An Emissions Management Framework for the Alberta Electricity Sector Report to Stakeholders

Prepared by the
Clean Air Strategic Alliance
Electricity Project Team

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By consensus, the CASA board of directors approved this report and the recommendations within at its November 27, 2003 meeting.

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All members of the Electricity Project Team showed remarkable dedication and commitment to the large and challenging tasks this project presented. The volunteer time given to this project by individuals and by organizations was significant and well beyond expectations.

About CASA

The Clean Air Strategic Alliance (CASA) is a non-profit association composed of stakeholders from three sectors – government, industry and non-government organizations such as health and environmental groups. All CASA groups and teams, including the board of directors, make decisions and recommendations by consensus. These recommendations are likely to be more innovative and longer lasting than those reached through traditional negotiation processes. CASA's vision is that the air will be odourless, tasteless, look clear and have no measurable short- or long-term adverse effects on people, animals or the environment.

The Electricity Project website (http://www.casahome.org/electricity) contains all the documents produced by the team, including materials for the public meetings, as well as presentations made at workshops and seminars sponsored by the team.

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List of Acronyms and Compounds

AENV	Alberta Environment
BATEA	Best Available Technology Economically Achievable
BAU	Business As Usual
BTEX	benzene, toluene, ethylbenzene, xylene
CABREE	Centre for Applied Business Research in Energy and the Environment
CASA	Clean Air Strategic Alliance
CCME	Canadian Council of Ministers of the Environment
CEPA	Canadian Environmental Protection Act
CO_2	Carbon dioxide
CWS	Canada-wide Standard
DLE	Dry Low Emission (NOx burners)
DLN	Dry Low NOx (burners)
EIA	Environmental Impact Assessment
EPEA	(Alberta) Environmental Protection and Enhancement Act
EUB	(Alberta) Energy and Utilities Board
EPT	Electricity Project Team
FGD	Flue Gas Desulphurisation
GHG(s)	Greenhouse gas(es)
Hg	Mercury
ISO	Independent System Operator
MCR	Maximum Capacity Rating
MOU	Memorandum of Understanding
MW	Megawatt (of power. One MW is 1000 kilowatts.)
MWh	Megawatt-hour
NGCC	Natural Gas Combined Cycle
NOx	Nitrogen oxides (also oxides of nitrogen)
PAHs	Polycyclic Aromatic Hydrocarbons
PM	Particulate matter
$PM_{2.5}$	Particulate matter less than 2.5 microns in diameter
PM_{10}	Particulate matter less than 10 microns in diameter
PPA	Power Purchase Arrangement
QA/QC	Quality Assurance/Quality Control
RATA	Relative Accuracy Technical Assessment
SCR	Selective Catalytic Reduction
SO_2	Sulphur dioxide (SOx refers to sulphur oxides)
VOCs	Volatile organic compounds
WHO	World Health Organization

Definitions for most of these acronyms and abbreviations are included in the glossary in Appendix A.

Preface

The Importance of Keeping this Framework Intact

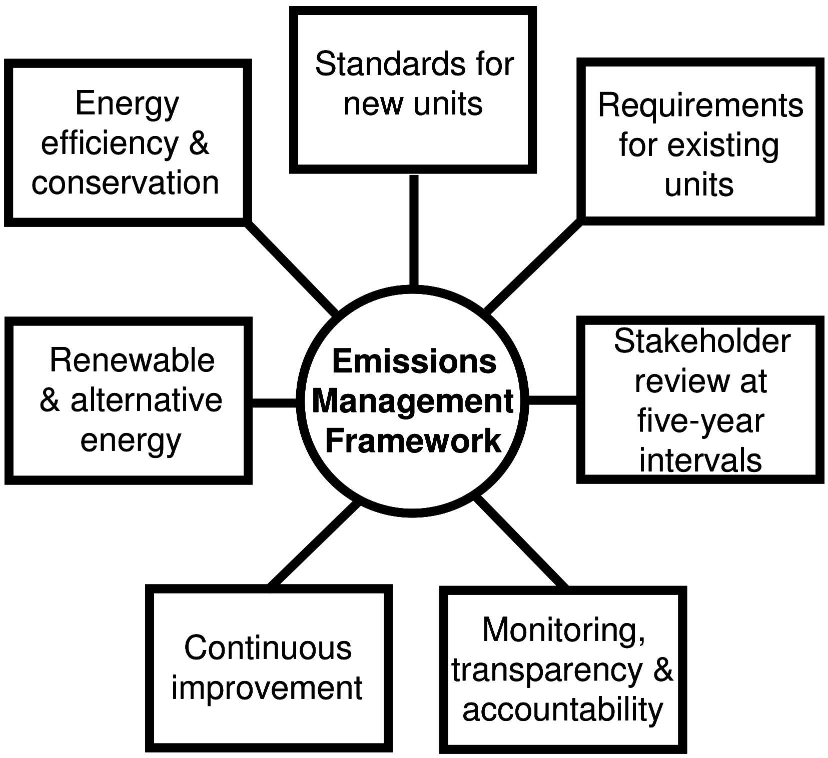
This report recommends a new management framework for air emissions from Alberta's electricity sector. This multi-pollutant framework represents an important step that, over time, will result in significant reductions in five key substances. The approach incorporates elements from the current system and proposes new mechanisms that balance environmental and economic interests in the province.

The Electricity Project Team worked diligently and in good faith to reach consensus on the framework. Throughout the process, representatives from all sectors provided their views and perspectives, raised concerns and offered alternative solutions. This framework is a set of consensus recommendations, negotiated by the team and agreed to as a package. **The package must therefore be considered in its entirety. If it is fragmented in any way, the overall framework can no longer be regarded as a consensus package with full stakeholder support.**

1 Executive Summary

In January 2002, Hon. Lorne Taylor, Alberta's Minister of Environment, asked CASA to develop an approach for managing air emissions from the electricity sector. This report and package of recommendations is CASA's response to that request. It is recommended that the new framework be fully implemented by January 1, 2006.

The Framework at a Glance



The proposed framework will lead to significant reductions over time in four priority air emissions: mercury, sulphur dioxide, nitrogen oxides and primary particulate matter. The main outcomes in terms of improved performance and emissions reductions are:

Standards for New Units

- New units will be governed by new emission standards for SO_2 and NOx, effective January 1, 2006.
- New coal-fired units will be required to add mercury controls and to reduce or offset their greenhouse gas emissions to natural gas combined cycle levels.
- Effective January 1, 2006, all standards for new units will be based on Best Available Technology Economically Achievable (BATEA).

Requirements for Existing Units

- There will be significant reductions in mercury by the end of 2009.
- Mercury control technologies may provide significant co-benefits, including reductions in primary particulate matter to levels consistent with BATEA.
- There is a new requirement for units to reduce emissions to the latest BATEA performance standard at the end of their design life.

Five-Year Review

- CASA is recommending a defined multi-stakeholder process to evaluate the performance of the framework at five-year intervals.
- The review will be a publicly credible, transparent and participatory process that will involve stakeholders from all sectors including the public.
- If core assumptions are proven wrong, the framework will be revised.

Renewable and Alternative Energy

- A target for the development of new renewable and alternative energy will apply to all electricity generation by 2008, subject to certain issues being resolved.
- Strategies, such as a “green certificate” program and emissions trading, are proposed to implement the target.
- A multi-stakeholder team is recommended to assess the need for a target beyond 2008.

Energy Efficiency and Conservation

- The framework includes strategies to reduce demand and encourage more efficient use of electrical energy.
- Stakeholders will undertake further work to refine strategies in this area.

Continuous Improvement and Hot Spots

- Recommendations include special provisions to address potentially emerging “hotspots.”
- Continuous improvement will occur through regular review and updating of technology performance standards.
- Industry will be setting continuous improvement goals at five-year intervals.

Monitoring and Transparency

- A key component of the framework is a comprehensive monitoring system to track compliance with emissions standards and reductions targets.
- There is greater emphasis on transparency with information available to the public.
- The framework recommends opportunities for public involvement in the management system.

Expected Emissions Reductions

Substance	Annual reductions	Reduction from 2003	Target year
Mercury	400 kg	50%	2009
Primary particulate matter (PM)	3,500 tonnes	51%	2025
Sulphur dioxide (SO_2)	52,000 tonnes	46%	2025
Nitrogen oxides (NOx)	29,000 tonnes	32%	2025

The team is of the general opinion that emissions reductions will likely be more than projected due to improved technologies and practices.

Wholesale Price and Cost Implications

Comprehensive economic modelling was conducted to assess the impact of the team's recommendations on wholesale electricity prices. The major factor affecting future wholesale prices is the forecast price of natural gas. The proposed emissions management approach is projected to have minimal additional impact on the wholesale electricity price. The forecast average impact of direct emissions control costs over the modelling period ranges from $0.73/MWh to $1.15/MWh. The costs to individual units for emissions management were inputs provided by the team to the modeler. Based on these cost inputs, the total emissions control costs from 2003-2025 for existing coal units could be in the range of $2.7-billion to $3.8-billion. When this amount is discounted back into 2004 dollars, the total emissions control costs are between $0.7-billion and $1.0-billion. This represents a cost range to a typical unit of $1.80/MWh to $2.70/MWh across the 2003-2025 period. It was also forecast that most new renewables arising from the renewable target would be wind energy. It was also forecast that wind would play a role in lowering electricity prices in the period prior to 2010, which may result in the need for incentives over and above the current federal incentive to encourage incremental wind generation. The overall average wholesale electricity price impact of wind energy for the forecast period is in the range of $0.82-$1.69/MWh.

When assessing the cost of the framework, it is crucial to balance this assessment with the knowledge that the status quo is not one of zero cost. In other words, there are economic costs as the electricity generation sector complies with current and emerging regulations and meets existing emission limits. In addition, the federal government has indicated that reductions in greenhouse gas emissions from current, or "business as usual," levels will be required as Canada moves to meet its commitment under the Kyoto Protocol.

Benefits

Key benefits of the proposed framework are many, and include:

- Significant reductions in four priority substances with anticipated co-benefits for a second list of substances.
- Emission reduction requirements that will put Alberta among the leaders in air quality management in North America, and help to guide the development of national standards for mercury and greenhouse gases.
- A sustainable emissions management system in terms of achieving environmental improvement within time frames that are economically achievable.

- Increased long term regulatory certainty for all parties.
- Ongoing multi-stakeholder input to the management of emissions from the electricity sector.
- A blend of management tools, including an emission trading system, that will provide industry with a wider range of choices, thus enabling it to minimize cost while meeting emission reduction targets
- Control strategies that that can be applied to bring about emissions reductions in more than one substance.

Conclusion

The framework represents a creative mix of management strategies that will increase long-term regulatory certainty for all parties, provide flexibility in reducing emissions and encourage continuous improvement of the overall management system.

In conclusion, the Electricity Project Team is of the view that the framework is a significant contribution to achieving CASA's goals for air quality, namely, protect the environment, optimize economic performance and efficiency, and seek continuous improvement.

Electricity Project Team Recommendations

No.	Recommendation	Page
1	**Generation Unit** For the purposes of this management framework, a "generation unit" refers to separate components of a power plant facility that result in the production of electrical energy and, where relevant, the combustion of fossil fuel (e.g., a boiler-generator pair or a gas turbine-generator pair).	40
2	**Existing Units** For the purposes of this management framework, an "existing" thermal generation unit be defined as follows: An existing coal or gas unit is one that, prior to the most recent review and update of the BATEA emission limits, 1) has valid EUB and Alberta Environment approvals in place for the eventual unit start-up dates contemplated in the approvals, or planned by the project proponent, AND 2) in addition to any conditions of EUB and Alberta Environment approvals regarding dates for commencement of construction or formal commissioning of the units, has a) within three years of receiving its Alberta Environment approval • continuous and substantive onsite construction, or • boiler foundation in place. AND b) has received formal commissioning and is available for commercial service within eight years of receiving its Alberta Environment approval for coal-fired units, or within five years of receiving its Alberta Environment approval for gas-fired units.	40
3	**New Units** For the purposes of this management framework, a "new" thermal generation unit, be defined as any unit that does not meet the criteria for an "existing" unit and will therefore be required to comply with the BATEA or other emissions limits in effect at the time.	41
4	**Transitional Units** For the purposes of this management framework, "transitional" units, which refer only to coal-fired generation, are those units that (a) hold valid EUB and Alberta Environment approvals received between June 1, 2001 and December 31, 2005, and (b) meet all criteria used to define existing generation units.	41
5	**Design Life** The Design Life for coal-fired units, except for the Wabamun generating facility, is defined as the date of expiry of the PPA term or 40 years from the date of commissioning, whichever is greater. The end of Design Life for Wabamun units 1, 2, and 4 is December 31, 2010, according to their EPEA approval (Approval 10323-02-00), which states that, "a decision must be made by December 2005 whether to modify the unit to meet applicable environmental standards or to commence decommissioning by 2010." Design Life for gas-fired units is the date of expiry of the PPA term or 30 years from the date of commissioning, whichever is greater. Design Life for peaking gas-fired units is the date of expiry of the PPA term or 60 years from the date of commissioning, whichever is greater.	41
6	**NOx and SO_2 Standards for New Thermal Generation Units** Effective January 1, 2006, the SO_2 and NOx BATEA standards for new coal-fired units be 0.80 kg/MWh for SO_2; and 0.69 kg/MWh for NOx. Effective January 1, 2006, the NOx BATEA standards for new gas-fired units will be: • 0.6 kg/MWh for units less than 20 MW power capacity • 0.4 kg/MWh for units between 20 and 60 MW power capacity • 0.3 kg/MWh for units greater than 60 MW power capacity For co-generation units, MWh includes combined steam heat and electricity.	43

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7	**NOx and SO_2 Standards for Transitional Coal-Fired Units** Transitional units be **expected**[1] to meet the 2006 BATEA level for SO_2 at start-up, and be **required** to meet 2006 BATEA levels for SO_2 by December 31, 2015. The deemed threshold for credit generation for SO_2 is the 2006 BATEA level. Transitional units will be required to meet the 2006 BATEA levels for NOx by December 31, 2015. Before December 31, 2015, the deemed threshold for NOx credit generation will be the 2001 Alberta standard. After this date, the deemed credit threshold for NOx will be 90% of the 2006 BATEA level.	43
8	**NOx and SO_2 Emissions Management Approach** The EPT recommends adoption of a baseline and credit emissions trading system at this time for SO_2 and NOx. To manage SO_2 and NOx from Alberta's electricity generation sector, the EPT recommends that 1. Baseline emission rates for both new units and existing units that are at the end of Design Life are the BATEA limits of the day. 2. The emission rate for existing units prior to the end of their Design Life is the currently approved emission rate as specified in the regulatory approval. 3. For the purposes of credit generation, where not otherwise covered by points 4, 5, 6 or 7 below, the following will apply. The baseline emission rate for existing units would be established based on the average emissions per MWh in the 2000-2002 period inclusive. For co-generation units, the baseline emission rate will be based on the combined heat and electricity in MWh. In the event of unusual operating conditions or a prolonged shutdown during that period, the baseline would be based on the three most recent "average" years of operation. A unit that has been recently commissioned would have its baseline set by the first three years of operation. In the case of an existing unit that does not yet have three years of operation, the first year of "normal" operation would be used. 4. The deemed credit threshold for the 2006 BATEA standards, as applied to new coal-fired units, is 90% of the BATEA level. 5. Credits for performance better than the deemed credit threshold are subject to a one-time discount of 10% if they are not used within twelve months of being certified. 6. The deemed NOx credit threshold for new (post-2005) gas units (including peaking units) is as follows: i. 0.5 kg/MWh for units less than 20 MW in capacity rating ii. 0.3 kg/MWh for units between 20 and 60 MW in capacity rating iii. 0.2 kg/MWh for units greater than 60 MW in capacity rating 7. The deemed NOx credit threshold for existing gas units is as follows: i. 0.2 kg/MWh for units operating below 0.2kg/MWh. As this threshold already incorporates the concept of deemed credit threshold and an environmental discount, #5 above would not apply to these units. ii. baseline emission rates for units operating above 0.2kg/MWh iii. 0.2 kg/MWh for all peaking units operating above 0.2 kg/MWh. Peaking units can generate credits to a maximum of the difference between actual NOx emissions and the NOx emission cap applying to that unit. 8. Credits for existing units that shut down before the end of Design Life will be granted based on: i. the number of years between shutdown and end of Design Life ii. the difference between the unit's baseline emission rate or deemed credit threshold, where applicable (kg/MWh), and the BATEA emission rate of the day and the corresponding deemed credit threshold applicable to new units. iii. the unit's generation rate (MWh/year), which will be the average of the three highest years' generation in the last five years before shutdown 9. Unlimited banking of credits 10. Units that reach the end of Design Life and commit to either shutting down on that date or upgrading to BATEA within three years of that date are eligible for transitional allocations based on the following formula: BATEA limit of the day (kg/MWh) x 3 years x the average of the three highest years' generation in the last five years (MWh). Consistent with the 2010 shutdown or upgrade requirements of their EPEA Approval, the Wabamun	46

[1] See the *Environmental Protection and Enhancement Act* approval for EPCOR's Genesee 3 expansion to see how this concept is applied.

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	generating units are not eligible for this provision. For units that have reached the end of their Design Life, there be a 10-year limitation, to a maximum operating life of 50 years for coal, 40 years for gas, and 60 years for peaking gas units, on the use of credits to meet new BATEA limits, at which time the existing unit must physically upgrade to comply with the BATEA emission limit of the day or shut down. Consistent with the 2010 shutdown or upgrade requirements of their EPEA Approval, the Wabamun generating units are not eligible for this provision. For exceptions, see recommendation 10.	
9	**Implementation of the Management Approach for NOx and SO_2** Alberta Environment establish a multi-stakeholder committee to support and advise the Department in the implementation of the NOx/SO_2 emissions management system, and address any outstanding details. Alberta Environment, in consultation with the multi-stakeholder committee, examine opportunities to merge or harmonize the NOx/SO_2 emissions management system for the electricity sector with a cross-sectoral cap and trade or any other form of emissions trading system. Access by any other types of electricity generators to any provincial SO_2/NOx trading system should also be examined at that time. Future consideration be given to converting the NOx/SO_2 emissions management system for the electricity sector to a cap and trade system	47
10	**Existing Gas-Fired Units** At the end of a gas-fired unit's Design Life, the emission limit will be set at the BATEA standard of the day. At that point, the unit can elect to do one of the following: 1. Install and upgrade technology to achieve the BATEA standard of the day; 2. For a maximum of 10 years, purchase allowances or credits for the difference between operating levels and the BATEA standard of the day. At the end of 40 years, the unit must meet the requirements described in 1, 3 or 4. 3. Shut down; or 4. Declare the unit as a peaking unit for a minimum three-year period, and run as a peaking unit to a maximum age of 60 years on the condition that the requirements for peaking units are met. As noted in recommendation 11, at the age of 60 years a unit can elect to install and upgrade technology to achieve the BATEA intensity level of the day or shut down. Three months' notice must be provided prior to the designation of a unit as a peaking unit. In the event a gas-fired unit's Design Life is reached before 2010, the unit will be given until December 31, 2010 to meet the framework requirement applicable to the age of that unit. For existing natural gas co-generation units currently under an industrial site environmental approval where the co-generation facility does not operate under its own Alberta Environment approval, it is recommended that the NOx emissions limits for these co-generation units continue to be incorporated into the allowable NOx emissions for the site. This would allow emission reductions to be dealt with on a site rather than on a specific unit basis, while still providing for the required reductions overall. At the end of 40 years the unit must meet the requirements described in 1, 3, or 4 above.	48
10a	**Co-generation Units Fired by Other Fuels** New co-generation units may use other fuels such as coke, hydrogen, bitumen, diesel fuel and others (e.g., biomass). These units should continue to be dealt with on an approval-by-approval basis and, consistent with the approach recommended for gas-fired co-generation units, the application of BATEA based limits to new units should be followed. If specific alternate fuel type co-generation units are proposed in the future, then as part of the Five-Year Review process, consideration should be given to developing specific BATEA-based emission limits for such units similar to those in recommendations 6 and 8. For existing co-generation units fired by other fuels currently under an industrial site environmental approval, where the co-generation facility does not operate under its own AENV approval, it is recommended that the NOx emissions limits for these co-generation units continue to be incorporated into the allowable NOx emissions for the site. This would allow emission reductions to be dealt with on a site rather than on a specific unit basis as part of the regular EPEA approval renewal process, while still providing for the required reductions overall.	48

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11	**Peaking Units** The emissions cap for NOx for gas-fired units declaring themselves as peaking units prior to December 31, 2010 is a gross emissions cap in kilograms per year, based on the following formula, consistent with the 1992 CCME guidelines: (1.008 kg/MWh) *(Maximum Capacity Rating in MW) * (1500 hours.) Units declaring themselves as peaking units after January 1, 2011 would be subject to a cap based on the following formula: peaking unit BATEA intensity level of the day * (Maximum Capacity Rating in MW) * (1500 hours). A peaking unit may operate to a maximum age of 60 years, at which time it can elect to: 1. Install and upgrade technology to achieve the BATEA intensity level of the day; or 2. Shut down. The emissions cap for a peaking unit may be exceeded if the units are required by the System Operator to operate for system security.	49
12	**Reciprocating Engines** Emissions from reciprocating engines, excluding stand-by and emergency units, be addressed on an approval basis and compared to the BATEA level of the day. If there is a significant increase in the size or number of these units, they may be addressed as part of the Five-Year Review	49
13	**Regulation of Mercury** a) Alberta Environment establish mercury control requirements in regulation or in standards through the *Environmental Protection and Enhancement Act,* and b) the requirements for mercury control be incorporated into the approvals for each coal-fired unit, according to the following recommendations.	52
14	**BATEA Review for Mercury** a) Alberta Environment continue to pursue the establishment of a BATEA level for mercury emissions from coal-fired units and, when established, amend existing regulations or standards to implement the new BATEA level. The mechanism for applying the BATEA level will be the same as that described in recommendation 17. b) the BATEA level for mercury be reviewed in 2005 by a multi-stakeholder group consisting of representatives from industry, government, non-government organizations and communities with an interest in the electricity sector, based on: • new monitoring data being collected by industry now, • commercially available and relevant technology and management options, and • new environmental and health information. The review should follow the same principles as described in recommendation 29 and, to the extent possible, also include the Alberta parties involved in the CWS process. c) PPA buyers and generators commit to enter into discussions with the objective of reaching agreement on: commercial arrangements to implement the BATEA level, the financial commitment for each unit, and shutdown dates for units identified in recommendation 17 for shutdown; and d) PPA buyers and generators commit to conclude these discussions by December 31, 2006.	53
15	**Five-Year Review for Mercury BATEA Level** Commencing in 2008, any established mercury BATEA emission level be reviewed as part of the general Five-Year Review of the BATEA limits in the overall emissions management framework.	53
16	**Required Level of Effort for Mercury Control** If a BATEA level for mercury is not identified in 2005: a) as a condition of their approvals, coal-fired units be required to implement a set level of effort for mercury control by the end of 2009 to reduce emissions to the extent possible, with the exception of those units noted in recommendation 17 for shutdown; and b) for existing units, the level of effort be defined to be financially equivalent to installing fabric filters and activated carbon at an injection rate to be determined as part of the 2005 BATEA review for mercury recommendation 14. New or transitional units that have fabric filters would only be expected to meet the activated carbon component of this level of effort commitment. This exception would not apply if a BATEA level has been determined in recommendation 14.	53

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	c) cost-effective alternatives to fabric filters and activated carbon injection can be installed by December 31, 2009 only if these technologies achieve mercury reductions equivalent to or better than those achieved using fabric filters and activated carbon injection; and d) PPA buyers and generators commit to enter into discussions with the objective of reaching agreement on: commercial arrangements to implement the level of effort for each unit, the equivalent financial commitment for each unit, and shutdown dates for units identified in recommendation 17 for shutdown; and e) PPA buyers and generators commit to conclude these discussions by December 31, 2006.	
17	**Units to Install Mercury Controls or Shut Down** The following coal-fired units install mercury controls by the end of 2009: Battle River 5; Sheerness 1 and 2; Genesee 1, 2 and 3; Sundance 3,4, 5 and 6; Keephills 1 and 2; Centennial 1 and 2; and Luscar's Brooks units 1 and 2. Wabamun units 1, 2 and 4 will be dealt with in accordance with their EPEA approval (Approval 10323-02-00, section 4.1.2), which states that, "a decision must be made by December 2005 whether to modify the unit to meet applicable environmental standards or to commence decommissioning by 2010." If the PPA buyers and generators agree to commercial arrangements to implement the level of effort approach described in recommendation 16 by December 31, 2006, the following units will not be required to install mercury control technology and will be required to shut down: HR Milner, Battle River 3 and 4, Sundance 1 and 2. It is agreed that their effective shutdown dates would be as follows: HR Milner – 2012; Battle River 3 and 4 – 2015; and Sundance 1 and 2 – 2017. If the PPA buyers and generators agree by December 31, 2006 to shut down only some of these units on the effective dates, those units that continue to operate will be required to install mercury controls by 2009, consistent with recommendation16. These commitments and deadlines are to be incorporated into the relevant approvals for all units.	54
18	**Alberta's Position on Addressing Mercury from Coal-fired Power Plants** The requirements and approach described in these recommendations be the position that Alberta presents to the Canadian Council of Ministers of the Environment Canada-wide Standards table addressing mercury emissions from coal-fired power plants.	55
19	**Primary PM Standard** Effective January 1, 2006, the primary particulate matter standard for new coal-fired units be 0.095 kg/MWh.	56
20	**Regulation of Primary PM** Alberta Environment regulate primary particulate matter on a unit-by-unit basis through the *Environmental Protection and Enhancement Act* approval process.	56
21	**Five-Year Review** Every five years, commencing in 2008, the technology be reviewed to determine BATEA level of the day for primary particulate matter, as part of the process described in recommendation 29.	56
22	**Co-benefits of Mercury Control** For existing and transitional coal-fired units, where mercury controls include fabric filters, the primary particulate matter target of 0.095 kg/MWh shall apply. If mercury control identified in the 2005 review does not provide this co-reduction of primary particulate matter, then the 2008 system review should develop a primary particulate matter management system for existing units.	56
23	**Thermal Generation Greenhouse Gas Intensity Target** – Under discussion	
24	**Rules for Offset Credits** Governments establish clear rules on acceptable offset credits that represent real greenhouse gas reductions that are measurable, verifiable, and do not result in double counting. Flexibility in the use of trading, bankable offset credits, and the potential use of research and development be provided to achieve reductions.[2]	58

[2] It is further recognized that the issue of financial additionality is to be resolved in another forum.

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25	**New Coal Unit NGCC Offset Requirement** The Alberta government continue to apply its Natural Gas Combined Cycle (NGCC) offset policy[3] requiring all new coal-fired units to reduce or offset their greenhouse gas emissions to the NGCC level of 418 kg/MWh. This requirement should also be applied to existing coal-fired units that reach their end of Design Life. This represents the greenhouse gas reduction commitment for the Design Life of the unit. It is recognized that future national or international greenhouse gas reduction commitments may result in additional management obligations. (Note: Flexibility should be provided to companies in meeting this offset requirement with special consideration given to offsets associated with in-province renewables, energy efficiency and conservation, and technology research, development, and investment. Where agreements do not already exist and government support is involved in the development of an offset credit, it is recognized that apportionment mechanisms must be developed by industry and government for the ownership of these greenhouse gas reductions.) This recommendation may need to be amended to fit with the approach agreed upon for recommendation 23.	58
26	**Greenhouse Gas Emission Credits for Early Shutdown** Credit for unit shutdown before the end of Design Life be given for a period of no greater than that remaining to the end of Design Life to a maximum of ten years, based on the required emission intensity target at the time of shutdown. These credits will not be available if the shutdown results from a government order or a court order. Credits for coal units will be the difference between that number and the NGCC offset policy as defined in recommendation 25. Credits for gas and co-generation will be the difference between their emission intensity target at the time of shutdown and the intensity target for new units defined at that time. The unit's generation number will be the average of the three highest years in the last five years before shutdown. This proposal would come into effect on January 1, 2006. Any banking of these credits is to be consistent with the rules of banking determined under recommendation 24.	59
27	**Discounting of Greenhouse Gas Emission Credits** There be no environmental discounting applied to greenhouse gas offset credits eligible for banking according to the rules determined under recommendation 24.	60
28	**"Green Tag" Credits for Renewable Energy** A "green tag" program for renewable and alternate energy be established, that is in units of "tonnes of CO_2-equivalent." This program should be developed by 2005 and applied to all renewable and alternate energy developed after December 31, 2001. Green tag credits, usable for compliance with individual units' greenhouse gas intensity targets, could be made available in addition to the green certificates proposed as part of achieving the 3.5% renewable energy target (see recommendation 59). This recommendation does not preclude the sale of credits from earlier reductions. It is recognized that the issue of credit for earlier action is to be resolved in another forum. This recommendation may need to be amended to fit with the approach agreed upon for recommendation 23.	60
29	**Five-Year Review** Alberta Environment lead, in consultation with Alberta Energy and other regulatory authorities, the establishment of a formal process, to be undertaken every five years, to review the following elements of the emissions management framework: 1. a technology review to identify the BATEA emission limit standards and corresponding deemed credit threshold for new thermal generation units, including new peaking units;[4] 2. the air emission substances subject to limits or formal management, including looking at existing List 2 and possible new substances; 3. co-benefits for priority substances and List 2 substances; 4. economic and environmental triggers as defined by recommendations 34 and 35;	67

[3] *In Albertans & Climate Change: Taking Action*, the Alberta government requires all new coal-fired generation facilities to offset their greenhouse gas emissions down to the level of a combined cycle natural gas turbine.

[4] See section 6.1 for a fuller discussion.

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<tr><th>No.</th><th>Recommendation</th><th>Page</th></tr>
<tr><td></td><td>5. additional information that illustrates potential health effects associated with emissions from the electricity sector; and
6. continuous improvement. With each Five-Year Review, the electricity sector will provide a continuous improvement report that summarizes action taken during the past five years. The report will also identify goals for further continuous improvement during the next five-year period, in particular with respect to the priority substances emitted by existing units. This report will be reviewed and discussed as part of the Five-Year Review process. Beginning with the second Five-Year Review (2013), upon reviewing system performance relative to the previous continuous improvement goal statements, the multi-stakeholder team can propose, where appropriate, recommendations for modifications to the framework that result in improved opportunities for supporting continuous improvement efforts.

This review should involve a multi-stakeholder group that:
a) consists of representatives from industry, government, non-government organizations and communities with an interest in the electricity sector;
b) conducts an initial scoping to determine which if any of the elements identified in the review process described in the above recommendation warrant a detailed review, and either recommends that no further work is necessary or undertakes a detailed review of those elements and makes recommendations on them;
c) has access to the resources necessary to obtain the information and technical advice needed to complete its review;
d) uses a consensus decision-making process; and
e) completes its review and provides its recommendations to Alberta Environment within 12 months of the group being formed.</td><td></td></tr>
<tr><td>30</td><td>Timing of the Five-Year Review
The first Five-Year Review commence no later than April 1, 2008 so that new BATEA levels can be identified well in advance of the January 1, 2011 effective date.</td><td>68</td></tr>
<tr><td>31</td><td>Responsibility for Implementing the Outcome of the Five-Year Reviews
Alberta Environment incorporate all consensus recommendations from each Five-Year Review into the existing management framework.</td><td>68</td></tr>
<tr><td>32</td><td>Identifying Hotspots
For the purposes of this management framework, that an area will be defined as a hotspot if, due to its location relative to, or its proximity to, one or more electricity generation facilities, one of a, b, or c applies:
a) It is an area where Alberta ambient air quality guidelines have been, or are projected to be, exceeded on an ongoing or repeated basis. It is understood that the existing mechanism used by regulatory agencies to respond to exceedances of ambient air quality guidelines will be maintained. Projected exceedances of emissions will be determined in one of two ways. For a new unit, emission projections and dispersion modelling will be done by the proponent as part of the environmental impact assessment process, and subjected to review by regulatory authorities. For existing units, ambient air quality monitoring, possibly supplemented by dispersion modelling, will be used. Emphasis should be placed on ambient air monitoring in areas where there is greater potential for hotspot issues; for example, where there is a large number of emitters and/or there are large amounts of emissions. Where appropriate, timely actions should be taken to address any gaps that may exist in ambient air monitoring systems.
b) It is an area that, under the Acid Deposition Management Framework or the PM and Ozone Management Framework, meets or exceeds the trigger level that requires emissions reduction action under a management plan (see recommendation 33).
c) The available peer-reviewed scientific information and/or risk-based assessment evidence indicates that electricity generation-related air emissions, either alone, or in combination with other emission sources, are contributing to or are projected to contribute to, adverse health or environmental outcomes. The precautionary principle will apply when this circumstance arises; the precautionary principle states “Where there are threats of serious</td><td>69</td></tr>
</table>

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	or irreversible damage, lack of full scientific certainty shall not be used as a reason for postponing cost-effective measures to prevent environmental degradation."[5] The precautionary principle is endorsed by Canada and Alberta in the Canada-wide Environmental Standards sub-agreement of the Harmonization Accord, which specifies that a lack of scientific certainty shall not be used as a reason to postpone the development and implementation of standards.	
33	**Addressing Hotspots** • Where a framework for dealing with a specific type of hotspot exists (e.g., PM and Ozone framework or Acid Deposition framework) that it be implemented as designed. • Where a framework does not exist for dealing with a specific type of hotspot, that the following steps be taken: ○ A multi-stakeholder team, consisting of representatives from industry, government, non-government organizations and communities with an interest in the electricity sector and under the leadership of Alberta Environment, be formed to develop and recommend a timely and cost-effective plan to resolve the hotspot as quickly as possible. ○ Alberta Environment use the EPT framework, legislation, standards and approvals as appropriate to implement the plan. ○ When a hotspot has been identified, an economic, health and environmental analysis will be part of the plan developed to address it.	70
34	**Emissions Growth Review Trigger** During the Five-Year Review, if the updated emissions forecast for any of NOx, SO_2, PM and mercury is 15% higher for a five-year period than projected in the previous Five-Year Review, the management framework elements addressing that substance should be reviewed.	71
35	**Economic Review Trigger** During the Five-Year Review, if the economic assumptions underlying the framework are significantly different so as to adversely affect the viability of the electricity sector, the framework will be reviewed.	71
36	**Current Compliance Principles** Alberta Environment and the electricity sector continue to use the current compliance principles for the management of emissions from thermal generation units, and that these principles also be applied to mercury emissions from coal-fired units. Consideration should be given to reviewing current principles to ensure they reflect the new emission management mechanisms and the intent to reward performance "beyond compliance" or to deter non-compliance.	76
37	**SO_2 Monitoring in Support of an Emissions Trading System** Alberta Environment and the electricity sector build upon the existing continuous emission monitoring program for SO_2 to develop an effective SO_2 monitoring and tracking system that can support a SO_2 emissions trading system.	76
38	**NOx Monitoring in Support of an Emissions Trading System** That Alberta Environment and the electricity sector build upon the existing continuous emission monitoring program for NOx to develop an effective NOx monitoring and tracking system that can support a NOx emissions trading system.	77
39	**Public Availability of SO_2 and NOx Monitoring Data** Alberta Environment and the electricity sector continue to ensure that SO_2 and NOx emission monitoring data from electricity generation units remains available to the public.	77
40	**Public Availability of SO_2 Emission Trading Information** a) Alberta Environment and the electricity sector ensure that information on SO_2 emission trading associated with achieving the SO_2 emission management targets in these recommendations is available to the public. b) Alberta Environment require, by regulation, approval or other legal means, that coal-fired power plants report on the creation and use of SO_2 credits and that this information be public.	77

[5] Principle 15 of the Rio Declaration, agreed to by Canada and 178 other nations during the 1992 United Nations Conference on Environment and Development; http://www.unep.org/Documents/Default.asp?DocumentID=78&ArticleID=1163 .

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41	**Public Availability of NOx Emission Trading Information** a) Alberta Environment and the electricity sector ensure that information on NOx emission trading associated with achieving the NOx emission management targets in these recommendations is available to the public. b) Alberta Environment require, by regulation, approval or other legal means, that thermal power plants report on the creation and use of NOx credits and that this information be public.	77
42	**Public Availability of Primary PM Monitoring Data** Alberta Environment and the electricity sector continue to ensure that the opacity and stack emission information on primary particulate matter from coal-fired power plants is available to the public upon request.	77
43	**Public Availability of Mercury Monitoring Data** Alberta Environment and the electricity sector ensure that mercury emission data from coal-fired power plants is available to the public upon request in the same manner as data for regulated parameters is currently available through the *Environmental Protection and Enhancement Act.*	78
44	**Measuring Mercury Emissions** Alberta Environment establish a multi-stakeholder process to evaluate economically-viable mercury monitoring methodologies and adopt a methodology that ensures the accurate measurement of mercury emissions.	78
45	**Monitoring for Primary Particulate Matter** Alberta Environment and the electricity sector continue to use continuous opacity measurement and limits as the surrogate for primary particulate matter control, and periodic stack testing requirements as verification that the emission limit for primary particulate matter is being met.	78
46	**Monitoring and Reporting on Greenhouse Gases** Alberta Environment and the electricity sector continue development of a monitoring and reporting system for greenhouse gas emissions from the electricity sector that provides reliable emission data, and that every effort be made to ensure that the Alberta system is compatible with any national or federal system.	78
47	**Tracking, Reporting and Information-Sharing Principles for Greenhouse Gases** For any sectoral agreement with the Alberta electricity sector, the Alberta government and the electricity sector incorporate tracking, reporting and information sharing principles for greenhouse gases, consistent with those prescribed for other emissions for the sector.	78
48	**Public Comment on Emission Guidelines and Standards** Alberta Environment implement a mechanism to ensure that potentially affected communities have a reasonable opportunity to comment on any air emission guidelines and standards for the electricity sector and as appropriate have reasonable access to funding support and technical experts to enable their informed and constructive participation.	80
49	**Public Input to Sectoral and Other Industry-Specific Agreements** Public input be part of Alberta Environment's approach to the development of the overall framework for both sectoral and other industry specific agreements initiated under any provincial law for the management of air emissions from the electricity sector, with due consideration to any potential application to other sectors. As appropriate, reasonable access should be provided to funding support and technical experts to enable informed and constructive public participation.	80
50	**Public Involvement in Developing any Emissions Trading System** Public input and involvement be part of Alberta Environment's development of any emission trading system including: a) A process to ensure reasonable opportunity for the public to comment on any proposed regulations, policies, guidelines or other measures to implement any emission-trading regime under Bill 37, EPEA or any other provincial law, for the electricity sector. b) Providing, as appropriate, the public with reasonable funding support and access to experts to enable their informed and constructive participation in (a) above, and c) Incorporating minimum provisions to ensure transparency in the operation and evaluation of the regime.	80
51	**Public Notice on Intergovernmental Agreements** Alberta Environment consider providing the public with notice of intent to enter into and a reasonable opportunity to comment on any proposed intergovernmental agreement on the management of air emissions from the electricity sector.	81

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52	**Public Access to Intergovernmental Agreements** A public repository be established to enable public access to any inter-governmental agreements relating to the management of air emissions from the electricity sector including those related to emission objectives, standard setting, monitoring, reporting and enforcement and compliance.	81
53	**Monitoring, Reporting and Surveillance** For any review of existing and any proposed new rules and regulations, procedures, accountability structures and capacity needed to monitor and enforce the new management framework for the electricity sector, a public review component be incorporated and include mechanisms to ensure reasonable public accountability and transparency.	81
54	**Transparency** Alberta Environment give to the public ready and timely access to information relating to air emissions from the electricity sectors, subject to necessary access restrictions to ensure protection of proprietary and confidential information relating to legitimate business interests.	81
55	**The Provincial Target for Renewable and Alternative Energy** The Alberta government implement at the very least the 3.5% target for new renewable and alternative energy referenced in its *Albertans & Climate Change - Taking Action* plan.	82
56	**The Basis for the Target for New Renewable and Alternative Energy** Irrespective of the mechanism adopted for its implementation, the Alberta government calculate the 3.5% target for new renewable and alternative energy based on 100% of electric energy sold through the Alberta Power Pool, from Alberta sources.	82
57	**Defining Renewable and Alternative Energy** The following definition of Renewable and Alternative Energy be adopted by the Alberta government for the purposes of calculating the 3.5% target for new renewable and alternative energy: Renewable and Alternative Electricity is defined as that which is: a) Power generated within the province of Alberta; and b) EcoLogo™ compatible in that it meets the EcoLogo™ criteria for Renewable Low-Impact Electricity, but from facilities that are not necessarily EcoLogo™ certified; OR Alternative electricity supplies whose source meets the following criteria: a) 5 MW or less; and b) greenhouse gas intensity less than or equal to combined cycle gas turbine 418 kg per MWh Projects eligible for the target would be those that begin producing electric energy after December 31, 2001.	82
58	**Calculating the Amount of New Renewable and Alternative Energy Generation** The Alberta government use the following energy-based method to calculate new renewable and alternative power: (Total new renewable and alternative electricity in MWh, as defined in recommendation 57) Divided by (Total power sold through the Alberta Power Pool in MWh)	83
59	**Mechanisms for Achieving the Renewable and Alternative Energy Target** The Alberta government consider developing a program to implement the mechanisms required to achieve a target of at least 3.5% new renewable and alternative energy by January 1, 2008. These mechanisms may include a "green certificate" program, emissions trading, offset credits, or any other mechanism to incent the use of green power.	83
60	**The Retailer-Based Method for Achieving the Renewable and Alternative Energy Target** The retailer-based method, described in this report, be the preferred option for achieving the target for additional renewable and alternative energy. The implementation team (see recommendation 64) will be tasked with recommending options to resolve the issues listed below and identifying any additional issues for resolution related to implementing the retailer-based method. The implementation of the retailer-based method is contingent upon the resolution of these issues to the satisfaction of affected stakeholders represented on the implementation team: • scope of audit process; • timely development of a market for green certificates;	83

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	• provisions to allow providers of the Regulated Default Supply Option to flow through the costs associated with meeting the 3.5% target; • provisions to ensure retailers that have taken prudent measures to achieve the 3.5% target are not penalized if supply does not materialize in a timely manner; and • transitional provisions that take into account previously signed long term contracts.	
61	**Sectoral Agreements and Green Power** The Alberta government, in any sectoral agreement negotiations, consider encouraging all purchasers of power to buy at least 3.5% new renewable and alternative electricity, as defined in recommendation 57, as a means of reducing their greenhouse gas emissions.	85
62	**Net Metering and Net Billing** Alberta Energy undertake a study to identify the technical, legal and financial issues associated with net metering and net billing, including a policy direction for the industry.	85
63	**Infrastructure Needs** Alberta Energy and the Alberta Electric System Operator examine the decision-making process for the renewable and alternative energy sector's infrastructure needs, with a view to: a) ensuring that the process is accessible to the renewable and alternative sector, and b) improving the infrastructure for renewable and alternative energy.	86
64	**Renewable and Alternative Energy Implementation Team** A CASA multi-stakeholder implementation team be formed to address the following issues, as well as issues that may be referred to it by other stakeholders or other sub-groups of the EPT. In forming this group, it is essential that all interested stakeholders who will be affected by the matters discussed be actively involved. a) Setting a further target for renewable and alternative energy beyond 2008. b) Clarifying the eligibility of upgraded facilities that result in incremental power for the target. c) Determining ways in which larger co-generation and waste heat facilities can be encouraged and incented. d) Clarifying whether the definition of retailer found in the *Electric Utilities Act* is sufficient for the purposes of implementing a retailer-based target for new renewable and alternative electricity. e) Seeking means by which the federal government's Wind Power Production Incentive program, the Renewable Energy Deployment Initiative and other production incentives described in this report, might be augmented and integrated into Alberta's renewable and alternative energy sector. f) Seeking means by which consumer engagement mechanisms as described in this report could be funded and implemented. g) Seeking means by which a Solar Infrastructure Initiative, described in this report, could be funded and implemented. h) Examining options that would allow Climate Change Central, with the assistance of other groups such as the Office of Energy Efficiency, ENGOs, and retailers, to take the lead in the educating consumers about the sources of their electrical power. i) Examining ways in which the Alberta emissions trading system might be used to assist in developing renewable and alternative energy.	87
65	**Energy Efficiency and Conservation Implementation Team** A CASA multi-stakeholder implementation team be struck and provided with sufficient funds to undertake the following tasks, and that it report to the CASA board in November 2004: a) Working with Climate Change Central's Energy Solutions Alberta, relevant Alberta government agencies and existing data centres in developing measurement tools and monitoring overall electrical energy efficiency for the province. b) Developing a process to determine the overall efficiency of the electrical system, "energy source to end user." c) Once tasks a) and b) are completed, the implementation team will undertake a detailed technical assessment as to the feasibility of developing a province-wide electric energy efficiency target and, if feasible, define what the target amount should be (including appropriate metrics) and costs to meet the target, its relationship to sector agreements and other ongoing programs, and mechanisms to meet this target. d) Reviewing electrical energy efficiency and conservation tools and programs and making recommendations for their implementation, including implementation of a pilot project. e) Working with retailers and the "wires" companies to ensure that "time of use" metering and	89

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	rates are made available where they are not available currently. f) Seeking ways in which the purchase of ENERGY STAR™ appliances can be encouraged and incented. g) Working with electricity retailers to find ways of assisting retailers in managing the risks and recovering lost revenues associated with energy efficiency and energy conservation programs. This could involve but would not be limited to performance-based incentive mechanisms that reward the achievement of targeted energy savings and program costs. h) Examining the issue of thermal loss at generation facilities, and exploring means of encouraging and incenting the co-location of other facilities that are able to use waste heat. This could include the use of emission credits and offsets for the use of this energy. i) Working with Alberta Energy, Alberta Environment, New Era, and the Alberta Electric System Operator with the goal of ensuring that the metering and transmission interconnection needs of distributed generation are met. j) Working with Alberta Environment with the goal of ensuring that verifiable improvements in energy efficiency and energy conservation are classified as useable offsets. k) Working with the federal government with the goal of examining the tax issues relating to district heating and other energy efficiency and conservation issues, in order that energy efficiency and conservation not be disadvantaged relative to other energy policies and programs.	
66	**Encouraging Electrical Energy Efficiency and Conservation by Industry** The Alberta government, in its upcoming greenhouse gas sectoral agreements with all sectors, consider including and encouraging electrical energy efficiency and energy conservation as options for reducing emissions from electricity generation in Alberta.	90
67	**Encouraging Electrical Energy Efficiency and Conservation by Governments** Climate Change Central • work with Alberta and municipal governments to encourage energy efficiency in residential housing design, both in building codes and in municipal planning. • examine the issue of “take or pay” contracts. This work would include: o gathering information on the extent of the issue; o providing information for consumers to assist them in making informed decisions about their electricity purchases; and o developing and piloting alternatives that would meet the retailer’s needs while allowing for consumers to benefit fully from energy efficiency and conservation practices. • provide a resource in which information about the various government programs all levels and funding options be made available.	90
68	**Funding Energy Efficiency and Conservation Programs** The Alberta and federal governments consider means for providing stable and sufficient funding to allow for the development and implementation of energy efficiency and energy conservation programs, and that the various options for funding described in the Energy Efficiency and Conservation Working Group’s report to the EPT be considered.	91
69	**Access to Information Gathered by the EPT** a) the CASA Secretariat retain the final versions of all materials, information, documents, reports and presentations that were obtained or produced in the course of the EPT’s work so that they are readily accessible to stakeholders until 2010; b) the CASA website provide details on how to access these materials, and c) hard copies and compact discs of these materials also be stored with Alberta Environment as a back-up.	93
70	**Water Vapour** The water vapour concerns noted in this report be addressed through existing site-specific regulatory processes and through the EUB applications process for electric generation facilities. Alberta Environment should play the lead role in ensuring the appropriate agencies are involved in addressing the issues as they arise. Any new information on water vapour should be considered in the five-year reviews described in recommendation 29.	98

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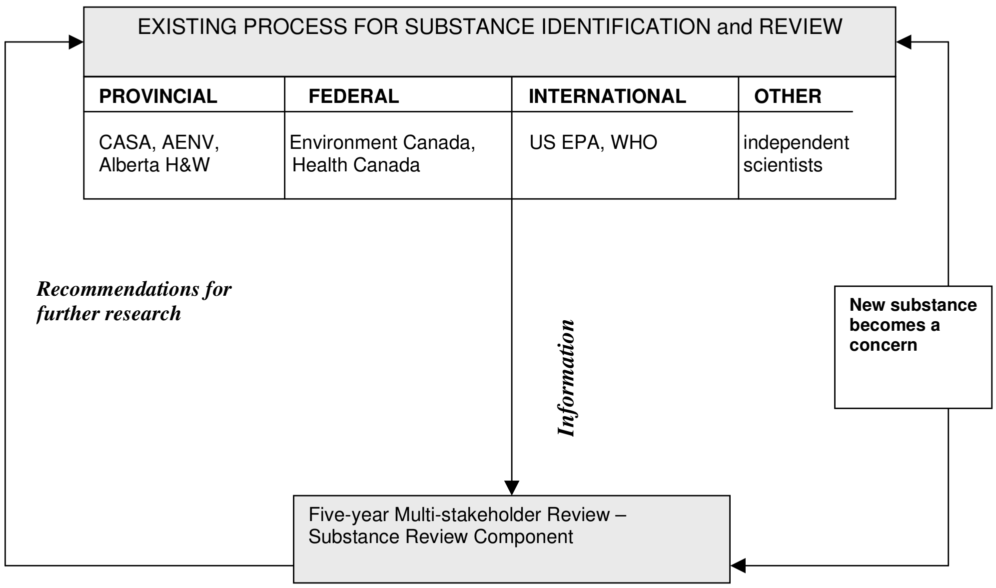
71	**Future Substance Reviews** A substance review component be included as part of the recommended multi-stakeholder reviews to be conducted every five years. The purpose of this substance review is to assess whether or not additional substances should be formally controlled based on new or emerging information, including the effects of complex mixtures emitted by power plants. This review should take into account both new and existing scientific information, with reference to the following flow diagram.	99



PART ONE: BACKGROUND AND POLICY CONSIDERATIONS

2 Alberta's Electricity Sector[6]

Reliable supplies of electricity are an essential commodity for Albertans. The province's electricity sector has seen substantial change in recent years, including a shift to deregulation (effective January 1, 2001) and a growing demand for power, which has put pressure on utility companies to expand generation in anticipation of meeting future needs. At the same time, concerns are being raised about the health and environmental impacts of air emissions, particularly from coal-fired generation plants, which remain the primary source of Alberta's electricity.

Between 1998 and 2003, over 2900 MW of new generation were added to the Alberta power supply. About 5200 MW of additional generation projects have been announced to come onstream between 2003 and 2006. Most of Alberta's electricity is from coal-fired generation, although in the last decade, gas-fired generation has nearly doubled. Gas- and coal-fired generation are referred to collectively as "thermal" generation.

Measuring Electricity

For residential consumers, the basic unit of power consumption is a *kilowatt-hour* (kWh); that is, the number of kilowatts used in one hour. A kWh equals 1000 watt-hours. Ten 100-watt light bulbs burning for an hour would use one kWh of electricity. Average residential electricity consumption in Alberta ranges from 600 to 1200 kWh per month, with an overall average of about 1000 kWh per month.*

One *megawatt* is 1000 kilowatts. A megawatt-hour (MWh) is the number of megawatts used or generated in one hour. Thus, one MWh of generation could provide electricity to an average home for a month.

source: EPCOR Utilities, October 2003

Alberta's existing installed electricity generation capacity, excluding 950 MW of provincial interconnections with BC and Saskatchewan, is nearly 11,500 MW, broken down as shown in Table 1.

Table 1: Alberta's Installed Generation Capacity

Source	Installed Capacity (MW)	% of total
Coal	5,523	48.1%
Gas	4,858	42.3%
Hydro	888	7.7%
Wind	127	1.1%
Biomass	71	0.6%
Total	11,467	

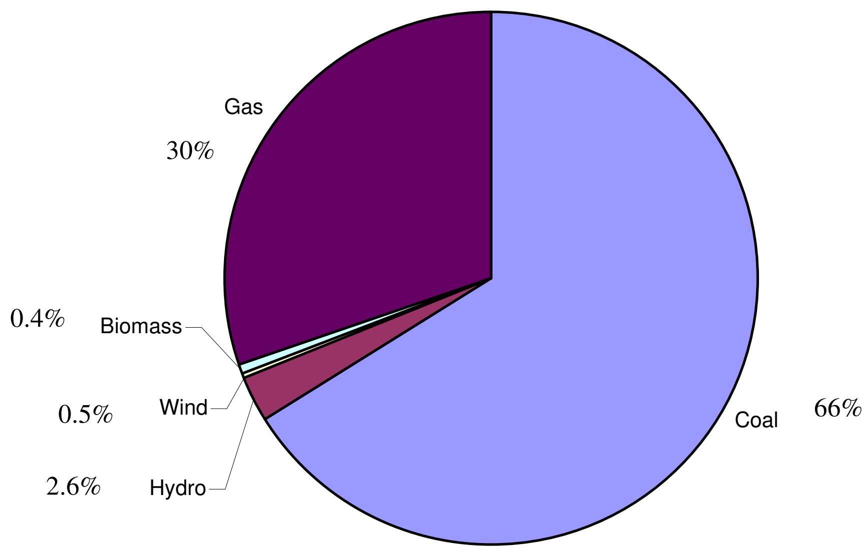
Source: Alberta Energy, numbers as of June 2003

Figure 1 illustrates the 2002 electrical energy production from each source. Total electrical energy production in 2002 was 64,280 GWh.[7]

[6] Adapted from Alberta Energy's "Introduction to Electricity" online at http://www.energy.gov.ab.ca/com/Electricity/Introduction/Electricity.htm and at http://www.energy.gov.ab.ca/com/Electricity/Key+Numbers/Key+Numbers.htm

[7] Source: Alberta Energy. A GWh is a Gigawatt-hour, or 1,000 megawatt-hours.

Figure 1: Electrical Energy Production by Source in 2002

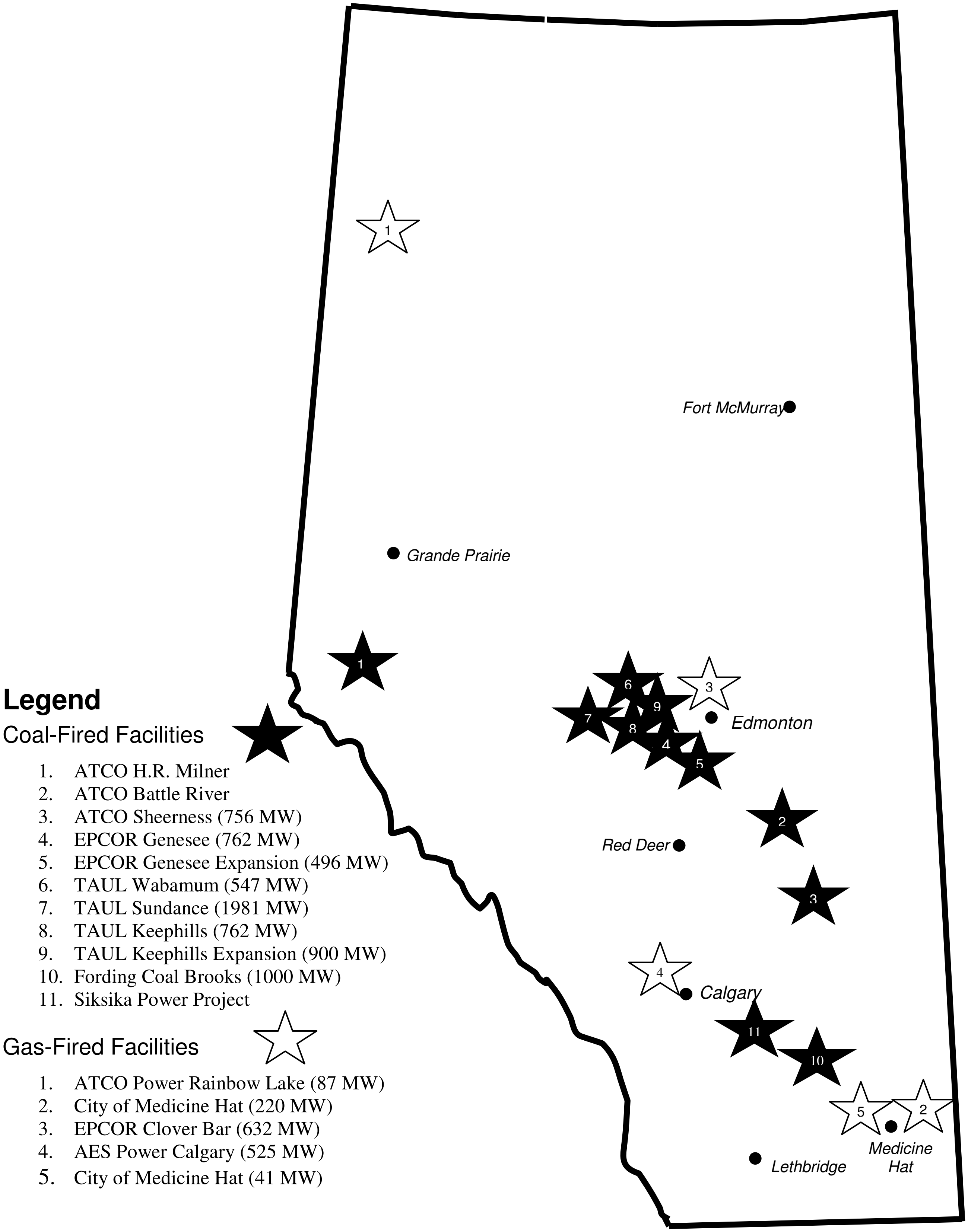


Although gas-fired and other types of generation are growing rapidly, coal is expected to continue as a major source of electricity production in Alberta. Current research into clean coal technologies may result in the development of generation systems that have lower emissions and are reliable and commercially viable.

Power generated in Alberta is exchanged through a power pool operated by the Independent System Operator (ISO), providing an open-access competitive market for electric energy. Power can also be exchanged through forward markets or direct sales arrangements. The ISO co-ordinates all electricity sales and purchases in the province, as well as all energy imports and exports; it also provides real-time control of the provincial electricity grid.

TransAlta, ATCO Power and EPCOR own about two-thirds of Alberta's current generating capacity and are expected to remain as significant players in the coming years. Various industrial producers and small and independent power producers generate the remaining one-third of Alberta's domestic electricity supply. Due to proximity to coal supplies, power generation has been concentrated in central Alberta, with a cluster of units near Lake Wabamun west of Edmonton, and other major units south and east of Edmonton at Battle River and Sheerness. The map in Figure 2 shows the location of coal- and gas-fired electrical utility facilities in Alberta.

Figure 2: Alberta's Coal- and Gas-Fired Electrical Utilities



Alberta's Energy and Utilities Board recently approved two major expansions of coal-fired plants.[8] EPCOR's application to expand its Genesee plant by 490 megawatts was approved December 12, 2001 and TransAlta's 900-MW Keephills expansion (two units) was approved on February 12, 2002.

Under the former regulated system, electricity generators were also electricity retailers. As part of the restructuring, the rights to the output of formerly rate-regulated units (the generators) were auctioned to non-affiliated buyers in the summer of 2000 in the form of Power Purchase Arrangements (PPAs). Among other things, the auction was designed to remove the need for ongoing regulatory hearings on utilities' generating costs and investments.[9]

Generation facilities constructed since 1998 are termed "independent power plants" and the generator may also be the electricity wholesaler. These plants must absorb all the costs of new environmental requirements.

What is a Power Purchase Arrangement?

Power Purchase Arrangements (PPAs) are similar to contracts. Each one is an arrangement between the generator and the PPA buyer. Buyers of PPAs have exclusive rights to the generation output of the facility and can sell this power to the marketplace. In return, the PPA buyer is obliged to pay the generator the fixed and variable costs of producing the electricity specified in the PPA.* The PPAs have a defined term after which the rights to the electricity revert to the generator. The term of PPAs depends on the age and condition of the generating facility. All PPAs associated with coal-fired generation facilities expire between 2010 and 2020.

* adapted from http://www.enmax.com/Corporation/Media+Room/Q+and+As+on+Power+Purchase+Arrangements.htm

In May 2003, the Alberta government announced major changes to the province's transmission policy. The effects of these changes are not yet known, but they are expected to influence the location of new generation. The new *Electric Utilities Act* (EUA 2003) came into force on June 1, 2003, legislating additional changes pertaining to restructuring. Section 4.1.1 describes the restructuring process in more detail, and the box below briefly outlines the roles and responsibilities of the Energy and Utilities Board and Alberta Environment in regulating the electric power generation sector in Alberta.

[8] More information on these decisions and other aspects of the electricity generation sector is available at the EPT's website at http://www.casahome.org/electricity/addreading.asp.
[9] Source: http://www.enmax.com frequently asked questions on PPAs

Roles and Responsibilities of the Energy and Utilities Board and Alberta Environment in regulating the Alberta Electricity Sector

The **Energy and Utilities Board** ensures that Alberta's electric industry builds, operates, and decommissions hydro developments, electric power plants, and transmission lines in an efficient and economic manner. The EUB regulates the construction and operation of electric power plants to ensure compliance with the provisions of the *Hydro and Electric Energy Act* and the *Electric Utilities Act*. When reviewing applications for new electric power plants, the EUB ensures that siting, land use, local and land ownership issues are addressed and resolved to the satisfaction of all parties concerned. The EUB also has a broad environmental mandate to review and consider environmental issues and matters that may be raised by those having a bona fide interest in a particular project. Before making a decision on an application, the EUB is required to provide notice to all those who may be directly and adversely affected if the application were to be approved. When resolution of outstanding issues, if any, cannot be reached between the parties concerned, the EUB may schedule a public hearing and make decisions based on the evidence presented at the hearing by interested parties and stakeholders.

Alberta Environment regulates emissions from the electricity sector under the provisions of the *Environmental Protection and Enhancement Act* (EPEA) and associated Regulations. This legislation establishes approval, registration and authorization processes for designated activities. Thermal electric and hydro-electric power generation units are designated activities. Thermal units greater than 1 MW in capacity are required to obtain an approval under EPEA, which covers construction, operation and decommissioning. Facility approvals outline emission limits and monitoring and reporting requirements. The approvals system is supported by a compliance program and there are various enforcement actions and possible penalties for non-compliance with requirements. The EPEA approvals for individual units can be viewed on Alberta Environment's website.

2.1 Air Emissions from the Electricity Generation Sector

Coal- and gas-fired generation accounts for a significant portion of Alberta's total air emissions, as shown in the table below.

Table 2: Priority Emissions from the Electricity Sector

Emission	Percentage of Alberta's total anthropogenic emissions	Approximate quantities of emissions emitted	Sources within the electricity sector
sulphur dioxide (SO_2)	21%	125 kilotonnes	coal-fired units[b]
nitrogen oxides (NOx)	14%	86 kilotonnes	coal- and gas-fired units
particulate matter (PM)	9%[a]	9 kilotonnes	coal-fired units
greenhouse gases	21%	50.3 megatonnes	coal- and gas-fired units
mercury (Hg)	approximately 80%	870 kilograms	coal-fired units

[a] industrial point sources only (does not include open sources)
[b] Gas-fired units emit small amounts of SO_2, which are not considered significant on a total emissions basis.

Source: Alberta Environment, 2002

In its request to CASA, the Alberta government indicated that reviewing the emissions standards for the electricity sector will assist the province in maintaining an appropriate level of environmental quality and in addressing the issues associated with greenhouse gas emissions. It also wanted to ensure that factors such as cost-effectiveness, fuel choice, investor certainty, and maintaining competitiveness within North America were considered in the development of these new standards.

Other agencies had also indicated an expectation of new standards for this sector in the not-too-distant future. Environment Canada has subsequently released new guidelines for NOx, SO_2 and PM, and the Canadian Council of Ministers of the Environment expects to have a Canada-wide Standard for mercury in place by 2005 that would take effect in 2010. In its approvals of the Genesee and TransAlta expansions, the EUB also indicated that the companies should retain flexibility to meet expected new standards and requirements for new technology.

3 The CASA Electricity Project Team and Its Mandate

In June 2001, Alberta's minister of environment announced new emission standards for new coal-fired electricity generation plants. Against the backdrop of deregulation of the electricity industry in Alberta and expected expansion of generation capacity, public concerns had been expressed about the process used to develop these new standards and about the standards themselves. As part of the June announcement, the Alberta government indicated it wanted to develop a new approach for setting standards and performance expectations for the electricity sector.

3.1 CASA's Task

In January 2002, Alberta Environment presented a statement of opportunity to the CASA board, asking CASA to recommend a new approach for managing emissions from the province's electricity sector. CASA responded by preparing terms of reference for a multi-stakeholder project team. The CASA board approved the terms of reference in March 2002 (Appendix B) and established the Electricity Project Team (EPT) with representatives from governments, the utility sector, other industries, and non-government organizations (Appendix C). The box to the right summarizes the process used by the team.

The Process

The Electricity Project Team formed smaller working groups to address the key task areas outlined in the terms of reference and to prepare recommendations for consideration by the full EPT. All subgroups were accountable to the EPT. The subgroups were:

- Information-Gathering Subgroup
- Prioritization Subgroup
- Public Consultation Subgroup
- Monitoring, Reporting, Compliance, Public Participation, Accountability and Transparency Subgroup
- Management Options Subgroup, which gave rise to the:
  - Energy Efficiency and Energy Conservation Working Group
  - Renewable and Alternative Energy Working Group
  - Straw Dog Subgroup
  - Gas-Cogen Subgroup

Several of the subgroups prepared and/or commissioned reports, which describe their work in more detail. These documents are listed in Appendix F.

3.2 Background Considerations

The goal of the project team was to develop an air emissions management approach, including standards and performance expectations, for the Alberta electricity sector that reflects CASA's goals for air quality, namely:

- protect the environment;
- optimize economic performance and efficiency; and
- seek continuous improvement.

In addition to the overall CASA goals for air quality, several other considerations also provided important context for the team's recommendations:

- There should be meaningful reductions over time of the five priority substances identified by the team, with as many other benefits as possible for managing other pollutants (a multi-pollutant approach).
- The management framework should not create hotspots.
- There should be policy certainty over the long term.
- The management system should encourage energy efficiency and capital stock turnover.

- The management system should maintain flexibility and balance in the provincial fuel supply.
- The structure of the electricity sector should be maintained.
- The impact on the cost of electricity to consumers must be acceptable.
- The team should consider the potential impact of its recommendations on PPA structure.
- The system should incorporate any advances in technology within a reasonable time frame.

The team decided early in its work to undertake focused public outreach and actively seek the input of interested Albertans on issues as well as their feedback on the team's proposed recommendations. For more details on the public outreach program, see section 13.

This report is the result of nearly two years of concentrated effort. It contains recommendations for managing and reducing emissions from the electric power generation sector, including a process to review and evaluate the new approach on a regular basis.

3.3 Additional Tasks Directed to the EPT

Two other CASA teams were completing their work in 2002 when the Electricity Project Team was formed. These were the Pollution Prevention/Continuous Improvement Project Team[10] and the Acidifying Emissions Management Implementation Team.[11] Both of these teams had identified particular areas for which they felt recommendations were needed. However, to avoid potential overlap and because they thought it was likely that the new electricity team would be considering these elements, they chose to direct their recommendations to the EPT.

The Pollution Prevention/Continuous Improvement Team's recommendations asked the EPT to: address renewable energy, consider pollution prevention and continuous improvement, and consider opportunities for co-generation in its overall management approach. The EPT believes it has addressed these areas in its recommendations.

The Acidifying Emissions Management Implementation Team's NOx Subgroup noted there was value in pursuing province-wide reduction targets for NOx and SOx but referred this task to the EPT. The EPT identified NOx and SO_2 as two of its five priority substances and has recommended ways in which they can be addressed in the overall management framework.

More details on the specific recommendations from these teams and the EPT's response can be found in Appendix D.

[10] The P2CI final report is available on request to the CASA office, or online at http://casahome.org/casa_library/bygroup.asp?idnumber=26
[11] The AEMIT final report is available on request to the CASA office, or online at http://casahome.org/casa_library/bygroup.asp?idnumber=13

4 Policy Considerations

The Electricity Project Team undertook its work against a complex backdrop of new and changing provincial and federal government policy and other activities. These circumstances presented a range of challenges for the team as it sought to develop a framework that would fit with the restructured electricity marketplace in Alberta and be flexible enough to accommodate emerging policies on key environmental and economic issues. The team was kept apprised of the various activities and policy changes and endeavored to take them into account.

4.1 Provincial Policy Considerations

The Alberta government has made several policy changes in recent years that affect the province's electricity sector. The biggest one was the restructuring of the electricity industry, a process that began in 1996 based on the principle that opening the marketplace to competition forces both the wholesale generation sector and the retail sector to become more efficient, cost-effective and creative.[12] At the same time, other provincial initiatives were relevant to the work of the Electricity Project Team; these included new legislation on climate change (Bill 37), an emissions trading study by Alberta Environment, and a new management framework for Particulate Matter and Ozone being developed by another CASA project team.

4.1.1 Restructuring of Alberta's Electricity Industry[13]

In 1996, the Alberta government began to restructure the electricity industry. Prior to restructuring, one company typically provided electricity generation, transmission, distribution, and retail services to customers. Utilities had assigned service areas throughout the province and customers were served by the company that operated in their area. With restructuring, these functions were separated and are now delivered by different organizations.

Two components of the electricity system were deregulated, effective January 1, 2001: power generation and some retail services. Under the new legislative framework in Alberta, the Energy and Utilities Board (EUB) no longer regulates wholesale electricity prices. Independent power producers compete to supply power, new supply can come into the system faster, and large industries can supply their own power needs. While the price of electricity is set in the competitive marketplace, the EUB is still responsible for approving the construction of any new power generation facilities in Alberta. The EUB ensures that these facilities are built, operated, and decommissioned in an economic and efficient way. Alberta Environment sets the environmental requirements for power generation facilities and ensures that they operate in an environmentally responsible manner.

Under deregulation, retailers can enter into contracts with customers to provide power. Retailers can purchase power through the Power Pool or from independent power producers

[12] Source: http://www.energy.gov.ab.ca/com/Electricity/Key+Publications/The+Power+of+Choice+Brochure.htm

[13] adapted from Alberta Energy, http://www.energy.gov.ab.ca/com/Room/Public+Reference/Commodity+Info/Electricity+FAQs.htm

or from other firms that buy and sell electricity. Customers can purchase power from any retailer they choose.

The transmission system remains fully regulated and the EUB continues to approve transmission tariffs. While utilities still own the transmission lines, the Independent System Operator administers the transmission system. Its role is to provide buyers and sellers with non-discriminatory access to the market and to ensure that the transmission system is reliable and is operated efficiently. As part of the Alberta government's ongoing commitment to restructuring of the electricity sector, the Minister of Energy announced a new transmission policy on May 5, 2003.[14]

In preparation for deregulation, the power from formerly regulated generating units was auctioned in the form of Power Purchase Arrangements (PPAs). The PPAs have a defined term after which the rights to the electricity revert to the generator. The term of PPAs depends on the age and condition of the generating unit. All PPAs associated with coal-fired generation expire between 2010 and 2020. If a PPA buyer decides to terminate the arrangement prior to its expiry, the PPA reverts to the Balancing Pool and the power is re-auctioned. The cost of environmental requirements for PPA buyers and generators is an important consideration in any new air emission management framework for the electricity system.

One result of deregulation is that there are now more participants and a wider range of interests in the province's electricity sector than existed five years ago. Any new management regime for emissions from this sector is bound to have different impacts on different companies, depending on their role(s) in the system.

4.1.2 Export Market

Alberta presently generates slightly more power than is consumed in the province. With a policy regime designed to encourage competition and new generation, the large amount of co-generation expected to occur in the oil sands area of northeastern Alberta, and the announcement in May 2003 of a change in the province's transmission policy, questions arose as to whether the longer-term intent was to develop an export market for Alberta-produced electricity. Forecasts available to the EPT did not explicitly predict significant exports of electricity, and stakeholders held various views on the export issue. Members agreed to focus on how to deal with air emissions associated with predicted growth in the electricity sector, irrespective of whether the power was produced for domestic use or for export. The team also built into its framework a provision that allows the framework to be revisited if emissions rise considerably beyond what was originally forecast, recognizing that one of the reasons this could occur is if Alberta were to begin exporting significant amounts of power.

[14] Minister Smith's speech announcing the new policy is online at http://www.energy.gov.ab.ca/com/Electricity/Transmission/CAMPUT+2003.htm.

4.1.3 Provincial Regulatory and Policy Initiatives

Other processes and initiatives occurred while the electricity team was developing its recommendations.

4.1.3.1 Bill 37, *Climate Change and Emissions Management Act*

In April 2003, Hon. Lorne Taylor, the Minister of Environment introduced legislation to implement the Alberta government's action plan on climate change. Third reading of Bill 37 is expected in the fall 2003 session of the Legislature. This Bill provides for

- An overall emission target for Alberta and targets for specific sectors that will be established by negotiated agreements.
- Options to facilitate sectoral agreements and to focus on cost-effective reductions in Alberta.
- A framework for how emissions offsets will be applied against Alberta regulatory requirements.
- A climate change management fund to help sectors reduce emissions and invest in Alberta energy conservation, energy efficiency and technology.

The Alberta government commenced working on sectoral agreements with industry for the monitoring and management of greenhouse gases. The Minister of Environment indicated that the EPT would not be negotiating any sectoral agreements but that the team's recommendations could be expected to influence the content of these agreements for the electricity sector.

A report was prepared to help the EPT better understand the public rights and opportunities offered by provincial and federal laws for managing air emissions from the electricity sector. This report reviewed the key relevant laws and also identified apparent gaps or constraints in the exercise of public rights and opportunities. The review included new management approaches introduced through Bill 37.[15] Transparency, accountability and public participation are discussed in more detail in section 9.

4.1.3.2 Emissions Trading

Emissions trading systems[16] have a number of features that, under the right circumstances, make them a good option for managing and reducing emissions. Emissions trading has been used in the United States for SO_2, NOx and other substances, and in the UK and Denmark for greenhouse gases, three of the priority substances for the Electricity Project Team. Under an emissions trading system, emissions are converted into allowances or credits. Emission limits and rates are still controlled by the regulatory agency but allowances or credits, which can be traded or banked, give companies some flexibility in terms of when, where and by how much to control emissions. The regulatory authority determines which sources will participate in the trading program as well as the individual and collective emissions limits. Sources must measure and report their emissions. At the end of the compliance period, usually a year, each participant submits to the regulatory authority whatever allowances or credits are necessary to cover

[15] The report was prepared by Linda Duncan, Environmental Law and Policy, and Keri Barringer, Environmental Law Centre. It is entitled *A Review of Legal Rights and Obligations Related to Transparency, Public Participation, and Accountability for Compliance in Current and Proposed Regimes for the Management of Air Emissions from the Alberta Electricity Sector,* and is available online at http://www.casahome.org/electricity/eptdocs.asp.

[16] Emissions trading is more precisely described as the trading of emission allowances or credits.

actual emissions during the period. To be in compliance, total emissions from all participants cannot exceed the emissions target.

With this market-based approach, participants are told their emissions allocation or limit, but they have flexibility to decide how to meet these limits – they can reduce their own emissions or they can buy allowances or credits from other sources. Sources that can cut their emissions at relatively low cost have a financial incentive to make larger reductions and to sell their surplus allowances or credits to other participants. Participants facing higher costs to reduce their emissions can then purchase allowances or credits for less than it would cost them to make the reductions. Allowances and credits can also be banked for future use, usually with some conditions.

In May 2003, Alberta Environment completed Phase One of a project[17] to explore the potential for using air emissions trading in Alberta to manage nitrogen oxides, sulphur oxides, volatile organic compounds, particulate matter and greenhouse gases. Phase One, consisted of various studies to determine the technical feasibility of multi-pollutant cross-sectoral emissions trading. A report entitled *Major Feasibility Study: A Preliminary Analysis and Discussion Document* was released in spring 2003 for public discussion. The report concluded that cross-sectoral emissions trading in Alberta is technically feasible for nitrogen and sulphur oxides, and for greenhouse gases.

The Major Feasibility Study took into account significant related developments. These included work by CASA and Climate Change Central in Alberta, federal and national work on greenhouse gas emissions trading, and any new developments in international plans for greenhouse gas emissions trading. EPT members were part of an external reference group for the major feasibility study; the team was also kept apprised of the study's modelling and results through briefings and was able to incorporate some of this work into its own modelling activity.

Alberta Environment is now working to identify, from a policy perspective, practical steps toward cross-sectoral, multi-pollutant trading for Alberta.

4.1.3.3 CASA Particulate Matter and Ground Level Ozone Project Team

In June 2000, the federal, provincial and territorial governments except Quebec agreed to national ambient air standards for $PM_{2.5}$ and ozone (the Canada-wide Standards, or CWS). Each jurisdiction committed to implementing the CWS by 2010 and to reporting on achievement once the target dates are reached. PM and ozone were considered together because they share common sources and both contribute to smog.

CASA established a project team in November 2000 to develop Alberta's implementation plan.[18] The management framework developed by this project team described actions that would be required if PM and ozone concentrations reached certain levels.

This CWS and the management framework for Alberta were relevant to the EPT because there is some concern that ozone levels in and around the Edmonton area may be approaching the CWS. NOx is a precursor of both ground level ozone and $PM_{2.5}$. The

[17] For more information, see http://www3.gov.ab.ca/env/air/emissions_trading/index.html.

[18] The report of the CASA PM and Ozone project team was accepted by the CASA board of directors on September 18, 2003 and is available in CASA's online library at http://www.casahome.org.

EPT has addressed NOx emissions in its framework, but any emissions reduction action to deal with an ozone hotspot, should it occur, would be carried out under the PM and Ozone Management Framework.

4.2 National Policy Considerations

Among national policies and approaches considered relevant to the EPT's work were Canada's international commitments under the Kyoto Protocol and the Heavy Metals Protocol; the principle of Keeping Clean Areas Clean; national efforts to develop Canada-wide Standards for mercury and the existing CWS for particulate matter and ozone; the application of pollution control technology; and potential implications of the North American Free Trade Agreement on the electricity sector. Although not a policy initiative *per se*, the Canadian Electricity Association launched its mercury monitoring program in 2002, which is relevant to the CWS for mercury and to the work of the EPT.

4.2.1 The Kyoto Protocol

Canada's greenhouse gas reduction commitment under the Kyoto Protocol is a 6% reduction from 1990 levels by the first Kyoto period of 2008-2012. Although the Protocol has not yet entered into force and views about it varied among EPT members, the team undertook its work on the assumption that the Protocol would come into force in the next year or so. The Kyoto Protocol will set legally binding targets and a timeframe within which these targets must be met, but each country must work out how it will meet its target. To give countries more options for meeting their targets, the Protocol contains three flexibility mechanisms[19] that will allow countries to find emissions reductions opportunities that make the most economic sense.

While the EPT was undertaking its work, discussions continued between the federal, provincial and territorial governments about how the national targets for greenhouse gases would be met, and Alberta also released its *Climate Change Action Plan* during this period.

EPT stakeholders exerted considerable effort to stay abreast of developments in federal-provincial negotiations on a wide range of matters related to meeting Canada's Kyoto commitment, including how reductions will be allocated across the country and across sectors, and credit for early action. The team reached consensus on a number of recommendations that it expects will inform the ongoing federal-provincial discussions.

4.2.2 Heavy Metals Protocol and Mercury[20]

In 1998, Canada ratified the *Protocol to the 1979 Convention on Long- Range Transboundary Air Pollution on Heavy Metals*, thereby committing to control emissions of heavy metals from specified activities, including combustion of fossil fuels. The Protocol commits the parties to take prescribed measures to anticipate, prevent or minimize emissions

[19] These three flexibility mechanisms are Joint Initiatives, Clean Development Mechanisms and Emissions Trading.

[20] Adapted from *A Review of Legal Rights and Obligations Related to Transparency, Public Participation, and Accountability for Compliance in Current and Proposed Regimes for the Management of Air Emissions from the Alberta Electricity Sector,* by Linda F. Duncan and Keri Barringer, available online at http://www.casahome.org/electricity/eptdocs.asp.

of heavy metals and their related compounds, taking into account the application of the precautionary approach. It notes that abating emissions of heavy metals may provide the additional benefit of abating emissions of other pollutants. The Protocol requires that the best available techniques for emission control be considered and prescribes target levels for reduction. In ratifying, Canada opted to comply with a total reduction target across sectors of at least 50% less than 1990 emission levels by 2011 and must report periodically on measures taken to implement the Protocol. Compliance will be reviewed regularly. The Protocol comes into effect in December 2003.

The North American Regional Action Plan on Mercury[21] commits Canada to help facilitate meaningful public participation on this issue in accordance with the principles set out in the North American Agreement on Environmental Cooperation. There is also a commitment to regular public reporting, audit processes to verify mercury reduction initiatives and periodic assessments of voluntary or regulatory mechanisms for reduction. Action Plans are to incorporate, as appropriate, pollution prevention principles and precautionary approaches to reduce risks associated with toxic substances.

In October 2000, Canada also signed the *Barrow Declaration* under which the eight Arctic States declare their common concern with releases of mercury, call upon the United Nations Environment Programme to initiate a global assessment as a basis for international action, and encourage other nations to ratify the *Heavy Metals Protocol*.

4.2.3 Keeping Clean Areas Clean

The Canada-wide Standards for PM and Ozone, signed in June 2000 by Canadian environment ministers (except Quebec), include provisions for keeping clean areas clean and continuous improvement.[22] "Keeping Clean Areas Clean" is the principle that polluting up to the allowed limit is not acceptable, and that the best strategy to avoid future problems is to ensure that clean areas are kept that way. This involves jurisdictions working with their stakeholders and the public to establish programs that apply pollution prevention and best management practices.

4.2.4 Canada-wide Standards[23]

Under the auspices of the Canadian Council of Ministers of the Environment (CCME), federal, provincial, and territorial environment ministers work together to establish common environmental standards across the country. The current Canada-wide Standards (CWSs) have been developed with the participation of various groups including industry, municipal, environmental, health and Aboriginal groups. Once ministers establish priorities for standards, jurisdictions work together to develop the appropriate type of standard for the designated environmental contaminant or issue. Generally, CWSs are developed using a firm scientific foundation and a risk-based approach. Standard development and implementation also consider socio-economic factors and issues of technical feasibility. How these techniques and procedures are applied may differ among standards, based on available information and the type of standard proposed.

[21] The Action Plans were developed pursuant to Resolution 95-05 on the Sound Management of Chemicals by the North American Council (of Ministers) of the North American Commission for Environmental Cooperation.

[22] See the CCME website at http://www.ccme.ca/assets/pdf/pmozone_standard_e.pdf

[23] adapted from CCME website at http://www.ccme.ca/initiatives/standards.html

4.2.4.1 Particulate Matter and Ground Level Ozone[24]

In June 2000, the federal, provincial and territorial governments except Quebec signed the Canada-wide Standards for Particulate Matter (PM) and Ozone, thereby agreeing to national ambient standards for $PM_{2.5}$ and ozone, and related provisions. Each jurisdiction committed to implementing the CWS by 2010 and reporting on achievement once the target dates are reached. PM and ozone were considered together because they share common sources and both contribute to smog. In 2000, CASA established a project team to develop an implementation strategy for Alberta (see section 4.1.3.3).

4.2.4.2 Mercury[25]

In 1998, the CCME identified mercury as one of the priority substances to be controlled. The CCME announced that a CWS for mercury from coal-fired thermal plants was to be issued by 1999, later extended to spring 2002. Since 1998, standards have been set for most of the other major mercury emitters and for some products containing mercury. Substantial efforts have been made by other industrial sources to eliminate mercury from their processes. The electric power generation sector is the largest single human-created source of mercury emissions in Canada. Alberta coal-fired generation units represent 30-40% of the total national mercury emissions from the electricity sector and approximately 80% of the human-related mercury emissions in Alberta.

Mercury is designated as a Track II substance under the *Canadian Environmental Protection Act* (CEPA) and, since 2000, the National Pollutant Release Inventory includes the requirement to report any releases and transfers from facilities manufacturing (i.e., emitting) more than five kilograms of mercury annually. In June 2003, the CCME Committee of Deputy Ministers committed to develop a CWS for the coal-fired electricity sector by 2005 to reduce mercury emissions by 2010, to explore national capture in the range of 60-90%, and to align with U.S. standards. Recent EUB decisions and provincial *Environmental Protection and Enhancement Act* (EPEA) approvals indicate an expectation by the regulators that facilities will be designed to meet reasonably foreseeable revisions to Alberta's emission standards, including mercury.[26] CWS development was an important consideration for the EPT in preparing its recommendations for mercury, and is reflected in the management approach for this substance.

4.2.5 Application of Pollution Control Technology

Many jurisdictions in Canada, including Alberta and the federal government, require the quality of air emissions from new industrial facilities to be consistent with that achievable through the installation of the best technology available that has been demonstrated to be economically feasible through successful commercial application across a range of regions and fuel types. Such technologies can be referred to as "Best Available Technology Economically Achievable," or BATEA. Jurisdictions generally do not specify the technology that industry must use, but rather base their standards or guidelines on the emission limits that can be achieved with BATEA. For example, effective in 2006, the EPT is recommending a

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[24] adapted from CCME website at http://www.ccme.ca/initiatives/standards.html?category_id=5

[25] See the CCME description of the mercury CWS at http://www.ccme.ca/initiatives/standards.html?category_id=4

[26] See EUB decisions 2001-111 and 2002-014, and EPEA Approval No. 773-01-05.

NOx emission limit for new coal-fired units of 0.69 kg per MWh, which recognizes that Selective Catalytic Reduction (SCR), the current BATEA for NOx control, can consistently achieve this level on an operational basis.

Control technologies that reduce emissions and/or improve efficiency are generally categorized as pre-combustion, combustion, and post-combustion controls. The best control strategies are hard to define because many factors influence their cost-effectiveness; among these are fuel type and composition, boiler design, emission characteristics, and emission concentrations.

In selecting a BATEA for a substance, consideration must be given to the fact that in some cases, technologies used to control one substance can increase the emissions of other substances and, in other cases, the control can have co-benefits; that is, it can also reduce the emissions of one or more other substances. In selecting a BATEA, it is desirable to maximize co-benefits.

Generally, emission control costs rise as the incremental capture of emissions gets smaller. The final incremental reduction (to zero or almost zero) can represent a substantial cost. It is generally not cost-effective to force the use of technologies beyond BATEA unless there are significant environmental issues that require such reductions. BATEA may be different for new and existing facilities.

4.2.6 The Electricity Sector and the North American Free Trade Agreement

The EPT sought clarification on whether any potential issues may arise under the North American Free Trade Agreement (NAFTA), or other trade law, for any of the proposed air emission management approaches or standards. For the most part, the EPT relied on reports commissioned by other entities, including the North American Commission for Environmental Cooperation (CEC)[27] and the Canadian Electricity Association,[28] and a brief consultation with a Canadian trade law expert.[29]

It was understood that between Canada and the United States, NAFTA is a pro-trade document in terms of energy and electricity. Electricity generation, transmission and distribution are all likely to be covered by trade agreements, including NAFTA. Under NAFTA, electricity at the consumer's door is generally considered a "good," whereas transmission and distribution are considered services. It has been suggested that the rules of the General Agreement on Tariffs and Trade (GATT) may apply if transmission and distribution are provided independently of generation.[30] The EPT did not pursue in any detail

[27] Gray Horlick, Christiane Schuchhardt and Howard Mann. "NAFTA Provisions and the Electricity Sector," in *Background Paper, Electricity and the Environment,* Commission for Environmental Cooperation: Montreal, November 8, 2001.

[28] Canadian Electricity Association. "Canadian Electricity and the Economy, The Integrated North American Electricity Market: Enhancing Opportunities for Cross Border Trading and Environmental Performance," CEA: March 2003.

[29] Conference call with Howard Mann, May 21, 2003 (The minutes of this call are available in the CASA online library at http://www.casahome.org.)

[30] Gray Horlick, Christiane Schuchhardt and Howard Mann. "NAFTA Provisions and the Electricity Sector," in *Background Paper, Electricity and the Environment,* Commission for Environmental Cooperation: Montreal, November 8, 2001; p. 4.

whether there may be any possible variances in application of the trade rules to the deregulated Alberta electricity market.

The EPT focused its review on whether the proposed measures might potentially trigger trade-related disputes or claims. It was understood that disputes were more likely to arise if the measures discriminated between domestic and foreign electricity sources, thereby creating a trade barrier. Key issues examined included:

- whether the government could regulate how electricity was generated (that is, process and production methods); and
- whether a renewable portfolio standard could trigger a trade dispute.

The EPT generally concluded that adoption of an open, transparent and scientifically sound and forward-looking standard setting and management regime for air emissions for the sector may provide the best means of avoiding future trade-related disputes. As a general rule, trade restrictive measures aimed at environmental protection can be justified so long as they are necessary to protect human, animal or plant life or health, or relate to the conservation of exhaustible natural resources[31] and are not applied in a manner that constitutes arbitrary or unjustifiable discrimination. Generally, trade law allows a jurisdiction to prescribe processes or production methods, so long as they are imposed for the purpose of domestic environmental protection, not to create a barrier to trade.

It was concluded that trade law may have particular significance for a renewable portfolio, including the 3.5% target for electricity generated in Alberta, and the proposed renewable portfolio criteria based on eco-logo or other requirements. It was determined that if the EPT proposed measures that were voluntary and non-binding, there would be minimal NAFTA effect. If the target were made mandatory to sell into the Alberta market, the situation would change. Nonetheless, it was suggested that allowing flexibility in the definition and application of the rule could alleviate potential trade disputes. It was also suggested that a trade rule dispute would be more likely to arise in relation to imports if the renewables standard was applied to retailers, not generators. So long as the renewable portfolio standard applies only to domestic generators or is applied equally to foreign and domestic sources, a trade law challenge would be minimized. It was noted that many U.S. states have already established or are in the process of adopting renewable portfolio standards. These factors were considered in the EPT recommendations on renewable energy.

4.2.7 Canadian Electricity Association Mercury Program

Recognizing the need for a solid information base around the measurement and control of mercury emissions, eight coal-fired power generation companies developed the Canadian Electricity Association's Mercury Program. The program includes research and development, and a mercury sampling and analysis program. The findings will provide critical information to assist in establishing a mercury standard for Canada. ATCO Power, EPCOR and TransAlta

[31] The definition of exhaustible resource has been interpreted to include clean air. Gray Horlick, Christiane Schuchhardt and Howard Mann. "NAFTA Provisions and the Electricity Sector," in *Background Paper, Electricity and the Environment,* Commission for Environmental Cooperation: Montreal, November 8, 2001; p. 13.

are participating in the program and their quarterly monitoring data is accessible on the CEA website.[32]

4.3 Public Policy Considerations

Communities in the vicinity of electricity generation facilities, and other members of the public, have raised a number of issues during public hearings on new facilities and during the approvals processes. Among the most important of these are concern about hotspots, the need to ensure a transparent and accountable process with opportunities for public participation, and the need to ensure continuous improvement in air quality.

4.3.1 Avoiding and Mitigating "Hotspots"

In designing an emission management regime, the goal is to improve air quality. Because an air emissions management system for a particular sector or substance may not produce the same level of emissions reductions in all areas, there is a need to ensure that "hotspots" are not inadvertently created. Concern about hotspots has focused on, but not been restricted to, areas near coal-fired generation facilities, which tend to produce more emissions than gas-fired units and are preferentially located near their fuel source, thus limiting the siting and development opportunities. This creates a challenge in ensuring that the air quality in nearby and downwind communities is protected.

The team agreed that avoiding potential hotspots would be an important consideration as it developed its recommendations. There was particular concern that the potential for local impacts be addressed in the design of any emissions trading system. The team has proposed several criteria for how hotspots would be defined and has given particular consideration to approaches that would avoid the creation of hotspots.

4.3.2 Ensuring Transparency, Participation and Accountability

It is generally considered good public policy to provide opportunities for citizens to become engaged with and provide input into issues that affect them. Members of the public should be made aware of and given opportunities to participate in an open, transparent and meaningful way. Alberta has committed to transparency, accountability and public participation through its involvement in, or endorsement of, a number of initiatives, including the Canada-Wide Accord on Environmental Harmonization and the North American Agreement on Environmental Cooperation.

Some members expressed concerns about an inconsistent application of these commitments to transparency and participation in processes for setting standards and developing management approaches for air emissions. The lack of public consultation prior to the Alberta government issuing the 2001 air emission standards for the electricity sector was cited as an example. Concerns were also noted about the lack of transparency and public engagement in the process for a Canada-wide Standard for mercury from coal-fired plants, as compared with other CWS processes.

The EPT established a subgroup to identify potential gaps and to explore alternative means to ensure that these principles of openness and participation are incorporated into any new

[32] See http://www.ceamercuryprogram.ca/EN/mercury_home.html for more information.

management regime for air emissions from the electricity sector. In support of these efforts, a background study was done to: a) identify gaps in the current management regime related to transparency, accountability and public participation, b) survey approaches adopted by other jurisdictions, and c) make recommendations for potential adoption for the Alberta regime.[33]

The EPT's composition and approach reflected a commitment to transparency and openness, as a wide variety of stakeholders were represented on the team and its subgroups, and the team made an early decision to incorporate public consultation and outreach into its overall process. Its recommendations also support consensual and open processes in future reviews of the framework.

4.3.3 Continuous Improvement

Continuous improvement is one of CASA's three air quality goals. Continuous improvement means there is an expectation on existing units to improve their performance over the lifetime of the facility. It was an important consideration for the EPT and was also raised by intervenors in recent EUB hearings and in EPEA reviews. Of particular concern are environmental and health impacts associated with the potential "grandfathering" of electricity generation facilities (that is, exempting them from future and stricter environmental standards). Fears were also expressed that new units would be licensed for 30 or 40 years and there would be no interim means of requesting performance improvements.

The EUB addressed this issue in its Decision Reports for the Genesee 3 (EUB Decision 2001-111) and Centennial (EUB Decision 2002-014) projects, expressing the view that grandfathering is not appropriate for either plant. The decisions went on to say:

> "In order to ensure that Albertans enjoy the best environment possible within standards considered appropriate, the Board recommends Alberta Environment give serious consideration to addressing the matter of power generation facilities being required to meet evolving standards. The Board believes that it is beneficial to minimize incremental air emissions to the extent practicable so that current air quality will either be sustained or improved."[34]

The EUB further noted that "proponents of new power plants need to be aware of reasonably foreseeable changes to current emission standards and need to incorporate flexibility in the design of the plants to facilitate retrofitting of improved controls should these become necessary."[35]

One of the EPT's objectives was to incorporate into its work the goal of continuous improvement, with the long-term aim of reducing emissions, protecting human health and the

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[33] Linda F. Duncan, Environmental Law and Policy and Keri Barringer, Environmental Law Centre. *A review of Issues related to Transparency, Participation and Accountability for Compliance in Relation to Current and Proposed Approaches for Management of Air Emissions from the Alberta Electricity Sector.* September 2003.

[34] EUB Decision 2001-111, December 21, 2001, *Expansion of Genesee Power Plant*, page 64. Virtually identical wording appears in EUB Decision 2002-014, February 12, 2002, *900MW Keephills Power Plant Expansion,* page 68.

[35] EUB Decision 2002-014, February 12, 2002, *900MW Keephills Power Plant Expansion,* page 64. Similar wording appears in EUB Decision 2001-111, page 60.

environment, and minimizing the potential for hotspots. Opportunities will remain for the public to raise continuous improvement concerns during facility licence reviews under EPEA, when significant changes may be made. It was also noted that companies regularly address continuous improvement as part of their long-term plans for setting and reporting on environmental goals.

5 Priority Substances

The team's task was to focus on the key emissions that should be addressed by the new management approach. The Prioritization Subgroup (PSG) compiled significant background information on other prioritization processes, substance review processes, emission inventories, risk factors and control technologies. The following substances were chosen by the EPT as its priority substances, and the PSG developed extensive criteria and rationale in support of this list:[36]

- sulphur dioxide (SO_2)
- nitrogen oxides (NOx)
- mercury (Hg)
- primary particulate matter (PM)
- greenhouse gases (CO_2)

Emissions of SO_2 and NOx can be associated with direct environmental and human health impacts. Both can contribute to acid deposition and the formation of fine particulate matter. NOx is also a major precursor of ground level ozone.

Mercury is a persistent, bioaccumulative and toxic substance that can have significant adverse environmental and human health effects. It is present as a trace element in coal and the long-term objective is to minimize or eliminate mercury emissions from coal-fired electricity generation. Most of the mercury emitted by coal units in Alberta is transported beyond the area in which it is emitted and enters the global pool. Some local stakeholders have strong concerns about the cumulative mercury emissions deposited in the Wabamun area, thereby creating a potential hotspot, notwithstanding that the primary pathway of exposure to mercury continues to be through fish consumption.

Particulate matter (PM) reduces visibility and contains many substances with potential environmental and health impacts. Primary PM emissions are associated mainly with coal-fired electricity generation and refer to the PM that comes directly out of the stack. These particles consist of various organic and inorganic substances, including metals, and can have environmental, health and aesthetic impacts.

Greenhouse gases are associated with climate change. Fossil fuel combustion to generate electricity produces carbon dioxide, which is one of the main long-lived greenhouse gases. Climate change can have significant implications for natural ecosystems, agriculture, forests, urban infrastructure, and human health.

These five substances have been widely assessed by many experts; additional details and criteria for why these were selected as priorities are contained in the report of the Prioritization Subgroup. The Subgroup also screened a number of additional substances potentially emitted by thermal generation units and assessed them for co-benefits, developed a second list of substances of possible concern, and considered the issue of water vapour in conjunction with the electricity generation sector before developing a recommendation for the future review and assessment of substances. This work is described in section 14.

[36] The report of the Prioritization Subgroup is available online at http://www.casahome.org/electricity/finalreports.asp.

PART TWO: THE RECOMMENDED EMISSIONS MANAGEMENT FRAMEWORK

In keeping with its terms of reference, the EPT is recommending a comprehensive approach for managing emissions from Alberta's electricity sector. Many of the individual recommendations are substance-specific, but others pertain to the policy direction that is needed to support the overall approach. The EPT has taken a "multiple emissions approach," focusing on the five priority substances, but recognizing that other emissions reductions also occur when priority substances are controlled. These are referred to as "co-benefits" and are described in more detail in section 7. These recommendations were informed by detailed modelling of various emission management scenarios (see section 15).

This framework is a set of consensus recommendations, negotiated by the team and agreed to as a package. All elements are equally important. **The package must therefore be considered in its entirety. If it is fragmented in any way, the overall framework can no longer be regarded as a consensus package with full stakeholder support.**

6 Reduction Strategies for Priority Emissions

Within the overall multi-pollutant approach to reducing emissions, the EPT selected what it regarded as the most appropriate strategies for each substance, also recognizing the differences between coal- and gas-fired units.[37] In developing its recommendations, the EPT considered the existing management system and the need to have an orderly transition to the new approach. It is thus proposing a phased reduction of emissions, based on the category into which the generation unit falls: existing, new or transitional.

Recommendation 1: Generation Unit

The EPT agreed that its recommendations should focus on electricity generation units rather than plants or facilities as a whole, since a facility may include several units with different conditions. The EPT recommends that

> For the purposes of this management framework, a "generation unit" refers to separate components of a power plant facility that result in the production of electrical energy and, where relevant, the combustion of fossil fuel (e.g., a boiler-generator pair or a gas turbine-generator pair).

Recommendation 2: Existing Units

Definitions for what constitutes a "new" and "existing" generation unit were needed to accommodate the Five-Year Review process. These definitions are intended to apply at a generating unit level and not on a facility-wide basis (where a facility may have more than one unit). Therefore, the EPT recommends that

> For the purposes of this management framework, an "existing" thermal generation unit be defined as follows:
>
> > An existing coal or gas unit is one that, prior to the most recent review and update of the BATEA emission limits,

[37] Appendix E lists some of the factors considered by the EPT in developing its management options.

1) has valid EUB and Alberta Environment approvals in place for the eventual unit start-up dates contemplated in the approvals, or planned by the project proponent, AND
2) in addition to any conditions of EUB and Alberta Environment approvals regarding dates for commencement of construction or formal commissioning of the units, has
   a) within three years of receiving its Alberta Environment approval
      - continuous and substantive onsite construction, or
      - boiler foundation in place.

   AND

   b) has received formal commissioning and is available for commercial service within eight years of receiving its Alberta Environment approval for coal-fired units, or within five years of receiving its Alberta Environment approval for gas-fired units.

The EPT recognized that there could be unforeseen delays in construction schedules for new units, in which case the proponent could request an extension from the EUB. The proposed timing described in this recommendation is not intended to fetter the EUB, but to allow for contingencies that cause delay. The EUB and Alberta Environment could insert their own conditions and requirements for timing into their respective approvals, independently of what this framework proposes. However, the EPT proposes that the timelines in its framework be the maximum time periods allowed.

Recommendation 3: New Units

The EPT recommends that

> For the purposes of this management framework, a “new” thermal generation unit be defined as any unit that does not meet the criteria for an “existing” unit and will therefore be required to comply with the BATEA or other emissions limits in effect at the time.

Recommendation 4: Transitional Units

The recommended emissions management approach is expected to be in place on January 1, 2006, at which time the definitions for new and existing units will come into effect. However, three large coal-fired power plant projects are in various stages of approval or construction and thus are caught in the transition to the new system. Other projects may also come forward during this transition period. The three coal plants are EPCOR’s Genesee 3 project, TransAlta’s Centennial project and Luscar’s Brooks project. The period between June 1, 2001 and December 31, 2005 is the only time in which there will be transitional units. As soon as this framework becomes effective, proposals will automatically fall into the category of new units. The EPT recommends that

> For the purposes of this management framework, “transitional” units, which refer only to coal-fired generation, are those units that (a) hold valid EUB and Alberta Environment approvals received between June 1, 2001 and December 31, 2005, and (b) meet all criteria used to define existing generation units.

Recommendation 5: Design Life

“Design life” of a unit is an important factor in a number of elements in the overall emission management framework. The design life of a unit generally refers to the time period that would allow a reasonable economic return on investment, after which the unit would be expected to meet the BATEA emission limits of the day or shut down. It is recognized that well-maintained units might in fact be capable of operating beyond this design life period.

"BATEA limits of the day" means the BATEA limits that are in force as regulatory standards at that time and that will apply to new units as well as to existing units that have reached the end of their design life. As noted in recommendation 29, the BATEA levels will be reviewed every five years and revised in accordance with the results of such reviews.

The EPT considered the relative capital costs of coal and gas generation, the tax depreciation rates, and the financial return on new units. The team agreed to a Design Life of 30 years for gas-fired units, and 40 years for coal-fired units. Where an existing PPA expires after the end of the unit's normal design life, the unit's design life is deemed to end at the expiration of the PPA. As described in recommendation 8, there is a subsequent ten-year period during which a unit could run if credits were purchased to bring emissions in line with BATEA limits of the day. There is also a provision for emission credit generation for the early shutdown of units prior to the end of Design Life.

The EPT recommends that

The Design Life for coal-fired units, except for the Wabamun generating facility, be defined as the date of expiry of the PPA term or 40 years from the date of commissioning, whichever is greater. The end of Design Life for Wabamun units 1, 2, and 4 is December 31, 2010, according to their EPEA approval (Approval 10323-02-00), which states that, "a decision must be made by December 2005 whether to modify the unit to meet applicable environmental standards or to commence decommissioning by 2010."

Design Life for gas-fired units is the date of expiry of the PPA term or 30 years from the date of commissioning, whichever is greater.

Design Life for peaking gas-fired units is the date of expiry of the PPA term or 60 years from the date of commissioning, whichever is greater.

6.1 Management Approach for NOx and SO_2

The EPT examined available control technology options for NOx and SO_2 as well as standards in other jurisdictions, and modelled a number of management scenarios. The cost implications are described more fully in the report of the modelling consultant,[38] but there were many economic implications for the electricity sector, with and without the team's proposed framework. The recommendations in the framework reflect the finding that many of the same emission reductions strategies can be applied to both NOx and SO_2. Coal-fired units emit both of these substances, while only NOx is emitted by gas-fired units.

Recommendation 6: NOx and SO_2 Standards for New Thermal Generation Units

Part of the task given to the EPT was to recommend standards for new electricity generation units that would contribute to an overall reduction in emissions. For new thermal generation units, the EPT recommends that

Effective January 1, 2006, the SO_2 and NOx BATEA standards for new coal-fired units be 0.80 kg/MWh for SO_2; and 0.69 kg/MWh for NOx.

Effective January 1, 2006, the NOx BATEA standards for new gas-fired units will be:

- 0.6 kg/MWh for units less than 20 MW power capacity
- 0.4 kg/MWh for units between 20 and 60 MW power capacity
- 0.3 kg/MWh for units greater than 60 MW power capacity

For co-generation units, MWh includes combined steam heat and electricity.

Recommendation 7: NOx and SO_2 Standards for Transitional Coal-Fired Units

Three large coal-fired power plants are in various stages of approval or construction, and are caught in the transition to the new management system. They are EPCOR's Genesee 3 project, TransAlta's Centennial project and Luscar's Brooks project. There are certain expectations for these plants with respect to meeting emission standards, and the EPT therefore recommends that

Transitional units be **expected**[39] to meet the 2006 BATEA level for SO_2 at start-up, and be **required** to meet 2006 BATEA levels for SO_2 by December 31, 2015. The deemed threshold for credit generation for SO_2 is the 2006 BATEA level.

Transitional units will be required to meet the 2006 BATEA levels for NOx by December 31, 2015. Before December 31, 2015, the deemed threshold for NOx credit generation will be the 2001 Alberta standard. After this date, the deemed credit threshold for NOx will be 90% of the 2006 BATEA level.

[38] The report by EDC Associates Ltd. is available on the CASA website at http://www.casahome.org/electricity/eptdocs.asp.

[39] See the *Environmental Protection and Enhancement Act* approval for EPCOR's Genesee 3 expansion to see how this concept is applied.

6.1.1 Managing SO_2 and NOx Emissions

The EPT considered two types of emission trading systems for SO_2 and NOx. One was a "cap and trade" system that involved setting a total sector emission cap, to take effect in 2010 with the cap dropping in 2015 and again in 2020. Two different sets of caps were considered, one more aggressive than the other. This type of emission trading system ensures an absolute level of emissions; once initial caps and associated emission allowance allocations are determined it is a relatively easy system to administer. The challenges with this type of system are accommodating new growth under a fixed cap and providing operators with some certainty as to their future emission allowance allocations.

The other type of emission trading system considered was a "baseline and credit" system. In this type of system each unit is given a baseline emission rate and, if it operates below this rate, it can generate credits, which can be banked or sold to units that operate above their baseline rate. If the baseline is an intensity limit, depending on the baseline emission rates, the same levels of emission control as with a cap and trade system can be achieved. The advantages of a baseline and credit system are that it allows for new growth, and baselines can be set based on some schedule for implementing BATEA levels that coincides with the capital stock turnover at individual units.

The EPT discussed at length the advantages of the two emission trading approaches for managing SO_2 and NOx. Among the issues discussed were certainty and extent of reductions, ease of implementation, the potential for expansion to other sectors, and possible constraints to future growth of new generation. The team agreed to recommend the baseline and credit approach, with further discussion to take place on the role of renewable energy and alternative generation in the electricity sector.

The team carefully considered and addressed many policy and technology factors to ensure the integrity of the proposed management system for SO_2 and NOx. A separate management system is proposed for greenhouse gases (see section 6.4). Appendix G provides examples and describes the design elements envisioned by the team for a baseline and credit system.

6.1.2 Deemed Credit Threshold

Under the current regulatory regime, approved emissions limits for generating units take into consideration the inherent variability in the operation of these units and the performance capability of the emission control technologies. This allows the emission performance of a unit to fluctuate within certain reasonably foreseeable limits without triggering an exceedance of approval limits. The proposed CASA framework anticipates that the BATEA emission limit standard will also incorporate provisions for such operational variability.

Unlike the current regulatory regime, the CASA framework offers a performance incentive for units by allowing them to generate saleable emission credits when operating at better than required performance levels. Since it would be inappropriate to issue credits for a unit operating below its licensed BATEA emission limits but within its normally expected operational variability, it is recommended that a "deemed credit threshold" be established for the NOx and SO_2 emission limits where emission credits would only be created for operating below the built-in operational variability in approved emission limits.

For example, recommendation 8 (below) recommends that the deemed credit threshold for new coal-fired units be set at 90% of the 2006 BATEA limits for SO_2 and NOx. Emission credits would be generated at an amount equal to the difference between the "90% of BATEA levels" and the annual averaged emission levels for years when this level is less than 90% of the BATEA level. Credit threshold generation limits have also been recommended for gas and co-generation units. The procedure for determining a baseline and generating credits from new and existing gas-fired units would be as described in the relevant sections of recommendation 8. The appropriate deemed credit threshold to apply to future BATEA emission levels should be determined during each Five-Year Review beginning in 2008.

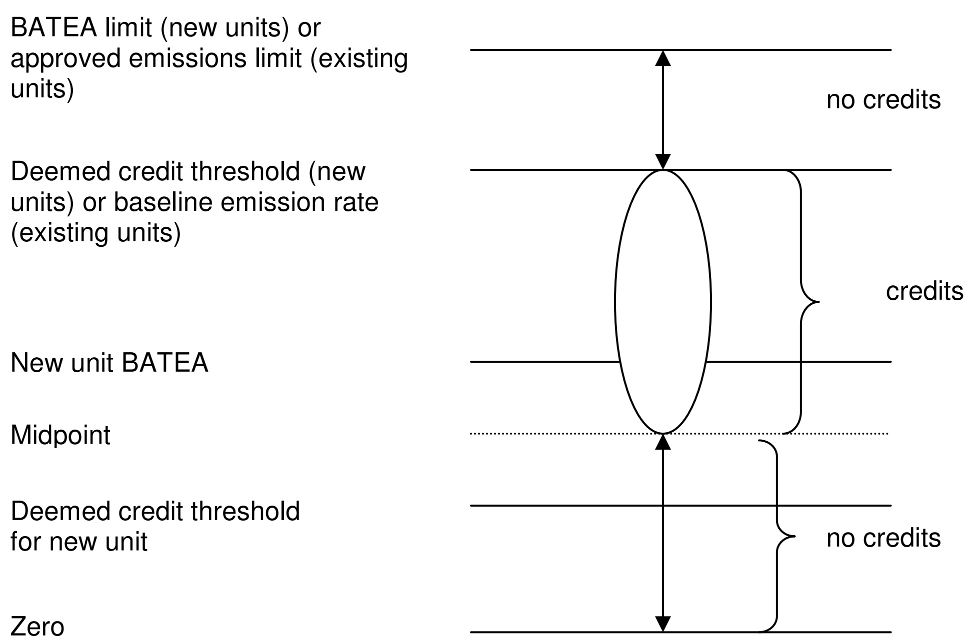
6.1.3 Credit Generation

The team identified several ways in which SO_2 and NOx credits can be created. These are:

i. performance better than a unit's pre-established baseline performance (which applies to existing units);
ii. performance better than the deemed credit threshold applying to that unit (which applies to some existing units and all post-2005 units);
iii. credits for early shutdown; and
iv. three years of transition credits at the end of design life.

The intent of credit generation is to: provide incentives and rewards for better than required or expected performance, encourage early shutdown of older units, and encourage implementation of new emission controls at existing units. Figure 3 demonstrates the concept behind credit generation for performance better than expectations.

Figure 3: Generation of NOx and SO_2 Credits for Early Shutdown



Examples of how credits for early shutdown and "transition" credits are created and granted are presented in Appendix G. All NOx and SO_2 credits created are subject to a 10% discount if not used in the year or period in which they are granted. This 10% discounting of credits is considered the "environmental benefit" component of emission trading. Without this discounting there are no overall environmental benefits from credit generation and emission trading because credits generated at one unit get applied to another unit in lieu of actual emission reductions; that is, there is a "zero sum" result.

Recommendation 8: NOx and SO_2 Emissions Management Approach

The EPT recommends adoption of a baseline and credit emissions trading system at this time for SO_2 and NOx. To manage SO_2 and NOx from Alberta's electricity generation sector, the EPT recommends that

1. Baseline emission rates for both new units and existing units that are at the end of Design Life are the BATEA limits of the day.
2. The emission rate for existing units prior to the end of their Design Life is the currently approved emission rate as specified in the regulatory approval.
3. For the purposes of credit generation, where not otherwise covered by points 4, 5, 6 or 7 below, the following will apply. The baseline emission rate for existing units would be established based on the average emissions per MWh in the 2000-2002 period inclusive. For co-generation units, the baseline emission rate will be based on the combined heat and electricity in MWh. In the event of unusual operating conditions or a prolonged shutdown during that period, the baseline would be based on the three most recent "average" years of operation. A unit that has been recently commissioned would have its baseline set by the first three years of operation. In the case of an existing unit that does not yet have three years of operation, the first year of "normal" operation would be used.
4. The deemed credit threshold for the 2006 BATEA standards, as applied to new coal-fired units, is 90% of the BATEA level.
5. Credits for performance better than the deemed credit threshold are subject to a one-time discount of 10% if they are not used within twelve months of being certified.
6. The deemed NOx credit threshold for new (post 2005) gas units (including peaking units) is as follows:
   i. 0.5 kg/MWh for units less than 20 MW in capacity rating
   ii. 0.3 kg/MWh for units between 20 and 60 MW in capacity rating
   iii. 0.2 kg/MWh for units greater than 60 MW in capacity rating
7. The deemed NOx credit threshold for existing gas units is as follows:
   i. 0.2 kg/MWh for units operating below 0.2kg/MWh. As this threshold already incorporates the concept of deemed credit threshold and an environmental discount, #5 above would not apply to these units.
   ii. baseline emission rates for units operating above 0.2kg/MWh
   iii. 0.2 kg/MWh for all peaking units operating above 0.2 kg/MWh. Peaking units can generate credits to a maximum of the difference between actual NOx emissions and the NOx emission cap applying to that unit.
8. Credits for existing units that shut down before the end of Design Life will be granted based on:
   i. the number of years between shutdown and end of Design Life
   ii. the difference between the unit's baseline emission rate or deemed credit threshold, where applicable (kg/MWh), and the BATEA emission rate of the day and the corresponding deemed credit threshold applicable to new units.
   iii. the unit's generation rate (MWh/year), which will be the average of the three highest years' generation in the last five years before shutdown
9. Unlimited banking of credits

10. Units that reach the end of Design Life and commit to either shutting down on that date or upgrading to BATEA within three years of that date are eligible for transitional allocations based on the following formula: BATEA limit of the day (kg/MWh) x 3 years x the average of the three highest years' generation in the last five years (MWh). Consistent with the 2010 shutdown or upgrade requirements of their EPEA Approval, the Wabamun generating units are not eligible for this provision.

For units that have reached the end of their Design Life, there be a 10-year limitation, to a maximum operating life of 50 years for coal, 40 years for gas, and 60 years for peaking gas units, on the use of credits to meet new BATEA limits, at which time the existing unit must physically upgrade to comply with the BATEA emission limit of the day or shut down. Consistent with the 2010 shutdown or upgrade requirements of their EPEA Approval, the Wabamun generating units are not eligible for this provision. For exceptions, see recommendation 10.

Recommendation 9: Implementation of the Management Approach for NOx and SO_2

Because of the general recognition that cap and trade systems have some inherent advantages over baseline and credit systems and because they may be implemented in other sectors in Alberta, the EPT recommends that

Alberta Environment establish a multi-stakeholder committee to support and advise the Department in the implementation of the NOx/SO_2 emissions management system, and address any outstanding details.

Alberta Environment, in consultation with the multi-stakeholder committee, examine opportunities to merge or harmonize the NOx/SO_2 emissions management system for the electricity sector with a cross-sectoral cap and trade or any other form of emissions trading system. Access by any other types of electricity generators to any provincial SO_2/NOx trading system should also be examined at that time.

Future consideration be given to converting the NOx/SO_2 emissions management system for the electricity sector to a cap and trade system.

6.1.4 Specific Considerations Related to Co-generation and Gas-Fired Units

Relative to coal, the use of natural gas to generate electricity has the advantages of:

- more flexible siting, which can reduce the number of lines required and associated line losses;
- lower capital cost and shorter construction times;
- easy start-up and shutdown, which mean it can be brought on-line quickly during periods of peak demand; and
- relatively low air emissions compared to coal-fired generation.

On the other hand, gas-fired electricity generation can be subject to significant price fluctuations caused by changes in the cost of natural gas.

Because the demand for electricity is not evenly distributed throughout the day or the year, there is a need for generating capacity that can be brought into the power grid quickly and easily due to high demand or to the planned or unplanned shutdown of other generation units. Units that can be powered up to meet these needs are referred to as "peaking" units and, in Alberta, these are mainly gas-fired.

Recommendation 10: Existing Gas-Fired Units

Gas-fired units have operational options, some of which are similar to coal-fired units and some that are different. The EPT recommends the following process for existing gas-fired units:

At the end of a gas-fired unit's Design Life, the emission limit will be set at the BATEA standard of the day. At that point, the unit can elect to do one of the following:

1. Install and upgrade technology to achieve the BATEA standard of the day;
2. For a maximum of 10 years, purchase allowances or credits for the difference between operating levels and the BATEA standard of the day. At the end of 40 years, the unit must meet the requirements described in 1, 3 or 4.
3. Shut down; or
4. Declare the unit as a peaking unit for a minimum three-year period, and run as a peaking unit to a maximum age of 60 years on the condition that the requirements for peaking units are met. As noted in recommendation 11, at the age of 60 years a unit can elect to install and upgrade technology to achieve the BATEA intensity level of the day or shut down. Three months' notice must be provided prior to the designation of a unit as a peaking unit.

In the event a gas-fired unit's Design Life is reached before 2010, the unit will be given until December 31, 2010 to meet the framework requirement applicable to the age of that unit.

For existing natural gas co-generation units currently under an industrial site environmental approval where the co-generation facility does not operate under its own Alberta Environment approval, it is recommended that the NOx emissions limits for these co-generation units continue to be incorporated into the allowable NOx emissions for the site. This would allow emission reductions to be dealt with on a site rather than on a specific unit basis, while still providing for the required reductions overall. At the end of 40 years the unit must meet the requirements described in 1, 3, or 4 above.

Recommendation 10a: Co-generation Units Fired by Other Fuels

Co-generation units fired by other fuels have some operational options that are similar to gas-fired units and some that are different. The EPT recommends the following for these units:

New co-generation units may use other fuels such as coke, hydrogen, bitumen, diesel fuel and others (e.g., biomass). These units should continue to be dealt with on an approval-by-approval basis and, consistent with the approach recommended for gas-fired co-generation units, the application of BATEA based limits to new units should be followed. If specific alternate fuel type co-generation units are proposed in the future, then as part of the Five-Year Review process, consideration should be given to developing specific BATEA-based emission limits for such units similar to those in recommendations 6 and 8.

For existing co-generation units fired by other fuels currently under an industrial site environmental approval, where the co-generation facility does not operate under its own AENV approval, it is recommended that the NOx emissions limits for these co-generation units continue to be incorporated into the allowable NOx emissions for the site. This would allow emission reductions to be dealt with on a site rather than on a specific unit basis as part of the regular EPEA approval renewal process, while still providing for the required reductions overall.

Recommendation 11: Peaking Units

Some peaking units may not generate for months at a time. As they are needed to maintain the integrity and functionality of the existing system, it is not considered reasonable to expect the same level of investment in emissions technologies for these units. The EPT agreed to a definition for peaking units, based on the 1992 CCME Guidelines.[40] Peaking units would receive an annual allocation based on what they actually emitted up to the emissions cap defined by this formula. The BATEA emission intensity limit to be applied after January 1, 2011 should be developed as part of the 2008 Five-Year Review and revised, as appropriate, during subsequent Five-Year Reviews. Thus the EPT recommends that

> The emissions cap for NOx for gas-fired units declaring themselves as peaking units prior to December 31, 2010 is a gross emissions cap in kilograms per year, based on the following formula, consistent with the 1992 CCME guidelines: (1.008 kg/MWh) *(Maximum Capacity Rating in MW)*(1500 hours).
>
> Units declaring themselves as peaking units after January 1, 2011 would be subject to a cap based on the following formula: peaking unit BATEA intensity level of the day *(Maximum Capacity Rating in MW)*(1500 hours).
>
> A peaking unit may operate to a maximum age of 60 years, at which time it can elect to:
>
> 1. Install and upgrade technology to achieve the BATEA intensity level of the day; or
> 2. Shut down.
>
> The emissions cap for a peaking unit may be exceeded if the units are required by the System Operator to operate for system security.

Recommendation 12: Reciprocating Engines

These units (excluding stand-by and emergency units) are almost all under 5 MW and were not within the range examined by the team, although some units may be slightly larger than this limit. These larger units would likely emit between 0.4 and 0.8 kg/MWh of NOx. The emissions from smaller units vary greatly but are likely to be higher. The team felt that the current number and size of these units did not justify setting standards for them. It was agreed that these units could be addressed on an approval basis and at the time of approval could be compared to the currently available technology to ensure that they are "state of the art" and not older units re-located from other jurisdictions. The team also agreed that if there is a significant increase in the size or number of these units they may need to be addressed as part of the proposed Five-Year Review noted in recommendation 29. The EPT thus recommends that

> Emissions from reciprocating engines, excluding stand-by and emergency units, be addressed on an approval basis and compared to the BATEA level of the day.
>
> If there is a significant increase in the size or number of these units, they may be addressed as part of the Five-Year Review.

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[40] *National Emission Guidelines for Stationary Combustion Turbines.* December 1992. CCME-EPC/AITG-49E; ISBN: 0-919074-85-5.

6.2 Management Approach for Mercury

Mercury management was a key issue for many stakeholders and was identified in the terms of reference as key task area 2. Some communities near coal-fired facilities have raised health and environmental concerns due in part to the bioaccumulative nature of this heavy metal. The issue is complicated by the fact that there are different chemical forms of mercury, and mercury is a global problem with emissions originating from many sources and being circulated around the world.

There was consensus among EPT members that the recommended management system for mercury should:

- reduce mercury emissions in Alberta;
- reduce the potential for the Wabamun area to become a hotspot; and
- provide an economically efficient way of reducing emissions.

Many jurisdictions, including Canada, have recognized mercury as a global environmental and health issue and are working to reduce mercury levels. The Canadian Electricity Association has established a mercury monitoring program to provide better information about mercury types and levels in Alberta (see section 4.2.7), and considerable effort in the U.S. is going into capture technology research, development and demonstration for the electricity sector.

Three mercury management options were initially modelled and, subsequently, one "optimized" option was modelled to determine the impact on electricity price, generation and emission reductions (see section 15). The optimized option had all coal units installing mercury controls in 2010. This date was chosen to align with national and international initiatives related to mercury control at coal units. The team recognized, however, that under this approach older units would face higher costs due to their shorter amortization periods. The team took this economic factor into consideration in developing its final recommendations. Certain older units are exempted from installing mercury controls if they commit to shutting down at the end of their Design Life, while the remaining units install mercury controls in 2009, a year earlier than the originally planned date of 2010. This approach results in a comparable overall level of mercury reduction while providing potential economic benefits to industry.

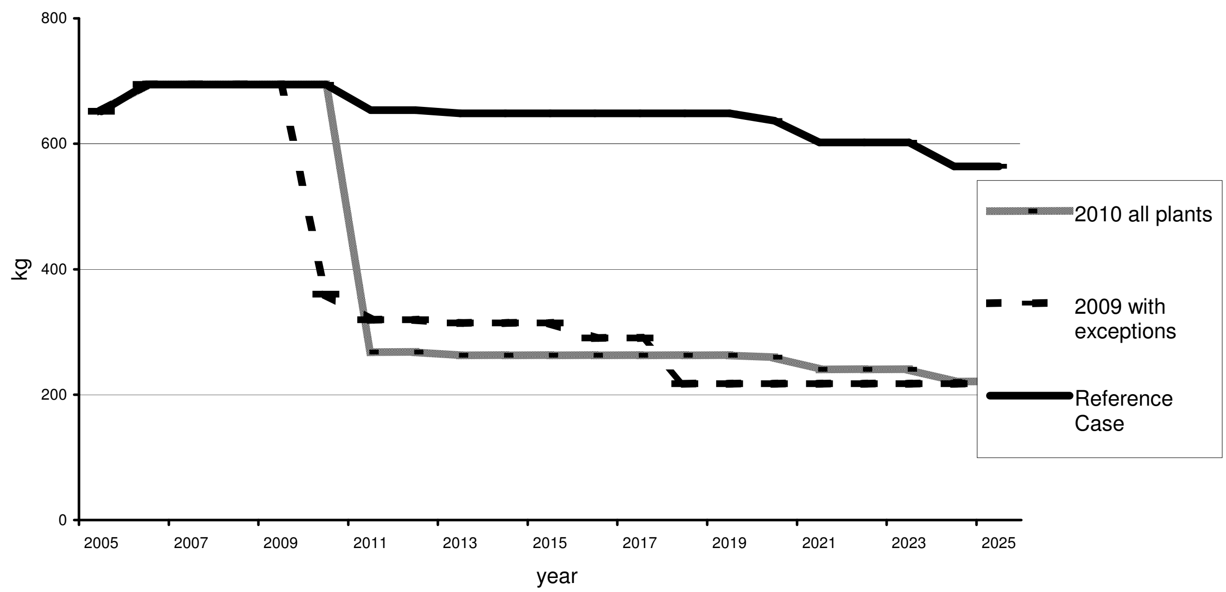
Table 3 and Figure 4 compare annual mercury emissions a) with control technology installed by the end of 2009, and b) with control technology installed by the end of 2010, using data that was provided as input to the modelling activity, described more fully in section 15. The business-as-usual reference case is also shown in Figure 4.

Table 3: Annual Emissions of Mercury from the Electricity Sector by Unit under Two Scenarios

	Current mercury emissions (kg/year)	Mercury emissions assuming 80% capture (kg/year)	Mercury emissions under 2009 option (kg/year)	Extra emissions due to exemptions of units
H.R. Milner	4.80	4.80	4.80	
Battle River 3	11.85	3.51	11.85	41.70
Battle River 4	12.35	3.66	12.35	43.46
Genesee 3	42.53 [a]	29.51	29.51	
Sundance 1	34.41	19.31	34.41	105.69
Sundance 2	38.53	19.31	38.53	134.48
Sundance 3	51.50	23.31	23.31	
Sundance 4	52.16	23.31	23.31	
Sundance 5	52.69	25.09	25.09	
Sundance 6	61.09	25.09	25.09	
Battle River 5	31.51	9.34	9.34	
Keephills 1	51.84	18.50	18.50	
Keephills 2	52.85	20.65	20.65	
Sheerness 1	36.00	9.66	9.66	
Genesee 1	41.28	11.36	11.36	
Sheerness 2	36.00	9.66	9.66	
Genesee 2	42.07	11.57	11.57	
Wabamun 1		0.00	0.00	
Wabamun 2		0.00	0.00	
Wabamun 3		0.00	0.00	
Wabamun 4	40.82	40.82	40.82	
Total	694.28	308.45	359.80	325.33
Difference between current emissions and emissions under 2009 option	334.48			
Benefit to the environment		9.15		

[a] Estimated. The Genesee 3 unit is not yet in operation.

Figure 4: Comparison of Annual Mercury Emissions under Two Scenarios



The EPT based its recommended emissions standards for NOx, SO_2 and PM on BATEA levels, but a specific capture limit for mercury could not be set at this time because there is no established BATEA level for mercury. The team was clear in its discussions and its recommendations that a BATEA standard for mercury emissions from coal-fired units is needed as soon as possible. To advance this goal, the EPT proposes a BATEA review for mercury in 2005, sooner than for other substances, to assess the rapidly evolving information and developments related to mercury emissions management and the feasibility of setting a BATEA standard at that time. To the extent feasible, this review should be coordinated with similar initiatives by other jurisdictions.

Recommendation 13: Regulation of Mercury

The team was aware that all approvals for coal-fired units in Alberta are up for renewal between 2005 and 2007. This provides an opportunity to include the mercury control requirements for these facilities at the time of the next approval renewal. The EPT recommends that

a) Alberta Environment establish mercury control requirements in regulation or in standards through the *Environmental Protection and Enhancement Act,* and

b) the requirements for mercury control be incorporated into the approvals for each coal-fired unit, according to the following recommendations.

The conditions inserted into approval renewals will depend on the status of a BATEA standard and would be expected to reflect the intent of recommendations 14 to 17 below.

Recommendation 14: BATEA Review for Mercury

The team discussed several management options including: the application of control technology to all units; applying technology to all units except those with a short operating life remaining; the use of emissions trading with assurances that hotspots would not be created; and application of a level of effort to be agreed upon by the parties involved. This discussion was hampered by the lack of a BATEA standard for mercury, so the team agreed that a technology review to assess new information and, if possible, identify a BATEA technology standard and associated emissions limits for mercury, should be undertaken in 2005. The EPT therefore recommends that

a) Alberta Environment continue to pursue the establishment of a BATEA level for mercury emissions from coal-fired units and, when established, amend existing regulations or standards to implement the new BATEA level. The mechanism for applying the BATEA level will be the same as that described in recommendation 17.

b) the BATEA level for mercury be reviewed in 2005 by a multi-stakeholder group consisting of representatives from industry, government, non-government organizations and communities with an interest in the electricity sector, based on:
   - new monitoring data being collected by industry now,
   - commercially available and relevant technology and management options, and
   - new environmental and health information.

The review should follow the same principles as described in recommendation 29 and, to the extent possible, also include the Alberta parties involved in the CWS process.

c) PPA buyers and generators commit to enter into discussions with the objective of reaching agreement on: commercial arrangements to implement the BATEA level, the financial commitment for each unit, and shutdown dates for units identified in recommendation 17 for shutdown; and

d) PPA buyers and generators commit to conclude these discussions by December 31, 2006.

Recommendation 15: Five-Year Review for Mercury BATEA Level

Mercury would also be part of the Five-Year Review process to determine BATEA level of the day, as proposed in recommendation 29. The EPT recommends that

Commencing in 2008, any established mercury BATEA emission level be reviewed as part of the general Five-Year Review of the BATEA limits in the overall emissions management framework.

Recommendation 16: Required Level of Effort for Mercury Control

If a BATEA standard is not identified in the 2005 review described above or if a Canada-wide Standard has not been set by 2005, the team agreed that a "safety net" is needed to ensure that timely action would be taken to reduce mercury emissions from coal-fired units. The EPT examined various mercury control options, including activated carbon injection, fabric filtration, spray cooling, wet flue gas desulphurisation and selective catalytic reduction. The latter two technologies, used primarily for controlling NOx and SO_2 emissions, were neither capable of nor cost-effective for achieving the desired level of mercury capture. Spray cooling, which is usually installed in conjunction with activated carbon injection, was determined to be unnecessary for the type of coal burned in Alberta. However, it was determined that activated carbon injection could achieve reasonable levels of capture, particularly in combination with fabric filtration, which increased the reaction time with the mercury and thereby increased mercury capture rates, for the same amount of carbon injected. This led the EPT to conclude that a reasonably foreseeable technology to be applied for mercury control was activated carbon injection in combination with fabric filtration. The team chose this approach partly because fabric filters will remove almost all the ionic form of mercury and a large fraction of the elemental mercury.[41] The EPT also recognized that a co-benefit of this choice would be the capture of other substances, including primary particulate matter.

It was agreed that a set level of effort in the form of a financial commitment equivalent to what is viewed as the most likely technology to be installed in 2009 – that is, activated carbon and fabric filters – would be established. The team modelled its best estimate of the cost of this technology and the capture rate, but could not recommend a capture rate at this time. If an improved capture rate can be identified in 2005, the commitment will be reviewed. Therefore, the EPT recommends that

If a BATEA level for mercury is not identified in 2005:

a) as a condition of their approvals, coal-fired units be required to implement a set level of effort for mercury control by the end of 2009 to reduce emissions to the extent possible, with the exception of those units noted in recommendation 17 for shutdown; and
b) for existing units, the level of effort be defined to be financially equivalent to installing fabric filters and activated carbon at an injection rate to be determined as part of the 2005 BATEA review for mercury (recommendation 14). New or transitional units that have fabric filters would only be expected to meet the activated carbon component of this level of effort commitment. This exception would not apply if a BATEA level has been determined in recommendation 14.
c) cost-effective alternatives to fabric filters and activated carbon injection can be installed by December 31, 2009 only if these technologies achieve mercury reductions equivalent to or better than those achieved using fabric filters and activated carbon injection; and
d) PPA buyers and generators commit to enter into discussions with the objective of reaching agreement on: commercial arrangements to implement the level of effort for each unit, the equivalent financial commitment for each unit, and shutdown dates for units identified in recommendation 17 for shutdown; and
e) PPA buyers and generators commit to conclude these discussions by December 31, 2006.

This management approach will require detailed discussions between generators and PPA buyers to decide which if any units should be shut down, and to determine an agreeable allocation of technology installation costs.

Recommendation 17: Units to Install Mercury Controls or Shut Down

The team identified those units with a significant amount of time remaining in their Design Life, and agreed that they should be required to install mercury controls by the end of 2009. The time frame being proposed for installation of mercury control technology would leave some units with only a few years of operating time remaining in their approvals. The objective of the discussions in recommendations 14 and 16 will be to determine how to handle such units. One option is for them to commit to shut down

[41] Mercury deposited in the local environment is in the ionic form, while elemental mercury is the form that can be transported long distances.

by a certain date; if they elect to do this, these units would not be required to install mercury controls. Thus, the EPT recommends that

> The following coal-fired units install mercury controls by the end of 2009: Battle River 5; Sheerness 1 and 2; Genesee 1, 2 and 3; Sundance 3, 4, 5 and 6; Keephills 1 and 2; Centennial 1 and 2; and Luscar's Brooks units 1 and 2.
>
> Wabamun units 1, 2 and 4 will be dealt with in accordance with their EPEA approval (Approval 10323-02-00, section 4.1.2), which states that, "a decision must be made by December 2005 whether to modify the unit to meet applicable environmental standards or to commence decommissioning by 2010."
>
> If the PPA buyers and generators agree to commercial arrangements to implement the level of effort approach described in recommendation 16 by December 31, 2006, the following units will not be required to install mercury control technology and will be required to shut down: HR Milner, Battle River 3 and 4, and Sundance 1 and 2. It is agreed that their effective shutdown dates would be as follows: HR Milner – 2012; Battle River 3 and 4 – 2015; and Sundance 1 and 2 – 2017. If the PPA buyers and generators agree by December 31, 2006 to shut down only some of these units on the effective dates, those units that continue to operate will be required to install mercury controls by the end of 2009, consistent with recommendation 16. These commitments and deadlines are to be incorporated into the relevant approvals for all units.

6.2.1 The Fallback Position on Mercury Controls

The provincial and federal governments have indicated that if the PPA buyers and generators cannot reach agreement on commercial arrangements and timing of shutdowns associated with the above recommendations, mercury controls will be required at all units by December 31, 2010, consistent with the intent of the Canada-wide Standard process for mercury emissions from coal-fired power plants. This fallback would then become the mechanism for the mercury management component of the overall framework.

Recommendation 18: Alberta's Position on Addressing Mercury from Coal-fired Power Plants

Alberta is actively participating in the Canada-wide Standards process for mercury and has committed to taking forward the consensus position of the EPT to the CWS table as Alberta's position. In support of this commitment, the EPT recommends that

> The requirements and approach described in these recommendations be the position that Alberta presents to the Canadian Council of Ministers of the Environment Canada-wide Standards table addressing mercury emissions from coal-fired power plants.

6.3 Management Approach for Primary Particulate Matter

The EPT identified primary particulate matter (PM) as a priority substance but recognized that reductions in primary PM are expected to happen as a result of the mercury management approach being proposed. Clean coal technologies now under development are also expected to reduce primary PM emissions.

Recommendation 19: Primary PM Standard

The EPT adopted the current federal guideline for primary PM as its recommended standard. This guideline came into effect in April 2003 and many coal units are close to that level now. Thus the EPT recommends that

> Effective January 1, 2006, the primary particulate matter standard for new coal-fired units be 0.095 kg/MWh.

Recommendation 20: Regulation of Primary PM

The team believes that the current system for regulating primary PM is adequate and recommends that

> Alberta Environment regulate primary particulate matter on a unit-by-unit basis through the *Environmental Protection and Enhancement Act* approval process.

Recommendation 21: Five-Year Review

As part of the Five-Year Review in recommendation 29, the EPT recommends that

> Every five years, commencing in 2008, the technology be reviewed to determine BATEA level of the day for primary particulate matter, as part of the process described in recommendation 29.

Recommendation 22: Co-benefits of Mercury Control

By controlling mercury through the use of fabric filters, emissions of primary particulate matter are also expected to decrease. The EPT was of the view that the co-benefits of controlling mercury would be adequate to address primary particulate matter and thus recommends that

> For existing and transitional coal-fired units, where mercury controls include fabric filters, the primary particulate matter target of 0.095 kg/MWh shall apply. If mercury control identified in the 2005 review does not provide this co-reduction of primary particulate matter, then the 2008 system review should develop a primary particulate matter management system for existing units.

6.4 Management Approach for Greenhouse Gases

At the time this report was written, the Electricity Project Team recognized that its recommendations were based on current understanding of strategies for the management of greenhouse gases. It was further recognized that these strategies were still evolving in terms of both federal and provincial policy development, co-ordination and integration, and reconciliation of provincial and federal interests. The team believes that its consensus multi-stakeholder nature combined with its considerable work on greenhouse gas management options, is such that its greenhouse gas recommendations should be adopted or strongly inform the positions and approaches the provincial and federal government take with respect to managing greenhouse gases from the Alberta electricity sector. The team encourages both orders of government to coordinate their efforts to avoid regulatory duplication and overlap as much as possible. The team therefore accepts that its recommendations related to the management of greenhouse gases are made "without prejudice" in the event that government strategies and approaches evolve beyond the current understanding.

In developing its recommendations, the EPT considered the following aspects of greenhouse gas management:

- A fair and equitable contribution to the reduction of greenhouse gas emissions from the Alberta electricity sector in keeping with broader multi-sectoral targets
- The projected business-as-usual emission intensity
- The nature, scope, availability and cost of eligible offsets
- Issues of double counting[42] (see recommendations 23, 24 and 28)
- Investment in innovative technology in Alberta
- Additional flexibility for dealing with Alberta's Natural Gas Combined Cycle offset requirement for new coal-fired units

These issues influenced the direction and content of the recommendations for managing greenhouse gases, and should be viewed as applying to the full package of recommendations.

6.4.1 Greenhouse Gas Target and Allocation Issues

Greenhouse gases were a distinct component of the EPT's mandate, although the team was aware that considerable work is being done by the Alberta government to develop a management framework for these emissions. The team had lengthy and detailed discussions on issues related to greenhouse gases, particularly around targets and allocation methods.

The team agreed to base its greenhouse gas recommendations on intensity, recognizing that this may need to be revisited. The EPT modelled a range of intensities and did a great deal of work to find targets on which stakeholders could reach consensus.

[42] For the greenhouse gas recommendations, "double counting" is not intended to refer to actions that are eligible to meet requirements of more than one jurisdiction, or to those actions eligible for compliance with the new coal unit NGCC offset requirement. The term is intended to ensure that those actions targeted for support by government to reduce generation intensity or output are not also "double-counted" when complying with specific unit intensity reduction targets. Where agreements do not already exist, it is recognized that apportionment mechanisms must be developed by industry and government for the ownership of the greenhouse gas reductions resulting from actions targeted for support by government to reduce generation intensity or output.

The team attempted to develop a set of consensus recommendations centred on an aggregate intensity target for thermal generation. Agreement was reached on a number of elements of the overall approach, but not on the core element of targets for specific generating units. The team views recommendations 24, 26 and 27 as completed but the wording, or even the substance, of recommendations 25 and 28 may have to be amended to fit with the approach agreed to for recommendation 23.

Building on prior work, the team is continuing to develop a consensus on the core element of greenhouse gas emission targets for generation units – recommendation 23 – together with possible related modifications to recommendations 25 and 28.

Recommendation 23: Thermal Generation Greenhouse Gas Intensity Target

Under discussion

Recommendation 24: Rules for Offset Credits

The Alberta government has indicated it intends to develop an emission offset trading system that reflects Alberta's unique needs and circumstances, complements the negotiated sectoral agreements and works with national, continental and international systems.[43] Offsets are mechanisms that allow a company (or other entity) that is unable to cost-effectively reduce emissions in its own facilities to purchase credits from another entity that has exceeded its emissions reduction target. The way in which offsets and credits are defined and quantified is critical to ensuring that real reductions in greenhouse gases occur. Recognizing the importance of a credible system for offsets and credits, the EPT recommends that

> Governments establish clear rules on acceptable offset credits that represent real greenhouse gas reductions that are measurable, verifiable, and do not result in double counting. Flexibility in the use of trading, bankable offset credits, and the potential use of research and development be provided to achieve reductions.[44]

Recommendation 25: New Coal Unit NGCC Offset Requirement

The Alberta government now requires all new coal-fired generation units to offset their greenhouse gas emissions down to the level of a combined cycle natural gas turbine.[45] The EPT generally supports this policy and its intent of encouraging investment in technological innovation in Alberta. Some team members felt strongly that a tonne of CO_2 reductions in BC or China should count as a tonne in Alberta or Denmark, for example. It makes no difference to the global atmosphere where the emission reduction occurs, but some stakeholders argue that by making the reductions within the province, jobs and other economic activity are encouraged. It was suggested that perhaps

[43] *Albertans and Climate Change: Taking Action.* October 2002. Government of Alberta.
[44] It is further recognized that the issue of financial additionality is to be resolved in another forum.
[45] The CASA EPT is aware of an Alberta Environment Transition Principles document concerning eligible offsets that can be used to meet the NGCC offset policy for new transitional coal-fired generation. Such a document is being contemplated to provide industry with interim certainty surrounding offsets that may be used to meet the NGCC offset policy. Any coal-fired units subject to the Transition Principles will comply by its terms until such principles expire. Upon expiration of the Transition Principles, relevant facilities are then governed by the CASA framework and its greenhouse gas requirements. (Note: This is most relevant to the recommendations pertaining to NGCC offsets policy, renewables credits, credit for early shutdown, and offsets rules and credits.)

investment in Alberta offsets may not yield a full tonne reduction in greenhouse gases, but credit might be given for a tonne because of the value added by making the investment within the province. The EPT recommends that

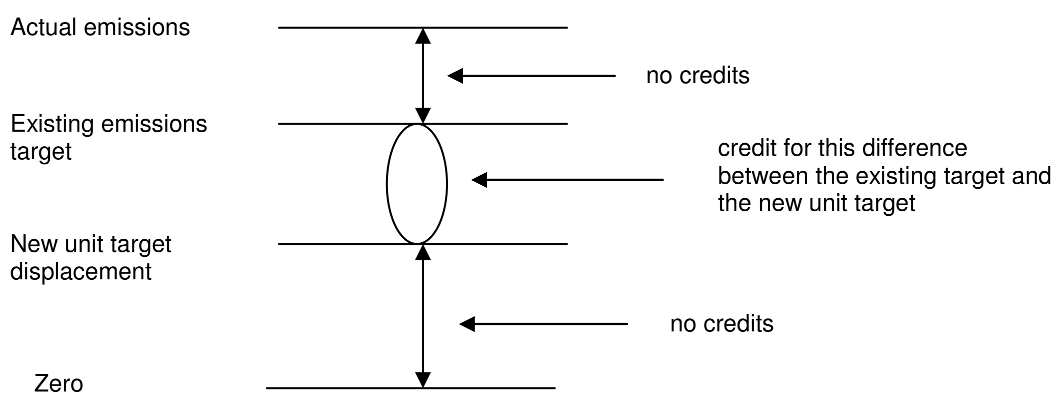
> The Alberta government continue to apply its Natural Gas Combined Cycle (NGCC) offset policy[46] requiring all new coal-fired units to reduce or offset their greenhouse gas emissions to the NGCC level of 418 kg/MWh. This requirement should also be applied to existing coal-fired units that reach their end of Design Life. This represents the greenhouse gas reduction commitment for the Design Life of the unit. It is recognized that future national or international greenhouse gas reduction commitments may result in additional management obligations.
>
> (Note: Flexibility should be provided to companies in meeting this offset requirement with special consideration given to offsets associated with in-province renewables, energy efficiency and conservation, and technology research, development, and investment. Where agreements do not already exist and government support is involved in the development of an offset credit, it is recognized that apportionment mechanisms must be developed by industry and government for the ownership of these greenhouse gas reductions.)

This recommendation may need to be amended to fit with the approach agreed upon for recommendation 23.

Recommendation 26: Greenhouse Gas Emission Credits for Early Shutdown

Within a trading system, incentives can be provided for earlier unit shutdown than would otherwise occur. This results in a lower overall fleet age, which generally translates to reduced emissions. The principle that guides credit for early shutdown is that if a unit is rebuilt at the end of its pre-set Design Life, it would get a new emissions allocation based on the improved efficiency of new units at that time. Credits for early shutdown could be banked for future use. Figure 5 illustrates how credits would be given.

Figure 5: Greenhouse Gas Credits for Early Shutdown



The team discussed whether greenhouse gas credits for early shutdown should be discounted and/or reduced in conjunction with any new sector greenhouse gas reduction obligations that occur during the early shutdown period. The team agreed that, to keep

[46] *In Albertans & Climate Change: Taking Action*, the Alberta government requires all new coal-fired generation facilities to offset their greenhouse gas emissions down to the level of a combined cycle natural gas turbine.

the system simple, there would be no discounting of early shutdown greenhouse gas credits, but that such credits would only be issued for a maximum early shutdown period of ten years. The EPT recommends that

> Credit for unit shutdown before the end of Design Life be given for a period of no greater than that remaining to the end of Design Life to a maximum of ten years, based on the required emission intensity target at the time of shutdown. These credits will not be available if the shutdown results from a government order or a court order. Credits for coal units will be the difference between that number and the NGCC offset policy as defined in recommendation 25. Credits for gas and co-generation will be the difference between their emission intensity target at the time of shutdown and the intensity target for new units defined at that time. The unit's generation number will be the average of the three highest years in the last five years before shutdown. This proposal would come into effect on January 1, 2006. Any banking of these credits is to be consistent with the rules of banking determined under recommendation 24.

Recommendation 27: Discounting of Greenhouse Gas Emission Credits

"Credits" refers to bankable emissions resulting from new or existing units operating below their required levels, as well as to emissions that are avoided by shutting down early. Such credits could be banked for future use. The EPT recommends that

> There be no environmental discounting applied to greenhouse gas offset credits eligible for banking according to the rules determined under recommendation 24.

Recommendation 28: "Green Tag" Credits for Renewable Energy

The government of Alberta has set a goal for increasing the renewable and alternative energy portion of total provincial energy capacity by 3.5% by 2008. The EPT supports this goal and is of the view that greenhouse gas credits should be provided for renewable energy. An important consideration will be ensuring that there is no double counting of emissions credits, while still allowing those who develop renewable energy projects to count them as contributing to the 3.5% target as well as being eligible for an offset. The EPT recommends that

> A "green tag" program for renewable and alternate energy be established, that is in units of "tonnes of CO_2-equivalent." This program should be developed by 2005 and applied to all renewable and alternate energy developed after December 31, 2001.
>
> Green tag credits, usable for compliance with individual units' greenhouse gas intensity targets, could be made available in addition to the green certificates proposed as part of achieving the 3.5% renewable energy target (see recommendation 59).
>
> This recommendation does not preclude the sale of credits from earlier reductions. It is recognized that the issue of credit for earlier action is to be resolved in another forum.

This recommendation may need to be amended to fit with the approach agreed upon for recommendation 23.

6.5 Impact of the Recommended Management Framework on Emissions

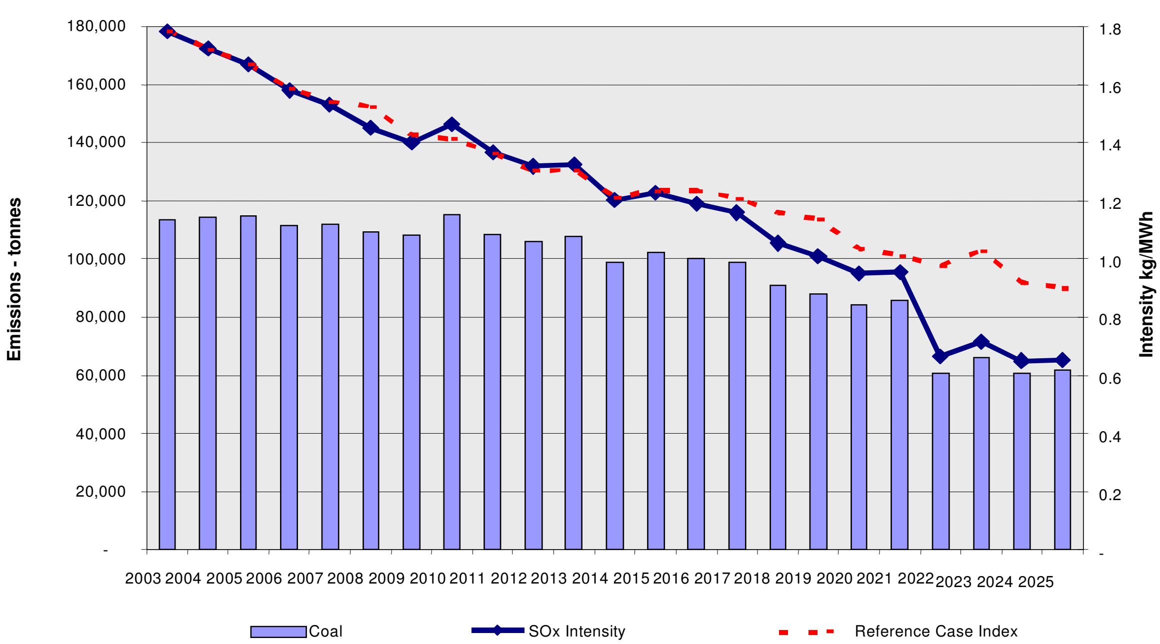
As part of its modelling work (see section 15), the EPT looked at the impact of its recommended management framework on emissions of the five priority substances from both coal- and gas-fired units. Figures 6-10 show the predicted impact of the framework on each of the five priority substances. The optimized scenarios are described more fully in section 15 of this report. For figures 6-10, modelling inputs were:

- CO_2 prices of \$9, \$12 and \$15 per tonne, and CO_2 targets to 0.66 t/MWh and 0.47 t/MWh
- Mercury and PM intensity reduction in 2009
- BATEA at 40 years for coal and 30 years for gas units
- Renewable energy target by 2008

Tables 4 and 5 illustrate the predicted impact of imposing on existing units, at the end of their Design Life, the 2006 BATEA standards for NOx, SO_2, and primary PM, and of requiring 80% capture of mercury, based on the best estimates available to the team at the time.

Figure 6 shows the impact of the proposed framework on SO_2 emissions, as modelled for the team in its optimized scenario 1.

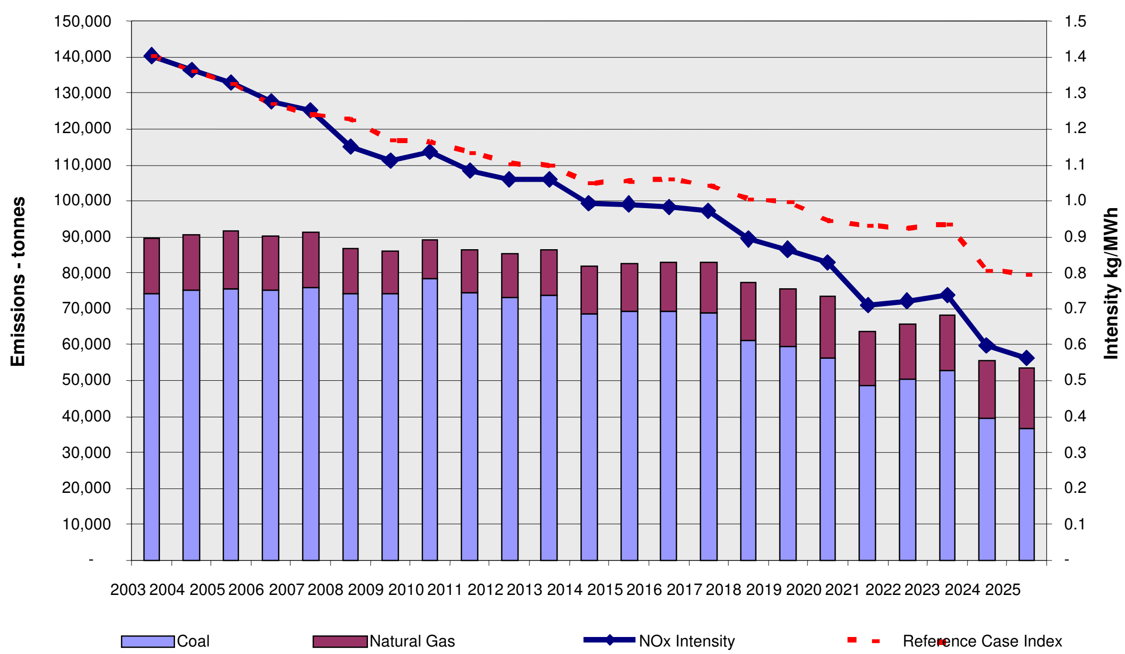
Figure 6: Predicted Impact of the Framework on SO_2 Emissions



SO_2 emissions are reduced when generation facilities are mandated to meet BATEA standards via technology or credit purchases. The result of this policy is that SO_2 emissions fall below the reference case over time as coal units reach the end of their design lives and are required to meet new standards. The minor deviation between the reference case and scenario 1 between 2016 and 2022 is not a direct result of the specific SO_2 policy. This earlier reduction occurs because four coal units retire earlier under scenario 1 than the reference case for reasons related to mercury mitigation costs. As a result of these earlier retirements, emissions fall.

Figure 7 shows the impact of the proposed framework on NOx emissions, as modelled for the team in its optimized scenario 1.

Figure 7: Predicted Impact of the Framework on NOx Emissions



NOx emission results for optimized scenario 1 are very similar to the SO_2 results in Figure 6. As some gas units reached the end of their design lives in the 2008-2010 period, they installed control technology to meet BATEA levels. This combined with coal unit shutdowns in the 2013-2017 period caused the emissions profile to be lower than in the reference case for the same period. Further declines in emissions are shown in the latter half of the forecast due to coal unit requirements to meet BATEA levels.

Figure 8 shows the impact of the proposed framework on mercury emissions, as modelled for the team in its optimized scenario 1. Mercury emissions in scenario 1 fall well below the reference case in 2009, which is the year the policy comes into effect. Mercury emissions fall by roughly half as a result of the policy. Significant reductions are also observed in 2018 when Sundance 1 and 2 retire; minor reductions are seen in 2014 and 2016 after the retirements of Battle River 3 and 4, respectively. A co-benefit of installing mercury control technology is a reduction in primary particulate matter (see Figure 9).

Figure 8: Predicted Impact of the Framework on Mercury Emissions

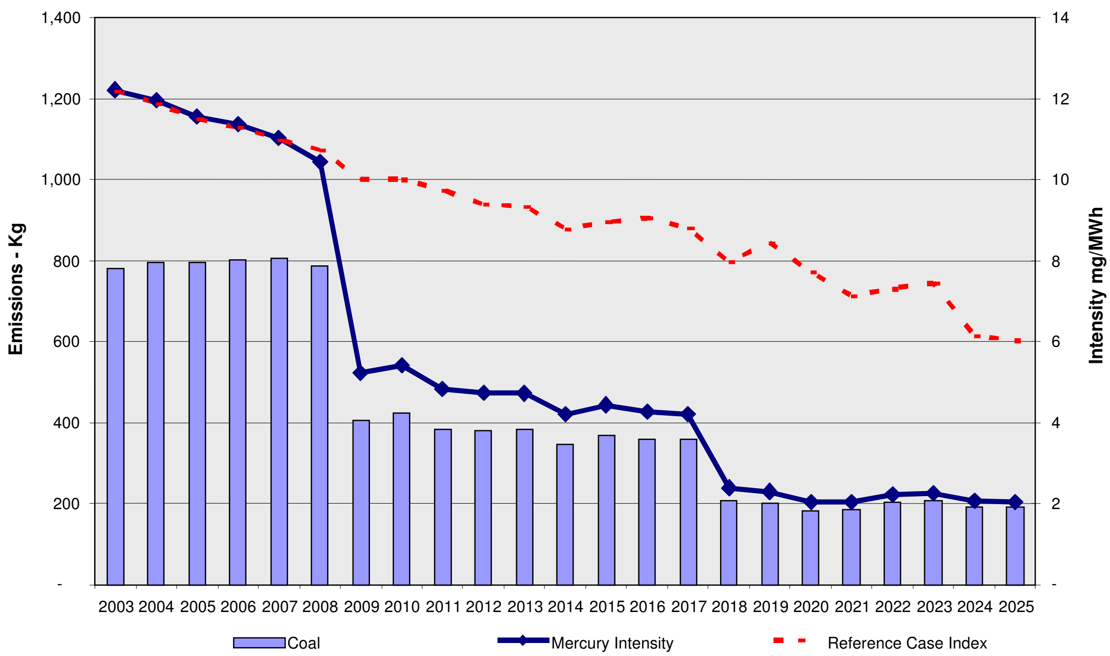
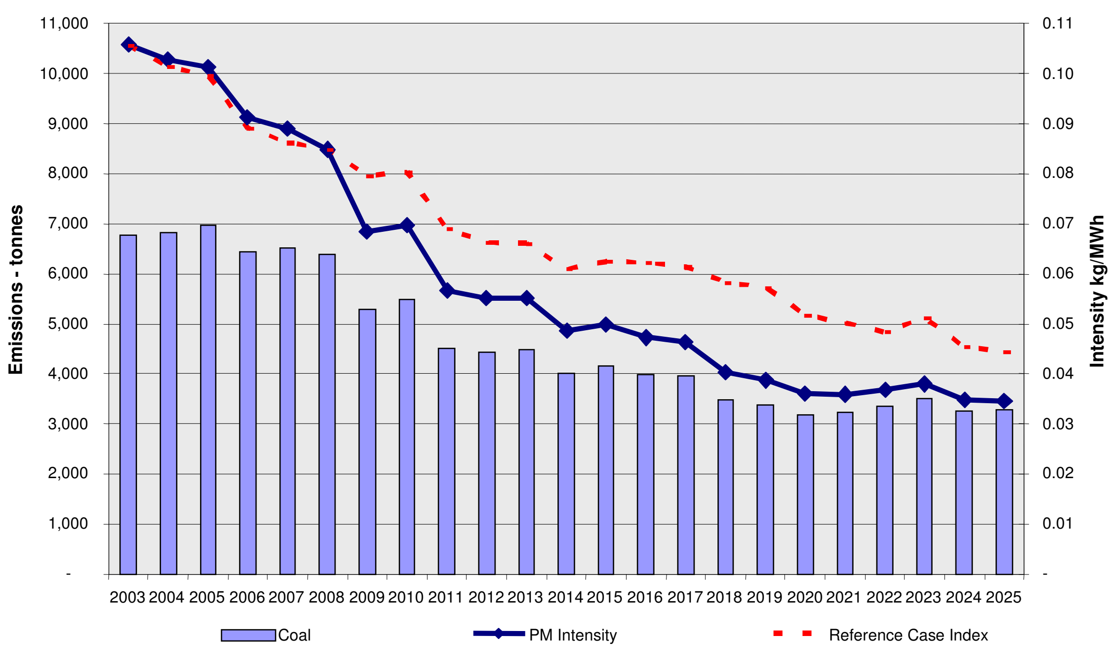


Figure 9 shows the impact of the proposed framework on emissions of primary particulate matter, as modelled for the team in its optimized scenario 1.

Figure 9: Predicted Impact of the Framework on Emissions of Primary Particulate Matter



Emissions of primary particulate matter fall as a co-benefit of the installation of mercury control, dropping dramatically in 2009 when the policy is enacted, just as mercury emissions did. There is a further reduction in 2011 as a result of the retirement of Wabamun 4, which was not quite as obvious in the mercury graph. Wabamun 4 retires in both the reference case and optimized scenario 1.

Figure 10 shows the impact of the proposed framework on greenhouse gas emissions, as modelled for the team in its optimized scenario 1. Greenhouse gas emissions are presented as gross emissions, which are defined as all the greenhouse gas emissions that physically occur as a result of generating electricity in Alberta. As such, greenhouse gas offsets such as those associated with Genesee 3 are not removed from the graph. The solid dark (blue) line in Figure 10 represents the target outlined in the policy framework. As the figure illustrates, the electricity industry exceeds the emission target from 2010 through 2013. In 2010, the industry is required to purchase offsets to meet the sector intensity target. The share of this reduction burden was distributed equally on a percentage basis across all units. However, by 2014, the industry will meet the targets without any significant purchases due to an overall improvement in the sector's intensity.

Figure 10: Predicted Impact of the Framework on Greenhouse Gas Emissions

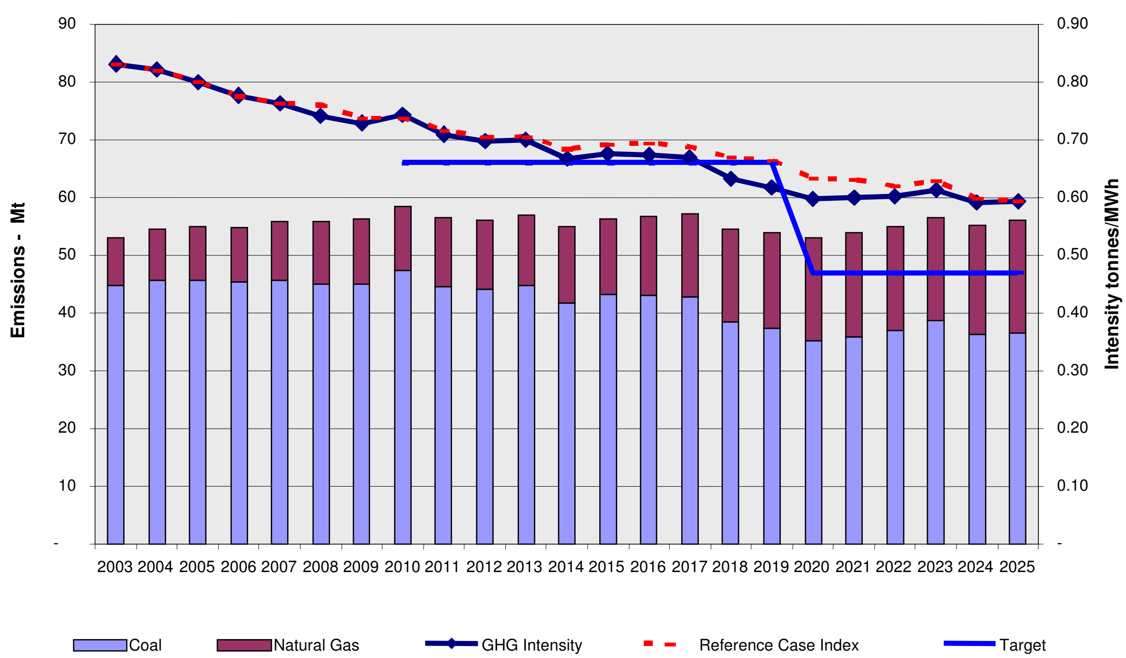


Table 4: Predicted Impact of the EPT's Management Framework on Emissions from Gas-Fired Generating Units Larger than 100 MW

Facility	Year built	Year BATEA must be installed (by Dec. 31)[a]	Year NOx and SO_2 limit to be applied (by Dec. 31)	Calculated NO_2 emissions at current intensity and operating capacity (tonnes)	NO_2 emissions based on new limit (tonnes) *Assumes installation of SCRs[b] for coal and Low NOx burners for gas*	Calculated CO_2 emissions at current intensity and operating capacity (tonnes)
					0.30 kg/MWh	
Muskeg River	2002	2042	2032	369.92	369.92	727,505
Joffre #1	2000	2040	2030	837.53	837.53	642,103
TransAlta/Air Liquide	1999	2039	2029	282.68	282.68	414,603
EnCana #1	2001	2041	2031	186.57	186.57	248,760
Nexen Inc #1	2001	2041	2031	161.10	161.10	214,800
Mahkeses Central Plant	2002	2042	2032	352.85	352.85	294,040
Suncor #1	2000	2040	2030	3,688.48	837.66	1,340,249
Syncrude #1	1999	2039	2029	1,297.13	778.28	700,450
Clover Bar #1	1970	2010	2010	137.79	6.89	33,215
Clover Bar #2	1973	2013	2010	310.04	15.50	73,125
Clover Bar #3	1977	2017	2010	241.14	12.06	56,029
Clover Bar #4	1979	2019	2010	378.94	18.95	87,127
ATCO/Shell Scotford (Upgrader)	2003	2043	2033	313.52	313.52	239,319
Calpine Energy Centre	2003	2043	2033	199.36	220.53	652,778
TCP PetroCan McKay River	2003	2043	2033	392.62	392.62	327,186
Hunt Power	2005	2045	2035	788.48	328.53	998,740
Opti Canada	2006	2046	2036	473.04	473.04	394,200
AES Merchant	2008	2048	2038	985.18	410.49	1,346,419
Opti Canada	2008	2048	2038	483.55	483.55	402,960
Syncrude	1978	2018	2008	3,252.15	162.61	543,759

[a] Consistent with recommendation 11, units that declare themselves peaking units and operate below the recommended cap, may continue to operate for an additional 20 years, at which time BATEA must be installed.

[b] SCR = Selective Catalytic Reduction technology, which uses ammonia and a catalyst to convert NOx to N_2.

Table 5: Predicted Impact of the EPT's Management Framework on Emissions from Major Coal-Fired Generating Units

Facility	Year built	Year BATEA must be installed	Year NOx and SO_2 limit to be applied	Calculated NO_2 emissions at current intensity and operating capacity (tonnes)	NO_2 emissions based on new limit (tonnes) *Assumes installation of SCRs for coal and Low NOx burners for gas*	Calculated CO_2 emissions at current intensity and operating capacity (tonnes)	Calculated SO_2 emissions at current intensity and operating capacity (tonnes)	SO_2 emissions based on new limit (tonnes) *Assumes installation of SDAs*	Current mercury emissions (kg/year)	New mercury emissions (kg/year) *Assumes installation of activated carbon and a fabric filter*	Current PM emissions (tonnes)	PM emissions based on new limit *Assumes installation of a fabric filter*	Controls currently installed
					0.69 kg/MWh			0.80 kg/MWh				0.095 kg/MWh	
Genesee 3 (estimated)	2005	2055	2015	4,559	2,666	3,283,686	6,567	3,091	42.53	29.51	367.00	367.00	FF
H.R. Milner	1972	2022	2012	1,080	532	1,033,293	3,084	617	4.80	4.80	624.60	73.26	FF
Battle River 3	1969	2019	2013	1,737	749	1,183,016	3,907	868	11.85	3.51	249.63	103.11	ESP
Battle River 4	1975	2025	2015	1,810	781	1,233,031	4,072	905	12.35	3.66	260.18	107.47	ESP
Sundance 1	1970	2020	2017	2,950	1,272	1,954,553	3,688	1,475	34.41	19.31	202.83	175.17	ESP
Sundance 2	1973	2023	2017	3,303	1,424	2,188,151	4,129	1,651	38.53	19.31	227.07	196.11	ESP
Sundance 3	1976	2026	2020	4,424	1,908	2,903,210	5,530	2,212	51.50	23.31	304.15	262.67	ESP
Sundance 4	1977	2027	2020	4,480	1,932	2,940,200	5,600	2,240	52.16	23.31	308.02	266.02	ESP
Sundance 5	1978	2028	2020	4,517	1,948	2,851,395	5,646	2,259	52.69	25.09	310.55	268.20	ESP
Sundance 6	1980	2030	2020	5,237	2,259	3,306,115	6,547	2,619	61.09	25.09	360.07	310.97	ESP
Battle River 5	1981	2031	2021	4,617	1,991	3,145,505	10,389	2,309	31.51	9.34	663.73	274.15	ESP
Keephills 1	1983	2033	2023	5,951	2,161	3,038,249	5,638	2,506	51.84	18.50	344.54	297.56	ESP
Keephills 2	1984	2034	2024	6,067	2,203	3,097,557	5,748	2,555	52.85	20.65	351.27	303.37	ESP
Sheerness 1	1986	2036	2026	5,504	2,110	3,241,458	15,290	2,446	36.00	9.66	397.54	290.51	ESP
Genesee 1	1989	2039	2029	6,469	2,126	2,803,259	6,469	2,464	41.28	11.36	431.27	292.65	ESP
Sheerness 2	1990	2040	2030	5,460	2,093	3,215,201	15,166	2,427	36.00	9.66	394.32	288.15	ESP
Genesee 2	1994	2044	2034	6,593	2,166	2,857,009	6,593	2,512	42.07	11.57	439.54	298.26	ESP
Wabamun 1	1958	2010	N/A	902	346	651,115	1,452	401	9.66	0.00	225.39	47.58	ESP
Wabamun 2	1956	2010	N/A	827	317	596,965	1,332	367	8.86	0.00	206.64	43.62	ESP
Wabamun 3	1962	2010	N/A	1,768	678	1,276,587	2,848	786	18.95	0.00	441.90	93.29	ESP
Wabamun 4	1968	2010	N/A	3,809	1,460	2,750,806	6,136	1,693	40.82	8.83	952.20	201.02	ESP

SCR = Selective Catalytic Reduction technology, which uses ammonia and a catalyst to convert NOx to N_2.
SDA = Spray Dry Absorber technology, which uses a lime slurry and contact vessel to convert SO_2 to $CaSO_4$.
FF = Fabric Filters ESP = Electrostatic Precipitators

6.6 Five-Year Review

The team agreed that the BATEA level and other components of the management framework should be reviewed on a regular basis using a multi-stakeholder process. Alberta Environment's ten-year approval process for licence renewal would still exist and be separate from the recommended Five-Year Review but could be used to apply the BATEA limit requirements.

Recommendation 29: Five-Year Review

The EPT recommends that:

Alberta Environment lead, in consultation with Alberta Energy and other regulatory authorities, the establishment of a formal process, to be undertaken every five years, to review the following elements of the emissions management framework:

1. a technology review to identify the BATEA emission limit standards and corresponding deemed credit threshold for new thermal generation units, including new peaking units;[47]
2. the air emission substances subject to limits or formal management, including looking at existing List 2 and possible new substances;
3. co-benefits for priority substances and List 2 substances;
4. economic and environmental triggers as defined by recommendations 34 and 35;
5. additional information that illustrates potential health effects associated with emissions from the electricity sector; and
6. continuous improvement. With each Five-Year Review, the electricity sector will provide a continuous improvement report that summarizes action taken during the past five years. The report will also identify goals for further continuous improvement during the next five-year period, in particular with respect to the priority substances emitted by existing units. This report will be reviewed and discussed as part of the Five-Year Review process. Beginning with the second Five-Year Review (2013), upon reviewing system performance relative to the previous continuous improvement goal statements, the multi-stakeholder team can propose, where appropriate, recommendations for modifications to the framework that result in improved opportunities for supporting continuous improvement efforts.

This review should involve a multi-stakeholder group that:

a) consists of representatives from industry, government, non-government organizations and communities with an interest in the electricity sector;
b) conducts an initial scoping to determine which if any of the elements identified in the review process described in the above recommendation warrant a detailed review, and either recommends that no further work is necessary or undertakes a detailed review of those elements and makes recommendations on them;
c) has access to the resources necessary to obtain the information and technical advice needed to complete its review;
d) uses a consensus decision-making process; and
e) completes its review and provides its recommendations to Alberta Environment within 12 months of the group being formed.

The review process entails two steps. Step one is an initial assessment and development of forecasts by one or more consultants to determine if a full review is triggered, with particular reference to the environmental and health factors noted in recommendation 34 and the economic factors noted in recommendation 35. If there is no new information on technology and there are no concerns arising from these factors, then a full review would

[47] See section 6.1 for a fuller discussion.

not be necessary. If a full review is needed, it would be undertaken by a broader range of stakeholders as described in the second part of recommendation 29. Under federal guidelines, a technology review will be done on a regular basis and, to the extent possible, Alberta should try to coordinate and take advantage of the federal review and any other review processes (e.g., U.S. Environmental Protection Agency).

Recommendation 30: Timing of the Five-Year Review

Given that this recommended framework will come into effect on January 1, 2006, the next BATEA levels would be effective January 1, 2011. Adequate lead time is required to determine what these new levels should be, so the EPT recommends that

> The first Five-Year Review commence no later than April 1, 2008 so that new BATEA levels can be identified well in advance of the January 1, 2011 effective date.

Recommendation 31: Responsibility for Implementing the Outcome of the Five-Year Reviews

Alberta Environment will be responsible for addressing the outcome of the Five-Year Reviews. The EPT recommends that

> Alberta Environment incorporate all consensus recommendations from each Five-Year Review into the existing management framework.

6.7 Continuous Improvement

After considering a number of approaches to continuous improvement, the team agreed to add a specific element to the Five-Year Review (see recommendation 29) in which the electricity sector will report on continuous improvement activities undertaken during the previous five years and identify goals for the next five-year period to be considered by the review team. The team also agreed to focus the continuous improvement components of its framework on performance improvements for the electricity generation system as a whole. Localized issues that may arise in relation to individual units are addressed through other mechanisms in the framework.

Modelling done for the team predicts a significant overall reduction in emissions between 2003 and 2025 as older units shut down. The management framework is expected to contribute to continuous improvement in the following ways:

- There will be a regular review and updating of BATEA levels for new units.
- There will be a regular review and communication of opportunities for existing units. Further, the availability of emission reduction credits will create an economic incentive to reduce emissions further and faster than might otherwise occur.

The team also has an expectation that cost-effective continuous improvement measures will occur as part of normal good business practice.

6.8 Identifying and Addressing Hotspots

It was recognized that a sector emission management approach, as opposed to a facility-by-facility approach, might not specifically protect against hotspots. To address this issue the team defined "hotspots" and recommended additional emission management actions that should be taken if a hotspot is identified. The intent is to ensure that, as necessary, the management framework is supplemented by other actions when there are local air quality issues related to electricity generation emissions either alone or in combination with other types of emissions.

Recommendation 32: Identifying Hotspots

The EPT recommends:

> For the purposes of this management framework, that an area will be defined as a hotspot if, due to its location relative to, or its proximity to, one or more electricity generation facilities, one of a, b, or c applies:
>
> a) It is an area where Alberta ambient air quality guidelines have been, or are projected to be, exceeded on an ongoing or repeated basis. It is understood that the existing mechanism used by regulatory agencies to respond to exceedances of ambient air quality guidelines will be maintained. Projected exceedances of emissions will be determined in one of two ways. For a new unit, emission projections and dispersion modelling will be done by the proponent as part of the environmental impact assessment process, and subjected to review by regulatory authorities. For existing units, ambient air quality monitoring, possibly supplemented by dispersion modelling, will be used. Emphasis should be placed on ambient air monitoring in areas where there is greater potential for hotspot issues; for example, where there is a large number of emitters and/or there are large amounts of emissions. Where appropriate, timely actions should be taken to address any gaps that may exist in ambient air monitoring systems.
>
> b) It is an area that, under the Acid Deposition Management Framework or the PM and Ozone Management Framework, meets or exceeds the trigger level that requires emissions reduction action under a management plan (see recommendation 33).
>
> c) The available peer-reviewed scientific information and/or risk-based assessment evidence indicates that electricity generation-related air emissions, either alone, or in combination with other emission sources, are contributing to or are projected to contribute to, adverse health or environmental outcomes. The precautionary principle will apply when this circumstance arises; the precautionary principle states "Where there are threats of serious or irreversible damage, lack of full scientific certainty shall not be used as a reason for postponing cost-effective measures to prevent environmental degradation."[48] The precautionary principle is endorsed by Canada and Alberta in the Canada-wide Environmental Standards sub-agreement of the Harmonization Accord, which specifies that a lack of scientific certainty shall not be used as a reason to postpone the development and implementation of standards.

[48] Principle 15 of the Rio Declaration, agreed to by Canada and 178 other nations during the 1992 United Nations Conference on Environment and Development; http://www.unep.org/Documents/Default.asp?DocumentID=78&ArticleID=1163 .

Recommendation 33: Addressing Hotspots

The team further agreed that a process is required to resolve hotspots in a timely fashion, and therefore recommends that the following process be followed in the event a hotspot is identified:

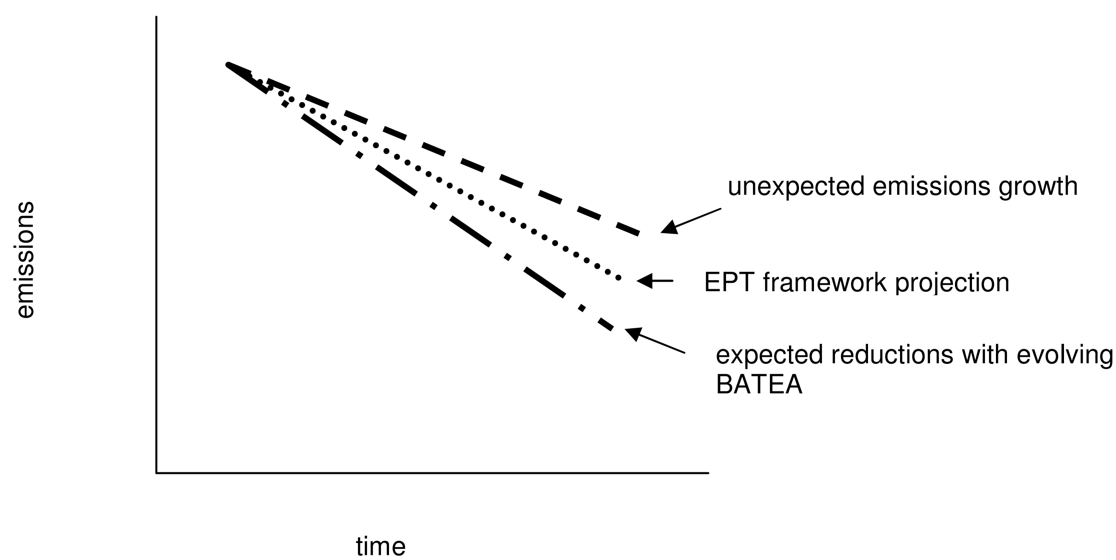
- Where a framework for dealing with a specific type of hotspot exists (e.g., PM and Ozone framework or Acid Deposition framework) that it be implemented as designed.
- Where a framework does not exist for dealing with a specific type of hotspot, that the following steps be taken:
  - A multi-stakeholder team, consisting of representatives from industry, government, non-government organizations and communities with an interest in the electricity sector and under the leadership of Alberta Environment, be formed to develop and recommend a timely and cost-effective plan to resolve the hotspot as quickly as possible.
  - Alberta Environment use the EPT framework, legislation, standards and approvals as appropriate to implement the plan.
  - When a hotspot has been identified, an economic, health and environmental analysis will be part of the plan developed to address it.

It was understood that any plans or actions related to a hotspot would be factored into the next Five-Year Review.

6.9 Emissions Growth Review Trigger

Concern has been expressed about emissions associated with significant new growth in electricity generation, whether for domestic use or export. At the same time, there is a strong desire on the part of the Alberta government not to impose any undue constraints on new growth in the electricity sector. Based on projections available to it, the EPT does not regard emissions from new growth as a major issue in the foreseeable future due to improvements in technology that are recommended for implementation by future Five-Year Reviews (see Figure 11). However, the impact on new growth of the transmission policy changes announced by the Alberta government in May 2003 is not yet known.

Figure 11: Expected Emissions Trends



Recommendation 34: Emissions Growth Review Trigger

If emissions from the electricity generation sector increase more rapidly than expected (the top line in Figure 11), a provision is needed to revisit the framework to ensure that health and environmental factors are addressed. The EPT recommends that

> During the Five-Year Review, if the updated emissions forecast for any of NOx, SO_2, PM and mercury is 15% higher for a five-year period than projected in the previous Five-Year Review, the management framework elements addressing that substance should be reviewed.

This recommendation acts as an "environmental safety net," allowing the framework to be re-opened and adjusted if the assumptions on which it is based change dramatically. It would enable trends to be identified early enough that appropriate action could be taken. There was discussion on whether the baseline emission forecast should include emissions from the proposed Centennial plant. It was agreed that a 15% variance from the baseline forecast used for the framework would accommodate emissions growth from the addition of this facility to the provincial generation supply.

6.10 Economic Review Trigger

The EPT agreed that there was some uncertainty regarding the price forecasts due to certain risks. For example, the impact of large amounts of new co-generation from the oil sands along with possible lower gas prices due to new supplies coming onto the market between 2010 and 2015 have raised concerns among some stakeholders that electricity prices could be significantly depressed for that period, affecting the viability of PPAs. The EPT agreed that, just as the proposed framework has a provision in case emissions rise significantly above what the framework anticipates, it should also have a provision in the event that the economic assumptions on which the framework was based change significantly.

Recommendation 35: Economic Review Trigger

The EPT recommends that

> During the Five-Year Review, if the economic assumptions underlying the framework are significantly different so as to adversely affect the viability of the electricity sector, the framework will be reviewed.

This recommendation addresses aspects of the framework that affect electricity prices and would serve as an economic trigger for reviewing the framework. The modelling results, summarized in section 15, indicate that natural gas price increases comprise a major portion of the total electricity price increase between the reference case (which assumes that demand growth in electricity continues on its present course, driven largely by economic activity) and the optimized cases (which assume that an emission management framework is adopted in Alberta and elsewhere, causing a significant increase in the use of natural gas as a primary fuel).

7 Co-benefits of the Recommended Emissions Management Framework

The air emissions management framework being proposed for sulphur dioxide, nitrogen oxides, mercury, greenhouse gases and particulate matter will have co-benefits in terms of reducing the emissions of other substances associated with fossil fuel combustion. The following is a summary of these co-benefits in terms of reduction in the List 2 substances identified by the Prioritization Subgroup.

Emissions from Coal-Fired Units

Nitrogen oxides

Proposed controls for NOx: Selective catalytic reduction (SCR)

Co-benefits

1. Ozone and $PM_{2.5}$ precursors will be controlled to a high level (i.e., largely controlled).

Due to the ammonia slip associated with the use of an SCR unit, emissions of ammonia will increase to a small extent.

Sulphur dioxide

Proposed controls for SO_2: Dry flue gas desulphurisation (dry FGD)

Co-benefits

1. Acid gases (HCl and HF) will be controlled to a high level.
2. $PM_{2.5}$ precursors will also be controlled to a high level.
3. Additional co-benefits from the application of dry FGD (usually installed with a fabric filter) have not been assigned to this particular management option.

Mercury

Proposed controls for mercury: activated carbon and fabric filters or equivalent

Co-benefits

1. Emissions of all metals and metalloids will be controlled to a high level, with the exception of arsenic, selenium, and radionuclides, which will be controlled to a medium level.
2. Any organics emitted will be controlled to a medium level with the exception of PAHs, which will be controlled to a high level.
3. Dioxins and furans will be controlled to a high level.
4. Emissions of particulates will be moderately reduced and emissions of primary particulate matter (one of the five priority substances being managed) will also be further reduced from current control levels.

All emissions

Proposed improvements in generation efficiency: Supercritical boiler technology

Co-benefits

1. Emissions of all List 2 substances will be reduced in direct proportion to the increase in efficiency achieved through application of this technology.

Emissions from Gas-Fired Units

Nitrogen oxides

Proposed controls for NOx: Dry low NOx combustors/burners (DLN or DLE)

Co-benefits

1. Ozone and $PM_{2.5}$ precursors will be controlled to a high level with the application of DLN/DLE but not quite as high as with post combustion controls such as SCR.

Optional controls for NOx: Selective catalytic reduction (SCR)

Co-benefits

1. Ozone and $PM_{2.5}$ precursors will be controlled to a high level.

Due to the ammonia slip associated with the use of an SCR unit, emissions of ammonia will increase to a small extent.

All Emissions

Proposed improvements in turbine generation efficiency: Output-based emission requirements

Co-benefits

1. Emissions of ozone and $PM_{2.5}$ precursors will be reduced in direct proportion to the increase in efficiency achieved through improved turbine design.

Renewables Target and Energy Efficiency Improvements

Improvements in fleet greenhouse gas emission intensity*:* The increased amount of renewable energy generation and improvements in energy efficiency

Co-Benefits: Since renewables have no appreciable direct emissions of List 2 substances, increases in renewable electricity generation or in efficiency improvements will result in reduced sector emissions of all substances on an intensity basis.

8 Monitoring, Reporting and Compliance Assurance

In discussing this part of its task, the EPT determined that a review of the existing monitoring, reporting and compliance assurance processes for air emissions and emission limits for the electricity sector would be desirable. This section summarizes a longer report that was prepared as background information.[49]

8.1 Introduction

Power plants producing steam or thermal electrical power greater than a rated production output of 1 MW under peak load require an approval from Alberta Environment pursuant to the *Environmental Protection and Enhancement Act*. The facility approval addresses source and ambient monitoring. It both specifies the emission limits for major emission sources (limits that typically restrict the rates of emission of NOx, SO_2, particulate matter and visible emissions), and also specifies what air emission parameters are to be monitored and what monitoring methods are to be used. The source monitoring data is used to establish compliance with the limits in the approval. The approval holder is required to report the monitoring data to Alberta Environment on a frequency stated in the approval – usually monthly and/or annually.

To assess the impact of the emissions from the stack on ambient air quality, the approval holder is also required to maintain and operate ambient air quality station(s) to measure continuously the concentrations of NO_2, SO_2, and total suspended particulate matter in the immediate area of the plant. A certain number of static exposure stations are located around facilities to gauge the cumulative impact of the emissions on sulphation (SO_2 impact) and the total dustfall.

8.2 Monitoring Documents

The current regulatory framework reflects a command and control approach using approvals as the mechanism for specifying emission limits, and monitoring and reporting requirements to establish compliance with the limits. The approval also relies on and refers to Alberta Environment documents such as codes and directives that stipulate how monitoring and reporting requirements are to be fulfilled to achieve compliance. The following documents are referenced in approvals and outline the details and specifics of what is required to comply with monitoring requirements:

a) the *Alberta Stack Sampling Code*;
b) the *Methods Manual for Chemical Analysis of Atmospheric Pollutants*,
c) the *Air Monitoring Directive*, and
d) the *Continuous Emissions Monitoring System Code*

8.3 Current Regulatory Requirements

8.3.1 Monitoring

Current regulatory requirements address both source and ambient monitoring. Coal-fired units are required to monitor continuously for NOx, SO_2, in-stack opacity, temperature and

[49] The Monitoring, Reporting and Compliance Assurance background report is available online at http://www.casahome.org/electricity/eptdocs.asp

gas flow rate. Gas-fired units above 25 MW are required to have NOx monitors, and temperature and flow rate measurements. Because the fuel gas used in gas-fired units contains only trace quantities of sulphur, SO_2 monitoring is not required. Biomass-fired units have CO, NOx and in-stack opacity monitoring requirements.

In addition to continuous monitoring, stack gas emissions must be sampled manually once or twice a year, depending on facility size; this is typically done by a third party consultant. The samples collected are analysed in accredited laboratories for NOx, SO_2 and particulate matter depending on the fuel type. The results from manual stack surveys can be used to check the accuracy of the continuous monitors and to establish compliance with the emission limits stated in the facility approval. In some cases, additional parameters must be tested, such as trace heavy metals, mercury or other substances of possible concern.

Ambient air quality monitoring stations continuously monitor the impact of emissions on air quality downwind from a facility. Equipment in these stations includes monitors for NO_2, SO_2, and total suspended particulate. Sulphation stations are also used to determine the cumulative exposure to SO_2 and other sulphur compounds. Dustfall stations are containers that collect suspended particulate matter, such as fly ash, that falls from the air.

8.3.2 Reporting

The facility approval specifies what monitoring information is to be reported, to whom and when. Depending on the fuel type, power plant approval holders are typically required to report:

- continuous monitoring data, once a month;
- manual stack survey results within 30 days after the survey was conducted;
- ambient air quality monitoring results, monthly;
- power production data, monthly;
- total mass emissions, annually,
- CO_2 emissions, annually (proposed);
- coal analysis, monthly;
- mercury deposition and other study results, as stated in the approval; and
- an annual summary of all monitoring.

Power production data submitted by approval holders is held in confidence by Alberta Environment.

8.3.3 Compliance Assurance

Alberta Environment has compliance assurance principles that establish the approach to ensure industry meets established performance requirements. Alberta Environment's monitoring and reporting requirements are intended to ensure reliable and representative information that can be used for compliance purposes. For example, where chemical analysis is involved, methods of analysis and appropriate quality assurance and quality control procedures ensure that the results are valid.

Alberta Environment policy specifies that all analytical laboratory data submitted to the department be from laboratories accredited by the Canadian Association for Environmental Analytical Laboratories or the Standards Council of Canada for analysis of the measured parameters. This policy ensures that environmental monitoring data is from credible laboratories and is subjected to proper quality assurance and quality control procedures.

Reporting protocols are contained in the Air Monitoring Directive. Alberta Environment is now reviewing and revising the directive to incorporate the requirements in a more comprehensive document entitled "Monitoring and Reporting Directive."

Mercury emissions from power plants are not currently regulated by Alberta but a Canada-wide Standard for mercury is being developed.[50] The recent *Environmental Protection and Enhancement Act* approval[51] for the expansion of the Genesee 3 plant requires that the company submit a "Mercury Assessment Program" to quantify mercury emissions from the plant and that it assess the ecological impacts of these emissions. These requirements have also been added to the TransAlta facilities in the Lake Wabamun area. The Alberta coal-fired power plants have, through a memorandum of understanding with Alberta Environment, initiated a comprehensive mercury sampling and monitoring program at all plants to better understand the quantities, speciation and behaviour of mercury during coal combustion. It is expected that mercury emission standards and related monitoring requirements will be addressed in future approvals for coal-fired units.

There was agreement that a key objective of the proposed new management regime is to reward or encourage action by the electricity sector to reduce air emissions below prescribed levels (i.e., beyond compliance). At the same time, it will be important for the integrity of the system to also incorporate mechanisms to deter non-compliance.

Recommendation 36: Current Compliance Principles

The EPT is of the view that Alberta Environment's current compliance principles[52] for managing emissions from the electricity sector are adequate and therefore recommends that

> Alberta Environment and the electricity sector continue to use the current compliance principles for the management of emissions from thermal generation units, and that these principles also be applied to mercury emissions from coal-fired units. Consideration should be given to reviewing current principles to ensure they reflect the new emission management mechanisms and the intent to reward performance "beyond compliance" or to deter non-compliance.

The team recognized that the present monitoring system for NOx and SO_2 provides a solid base on which to build an expanded system capable of supporting an emissions trading system for these substances.

Recommendation 37: SO_2 Monitoring in Support of an Emissions Trading System

The EPT recommends that

> Alberta Environment and the electricity sector build upon the existing continuous emission monitoring program for SO_2 to develop an effective SO_2 monitoring and tracking system that can support a SO_2 emissions trading system.

[50] See section 4.2 of this report for more background on mercury policy in Canada.

[51] EPEA Approval No. 773-01-05.

[52] These principles are available online at http://www3.gov.ab.ca/env/protenf/documents/CAP_Final_2000.pdf

Recommendation 38: NOx Monitoring in Support of an Emissions Trading System

The EPT recommends that

That Alberta Environment and the electricity sector build upon the existing continuous emission monitoring program for NOx to develop an effective NOx monitoring and tracking system that can support a NOx emissions trading system.

Public Availability of Monitoring Information

Public access to monitoring information contributes to openness and transparency. Such information has been accessible in the past. The team is hopeful that this approach on the part of Alberta Environment and the electricity sector will continue, and makes the following recommendations with respect to public availability of monitoring information for SO_2, NOx, primary particulate matter and mercury.

Recommendation 39: Public Availability of SO_2 and NOx Monitoring Data

The EPT recommends that

Alberta Environment and the electricity sector continue to ensure that SO_2 and NOx emission monitoring data from electricity generation units remains available to the public.

Recommendation 40: Public Availability of SO_2 Emission Trading Information

The EPT recommends that

a) Alberta Environment and the electricity sector ensure that information on SO_2 emission trading associated with achieving the SO_2 emission management targets in these recommendations is available to the public.
b) Alberta Environment require, by regulation, approval or other legal means, that coal-fired power plants report on the creation and use of SO_2 credits and that this information be public.

Recommendation 41: Public Availability of NOx Emission Trading Information

The EPT recommends that

a) Alberta Environment and the electricity sector ensure that information on NOx emission trading associated with achieving the NOx emission management targets in these recommendations is available to the public.
b) Alberta Environment require, by regulation, approval or other legal means, that thermal power plants report on the creation and use of NOx credits and that this information be public.

Recommendation 42: Public Availability of Primary PM Monitoring Data

The EPT recommends that

Alberta Environment and the electricity sector continue to ensure that the opacity and stack emission information on primary particulate matter from coal-fired power plants is available to the public upon request.

Recommendation 43: Public Availability of Mercury Monitoring Data

The EPT recommends that

> Alberta Environment and the electricity sector ensure that mercury emission data from coal-fired power plants is available to the public upon request in the same manner as data for regulated parameters is currently available through the *Environmental Protection and Enhancement Act.*

Recommendation 44: Measuring Mercury Emissions

Given the expressed interest in reducing mercury emissions from the electricity sector and the need for reliable methodology for measuring such emissions, the EPT recommends that

> Alberta Environment establish a multi-stakeholder process to evaluate economically-viable mercury monitoring methodologies and adopt a methodology that ensures the accurate measurement of mercury emissions.

Recommendation 45: Monitoring for Primary Particulate Matter

The EPT recognizes the value of the present monitoring approach for primary particulate matter and therefore recommends that

> Alberta Environment and the electricity sector continue to use continuous opacity measurement and limits as the surrogate for primary particulate matter control, and periodic stack testing requirements as verification that the emission limit for primary particulate matter is being met.

Recommendation 46: Monitoring and Reporting on Greenhouse Gases

As Alberta proceeds with its climate change strategy and as Canada considers how it will meet its commitments under the Kyoto Protocol, the monitoring and reporting of greenhouse gases becomes an increasingly important issue. Many companies have experience reporting their greenhouse gas emissions as part of the Voluntary Challenge and Registry program. Whatever mechanism is put in place provincially and federally to achieve greenhouse gas management targets, the tracking of these emissions will be a fundamental underpinning. Therefore, the EPT recommends that

> Alberta Environment and the electricity sector continue development of a monitoring and reporting system for greenhouse gas emissions from the electricity sector that provides reliable emission data, and that every effort be made to ensure that the Alberta system is compatible with any national or federal system.

Recommendation 47: Tracking, Reporting and Information-Sharing Principles for Greenhouse Gases

The EPT recommends that

> For any sectoral agreement with the Alberta electricity sector, the Alberta government and the electricity sector incorporate tracking, reporting and information sharing principles for greenhouse gases, consistent with those prescribed for other emissions for the sector.

9 Enhancing Transparency, Accountability and Public Participation

Air emissions from the Alberta electricity sector are regulated under the *Environmental Protection and Enhancement Act* (EPEA). Bill 37, the *Climate Change and Emissions Management Act*, introduced on April 7, 2003 is intended to strengthen and complement the existing regulatory regime. EPEA and Bill 37, once passed and proclaimed in force, will provide the provincial legislative framework and authority for the establishment and implementation of any management system for air emissions that affect the environment.

The detailed framework for the new approaches being recommended by the EPT has yet to be fully designed and constructed with regulations, rules and procedures. In preparing this new framework, due consideration should be given to, at a minimum, carrying forward rights that are provided by existing legislation such as EPEA.[53]

Some members of the team also suggested that in the design of any detailed framework, consideration be given to what are sometimes referred to as "environmental justice" principles. These principles can be summarized as follows:

- ***Distributional justice*** is a term used to describe the principle that no community or identifiable group of people bear an inequitable burden of actual or potential harm from development or activities. As provided in the CASA principles, all Albertans have an equal right to clean air. Consistent with this principle and that of accountability, decision makers should consider and seek to avoid increased risks to already impacted communities. Equitable consideration should be given to rural and urban populations in siting processes and criteria. Decision-making criteria should consider cumulative effects. Air quality should be managed to meet scientifically based health and environmental guidelines.
- ***Procedural justice*** is a term used to describe the principle that decisions be made through a fair and open process. This includes procedural fairness and the effective ability to participate, through access to the resources necessary to play an active and constructive role in decisions, and the right of affected communities to be involved in all stages of any planning or decision process.
- ***Entitlement*** is consistent with the "precautionary principle" and requires that efforts be made to prevent adverse effects, not merely to remediate or provide for redress after the fact. It includes the principle of intergenerational distributive justice; that is, that development meets the needs of the present without compromising the ability of future generations to meet their own needs.

Opinions varied as to interpretation of some of the terminology and how these principles might be applied and implemented. Stakeholders recognize the need to understand the definitions and implications of adopting or not adopting such principles. More discussion is

[53] See also the report prepared for use by the team by Linda F. Duncan and Keri Berringer, *A Review of Legal Rights and Obligations Related to Transparency, Public Participation, and Accountability for Compliance in Current and Proposed Regimes for the Management of Air Emissions from the Alberta Electricity Sector,* available online at http://www.casahome.org/electricity/eptdocs.asp.

needed on these issues before some stakeholders would consider their possible application to an air emissions management framework. Nevertheless, there was agreement on the need for transparency, public participation and accountability to be applied to the electricity sector. Therefore, the EPT puts forward the following recommendations for consideration when adopting any new emission management system for the electricity sector in Alberta.

Recommendation 48: Public Comment on Emission Guidelines and Standards

Communities, whose concerns and potential impacts are identified with electricity generating projects, should be informed and engaged in the development of any air emission guidelines and standards for the electricity sector. The EPT recommends that

> Alberta Environment implement a mechanism to ensure that potentially affected communities have a reasonable opportunity to comment on any air emission guidelines and standards for the electricity sector and, as appropriate, have reasonable access to funding support and technical experts to enable their informed and constructive participation.

Recommendation 49: Public Input to Sectoral and Other Industry-Specific Agreements

Concerns have been expressed that current and proposed laws are silent on any rights or opportunities for the public to access or review sectoral or other agreements concerning the management of greenhouse gases or other substances that are negotiated between the government and the electricity sector. The EPT recommends that

> Public input be part of Alberta Environment's approach to the development of the overall framework for both sectoral and other industry specific agreements initiated under any provincial law for the management of air emissions from the electricity sector, with due consideration to any potential application to other sectors. As appropriate, reasonable access should be provided to funding support and technical experts to enable informed and constructive public participation.

Recommendation 50: Public Involvement in Developing any Emissions Trading System

There is a desire on the part of the broader public to be consulted in the design and implementation of any emission trading regime for the management of air emissions from the electricity sector and that specific aspects of the process be made transparent and accountable. The EPT recommends that

> Public input and involvement be part of Alberta Environment's development of any emission trading system including:
>
> a) A process to ensure reasonable opportunity for the public to comment on any proposed regulations, policies, guidelines or other measures to implement any emission trading regime under Bill 37, EPEA or any other provincial law, for the electricity sector.
> b) Providing, as appropriate, the public with reasonable funding support and access to experts to enable their informed and constructive participation in (a) above, and
> c) Incorporating minimum provisions to ensure transparency in the operation and evaluation of the regime.

Recommendation 51: Public Notice on Intergovernmental Agreements

Concern has been expressed regarding the lack of consistent access to processes for negotiating intergovernmental agreements on air emissions standards for the electricity sector. There is a desire for more consistent, timely and ready access to information on existing and proposed related intergovernmental agreements. The EPT recommends that

> Alberta Environment consider providing the public with notice of intent to enter into, and a reasonable opportunity to comment on, any proposed intergovernmental agreement on the management of air emissions from the electricity sector.

Recommendation 52: Public Access to Intergovernmental Agreements

The EPT recommends that

> A public repository be established to enable public access to any intergovernmental agreements relating to the management of air emissions from the electricity sector, including those related to emission objectives, standard setting, monitoring, reporting, and enforcement and compliance.

Recommendation 53: Monitoring, Reporting and Surveillance

Concerns have been expressed about the potential lack of transparency and public accountability for compliance under any new management regime for air emissions for the electricity sector, in particular for emissions trading and credit regimes, sectoral or other industry specific agreements, and industry or private monitoring or audit systems. There is a concern that current rights of access to monitoring and compliance information may be reduced under these more market driven, privatized mechanisms. The EPT recommends that

> For any review of existing and for any proposed new rules and regulations, procedures, accountability structures and capacity needed to monitor and enforce the new management framework for the electricity sector, a public review component be incorporated and include mechanisms to ensure reasonable public accountability and transparency.

Recommendation 54: Transparency

A desire has been expressed that any new management regime for air emissions from the electricity sector ensure continued and ready access to information, including any related guidelines, standards, sectoral agreements, and intergovernmental agreements; emission trading activities, audit and monitoring results, surveillance activities and their outcomes. It is recognized that some limitations on access may be necessary to protect proprietary and confidential information relating to legitimate business interests. The EPT recommends that

> Alberta Environment give to the public ready and timely access to information relating to air emissions from the electricity sectors, subject to necessary access restrictions to ensure protection of proprietary and confidential information relating to legitimate business interests.

10 Renewable and Alternative Energy

Increased use of electricity from zero or low emission sources is one way to reduce emissions from the electricity sector. When wind, solar, hydro, biomass and small "alternative" sources (e.g., small on-site generators using waste heat or gases) displace traditional fossil fuel-fired generation, emissions decrease. Members of the public expressed strong support for renewable and alternative energy during the two sets of meetings held in 2003 and the Electricity Project Team regards the development of these energy sources as a fundamental component of its emissions management approach. For more background, see the report prepared by the Renewable and Alternative Energy Working Group.[54]

Recommendation 55: The Provincial Target for Renewable and Alternative Energy

The Electricity Project Team applauds the Alberta government for showing leadership in its decision to purchase green power for 90% of its electricity needs. This purchase should help stimulate growth in the sector. The Alberta government has also set a goal for "increasing the renewable and alternative energy portion of total provincial electrical energy capacity by 3.5% by 2008."[55] To underscore its support for this policy, the EPT recommends that

> The Alberta government implement, at the very least, the 3.5% target for new renewable and alternative energy referenced in its *Albertans & Climate Change - Taking Action* plan

Recommendation 56: The Basis for the Target for New Renewable and Alternative Energy

The proposed implementation mechanisms affect various parts of the electricity sector, as some mechanisms are specific to particular types of electricity generation. Nevertheless, the EPT recommends that

> Irrespective of the mechanism adopted for its implementation, the Alberta government calculate the 3.5% target for new renewable and alternative energy based on 100% of electric energy sold through the Alberta Power Pool, from Alberta sources.

Recommendation 57: Defining Renewable and Alternative Energy

Various criteria are used to define renewable and alternative energy, and the team was of the view that how it is defined is an important factor in meeting the 3.5% target. The Alberta government's Climate Change Action Plan does not lay out in detail the definition used to decide on the 3.5% target. The EPT agreed on a definition that will achieve the environmental goals stated in the action plan and that is agreeable to the stakeholders involved. Therefore, the EPT recommends that

> The following definition of Renewable and Alternative Energy be adopted by the Alberta government for the purposes of calculating the 3.5% target for new renewable and alternative energy:
>
> Renewable and Alternative Electricity is defined as that which is:
>
> a) Power generated within the province of Alberta; and

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[54] The report of the Renewable and Alternative Energy Working Group is available on request to the CASA office and on the CASA electricity website at http://www.casahome.org/electricity/finalreports.asp.

[55] *Albertans and Climate Change*. *Taking Action*. October 2002. page 34.

b) EcoLogo™ compatible in that it meets the EcoLogo™ criteria for Renewable Low-Impact Electricity, but from facilities that are not necessarily EcoLogo™ certified;

OR

Alternative electricity supplies whose source meets the following criteria:

a) 5 MW or less; and
b) Greenhouse gas intensity less than or equal to natural gas combined cycle (418 kg per MWh).

Projects eligible for the target would be those that begin producing electric energy after December 31, 2001.

Recommendation 58: Calculating the Amount of New Renewable and Alternative Energy Generation

If a target is to be useful, there must be some means of determining if it has been achieved. Agreement on an energy-based method (megawatt-hours) of calculating the actual amount of electricity generation that will be provided by new renewable and alternative energy by the end of 2008 was also reached. The EPT recommends that

The Alberta government use the following energy-based method to calculate new renewable and alternative power:

(Total new renewable and alternative electricity in MWh, as defined in recommendation 57)

Divided by (Total power sold through the Alberta Power Pool in MWh)

Recommendation 59: Mechanisms for Achieving the Renewable and Alternative Energy Target

A key task given to the CASA EPT was to determine a method for implementing the renewable and alternative energy target. Various mechanisms are available to reduce the cost and increase the uptake of renewable and alternative energy. To encourage the use of green power, the EPT recommends that

The Alberta government consider developing a program to implement the mechanisms required to achieve a target of at least 3.5% new renewable and alternative energy by January 1, 2008. These mechanisms may include a “green certificate” program, emissions trading, offset credits, or any other mechanism to incent the use of green power.

Recommendation 60: The Retailer-Based Method for Achieving the Renewable and Alternative Energy Target

A great deal of discussion and negotiation went into finding an implementation approach on which all stakeholders could agree, and the “retailer-based” method was identified as the best option. It allows for flexibility in both the wholesale and retail purchase of power, will assure the development of this sector of Alberta’s electricity industry, and will reduce the emissions caused by electricity generation in Alberta.

With this method, retailers would undertake to include in their electricity portfolio 3.5% of new renewable and alternative power (as defined in recommendation 57) by 2008 and maintain those purchases within their portfolio for a minimum of ten years. “Retailer” is defined in the *Electric Utilities Act*. Retailers could achieve the target through purchasing renewable and alternative power from generators of such power, building new renewable and alternative capacity themselves, purchasing government-recognized certificates equivalent to renewable and alternative generation, or some combination thereof. The purchases of this power would be from a free and competitive market, which would ensure the lowest prices and would drive the price downwards over time.

To allow maximum flexibility for retailers in dealing with the potential cost increases this might entail, they would be free to allocate this 3.5% as their business dictated. Retailers might market some of this amount as premium "green power," some as part of the general mix, and some as "green" certificates. The target would apply to their entire operation, not to each individual customer. For example, if a single large customer (such as a transit company) purchased a large amount of wind power, that company's obligations might be met through one contract, while another retailer might choose to distribute the extra cost evenly among many customers, or might be able to purchase renewable energy from sources that are cost-competitive with other sources.

The EPT recommends that

> The retailer-based method, described above, be the preferred option for achieving the target for additional renewable and alternative energy. The implementation team (see recommendation 64) will be tasked with recommending options to resolve the issues listed below and identifying any additional issues for resolution related to implementing the retailer-based method. The implementation of the retailer-based method is contingent upon the resolution of these issues to the satisfaction of affected stakeholders represented on the implementation team:
>
> - scope of audit process;
> - timely development of a market for green certificates;
> - provisions to allow providers of the Regulated Default Supply Option to flow through the costs associated with meeting the 3.5% target;
> - provisions to ensure retailers that have taken prudent measures to achieve the 3.5% target are not penalized if supply does not materialize in a timely manner; and
> - transitional provisions that take into account previously signed long-term contracts.

A number of important issues remain to be resolved before this method can be implemented. The implementation team noted in recommendation 64 will work to refine the details and recommend options for resolution.

Various other options were also considered to encourage the development of green power. Three of these (production incentives, consumer engagement initiatives, and a solar infrastructure initiative) are described briefly below and more details are available in the full report of the Renewable and Alternative Energy Working Group. More work is needed on these mechanisms, and the team is recommending that they be addressed by an implementation team (recommendation 64).

Production incentives. The federal government's Wind Power Production Incentive (WPPI) and Renewable Energy Deployment Initiative (REDI) programs provide financial incentives to producers and marketers of renewable energy. The Alberta government might consider matching or supplementing these programs, either in the form of tax credits like the U.S. Production Tax Credit or as a cash incentive like WPPI and REDI. These initiatives could be funded directly by the Alberta government or through some form of systems benefit charge. The "Climate Change and Emissions Management Fund" in Alberta's Bill 37 is a potential funding source, but will not be able to provide funding in the short term. If incentives are going to be used it is important that the programs and funding be designed to work in concert with federal initiatives.

Consumer engagement mechanisms. To build consumer demand for renewable and alternative power supplies and provide a financial value for the environmental benefits of them, consumers could receive a cash or tax incentive for purchasing a premium green power product. Such an incentive could be provided though an income or business tax credit for purchases of renewable and alternative energy or through a retailer administered cash rebate. This approach would be compatible with the federal government's "One Tonne Challenge" and would complement such initiatives as the "Teletrips" program being promoted by Climate Change Central. This option does not guarantee a certain delivered energy outcome, but a target (e.g., 3.5%) for the consumer incentive could be established to determine funding levels. This option does not stand alone but is seen as a complement to the implementation of renewable and alternative power.

Solar Infrastructure Initiative. Solar photovoltaic systems, backed with other green power, have been demonstrated to provide heat and electricity in remote sites and are ideal for parks, recreational facilities, campgrounds, pools, and lawn irrigation. They can also work for office buildings and homes. As part of a Solar Infrastructure Initiative, consideration could be given to allowing individuals to claim a tax credit for the cost of solar panels for buildings and homes. With applications such as municipal pools, recreational facilities, campsites, and traffic control equipment, partnerships could be developed with the solar industry, local governments and other agencies and stakeholders to remove barriers, strengthen the demand for solar technologies and support the creation of local, high technology jobs. This proposal would need to be supported by net metering to allow additional cost benefits for individuals and governments taking action.

Recommendation 61: Sectoral Agreements and Green Power

Much of Alberta's electricity is used in industrial sectors, many of which will be negotiating sectoral agreements with the Alberta government. In many cases these companies will have to offset their greenhouse gas emissions. One way this could be done is through the purchase of green power. Therefore, the EPT recommends that

> The Alberta government, in any sectoral agreement negotiations, consider encouraging all purchasers of power to buy at least 3.5% new renewable and alternative electricity, as defined in recommendation 57, as a means of reducing their greenhouse gas emissions.

Recommendation 62: Net Metering and Net Billing

It was recognized that micro-distributed generation will not be widely adopted without some form of net metering or net billing. Net metering is where a single meter runs both forward and backward. Net billing requires two meters or one meter with two registers – one measuring the power that comes in and one measuring the power that goes out. Net metering and net billing allow small players to bank their surplus power into the grid without participating in the Power Pool. To be successful, such a program would need to simplify the interconnection requirements for micro-distributed generation; otherwise the transaction costs would be too high for all but a few very determined people to participate. Net billing could make it possible for power produced and fed into the grid by micro-distributed generation to be sold as premium green power, exportable at a higher price.

Among the present barriers to net metering and net billing are the *Electricity Utilities Act*, section 13 of which requires that all electricity be exchanged through the Power Pool. It has not been possible to get the required approvals from the EUB for net metering. The net billing approach may solve this problem. There has also been some difficulty in getting meters certified for accuracy by Measurement Canada.

Although most distributed generation owners support net metering and net billing, many wire owners are against net metering, but are agreeable to net billing. There are significant territorial and some practical barriers to net metering, and also some practical barriers to net billing. These make implementation difficult unless wire owners are able to pass on the costs to their customer base. Therefore the EPT recommends that

> Alberta Energy undertake a study to identify the technical, legal and financial issues associated with net metering and net billing, including a policy direction for the industry.

Recommendation 63: Infrastructure Needs

The increased generation of renewable and alternative energy envisioned by the Alberta government's target will require a corresponding commitment to providing the infrastructure to support it. This includes land use policies, regulations, EUB policies and procedures for approvals, and transmission capacity in the parts of the province where this power is generated. Additional resources need to be obtained by the Alberta Electric System Operator and those resources focused specifically on helping with system planning and studies and the processing of applications for renewable and alternative energy projects. From the perspective of renewable developers, this is needed to help reduce the time and costs required for interconnection and to allow for proper system planning to ensure greater access for alternative and renewable sources on the Alberta grid. The creation of a position specifically to pursue the goals outlined above and the additional resources needed to fund such a position would be one way to accomplish these important changes.

A generator, no matter how ecologically beneficial, is of limited value without the means of tying the power into the grid. Meeting the Alberta government's target for renewable and alternative energy will require the corresponding infrastructure to be in place, and planning should begin. Therefore, the EPT recommends that

> Alberta Energy and the Alberta Electric System Operator examine the decision-making process for the renewable and alternative energy sector's infrastructure needs, with a view to:
>
> a) ensuring that the process is accessible to the renewable and alternative sector; and
> b) improving the infrastructure for renewable and alternative energy.

Recommendation 64: Renewable and Alternative Energy Implementation Team

A number of issues remain outstanding, in addition to those specifically related to the "retailer method" (recommendation 60). Among these are the inclusion of incremental power in the new target and the setting of further targets. This work could not be completed due to time constraints, the need for clarification of government policies, and analysis of the market impact of more ambitious targets. Furthermore, national and international policy considerations make this a very dynamic field with considerable potential for expansion in an environmentally and economically beneficial manner. A multi-stakeholder process is well suited to this work, and therefore the EPT recommends that

A CASA multi-stakeholder implementation team be formed to address the following issues, as well as issues that may be referred to it by other stakeholders or other sub-groups of the EPT. In forming this group, it is essential that all interested stakeholders who will be affected by the matters discussed be actively involved.

a) Setting a further target for renewable and alternative energy beyond 2008.
b) Clarifying the eligibility of upgraded facilities that result in incremental power for the target.
c) Determining ways in which larger co-generation and waste heat facilities can be encouraged and incented.
d) Clarifying whether the definition of retailer found in the *Electric Utilities Act* is sufficient for the purposes of implementing a retailer-based target for new renewable and alternative electricity.
e) Seeking means by which the federal government's Wind Power Production Incentive program, the Renewable Energy Deployment Initiative and other production incentives described above, might be augmented and integrated into Alberta's renewable and alternative energy sector.
f) Seeking means by which consumer engagement mechanisms as described above could be funded and implemented.
g) Seeking means by which a Solar Infrastructure Initiative, described above, could be funded and implemented.
h) Examining options that would allow Climate Change Central, with the assistance of other groups such as the Office of Energy Efficiency, ENGOs, and retailers, to take the lead in the educating consumers about the sources of their electrical power.
i) Examining ways in which the Alberta emissions trading system might be used to assist in developing renewable and alternative energy.

11 Energy Efficiency and Conservation

The Energy Efficiency and Energy Conservation Working Group was convened to examine the issues of energy efficiency and conservation as they affect air quality and emissions in the electricity sector, and to recommend how these issues might be addressed. Strong support for the promotion of energy conservation and energy efficiency was evident during the two sets of public meetings held in 2003.

During the course of its work, the group established energy efficiency targets, identified potential policy mechanisms to facilitate energy efficiency in the province, outlined the advantages and disadvantages of various funding methods, and identified some of the challenges that will be faced in this area.

Energy efficiency and conservation programs and initiatives should be implemented for a number of reasons:

- Efficiency and conservation are among the least expensive means of achieving reductions in the emissions related to electricity generation.
- Energy efficiency and conservation can result in significant financial savings for industrial and residential end users.
- Investment in energy efficiency work is employment intensive.
- Many efficiency and conservation programs are modular and can be implemented in stages as resources are made available.
- Improvements in efficiency can increase the value of assets, particularly buildings.

Funding, regulatory backstops, market transformation programs, and behavioural change all contribute to improvements in energy efficiency. At issue are not just technology and economics but desire. In most homes and offices a few simple changes can bring about significant transformations in energy usage, yet the effort needed to turn off lights or put on a sweater rather than turn up the thermostat often seems insurmountable. Experience in many jurisdictions has shown that successful energy efficiency and conservation programs use a variety of levers to bring about changes in energy consumption.

The challenges for implementing efficiency and conservation programs include:[56]

- Some of the sectors that could make significant gains in efficiency are "dis-aggregated"; that is, no one organization speaks for the sector. For example, many commercial buildings have absentee owners, and negotiations can be complicated and expensive.
- Small to medium sized companies need resources and support in planning and implementing energy efficiency in their businesses. Companies that understand the financial implications are often more receptive to implementing energy efficiency programs.
- The transmission companies might be well positioned to address some of these issues but are not at the table. They need to be involved in this discussion and are not currently engaged.

[56] These challenges, along with more details on recommendations, are described in the full report of the Energy Efficiency and Conservation Working Group, available online at http://www.casahome.org/electricity/finalreports.asp.

- Some long-term power contracts are for a certain amount of power and include penalties if the customer doesn't use the amount of power anticipated in the contract (take-or-pay). Retailers must purchase the power required to fulfill these contracts whether the power is used or not. This may be a strong economic disincentive for pursuing efficiency and conservation.
- The residential and small business sectors can be the most difficult place to get efficiency without price drivers or incentives.
- Experience has shown that significant increases in efficiency will require a combination of funding, education, capacity building among energy and building professionals, targets, regulatory support, and market transformation initiatives.
- Financial barriers can be significant, and energy efficiency and conservation work often requires more funding than is currently available.
- In landlord and tenant situations, the party who pays the electricity bills is often not the same one who makes the decisions about expenditures that would lead to less electricity use, such as the installation of energy efficient appliances.

Some efficiency and conservation work is already underway at both the federal and provincial levels. In Alberta, Energy Solutions Alberta and other existing channels should be used for this work rather than creating new bodies and programs.

Recommendation 65: Energy Efficiency and Conservation Implementation Team

It quickly became apparent that much more work remains to be done on energy efficiency and conservation as it relates to electricity. This area was also of great interest to the public. EPT stakeholders debated the need for further work on this topic and considered how it could be done, with reference to the option of a CASA implementation team. Alberta Environment indicated its commitment to participating on a CASA Energy Efficiency and Conservation Implementation Team and will commit funds for the team's work. The department hopes that other stakeholders will also provide funding for such a team but if not, Alberta Environment will endeavour to provide the funding and/or resources necessary to undertake the identified tasks. Therefore, the EPT recommends that

A CASA multi-stakeholder implementation team be struck and provided with sufficient funds to undertake the following tasks, and that it report to the CASA board in November 2004:

a) Working with Climate Change Central's Energy Solutions Alberta, relevant Alberta government agencies and existing data centres in developing measurement tools and monitoring overall electrical energy efficiency for the province.
b) Developing a process to determine the overall efficiency of the electrical system, "energy source to end user."
c) Once tasks a) and b) are completed, the implementation team will undertake a detailed technical assessment as to the feasibility of developing a province-wide electric energy efficiency target and, if feasible, define what the target amount should be (including appropriate metrics) and costs to meet the target, its relationship to sector agreements and other ongoing programs, and mechanisms to meet this target.
d) Reviewing electrical energy efficiency and conservation tools and programs and making recommendations for their implementation, including implementation of a pilot project.
e) Working with retailers and the "wires" companies to ensure that "time of use" metering and rates are made available where they are not available currently.

f) Seeking ways in which the purchase of ENERGY STAR™ appliances can be encouraged and incented.
g) Working with electricity retailers to find ways of assisting retailers in managing the risks and recovering lost revenues associated with energy efficiency and energy conservation programs. This could involve but would not be limited to performance-based incentive mechanisms that reward the achievement of targeted energy savings and program costs.
h) Examining the issue of thermal loss at generation facilities, and exploring means of encouraging and incenting the co-location of other facilities that are able to use waste heat. This could include the use of emission credits and offsets for the use of this energy.
i) Working with Alberta Energy, Alberta Environment, New Era, and the Alberta Electric System Operator with the goal of ensuring that the metering and transmission interconnection needs of distributed generation are met.
j) Working with Alberta Environment with the goal of ensuring that verifiable improvements in energy efficiency and energy conservation are classified as useable offsets.
k) Working with the federal government with the goal of examining the tax issues relating to district heating and other energy efficiency and conservation issues, in order that energy efficiency and conservation not be disadvantaged relative to other energy policies and programs.

Recommendation 66: Encouraging Electrical Energy Efficiency and Conservation by Industry

Although the EPT's mandate was confined to the electricity sector, everyone is a user of electricity and can help improve the efficiency with which power is used. Therefore, the EPT recommends that

The Alberta government, in its upcoming greenhouse gas sectoral agreements with all sectors, consider including and encouraging electrical energy efficiency and energy conservation as options for reducing emissions from electricity generation in Alberta.

Recommendation 67: Encouraging Electrical Energy Efficiency and Conservation by Governments

Alberta's provincial and municipal governments are major users of electricity in the province too. There are many opportunities for these levels of government to be innovative and creative in the way they design and use building space. Climate Change Central is a logical organization to work with governments in finding new and better ways to use and conserve electricity. The EPT recommends that

Climate Change Central

- work with Alberta and municipal governments to encourage energy efficiency in residential housing design, both in building codes and in municipal planning.
- examine the issue of "take or pay" contracts. This work would include:
  - gathering information on the extent of the issue;
  - providing information for consumers to assist them in making informed decisions about their electricity purchases; and
  - developing and piloting alternatives that would meet the retailer's needs while allowing for consumers to benefit fully from energy efficiency and conservation practices.
- provide a resource in which information about the various government programs (all levels) and funding options is made available.

Recommendation 68: Funding Energy Efficiency and Conservation Programs

While most energy efficiency and conservation practices offer economic returns through reduced energy costs, the initial costs for education and outreach, effective market transformation programs and the uptake of the technology needed to reach the energy efficiency targets will require additional ongoing funding.

Various sources for funding programs to encourage and implement energy efficiency and conservation practices were considered. While consensus was not reached on a preferred method for funding, conventional financing and credits, offsets, and allowances were seen as less effective for most of this work. The federal government's commitment of $1.8-billion for action on climate change could be a source of matching funds and provincial funding programs should be established with a view to leveraging these federal funds. In many cases, these funds can be matched dollar per dollar.

Among the funding options considered were a public benefits surcharge, a one-time government funded endowment, annual government funding, conventional financing, and the use of greenhouse gas credits, offsets and allowances. (These options are described in more detail in the report of the Energy Efficiency and Conservation Working Group.) Stable and sufficient funding for energy efficiency and conservation efforts would allow planning and implementation of effective programs that could enable Alberta to improve its energy efficiency and conservation performance. Experience in many jurisdictions has shown that the type of change that is needed to affect energy use significantly does not happen without a multi-pronged approach. The EPT recommends that

> The Alberta and federal governments consider means for providing stable and sufficient funding to allow for the development and implementation of energy efficiency and energy conservation programs, and that the various options for funding described in the Energy Efficiency and Conservation Working Group's report to the EPT be considered.

PART THREE: THE ELECTRICITY PROJECT TEAM'S PROCESS

12 Information Gathering

Developing a solid information base and common understanding of Alberta's electricity generation sector was fundamental to the team's success. The Information subgroup was responsible for compiling the information needed by the team, which included a workshop with experts in a number of relevant areas.[57] The workshop covered the following topics:

- current and projected emissions
- current management regime
- the science relating to air emissions from the electricity sector
- the technology relating to air emissions from the electricity sector
- structure of the electricity sector in a deregulated marketplace
- economics and markets of the electricity sector
- related work underway and completed by CASA and other processes
- environmental and health impacts information.

The subgroup then proposed actions for filling remaining information gaps. Among the subsequent topics covered were the following:

- Growth forecasts.
- A possible connection between mercury and multiple sclerosis (MS). Alberta Health and Wellness made a presentation to the EPT on this topic and also undertook a literature search of any reported connections. The literature reviewed found no causal association between exposure to mercury and the development of MS. However, for individuals with MS, mercury was associated with an exacerbation of symptoms.[58]
- A presentation on the Power Purchase Arrangement (PPA) "Change in Law" provision.[59]
- A need to better understand the implications of PPA contractual arrangements and the impact of the wholesale electricity market organization on possible emission management options.[60]
- The implications of the North American Free Trade Agreement for the electricity sector.
- Issues related to transparency, accountability and public participation.

[57] The report from this workshop and the information matrix identifying gaps and information sources are available online at http://ww.casahome.org/electricity/eptdocs.asp.

[58] Source: Siblerud, R.L., and E. Kienholz. 1994. "Evidence that mercury from silver dental fillings may be an etiological factor in multiple sclerosis," in *Science of the Total Environment*, 142(3):191-205.

[59] See section 4.3, Power Purchase Arrangements Determination Regulation 175/2000.

[60] The EPT commissioned a report by Dr. Joseph Doucet of the University of Alberta's Faculty of Business, entitled *Power Purchase Arrangements, Wholesale Market Organization and Air Emission Management Options.* It is available online at http://www.casahome.org/electricity/eptdocs.asp.

Recommendation 69: Access to Information Gathered by the EPT

The EPT undertook a considerable amount of research and assembled a vast amount of documentation. The team expects that future multi-stakeholder processes would want to have access to this information so they could better understand the rationale and thinking behind the team's recommendations. Therefore, the EPT recommends that

a) the CASA Secretariat retain the final versions of all materials, information, documents, reports and presentations that were obtained or produced in the course of the EPT's work so that they are readily accessible to stakeholders until 2010;
b) the CASA website provide details on how to access these materials; and
c) hard copies and compact discs of these materials also be stored with Alberta Environment as a back-up.

13 Public Consultation

The consensus-based process used by CASA incorporates consultation in many forms. Public input is embedded in the CASA multi-stakeholder process and several representatives from local communities participated on the Electricity Project Team and its subgroups. The team also believed it was important to have an open and transparent public consultation program to ensure any interested person could participate and provide input.[61] This was especially important in the context of concerns expressed to the Alberta Energy and Utilities Board at public hearings in 2001 on proposed new electricity generation developments in the Wabamun, Edmonton and Calgary areas.

In March 2002, the EPT established a Public Consultation Subgroup to develop and implement a targeted public consultation and stakeholder communication program. The program emphasized the importance of two-way communication and was implemented in three phases. The main objective of Phase One was to promote public awareness of the EPT's existence and its plans, and to emphasize the available opportunities for direct input to the EPT. Phase Two provided information about the project to the public, tested some concepts, gathered initial input and determined the public's interest in continuing to be involved. Phase Three was an opportunity for the EPT to find out if the main issues of concern for Albertans were being addressed in the team's draft recommendations.

Table 6: Public Consultation Program Summary

Phase	Objectives	Target Audiences	Communication Tools
Phase 1	• Increase public awareness of the project • Emphasize opportunities to provide input • Promote the transparency of and accessibility to information compiled through the CASA process	• Interested Albertans • Residents, groups and First Nations near existing or future facilities • Chambers of Commerce • Consumer associations • Small- and medium-sized enterprises • Participants in other processes (CASA teams, CCME, etc.) • Scientific and technical experts	• CASA electricity web site • Self-subscribed e-mail list • Information packages • Discussions and meetings with groups on an "as requested" basis • Feature articles in community newspapers, electronic media and stakeholder publications • Public participants at the EPT's Management Options Seminar

Phase 2	• Emphasize opportunities to provide input
	• Inform potentially affected stakeholders about the team's progress
	• Provide an opportunity to comment on the team's direction and focus
	• Determine level of the public's interest in staying involved
		• Interested Albertans
		• Residents, groups and First Nations near existing or future facilities
		• Local municipalities
			• Public meetings in nine locations:
			  ◦ Brooks
			  ◦ Chestermere
			  ◦ Edmonton
			  ◦ Forestburg
			  ◦ Grande Cache
			  ◦ Hanna
			  ◦ Keephills
			  ◦ Pincher Creek
			  ◦ Stony Plain
			• CASA electricity web site
			• Self-subscribed e-mail list
			• Discussions and meetings with groups on an "as requested" basis
			• Public service announcements in

[61] The full report of the Public Consultation Subgroup is available online at http://www.casahome.org/electricity/finalreports.asp.

Phase	Objectives	Target Audiences	Communication Tools
			community newspapers, electronic media and stakeholder publications • Advertisements in community newspapers and daily newspapers • Phase Two input forwarded to the team • Distribution of a follow-up report to public meeting attendees
Phase 3	• Inform potentially affected stakeholders about the EPT's progress • Provide an opportunity for the targeted audiences to comment on the team's draft recommendations	• Interested Albertans • Residents, groups and First Nations near existing or future facilities • Attendees of Phase Two meetings • Local municipalities	• Public meetings, one in Chestermere and one in Stony Plain • Public service announcements in community newspapers, electronic media and stakeholder publications • Advertisements in community newspapers and daily newspapers • Phase Three input forwarded to the team • Distribution of a follow-up report to public meeting attendees

13.1 What We Heard

About 250 people attended the nine public meetings held during Phase Two and some 100 individuals came to the two public meetings held in Phase Three. A number of meetings were also held with stakeholders throughout the process.

Input from Phase Three was used to test and fine-tune the draft recommendations. Although the EPT heard a range of views from the public during these meetings, concerns identified by some of the attendees were very similar to the issues and concerns that the EPT had considered. Key issues identified by the public, which the team discussed at length, included continuous improvement, electricity exports, hotspots, implementation of an emissions trading system, renewable energy, and management of mercury emissions.

The main issues raised at the Phase Three public meetings are noted below, with some generalized points that reflect the overall comments.

Renewables and alternative energy

- Barriers to increasing renewables (such as legislative and market-based barriers) make it difficult for small power producers to connect to the grid.
- Encourage renewables such as co-generation, solar, waste, dispersed energy, wind and hydrogen cells.
- The 3.5 % target is too small; up to 5% is more acceptable
- Some participants felt the target should be voluntary, and some felt it should be mandatory.

Energy efficiency and conservation

- There needs to be more promotion, education and incentives to encourage energy efficiency and conservation.
- Concern was expressed about programs that would result in extra costs to the consumer.

Emissions trading

- There is frustration with the complexity of the various emissions trading schemes. There was not much understanding of or support for either emissions trading model being considered by the team and presented at the public meetings. Participants asked that this information be made clearer in an effort to promote better understanding of what is involved. In the absence of clearer information there was not much support for emissions trading.
- There was a particular concern that emissions trading would not benefit local areas where generation is concentrated.

Reduction targets

- Many participants wanted faster reductions in emissions; that is, don't wait until 2009 for implementation of new mercury standards; the ultimate goal for mercury reduction should be zero emissions.

BATEA

- Some participants wanted to factor in health and environmental costs when determining Best Available Technology Economically Achievable (BATEA).

Greenhouse Gases

- Some participants were concerned about buying "hot air" from other countries and therefore reducing the investment and benefits for Albertans.

Hotspots

- Some participants were concerned that the EPT's definition of hotspots would not identify any region in Alberta as a hotspot.
- Participants went on to say the definition of a hotspot should reflect and include health effects, concentration of sources and weather inversions.

Grandfathering

- Grandfathering of existing plants is seen as an impediment to continuous improvement and delay in emission reductions and local benefits.
- Timelines are not reasonable.
- Genesee 3 and Centennial should not be grandfathered.
- Some members of the public wanted plants to be shut down at the end of their design life.
- They suggested that when an approval or licence from an existing facility expires, then the BATEA of the day should apply.

Transition units

- Some participants expressed concern that transition units will be grandfathered.

Monitoring

- Some participants requested real-time reporting rather than monthly averages.
- Participants wanted exceedances called in and fines made public.

14 Prioritization of Emissions

In addition to developing extensive criteria and rationale in support of the five priority substances, the Prioritization Subgroup undertook a great deal of work to screen a number of additional substances potentially emitted by thermal generation units and assess them for co-benefits. They also developed a second list of substances that subgroup members or members of the public identified as a possible concern. The PSG looked at the issue of water vapour in conjunction with the electricity generation sector, and developed recommendations on water vapour and on the future review and assessment of substances. This work is summarized here and described in more detail in the Subgroup's full report.[62]

14.1 Substances Screened and Substances Assessed for Co-benefits

The PSG conducted an initial screening of a number of substances. This process produced a shorter list of substances that did not meet the extensive criteria and rationale set out for priority substances, yet warranted further assessment for co-benefits resulting from the management of priority substances. Table 7 lists all substances that were screened as to whether they should ultimately be included on a final second list of emissions from the electricity generation sector. It also indicates which substances were assessed for co-benefits.

Table 7: Substances Screened for Possible Inclusion on List Two

Hydrogen fluoride (HF)$^{(2)}$	Hydrogen chloride (HCl)$^{(2)}$	Arsenic (As)$^{(2)}$
Beryllium (Be)$^{(2)}$	Cadmium (Cd)$^{(2)}$	Chromium (Cr)$^{(2)}$
Cobalt (Co)$^{(2)}$	Lead (Pb)$^{(2)}$	Manganese (Mn)$^{(2)}$
Nickel (Ni)$^{(2)}$	Selenium (Se)$^{(2)}$	Thallium (Tl)$^{(2)}$
Dioxins and furans (TCDD/TCDFF)$^{(2)}$	Hexachlorobenzene$^{(2)}$	Acrolein$^{(2)}$
Formaldehyde$^{(2)}$	Pentachlorophenol (PCP)$^{(1)(2)}$	Benzene$^{(2)}$
Ethylbenzene$^{(2)}$	Toluene$^{(2)}$	Xylene$^{(2)}$
PAHs$^{(2)}$	Ammonia (NH_3)$^{(2)}$	Carbon monoxide (CO)
Radionuclides$^{(2)}$	Ozone (O_3)$^{(2)}$	$PM_{2.5}$$^{(2)}$
Reduced sulphurs* $^{(1)}$	Carbon disulphide* $^{(1)}$	Water vapour/steam
BTEX*	VOCs*	

Notes:
* Denotes substances identified by the public that were not previously identified. The public had also identified certain metals (Pb, Se, As, Cd, Ni, Co, Cr), dioxins and furans, and PAHs that were already listed.
$^{(1)}$ These substances have not been found in emissions from coal-fired generation facilities.
$^{(2)}$ These substances were assessed in terms of co-benefit possibilities.

14.2 List 2 Substances

The PSG agreed that the final List Two should include any substance that was of concern to any member. These substances are noted in Table 8.

[62] The report of the Prioritization Subgroup is available on request to the CASA Secretariat or online at http://www.casahome.org/electricity/finalreports.asp.

Table 8: Final List 2 Substances

Hydrogen fluoride*	Hydrogen chloride*	Arsenic*
Cadmium*	Chromium*	Cobalt*
Lead*	Manganese*	Selenium*
Dioxins/Furans	Hexachlorobenzene	Benzene
PAHs	Beryllium	Thallium

* indicates substance listed as a result of consensus of subgroup members

The information available on emissions of the non-consensus substances (those without an *) from thermal electricity generating plants was, in many cases, scarce, inconclusive, conflicting or all three. This list does not represent a consensus that the emission of any of the above substances from power plants is causing a significant adverse effect in Alberta. The rationale for this final List 2 is described more fully in the PSG's report.

14.3 Water Vapour

The EPT discussed the matter of water vapour as an emission from the electricity sector. Water vapour was raised as an issue of concern by some team members and it also came up at the public meetings. "Water" is not considered a contaminant, as water itself does not cause toxic effects, and water vapour is not present as a contaminant of concern on List Two.

Water vapour is released from power plants via the stack, cooling towers and ponds. Water vapour, in particular that from cooling towers and ponds, may be a transportation and public safety issue arising from decreased visibility and localized icing of roads. Water vapour may have a localized impact on agricultural crops through excessive moisture. Some of the contaminants released from power plants exist in the liquid or gaseous phase, like SO_2 and NOx in the stack. Debate remains among team members as to whether this changes the toxic properties of the contaminants. More research needs to be conducted to clarify this issue.

Recommendation 70: Water Vapour

The EPT recommends that

> The water vapour concerns noted in this report be addressed through existing site-specific regulatory processes and through the EUB applications process for electric generation facilities. Alberta Environment should play the lead role in ensuring the appropriate agencies are involved in addressing the issues as they arise. Any new information on water vapour should be considered in the Five-Year Reviews described in recommendation 29.

14.4 Complex Mixtures

The PSG did not have an opportunity to address complex mixtures in the course of its work, but agreed that complex mixtures are not well understood and should be flagged as an issue to track. Complex mixtures consist of two or more substances acting in a parcel of air. The mixtures of interest are those where the normal environmental or health effects of any one substance are amplified by the presence of another. Urban smog is an example of a complex mixture, although its makeup may vary somewhat from place to place. BTEX is another commonly known complex mixture. The PSG has therefore suggested that the issue of complex mixtures be included, as appropriate, in future substance review processes.

14.5 Future Review and Assessment of Substances

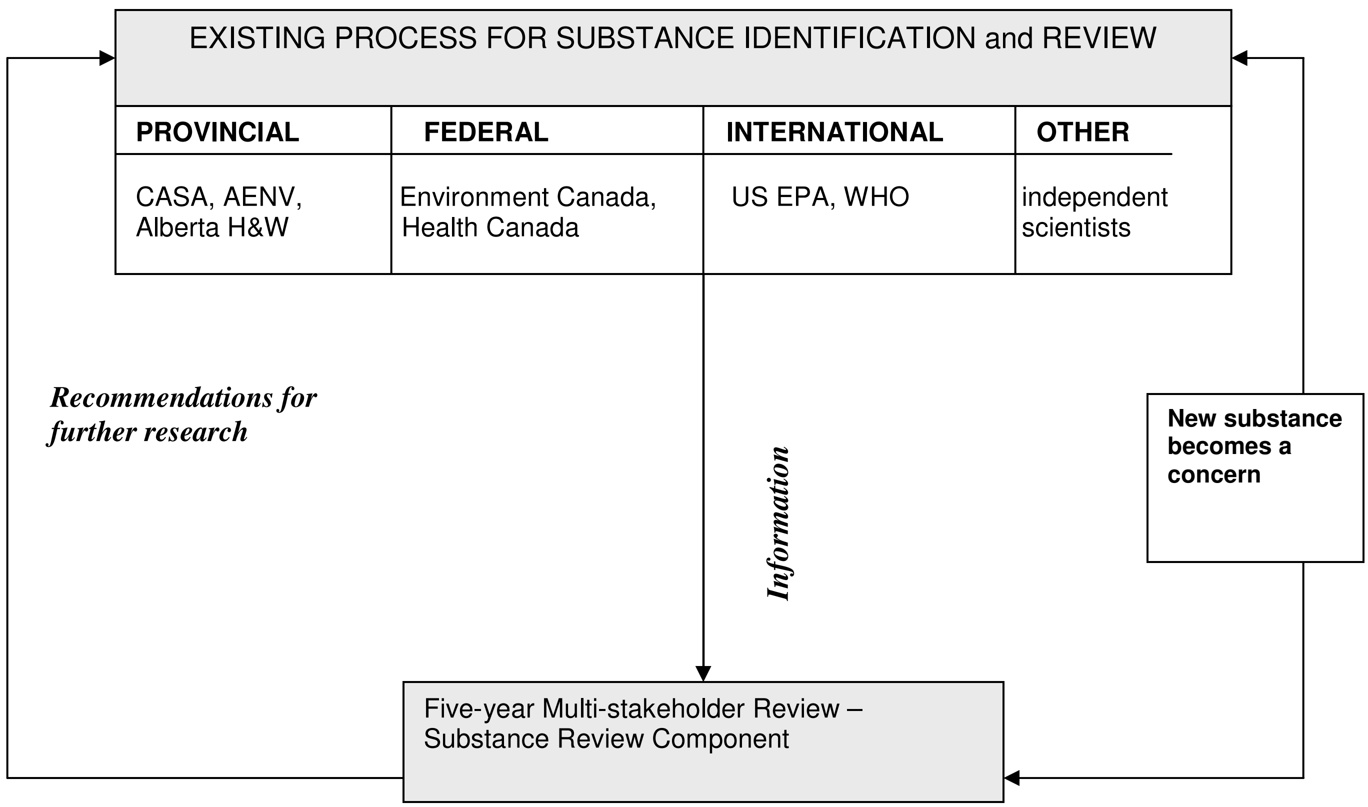
To ensure that substances emitted by power generation facilities are periodically reviewed in the future and assessed against new scientific information, the EPT has identified a process for future substance reviews.

Recommendation 71: Future Substance Reviews

The EPT recommends that

> A substance review component be included as part of the recommended multi-stakeholder reviews to be conducted every five years. The purpose of this substance review is to assess whether or not additional substances should be formally controlled based on new or emerging information, including the effects of complex mixtures emitted by power plants. This review should take into account both new and existing scientific information, with reference to the following flow diagram.

Figure 12: Process for Future Substance Reviews



15 Modelling

15.1 Background

A Management Options Subgroup (MOS) of the Electricity Project Team identified and assessed emissions management options and facilitated development of associated recommendations. An important element of its work was a seminar in September 2002 to:

- learn about the range of management options available to address emissions from the electric power sector; and
- obtain sufficient information and background on the various options to support the Electricity Project Team in its discussions around assessment, design and development of management options for electricity sector emissions in Alberta.

Speakers from across North America provided information on the pros and cons (legal, economic, social, environmental) of different options, perspectives based on "hands on" experience, why certain options were chosen, and lessons learned. More than 100 delegates attended the two-day seminar, and the EPT provided limited subsidies to enable interested members of the public to participate.[63] The seminar, which was open to the public, was followed by a workshop for team members to reflect on the seminar content and begin to develop potential management options.[64]

At the team's management options workshop, members identified factors that they viewed as important when considering and evaluating management options (see Appendix E) and agreed to model some scenarios to help them better understand the impacts of potential options. A number of scenarios were subsequently modelled by two graduate students from the Centre for Applied Business Research in Energy and the Environment at the University of Alberta, under the direction of Alberta Environment (referred to as the "CABREE work"). At the same time, Alberta Environment was undertaking a Major Feasibility Study to assess the potential of emissions trading to help achieve broad objectives for airborne pollutants and greenhouse gases in Alberta. The department shared preliminary results with the EPT and a discussion document on the project was publicly released in May 2003.[65] Some of the data and outputs from this project were used in the modelling done specifically for the EPT.

As the potential range of scenarios became clearer, a small group was given the task of developing what the EPT called "straw dog" options. This group (the Straw Dog subgroup) began meeting in January 2003 to develop and refine scenarios for consideration by the EPT.

The EPT recognized that modelling was needed to assess and understand the potential implications of various emissions management options, alone and in combination. Key outputs sought were the effects on the marginal price of electricity, during both peak and off-peak hours, the energy production by unit, and the emissions forecast for the five priority pollutants, for each year from 2003 to 2025. The team also recognized the need to obtain

[63] The seminar report and presentations, along with a transcript of questions and answers are online at http://casahome.org/electricity/MOIS.asp.

[64] The report from the management options workshop is available online at http://casahome.org/electricity/MOIS.asp.

[65] More information on the Emission Trading Project is available online at http://www3.gov.ab.ca/env/air/emissions_trading/.

information on any potential unintended ramifications of its emission management recommendations, including impacts on facility design and location, fuel switching and transmission requirements. The team engaged Energy Demand Consulting Associates (EDC) to undertake this work, which was done in two phases.

15.2 Objectives of the Modelling

The specific objectives of the modelling were to:

1. estimate the incremental impact on the annual average Alberta wholesale electricity price from implementing a proposed emissions management framework, with various options for the timing and scale of emission reductions;
2. estimate the impact on the supply stacking order from implementing a proposed emissions management framework (and variables) and the impact on particular facilities that are subject to Power Purchase Arrangements;
3. determine the electricity power generation sector's annual aggregate emissions profile by technology type as a result of implementing the proposed emissions management framework and variables; and
4. determine the impact on 1, 2 and 3 above from imposing a target on retailers that would require an incremental 3.5% of renewable generation by the end of 2008, and 10% by 2012.

15.3 Phase I

The purposes of phase I were to:

1. impose emission reductions in a manner that would demonstrate environmental and economic impacts relative to a business as usual scenario; and
2. adjust single parameters to show the impact of that parameter independent of the effects of the others.

This phase was intended to help the EPT develop a short list of management framework options that appeared to be both feasible and acceptable to all stakeholders.

Initially, two scenarios were modelled:

1. EDC's Reference Case: This was the "Business As Usual" (BAU) case, which assumed that the current economic and regulatory regime remained largely unchanged. The Reference Case is driven by the assumption that no specific emission reduction targets are implemented in Alberta, Canada or elsewhere. Thus the energy demand grows and generation additions occur as they naturally would and each generator bids its power into the Alberta market assuming no incremental costs for environmental operating and maintenance or offset purchases or sales. This was a model of Alberta electricity generation, which included demand, generation mix, dispatch order, capacity factors and electricity prices. This was an important first step as the resulting scenario became the basis upon which the benefits and costs of proposed management options were assessed.

2. EPT's Base Case scenario: This scenario incorporated proposed emissions reductions for NOx, SO_2, primary particulate matter, mercury and CO_2 over the period 2003 to 2025.

This was followed by 16 sensitivity runs against either the reference case or the base case. The sensitivities tested were:

- ranges of emission intensity targets for CO_2
- alternative trading systems for NOx and SO_2 (e.g., baseline and credit system versus cap and trade system)
- various timing of reductions for NOx and SO_2 within these different trading systems
- various timing of mercury reductions
- different prices of emission allowances assuming multi-sectoral trading versus restricted trading within the electricity sector in Alberta
- a 3.5% and 10% target for new renewables by 2008 and 2012 respectively
- a decrease in electricity demand of 2% per year to simulate energy efficiency targets
- a decrease in the gas price to the reference case level to isolate the direct emissions reduction cost impact
- various timing for implementation of NOx and SO_2 control technologies on transition units

The team used the information from Phase I to develop a short list of promising management options.

15.4 Phase II Optimized Scenarios

Phase II examined three optimized scenarios that represented management options that seemed feasible and might be acceptable to all stakeholders. These three scenarios are described in detail in the EDC report.[66] Scenario 1 was a baseline and credit system for NOx and SO_2 that required units to reduce to BATEA levels at the end of Design Life. Scenarios 2 and 3 were cap and trade systems for NOx and SO_2 where the caps were reduced every five years, with scenario 2 being the more stringent of the two. The same set of requirements for mercury, greenhouse gas, and primary PM emissions, and for renewables was used in all three scenarios.

Five additional sensitivity runs were also included in this phase. Three addressed varying greenhouse gas emission intensity targets. The fourth evaluated the impacts of holding the price of natural gas fixed at $4/gigajoule for the period 2010-2014. The fifth sensitivity was run with only the renewable target – that is, no emission control requirements – to demonstrate the impacts of the direct costs to generators of technology retrofits and emission offset purchases independent of other market effects.

[66] The EDC report is available online at http://casahome.org/electricity/eptdocs.asp.

15.5 Modelling Inputs, Data Sources and Key Assumptions

15.5.1 Inputs and Sources of Data

EDC Associates Ltd has an extensive database on all the existing units in Alberta, but certain key inputs were developed by the EPT and provided to the consultant for modelling purposes (see Table 9).

Table 9: Inputs to the Model

Emission	BATEA Based Emissions Intensity Standard, Target or Assumed Reduction	Technology	Capital Cost	Operating Cost
NOx – Coal Unit	0.69 kg/MWh	Selective Catalytic Reduction (SCR)	$125/KW	$3.86/MWh ($1500/tonne) Allowance prices $800 - $2800 per tonne over the forecast period
NOx – Gas Unit	0.30 kg/MWh	Dry Low NOx Engines	Not applicable	Not applicable Allowance prices $800 - $2800 per tonne over the forecast period
NOx – Gas Unit	0.125 kg/MWh	SCR	$40/KW	$2.00/MWh. Allowance prices $800 - $2800 per tonne over the forecast period
SOx	0.80 kg/MWh	Scrubbers	$225/KW	$1.73/MWh ($900/tonne) Allowance prices $1100-$2300 per tonne over the forecast period
Hg	Assumed 80% capture	ACI + FF[67]	$52/KW	$1.20/MWh[68]
PM	0.095 kg/MWh	Assumed Co-benefit of Hg control		
CO_2	Sector Target Intensity 2010 - 0.66 t/MWh 2020 - 0.47 t/MWh	Not applicable. GHG Allowance Trading		Allowance prices: 2010 - $9/tonne 2015 - $12/tonne 2020 - $15/tonne

[67] ACI-FF is activated carbon injection and fabric filters

[68] The carbon portion of this cost was $0.90/MWhr, which was based on an injection rate of 1.3 lb/hr/MW and a carbon cost of $1.50/kg. This rate was based on the carbon injection rates used at the Pleasant Prairie full-scale test site where the technology employed was activated carbon injection and an electrostatic precipitator to achieve a capture rate of 60%.

15.5.2 Key Data Inputs

1. Baseline intensities for all existing units in Alberta for NOx, SO_2 and PM were sourced primarily from Alberta Environment approvals with input from some owners of the units. Emissions data for mercury was gathered in the first phase from a report provided by CABREE and in the second phase from the Canadian Electricity Association's mercury monitoring program.
2. BATEA emission intensity standards for NOx, SO_2 and primary PM, consistent with the 2003 Environment Canada federal guidelines for thermal generating facilities.
3. Sector intensity targets for greenhouse gases.
4. Mercury capture rates were developed with reference to CABREE work, the U.S. Environmental Protection Agency (EPA) and other research studies on the control of mercury from coal-fired power plants.
5. Incremental capital and operating costs for pollution control technologies to achieve the defined intensity standards. Many sources were used to develop the cost information including the CABREE work, the Alberta Emission Trading Feasibility Study data, pollution control cost data from Environment Canada, various engineering studies, the U.S. EPA and the U.S. Department of Energy.
6. Allowance prices for NOx and SO_2. Prices are derived from the demand and potential supply of credits under each of the scenarios. Demand is initially met by units that shut down prior to reaching the end of design life in a baseline and credit system or by retiring part way through a capped period. The remainder of the demand is met by units that install technology, and those units with the least cost reductions install first. The last unit to install sets the price for all credits sold that year and every subsequent year until the next unit installs. If no unit installs then the price is set at the least cost retrofit on any unit. The cost per tonne of retrofitting a unit in any given year is calculated by adding its annual operating and capital costs, and dividing them by the reductions required to achieve BATEA levels. The annual capital cost is determined by amortizing over the remaining life of the unit. Prices for greenhouse gases were sourced from the Alberta Emissions Trading Feasibility Study data.

15.5.3 Key Assumptions

1. The analysis was on a unit basis without consideration of the Power Purchase Arrangements associated with each unit. Omitted from this analysis were the prices paid for the PPA contracts or any hedging decisions that may have been made as a result of the PPA purchase due to competitive confidential requirements. It was assumed that all incremental variable emission costs levied on any generation asset would be bid into the pool price and therefore reflected in the impact on electricity prices.
2. For the purpose of allowance creation and purchase, capacity factors were assumed to be the average capacity factor over the remaining life of the unit and were provided by EDC.
3. Life extension capital of $300/kw to life-extend the coal units to 50 years was included in both the reference case and the optimization scenarios. No additional capital was included to life extend the gas units.
4. The amortization period for pollution control technology costs was assumed to be the remaining term from the date of installation to the end of 40 years (gas units) and 50 years (coal units).

5. Start up and shut down of units was assumed to be December 31 of the relevant year.
6. The BATEA emission standards were used across the forecast period to ensure that the emissions reductions represented a conservative estimate of the future.

15.6 Forecast Risk

A number of forecast risks were identified throughout the EDC report but two of the key risks are:

Future Generation Mix

The forecast assumes only one 450 MW coal facility will be built. Natural gas-fired co-generation is expected to be developed in Alberta, particularly associated with robust oil sands development and commensurate with northern transmission capabilities. However, a forecast risk exists in that the generation development sequence will not progress as forecast and could have implications for the electricity price and the emissions. A detailed discussion of this risk and its implications is contained in the EDC report in chapter 7, "Key Assumptions and Results," in the section on "New Generating Units"(page 65).

Natural Gas Price Risk

Natural gas prices are recognized as a major risk factor in forecasting electricity prices, future generation development and overall sector emissions. For example, a sensitivity modelling run using a natural gas price of $4/GJ for the period 2010-2014 resulted in an electricity price that was $14/MWh lower than the price derived from the $5.60/GJ forecast natural gas price.

15.7 Modelling Results

The complete report from EDC Associates Ltd describes the results from Phase I and Phase II in more detail.

15.7.1 Wholesale Electricity Price Impacts

- There was no significant difference in the three optimized management options identified by the team in terms of impact on wholesale electricity prices, dispatch order and electricity production.
- The direct impact from the emissions costs on price was limited. The average impact over the forecast period from the direct emission costs ranges from $0.73/MWh to $1.15/MWh as presented in Table 10, below. The price impacts are limited because the emission costs on a dollar-per-MWh basis are lower for a natural gas unit and, unlike coal units, the gas units have the ability to pass on their incremental emission costs into the price due to their marginal status in the supply queue.
- The policy requiring 3.5% of energy to be supplied by incremental renewable generation by 2008 puts downward pressure on prices in the near term, but eventually contributes to higher prices in the post-2010 period. It was forecast that most new renewables would be wind energy, therefore the intermittent nature of wind results in higher prices when the wind does not blow. If the renewables target is met by renewables with a higher capacity factor than wind, these impacts would be mitigated. A fuller discussion of wind economics is contained in the EDC report Chapter 7, "Key Assumptions and Results," in the section on "Wind Economics" (page 68).

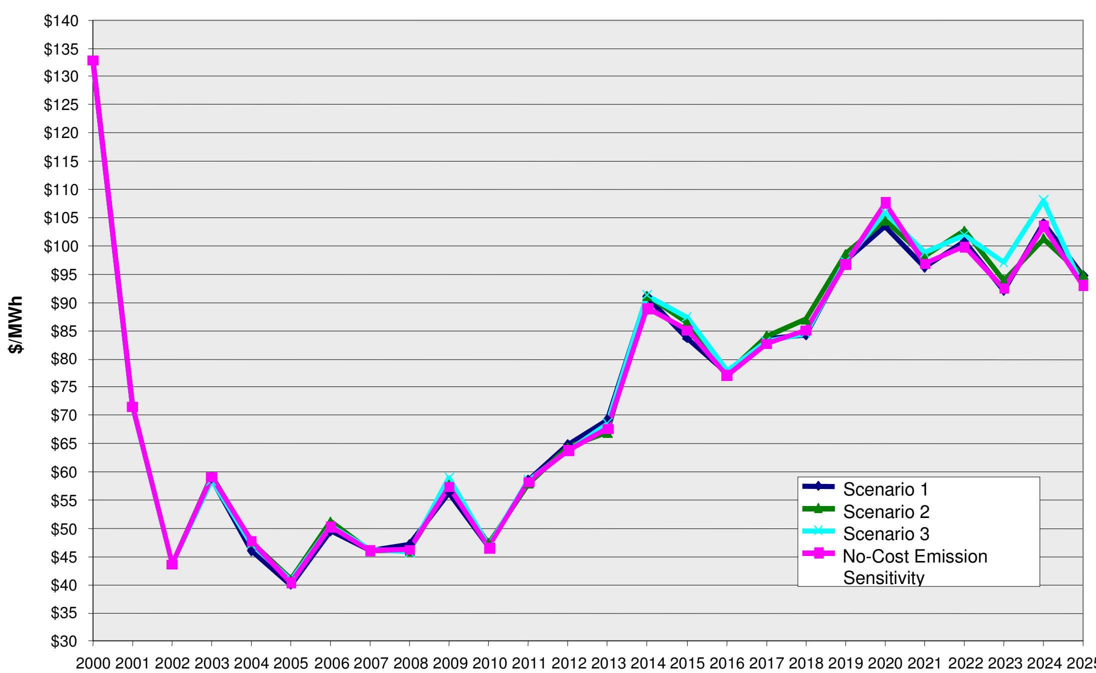
- Under current wind economics, there is a need for incentives over and above the Wind Power Production Incentive to encourage incremental wind generation. However, as wind technology costs drop over time from current capital costs of $1500/kw to $1000/kw, the need for incentives is eliminated.
- The major factor affecting future electricity prices is the price of natural gas. As Table 10 shows, approximately 70-75% of the increase in electricity price is due to an increase in the natural gas price from the reference case.
- Increasing the greenhouse gas intensity reduction target from 0.66t/MWh in 2010 to 0.59t/MWh and from 0.47t/MWh to 0.37t/MWh in 2020 resulted in wholesale electricity price increases of roughly $0.10/MWh in the 2010-2019 period and $1.96/MWh in the 2020-2025 period.

Table 10: Summary of Electricity Price Impacts ($/MWh) (Optimized Cases relative to the Reference Case)

Cost Category	Scenario 1			Scenario 2			Scenario 3		
	pre-2010	post-2010	overall	pre-2010	post-2010	overall	pre-2010	post-2010	overall
Natural gas price	$3.11	$12.89	$9.41	$3.11	$12.89	$9.41	$3.11	$12.89	$9.41
Wind energy, demand and stochastic difference	($8.95)	$4.38	$0.82	($8.25)	$4.92	$1.41	($8.38)	$5.38	$1.69
Direct emission costs	-	$1.06	$0.73	-	$1.66	$1.15	-	$1.55	$1.08
Total	**($5.84)**	**$17.26**	**$10.23**	**($5.14)**	**$17.81**	**$10.83**	**($5.27)**	**$18.27**	**$11.10**

Figure 13 shows the comparative wholesale electricity prices for scenarios 1, 2 and 3 and the "no-cost" emission sensitivity.

Figure 13: Comparative Wholesale Electricity Price

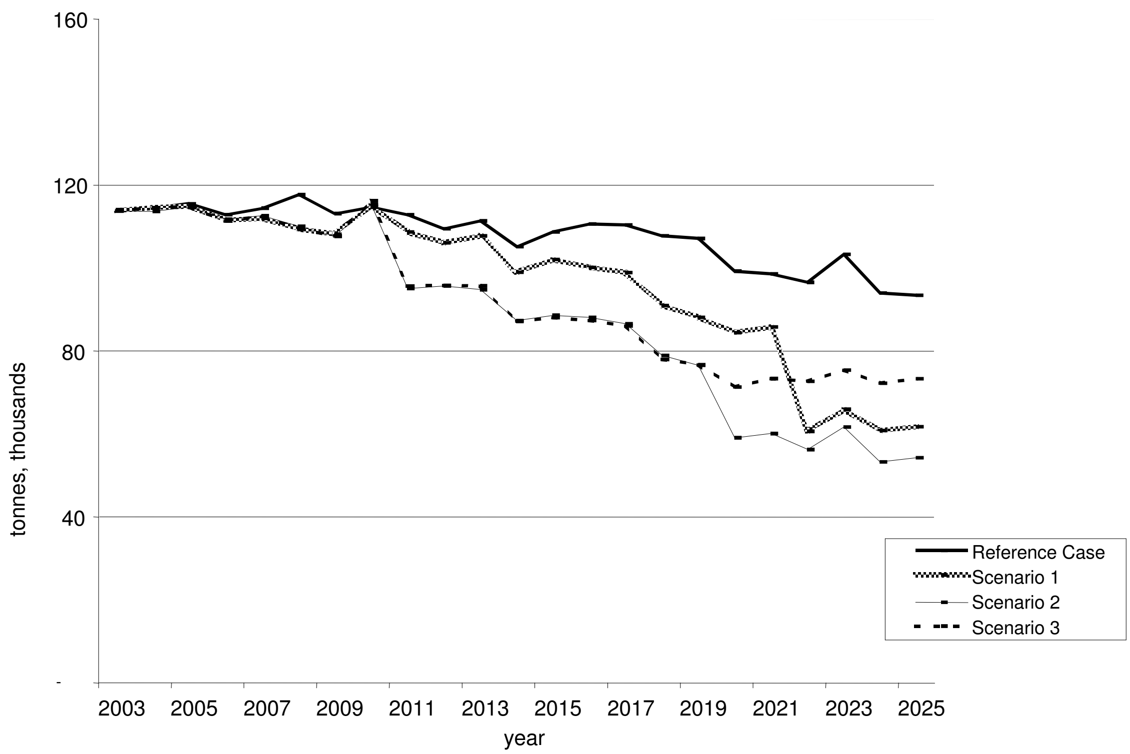


The no-cost sensitivity is used to isolate the direct cost impact of the management framework on the wholesale electricity price forecast. The direct costs related to greenhouse gas offset purchases, mercury control costs and NOx/SO_2 credit purchases are removed from the optimized scenarios while natural gas price impacts and the impact of the renewable targets are retained. As expected, the forecast electricity price is generally lower than the three optimized scenarios, but the overall impact is not very strong. For example, during the years 2010 through 2025, the average direct impact of the policy is about $0.70/MWh. The figure suggests that energy prices will not be significantly altered as a result of the direct costs associated with the framework tested in this analysis.

15.7.2 Impacts of the Framework on Emissions

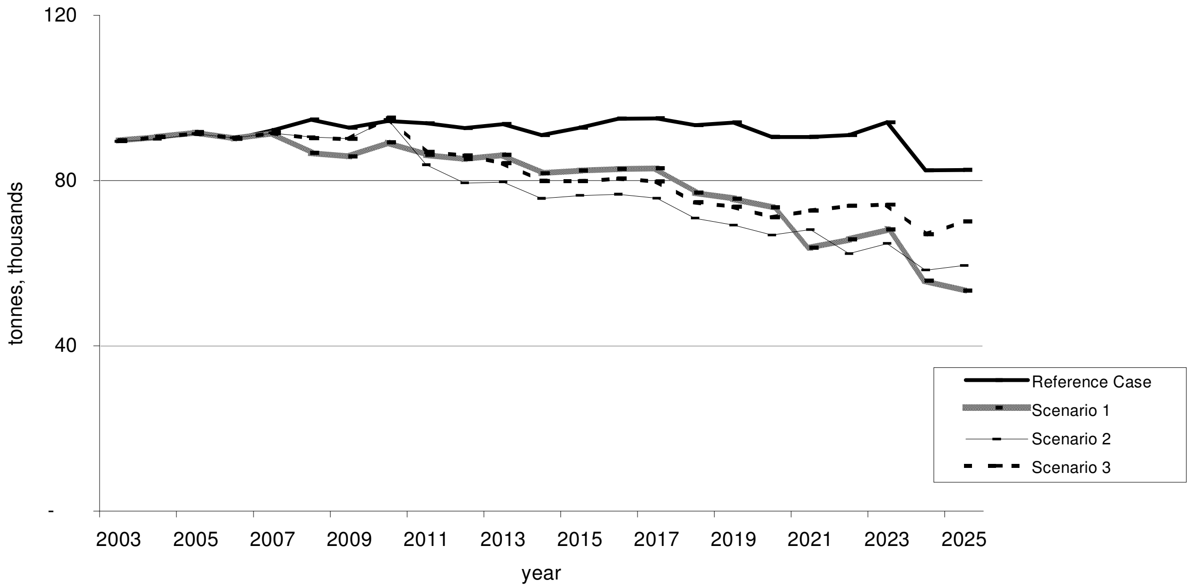
The emission reductions associated with the optimized scenarios are shown in Figures 14 to 19. Each scenario resulted in long-term emission reductions, with the timing and level of reductions varying between the scenarios. These emission impacts were strongly considered by the team in its finalization of emission management recommendations.

Figure 14: Modelled SO_2 Emissions Reductions



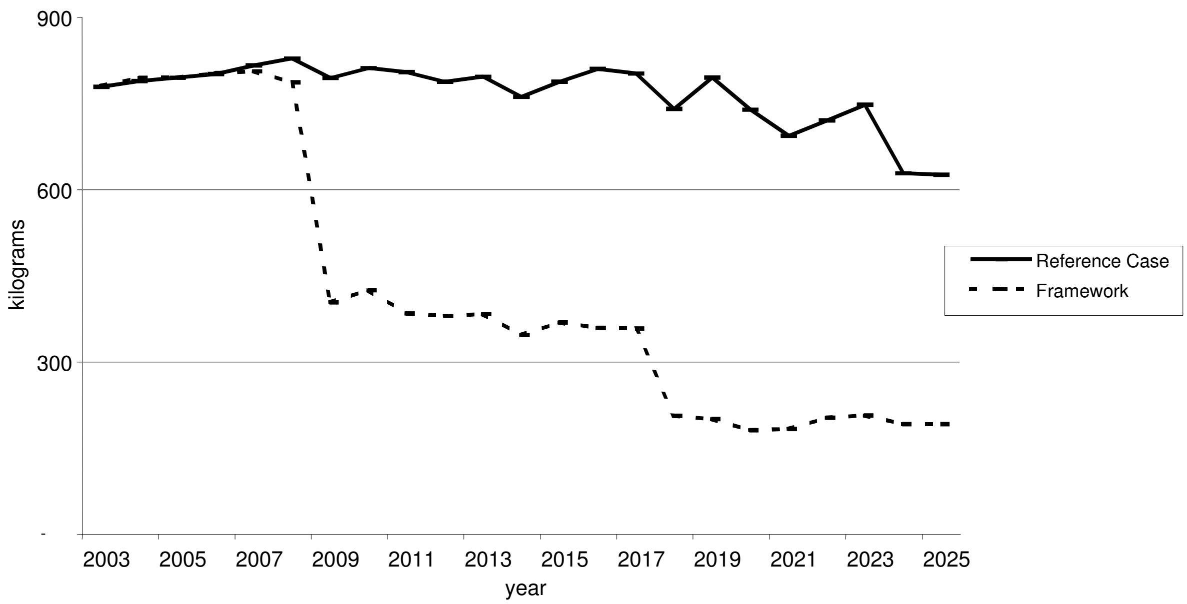
In scenario 1, SO_2 emissions are reduced when generation facilities are mandated to meet BATEA standards via technology or credit purchases. The minor deviation between the reference case and scenario 1 between 2016 and 2022 is not a direct result of the specific SO_2 policy. This earlier reduction occurs because four coal units retire earlier in scenario 1 than in the reference case for reasons related to mercury mitigation policy. In scenario 2, emissions decline sharply in 2011 as a result of the first cap on emissions being imposed on the sector. Although the cap reduces in a step-wise fashion, the banking of allowances results in units installing control technology at different points in time. Scenario 3 is a cap and trade system similar to scenario 2 but with less stringent reductions, especially in the latter years. In this case, one coal unit installs technology in 2011 as a result of the first cap on emissions being imposed on the sector. A declining emissions intensity from coal unit retirements and new gas generation causes the sector to meet the less stringent caps for the remaining periods without additional units installing technology.

Figure 15: Modelled NOx Emissions Reductions



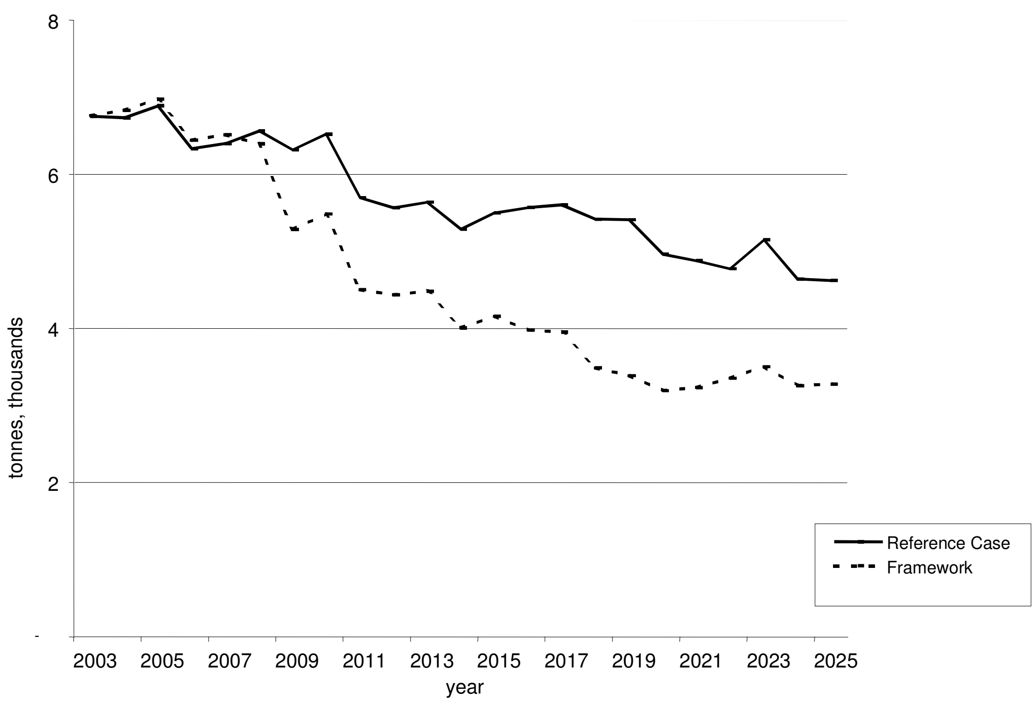
In the first scenario, some gas units reached the end of their design lives in the 2008-2010 period and installed control technology to meet BATEA levels. This combined with coal unit shutdowns in the 2013-2017 period caused the emissions profile to be lower than in the reference case for the same period. Further declines in emissions are shown in the latter half of the forecast due to coal plant requirements to meet BATEA levels. The second scenario shows a steeper decline of NOx emissions than in the first. In this case, emissions decline in 2011 and 2012 as coal and gas units install technology to comply with the sector cap. The most significant reduction in the cap occurred in 2020 thus forcing more coal units to install technology to ensure compliance with the cap. The emissions declines in the third scenario follow similar trends to the declines in the second scenario, however fewer plants install technology in each period due to less stringent caps.

Figure 16: Modelled Mercury Emissions Reductions



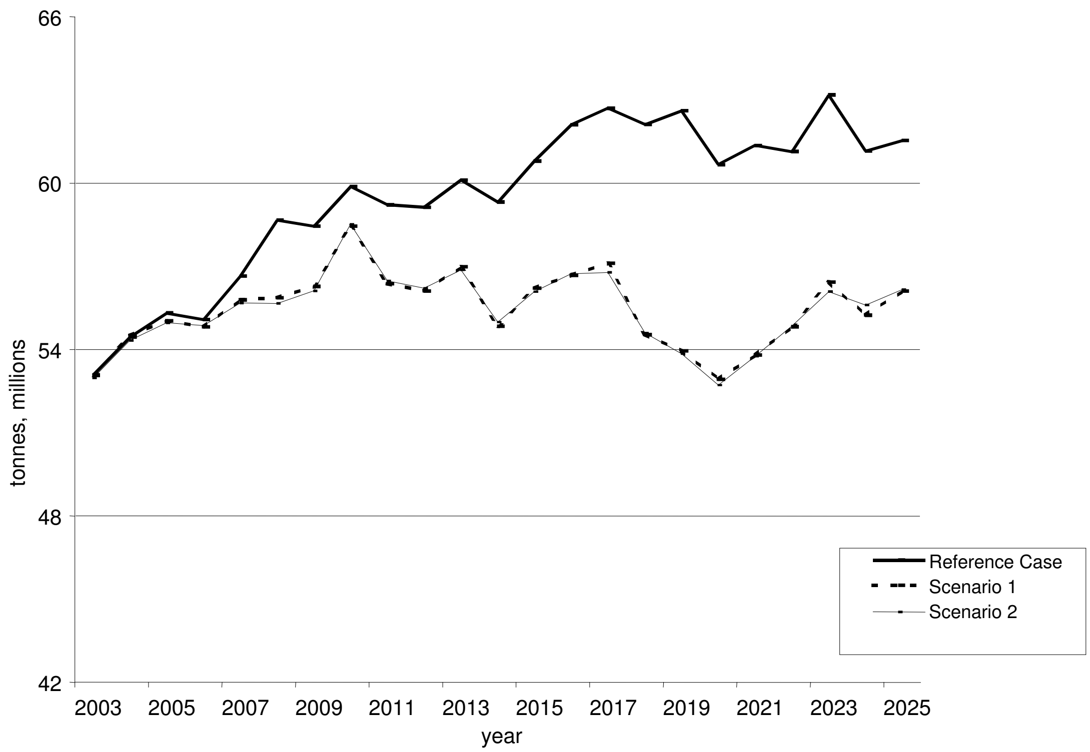
Mercury emissions in the framework line fall well below the reference case in 2009, which is the year the policy comes into effect. Mercury emissions fall by roughly half as a result of the policy. Significant reductions are also observed in 2018 when Sundance 1 and 2 retire, and minor reductions are seen in 2014 and 2016 after the retirements of Battle River 3 and 4, respectively.

Figure 17: Modelled Primary Particulate Emissions Reductions



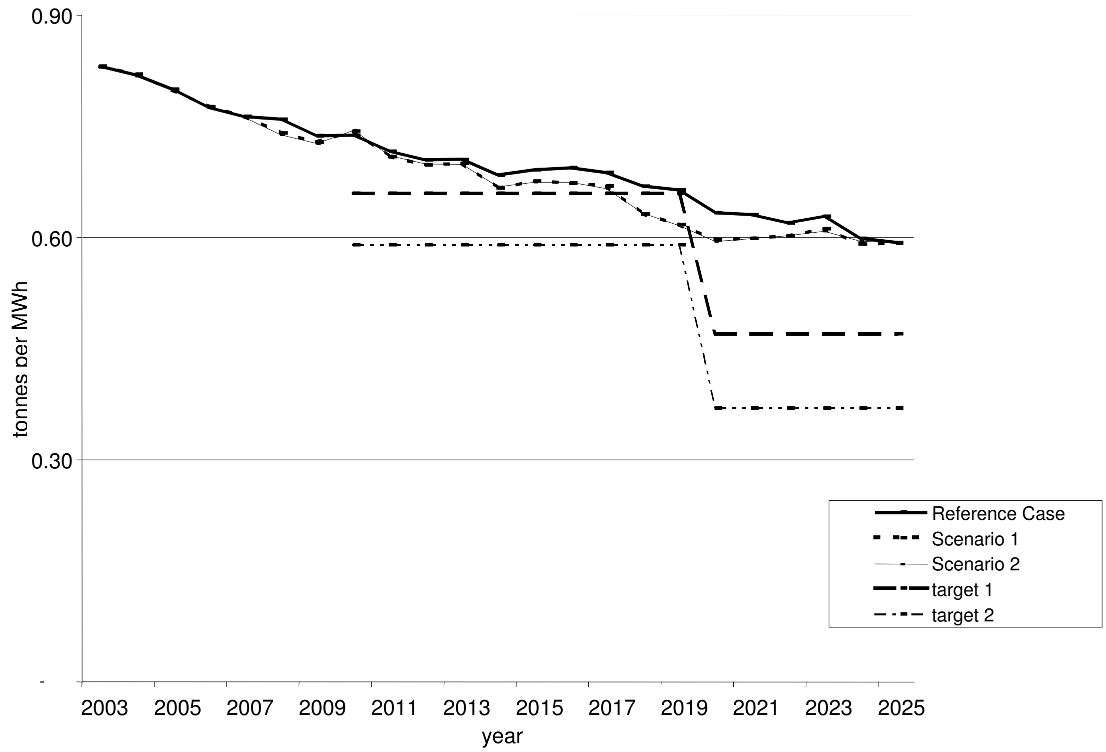
Primary particulate matter emissions fall as a co-benefit of the installation of mercury controls, dropping dramatically in 2009 when the policy is enacted, just as mercury emissions did. A further reduction is evident in 2011 as a result of the retirement of Wabamun 4, which was not quite as obvious in the mercury graph. Wabamun 4 retires in both cases.

Figure 18: Modelled Changes in Greenhouse Gas Emissions



Greenhouse gas emissions are presented as gross emissions, which are defined as all the greenhouse gas emissions that physically occur as a result of generating electricity in Alberta. As such, greenhouse gas offsets such as those associated with Genesee 3 are not removed from the graph.

Figure 19: Modelled Reductions in Greenhouse Gas Intensity



The target line in Figure 19 represents the target outlined in the policy framework. As the figure illustrates, the electricity industry exceeds the emission target from 2010 through 2013. In 2010, the industry is required to purchase greenhouse gas offsets to meet the sector intensity target. The share of this reduction burden was distributed equally on a percentage basis across all units. However, by 2014, the industry will meet the targets without any significant purchases due to an overall improvement in the sector's intensity caused by the retirement of older inefficient coal units and their replacement by new gas-fired generation. In the greenhouse gas sensitivity, the industry does not physically meet the first emission targets in any year. Since the target is more stringent, generators must purchase more offsets and for more years between 2010 and 2019 to be compliant with the policy. The same situation holds for the 2020 through 2025 period; the more stringent targets mean the industry must purchase a greater volume of emission offsets in order to meet the emission targets.

15.7.3 Costs and Impact on Generation

Emission management requirements introduce incremental emission costs to generators in Alberta. In addition to forecasting the impact these costs had on electricity prices, the modelling also examined whether or not emission costs rendered the existing generation fleet uneconomic. None of the existing coal units saw a shift in their capacity factors as a result of their incremental emission costs. However, as seen in Table 11, the total emissions control costs from 2003-2025 for existing coal units could be in the range of \$2.7-billion to \$3.8-billion. When this amount is discounted back into 2004 dollars, the total emissions control costs are between \$0.7-billion and \$1.0-billion. This represents a cost range to a typical unit of \$1.80/MWh to \$2.70/MWh across the 2003-2025 period. Based on an estimated all-in cost for a new coal plant of $50-$55/MWh with no emission costs, this represents a cost increase of approximately 3% to 5%.

Table 11: Generation Impacts of the Proposed Framework

	Scenario 1	Scenario 2 with Greenhouse Gas Sensitivity
Cumulative total emission costs ($000)	$2,735,433	$3,820,971
Present value of total emission costs (($000)[1]	$696,808	$1,036,879
Cumulative coal plant capacity (MW) [2]	$4,923	$4,923
Total emission costs present value per kW[1]	$142	$211
Levelized total emission costs per MWh[1, 2]	$1.80	$2.68
[1] Discount rate of 10% assumed [2] Based on capacity in service Jan. 1, 2011 (excl. Wab 1-2, Wab 4, and HR Milner)		

When assessing the cost to industry, it is crucial to balance this assessment with the knowledge that the alternative to the proposed framework is not one of zero cost. The framework incorporates various economic incentives and flexibility mechanisms that would not be realized on a facility-by-facility basis under the current provincial system. Under the existing regulatory regime, the EUB and Alberta Environment have already defined timeframes within which an older existing plant (i.e., the Wabamun Generating Facility) must come into compliance with current standards of the day. The approvals for Genesee 3 and Centennial also contemplate upgrades for both NOx and mercury. Thus upgrades in NOx and SO_2 recovery from existing and newly approved units would reasonably be expected to occur as each facility enters into its 10-year EPEA Approval renewal during the near and mid-term future.

As discussed in section 4.2.4, federal and provincial jurisdictions are committed through the CCME CWS process to require substantial reductions in mercury emissions at every facility by 2010. The CASA framework is consistent with this direction while offering flexibility to industry to minimize the overall cost of taking action. With Canada's ratification of the Kyoto Protocol, active discussions are underway to require greenhouse gas emission reductions by industry during the 2008-2012 period. The proposed framework aims to influence such discussions by furthering the environmental objective of reducing greenhouse gases in a manner that addresses the key interests of the stakeholders represented on the EPT.

PART FOUR: THE BENEFITS OF THE RECOMMENDED MANAGEMENT FRAMEWORK

This package of recommendations reflects significant reductions in four priority substances over time. It is a balanced approach in terms of both timing and cost, and the proposed framework aims to optimize reductions of multiple pollutants simultaneously. The recommended approach draws on a mix of economic instruments and management strategies, and its overall effectiveness depends on keeping all the recommendations intact.

The team is optimistic that emission reductions will in fact be better than projected due to improved technologies and practices. Several levels of environmental protection are built into the framework design, including special provisions to address potential hotspots and a recommended process for future substance reviews. The entire approach has also incorporated a number of mechanisms to ensure a publicly credible, transparent process with access to information and ongoing opportunities for multi-stakeholder involvement.

An emission trading system provides flexibility to the electricity sector in reducing emissions and to encourage improved performance. The framework clearly defines a process for revising and updating various components and it provides increased long-term certainty for all parties with respect to regulatory processes.

The Electricity Project Team believes its recommended approach is sufficiently flexible and robust to serve Albertans well into the future.

APPENDICES

Appendix A: Glossary

AESO (Alberta Electric System Operator)
The AESO is responsible for the safe, reliable and economic operation and planning of Alberta's interconnected power system and the facilitation of Alberta's real-time wholesale electricity market.

AIES (Alberta Interconnected Electric System)
The AIES, often called the grid, consists of transmission lines and substations that move power from generation facilities to end users.

Allowance
An authorization to emit a specific amount of pollutant under a cap and trade program. Under a cap and trade program, an emissions source must remit to the proper authority allowances equal to the amount of its emissions.

Atmospheric emissions
Pollutants emitted into the atmosphere. These are onsite air releases from sources at a facility and include: stack (or point source) emissions; emissions from storage and handling; fugitive emissions; and emissions from other sources such as spills.

Baseline and credit
A type of emission trading system. In a "baseline and credit" system, which is also sometimes referred to as a "rate-based system," the regulatory authority sets a level of allowable emissions for each participant (source) in the trading system. Allowable emissions in this system are generally based on intensity or rate (i.e., "X" tonnes or kilograms per unit of output). The source receives credits for reductions it makes below that baseline and credits may be traded with other participants or banked. Some sources are therefore credit buyers and others are credit generators (sellers), but the total overall emissions must be below the baseline.

BATEA (Best Available Technology Economically Achievable)
BATEA refers to technology that can achieve superior emissions performance and that has been demonstrated to be economically feasible through successful commercial application across a range of regions and fuel types. BATEA is used to establish emission control expectations or limits. Generally it is the emission limit that is specified and not the specific BATEA. Facilities can opt for other technologies or emission strategies as long as the emission limit is met. For example, for NOx control, the BATEA is considered to be selective catalytic reduction (SCR), but the NOx emissions requirement is 0.69 kg/MWh, a level considered achievable based on SCR technology.

BATEA of the day
"BATEA of the day" means the BATEA limits that are in force as regulatory standards at that time and that will apply to new units as well as to existing units that have reached the end of their design life. As noted in recommendation 29, the BATEA levels will be reviewed every five years and revised in accordance with the results of such reviews.

Behind the fence
Power that is generated by an industrial facility and used to meet its own electricity needs (e.g., the generation of electricity by co-generation units that also provide process steam/heat) is referred to as being "behind the fence."

Bill 37
Alberta government bill introduced in spring 2003 to address climate change and related emission management issues.

Bioaccumulative compounds
Bioaccumulative compounds are not usually broken down in the environment, which means they can become increasingly concentrated in organisms that are exposed to them.

BTEX (benzene, toluene, ethylbenzene, xylene)
BTEX is an acronym for a group of organic compounds found in petroleum products.

Cap and trade
A type of emission trading system. In a "cap and trade" system, the regulatory authority sets a cap on total emissions from the participants (or sector) in the trading system. The regulator then creates and allocates allowances to each participant, the total of which is equal to the overall cap. The allowances held by each participant must balance with their emissions at the end of each compliance period; the allocation is typically done annually, and thus the compliance period is also one year. Allowances are based on an absolute amount of emissions produced (that is, tonnes or kilograms) per year. If a participant can reduce emissions below their allocated allowances, the surplus amounts can be traded or banked.

CO_2 (carbon dioxide)
A greenhouse gas that is produced in the burning of fossil fuels

Co-benefits
When a technology to reduce a specific emission also has the benefit of reducing other emissions

Co-generation
Co-generation is the combined production of heat for use in manufacturing processes and the production of electricity as a by-product. Electricity not used within the plant may be offered to the competitive electricity market.

Credit
Under a rate-based trading program, credits take the form of an authorization to emit a specific quantity of emissions. The amount of credit generated will be equal to the emission source's performance below a specified performance rate. Conversely, credits can be applied to an emissions source that operates above a specific performance rate, helping it to achieve compliance.

Cumulative impact
The impact of emissions over time, or from a number of facilities in a given region.

CWS (Canada-wide Standards)
Initiatives undertaken by the Canadian Council of Ministers of the Environment (CCME) to develop national standards for certain substances; at the time this report was prepared, a CWS for mercury was being developed.

DLN/DLE (Dry Low NOx, Dry Low Emission)
These terms refer to pre-combustion burner technology for controlling NOx emissions.

Emissions trading
The use of allowances or credits to motivate improved performance while allowing some flexibility for facilities to achieve emission controls in the least cost manner. The experience has been that emissions trading encourages greater reductions earlier. This system was highly successful in reducing lead in gasoline, and has also been used for SO_2 and NOx in the U.S.

Fossil fuels
Fuels such as coal and natural gas that are derived from the Earth's fossilization process.

GHG (greenhouse gas(es)
These gases enhance the Earth's natural greenhouse effect and are major contributors to global climate change. The greenhouse gases covered by the Kyoto Protocol are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride.

GWh (Gigawatt-hour)
A Gigawatt-hour equals 1000 megawatt-hours or 1,000,000 kilowatt-hours or 1,000,000,000 watt-hours.

Hg (mercury)

A natural element that is widespread in the environment. It is toxic and bioaccumulates. It is present in coal and therefore the burning of coal results in mercury releases to the environment.

Intensity

An approach to reporting or managing emissions that relates the amount of emissions to some other variable; e.g., unit of input, unit of output, and Gross Domestic Product (GDP) of a nation, province or state. Other standards by which emissions intensity can be measured include: per barrel of oil; per million cubic feet of natural gas; per tonne of coal, cement, etc. produced; or per megawatt-hour of electricity.

For the electricity industry, intensity is a ratio that shows the mass of pollutants produced per unit of electric power produced. In general, the cleaner power production is, the lower the intensity. Critics point out that intensity measures do not necessarily relate to the absolute, or total, mass of pollutants emitted. For example, a power plant might emit 10 tonnes of pollution every day it operates at half capacity. If the plant implements an improvement and thereafter emits only eight tonnes of pollution per day at half capacity, that is a 20% improvement in emissions intensity. However, if the same plant increases production up to full capacity, it would emit 16 tonnes of pollution per day. By the intensity measure, the plant is still operating at the improved intensity, while absolute, or total, emissions would show that emissions doubled when the power produced doubled. When intensity targets factor in projected output growth they can achieve equivalent reductions to absolute targets.

Governments, Alberta included, tend to favour intensity measures because they are less likely to restrict expansion of power production and they provide a clear signal that there is an expectation of cleaner production.

kW (kilowatt)

A kilowatt is 1000 watts. A kilowatt-hour is the number of kilowatts used in one hour.

Marginal unit

The generation unit that is last in the order of units providing electricity into the Power Pool. This unit has the highest power cost of all units providing power into the grid at any given time and its power cost determines the wholesale electricity price and the price that all other generation units receive for their power.

MCR (Maximum Capacity Rating)

Maximum Capacity Rating is the manufacturer’s normal maximum continuous power output rating of the unit, in megawatts, at certain standard conditions.

MW (Megawatt)

Megawatt (1,000,000 watts or 1000 kilowatts); unit of capacity.

MWh (Megawatt-Hour)

Megawatt-hour is a unit of usage of power usage or generation; i.e., the number of megawatts used or generated in one hour. One megawatt equals 1000 kilowatts or 1,000,000 watts.

NGCC (Natural Gas Combined Cycle)

With NGCC, gas is combusted in a gas turbine and the expanding gas drives a generating turbine and the hot exit gases are used in a boiler to produce high-pressure steam, which drives a steam turbine generator that also produces electricity (sometimes supplementary gas is used in the steam generation cycle).

NGO (Non-government organization)

NGOs are usually non-profit or community groups. ENGOs are environmental non-government organizations.

NOx (nitrogen oxides, also called oxides of nitrogen)

Emissions produced in the burning of fossil fuels, arising largely from the oxidation of the nitrogen present in air that is used to support fuel combustion. NOx includes NO (nitrogen oxide) and NO_2 (nitrogen dioxide) but not N_2O (nitrous oxide).

Offsets

Setting an emission limit that allows emitters to use equal emission reductions from other sources, e.g., capturing and using methane emissions from landfill to offset CO_2 emissions, paying for the conversion of diesel buses to natural gas, propane, or biodiesel power to offset CO_2 emissions. These alternatives may achieve the same environmental goal at less cost and with additional benefits. Offsets are ideally suited for substances that don't have regional impacts, e.g., greenhouse gases.

PAHs (polycyclic aromatic hydrocarbons)

PAHs are a group of more than 100 chemicals formed during the incomplete combustion of fossil fuels and other organic substances. They are usually found as a mixture of several compounds. Some PAHs are manufactured.

PM (particulate matter)

Small particles produced in the burning of fossil fuels that are emitted into the atmosphere

PPA (Power Purchase Arrangements)

Contracts between power generators and electricity wholesalers. PPAs are intended to create a competitive market and all will expire by or before 2020.

Precursor

A chemical compound that leads to the formation of another compound in a series of chemical reactions.

Reduction targets

A requirement for power generators to reduce the amount of their emissions to meet a specific target; targets can be province-wide, regional or local.

SCR (Selective Catalytic Reduction)

SCR is a control technology for nitrogen oxides (NOx) that uses ammonia and a catalyst to convert NOx to N_2.

SO_2 (sulphur dioxide)

An emission produced in the burning of coal. All coals contain some sulphur.

Stack emissions

The amount of emissions directly measured at the stack of the facility.

Stacking order

Stacking order refers to the order in which generation units are directed by the Power Pool to provide electricity to the power grid. This is also referred to as "dispatch order." The units that produce the lowest cost power are normally dispatched first (coal); as demand rises, other units are brought on.

US Clear Skies

A multi-pollutant air quality initiative applying to the electricity sector and being considered by the United States.

UV (Ultraviolet)

Light that is characterized by shorter wavelengths and higher energy.

VOCs (volatile organic compounds)

Organic compounds that evaporate readily into the air. They include substances such as benzene, toluene, methylene chloride, formaldehyde and methyl chloroform. They are common ingredients in many household products. Many VOCs contribute to the formation of ground level ozone.

Appendix B: Electricity Project Team Terms of Reference

approved by the CASA board on March 7, 2002

Context:
The Terms of Reference for this Project Team supports the objectives identified in CASA's *Business Plan 1999-2002*, fits well within the priorities, values, and expectations of the Board, and is in accordance with the CASA vision for air quality, which states:

"The air will be odourless, tasteless, look clear and have no measurable short- or long-term adverse effects on people, animals or the environment."

The outcome of this process will provide certainty for the environmental performance of Alberta's electricity sector related to air emissions. It is anticipated that the results of this process may be applied to other sectors in the province.

The project team will operate in a manner that is consistent with the rules, policies and procedures adopted by CASA (multi-stakeholder, consensus decision-making, CAMS).

Goal:

To develop an air emissions management approach including standards and performance expectations for the Alberta electricity sector.

Objectives:

Recommend strategies to improve the air emissions performance of Alberta's electricity sector that reflect CASA's goals for air quality, namely:

1. Protect the Environment
2. Optimize Economic Performance and Efficiency; and
3. Seek Continuous Improvement.

Key Task Areas:

1. To develop a common information base, identify information needs, compile the information, and develop a strategy to fill gaps.
2. Identify which air emissions from the electricity sector, in addition to mercury, are a priority to be addressed.
3. Assess the feasibility of and recommend an approach to reducing greenhouse gas emissions from the electricity sector.
4. Identify, assess, and develop emissions management options and mixtures of options including standards and performance targets and measures for existing and new facilities.
5. Evaluate the appropriateness of management options for the project team's priority air emissions.
6. Recommend management approaches that include an innovative mix of options.
7. Recommend how management approaches, including standards and performance expectations, should be applied to new and existing facilities (e.g., zonal, regional, sector, local, facility or company approach).

8. Recommend appropriate monitoring, reporting, information sharing, and compliance mechanisms.
9. Coordinate and communicate as appropriate with relevant CASA, provincial, national and other processes.
10. Develop and implement a strategy and action plan for communicating and consulting with stakeholders and the public.
11. Develop a work plan and secure resources to carry out the work plan.
12. Develop final report and recommendations (including timelines, action that needs to be taken, agency responsible, etc).

Membership on the Project Team

A list of Project Team members is attached.

Reporting to the CASA Board

The Team will prepare and make the following reports to the CASA Board:

1. Terms of Reference and establishment of a Project Team	March 2002
2. Budget and Project Team work plan	June 2002
3. Interim review	Nov 2002
4. Final report and recommendations	June 2003

Budget

To be developed

Appendix C: Project Team Members and Subgroup Members[69]

* designates a co-chair of the group

Keri Barringer	Environmental Law Centre
Peter Blackall	Environment Canada
Claude Chamberland	Canadian Petroleum Products Institute (CPPI)
Kerra Chomlak	Clean Air Strategic Alliance (CASA)
Susan Dowse	Calpine Canada
Linda Duncan	Lake Wabamun Enhancement Protection Association
Jason Edworthy	Vision Quest Windelectric Inc. (corresponding member
Pat Garvin	Luscar/Coal Association of Canada
Ed Gibbons	Alberta Urban Municipalities Association (AUMA)
Paul Hunt	Climate Change Central
Les Johnston	EPCOR
Mike Kelly*	TransAlta Corporation
Joe Kostler	ATCO Power (now with ATCO Electric)
Martha Kostuch*	Prairie Acid Rain Coalition and Bert Riggall Environmental Foundation
Bevan Laing	Alberta Energy
Tim Lambert	Canadian Public Health Association
Christine Macken	CASA
Satwant Lota	Alberta Energy and Utilities Board (AEUB)
Alex MacKenzie/ Justin Balko	Alberta Health and Wellness
Tom Marr-Laing	Pembina Institute
Don Macdonald	Alberta Environment
Ted Ostrowski	Canadian Association of Petroleum Producers (CAPP) / Oil sands
Al Schulz	Canadian Chemical Producers Association (CCPA)
Herman Schwenk	Agricultural producers
Nashina Shariff	Toxics Watch Society
David Spink*	Alberta Environment
John Squarek	CAPP / Upstream oil and gas
Harry Tyrrell/ Ruth Yanor	Mewassin Community Action Council
Evelyn Walker	Power Purchase Arrangement Buyers

Former Team Members

Doug Castellino	PPA Buyers
Matthew Dance	Sierra Club
John Donner	Alberta Environment
Rod Frith	Environment Canada
Bart Guyon	Alberta Association of Municipal Districts and Counties (AAMD&C)
Brent Lakeman	Alberta Environment
Dermot Lane	Coal Association of Canada

[69] The affiliations of some former team members and members of subgroups have since changed; the affiliation shown was accurate at the time the individual was active.

Chow-Seng Liu	Alberta Environment
Rob McManus	Calpine Canada
Dennis Paul	First Nations Energy Task Force
Larry Phillips	Western Canada Wilderness Committee
Ansar Qureshi	Alberta Health and Wellness
Neil Shelly	Alberta Forest Products Association

EPT Subgroups

Energy Efficiency and Energy Conservation Working Group

Mark Antoniuk	ATCO Power
Denise Chang-Yen	EPCOR Energy Services
Keith Denman	CASA
Gordon Howell	Howell-Mayhew Engineering
Simon Knight	Climate Change Central
Bevan Laing	Alberta Energy
Brian Mitchell*	Mewassin Community Action Council
Andrew Pape-Salmon	Pembina Institute
Nashina Shariff	Toxics Watch Society
Justin Thompson	Vision Quest Windelectric
Sarah Waddington	Alberta Environment

Gas/Co-Gen Subgroup

Rick Barteluk	TransCanada
Peter Blackall	Environment Canada
Pat Bowes	Calpine
Claude Chamberland	Shell/CPPI
Keith Denman	CASA
Kendall Dilling	Encana/CAPP
Susan Dowse	Calpine
Paul Godman	Encana
Brad Howard	TransCanada
Mike Kelly	TransAlta
Joe Kostler	ATCO Power (now with ATCO Electric)
Bevan Laing	Alberta Energy
Chow-Seng Liu	Alberta Environment
Tom Marr-Laing	Pembina Institute
Ted Ostrowski	Syncrude/CAPP
Dwight Redden	ATCO Power
Doug Shaigec	TransCanada
Nashina Shariff	Toxics Watch
Elizabeth Siarkowski	TransCanada
David Spink*	Alberta Environment
John Squarek	CAPP
Wil Vandenborn	Dow Chemical
Evelyn Walker*	TransCanada

Information Gathering Subgroup

Linda Duncan	Lake Wabamun Enhancement and Protection Association
Mary Griffiths*	Pembina Institute
Markus Kellerhals	Environment Canada
Mike Kelly*	TransAlta Corporation
Bevan Laing	Alberta Energy
Dermot Lane	Coal Association of Canada
Ingrid Liepa	CASA
Satwant Lota	Alberta Energy and Utilities Board
Bill Peel	ATCO Power Canada Ltd.
Ansar Qureshi	Alberta Health and Wellness
David Spink	Alberta Environment

Management Options Subgroup

Keri Barringer	Environmental Law Centre
Peter Blackall	Environment Canada
Kerra Chomlak	Clean Air Strategic Alliance Association
Susan Dowse	Calpine Canada
Linda Duncan	Lake Wabamun Enhancement and Protection Association
Ed Gibbons	Alberta Urban Municipalities Association
Paul Hunt	Climate Change Central
Les Johnston	EPCOR
Mike Kelly	TransAlta Corporation
Joe Kostler*	ATCO Power (now with ATCO Electric)
Tim Lambert	Canadian Public Health Association
Chow-Seng Liu	Alberta Environment
Satwant Lota	Alberta Energy and Utilities Board
Tom Marr-Laing*	Pembina Institute
Brian Mitchell	Mewassin Community Action Council
Kim Sanderson	CASA
Nashina Shariff	Toxics Watch Society
David Spink*	Alberta Environment
John Squarek	Canadian Association of Petroleum Producers
Justin Thompson	Alternate Energy
Evelyn Walker	PPA Buyers

Monitoring, Reporting, Compliance, Public Participation, Accountability and Transparency Subgroup

Keri Barringer	Environmental Law Centre
Kerra Chomlak	CASA
Keith Denman	CASA
Linda Duncan*	Lake Wabamun Enhancement and Protection Association
Joe Kostler*	ATCO Power (now with ATCO Electric)
Tim Lambert	Canadian Public Health Association
Ian Peace	Residents for Accountability in Power Industry Development
Chow-Seng Liu*	Alberta Environment
David Spink	Alberta Environment
Elizabeth Swanson	TransCanada

Alex MacKenzie, Alberta Health and Wellness, provided valuable input although not a formal member of the subgroup.

Prioritization Subgroup

Randy Dobko	Alberta Environment
Linda Duncan	Lake Wabamun Enhancement and Protection Association
Les Johnston	EPCOR
Tim Lambert*	Canadian Public Health Association
Dermot Lane*	Coal Association of Canada
Frank Letchford	Environment Canada
Ingrid Liepa	CASA
Chow-Seng Liu	Alberta Environment
Ken Omotani	TransAlta Corporation
Ansar Qureshi	Alberta Health and Wellness
David Spink	Alberta Environment
Harry Tyrrell	Mewassin Community Action Council

Public Consultation Subgroup

Keri Barringer	Environmental Law Centre
Marilyn Carpenter*	TransCanada
Matthew Dance	CASA
Shannon Flint	Alberta Environment
Ed Gibbons	Alberta Urban Municipalities Association
Mike Kelly	TransAlta Corporation
Frank Letchford	Environment Canada
Ian Peace*	Residents for Accountability in Power Industry Development
Sari Shernofsky	Public Consultation Consultant
Harry Tyrrell	Mewassin Community Action Council
Sarah Waddington*	Alberta Environment

Former Subgroup Members

Linda Duncan	Lake Wabamun Enhancement and Protection Association
Catherine Hart*	Fording Coal
Bart Guyon	AAMD&C

Renewable and Alternative Energy Subgroup

Keith Denman	CASA
Rob Falconer	ENMAX Energy Corporation
Gordon Howell	Howell-Mayhew Engineering
Shannon Flint	Alberta Environment
Theresa Howland	VisionQuest Windelectric
Dianne Humphries	Suncor Energy Inc.
Paul Hunt	Climate Change Central
Les Johnston	EPCOR
Simon Knight	Climate Change Central
Bevan Laing	Alberta Energy
Brian Mitchell*	Mewassin Community Action Council
Andrew Pape-Salmon	Pembina Institute
Nashina Shariff	Toxics Watch Society

Justin Thompson	Vision Quest Windelectric
Evelyn Walker	PPA Buyers

Straw Dog Subgroup

Peter Blackall	Environment Canada
Kerra Chomlak/ Christine Macken	CASA
Mike Kelly	TransAlta Corporation
Tom Marr-Laing	Pembina Institute
Kim Sanderson	CASA
Nashina Shariff	Toxics Watch Society
David Spink	Alberta Environment
Evelyn Walker	PPA Buyers

Former Subgroup Member

Chow-Seng Liu	Alberta Environment

Appendix D: Additional Tasks of the EPT

Recommendations from the Pollution Prevention/Continuous Improvement Project Team

Three areas were identified by the Pollution Prevention/Continuous Improvement (P2CI) Project Team, which recommended that:

- CASA's Electricity Project Team address **renewable energy** as part of its task to identify, assess and develop emissions management options and mixtures of options.
- CASA's Electricity Project Team **consider P2/CI** in the development of its management approach for that sector.
- CASA's Electricity Project Team consider **opportunities for co-generation** as part of its overall approach to managing emissions from the electricity sector.

Response from the EPT to the Recommendations from the Pollution Prevention/Continuous Improvement Project Team

The EPT believes it has addressed all of the recommendations from the Pollution Prevention/Continuous Improvement Project Team. Renewable energy was an important consideration and the EPT has made recommendations that will support renewable energy development in Alberta (see section 10).

A key goal for the EPT was that its approach reduce emissions of five priority substances – SO_2, NOx, primary particulate matter, mercury and greenhouse gases – in other words, prevent pollution. Reducing these priority substances will also reduce emissions of other substances, referred to as "co-benefits." Continuous improvement was the subject of considerable discussion, and the team has developed a number of recommendations that will result in better performance of the electricity generation sector over time (see section 6.1.7 and recommendation 29).

The team's recommendations acknowledge the importance of co-generation, both as a behind-the-fence source of power for industry and as a source of electricity to the grid. Co-generation is growing rapidly in Alberta, particularly in association with oil sands in the northeast, and recent changes in the province's transmission policy are expected to encourage this growth.

Recommendations from the Acidifying Emissions Management Implementation Team

The Acidifying Emissions Management Implementation Team (AEMIT) noted there was value in pursuing province-wide reduction targets for NOx and SOx, but decided to refer this issue to the Electricity Project Team. The AEMIT's NOx Subgroup had specifically considered that:

1. A provincial emission target for existing sources (on an acidifying basis) should be set. This target would be somewhere between full penetration of new source standards versus existing business as usual.

2. An economic efficiency target also must be set; e.g., 50% penetration of Best Available Technology (equivalent) should cost less than 50% of BAT.
3. AEMIT should establish the management option (unlike the sour gas sulphur recovery review).
4. Improved source emission inventory information should be gathered.

Response from the EPT to the items from the Acidifying Emissions Management Implementation Team

The EPT identified SO_2 and NOx as two of the priority substances and has proposed ways in which they can be addressed. The EPT also spent significant time considering targets, timelines and mechanisms for reducing SO_2 and NOx, as well as discussing how to deal with local concerns and hotspots. The team's recommended approach for managing NOx and SO_2 could help form the basis for the provincial NOx/SO_2 emissions management approach that the AEMIT identified. The team has recommended that a multi-stakeholder team be established to examine the possibility of integrating the emissions trading system developed in this framework with a multi-sectoral emissions trading system. Some of the work still be completed may result in recommendations that would encourage co-generation.

Although the EPT did not establish an economic efficiency target, considerable effort went into modelling the economic impacts of the reduction targets that were considered. The EPT's recommendations on monitoring, reporting and compliance will improve source emission inventory information.

Appendix E: Factors for Consideration in Selecting Management Options

This list contains many of the factors that were raised by one or more Electricity Project Team and Management Options Subgroup members at the September 2002 Management Options Workshop. These factors were regarded as important when considering and evaluating management options. The factors are listed in the order in which they were provided and have not been ranked or edited.

Demonstrated effectiveness
Cost of implementation
Cost of compliance
Regulatory certainty
Outcome certainty
Investment certainty
Simplicity in establishment
Simplicity in administration
Time to implement
Adaptability and/or expandability
Stakeholder support
Local air quality
Multi-pollutant management
Fairness/equity
Enforceability/compliance
Compatibility
Simplicity
Transparency
Stakeholder participation
Clarity
Comprehensive
Fed/provincial applications
Technological achievability
Continuous Improvement
Cost
Precautionary
Co-benefits
Environmental need
Health need
Extent of known environmental deterioration
Health impact indicators
Relationship to provincial and national standards
Cost implications to consumers
Suitability
Cost-effectiveness
Potential performance successes
No reduction in electricity service reliability
No distortion of the competitive electricity market intended by the Electrical Utilities Act
Environmental protection
“Clean hands” (lead by example)
Exported and imported pollution
Level playing field
Cost sharing
Competitiveness
Full cost accounting
Adequacy of scientific data
Loading limits (local and global)
Location of emission sources
Naturally occurring background and baseline levels
Prevention
Justice
Sources of emissions

Appendix F: Documents Prepared by or for the Electricity Project Team

The following documents were prepared during the course of the work of the Electricity Project Team, either by the team or commissioned for them. Workshop reports and documents other than final reports of the team and subgroups are available online at http://www.casahome.org/electricity. Final reports, as noted below, are available online at http://www.casahome.org/electricity/finalreports.asp. All documents are also available on request to the CASA Secretariat.

- Electricity Project Team *Report from the Information Gathering Workshop*, May 27-29, 2002, Terratima Lodge. 23 pages.
- Presentations, questions and answers from the *Management Options Information Seminar,* September 16-17, 2002, Calgary, Alberta.
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Final Reports

- *Energy Efficiency and Conservation Working Group Report to the EPT.* October 2003.
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- *Renewable and Alternative Energy Working Group Report to the EPT.* October 2003.
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Appendix G: Examples of the Application of the NOx and SO_2 Management System under Different Possible Scenarios

PART 1: NOx and SO_2 APPLICATION EXAMPLES FOR COAL-FIRED UNITS

Purpose

To provide some specific examples of how the NOx and SO_2 management framework would apply to coal units under certain circumstances or situations. The examples try to represent plausible, and even likely, situations.

Assumptions and Example Unit Descriptions

Assumptions:

BATEA limits and deemed credit thresholds for NOx and SO_2 in future years (these are assumed; actual limits and thresholds would be set every five years through a multi-stakeholder process):

Period	BATEA Based Limit for NOx (kg/MWh)	Deemed Credit Threshold for NOx (kg/MWh)	BATEA Based Limit for SO_2 (kg/MWh)	Deemed Credit Threshold for SO_2 (kg/MWh)
2006-2010	0.69	0.62	0.80	0.72
2011-2015	0.60	0.54	0.70	0.63
2016-2020	0.50	0.45	0.50	0.45
2021-2025	0.45	0.40	0.40	0.36
2026-2030	0.20	0.18	0.20	0.18
2031-2035	0.20	0.18	0.20	0.18
2036-2040	0.15	0.14	0.15	0.14
2041-2045	0.10	0.09	0.15	0.14

The natural gas combined cycle (NGCC) offset requirement for new coal units and existing coal units that reach the end of Design Life is based on an NGCC CO_2 intensity of 0.418t/MWh, which remains the same until 2050.

Example Unit Descriptions

UNIT "A"

- Unit's operational commencement date: January 1, 1975
- End of unit's 40 year life: January 1, 2015
- End of PPA (which is end of Design Life for this unit) January 1, 2020
- Maximum Capacity Rating (MCR): 500 MW
- NOx, SO_2 and CO_2 emission intensity in 2000-2002 period:

Year	NOx Emission Intensity (kg/MWh)	SO_2 Emission Intensity (kg/MWh)	CO_2 Emission Intensity (t/MWh)
2000	1.55	2.35	1.00
2001	1.60	2.45	1.04
2002	1.50	2.40	1.02
2000-2002 average	**1.55** (This is the unit's baseline NOx intensity for the purpose of credit generation.)	**2.40** (This is the unit's baseline SO_2 intensity for the purpose of credit generation.)	**1.02** (This is the unit's baseline CO_2 intensity for the purpose of credit generation.)

- Unit A's output in specific years:

Year	Output GWh	Year	Output GWh
2012	3000	2017	3000
2013	3100	2018	2600
2014	3200	2019	2700
2015	2800	2020	2800
2016	2900		

UNIT "B"

- Unit's operational commencement date: January 1, 1975
- End of unit's 40 year life: January 1, 2015
  (which is end of Design Life for this unit)
- End of PPA: January 1, 2010
- Maximum Capacity Rating (MCR): 500 MW
- NOx, SO_2 and CO_2 emission intensity in 2000-2002 period:

Year	NOx Emission Intensity (kg/MWh)	SO_2 Emission Intensity (kg/MWh)	CO_2 Emission Intensity (t/MWh)
2000	1.55	2.35	0.98
2001	1.60	2.45	0.99
2002	1.50	2.40	1.00
2000-2002 average	**1.55** (This is the unit's baseline NOx intensity for the purpose of credit generation.)	**2.40** (This is the unit's baseline SO_2 intensity for the purpose of credit generation.)	**0.99** (This is the unit's baseline CO_2 intensity for the purpose of credit generation.)

- Unit B's output in specific years:

Year	Output GWh	Year	Output GWh	Year	Output GWh
2002	3000	2010	3000	2018	2600
2003	3100	2011	3100	2019	2700
2004	3200	2012	3000	2020	2800
2005	2800	2013	3100		
2006	2900	2014	3200		
2007	2850	2015	2800		
2008	2900	2016	2900		
2009	3000	2017	3000		

UNIT "C"

- Unit's operational commencement date: January 1, 2010
- End of unit's 40 year life: January 1, 2050
  (which is end of Design Life for this unit)
- End of PPA: n/a
- Maximum Capacity Rating (MCR): 500 MW
- Unit's GHG Emission Intensity: 0.86t/MWh (but must be offset to 0.418t/MWh)

- NOx and SO_2 emission intensity in unit's approval (these are the 2006-2011 BATEA limits) and deemed credit thresholds:

NOx Emission Intensity Limit (kg/MWh)	NO_x Deemed Credit Threshold Intensity (kg/MWh)	SO_2 Emission Intensity Limit (kg/MWh)	SO_2 Deemed Credit Threshold Intensity (kg/MWh)	CO_2 Emission Intensity Limit (t/MWh)
0.69	0.62	0.80	0.72	0.418

- Unit C's actual performance in noted years:

Year	NOx Emission Intensity (kg/MWh)	SO_2 Emission Intensity (kg/MWh)
2010	0.65	0.75
2011	0.62	0.73
2012	0.58	0.69

- Unit C's output in specific years:

Year	Output GWh	Year	Output GWh	Year	Output GWh
2011	3000	2016	2900	2040	2100
2012	3000	2017	3000	2041	1800
2013	3100	2018	2600	2042	1500
2014	3200	2019	2700	2043	1300
2015	2800	2020	2800	2044	1000

UNIT "D" (Note: This is assumed to be a transition unit (see recommendations 4 and 7)

- Unit's operational commencement date: January 1, 2007
- End of unit's 40 year life: January 1, 2047
  (which is end of Design Life for this unit)
- End of PPA: n/a
- Maximum Capacity Rating (MCR): 450 MW
- Unit's GHG Emission Intensity: 0.86t/MWh (but must be offset to 0.418t/MWh)
- NOx and SO_2 emission intensity requirements and deemed credit thresholds:

Year/Period	NOx Emission Intensity Limit (kg/MWh)	NO_x Deemed Credit Threshold Intensity (kg/MWh)	SO_2 Emission Intensity Limit (kg/MWh)	SO_2 Deemed Credit Threshold Intensity (kg/MWh)	CO_2 Emission Intensity Limit (t/MWh)
2007-2015	1.18[1]	1.18[1]	1.70[1,2]	0.80	0.418
Post 2015	0.69	0.62	0.80	0.80	0.418

[1] These values are converted from the 2001 standards, which are in ng/L units; the values should be considered approximate

[2] This is the approved limit but the expected performance limit for the unit is 0.80kg/MWh (see recommendation 7).

- Unit D's actual performance in noted years:

Year	NOx Emission Intensity (kg/MWh)	SO_2 Emission Intensity (kg/MWh)
2008	1.10	0.75
2009	1.09	0.73
2010	1.11	0.69
2016	0.65	0.75
2017	0.64	0.73
2018	0.63	0.69

- Unit D's output in specific years:

Year	Output GWh	Year	Output GWh
2007	3000	2016	2900
2008	3000	2017	3000
2009	3100	2018	2600
2010	3200	2019	2700
2011	2800	2020	2800

Scenario 1: Credit generation by existing units

Situation:
A retrofit occurs at UNIT "A" in 2012 for NOx control. The retrofit NOx control device can reduce NOx emissions by about 20% to 1.3 kg/MWh. The unit is eligible for NOx credits for this change.

The credits generated would be calculated as follows:

- **Baseline Intensity:** The unit's NOx baseline would be established based on the 2000-2002 NOx emission intensity (see above table). In this example the baseline NOx intensity is 1.55 kg/MWh.
- **Actual Intensity:** The unit's NOx intensity each year after the retrofit would be reported along with the unit's output. In this example the actual intensity is 1.3 kg/MWh.
- **Credit Generation:** The unit would be granted the following number of credits each year until PPA expiry (in cases where the unit design life date is greater than PPA expiry date, such as Unit "B", then the unit would get credits until its end of design life date).
    - Credits generated (tonnes)=(baseline intensity-actual intensity) X (output)
      For this example (in 2013) = (1.55 kg/MWh - 1.3 kg/MWh) X 3100GWh X 1000MW/GW X 1 tonne/1000kg = **775 tonnes of NOx credits**

If for any reason the intensity in a given year were higher than the baseline intensity, then the above calculation would give a negative credit figure. In such a case, the unit would have to purchase credits or use banked credits to achieve a zero net credit balance. Any generated credits that are not used in the year in which they were granted would be subject to a one-time 10% discount.

Scenario 2: Credit generation by new (post-2005) units

Situation:
Unit "C" installs NOx and SO_2 controls that result in performance better than its BATEA limits. The unit may be eligible for credits. (This example considers only SO_2 credit generation but the same approach would apply to NOx credit generation.)

The credits generated would be calculated as follows:

- **Deemed Credit Threshold:** The unit's SO_2 deemed credit threshold is 0.72 kg/MWh (see above assumption table). See report Section 6.1.2 for details.
- **Actual Intensity:** The unit's SO_2 intensity each year after the retrofit would be reported along with the unit's output. The actual intensities in this example are:

Year	SO_2 Emission Intensity (kg/MWh)
2010	0.75
2011	0.73
2012	0.69

- **Credit Generation:** The unit would generate SO_2 credits based on the following formula:
    - Credits generated (tonnes) = (deemed credit threshold - actual intensity) X (output)

  For this example credits would not be generated in 2010 or 2011 because the actual emission intensities are higher than the deemed credit threshold.

  In 2012, credits would be generated and would = (0.72 kg/MWh-0.69 kg/MWh) X 3100GWh X 1000MW/GW X 1 tonne/1000kg = **93 tonnes of SO_2 credits**

  In this example, in some years, the actual emission intensity is above the deemed credit threshold. In such cases the above calculation gives a negative credit figure. This is **not** a credit shortfall, there are just no credits generated. Any credits that are not used in the year in which they were certified would be subject to a one-time 10% discount.

Scenario 3: Credit generation by transition units

Situation #1:
Unit "D" commences operation and wants to determine the credits it is generating. This example looks at the year 2009.

The credits generated would be calculated as follows:

- **Deemed Credit Threshold:** The unit's SO_2 deemed credit threshold is 0.80 kg/MWh and the NOx deemed credit threshold is 1.18 kg/MWh (see above assumption table). These thresholds are different than for post-2005 units and were set based on considerations related to the transitioning of these units from the old to the new framework and from the 2001 to 2006 BATEA limits.

- **Actual Intensity:** The unit's SO_2 and NOx intensity would be reported each year along with the unit's output. The intensities and generation in this example in 2009 are:

Year	SO_2 Emission Intensity (kg/MWh)	NOx Emission Intensity (kg/MWh)	Generation (GWh)
2009	0.73	1.09	3100

- **Credit Generation:** The unit would generate NOx and SO_2 credits based on the following formula:

  Credits generated (tonnes) = (deemed credit threshold - actual intensity) X (output)

  NOx credits would therefore be:
  - Credits generated = (1.18 kg/MWh – 1.09 kg/MWh) X 3100 GWh X 1000MWh/GWh X 1 tonne/1000kg = **279 tonnes of NOx credits**

  SO_2 credits would therefore be:
  - Credits generated = (0.80 kg/MWh – 0.73 kg/MWh) X 3100 GWh X 1000MWh/GWh X 1 tonne/1000kg = **217 tonnes of SO_2 credits**

  Transition units would be expected to generate NOx and SO_2 credits in the period up to 2015 when new limits and deemed credit thresholds take effect. This is because the NOx deemed credit threshold is the same as the approval limit and the SO_2 deemed credit threshold is the same as the expected performance level. In both cases, performance better than these levels is expected.

  Any generated credits that are not used in the year in which they were certified would be subject to a one-time 10% discount.

Situation #2:
Unit D's emission limits and deemed credit threshold change in 2015 and the following example calculates the credits the unit would receive in 2016 based on the assumed emission intensities and generation at that time.

The credits generated would be calculated as follows:

- **Deemed Credit Threshold:** The unit's SO_2 deemed credit threshold is now 0.80kg/MWh and NOx deemed credit threshold is 0.62 kg/MWh (see above assumption table). These thresholds are different than for post-2005 units and were set based on considerations related to the transitioning of these units from the old to the new framework and from the 2001 to 2006 BATEA limits.
- **Actual Intensity:** The unit's SO_2 and NOx intensity would be reported each year along with the unit's output. The intensities and generation in this example in 2009 are:

Year	SO_2 Emission Intensity (kg/MWh)	NOx Emission Intensity (kg/MWh)	Generation (GWh)
2009	0.75	0.65	2900

- **Credit Generation:** The unit would generate NOx and SO_2 credits based on the following formula:

  Credits generated (tonnes) = (deemed credit threshold - actual intensity) X (output)

  NOx credits would therefore be:
  - Credits generated = (0.62 kg/MWh – 0.65 kg/MWh) X 2900 GWh X 1000MWh/GWh X 1 tonne/1000kg = **-87 tonnes of NOx credits**

  In this example the actual emission intensity is above the deemed credit threshold and the calculation gives a negative credit figure. This is **not** a credit shortfall, there are just no credits generated.

  SO_2 credits would therefore be:
  - Credits generated = (0.80 kg/MWh – 0.75 kg/MWh) X 2900 GWh X 1000MWh/GWh X 1 tonne/1000kg = **145 tonnes of SO_2 credits**

  Transition units would be expected to generate SO_2 credits in the post-2015 period because the SO_2 deemed credit threshold is the same as the approval limit and actual performance should always be better than the approval limit. In the post-2015 period, the approval limit for NOx is higher than the deemed credit threshold and therefore as in the above example NOx credits may not always be generated.

  Any generated credits that are not used in the year in which they were certified would be subject to a one-time 10% discount.

Scenario 4: Credits for early shutdown

Situation #1:
Unit "A" decides to shutdown on January 1, 2017, which is before the end of its Design Life (in this case PPA expiry). The unit is eligible for NOx and SO_2 credits for early shutdown.

The early shutdown credits for which it is eligible would be calculated as follows:

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the Design Life date and the shutdown date. In this case it is the PPA expiry date that applies and the number of early shutdown years is: *January 1, 2020 (PPA expiry date) – January 1, 2017 (shutdown date) = 3 years*
- **Emission Intensity Difference:** The NOx and SO_2 intensity values used to calculate credits for early shutdown are the unit's baseline NOx and SO_2 intensity values and the midpoint between the BATEA limit for new units at the time of shutdown and the "deemed credit threshold" NOx and SO_2 intensities at the time of shutdown. In this case the NOx and SO_2 intensities used to calculate NOx and SO_2 credits for early shutdown would be:
  - NOx = Baseline NOx emission intensity –(((2016-2020 BATEA limit) + (2016-2020 deemed credit threshold))/2)
    NOx = 1.55 kg/MWh – ((0.50 kg/MWh+ 0.45 kg/MWh)/2) = **1.075 kg/MWh**

  - SO_2 = Baseline SO_2 emission intensity –(((2016-2020 BATEA limit) + (2016-2020 deemed credit threshold))/2)
  - **SO_2** = 2.40 kg/MWh –((0.50 kg/MWh + 0.45 kg/MWh)/2) = **1.925 kg/MWh**

- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2012 to January 1, 2017.
  - The best 3 years of output during this period (see above table) is 3000GWh (in 2012), 3100 GWh (in 2013) and 3200 GWh (in 2014), the average of which is **3100 GWh.**

- **Credits for Early Shutdown:** The block of early shutdown credits the unit would receive is calculated as follows:
  - NOx early shutdown credits = (Baseline NOx emission intensity – (((2016-2020 BATEA limit) + (2016-2020 deemed credit threshold))/2)) X (unit output rate) X (number of early shutdown years)

    For this example: NOx early shutdown credits = (1.075 kg/MWh) X 3100 GWh X 3 years X 1000 MW/GW X 1 tonne/1000kg = **9998 tonnes of NOx credits**

  - SO_2 early shutdown credits = (Baseline SO_2 emission intensity – (((2016-2020 BATEA limit) + (2016-2020 deemed credit threshold))/2)) X (unit output rate) X (number of early shutdown years)

    For this example: SO_2 early shutdown credits = (1.925 kg/MWh) X 3100 GWh X 3 years X 1000 MW/GW X 1 tonne/1000kg = **17,903 tonnes of SO_2 credits**

  Any of these credits that are not used in the early shutdown period as noted above would be subject to a one-time 10% discount.

Situation #2:
Unit "B" decides to shut down on January 1, 2007*, *which is before the end of its Design Life (in this case 40 years). The unit is eligible for NOx and SO_2 credits for early shutdown.

The early shutdown credits would be calculated as in Situation #1 except that the design life date, which is greater than the PPA expiry date, would be used to calculate the period for which early shutdown credits are granted.

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the design life date and the shutdown date. In this case the number of years is: *January 1, 2015 (Design life date) – January 1, 2007 (shutdown date) = 8 years*
- **Emission Intensity Difference:** The NOx and SO_2 intensity values used to calculate credits for early shutdown are the unit's baseline NOx and SO_2 intensity values and the deemed credit threshold NOx and SO_2 intensities at the time of shutdown. In this case the NOx and SO_2 intensity values used to calculate NOx and SO_2 credits for early shutdown would be:

  - NOx = Baseline NOx emission intensity – (((2006-2010 BATEA limit) +(2006-2010 deemed credit threshold))/2)
    NOx = 1.55 kg/MWh –((0.69 kg/MWh+0.62kg/MWh)/2) = **0.895 kg/MWh**
  - SO_2 = Baseline SO_2 emission intensity – (((2006-2010 BATEA limit) +(2006-2010 deemed credit threshold))/2)
    SO_2 = 2.40 kg/MWh – ((0.80 kg/MWh+ 0.72 kg/MWh)/2) = **1.64 kg/MWh**

- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2002 to January 1, 2007.
  - The best 3 years of output during this period (see above table) are 3000 GWh (in 2002), 3100 GWh (in 2003) and 3200 GWh (in 2004), the average of which is **3100 GWh**

- **Credits For Early Shutdown:** The block of early shutdown credits the unit would receive is calculated as follows:
  - NOx early shutdown credits = (Baseline NOx emission intensity – (((2016-2020 BATEA limit) + (2016-2020 deemed credit threshold))/2)) X (unit output rate) X (number of early shutdown years)

    For this example: NOx early shutdown credits = (0.895 kg/MWh) X 3100 GWh X 8 years X 1000 MW/GW X 1 tonne/1000kg = **22,196 tonnes of NOx credits**

  - SO_2 early shutdown credits = (Baseline SO_2 emission intensity - (((2016-2020 BATEA limit) + (2016-2020 deemed credit threshold))/2)) X (unit output rate) X (number of early shutdown years)

    For this example: SO_2 early shutdown credits = (1.64 kg/MWh) X 3100 GWh X 8 years X 1000 MW/GW X 1 tonne/1000kg = **40,672 tonnes of SO_2 credits**

  Any of these credits that are not used in the early shutdown period as noted above would be subject to a one-time 10% discount.

Situation #3:
Unit "C" decides to shut down on January 1, 2045, which is before the end of its Design Life. The unit is eligible for NOx and SO_2 credits for early shutdown.

The early shutdown credits would be calculated as follows:

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the design life date and the shutdown date. In this case the number of years is: *January 1, 2050 (Design life date) – January 1, 2045 (shutdown date) = 5 years*

- **Emission Intensity Difference:** The NOx and SO_2 intensity values used to calculate credits for early shutdown are the unit's NOx and SO_2 baseline intensity limits, which are its deemed credit threshold intensities (these are the deemed credit threshold intensities that were in effect when the unit was initially approved) and the midpoint between the BATEA limit for new units at the time of shutdown and the deemed credit threshold NOx and SO_2 intensities at the time of shutdown.

In this case the NOx and SO_2 intensity limits used to calculate NOx and SO_2 credits for early shutdown would be:

- NOx = (Deemed credit threshold at time unit approved) – (((2041-2045 BATEA limit) + (2041-2045 deemed credit threshold))/2))
  NOx = 0.62 kg/MWh – ((0.10 kg/MWh + 0.09 kg/MWh)/2) = **0.525kg/MWh**
- SO_2 = (Deemed credit threshold at time unit approved) – (((2041-2045 BATEA limit) + (2041-2045 deemed credit threshold))/2))
  SO_2 = 0.72 kg/MWh– ((0.15 kg/MWh + 0.14 kg/MWh)/2) = **0.575kg/MWh**

- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2040 to January 1, 2045.
  - The best 3 years of output during this period (see above table) are 2100 GWh (in 2040), 1800 GWh (in 2041) and 1500 GWh (in 2042), the average of which is **1800 GWh**
- **Credits for Early Shutdown:** The block of early shutdown credits the unit would receive is calculated as follows:
  - NOx early shutdown credits = ((Deemed credit threshold at time unit approved) - (((2041-2045 BATEA limit) + (2041-2045 deemed credit threshold))/2)) X (unit output rate) X (number of early shutdown years)

    For this example: NOx early shutdown credits = (0.525 kg/MWh) X 1800GWh X 5 years X 1000MW/GW X 1 tonne/1000kg = **4725 tonnes of NOx credits**

  - SO_2 early shutdown credits = ((Deemed credit threshold at time unit approved) – (((2041-2045 BATEA limit) + (2041-2045 deemed credit threshold))/2)) X (unit output rate) X (number of early shutdown years)

    For this example: SO_2 early shutdown credits = (0.575 kg/MWh) X 1800 GWh X 5 years X 1000 MW/GW X 1 tonne/1000kg = **5175 tonnes of SO_2 credits**

Any of these credits that are not used in the year in which they were granted would be subject to a one-time 10% discount.

Scenario 5: End of Design Life transition credits

The intent of three-year transition credits is to give units some flexibility in scheduling upgrades at the end of Design Life or to provide an incentive for these older units to shut down.

Situation #1:
Unit "A" decides to shut down on January 1, 2020, which is at the end of its Design Life (which in this example is the end of its PPA expiry), and it may be eligible for transition credits. (An equivalent situation in terms of transition credits is that the unit indicates that it plans, within three years, to upgrade its pollution control equipment to meet the BATEA limits of the day.)

The amount of transition credits granted is determined as follows:

- **Eligibility:** Transition credits are only granted to units that reach the end of Design Life and commit to either shutting down on that date or installing, within three years of that date, new pollution control equipment to meet the BATEA limits of the day. Because at the end of its Design Life the unit has committed to shut down, it is eligible for transition credits.

  If the unit had elected to upgrade to the BATEA of the day within three years, it would also be eligible for transition credits. Since these credits represent an upfront allocation of three years worth of credits at the new BATEA limit, the unit would not be eligible for additional operating credits during this three-year period.

- **Emission Intensity:** The NOx and SO_2 intensity limits used to calculate transition credits are the BATEA limits in effect at the time the PPA expires (Deemed credit thresholds are not used to calculate transition credits). In this case the NOx and SO_2 intensity limits would be:

BATEA Based Limit for NOx (kg/MWh) in 2020	BATEA Based Limit for SO_2 (kg/MWh) in 2020
0.50	0.50

- **Output Rate:** The output (generation) capacity assumed for transition credits is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2015 to January 1, 2020.
  - The best 3 years of output during this period (see above table) are 2800 GWh (in 2015), 2900 GWh (in 2016) and 3000 GWh (in 2017), the average of which is **2900 GWh**

- **Transition Credits:** The block of transition credits the unit would receive is calculated as follows:
  - NOx transition credits = (current BATEA based NOx intensity limit) X (unit output rate) X (3 years)

    For this example: NOx transition credits = (0.5 kg/MWh) X 2900GWh X 3 years X 1000MW/GW X 1 tonne/1000kg = **4350 tonnes of NOx credits**

- SO_2 transition credits =(current BATEA based SO_2 intensity limit) X (unit output rate) X (3 years)

  For this example: SO_2 transition credits = (0.50 kg/MWh) X 3100GWh X 3 years X 1000MW/GW X 1 tonne/1000kg = **4350 tonnes of $S0_2$ credits**

Any of these credits that are not used in the first three years after issuance would be subject to a one-time 10% discount.

Situation #2:
Unit "A" decides, at the end of its Design Life, to continue operating indefinitely without any significant change in its actual emissions i.e. it will meet its new BATEA emission limits through the use of credits.

- **Eligibility:** Since the unit is neither shutting down nor committing to put in new emission controls it **is not eligible for transition credits.**

Scenario 6: The new emission limits that apply to existing units at end of Design Life or PPA expiry and when installation of controls to meet these new limits becomes mandatory

Situation #1:
Unit "A" wants to know what its requirements and options are if it operates past January 1, 2020, which is its PPA expiry date.

- **Emission Limits:** The unit would have its emission limits reduced to the BATEA limits of the day. In this case those limits would be reduced as follows:

Year	BATEA Based Limit for NOx (kg/MWh)	BATEA Based Limit for SO_2 (kg/MWh)
2020	0.50	0.50
2021-2025	0.45	0.40

- **Transition Credits:** The unit is not eligible for transition credits unless it chooses the option of upgrading its controls or commits to shutting down in the first three years after the end of its Design Life, that is. by 2023.
- **BATEA Control Requirement:** Units can operate up to 10 years after the end of their 40-year life without physically meeting the BATEA limits of the day at that unit; i.e., they can meet the limit through a combination of controls and credit use. In this case the 40-year life of the unit ends January 1, 2015 and therefore it can only operate until January 1, 2025 (design life + 10 years) before meeting the BATEA limits of the day through onsite controls. However, the PPA expiry is January 1, 2020 and therefore the new BATEA limits requirement does not apply until January 1, 2020 (PPA expiry). In 2025 the unit would therefore have to meet the following BATEA limits without the use of credits:

2025 BATEA Based Limit for NOx (kg/MWh)	2025 BATEA Based Limit for SO_2 (kg/MWh)
0.45	0.40

The unit could decide to install BATEA based controls at any time before January 1, 2025. If it did, the BATEA limits in effect at the time would become the emission limits for the unit for another 40 years and it would in effect become a new unit.

Situation #2:
Unit "B" wants to know what its requirements and options are if it operates past January 1, 2015 which is the end of its Design Life.

- **Emission Limits:** The unit would have its emission limits reduced to the BATEA limits of the day. In this case those limits would be reduced as per the following:

Years	BATEA Based Limit for NOx (kg/MWh)	BATEA Based Limit for SO_2 (kg/MWh)
2015	0.60	0.70
2016-2020	0.50	0.50
2021-2025	0.45	0.40

- **Transition Credits:** The unit is not eligible for transition credits unless it chooses the option of upgrading its controls or commits to shutting down in the first three years after the end of its Design Life; i.e., by 2018.
- **BATEA Control Requirement:** A unit can operate up to 10 years after the end of its 40-year life without physically meeting the BATEA limits of the day at that unit; that is, it can meet the limit through a combination of controls and credit use. In this case, the end of 40 years is January 1, 2015 and therefore it can only operate until January 1, 2025 (i.e., 40 year life + 10 years) before meeting the BATEA limits of the day through onsite controls. In 2025 the unit would have to meet the following BATEA limits without the use of credits:

BATEA Based Limit for NOx (kg/MWh)	BATEA Based Limit for SO_2 (kg/MWh)
0.45	0.45

The unit could decide to install BATEA based controls at any time during this 10-year period. If it did, the BATEA limits in effect at the time would become the emission limits for the unit for another 40 years and it would then be considered a new unit.

Scenario 7: Existing vs. new units in terms of application of new BATEA limits

Situation:

Assume a number of possible project status situations for Unit "C" in 2011 when the SO_2 and NOx BATEA limits change (in this hypothetical example) from 0.69 kg/MWh in 2006-2010 to
0.6 kg/MWh in 2011-2015 for NOx, and from 0.80 kg/MWh in 2006-2010 to 0.70 kg/MWh in 2011-2015 for SO_2.

Project Status	BATEA Emission Limits that Applies
All EUB and Alberta Environment approvals issued by end of 2010 and plant has completed significant construction in 3 years and is operating within 8 years of the final approval being granted	2006-2010 limits apply
All EUB and Alberta Environment approvals not issued until 2011	2011-2015 limits apply or possibly 2016-2020 limits depending on construction and commissioning times
All EUB and Alberta Environment approvals issued by end of 2010 but plant has either not undertaken significant construction within 3 years of receiving its AENV approval or is not operational within 8 years of the final approval being granted	2011-2015 limits apply or possibly 2016-2020 limits depending on construction and commissioning times

The intent of the framework is to review BATEA limits every five years starting in 2008, and to provide notice of a change in BATEA limits approximately two years in advance of the new limits coming into effect. Whether or not the current or planned new BATEA limits will apply to a proposed unit will depend on the project schedule for the unit. Since project schedules and approval processes cannot be precisely established, proposed units should consider the possibility that the planned new BATEA limits may apply to their unit.

PART 2: NOx APPLICATION EXAMPLES FOR GAS-FIRED UNITS

Purpose

To provide some specific examples of how the NOx management framework would apply to gas units (stand-alone and co-generation) under certain circumstances or situations. The examples try to represent plausible, and even likely, situations.

Assumptions and Example Unit Descriptions

Assumptions:

- BATEA limits and deemed credit threshold intensities for NOx in future years (these are assumed – actual limits and deemed credit threshold would be set every five years through the Five-Year Review process):

Period	BATEA Based Limit for NOx (kg/MWh) and (in brackets) the Deemed Credit Threshold in kg/MWh for different Types and Sizes of Unit			
	<20MW	20-60MW	>60MW	Peaking
2006-2010	0.6 (0.5)	0.4 (0.30)	0.3 (0.2)	1.008 (0.2)
2011-2015	0.45 (0.40)	0.3 (0.25)	0.2 (0.18)	1.008 (0.2)
2016-2020	0.4 (0.35)	0.25 (0.20)	0.15 (0.12)	0.9 (0.2)
2021-2025	0.4 (0.35)	0.25 (0.20)	0.15 (0.12)	0.8 (0.2)
2026-2030	0.35 (0.30)	0.20 (0.18)	0.1 (0.08)	0.7 (0.2)
2031-2035	0.3 (0.25)	0.15 (0.12)	0.1 (0.08)	0.5 (0.2)
2036-2040	0.2 (0.18)	0.1 (0.08)	0.1 (0.08)	0.4 (0.2)
2041-2045	0.15 (0.12)	0.1 (0.08)	0.08 (0.08)	0.3 (0.2)

- The deemed credit threshold for existing units (pre-2006) is as follows (these are actual values):
  - The unit's baseline intensity if it is a non-peaking unit and has an NO_x intensity greater than 0.2 kg/MWh
  - 0.2 kg/MWh of NO_x if the unit is a peaking unit or its baseline intensity is less than 0.2 kg/MWh
- The greenhouse gas emission intensities for the purpose of calculating credits for early shutdown are assumed to be as follows:

Period	CO_2 Emission Intensity Target Used to Calculate Credits for Early Shutdown in t/MWh for different Types of Units*		Assumed Deemed Credit Generation Threshold for Peaking Units for Early Shutdown Credits (t/MWh)
	NGCC/Peaking	Co-gen	Peaking
2006-2010	0.38	0.33	0.40
2011-2015	0.38	0.33	0.40
2016-2020	0.37	0.32	0.40
2021-2025	0.36	0.31	0.40
2026-2030	0.36	0.31	0.40
2031-2035	0.35	0.31	0.38
2036-2040	0.34	0.30	0.38
2041-2045	0.34	0.30	0.38

*The CASA EPT did not set any targets or deemed credit thresholds for CO_2 credit generation other than the 0.418 t/MWh NGCC offset limit for coal units. Specific intensity target levels for gas, co-gen and peaking units will have to be set in another forum. The above numbers are for illustrative purposes only. A deemed credit threshold for peaking units is being used in this example because it is anticipated that these units will needed to be treated differently than other units as been done with NOx credit generation. This different approach is to prevent units from declaring themselves peaking units and then shutting down shortly thereafter and generating a large number of early shutdown credits.

Example Unit Descriptions:

UNIT "A"

- Unit's operational commencement date: January 1, 1988
- End of unit Design Life: January 1, 2018
- Maximum Capacity Rating (MCR): 200 MW
- NOx emission intensity in 2000-2002 period:

Year	NOx Emission Intensity (kg/MWh)	CO_2 Emission Intensity (t/MWh)
2000	0.6	0.46
2001	0.58	0.45
2002	0.62	0.44
2000-2002 Average	**0.6 This is the unit's baseline NOx intensity for the purpose of credit generation.**	**0.45 This is the unit's baseline** CO_2 **intensity for the purpose of credits for early shutdown.**

- Unit A's output in specific years:

Year	Output GWh	Year	Output GWh
2006	600	2014	500
2007	750	2015	500
2008	900	2016	450
2009	550	2017	600
2010	700	2018	500
2011	750	2019	350
2012	500	2020	200
2013	650	2021	200

UNIT "B"

- Unit's operational commencement date: January 1, 1975
- End of unit's design Life: January 1, 2005
- Maximum Capacity Rating (MCR): 300 MW
- NOx emission intensity in 2000-2002 period:

Year	NOx Emission Intensity (kg/MWh)	CO_2 Emission Intensity (t/MWh)
2000	1.55	0.62
2001	1.60	0.58
2002	1.50	0.60
2000-2002 Average	**1.55 This is the unit's baseline NOx intensity for the purpose of credit generation.)**	**0.60 This is the unit's baseline** CO_2 **intensity for the purpose of credits for early shutdown.**

- Unit B's output in specific years:

Year	Output GWh	Year	Output GWh	Year	Output GWh
2002	500	2010	400	2018	400
2003	400	2011	500	2019	500
2004	500	2012	400	2020	400
2005	400	2013	500		
2006	500	2014	400		
2007	400	2015	500		
2008	500	2016	400		
2009	400	2017	500		

UNIT "C"

- Unit's operational commencement date: January 1, 2010
- End of unit Design Life: January 1, 2040
- Maximum Capacity Rating (MCR): 500 MW
- Unit's GHG Emission Intensity: 0.39t/MWh
- NOx emission intensity in unit's approval (these are the 2006-2011 BATEA) limits and deemed credit threshold:

NOx Emission Intensity (kg/MWh)	NO_x Deemed Credit Generation Intensity (kg/MWh)
0.3	0.2

- Unit C's actual performance in noted years:

Year	NOx Emission Intensity (kg/MWh)
2010	0.18
2011	0.22
2012	0.17

- Unit C's output in specific years:

Year	Output GWh	Year	Output GWh	Year	Output GWh
2010	3000	2015	2900	2040	2100
2011	3000	2016	3000	2041	1800
2012	3100	2017	2600	2042	1500
2013	3200	2018	2700	2043	1300
2014	2800	2019	2800	2044	1000

UNIT "D"

- Unit's operational commencement date: January 1, 1998
- End of unit Design Life: January 1, 2028
- Maximum Capacity Rating (MCR): 300 MW
- Unit's GHG Emission Intensity: 0.38kg/MWh
- NOx emission intensity:

Year	NOx Emission Intensity (kg/MWh)
2000	0.15
2001	0.16
2002	0.14
2003	0.15
2004	0.14
2005	0.15
2006	0.13

- Unit D's output in specific years:

Year	Output (GWh)	Year	Output (GWh)
2006	600	2014	500
2007	750	2015	500
2008	900	2016	450
2009	550	2017	600
2010	600	2018	500
2011	750	2019	350
2012	500	2020	200
2013	650	2021	200

Scenario 1: Credit generation by existing units

Situation #1:
A retrofit occurs at Unit "A" in 2012 for NOx control. The retrofit NOx control device can reduce NOx emissions by about 20% to 0.48 kg/MWh. The unit is eligible for NOx credits for this change. (Unit "A" could be a stand-alone gas unit or a co-gen unit. If it were a co-gen unit then the NOx intensity would be calculated based on total NOx emissions divided by total energy (steam+power) output converted to MWh. The calculation of credit generation would however only be based on the output of power.)

The "credits" generated would be calculated as follows:

- **Baseline Intensity:** The unit's NOx baseline would be established based on the 2000-2002 NOx emission intensity (see above table). In this example, the baseline NOx intensity is 0.6 kg/MWh.
- **Actual Intensity:** The unit's NOx intensity each year after the retrofit would be reported along with the unit's output. In this example this is 0.48kg/MWh.
- **Credit Generation:** The unit would be granted the following number of credits each year until the end of Design Life
    - Credits generated (tonnes) = (baseline intensity - actual intensity) X (output)

For this example (in 2013), credits = (0.6 kg/MWh - 0.48 kg/MWh) X 650GWh X 1000MW/GW X 1 tonne/1000kg = **78 tonnes of NOx credits**

If for any reason the intensity in a given year were higher than the baseline intensity, then the above calculation would give a negative credit figure. In such a case the unit would have to purchase credits or use banked credits to achieve a zero net credit balance. Any generated credits that are not used in the year in which they were granted would be subject to a one-time 10% discount.

Situation #2:
Unit "D" is operating below the deemed NOx credit threshold for existing units and is therefore eligible for NOx credits. (Unit "D" could be a stand-alone gas unit or a co-gen unit. If it were a co-gen unit the NOx intensity would be calculated based on total NOx emissions divided by total energy (steam+power) output converted to MWh. The calculation of credit generation would however only be based on the output of power.)

The credits generated would be calculated as follows:

- **Deemed Credit Threshold:** The deemed credit threshold for existing units operating below a NOx intensity of 0.2kg/MWh is 0.2 kg/MWh.
- **Actual Intensity:** The unit's NOx intensity each year would be reported along with the unit's output. This example uses 2006 intensity and output. The 2006 intensity is 0.13kg/MWh.
- **Credit Generation:** The unit would be granted the following number of credits each year until the end of Design Life.
  - Credits generated (tonnes) = (credit threshold-actual intensity) X (output)

    For this example (in 2006), credits = (0.2 kg/MWh - 0.13 kg/MWh) X 600GWh X 1000MW/GW X 1 tonne/1000kg = **42 tonnes of NOx credits**

  If for any reason the intensity in a given year were higher than the deemed credit threshold, then the above calculation would give a negative credit figure. This is **not** a credit shortfall there are just no credits generated. **In this case, the credits generated are not subject to a 10% discount because the concept of operational variability and credit discounting are incorporated in the deemed credit threshold number**.

Situation #3:
Unit "B" declares itself a peaking unit in 2006 (see Scenario #5 option 4 in the two situations presented) and wants to determine if it is eligible for NOx credits.

Whether or not "credits" are generated would be determined as follows:

- **Deemed Credit Threshold:** The deemed credit threshold for existing peaking units is 0.2 kg/MWh.
- **Actual Intensity:** The unit's NOx intensity is well above 0.2 kg/MWh so it would **not** be eligible for any NOx credits. **The remainder of this example, however, will assume that the NOx intensity of the unit is 0.15kg/MWh, which would make it eligible for credit generation.**

- **Credit Generation:** If the unit had a NOx intensity of 0.15kg/MWh the credit generation calculation would be as follows (using year 2007 in the calculation example).
  - Peaking units are subject to a NOx cap which is calculated as follows: (NOx cap) = (peaking unit BATEA intensity) X (MCR in MW) X (1500 hours)

    For this example (in 2007) = (1.008 kg/MWh) X 300 MW X 1500 hours X 1 tonne/1000kg = **454 tonnes of NOx emissions is the cap**
  - Actual NOx emissions (tonnes) = (actual intensity) X (output)

    For this example (in 2007) = (0.15 kg/MWh) X 400GWh X 1000MW/GW X 1 tonne/1000kg = **60 tonnes of NOx credits**
  - Credits generated (tonnes)=((deemed credit threshold) – (actual intensity)) X (lesser of (MCR in MW) X (1500 hours) <u>or</u> (output))

    For this example (in 2007) = (0.2 kg/MWh – 0.15 kg/MWh) X lesser of (450 GWh or 400GWh) = **20 tonnes of NOx credits**

  Any generated credits that are not used in the year in which they were granted would be subject to a one-time 10% discount.

<u>Scenario 2: Credit generation by new (post-2005) units</u>

Situation:
Unit "C" installs NOx controls that result in performance better than its BATEA limits. The unit <u>may</u> be eligible for credits. (Unit "C" could be a stand-alone gas unit or a co-gen unit. If it were a co-gen unit the NOx intensity would be calculated based on total NOx emissions divided by total energy (steam+power) output converted to MWh. The calculation of credit generation would however only be based on the output of power.)

The possible "credits" generated would be calculated as follows:

- **Deemed Credit Threshold:** The BATEA limit for gas units >60MW is 0.3kg/MWh but the deemed credit threshold is 0.2 kg/MWh.
- **Actual Intensity:** The unit's NOx intensity each year after the retrofit would be reported along with the unit's output. The actual intensities in this example are:

Year	NOx Emission Intensity (kg/MWh)
2010	0.18
2011	0.22
2012	0.17

- **Credit Generation:** The unit would generate NOx credits based on the following formula:
  - Credits generated (tonnes) = (feemed credit threshold - actual intensity) X (output)

For this example credits would not be generated in 2011 because the actual emission intensities are higher than the deemed credit threshold of 0.2kg/MWh.

> In 2010, credits would be generated and would be = (0.2 kg/MWh - 0.18 kg/MWh) X 3000 GW/h X 1000MW/GW X 1 tonne/1000kg = **60 tonnes of NOx credits**

In this example, in some years the actual emission intensity is above deemed credit threshold, i.e., 0.2 kg/MWh. In such cases the above calculation gives a negative credit figure. This is **<u>not</u>** a credit shortfall, there are just no credits generated. **In this case the credits generated are not subject to a 10% discount because the concept of operational variability and credit discounting are incorporated in the deemed credit threshold number**.

Scenario 3: Credits for early shutdown

Situation #1:
Unit "A" decides to shut down on January 1, 2014, which is before the end of its Design Life. The unit is eligible for NOx credits for early shutdown.

The early shutdown credits it is eligible for would be calculated as follows:

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the end of Design Life and the shutdown date. In this case the number of years is: *January 1, 2018 (end of design Life) – January 1, 2014 (shutdown date) = 4 years*
- **Emission Intensity Difference:** The NOx intensity values used to calculate credits for early shutdown are the unit's baseline NOx intensity value and the midpoint between the BATEA limit for new units at the time of shutdown and the "deemed credit threshold" NOx intensities at the time of shutdown. In this case NOx intensities used to calculate NOx credits for early shutdown would be:
    - NOx = Baseline NOx emission intensity – (((2011-2015 BATEA limit) +(2011-2055 deemed credit threshold))/2)
      NOx = 0.6 kg/MWh –((0.2kg/MWh+ 0.18kg/MWh)/2) = **0.41kg/MWh**
- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
    - The last 5 years are January 1, 2009 to January 1, 2014.
    - The best 3 years of output during this period (see above table) are 700 GWh (in 2010), 750 GWh (in 2011) and 650 GWh (in 2013), the average of which is **700 GWh**
- **Credits for Early Shutdown:** The block of early shutdown credits the unit would receive is calculated as follows:
    - NOx early shutdown credits = (Baseline NOx emission intensity – (((2011-2015 BATEA limit) + (2011-2055 deemed credit threshold))/2)) X (unit output rate) X (number of early shutdown years)

For this example: NOx early shutdown credits = (0.41kg/MWh) X 700GWh X 4 years X 1000MW/GW X 1 tonne/1000kg = **1148 tonnes of NOx credits**

Any of these credits that are not used in the early shutdown period as noted above would be subject to a one-time 10% discount.

Situation #2:
Unit "B" declares itself a peaking unit in 2005 and then shuts down on January 1, 2010, which would be before the end of the 60-year design life for a peaking unit. The unit wants to know if it is eligible for credits for early shutdown.

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the Design Life date and the shutdown date. In this case the number of years is: *January 1, 2035 (Design Life date – i.e., commissioning date + 60 years) – January 1, 2010 (shutdown date) = 25 years*
- **Emission Intensity Difference:** The NOx value used to calculate credits for early shutdown are the unit's established deemed credit threshold and the deemed credit threshold NOx intensities at the time of shutdown. (Note: for peaking units there is no BATEA *per se*, only a NOx emission cap, therefore the deemed credit threshold and not the midpoint between BATEA and the deemed credit threshold is used to calculate early shutdown credits for peaking units). In this case NOx intensities used to calculate NOx credits for early shutdown would be:

  NOx = (Deemed credit threshold for unit) – (2006-2010 deemed credit threshold for peaking units)

  NOx = 0.2 kg/MWh – 0.2 kg/MWh = 0.0 kg/MWh (therefore no credits generated. For the remainder of example, however, it is assumed that the 2006-2010 deemed credit threshold for peaking units was 0.15kg/MWh and therefore above value was 0.05kg/MWh)
- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years or the MCR times 1500 hours, whichever is less. In this case:
  - The last 5 years are January 1, 2005 to January 1, 2010.
  - The best 3 years of output during this period (see above table) are 500GWh (in 2006), 400 GWh (in 2007) and 500 GWh (in 2008) the average of which is **467 GWh**
  - (MCR) X (1500)=(300MW) X (1500 hours) = **450 GWh**
- **Credits for Early Shutdown:** The block of early shutdown credits the unit would receive are calculated as follows:
  - NOx early shutdown credits = (deemed credit generation that applies to unit – current deemed credit generation that applies to this type of unit) X (unit's output rate or MCR X 1500hrs, whichever is smaller) X (number of early shutdown years)

    For this example: NOx early shutdown credits = (0.2 kg/MWh – 0.15 kg/MWh) X 450GWh X 25 years X 1000MW/GW X 1 tonne/1000kg = **562.5 tonnes of NOx credits.**

Any of these credits that are not used in the early shutdown period as noted above would be subject to a one-time 10% discount.

Scenario 4: End of Design Life transition credits

The intent of three-year transition credits is to give units some flexibility in scheduling upgrades at the end of Design Life or to provide an incentive for these older units to shut down.

Situation #1:
Unit "A" decides to shut down on January 1, 2017, which is at the end of its Design Life. It is eligible for transition credits. (An equivalent situation in terms of transition credits is that the unit indicates that it plans, within three years, to upgrade its pollution control equipment to meet the BATEA limits of the day.)

The amount of transition credits granted is determined as follows:

- **Eligibility:** Transition credits are only granted to units that reach the end of Design Life and commit to either shutting down on that date or installing, within three years of that date, new pollution control equipment to meet the BATEA limits of the day. Because at the end of its Design Life the unit has committed to shut down, it is eligible for transition credits.

  If the unit had elected to upgrade to the BATEA of the day within three years, it would also be eligible for transition credits. Since these credits represent an upfront allocation of three year's worth of credits at the new BATEA limit, the unit would not be eligible for additional operating credits during this three-year period.

- **Emission Intensity:** The NOx intensity limit used to calculate transition credits is the BATEA limit in effect at the time the PPA expires (deemed credit thresholds are <u>not</u> used to calculate transition credits). In this case, for this size of unit, the NOx intensity limit would be:

  BATEA Based Limit for NOx (kg/MWh) in 2016-2020 period = 0.15

- **Output Rate:** The output (generation) capacity assumed for transition credits is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2012 to January 1, 2017.
  - The best 3 years of output during this period (see above table) are 500 GWh (in 2011), 500 GWh (in 2013) and 500 GWh (in 2015) the average of which is **500 GWh.**

- **Transition Credits:** The block of 'transition" credits the unit would receive are calculated as follows:
  - NOx transition credits = (current BATEA based NOx intensity limit) X (unit output rate) X (3 years)

    For this example: NOx transition credits = (0.15kg/MWh) X 500GWh X 3 years X 1000MW/GW X 1 tonne/1000kg =**225 tonnes of NOx credits**

Any of these credits that are not used in the first three years after issuance would be subject to a one-time 10% discount.

Situation #2:
Unit "A" decides, at the end of its design life (January 1, 2017) to continue operating indefinitely without any significant change in its actual emissions (i.e.. it will meet its new BATEA emission limits through the use of credits).

Eligibility: Since the unit is not shutting down or is not committing to put in new emission controls it **is not eligible for "transition" credits.**

Scenario 5: The new emission limits that apply to existing units at end of Design Life and when installation of controls to meet these new limits becomes mandatory

Situation #1:
Unit "B" wants to know what its requirements and options are if it operates past January 1, 2005, which is its end of design life under this management system. (For units that are operating when this framework takes effect on January 1, 2006 and whose end of design life was, or is, on or before January 1, 2010, their end of Design Life for the purpose of new limits is January 1, 2010.)

Unit "B" has 4 options:

Option #1: Continue to operate without putting in new emission controls.

- **Emission Limits:** The unit would have its emission limits reduced to the BATEA limits of the day in January 1, 2010 and then dropped again in 2011 when the BATEA limit changes. The deemed credit threshold also changes. For this type and size of unit the emission limits and deemed credit threshold would be as follows:

Years	BATEA Based Limit for NOx (kg/MWh)	"Deemed Credit Threshold" (kg/MWh)
2010	0.3	0.2
2011-2015	0.2	0.18

- **BATEA Control Requirement:** Units can operate up to 10 years after the end of Design Life without physically meeting the BATEA limits of the day at that unit (i.e., they can meet the limit through the use of credits). In this case the Design Life of the unit ends January 1, 2005 and therefore it can only operate until January 1, 2015 (Design Life + 10 years) before it is required to meet the BATEA limits of the day through onsite controls. (Note: Under the framework, the new emission limits for existing units do not apply until 2010 but the unit's end of design life remains 2005 when determining the Design Life + 10 year period.) The BATEA limit in 2015 would be:

  2015 BATEA Based Limit for NOx (kg/MWh) = 0.2 kg/MWh

  The unit could decide to install BATEA based controls at any time before January 1, 2015. If it did, the BATEA limits in effect at the time would become the emission limits for the unit for another 30 years and it would in effect become a new unit.

Option #2: Continue to operate but put new controls in to meet the BATEA limits of the day.

- **Emission Limits:** The unit would have its emission limits reduced to the BATEA limits of the day in January 1, 2010 and these would become the emission limits for the unit for the next 30 years. For this type and size of unit the NO_x emission limit would be 0.3 kg/MWh.
- **Transition Credits:** As outlined in Scenario #4, Situation #1, the unit is eligible for transition credits.

Option #3: Shut down the unit.

Transition Credits: As outlined in Scenario #4, Situation #1, the unit is eligible for transition credits.

Option #4: Declare the unit a peaking unit. (When a unit declares itself a peaking unit it receives a NOx emission cap.)

- NOx Emission Cap: The annual NOx emission cap for peaking units is calculated as follows:

  (peaking unit BATEA limit of day) X (MCR in MW) X(1500 hours)

  In this example, this equals (1.008 kg/MWh) X (300MW) X (1500hours) X (1 tonne/1000kg) = **302 tonnes of NOx per year**

A peaking unit's emissions cannot exceed this cap except under special circumstances. A peaking unit can operate for up to 60 years (from the date the unit was commissioned) and then it must either shut down or update its controls to meet the BATEA limits of the day for a gas plant of that type and size.

Situation #2:
This is the same as Situation #1 but with a different unit to further demonstrate the options available and how the various BATEA limits apply. Unit "A" wants to know what its requirements and options are if it operates past January 1, 2018, which is its end of Design Life under this management system.

Unit "A" has 4 options:

Option #1: Continue to operate without putting in new emission controls.

- **Emission Limits:** The unit would have its emission limits reduced to the BATEA limits of the day in January 1, 2018 and then dropped again in 2026 when the BATEA limit changes (Note: With the assumed future BATEA limits, the BATEA limit did not change between the 2016-2020 and the 2021-2025 periods but if it did then the limits for this unit would change in 2011). For this type and size of unit the emission limits would be as follows:

Years	BATEA Based Limit or NOx (kg/MWh)
2018	0.15
2021-2025	0.15
2026-2027	0.1

- **BATEA Control Requirement:** Units can operate up to 10 years after the end of Design Life without physically meeting the BATEA limits of the day at that unit; that is, they can meet the limit through a combination of controls and credit use. In this case, the Design Life of the unit ends January 1, 2018 and therefore it can only operate until January 1, 2028 (Design Life + 10 years) before meeting the BATEA limits of the day through onsite controls. The BATEA limit in 2018 would be:

  2016-2020 BATEA Based Limit for NOx (kg/MWh = 0.1

  The unit could decide to install BATEA based controls at any time before January 1, 2028. If it did the BATEA limits in effect at the time would become the emission limits for the unit for another 30 years and it would in effect become a new unit.

Option #2: Continue to operate but put new controls in to meet the BATEA limits of the day.

- **Emission Limits:** The unit would have its emission limits reduced to the BATEA limits of the day in January 1, 2018 and these would become the emission limits for the unit for the next 30 years. For this type and size of unit the emission limit would be 0.1 kg/MWh.
- **Transition Credits:** As outlined in Scenario #4, Situation #1, the unit is eligible for "transition" credits.

Option #3: Shut down the unit.

Transition Credits: As outlined in Scenario #4, Situation #1, the unit is eligible for "transition" credits.

Option #4: Declare the unit a peaking unit. (When a unit declares itself a peaking unit it receives a NOx emission cap.)

- NOx Emission Cap: The annual NOx emission cap for peaking units is calculated as follows:

  (peaking unit BATEA limit of day) X (MCR in MW) X (1500 hours)

  In this example this equals (0.9kg/MWh) X (200MW) X (1500hours) X (1 tonne/1000kg) = **180 tonnes of NOX per year**

A peaking unit's emissions cannot exceed this cap except under special circumstances. A peaking unit can operate for up to 60 years (from the date the unit was commissioned) and then it must either shut down or update its controls to meet the BATEA limits of the day for a gas plant of that type and size.

Scenario 6: Existing vs. new units in terms of application of new BATEA limits

Situation:
Assume a number of possible project status situations for Unit "C" in 2011 when the NO_x BATEA limit for a unit of its size changes from 0.3kg/MWh to 0.2kg/MWh.

Project Status	BATEA Emission Limit that Applies
All EUB and Alberta Environment approvals issued by end of 2010 and plant constructed and operating within 3-5 years	2006-2010 limits apply i.e. 0.3kg/MWh
All EUB and Alberta Environment approvals not issued until 2011	2011-2015 limits apply i.e. 0.2kg/MWh, or possibly 2016-2020 limits depending on construction and commissioning times
All EUB and Alberta Environment approvals issued by end of 2010 but plant not constructed and operating within 3-5 years of receiving its AENV approval	2011-2015 limits apply i.e. 0.2kg/MWh, or possibly 2016-2020 limits depending on construction and commissioning times

The intent of the framework is to review BATEA limits every five years starting in 2008 and provide notice of a change in BATEA limits approximately two years in advance of the new limits coming into effect. Whether or not the current or planned new BATEA limits will apply to a proposed unit will depend on the project schedule for the unit. Since project schedules and approval processes cannot be precisely established, proposed units should consider the possibility that the planned new BATEA limits may apply to their unit.

PART 3: CO_2 APPLICATION EXAMPLES FOR COAL and GAS-FIRED UNITS

Purpose

To provide some specific examples of how the CO_2 management framework recommendation related to greenhouse gas emission credits for early shutdown would apply to gas and coal units. The examples try to represent plausible, and even likely, situations.

Example Unit Descriptions: The unit descriptions are the same as those for the previous NOx and SO_2 examples for coal and gas.

Scenario 1: Credits for early shutdown – coal units

Situation #1:
Coal Unit "A" decides to shut down on January 1, 2017, which is before the end of its Design Life (in this case PPA expiry). The unit is eligible for CO_2 credits for early shutdown.

The early shutdown credits it is eligible for would be calculated as follows:

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the Design Life date and the shutdown date. In this case it is the PPA expiry date that applies and the number of early shutdown years is: *January 1, 2020 (PPA expiry date) – January 1, 2017 (shutdown date) = 3 years*
- **Emission Intensity Difference:** The CO_2 intensity value used to calculate credits for early shutdown is the difference between the unit's baseline CO_2 intensity and the NGCC offset limit, which is 0.418t/MWh. In this case the CO_2 intensity used to calculate CO_2 credits for early shutdown would be:
  - CO_2 = Baseline CO_2 emission intensity – NGCC offset target
    CO_2 = 1.02 t/MWh – 0.418t/MWh = **0.602t/MWh**
- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2012 to January 1, 2017.
  - The best 3 years of output during this period (see above table) are 3000GWh (in 2012), 3100 GWh (in 2013) and 3200 GWh (in 2014), the average of which is **3100 GWh**
- **Credits for Early Shutdown:** The early shutdown credits the unit would be eligible to receive are calculated as follows:
  - CO_2 early shutdown credits = (baseline CO_2 emission intensity – NGCC offset target) X (unit output rate) X (number of early shutdown years)

    For this example: CO_2 early shutdown credits = (0.602t/MWh) X 3100GWh X 3 years X 1000MW/GW = **5.6 megatonnes**

  These credits are not subject to any discount and can be banked indefinitely for purposes of the Alberta NGCC offset requirement (see recommendation 25). Banking of these credits for other purposes is to be consistent with the rules of banking determined under recommendation 24.

Situation #2:
Coal ***Unit "B" decides to shut down on January 1, 2007*, *which is before the end of its Design Life (in this case 40 year life). The unit is eligible for CO_2 credits for early shutdown.***

The early shutdown credits would be calculated as in Situation #1 except that the Design Life date, which is greater than the PPA expiry date, would be used to calculate the period for which early shutdown credits are granted.

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the design life date and the shutdown date. In this case the number of years is: *January 1, 2015 (Design Life date) – January 1, 2007 (shutdown date) = 8 years*
- **Emission Intensity Difference:** The CO_2 intensity value used to calculate credits for early shutdown is the difference between the unit's baseline CO_2 intensity and the NGCC offset limit, which is 0.418 t/MWh. In this case the CO_2 intensity used to calculate CO_2 credits for early shutdown would be:
    - CO_2 = Baseline CO_2 emission intensity – NGCC offset target
      CO_2 = 0.99 t/MWh – 0.418t/MWh = **0.572 t/MWh**
- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
    - The last 5 years are January 1, 2002 to January 1, 2007.
    - The best 3 years of output during this period (see above table) are 3000GWh (in 2002), 3100 GWh (in 2003) and 3200 GWh (in 2004), the average of which is **3100 GWh**
- **Credits For Early Shutdown:** The early shutdown credits the unit would be eligible to receive are calculated as follows:
    - CO_2 early shutdown credits = (Baseline CO_2 emission intensity – NGCC offset target X (unit output rate) X (number of early shutdown years)

      For this example: CO_2 early shutdown credits = (0.572t/MWh) X 3100GWh X 8 years X 1000MW/GW = **14.19 megatonnes**

  These credits are not subject to any discount and can be banked indefinitely for purposes of the Alberta NGCC offset requirement (see recommendation 25). Banking of these credits for other purposes is to be consistent with the rules of banking determined under recommendation 24.

Situation #3:
Coal Unit "C" decides to shut down on January 1, 2045*, *which is before the end of its Design Life. The unit <u>may</u> be eligible for CO_2 credits for early shutdown.

The early shutdown credits would be calculated as follows:

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the design life date and the shutdown date. In this case the number of years is: *January 1, 2050 (Design life date) – January 1, 2045 (shutdown date) = 5 years*

- **Emission Intensity Difference:** The CO_2 intensity value used to calculate credits for early shutdown is the difference the unit's baseline CO_2 intensity and the NGCC offset limit, which is 0.418t/MWh. In this case the CO_2 intensity used to calculate CO_2 credits for early shutdown would be:
  - CO_2 = Baseline CO_2 emission intensity – NGCC offset target
    CO_2 = 0.418 t/MWh – 0.418t/MWh = **0.0 t/MWh**

  Therefore the unit is not eligible for early shutdown credits. Note: If in 2045, the NGCC offset level were lower (e.g., 0.4 t/MWh) then the above calculation would give 0.418t/MWh – 0.400t/MWh = 0.018t/MWh, and the unit would get some credits for early shutdown.

Scenario 2: Credits for early shutdown – gas units

Situation #1:
Gas Unit "A" decides to shut down on January 1, 2014, which is before the end of its Design Life. The unit is eligible for CO_2 credits for early shutdown.

The early shutdown credits it is eligible for would be calculated as follows:

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the end of Design Life and the shutdown date. In this case the number of years is: *January 1, 2018 (end of design Life) – January 1, 2014 (shutdown date) = 4 years*
- **Emission Intensity Difference:** The CO_2 intensity value used to calculate credits for early shutdown is the difference between the unit's baseline CO_2 intensity and the target CO_2 at the time of unit shutdown (see footnote 1 in the CO_2 assumptions table in Part 2 of this Appendix). In this case the CO_2 intensity used to calculate CO_2 credits for early shutdown would be:
  - CO_2 = Baseline CO_2 emission intensity –Target intensity in 2014 = 0.45 t/MWh – 0.38t/MWh = **0.07t/MWh**

    (Note: This example assumes that this is a gas unit. If it were a co-gen unit the target intensity would be 0.33t/MWh and credits would be generated at 0.45 t/MWh – 0.33t/MWh = **0.12t/MWh.)**

- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2009 to January 1, 2014.
  - The best 3 years of output during this period (see above table) are 700 GWh (in 2010), 750 GWh (in 2011) and 650 GWh (in 2013), the average of which is **700 GWh.**
- **Credits for Early Shutdown:** The early shutdown credits the unit would be eligible to receive are calculated as follows:

- CO_2 early shutdown credits = (Baseline CO_2 emission intensity – 2011-2015 target limit) X (unit output rate) X (number of early shutdown years)

  For this example: CO_2 early shutdown credits = (0.07 t/MWh) X 700GWh X 4 years X 1000MW/GW = **196 kilotonnes of CO_2 credits**

These credits are not subject to any discount and can be banked indefinitely for purposes of the Alberta NGCC offset requirement (see recommendation 25). Banking of these credits for other purposes is to be consistent with the rules of banking determined under recommendation 24.

Situation #2:
Gas Unit "B" declares itself a peaking unit in 2005 and then shuts down on January 1, 2010, which would be before the end of the 60-year design life for a peaking unit. The unit wants to know if it is eligible for credits for early shutdown.

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the Design Life date and the shutdown date. In this case the number of years is: *January 1, 2035 (Design Life date i.e. commissioning date + 60 years) – January 1, 2010 (shutdown date) = 25 years* Note: early shutdown credits for CO_2 are only given for a maximum of 10 years so this becomes **10 years.**
- **Emission Intensity Difference:** The CO_2 intensity value used to calculate credits for early shutdown for peaking units is assumed to be the difference the unit's deemed credit threshold intensity at the time of shutdown and the target intensity for a peaking unit at the time of shutdown (see footnote 1 in the assumptions table in Part 2). In this case the CO_2 intensity used to calculate CO_2 credits for early shutdown would be:
  - CO_2 = deemed credit threshold at the time of shutdown – Target intensity for a peaking unit at the time of shutdown = 0.4 t/MWh – 0.38 t/MWh = **0.02t/MWh**
- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years or the MCR times 1500 hours whichever is less. In this case:
  - The last 5 years are January 1, 2005 to January 1, 2010.
  - The best 3 years of output during this period (see above table) are 500GWh (in 2006), 400 GWh (in 2007) and 500 GWh (in 2008) the average of which is **467 GWh**
  - (MCR) X (1500)=(300MW) X (1500 hours) = **450 GWh**
- **Credits for Early Shutdown:** The early shutdown credits the unit would receive are calculated as follows:
  - CO_2 early shutdown credits = (deemed CO_2 credit threshold for peaking units at time of shutdown – peaking unit target intensity at the time of shutdown) X (unit's output rate <u>or</u> MCR X 1500 hrs- whichever is smaller) X (number of early shutdown years)

    For this example: CO_2 early shutdown credits = (0.40 t/MWh – 0.38 t/MWh) X 450GWh X 10 years X 1000MW/GW = **90 kilotonnes of CO_2 credits**

These credits are not subject to any discount and can be banked indefinitely for purposes of the Alberta NGCC offset requirement (see recommendation 25). Banking of these credits for other purposes is to be consistent with the rules of banking determined under recommendation 24.

Situation #3:
Gas Unit "C" decides to shut down on January 1, 2035, which is before the end of its Design Life. The unit is eligible for CO_2 credits for early shutdown.

The early shutdown credits it is eligible for would be calculated as follows:

- **Period:** The number of years for which early shutdown credits would be granted is the difference between the end of Design Life and the shutdown date. In this case the number of years is: *January 1, 2040 (end of design Life) – January 1, 2035 (shutdown date) = 5 years*
- **Emission Intensity Difference:** The CO_2 intensity value used to calculate credits for early shutdown is the difference between the unit's target CO_2 intensity at the time it was approved and the target CO_2 for that type of unit at the time of shutdown (see footnote 1 in the CO_2 "assumptions" table in Part 2 of this Appendix). In this case the CO_2 intensity used to calculate CO_2 credits for early shutdown would be:
  - CO_2 = target intensity in 2010 –target intensity in 2035 = 0.38 t/MWh – 0.35t/MWh = **0.03t/MWh**

  (Note: This example assumes that this is a gas unit. If it were a co-gen unit the target intensity in 2010 would be 0.33t/MWh and in 2035 0.31t/MWh and the credits would be generated at 0.33 t/MWh – 0.31t/MWh = **0.02t/MWh.)**

- **Output Rate:** The output (generation) capacity assumed for the early shutdown period is the average of the best three years of output in the last five years. In this case:
  - The last 5 years are January 1, 2009 to January 1, 2014.
  - The best 3 years of output during this period (see above table) are 700 GWh (in 2010), 750 GWh (in 2011) and 650 GWh (in 2013), the average of which is **700 GWh.**
- **Credits for Early Shutdown:** The early shutdown credits the unit would be eligible to receive are calculated as follows:
  - CO_2 early shutdown credits = (target CO_2 emission intensity in 2010 – 2035 target intensity) X (unit output rate) X (number of early shutdown years)

    For this example: CO_2 early shutdown credits = (0.03t/MWh) X 700GWh X 5 years X 1000MW/GW = **105 kilotonnes of CO_2 credits**

These credits are not subject to any discount and can be banked indefinitely for purposes of the Alberta NGCC offset requirement (see recommendation 25). Banking of these credits for other purposes is to be consistent with the rules of banking determined under recommendation 24.