on the operations of the Fort Nelson Gas Plant or other large-scale sour gas processing facilities in British Columbia, some of the largest sour gas processing facilities in North America. We are concerned that the timing associated with the development of this report as well as the lack of an opportunity to complete an in-depth analysis and review of potential recommendations, makes it virtually impossible for Spectra Energy to reach a consensus on this matter.

The main reason for the Fort Nelson facility not meeting the minimum sulphur recovery efficiency in the ERCB ID 2001-03 is low sulphur plant feed gas H_2S concentration resulting from the composition of produced gas in the area. The ERCB ID 2001-03 does not include consideration of low H_2S concentration sulphur plant feed gas. As indicated in the Sulphur Experts report provided by Environment Canada (figure 2.3 of Evaluation of Sulphur Recovery Technologies Used in Processing Sour Gas, March, 2008), the lower the H_2S concentration in the sulphur plant feed gas, the lower the sulphur recovery efficiency.

<u>Spectra Energy proposes the following amendments:</u>

1. Spectra requests that a lower sulphur recovery efficiency be applied to plants with low H2S sulphur plant feed gas (details in Appendix C). Spectra proposes using a system similar to the U.S. EPA guidelines in which two criteria, inlet sulphur rate and sulphur plant feed gas H2S concentration are both taken into account when specifying minimum sulphur recovery efficiency. Spectra proposes using a system similar to the U.S. EPA guidelines but does not propose using the specific sulphur recoveries listed in the U.S. EPA guidelines.

2. Spectra proposes that facilities incorporating both acid gas injection and sulphur recovery systems are required to meet minimum sulphur recovery efficiency according to the inlet sulphur rate for the sulphur recovery section of the facility and not the inlet sulphur rate for the entire facility.

3. Even if the modifications to the Alberta regulation described in point 1 above are implemented, it is possible that the cost of the capital modifications to allow Spectra's Fort Nelson Gas Plant to meet this regulation would seriously alter the economic viability of this facility. Spectra requests that before revised sulphur recovery regulations are applied to British Columbia, a thorough investigation of the impacts on BC gas processing facilities is carried out with detailed cost estimates to determine whether the overall economic costs and impacts (to Spectra Energy, the gas industry and to society) are acceptable and desirable versus the health benefits of the emission reductions. If not, we expect any facilities that do not meet the performance standard to have a continued licence to operate under existing (BC) regulations and permits or a grandfather agreement.

ENGO Member

There should be no exemptions or amendments granted regarding the BLIERS for any facility, particularly considering the relatively large sulphur emissions from this facility and the decades which it has operated. Certainly, the purpose of the BLIERS should bring every facility on board to meet the minimum sulphur recovery efficiency.

Flaring

Other members

Performance based approach

Some members support performance-based regulatory approaches and have concerns that adopting the provincial guideline could limit flexibility upon implementation and the goal of a reduction in flaring could be lost. There is also uncertainty in committing to accommodating future updates to the guideline without knowing the burden of the future changes.

APPENDIX D – SULPHUR RECOVERY AND FLARING STANDARDS: JURISDICTIONAL REVIEW

Alberta

- Alberta Sulphur Recovery Requirements: ERCB ID2001-03 – Sulphur Recovery and non-proliferation requirements for the province of Alberta:

Sulphur inlet rate (tonnes/day)	**Design sulphur recovery** (% inlet sulphur)	**Calendar quarter-year sulphur recovery guidelines** (% inlet sulphur)
>2000	99.8%	99.5%
>50-2000	98.5% - 98.8%	98.2% - 98.5%
>10-50	96.2%	95.9%
>5-10	90%	89.7%
1-5	70%	69.7%

New sour gas processing plants must comply with the calendar quarter-year sulphur recoveries listed in the table unless alternative requirements are set out as the result of a specific facility application review and approval. The sulphur recovery for sour gas processing plants must be determined based on mass (tonnes sulphur equivalent) and calculated on the following basis:

Sulphur Recovery = Sulphur Production / (Sulphur Production + Sulphur Emissions)

Where:

Sulphur Production = tonnes of sulphur product and/or tonnes sulphur equivalent contained in injected sour or acid gas streams

Sulphur Emissions = tonnes sulphur equivalent contained in flared sour and acid gas streams and in the sulphur recovery unit tail gas or incinerator stack emissions

Non-Proliferation

To preclude the unnecessary development of new sour gas processing plants, applicants must vigorously explore and assess all existing facilities in the area that afford technically viable alternatives, regardless of ownership or interest, prior to applying for approval to construct a new sour gas plant. The assessment must thoroughly evaluate the feasibility of upgrading existing facilities and/or forging commercial partnerships with related operators. Operators of existing sour gas processing plants are expected to cooperate in the assessment of alternatives, including the evaluation of upgrading existing facilities to accommodate additional sour gas volumes. Applicants must consult and involve local residents in their evaluation of alternatives. It is expected that applicants will assess, compare, and document the following as a minimum:

- Surface disturbance impacts of a new plant project with potential impacts of incremental pipelines and other facilities required to use existing facilities;
- Overall air emissions (SO_2, NO_x, CO_2) of alternatives and estimated contribution to cumulative impacts in terms of acid deposition rates and ambient concentrations;
- Public proximity to alternative facilities and relative health and safety risk concerns;
- Views of local stakeholders regarding the alternatives under consideration; and
- Estimates of future local oil and gas development and the impacts such development may have on the viability of the options examined.

British Columbia

- BC Sulphur Recovery Criteria for Natural Gas Processing Plants (January 1994*), Waste Management Act*
- **Applicability**
  - New Plants: The plant inlet sulphur rate for the purpose of applying these criteria is the maximum value as determined from design information submitted with the application.
  - Plants Undergoing Modifications: If a permittee proposes a substantial plant modification, such as a process change or increase in the permitted emission rate by more than 25%, then the revised sulphur recovery criteria are to be applied when the plant's permit is updated to accommodate the increased emission rate. The sulphur emission rate to be used for evaluating whether or not an expansion is major is the sulphur emitted from the incinerator stack.
  - Existing Plants: The criteria are to be applied to existing plants.. In cases where the current permitted sulphur recovery is more stringent than the recovery set out in the table below, the permitted sulphur recovery will remain at the current value.

Plant Inlet Sulphur Rate (t/d)	Minimum Sulphur Recovery (1) (%)	Technology (2)
< 2	0	N/A
2 - < 10	89.7	2 stage Claus unit
10 - < 50	95.9	3 stage Claus unit
50 - < 2000	98.2 - 98.5 (3)	2 - 3 stage sub-dewpoint Claus unit
2000 +	99.5	2 - 3 stage Claus + selective absorption tail gas unit

Notes:

1. The minimum sulphur recovery criteria will be decreased in cases of poor acid gas quality (i.e. where the mole percentage of H2S in the acid gas feed stream from the amine unit or equivalent is less than 40%). The minimum sulphur recovery will be decreased by 0.068% for every 1.0 mole % H2S that the acid gas feed stream has less than 40 mole % H2S. The Regional Environmental Protection Manager may on occasion require operations which qualify for this relaxation to conduct sulphur recovery technology evaluations to explore if reducing or removing the relaxation is reasonable.
2. Technologies are cited as examples of technology which typically could meet these requirements and are not intended as requirements or recommendations.
3. For plant sizes 50 - < 2000 t/d, % sulphur recovery required = 98.2 + 0.187[log10(plant size/50)].

U.S. EPA Requirements

- Standards of Performance for New Stationary Sources; Onshore Natural Gas Processing; SO2 Emissions; Final Rule, October 1, 1985

H2S Content of acid gas (Y), %	**Sulfur Inlet Concentration (X), LT/D**			
	2.0≤X≤5.0	5.0<X≤15.0	15.0<X≤300.0	X>300.0
Y≥ 50	74	$85.35X^{0.0144} Y^{0.0128}$ or 99.8, whichever is smaller		
20≤Y<50	74	$85.35X^{0.0144} Y^{0.0128}$ or 97.5, whichever is smaller		97.5
10≤Y<20	74	$85.35X^{0.0144} Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
Y<10	74	74	74	74

US Requirements at State Level

Summary, by state, of rules for limiting SO2 emissions from sources applicable to the upstream oil and gas industry (Cheminfo and Clearstone, 2007)

State	Source	Rating	Date	Limit
Colorado	Natural Gas Desulphurization Plants	All	Built Prior to Aug 11, 1977	2 lb SO2 per 1000 cubic feet of (actual) delivered gas.
		Emitting < 3 tons/d of SO2	Build after Aug 11, 1997	2.0 lb SO2 per 1000 cubic feet of (actual) delivered gas.
		Emitting ≥3 tons/d of SO2	Build after Aug 11, 1997	0.8 lbs SO2 per 1000 cubic feet of (actual) delivered gas.
Florida	Sulphur Recovery Plant	All	New	0.004 lb of SO2 per lb of sulphur input to the recovery system or 0.004 lb of SO2 per lb of sulphur removed from an oil well.
			Construction Permit Issued Prior to 1 July 1973	0.08 lb of SO2 per lb of sulphur input to the recovery system or 0.08 lb of SO2 per lb of sulphur removed from crude oil or gas processed.
Mississippi	Sulphur Recovery Plant	All	All	0.12 lb of SO2 per lb of sulphur processed.
Oklahoma	Natural Gas Processing Plants and Petroleum Refineries	> 0.54 LT/D ≤ 5 LT/D *(> 0.55 t/d ≤ 5.1 t/d)*	New	SO2 emission reduction efficiency shall be at least 75.0%
		> 5 LT/D ≤ 150 LT/D *(> 5.1 t/d ≤ 152 t/d)*	New	Z is the minimum emissions reduction efficiency required at all time and X is the sulfur feed rated expressed in LT/D rounded to one decimal place: Z = 92.34 ^(0.00774)
		> 150 LT/D ≤ 1500 LT/D *(> 152 t/d ≤ 1524 t/d)*	New	Z is the minimum emissions reduction efficiency required at all time and X is the sulfur feed rated expressed in LT/D rounded to one decimal place: Z = 88.78 ^(0.0156)
		> 1500 LT/D *(> 1524 t/d)*	New	SO2 reduction efficiency shall be at minimum 99.5%
New Mexico	Gas Processing Plant	≥10 tons/d of sulphur in plant processes, and <20 mol% H2S	Existing	12 lb of sulphur for every 100 lb released in the plant processed.
		≥5 tons/d and less than 20 tons/d of sulphur in plant processes	New	≤10 lb of sulphur for every 100 lb of sulphur released in plant processes.
		≥20 tons/d and less than 50 tons a day of sulphur in plant processes	New	≤4,000 lb per day.
		≥50 tons/d of sulphur in plant processes	New	≤2 lb of sulphur for every 100 lb of sulphur released on plant processes.

Summary of Regulatory Regimes for Flaring Sources

Jurisdiction	Standard / Regulation
Alberta	☐ ERCB Directive 60 (D.60) – Limits for allowable flaring ▪ Decision tree analyses for all flaring sources i.e. evaluate and implement i) eliminate flaring, ii) reduce flaring, iii) flaring meets performance requirements ▪ Solution gas conservation requirements ▪ Well test flaring limits ▪ Limits on nonroutine flaring ▪ Gas plant flaring volume limits ▪ Reporting of flared volumes ☐ Alberta Environment's Specified Emitters Gas Regulation applies to facilities emitting > 100 kilotonnes CO_2-eq per year.
British Columbia	☐ Carbon tax in effect since July 1, 2008. ☐ BC Oil and Gas Commission Flaring, Incinerating and Venting Guidelines – Sets limits for allowable flaring, similar to ERCB D.60.
Brazil	☐ Limits on allowable flaring determined each year by the National Petroleum Agency (e.g., 15,000 m3 per month for the equipment burner pilots).
European Union	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities.
Germany	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities.
Netherlands	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities. ☐ General restrictions on flaring identified in Mining Decree. More details contained in issued licenses.
Norway	☐ Carbon tax. ☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities (off-shore exempted) ☐ Issuance of flaring consents
United Kingdom	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities (off-shore exempted) ☐ Issuance of flaring consents – general goal is to reduce flaring by 5% per year.
United States (Federal)	☐ Offshore flaring is controlled by permits issued by the Minerals Management Service of the Department of the Interior. These permits are proprietary.

APPENDIX E – VOCs FUGITIVE EQUIPMENT LEAKS, STORAGE LOSSES AND VENTING SOURCES: MEMBERSCOMMENTS AND JURISDICTIONAL REVIEW

MEMBER COMMENTS

Storage Losses and Venting

Some members support performance-based regulatory approaches and have concerns that adopting the provincial guideline could limit flexibility upon implementation and the goal of a reduction in storage losses and venting would not meet expectations. There is also uncertainty in committing to accommodating future updates to the guideline without knowing the burden of the future changes.

SUMMARY OF REGULATORY REGIMES FOR FUGITIVE EQUIPMENT LEAKS

Jurisdiction	Standard / Regulation
Alberta	☐ ERCB Directive 60 requires operators to meet or exceed the CAPP Best Management Practice for Fugitive Emissions Management, as of January 2010.
British Columbia	☐ BC Oil and Gas Commission Flaring, Incinerating and Venting Guidelines require operators to meet or exceed the CAPP Best Management Practice for Fugitive Emissions Management.
Norway	☐ Controlled through issuance of discharge permits.
United Kingdom	☐ Issuance of permits incorporating limits to emissions.
United States (Federal)	☐ New source performance standards for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants[8]: Targets components in VOC service at gas processing plants only; all other facility types exempt. Establishes a leak detection and repair program specifying sampling frequency and time allowed for repairs. ☐ National Emission Standards for Hazardous Air Pollutants for Equipment Leaks: Applies to sources operating in volatile hazardous air pollutant (VHAP) service[9]
United States (State level)	☐ The only states to have developed enhanced requirements for this sector are California and Texas, and these requirements are specifically applied in non-attainment areas. Requirements are highly prescriptive and have a significant reporting component.

Summary of Regulatory Regimes for Storage Tanks

Jurisdiction	Standard / Regulation
Canada (Federal)	☐ Canadian Council of Ministers of the Environment (CCME) National Guidelines for Controlling Emissions from Aboveground Storage Tanks provides guidelines for controlling VOC emissions from tanks with capacities > 75m^3. Specifies when vapour controls are required, performance standards, and inspection, maintenance and reporting requirements.
Alberta	☐ ERCB D.60 includes following requirements relevant to storage tanks: hydrocarbon products stored in atmospheric

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[8] 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants, available at: http://www.tceq.state.tx.us/permitting/air/rules/federal/60/kkk/kkkhp.html

[9] 40 CFR Part 61, Subpart V - National Emission Standards for Equipment Leaks, available at: http://www.tceq.state.tx.us/permitting/air/rules/federal/61/v/vhp.html

	storage tanks must not exceed a true vapour pressure of 83 kPa at 21.1 °C if such tanks are vented to atmosphere
Saskatchewan	☐ Installation of a vapour recovery unit from storage devices and associated equipment at a facility or well site that emits >= $50m^3$ of sour gas per day.
Netherlands	☐ Covenant – 30% reduction in VOC emissions in 2010 compared to 2000. ☐ Specify technologies to employ to reduce VOC emissions in operating licenses.
Norway	☐ VOCs from storage and loading are controlled through permits granted under the *Petroleum Control Act*, which requires the use of best available technology (BAT). (e.g., use BAT which will reduce VOC emissions by 78%).
United Kingdom	☐ Issuance of permits incorporating limits to emissions.
United States (Federal)	☐ National Emission Standards for Hazardous Air Pollutants – Storage Vessels (page 244 of Cheminfo and Clearstone, 2007)
United States (State level)	☐ Santa Barbara County and Ventura County in California (non attainment area) have specific regulations (Rule 325 and Rule 71.1, respectively) covering the storage of oil from production operations. The regulation requires vapor recovery from storage tanks and 90 percent control of the captured emissions. Tank batteries are exempt if the crude oil has a vapour pressure at the initial storage tank entry point of less than 0.5 psi absolute. ☐ Ventura County (non-attainment area) has implemented a regulation (Rule 74.26 – Crude Oil Storage Tank Degassing Operations) governing the control of vapour emissions during the degassing and cleaning of crude oil storage tanks. There is no comparable regulation in Canada or in any other states or at the U.S. federal level.

Summary of Regulatory Regimes for Venting

Jurisdiction	Standard / Regulation
Alberta	☐ ERCB Directive 60 (D.60) – Limits for allowable venting ▪ Decision tree analyses for all venting sources i.e. evaluate and implement i) eliminate venting, ii) reduce venting, iii) venting meets performance requirements ▪ Solution gas conservation requirements (e.g., solution gas production > 900 m3 requires an economic test to determine whether gas production should be conserved). ▪ Well test venting limits ▪ Limits on nonroutine venting ▪ Gas must be burned if volumes and flow rates are sufficient to support stable combustion ▪ Hydrocarbon products stored in atmospheric storage tanks must not exceed a true vapour pressure of 83 kPa at 21.1 °C if such tanks are vented to atmosphere ▪ Venting must not constitute an unacceptable fire or explosion hazard ▪ Venting of gas containing > 5ppm H2S from pipelines, must be burned ▪ Gas containing more than 1% H2S must not be vented to atmosphere ▪ Venting must not result in H2S odours outside the lease boundary ▪ Venting must not result in off-site exceedances of

	Alberta Ambient Air Quality Objectives ▪ Limits on all sources of benzene emissions ▪ Reporting of vented volumes ☐ Alberta Environment's Specified Emitters Gas Regulation applies to facilities emitting > 100 kilotonnes CO_2-eq per year.
British Columbia	☐ Carbon tax in effect since July 1, 2008. ☐ BC OGC Flaring, Incinerating and Venting Guidelines – Sets limits for allowable flaring, similar to ERCB D.60.
Brazil	☐ Limits on allowable venting determined each year by the National Petroleum Agency.
European Union	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities.
Germany	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities.
Netherlands	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities.
Norway	☐ Carbon tax. ☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities (off-shore exempted)
United Kingdom	☐ CO2 emissions trading with allowances assigned to upstream oil and gas facilities (off-shore exempted) ☐ Issuance of venting consents – general goal is to reduce flaring by 5% per year.
United States (Federal)	☐ Offshore venting is controlled by permits issued by the Minerals Management Service of the Department of the Interior. These permits are proprietary.
United States (State level)	☐ San Joaquin Valley and Monterey Bay Air Pollution Control Districts in California (non attainment areas) have regulations (Rule 4401 and Rule 427) to limit the VOC emissions from steam-enhanced crude oil production well vents and associated vapor collection and control systems. ☐ Texas has established regulations governing venting and purging activities for gaseous and liquid petroleum pipelines.

APPENDIX F: FUTURE WORK

The Upstream Oil and Gas SSG members believe that further work will need to be completed on proposed BLIERS, or in development new BLIERS in future phases of CAMS development. The following discussion lists those substances or sources that should be considered in future work. The list should not be considered as consensus recommendations by all stakeholders.

FUTURE WORK NEEDED TO DEVELOP BLIERS OR TO CONVERGE ON CONSENSUS RECOMMENDATIONS

Offshore Oil and Gas

- Implication of recommended onshore upstream oil and gas (UOG) BLIERS for offshore upstream oil and gas (UOG), and consideration of BLIERS unique to offshore applications. Timelines for the current process were too short to consider the implications of recommended BLIERS for the offshore upstream oil and gas sector.

NOx (Reciprocating engines)

- Determine the economic and resource recovery impacts and the emission reductions from lowering thresholds for both new and existing engines to ≥ 100 kW
- Determine the economic costs of lowering thresholds for both new and existing engines to ≥ 100 kW
    - Determining the greenhouse gas emission tradeoffs and availability of new engines with emission standards of 1.3 g/kWh. Consultation with manufacturers is needed.
- Develop timelines for a phased-in approach for existing reciprocating engine requirements
    - Requires an understanding of capital and labour availability within industry to retrofit thousands of engines and manufacturers' ability to produce the retrofit technologies required.
- Consider the applicability of a future BLIER for diesel engines
    - Small source of NOx emissions from the sector however, could be reconsidered if a BLIER or other regulatory requirement was created for all diesel engines.
    - These engines are primarily used in exploration and are not in long term application. Stationary diesel engines used in the sector for emergency uses.

NOx (Boilers and Heaters and Turbines)

- Most heaters and boilers in UOG are < 10.5 GJ/hr. Consideration of an emission standard for boilers and heaters < 10.5 GJ/hr is recommended for future work under CAMS.

- No recommended BLIER for existing turbines. This could be revisited in the future, however is a small source of NOx emissions from the sector.

SO2 and VOCs

- Some members believe that future work is needed for consideration for a sulphur recovery standard for facilities with low concentrations of H_2S in inlet acid gas and for facilities that combine acid injection and sulphur recovery. Some members do not feel that a caveat should be granted based on the potential closure of one facility (Appendix C).

- Determine how Alberta ERCB Directive 60 flaring and venting minimization requirements, which are periodically updated, could be made into a national standard for flaring and venting.

- Utilization of the CAPP Best Management Practices for Facility Flare Reduction as part of a BLIER for flaring and/or venting

- Development of regulated code of practice for managing VOCs from equipment leaks and storage losses and timelines for implementation.

FUTURE WORK FOR POSSIBLE ADDITIONAL BLIERS

Benzene

- The CAMS proposal addresses only CACs at this time; the upstream oil and gas sector is the largest industrial source of benzene. Some members believe a future BLIER or other national process should be considered to address benzene.
- Industry stakeholders do not necessarily support a BLIER for benzene emissions. The largest source of UOG benzene emissions are glycol dehydrators, which are currently regulated by the ERCB Directive 60 and Directive 39. British Columbia and Saskatchewan have equivalent regulations.
- Controls developed in the current BLIERS process for VOCs may result in some benzene emission reductions. The impact (if any) of this BLIER for VOCs on benzene emissions has not been quantified.

Particulate Matter

- As indicated in the SSG's report to the BLIERS-What Working Group on September 18 (shown in Appendix B), there was no agreement on whether PM was to be considered within for this sector. Some stakeholder views on future work are in Appendix G.

APPENDIX G – MEMBER RECOMMENDATIONS FOR FUTURE WORK ON PM2.5

Health Canada

Fine particulate matter (PM2.5) poses a very significant threat to human health. The upstream oil & gas sector is estimated to be the third largest industrial source of PM2.5 emissions. Therefore, it is recommended that actions be taken to reduce PM2.5 emissions from the sector.

It is true that reductions in NOx, SOx, and VOC emissions from the sector will reduce the formation of secondary PM in the atmosphere. However, reducing primary PM emissions would provide significant additional benefits. Additional action to address PM through the development of a BLIER is, therefore, warranted.

Whether a BLIER for PM would be in the form of a facility limit, equipment requirement, or code of practice should be identified as part of future work. Whatever form the BLIER takes, it should require specific, verifiable, and enforceable action from industry. Identifying the most appropriate form of a BLIER and developing the BLIER should be a very high priority for future work on emissions from upstream oil & gas.

It is recognized that current PM2.5 emissions data from the upstream oil & gas sector is based on emissions factors and is not directly measured.

This poses difficulties in setting a BLIER specifically for PM2.5. It is recommended that as part of future work, more reliable PM2.5 estimates and monitoring methods be implemented. Once better PM2.5 emission baseline data and monitoring capacity is available, a BLIER for PM2.5 could be precisely defined.

In the mean time, however, uncertainty in measuring emissions should not stand in the way of action to address sources. The main sources of PM2.5 emissions are known, as are the actions that would be likely to reduce those emissions. Requirements to address PM2.5 emissions could be developed and implemented in the near term. Once better PM2.5 monitoring is available, compliance with the BLIERs could be judged based on actual PM2.5 measurements. In the mean time though, compliance with the BLIER for PM could be judged based on monitored TPM emissions.

ENGO Member

An ENGO member expressed support for Health Canada's comments. In light of the health and environmental adverse effects of fine particulate matter, and other components such as the speciation of PM and the fine fractions and the potential for long-range transport, particularly from climatic conditions. it is critical that PM2.5 emissions be addressed, particularly considering the number of facilities involved.

There are currently monitors to measure PM2.5 emissions and improvements to monitoring and measurement are being continually made. At the same time, estimation of the proportion of PM2.5 (and PM10) in total PM is reasonable.

Canadian Association of Petroleum Producers

As recognized by Environment Canada in the Turning the Corner Framework on Air Pollutants, PM reductions will occur as a result of the emissions reductions measures undertaken to reduce NOx, SO_2 and VOCs. Indeed, Turning the Corner did not consider PM emissions reductions from the UOG sector.

The main sources of PM from the UOG industry are flaring, and fuel combustion in reciprocating engines, boilers and heaters. As all of these sources are currently being evaluated for BLIERS that will inherently reduce PM emissions, developing BLIERS for PM is redundant and/or unnecessary.

As a mention on reporting and estimating PM emissions: Currently PM emissions from the UOG are estimated using best available emissions factors, which show that flaring is the largest source of PM (~70% of industry total). The emissions factors used to estimate PM from flaring is conservative, as they are based on a study conducted in the early 1980s on landfill gas flares in the US. Landfill gas has poor combustion and higher PM than would be expected from flares. There is research ongoing at Carleton University on quantification of PM emissions from flaring. Preliminary results from this research show that PM emissions from flaring may be significantly over-estimated using existing emissions factors.

APPENDIX H – SECTOR SUBGROUP INTERIM REPORT TO BLIERS WHAT WG – SEPTEMBER 18, 2009 (Revised to Reflect BLIERS-What Working Group Comments)

Upstream Oil and Gas Sector Subgroup
Report to the BLIERs What Working Group on
Criteria Air Contaminants (CACs)

Summary

For the Upstream Oil and Gas sector (including offshore), BLIERS are recommended for the following CACs: SO2, NOx and VOCs.

We did not have agreement of all members that a BLIERS should be developed for particulate matter (including TPM, PM10 and PM2.5).

Criteria Air Contaminants

The list below shows the CACs and other air pollutants identified in the BLIERS process for this sector. The Upstream Oil and Gas Sector Subgroup has considered each one and has consensus to recommend BLIERS for the following CACs: SO2, NOx and VOCs.

SO_2

Recommendation: A quantitative BLIER is recommended for this sector.

Rationale: This sector emits 10% of all industrial SO_2 emissions in Canada. Within the sector, 82% of emissions come from the sour gas processing facilities.

NOx

Recommendation: A quantitative BLIER is recommended for this sector.

Rationale: This sector emits approximately 42% of industrial NOx. Over 84% of emissions from the sector come from natural-gas-fired reciprocating engines, with a further 5% from boilers and heaters which may be addressed in the boilers and heaters BLIERS sub group.

VOC

Recommendation: We expect that a qualitative BLIER will be developed for most sources in this sector however quantitative approaches will be considered where possible. BLIERS for VOCs will also address benzene released from the same sources.

Rationale: This sector emits approximately 48% of all industrial VOC emissions in Canada. VOC emissions from equipment leaks and storage and loading activities are difficult to quantify. Technological advances and research are ongoing to improve quantification of fugitive sources, including the magnitude of leaks, but work is still needed to quantify VOC emissions on a per tonne basis and over time. Other sources of VOCs from this sector may be addressed through quantitative measures if possible or through qualitative measures.

Particulate matter (PM)

Recommendation: Most members agreed that the development of a BLIER is not recommended for this sector. Some members were concerned about exclusion of PM (including TPM, PM10 and PM2.5) due to the contribution of the sector as a whole.

Rationale: The Boilers and Heaters BLIERS may include PM and may apply to upstream oil and gas sector. No *Turning the Corner* (TtC) target was set for PM from the upstream sector, due to its contribution to national emissions (3% for PM2.5, less then 3% for TPM and PM10). The primary fuel used by the sector is natural gas. The estimated emissions of PM are from a large number of very small distributed sources, typically located in sparsely populated and remote locations. PM emissions from flares are difficult to quantify. Research to characterize and quantify PM from sources such as flares will inform future discussions of PM emissions from this sector. If technology were available for measuring fine particulates then a BLIER may be reconsidered in the future.

Benzene

Recommendation: The CAMS proposal does not address benzene.