CASA
Clean Air Strategic Alliance

Electricity Management Framework Review Report

October 2021

About the Clean Air Strategic Alliance

The Clean Air Strategic Alliance (CASA) is a multi-stakeholder partnership. It is composed of representatives selected by industry, government, and non-government organizations to provide strategies to assess and improve air quality for Albertans, using a collaborative consensus process. Every partner is committed to a comprehensive air quality management system for Alberta.

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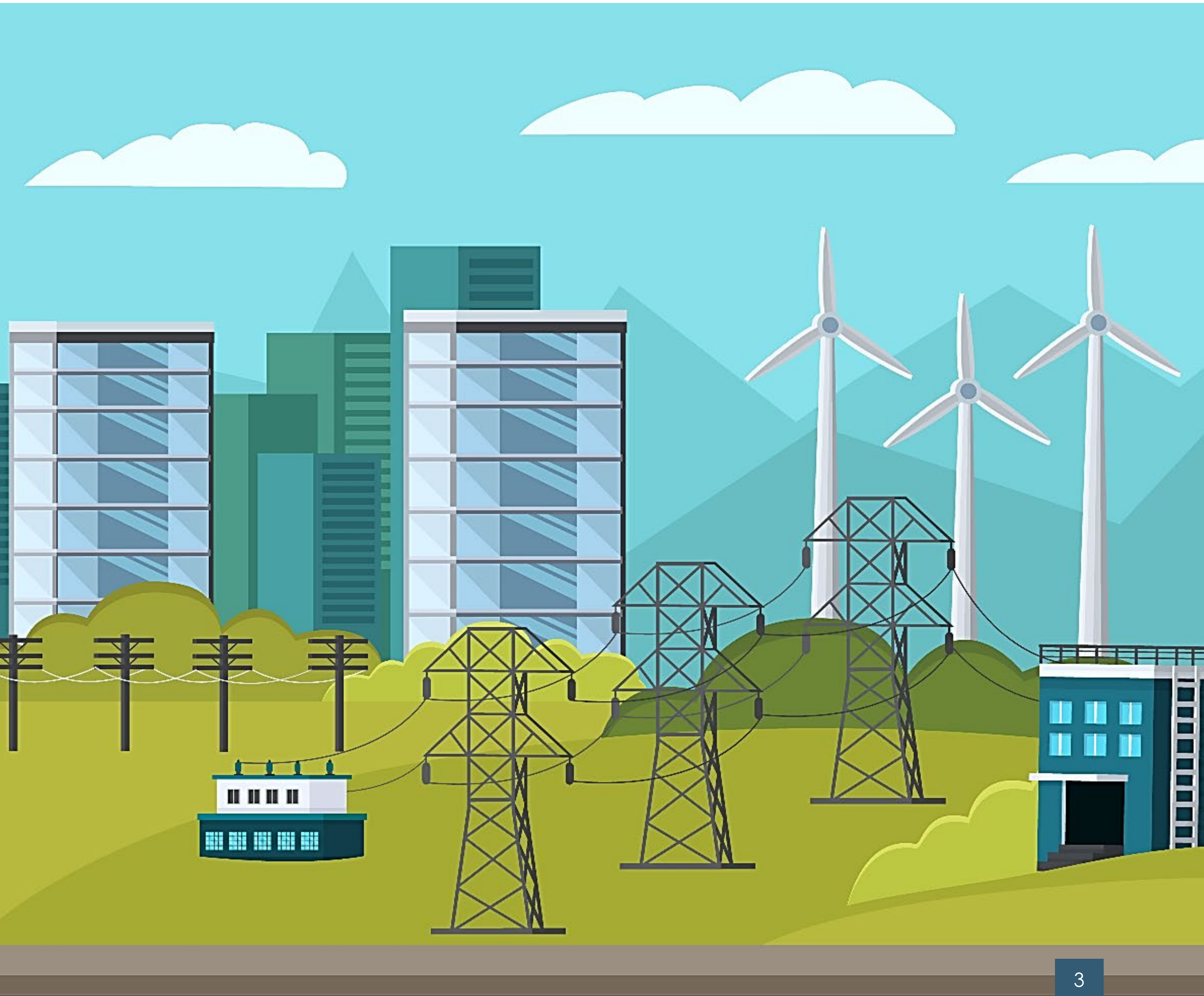
Acronyms

AEP	Alberta Environment and Parks
AESO	Alberta Electric Systems Operator
BATEA	Best Available Technology Economically Achievable
BLIERs	Base Level Industrial Emissions Requirements
CCME	Canadian Council of Ministers of the Environment
CASA	Clean Air Strategic Alliance
COHPAC	Compact hybrid particulate collection
CO_2	Carbon dioxide
CTRS	Control technologies and reduction strategies
ECCC	Environment and Climate Change Canada
EFR	Electricity Framework Review
EEC	Electrical efficiency and conservation
EUB	Alberta Energy and Utilities Board
EoDL	End of design life
EoUL	End of useful life
EPEA	Environmental Protection and Enhancement Act
ESRD	Environment and Sustainable Resource Development
ETR	Emissions Trading Regulation
ETS	Emissions Trading System
g	Gram
GHG	Greenhouse gas
GoA	Government of Alberta
GWh	Gigawatt-hour
HEAT	Health and Ecological Assessment Task (Group)
Hg	Mercury
J	Joule
Kg	Kilogram
kWh	Kilowatt-hour
LTO	Long-term outlook
MCR	Maximum continuous rating
MW	Megawatt
MWh	Megawatt-hour
NGCC	Natural Gas Combined Cycle
Ng	Nanogram
NGO	Non-governmental organization
NO_x	Nitrogen oxides (also oxides of nitrogen)
PM	Particulate matter

SCR	Selective Catalytic Reduction
SO_2	Sulphur dioxide
TWh	Terawatt-Hours



Executive Summary

In November 2003, CASA published *An Emissions Management Framework for the Alberta Electricity Sector.* The report contained 71 recommendations for managing air emissions from electricity generation that were then accepted by the Government of Alberta.

To ensure continuous improvement and to keep the Framework relevant, it included a recommendation (no. 29) that a multi-stakeholder review be completed every five years. The review is to include the following tasks:

- assess new emission control technologies
- update emission limits for new generation units
- determine if emission limits for new substances need to be developed
- review implementation progress
- determine if the Framework is achieving its emission management objectives

The first five-year review was initiated in 2008, and the project team produced a final report in 2010 that contained 10 consensus recommendations. The second five-year review was initiated in 2013 and contained a further 13 recommendations.

In 2018, the CASA Board approved a project charter and established a multi-stakeholder project team to conduct the third five-year review of the Framework. The work was completed in two phases, with the submission of an interim report in December 2018 marking the end of Phase 1 and the beginning of Phase 2.

CASA was not able to reach consensus on their Phase 1, Task 1 to update NO_x air emission standards for new continuous (non-peaking) and intermittent (peaking) natural gas-fired turbine units and industrial co-generation plants using gas-fired turbines. Stakeholder perspectives on this task were submitted as part of the interim report.

CASA reached consensus on the remainder of the project tasks, and associated recommendations are summarized below:

Recommendation No. 1: NO_x Emissions Standards for Gas-Fired Reciprocating Engines

The 2023 Five-Year Review Project Team review this issue and if there is a need, the 2023 Team should determine BATEA-based NO_x emissions standards for gas-fired reciprocating engines used for electricity generation.

Recommendation No. 2: NO_x Emissions Standards for Biogas-Fired Engines

The 2023 Five-Year Review Project Team review this issue and if there is a need to develop NO_x emissions standards, the 2023 Team should determine BATEA-based emissions standards for biogas-fired engines.

Recommendation No. 3: Assessment of the Emissions Trading System
The Government of Alberta should provide a consultation opportunity to provide input on the Emissions Trading Regulation through the regulatory review process in 2021.

Recommendation No. 4: Emissions Standards for Biomass-Fired Units
The 2023 Five-Year Review Project Team review this issue and if there is a need to develop emissions standards, the 2023 Team should determine BATEA-based emissions standards for biomass-fired units.

Recommendation No. 5: Federal Stationary Diesel Engine Regulations
There is no further need to set specific emission standards for Alberta for off-road compression ignition engines used in electricity generation.

Recommendation No. 6: Primary PM Management System
Based on off-coal milestones occurring in 2023 or earlier for all units, there is no

need to develop a primary PM Management System as primary PM emissions are expected to be substantially reduced by 2023.

Recommendation No. 7: Information Gathering
To assist in meeting the goal of completing the five-year reviews within one year, the Working Group for the next five-year review should identify information needs and scope of work for any contracts required so they can be initiated and completed prior to creation of the 2023 EFR Project Team.

Recommendation No. 8: Assessment of the 2003 Framework and Scope of the Five-Year Review
A working group drawn from previous stakeholders who have participated in EFRs should be struck to undertake a holistic review of the tasks traditionally included in the project charter for five-year reviews. This review should include an assessment of the recommendations for five-year reviews from the 2003 Framework, exclusion of non-relevant tasks, and inclusion of new tasks deemed relevant to the electricity sector in its current form.

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1 Project Background

This project builds on the work completed by the original Electricity Project Team and the previous five-year review project teams in addition to taking on new tasks relevant to Alberta's electricity sector.

1.1 The Electricity Sector in Alberta

Albertans expect to have a reliable supply of electricity available to support their needs. The electricity sector provides this service through electricity generation using various fuels and technologies, a transmission component to transport electricity via high voltage transmission lines to local substations, and a distribution component to transport electricity over lower voltage lines to homes and businesses. Industrial sites may also generate electricity for their own use and provide surplus energy into the provincial electricity system.

The Emissions Management Framework for the Alberta Electricity Sector focuses on the generation component of the electricity sector to manage air quality impacts from these emissions sources. Electric power generation is a significant emitter of several major air pollutants: sulphur dioxide, nitrogen oxides, and mercury. Coal-fired units also produce primary particulate matter and electricity generated by the burning of fossil fuels creates greenhouse gas emissions. In 2018, this sector produced 31% of Alberta's total SO_2, 8% of its total NO_x, 4.6% of its total fine particulate matter, 29% of its total mercury, and 24% of its total GHG emissions.

The electricity sector is undergoing significant transformation in response to climate change objectives, which have resulted in increasing low- and non-emitting generation share in the provincial generation mix. This transformation is expected to continue in the coming years because electrification is expected to be a critical pathway for achieving Canada's goal of net zero GHG emissions by 2050. The management of air emissions from the electricity sector will continue to benefit from the initiatives driven by climate change policy.

Figure 1 shows the 2019 installed capacity in the province, by source. Installed capacity is the maximum amount of electric power that theoretically could be produced if all the generating facilities in Alberta were generating power at their rated specifications. Total installed capacity as reflected in the chart represents 16.5 gigawatts (GW). Natural gas generation was the largest share of installed capacity in 2019.

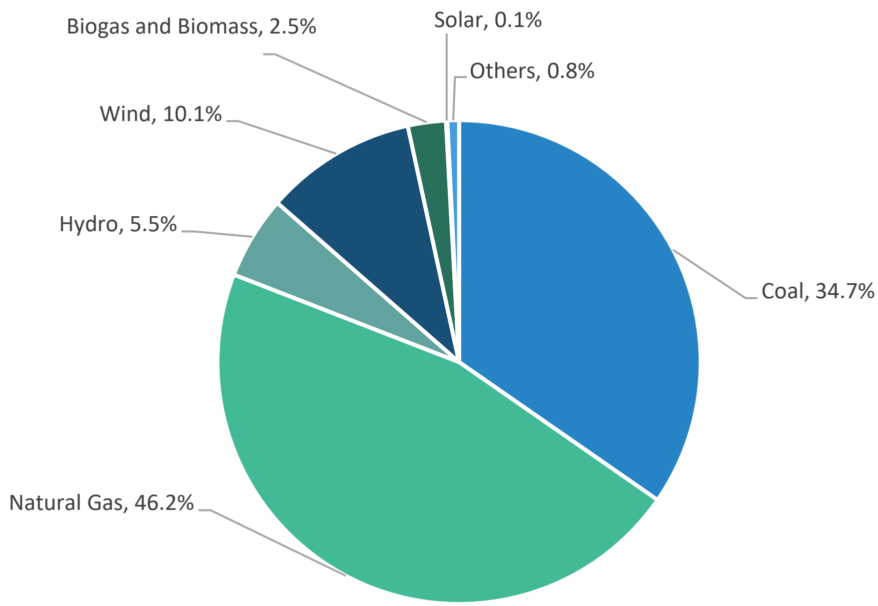

FIGURE 1: ALBERTA ELECTRIC ENERGY NET INSTALLED CAPACITY (MCR MW) BY RESOURCE

SOURCE: ALBERTA UTILITIES COMMISSION WEBSITE, HTTPS://WWW.AUC.AB.CA/PAGES/ANNUAL-ELECTRICITY-DATA.ASPX, DOWNLOADED FEBRUARY 17, 2020

In 2019, the actual electricity produced in Alberta was 84.8 Terawatt-hours (TWh) of electricity; sources of this generation are illustrated in Figure 2. Natural gas generation was the largest portion of actual generation produced in 2019.

The contribution mix of the type of generating unit resources providing actual energy is different than the contribution mix of installed capacity. This difference is a result of the generating units not operating at their full capacity or operating for shorter periods. An example of this would be a wind generator that may not operate all hours of the day depending on whether there is the required wind. The generation mix in Alberta continues to shift from what was a predominantly coal-based fleet to a natural gas-based fleet. Future generation additions are expected to come from gas-fired combined cycle, co-generation, wind generation, and small-scale renewables. This different mix of generating types and the replacement of retired units with more efficient generating technologies will result in lower air emissions from the electricity sector.

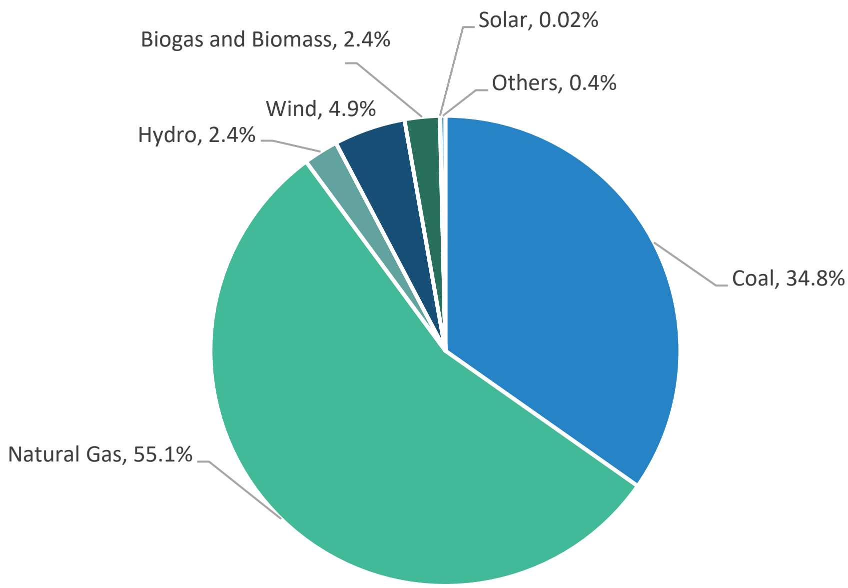

FIGURE 2: ALBERTA'S ELECTRIC ENERGY GENERATION BY SOURCE, 2019

SOURCE: ALBERTA UTILITIES COMMISSION WEBSITE, HTTPS://WWW.AUC.AB.CA/PAGES/ANNUAL-ELECTRICITY-DATA.ASPX DOWNLOADED FEBRUARY 17, 2020; "OTHER" SOURCES INCLUDE FUEL OIL AND WASTE HEAT.

The 2019 Long-term Outlook (LTO) for the electricity sector prepared by the Alberta Electric System Operator (AESO) includes a 20-year electricity consumption forecast and a generation capacity projection for Alberta. The AESO indicated that the 2019 LTO was developed during a period of uncertainty and the outlook covers a period of transformation of Alberta's electricity industry. Changes in economics, government policies, technology, and the way power is produced and consumed can significantly impact load growth and development of generation. The AESO used a series of scenarios to develop the outlook. Key highlights of the reference case are as follows:

- Load is forecast to grow at a compound annual growth rate of 0.9% until 2039, approximately half the rate of growth experienced in the previous 20 years.
- Approximately 13 GW of new generation capacity is expected by 2039 with natural gas-fired generation as the predominant source.

In addition to the reference case, the AESO LTO included scenarios for high oilsands co-generation growth, high renewable energy growth, high economic growth, low economic growth, and a diversification scenario that shifts Alberta's economy away from oil and gas. The next AESO LTO will be undertaken in 2021.

The transformation of the electricity sector in Alberta is due, in part, to evolving technology, policies, and social and economic drivers that affect future generation development and load growth. The electricity system's reliance on coal-fired generation is changing, and coal-fired generation operators have aggressively accelerated the phase-out of coal. Although we can expect more gas-fired and renewable generation, the ongoing transformation of the electricity sector may take some new paths.

1.2 Alberta's Emissions Management Framework for the Electricity Sector

In January 2002, Lorne Taylor, Alberta's then-Minister of Environment, asked CASA to develop a new way to manage air emissions from the electricity sector. The Electricity Project Team developed *An Emissions Management Framework for the Alberta Electricity Sector* (the Framework). The Framework was developed through a collaborative, multi-stakeholder process that included government, non-governmental organizations, locally affected interest groups, and the Alberta electricity sector. The Framework is a set of 71 consensus recommendations, negotiated by the team and agreed to as a package. These recommendations were adopted by consensus of the CASA Board in 2003 and subsequently implemented as regulations in 2004–2005 by the Government of Alberta. The Framework reflects a creative mix of management strategies that increase long-term regulatory certainty for all parties, provide flexibility in reducing emissions, and encourage continuous improvement of the overall management system.

To ensure continuous improvement in both management and performance, the Framework recommends a defined multi-stakeholder evaluation process at five-year intervals (Recommendation No. 29). The intent of the five-year review is to assess new emission control technologies, update emission limits for new generation units, determine if emission limits for new substances need to be developed, review implementation progress, and determine if the Framework is achieving its emission management objectives.

Each five-year review should be a publicly credible, transparent, participatory process that involves stakeholders from all sectors. If core assumptions are proven wrong, the Framework will be revised. A full review of the structure of the Framework itself would be triggered by the environmental and health factors noted in Recommendation No. 34 and the economic factors noted in Recommendation No. 35.

First Five-Year Review (2008)

The first five-year review began in 2008, and the EFR Team submitted its report and recommendations to the CASA Board in June 2009. The report contained 10 consensus recommendations and one non-consensus item. The consensus items included revisions to the PM, NO_x, and SO_2 emission standards for new coal-fired units based on improvements in emission control technologies, effective January 1, 2011. The non-consensus item pertained to NO_x emission standards for new gas-fired generation for both peaking and non-peaking units. Rob Renner, Alberta's then-Minister of Environment, asked the team to continue seeking consensus on this matter and substantial effort was made from 2009 to 2010 in response to this request. Despite those best efforts, consensus could not be achieved. A final report, including the interests and rationale with respect to the non-consensus recommendation, was forwarded to the Government of Alberta in May 2010 for decision.

Second Five-Year Review (2013)

The second five-year review began in 2013. The project team reviewed GHG regulations to identify potential implications and emissions management issues of the Framework created by the implementation of federal GHG regulations in addition to environmental and economic triggers (Recommendation Nos. 34 and 35).

The group was unable to reach consensus on the need to review or adjust the Framework, given divergent views of the members as to what was required to allow changes to the Framework. An interim report identifying the key issues and differing perspectives was submitted to the CASA Board. The CASA Board asked the Government of Alberta to weigh in on the matter and to describe the path forward as appropriate. In August 2014, CASA was notified that the Department of Environment and Parks was working on a cross-ministry plan with the Departments of Energy and Health that would review the interim report and determine the next steps for the Framework. In June 2015, Environment and Parks notified CASA that in the absence of a decision on the interim report and Framework, the Government of Alberta would continue to make regulatory decisions in accordance with the existing 2003 Framework.

In March 2015, the project team provided 13 recommendations to the CASA Board, one of which was non-consensus (Recommendation No. 3, emissions standards for gas-fired generation).

Third Five-Year Review (2018)

The third five-year review was initiated in 2018, the results of which are summarized in this report. Specific details on the project scope and tasks are outlined in the following sections.

1.3 Project Scope and Goal

The current five-year review goal was to ensure that the *Emissions Management Framework for Alberta's Electricity Sector* reflected current circumstances and to complete the review as stated in the following recommendations:

Recommendation No. 29 (2003)

This recommendation outlines the following elements of the Framework that must be reviewed
by the project team:

1. a technology review to identify the Best Available Technology Economically Achievable (BATEA) emission standards
2. the air emission substances subject to limits or formal management
3. co-benefits for priority substances and List 2 substances
4. a review of economic and environmental triggers as set out in the Framework in Recommendations Nos. 34 and 35
5. additional information that illustrates potential health effects associated with emissions from the electricity sector; and
6. a report from the electricity sector on continuous improvement

Recommendation No. 22 (2003)

This recommendation states that if mercury control does not provide the anticipated co-reduction of primary particulate matter, the five-year review should develop a primary particulate matter management system for existing units.

Recommendation No. 9 (2010)

This was a non-consensus recommendation for source standards for new gas-fired non-peaking thermal generation units. The 2015 Five-Year Review was asked to revisit this issue.

Recommendation No. 3 (2015)

This was a non-consensus recommendation for emissions standards for gas-fired generation. The current five-year review will revisit this issue.

Recommendation No. 4 (2015)
This recommendation states that the 2018 Five-Year Review should include a review of the need to include biomass sources of electricity generation in the Framework.

Recommendation No. 8 (2015)
This recommendation states that the 2018 Five-Year Review should ensure that each substance listed in Category 2 (i.e., management actions need to be considered) of the Air Emissions Substance Review are evaluated, considering:

- the state of the science on the substance
- substance reduction potential including management and cost
- co-benefits to be managed
- requirements for monitoring

Recommendation No. 9 (2015)
This recommendation states that the group undertaking the health and ecological assessment in the 2018 Five-Year Review should explicitly include substances listed in Category 3 (i.e., ongoing surveillance is recommended) in the search terms for the health and ecological literature reviews.

Recommendation No. 10 (2015)
This recommendation states that the Health and Environmental Assessment Task (HEAT) Group should be convened as soon as possible in the 2018 Five-Year Review and should be provided with the terms of reference from the 2013 HEAT Group, to adjust as the new group deems necessary.

Recommendation No. 11 (2015)
This recommendation states that the implementation of the Emissions Trading System should be assessed as part of the 2018 Five-Year Review of the Framework.

Recommendation No. 13 (2015)
This recommendation states that the 2018 Five-Year Review should consider the role of public consultation and develop a plan at the beginning of its process.

1.4 Project Tasks

The project was completed in two phases, with initial high-priority tasks to be completed on a short-term timeline (Phase 1) and delivered to the CASA Board no later than December 2018. The remaining long-term tasks (Phase 2) were to be completed by mid-2021. The tasks are summarized below.

Short-Term Tasks (Phase 1)

1. A technology review to identify the BATEA to update NO_x air emission standards for new gas-fired generation units, including the following:
    - continuous (non-peaking) and intermittent (peaking) natural gas-fired turbine units
    - industrial co-generation plants using gas-fired turbines
    - gas-fired reciprocating engines used for both industrial co-generation and electricity generation when multiple units are banked
    - gas turbines fired by biogas
    - design life considerations for gas-fired units

2. Updates to consultant reports from the first and second five-year reviews to determine BATEA-based emission standards for gas-fired generation, if deemed appropriate.

3. Review lessons learned from industry members using Selective Catalytic Reductions (SCR) in their operations.

4. As stated in Recommendation No. 11 of the 2013 Five-Year review, complete an assessment of the implementation of the Emissions Trading System, with a focus on NO_x emission credits. This assessment will include what the system is achieving and will continue to achieve, the intended objectives of providing incentives and rewards for better than required or expected performance, encouraging early shutdown of older units, and encouraging implementation of new emissions controls at existing units.

5. As stated in Recommendation No. 13 of the 2013 Five-Year Review, develop and implement a strategy and action plan for communicating and engaging with stakeholders and the public with a goal of informing and increasing the public's awareness and understanding of the following:
    - the 2003 Framework and how it works to improve performance and reduce emissions
    - the 2013 Five-Year Review process and outcomes
    - the implications of the implementation of recommendations resulting from the 2013 Five-Year Review
    - the 2018 Five-Year Review process

Long-Term Tasks (Phase 2)

1. As stated in Recommendation No. 4 in the 2013 Five-Year Review, review the need to develop emission standards for biomass-fired electricity generation sources.

2. Review the draft federal stationary diesel engines regulations for electricity generation, for engines used both in continuous and standby service, and consider implications for, and alignment with, the Framework.

3. As stated in Recommendation No.22 of the Framework, review primary PM management and develop a primary PM Management System for existing coal-fired units if deemed appropriate.

4. As stated in Recommendation No. 8 of the 2013 Five-Year Review, review air emission substances emitted by electricity generation that are subject to formal control, including existing Category 2 substances and emergent substances and their impacts. This task should consider the following:
   - the state of the science on the substance
   - the substance reduction potential including management and cost
   - co-benefits to be managed
   - requirements for monitoring

5. As stated in Recommendation No. 10 of the 2013 Five-Year Review, convene a HEAT Group to oversee a review to identify any new and relevant studies or research findings regarding potential environmental or health effects from air emissions substances from electricity generation, including an independent peer review on results.

   As stated in Recommendation No. 9 of the 2013 Five-Year Review, this task should explicitly include air emissions substances listed in Category 3 (i.e., ongoing surveillance is recommended) in the search terms for the health and ecological assessment literature review.

6. Modernize the Framework document itself by consolidating the recommendations from the first and second five-year reviews into the main Framework document, including adding information on implementation status of recommendations where applicable, and reviewing the recommendations for relevancy considering the changes to the electricity sector since the document was created.

7. As stated in Recommendation No. 13 of the 2013 Five-Year Review, develop and implement a strategy and action plan for communicating and engaging with stakeholders and the public with a goal of informing and increasing the public's awareness and understanding of the following:
    - the 2003 Framework and how it works to improve performance and reduce emissions
    - the 2013 Five-Year Review process and outcomes
    - the implications of the implementation of recommendations resulting from the 2013 Five-Year Review
    - the 2018 Five-Year Review process

8. Review a report from the electricity sector on continuous improvement.

9. Make recommendations for future five-year reviews.

This report documents the outcomes of the project team's tasks, including those from the December 2018 interim report. The results from the interim report are found in section 3, and the document itself in Appendix III.

2 Modernizing the Framework

This component of the five-year review focused on reviewing the status of the recommendations made in the Framework and the first two five-year reviews. The original 2003 Framework contained 71 recommendations. The reports from the first and second five-year reviews contained a further 11 and 13 recommendations, respectively. The team reviewed the recommendations for implementation status and relevancy. Table 1 contains the implementation status of the recommendations made during the second five-year review. The implementation status of the recommendations from the original 2003 Framework and the first five-year review can be found in Appendix III.

TABLE 1: IMPLEMENTATION STATUS OF THE SECOND (2013) FIVE-YEAR REVIEW RECOMMENDATIONS UPDATED DURING THE THIRD (2018) FIVE-YEAR REVIEW

No.	Recommendation	Implementation Status
1	**Emissions Standards for Conventional Coal-Fired Generation** The standards and credit limits in the Report on the First Five-Year Review of the Emissions Management Framework for the Alberta Electricity Sector, May 13, 2010, be carried over for conventional coal.	As the original standards document has not been revised, these requirements have been implemented through Environmental Protection and Enhancement Act (EPEA) approval processes, as necessary. Coal-fired generation in Alberta will be phased out by 2023.
2	**Emissions Standards for Unconventional Coal-Fired Generation** The standards and credit limits for unconventional coal should be approved on a case-by-case review by the regulator.	There have been no applications for any unconventional coal-fired unit.
3	**Emissions Standards for Gas-Fired Generation (Non-Consensus)** Although the Control Technologies and Reduction Strategies (CTRS) Task Group had extensive discussions on developing an emissions standard for gas-fired generation, they were unable to reach agreement on a standard. The group's final report will include information on its six consensus recommendations, as well as details on the diversity of perspectives regarding the non-consensus on emissions standards for gas-fired generation. The intent of the group's final report will be to provide input to any future policy development the GoA might undertake on this issue.	No consensus was reached, and no further clarification has been made by the GoA.
4	**Emissions Standards for Biomass-Fired Generation** The 2018 Five-Year-Review team review the need to include biomass sources of electricity generation in the Alberta Electricity Framework.	The 2018 Five-Year Review team determined no further action was required, and

		these facilities should be managed through the EPEA approval process.
5	**Emissions Standards for New Diesel-Fired Reciprocating Engines (regular use units)** The following standards apply to new diesel-fired reciprocating engines in regular use units that are approved on January 1, 2016 or later: • 1200 HP (0.89 MW) (<30 L displacement per cylinder): 0.50 g/bhp-hr (approximately 0.67 g/kWh) • 699 kW (805 HP) (≥30 L displacement per cylinder): 1.8 g/kWh (approximately 1.34 g/bhp-hr) These standards are expressed in a similar format to the US EPA Tier 4 Compression Ignition New Source Performance Standards, which include diesel-powered generator sets, and is based on selective catalytic reduction.	As the original standards document has not been revised, these requirements have been implemented through EPEA approval processes, as necessary. These requirements will become redundant when updated federal requirements are issued in Canada Gazette Part 2.
6	**Emissions Standards for New Diesel-Fired Reciprocating Engines (standby units)** The following standard apply to new diesel-fired reciprocating engines in standby units that are approved on January 1, 2016 or later: • 750 HP (0.560 MW) 4.8 g (NMHC+NOx)/bhp-hr (approximately 6.4 g (NOx+NMHC)/kWh) This standard is expressed in a similar format to the US EPA Tier 2 Compression Ignition New Source Performance Standards for generator sets, and is based on combustion controls (that is, no SCR).	As the original standards document has not been revised, these requirements have been implemented through EPEA approval processes, as necessary. These requirements will become redundant when updated federal requirements are issued in Canada Gazette Part 2.
7	**Emissions Standards for New Natural Gas-Fired Reciprocating Engines** The following standard apply to new natural gas-fired reciprocating engines that approved on January 1, 2016 or later: • 75 kW (500 hp is US size range): 2.7 g/kWh (based on 2.01 g/bhp-hr) This standard is based on the BLIERs for NOx for natural gas-fired reciprocating spark ignition engines, which are based on the US EPA requirements for these types of engines.	As the original standards document has not been revised, these requirements have been implemented through EPEA approval processes, as necessary. More stringent requirements can be set through the approval process based on different installations where multiple engines are banked to achieve a higher generation capacity.
8	**Evaluation of Category 2 Substances** The multi-stakeholder group undertaking the 2018 Electricity Framework Review ensure that each substance listed in Category 2 (i.e., management actions need to be considered) is evaluated as described in Table 1 of this report.	The review is being completed.

9	**Substances for Ongoing Surveillance** The multi-stakeholder group undertaking the health and ecological assessment for the next five-year review explicitly include substances listed in Category 3 in the search terms for the health and ecological literature reviews.	The review is being completed.
10	**Future Substance Reviews** A multi-stakeholder Health and Environmental Assessment Task Group be convened as soon as possible after the 2018 Electricity Framework Review Project Team is established and that it be provided with the terms of reference from the 2013 HEAT Group to adjust, as the new Group deems necessary.	The review is being completed.
11	**Implementation of the Emissions Trading System** Implementation of the Emissions Trading System be assessed as part of the 2018 Five-Year Review of the Alberta Electricity Emissions Management Framework.	The review was completed, and no changes were proposed. As the regulation will be undergoing a review in 2021, stakeholders will be asked for input.
12	**GoA Decision on Previous Recommendations** The CASA Board request an update on the status of the GoA decision process related to Recommendations Nos. 6, 7, and 9, as found in the 2010 report from the first five-year review.	No further clarification has been made by the GoA.
13	**Public Consultation** The 2018 Five-Year Review Project Team consider the role of public consultation and develop a plan at the beginning of its process.	Direction was provided by the CASA Board on consultation requirements for CASA projects.

3 Interim Report Summary

The Electricity Framework Review Project Team submitted an interim report to the CASA Board in December 2018. This interim report partially addressed the short-term tasks from the project charter and identified next steps for the ones not fully resolved. The status and next steps for the Phase 1 tasks as provided in the interim report are summarized in Table 1.

The project team was not able to reach consensus on a NO_x emission standard for natural gas-fired continuously or intermittently operating combined cycle units or co-generation units (short-term Task 1). Two approaches to managing NOx emissions were discussed: a Proposal "A" and a Proposal "B." These proposals and perspectives documents from stakeholders can be found in the Interim report.[1]

TABLE 2: STATUS AND NEXT STEPS FOR THE PHASE 1 TASKS AS PRESENTED IN THE 2018 CASA ELECTRICITY FRAMEWORK REVIEW: PERSPECTIVES ON A NOX EMISSION STANDARD FOR NATURAL GAS-FIRED TURBINES REPORT IN DECEMBER 2018

Task Description	Status	Next Steps
Review of environmental and economic triggers (Recommendation Nos. 34 and 35)	Discussed by the working group and decided that because it was unlikely the triggers have been met, there was no value in allocating budget to have a consultant complete a trend assessment.	n/a
NO_x air emission standards for new gas-fired generation units	Largely addressed during Phase 1 and resulted in non-consensus and a perspectives document.	Subtasks to be discussed further in Phase 2.
NO_x air emission standards for gas-fired reciprocating engines	Discussion initiated during Phase 1, specifically on treatment of banked units.	Continued discussion in Phase 2 with a recommendation to be included in either a second interim report or the final deliverable for the project in 2019.
NO_x air emission standards for gas turbines fired by biogas	Discussions initiated during Phase 1.	Continued discussion in Phase 2 with a recommendation to be included in either a second

1 https://www.casahome.org/attachments/EFR%20Interim%20Report%20Incl%20Appendices%20Dec%2018%202018%20Reduced%20Size.pdf

		interim report of the final deliverable for the project in 2019.
Design life considerations	Discussions initiated during Phase 1.	Continued discussions in Phase 2 with a recommendation to be included either in a second interim report or in the final deliverable for the project in 2019.
Determine BATEA for gas-fired generation	Completed. The project team reviewed the BATEA review completed during the 2013 EFR along with information obtained by industry representatives from manufacturers.	Full details to be provided in the final deliverable for the project in 2019.
Review lessons learned from industry using Selective Catalytic Reductions (SCR)	Industry representatives on the project team provided information on their experiences with SCR in their operations.	None, task complete.
Complete an assessment of the Emissions Trading System	The project team received information on the Emissions Trading System from the Government of Alberta and provided some feedback.	The Emissions Trading System will be reviewed again in Phase 2, and any further feedback provided in the final deliverable for the project in 2019.
Develop and implement a communications strategy and action plan	Discussed by the project team in Phase I. Decided to postpone further discussion on details until Phase 2.	A draft communications strategy for the project will be developed early in Phase 2 of the project.

4 Outstanding Task Outcomes

4.1 Selective Catalytic Reduction: Lessons Learned

SCR units are used in the power generation industry to reduce NO_x emissions, and the project team was tasked with obtaining information on how SCRs are used in electricity generation units in Alberta. To address this task, Alberta Newsprint Company, Capital Power, and ENMAX provided presentations on their experiences using SCR in their operations. This information was used to support discussions on NO_x air emission standards for new electricity generation units.

This task was completed in Phase 1, but as minimal information was provided in the interim report, this task has been included in the final report for completeness. The presentations are provided in Appendix IV.

4.2 Emissions Standards for Reciprocating Engines

This item was brought forward by Alberta Environment and Parks, initiated in Phase 1 of the 2018 review and continued in Phase 2. Based on recommendations from the original Electricity Project Team, the 2005 NO_x emission standards currently in use are primarily based on gas-fired turbines. Identified issues that were discussed included the difference between the NO_x emission intensity of gas-fired reciprocating engines versus the gas-fired turbine engines, the banking of multiple reciprocating engines as an area of growth in Alberta, the need for clear policies and consistent NO_x emission standards and impacts on these engines from the greenhouse gas regulations. The project team decided to reassess and consider this issue in the next five-year review.

Recommendation No. 1: The 2023 Five-Year Review Project Team review this issue and if there is a need, the 2023 Team should determine BATEA-based NO_x emissions standards for gas-fired reciprocating engines used for electricity generation.

4.3 Emissions Standards for Biogas-Fired Engines

This item was brought forward by Alberta Environment and Parks, initiated in Phase 1 of the 2018 review and continued in Phase 2. Because of variable fuel composition of lower heating value, biogas-fired engines use conventional burners systems to ensure combustion of the biogas. Use of a conventional burner system can have a high NO_x emission intensity especially if the engines will fire natural gas in the case of less biogas supply. Currently, applications with biogas-fired engines are dealt with on a one-off basis. Relevant stakeholders will need to be present for discussion of an emission standard for these engines. These engines are flexible in application and are primarily used for generation of greenhouse gas credits. Currently the number of units in the electricity market using biogas as a fuel is not significant, but this is likely a growth area in Alberta and could be an issue to address in future reviews.

Recommendation No. 2: The 2023 Five-Year Review Project Team review this issue and if there is a need to develop NO_x emissions standards, the 2023 Team should determine BATEA-based emissions standards for biogas-fired engines.

4.4 Design Life

The project team discussed design life in the context of the NO_x emission standards and the emissions trading regulation tasks. The team decision was that no recommendations were required related to NO_x emissions standards and that any further discussions or recommendations needed would be addressed through the emissions trading regulation discussion.

For more information, see section *4.6 Emissions Trading System Review.*

4.5 Best Available Technology Economically Achievable

The need to update the second five-year review BATEA report, Control Technologies Review for Gas Turbines in Simple Cycle, Combined Cycle and Co-generation Installations,[2] was discussed by the current project team during Phase 1 (short-term tasks). The team agreed that a full BATEA review was not required; however, Table 3-1 from the previous review's report could be updated to reflect current circumstances. Team members were tasked with this update, and the revised table is included here.

TABLE 3: TABLE 3-1 (AVAILABLE DLN AND UDLN TURBINES) FROM THE CONTROL TECHNOLOGIES REVIEW FOR GAS TURBINES IN SIMPLE CYCLE, COMBINED CYCLE AND CO-GENERATION INSTALLATIONS REPORT (2015 BATEA REPORT) UPDATED WITH INFORMATION AVAILABLE AS OF 2018

Manufacturer	Frequency	Model	MW(1)	NO_x Level(2), ppmv
Mitsubishi Hitachi	60	H-25	41	15

[2] https://www.casahome.org/attachments/Control%20Tech%20Review%20Consultant%20Report%20(Eastern%20Research%20Group).pdf

Mitsubishi Hitachi	60	H-100	105.7	9
Mitsubishi Hitachi	60	M501F	185.4	25
Mitsubishi Hitachi	60	M501G	267.5	15
Mitsubishi Hitachi	60	M501GAC	283	15
Mitsubishi Hitachi	60	M501J	330	25
Mitsubishi Hitachi	60	M501JAC	400	25
Pratt & Whitney	60	FT8 SwiftPac 30 DLE	25.5	25
Pratt & Whitney	60	FT8 SwiftPac 60 DLE	51.2	25
GE Heavy Duty	60	6B.03	44	4
GE Heavy Duty	60	6F.03	87	15
GE Heavy Duty	60	7E.03	91	4
GE Heavy Duty	60	7F.04	198	9
GE Heavy Duty	60	7F.05	243	12
GE Heavy Duty	60	7F.05	231	9
GE Heavy Duty	60	7F.05	224	5
GE Heavy Duty	60	7HA.01	290	25
GE Heavy Duty	60	7HA.02	384	25
GE Aeroderivative	60	LM2500+DLE	34.5	25
GE Aeroderivative	60	LM6000 DLE	45	15
GE Aeroderivative	60	LM6000 DLE Sprint	50	15
GE Aeroderivative	60	LM6000 DLE	53	25
GE Aeroderivative	60	LM6000 DLE Sprint	57	25
GE Aeroderivative	60	LM9000 DLE	66	25
GE Aeroderivative	60	LM9000 DLE Sprint	75	25
GE Aeroderivative	60	LMS100	118	25
Siemens Energy	60	SGT6-2000E	117	25
Siemens Energy	60	SGT6-5000F	226	9
Siemens Energy	60	SGT6-8000H	310	25
Siemens Energy	60	SGT6-9000HL	388	2 with SCR
Siemens Energy	60	SGT6-600	24.5	15
Siemens Energy	60	SGT6-700	32.8	15
Siemens Energy	60	SGT6-800	50.5	15
Siemens Energy	60	SGT6-A35	32.5	25
Siemens Energy	60	SGT6-A65	59.6	25
Siemens Energy	60	SGT6-A65 ISI	64.9	25
Note: 1 - power output at ISO conditions				
2 - NOx emission without SCR unless otherwise noted				

With the revision to Table 3-1, the project team considered this task complete and did not have any associated recommendations. The information was used in support of the discussion on NOx emission standards for new gas-fired electricity generation units, which resulted in non-consensus perspectives documents submitted to AEP as advice for their decision making. Please see Appendix III for more details.

4.6 Emissions Trading System Review

Recommendation No. 11 of the 2013 Five-Year Review required assessing the implementation of the Emissions Trading System, with a focus on NO_x emission credits to be conducted in the 2018 Five-Year Review. It was included as Phase 1, Task 4, and this assessment was to include what the system is achieving and will continue to achieve, what the intended objectives of providing incentives and rewards for better than required or expected performance are, how to encourage early shutdown of older units, and how to encourage implementation of new emissions controls at existing units. This task was originally planned for Phase 1 of the 2018 review but was rescheduled to Phase 2 to provide an opportunity to review the aspects that should be considered.

On September 19, 2019, the EFR Project Team met to discuss concerns that industry members had identified with the Emissions Trading System and the need to provide clarity about the treatment of coal-to-gas conversions. This session did not have all sectors represented and was solely to explore industry concerns. The review of the coal-to-gas conversions was thought to be best addressed through the Emissions Trading System assessment of the Electricity Framework Review.

The EFR team meeting on February 18, 2020 included a discussion on the Emissions Trading System review. Items identified requiring clarity included the following:

- treatment of moth-balled generating units under the Emissions Trading Regulation (ETR) with respect to emissions credits
- whether coal-to-gas conversions completed before the end of design life would be eligible for emissions credits under the ETR
- in general, how coal-to-gas conversions are handled or not handled under the ETR
- if co-generation or other gas generation units under an industrial approval be included (or be eligible to be included) in the emissions trading program or any other element of the ETR

To further the discussion and understand the different perspectives on emissions trading, industry representatives were asked to meet and develop a proposal for how they believe the ETS should work to address their interests.

Industry representatives reported back to the EFR team that no proposals for changes to the ETR would be tabled. Key points from the industry view were as follows:

- No changes are proposed for coal-to-gas conversions. The ETR expires November 30, 2021, and proposed changes to the existing regulations could be addressed at that time through a consultation process.
- Co-generation or other gas generation providing energy to the electricity grid are not prevented from making an application to have a baseline emission rate set and participating in the ETS. No changes are necessary to accommodate these units.

The EFR team discussed the status of the ETS assessment and deemed that no further action was necessary.

Recommendation No. 3: The Government of Alberta should provide a consultation opportunity to provide input on the Emissions Trading Regulation through the regulatory review process in 2021.

4.7 Communication Plan

The 2013 EFR Project Team recommended the 2018 Five-Year Review Project Team consider the role of public consultation and develop a plan at the beginning of its process. The project team discussed public consultation during both Phase 1 and Phase 2 of the current review and sought direction from AEP on whether it was appropriate to develop a public consultation plan for this review.

The EFR Project Team consulted the AEP Air Policy Group about whether the group thought that public consultation was required to support the desired outcomes from the 2018 Five-Year Review. The group believed that increasing public awareness and understanding of the work was important and that ideally a communications plan should be developed while the 2018 Five-Year Review was ongoing. The group did not believe gathering further public input about the products by engaging the public was necessary because the structure of CASA and its participants was intended to bring broad views to the table.

To align with the direction provided from the group, the project team developed a communications plan to disseminate the products of the 2018 Five-Year Review to stakeholders and the public once the project reports were complete. Please see Appendix V for the communications plan.

4.8 Emissions Standards for Biomass-fired Units

This item was brought forward by AEP, initiated in Phase 1 of the 2018 review, and continued in Phase 2. Depending on the biomass fuel being used, development of these units is considered an environmentally proactive initiative and is considered carbon neutral. Any potential emissions standard should avoid being too restrictive. However, the emissions profiles of these units are unknown, which can be challenging when completing health and environmental assessments. Primary PM is one possible concern for these units. Potential emissions profiles of these units could be cross-referenced with the literature review from the HEAT Group. This item should remain on the task list for the next framework review, at which time the project team can review information on emissions as it is received and decide on next steps.

Recommendation No. 4: The 2023 Five-Year Review Project Team review this issue and if there is a need to develop emissions standards, the 2023 Team should determine BATEA-based emissions standards for biomass-fired units.

4.9 Federal Stationary Diesel Engine Regulations

Environment and Climate Change Canada (ECCC) initiated a national standard setting process for off-road compression ignition engines that involved a multi-stakeholder group. As a result of the process, new emission standards for these engines are now published in Canada Gazette Part 2.[3] Given that they would reflect current US EPA emission standards for off-road engines used in electricity generation and are considered BATEA, the project team believes there is no further need to set specific emission standards for Alberta.

Recommendation No. 5: There is no further need to set specific emission standards for Alberta for off-road compression ignition engines used in electricity generation.

[3] http://www.gazette.gc.ca/rp-pr/p2/2020/2020-12-23/html/sor-dors258-eng.html

4.10 Primary Particulate Matter Management System

Background

This task is based on Recommendation No. 22 in the 2003 Framework and entailed considering the feasibility of developing a PM management system for existing generation units. The 2003 Electricity Project Team identified PM as a priority substance but recognized that reductions in primary PM were expected because of the proposed mercury management approach. There were challenges with including activated carbon and compact bag houses (compact hybrid particulate collection, COHPAC) that were expected to have the co-benefit of improved primary PM capture, so these reductions in primary PM were not realized.

During the first five-year review in 2008, the project team hired a consultant to assess PM controls on existing coal-fired electricity units in Alberta to determine the performance of PM controls. The task team attempted to develop a formal PM management plan; however, no agreement could be reached on the format and content of such a plan.

The issue was revisited during the second five-year review in 2013, and a task team was struck to review existing information and discuss whether PM optimization was sufficient or if a PM management system needed to be developed. Agreement was not reached, and stakeholders provided discussion papers outlining their interests. An outcome of the second five-year review was that the need for a PM Management System should be re-evaluated at each five-year review.[4]

Coal-to-Gas Transition Project

In 2018, the federal Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations were amended to accelerate the end of useful life of coal-fired units to no later than December 31, 2029, after which a performance standard would apply. Also in 2018, federal Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity were introduced to allow units converted from coal to natural gas to defer the end of useful life for up to 10 years. AEP asked CASA to develop and recommend a NOx emission standard that could be applied to coal-fired electricity generation units that converted to fire natural gas instead of coal. This work included draft

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[4] https://www.casahome.org/attachments/PM%20Management%20System%20Recommendation%20to%20Project%20Team.pdf

technology requirements for coal-to-gas unit conversions, a recommendation for a NO_x emission standard for a coal-to-gas unit conversion, and allowable lifespan for a coal-to-gas unit conversion based on the proposed NO_x emission standard.

The team reached consensus and provided advice to the GoA.[5]

Current Five-Year Review

This task was included in the current five-year review, and the project team reviewed the following:

- information on PM management available from previous five-year reviews
- historical PM emission information from the NPRI
- PM emission scenarios from 2010 to 2030
- the planned schedule for conversion of coal units to natural gas and unit retirement

Table 4 lists all coal-fired electricity generation units in Alberta and information on coal-to-gas conversion and retirement schedules. Milestone dates are based on public announcements and are conservative. Several Alberta coal units have completed gas conversion work ahead of milestones with more to be undertaken in the near term. This voluntary early action is well ahead of the regulated phase-out for coal generation.

TABLE 4: RETIREMENT AND/OR COAL UNIT NATURAL GAS CONVERSION SCHEDULE

Generating Unit	Capacity (MW)	Off-Coal Milestone	Additional Information
Battle River Unit 3	158	2020	Battle River 3 was retired in December 2019.
Battle River Unit 4	155	2022	Heartland Generation Ltd. began the transition from coal-to-gas in 2018 and the transition will be completed no later than the end of 2022.
Battle River Unit 5	385	2022	
Sheerness Unit 1	400	2022	
Sheerness Unit 2	400	2022	
HR Milner	150	2020	In June 2020, Maxim Power Corp commissioned a 204 MW state-of-the-art natural gas-fired turbine generator at the HR Milner Generating and laid up the existing Milner 1 - 150 MW dual fuel unit. Milner 1 is permitted to run at no more than 9% capacity factor until December 31, 2029
Sundance 1	288	2018	Sundance 1 was retired in January 2018.

[5] https://www.casahome.org/attachments/CASA%20CTG%20Project%20Report%20Dec%20212017_FINAL.pdf

Sundance 2	288	2018	Sundance 2 was retired in July 2018
Sundance 3	353	2020	Sundance 3 retired in July 2020.
Sundance 4	406	2022	November 4, 2020: TransAlta announced that effective January 1, 2022, the Company will cease coal-fired generation in Canada.
Sundance 5	406	2022	
Sundance 6	401	2022	
Keephills 1	395	2022	
Keephills 2	395	2022	
Keephills 3	463	2022	
Genesee Unit 1	400	2023	December 3, 2020: Capital Power announced that operations will be off coal in 2023. Genesee 1 and 2 will be repowered using natural gas combined cycle technology. Genesee 3 dual fuel upgrades will be 100% natural gas fired by 2023.
Genesee Unit 2	400	2023	
Genesee Unit 3	466	2023	

Based on off-coal milestones occurring in 2023 or before for all units and the expected reduction in PM emissions, the project team decided a primary PM management system is not required.

Recommendation No. 6: Based on off-coal milestones occurring in 2023 or earlier for all units, there is no need to develop a primary PM Management System as primary PM emissions are expected to be substantially reduced by 2023.

4.11 Substance and Health and Environmental Assessment Literature Reviews

The HEAT Group retained Golder Associates Ltd. to conduct a literature review on the public health and ecological effects of substances known to be emitted into the air from electricity generation using various resource types (e.g., coal, biomass, fuel oil, waste) from power plants (not limited to stack emissions). The objective of the literature review was to identify new information published from 2013 to 2020.

Golder conducted a search of white and grey literature. White literature included primary peer-reviewed journal articles and grey literature included literature published by provincial, federal, and international organizations. The literature review focused on the following substance categories:

- Category 1: Priority List
- Category 2: Management Actions Need to be Considered
- Category 3: Ongoing Surveillance

The literature review was limited to public health and ecological effects, which considered both effects to biotic (e.g., vegetation and wildlife) and abiotic media (e.g., surface water, soil, and air). Based on the data gaps identified in previous five-year reviews, the literature search also considered public health and ecological effects associated with new substances or groups of substances, effects of mixtures, effects of low doses over long periods of time, and long- and short-range dispersion and deposition.

Forty-seven white literature articles and five grey literature reports were identified for evaluation. Most of these publications evaluated human health effects; one publication evaluated ecological endpoints. No studies were identified in relation to new substances. Please see the CASA website for Golder's final report,[6] including their methods and evaluation of the identified articles and reports.

The HEAT Group reviewed the outcome of Golder's work as well as the literature review process and recommended the EFR Project Team consider scoping and completing information-gathering activities before the initiation of the Five-Year Review Project Teams. This proactive information-gathering exercise will support the project team in completing the reviews in a one-year timeframe, as stated in the original 2003 Framework recommendation on the length of the five-year reviews.

Recommendation No. 7: To assist in meeting the goal of completing the five-year reviews within one year, the health and environmental assessment and substance review contracts should be scoped by the 2023 EFR Working Group then completed prior to the initiation of the 2023 EFR Project Team.

4.12 Continuous Improvement Report

Recommendation No. 29 of the 2003 Framework specifies that continuous improvement would be addressed in each five-year review. The expectation was that electricity generators would prepare a continuous improvement report as part of each five-year review that summarizes emissions control initiatives taken during the previous five years and identify goals for further continuous improvement during the next five-year period. Progress against these goals would then be assessed at each subsequent review, starting in 2013. If appropriate, the project could recommend modifications to the Framework that enhance opportunities for supporting continuous improvement efforts.

[6] https://www.casahome.org/attachments/20397046-001-R-Rev0-Lit%20Review%20Rpt%2018MAR_21.pdf

The contribution of priority air emissions from Alberta's electricity sector has been decreasing for several years. From 2013 to 2018, the period for this review, the electricity sector mass emissions of nitrogen oxides decreased by 27%, sulphur dioxide decreased 35%, particulate matter decreased 26%, mercury decreased 55%, and greenhouse gases decreased 14%. These significant reductions have been accomplished while meeting the need for a 10% increase in electricity demand to accommodate Alberta's growing economy. The reduced operation of higher emitting units, retirement of older units, additions of new low-emitting generation, and emissions reduction efforts undertaken by electricity sector participants have all contributed to achieving the emissions reductions. The mix of resource types that provide electricity generation has shifted from a majority coal-fired generation mix to one with increased natural gas-fired and renewable generation and an aggressive phase-out of coal-fired generation. The transformation of the electricity sector in Alberta and evolution of climate change policy drivers is expected to influence future generation development and load growth and to continue delivering emissions reductions.

The Continuous Improvement report was completed, and the project team did not identify any modifications needed to the Framework. Please see Appendix VI for the full report.

5 Future Five-Year Reviews

Based on the experience and learnings of the 2018 EFR Project Team, advice is provided to support the work of the 2023 EFR Project Team.

The working group should be established in 2022 to undertake a holistic scoping exercise to review the 2003 Framework recommendations for five-year reviews and consider any new tasks that should be included because of changes to the electricity sector since 2003 and expected upcoming changes. These areas of assessment could include the following:

- relevancy of the substance and health and environmental assessment reviews, including how they are used and applied and how they can be improved
- relevancy of parameters used in the substance and health and environmental assessment reviews given the shift of fuel type from coal to natural gas and consideration of the addition of other substances
- decarbonization and the implications of the use of this technology
- methods to ensure information needed by the project team is obtained in a timely manner so the project can be completed over the recommended one-year timeframe
- appropriate communication and engagement approaches based on the information being generated through five-year reviews

Recommendation No.8: Assessment of the Five-Year Review Process

A working group drawn from previous stakeholders who have participated in EFRs should be struck to undertake a holistic review of the tasks traditionally included in the project charter for five-year reviews. This review should include an assessment of the recommendations for five-year reviews from the 2003 Framework, exclusion of non-relevant tasks, and inclusion of new tasks deemed relevant to the electricity sector in its current form.

Appendix I: Project Charter

Emissions Management Framework for the Alberta Electricity Sector: 2018 Five-Year Review

Approved by the CASA
Board December 2020

Contents

Background

In January 2002, Alberta Environment asked the Clean Air Strategic Alliance (CASA) to develop a new way to manage air emissions from electricity generation in Alberta. Using a multi-stakeholder collaborate approach, CASA developed innovative solutions in the form of 71 recommendations comprising a management framework and presented it to the Government of Alberta in November 2003. The report, *An Emissions Management Framework for the Alberta Electricity Sector* (the Framework), was accepted by the Government of Alberta and implemented through regulations, standards, and facility approvals. The first emission standards were effective January 1, 2006.

To ensure continuous improvement and keep the Framework timely and relevant, a formal review of the Framework is to be undertaken every five years according to recommendation 29. This review should include a multi-stakeholder group consisting of industry, government, non-governmental organizations, and communities with an interest in electricity generation in Alberta. The intent of the five-year review is to assess new emission control technologies, update emission standards for new generation units, determine if emission standards for new substances need to be developed, review implementation progress, and determine if the Framework is achieving its emission management objectives.

A full review of the structure of the Framework itself would be triggered by the environmental and health factors noted in recommendation 34 (emission forecast is 15% higher than projected in the previous five-year review) and the economic factors noted in recommendation 35 (economic assumptions are significantly different to adversely affect the viability of the electricity sector). A full structural review would consider changes to the Framework to reflect current circumstances.

First Five-Year Review

The first five-year review began in 2008 and the Electricity Framework Review Team submitted their report and recommendations to the CASA Board in June 2009. The report contained ten consensus recommendations and one non-consensus item. The consensus items included revisions to the particulate matter (PM), nitrogen oxides (NO_x), and sulphur dioxide (SO_2) emission standards for new coal-fired units based on improvements in emission control technologies, effective January 1, 2011. The non-consensus item pertained to NO_x emission standards for new gas-fired generation for both peaking and non-peaking units. A final report, including the interests and rationale with respect to the non-consensus recommendation, was forwarded to the Government of Alberta in May 2010 for decision.

A subgroup-continued to meet to develop a particulate matter system for existing units, as stated in recommendation 22 of the Framework. In June 2010, the Federal Minister of Environment announced a proposed regulation for CO_2 emissions from coal-fired power plants. The specific details of the proposed federal coal regulation were not available until it was published in the Canada Gazette, making it difficult for the sub-group to reach agreement on a PM management system for existing coal units. As such, the board put the sub-group into abeyance until the details of the proposed regulation were available.

Second Five-Year Review

The second five-year review began in 2013. The project team reviewed greenhouse gas (GHG) regulations to identify potential implications and emissions management issues of the Framework created by the implementation of federal GHG regulations in addition to environmental and economic triggers (recommendation 34 and 35).

The group was unable to reach consensus on the need to review or adjust the Framework, given divergent views of the members as to what was required to allow changes to the Framework. An interim report identifying the key issues and differing perspectives was submitted to the CASA Board. The board asked the Government of Alberta to weigh in on the matter and to describe the path forward as appropriate. In August 2014, CASA was notified that the Department of Environment and Parks was working on a cross-ministry plan with the Departments of Energy and Health that would review the interim report and determine the next steps for the Framework. In June 2015, Environment and Parks notified CASA that in the absence of a decision on the interim report and Framework, the Government of Alberta would continue to make regulatory decisions in accordance with the existing 2003 Framework.

In March 2015, the project team provided 13 recommendations to the CASA Board, one of which was non-consensus (Recommendation No. 3, emissions standards for gas-fired generation).

Project Goal

To ensure the Emissions Management Framework for Alberta's Electricity Sector reflects current circumstances, the project team will conduct the third five-year review, as outlined in Recommendation No. 29 of the Framework.

Project Scope

The requirements of the five-year review are reflected in the following recommendations:

Recommendation No. 29 (2003)
This recommendation outlines the following elements of the Framework that must be reviewed
by the project team:

1. A technology review to identify the BATEA emission standards
2. The air emissions substances subject on limits on formal management
3. Co-benefits for priority substance and List 2 substances
4. A review of economic and environmental triggers as set out in the Framework in Recommendations Nos. 34 and 35
5. Additional information that illustrates potential health effects associated with emissions from the electricity sector
6. A report from the electricity sector on continuous improvement.

Recommendation No. 22 (2003)
This recommendation states that if mercury control does not provide the anticipated co-reduction of primary particulate matter, the five-year review should develop a primary particulate matter management system for existing units.

Recommendation No. 9 (2010)
This was a non-consensus recommendation for source standards for new gas-fired non-peaking thermal generation units. The 2015 Five-Year Review was asked to revisit this issue.

Recommendation No. 3 (2015)
This was a non-consensus recommendation for emissions standards for gas-fired generation. The current five-year review will revisit this issue.

Recommendation No. 4 (2015)
This recommendation states that the 2018 Five-Year Review should include review of the need to include biomass sources of electricity generation in the Framework.

Recommendation No. 8 (2015)
This recommendation states that the 2018 Five-Year Review should ensure that each substance listed in Category 2 (i.e., management actions need to be considered) of the Air Emissions Substance Review is evaluated, considering the following:

- the state of the science on the substance
- substance reduction potential including management and cost
- co-benefits to be managed
- requirements for monitoring

Recommendation No. 9 (2015)
This recommendation states that the group undertaking the health and ecological assessment in the 2018 Five-Year Review should explicitly include substances listed in Category 3 (i.e. ongoing surveillance is recommended) in the search terms for the health and ecological literature reviews.

Recommendation No. 10 (2015)
This recommendation states the Health and Environmental Assessment Task (HEAT) Group should be convened as soon as possible in the 2018 Five-Year Review and should be provided with the terms of reference from the 2013 HEAT Group, to adjust as the new Group deems necessary.

Recommendation No. 11 (2015)
This recommendation states the implementation of the Emissions Trading System should be assessed as part of the 2018 Five-Year Review of the Framework.

Recommendation No. 13 (2015)
This recommendation states the 2018 Five-Year Review should consider the role of public consultation and develop a plan at the beginning of its process.

Key Task Areas

This project will be completed in two phases, with initial high-priority tasks to be completed on a shorter timeline ("short-term" or Phase 1) and delivered to the CASA Board no later than December 2018. The remaining tasks ("long-term" or Phase 2) will be completed by mid-2019.

It is likely the environmental and economic triggers (recommendation 34 and 35 of the Framework) have not been triggered.

Short-Term Tasks (Phase 1)

1. A technology review to identify the BATEA to update NO_x air emission standards for new gas-fired generation units, including the following:
    - continuous (non-peaking) and intermittent (peaking) natural gas-fired turbine units
    - industrial co-generation plants using gas-fired turbines
    - gas-fired reciprocating engines used for both industrial co-generation and electricity generation when multiple units are banked
    - gas turbines fired by biogas
    - design life considerations for gas-fired units

2. Updates to consultant reports from the first and second five-year reviews to determine BATEA-based emission standards for gas-fired generation, if deemed appropriate.

3. Review lessons learned from industry using Selective Catalytic Reductions in their operations.

4. As stated in Recommendation No. 11 of the 2013 Five-Year Review, complete an assessment of the implementation of the Emissions Trading System, with a focus on NO_x emission credits. This assessment will include what the system is achieving and will continue to achieve, the intended objectives of providing incentives and rewards for better than required or expected performance, encouraging early shutdown of older units, and encouraging implementation of new emissions controls at existing units.

5. As stated in Recommendation No. 13 of the 2013 Five-Year Review, develop and implement a strategy and action plan for communicating

and engaging with stakeholders and the public with a goal of informing and increasing the public's awareness and understanding of the following:

- the 2003 Framework and how it works to improve performance and reduce emissions
- the 2013 Five-Year Review process and outcomes
- the implications of the implementation of recommendations resulting from the 2013 Five-Year Review
- the 2018 Five-Year Review process

Long-Term Tasks (Phase 2)

1. As stated in Recommendation No. 4 in the 2013 Five-Year Review, review the need to develop emission standards for biomass-fired electricity generation sources.

2. Review the draft federal stationary diesel engines regulations for electricity generation, for engines used both in continuous and standby service and consider implications for and alignment with the Framework.

3. As stated in Recommendation No. 22 of the Framework, review primary PM management, and develop a primary PM Management System for existing coal-fired units if deemed appropriate.

4. As stated in Recommendation No. 8 of the 2013 Five-Year Review, review air emission substances emitted by electricity generation that are subject to formal control, including existing Category 2 substances and emergent substances and their impacts. This task should consider:
    - the state of the science on the substance
    - the substance reduction potential including management and cost
    - co-benefits to be managed
    - requirements for monitoring

5. As stated in Recommendation No. 10 of the 2013 Five-Year Review, convene a HEAT Group to oversee a review to identify any new and relevant studies or research findings regarding potential environmental or health effects from air emissions substances from electricity generation, including an independent peer review on results.

As stated in Recommendation No. 9 of the 2013 Five-Year Review, this task should explicitly include air emissions substances listed in Category 3 (i.e., ongoing surveillance is recommended) in the search terms for the health and ecological assessment literature review.

6. Modernize the Framework document itself by consolidating the recommendations from the first and second five-year reviews into the main Framework document, including adding information on implementation status of recommendations where applicable, and reviewing the recommendations for relevancy in light of the changes to the electricity sector since the document was created.

7. As stated in Recommendation No. 13 of the 2013 Five-Year Review, develop and implement a strategy and action plan for communicating and engaging with stakeholders and the public with a goal of informing and increasing the public's awareness and understanding of the following:
    - the 2003 Framework and how it works to improve performance and reduce emissions
    - the 2013 Five-Year Review process and outcomes
    - the implications of the implementation of recommendations resulting from the 2013 Five-Year Review
    - the 2018 Five-Year Review process

8. Review a report from the electricity sector on continuous improvement.

9. Make recommendations for future five-year reviews.

Project Deliverables

The following deliverables will be developed by the project team and provided to the CASA Board:

- interim report on short-term tasks to be provided no later than December 2018
- final report including both the short and long-term tasks to be provided by mid-2019
- communications plan

It should be noted that *CASA's Performance Measures Strategy: A "how-to" guide to performance measurement at CASA* indicates that each project team is required to generate one specific metric that will allow the success of the team to be evaluated five years in the future. More guidance on how this can be achieved can be found in the strategy.

Project Structure and Schedule

Project work should begin in June 2018, with a completion date of no later than December 2018 for the short-term tasks and April 2021 for the long-term tasks. Table 1 outlines the timeline for outstanding short-term and long-term tasks as of December 2020. Tasks completed by the project team and approved by the board before February 2020 are not included in the table.

TABLE 1: 2018 EFR PROJECT TASK SCHEDULE (FEBRUARY 2020 TO DECEMBER 2020)

Task Description	Phase No. (Task No.)	2020											2021			
		Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Primary PM management for coal-fired units	2 (3)															
Emissions Trading System review	1 (4)															
NOx standards –reciprocating engines	1 (1)															
NOx standards – biogas	1 (1)															
NOx standards –design life	1 (1)															
Report on continuous improvement	2 (8)															
Air emissions substance review	2 (4)															
Environmental and health effects review	2 (5)															
Emissions standards for biomass	2 (1)															
Federal stationary diesel engines regulations	2 (2)															
Modernize the Framework	2 (6)															
Recommendations for future reviews	2 (9)															
Communications plan	1 (5) & 2 (7)															
Write final report	2 (n/a)															
Broad sector review (six weeks)	2 (n/a)															
Board decision	2 (n/a)															

Projected Resources and Costs

Table 2 outlines the potential external costs over the life of the project as anticipated by the project team. These figures are estimates only. As the work of the project team progresses, detailed work plans and associated budgets will need to be created.

TABLE 2: ESTIMATED COSTS ASSOCIATED WITH THE FIVE-YEAR REVIEW OF THE ELECTRICITY MANAGEMENT FRAMEWORK

Key Task	Estimated Budget
Environmental effects literature review (Phase 2, Task 5)	$20,000
Health effects literature review (Phase 2, Task 5)	$20,000
PM management system consideration (Phase 2, Task 3)	$20,000
Communication/Consultation (Phase 1, Task 5 and Phase 2, Task 7)	$15,000
Total	$75,000

Risk Analysis

Identifying, analyzing, and mitigating project risks is a key component of executing a successful project. The project team should incorporate proactive risk management into the project to mitigate risks that could undermine its success.

Table 3 lists the risks as well as possible mitigation strategies that the project team should consider as they undertake their work.

TABLE 3: ELECTRICITY MANAGEMENT FRAMEWORK REVIEW RISK ANALYSIS INCLUDING POSSIBLE MITIGATION STRATEGIES

Risks	Possible Mitigation Strategies
Process	
Timely funding not available for long-term (Phase 2) tasks.	• Identify who the "customers" of this work are. Who will find this valuable? Seek funding there. • Develop a strong value proposition that includes examples of sectors that may be involved or affected. • Ensure that project team members discuss the work and associated need for funding with their constituents early in the process.
Recommended management actions are too broad or not specific to the project goal.	• Seek a balance between regional needs and provincial applicability in management actions chosen. • Consider prioritizing cross-cutting actions that provide regional benefit and have the potential to be broadly applicable. • Consider ways to align this work with existing management frameworks and plans.

The project team cannot reach agreement, e.g., management actions or communications.	• Determine in advance which pieces of work require consensus. • Outline a clear decision-making process that includes what happens if the team cannot agree and who will then make the decision. • Have an explicit discussion around interest-based negotiation and ensure that all the team members' interests are at the table.
Project team does not understand or follow the Project Charter.	• Have the working group create a project charter that is clear, especially regarding the intent for sequencing of objectives. • Ensure that the board receives regular updates so that progress is monitored.
CASA Board does not agree with management actions identified in Objective 4	• Make sure that project team members liaise with their constituents and board members on an ongoing basis. • Ensure that the project team provides regular status reports for board meetings.
Recommendations of the project team are not implemented.	• This risk is outside the scope of the project team to mitigate; however, this risk will be reduced if i) the parties potentially involved in implementation are engaged, and ii) reference to implementation (who and how) is included in the report's recommendations.
Information Collection	
Consultant is not available during the project timeline	• Engage the consultant as far in advance as possible to ensure availability.
Lack of / limited information (accessibility)	• Ensure project team membership enables the team to access information. • Use appropriate judgement where information is unavailable.
Stakeholder Engagement	
During stakeholder engagement, "interested parties" do not agree with the list of management actions	• Try to develop the potential management actions collaboratively. • Seek to understand stakeholder reasons for disagreement if stakeholders disagree. • Identify non-consensus recommendations where appropriate.
Lack of engagement and ownership by project team	• Identify and communicate with potential stakeholders early in the process. • Create a clear value proposition. • Be clear about what is being asked of stakeholders.

Obtaining stakeholder feedback and refining management actions with interested parties takes longer than expected or causes scope creep.	• Set specific parameters for this piece of work:
	  o purpose of soliciting feedback
	  o scope of influence that outcomes will have on overall process
	• Work within the time available.

Operating Terms of Reference

Operating terms of reference describe how the project team agrees to work together. The project team should discuss and reach consensus on the following items:

- requirements for quorum

- governance
- meeting protocols
- roles and expectations of project team members
- how decisions will be made
- ground rules
- frequency of project team meetings
- frequency of updates and reports to the CASA Board
- protocols for handling media requests
- protocols for providing updates to interested parties
- any other considerations for working together

Stakeholder Analysis and Engagement Plan

The project team would benefit from engaging different stakeholders for different purposes. Different stakeholders could be engaged in a variety of capacities and at different times throughout the project.

The working group identified the following categories of stakeholders that may be involved:

- project team: stakeholders who are required at the table to reach consensus agreement
- corresponding members: stakeholders who receive all correspondence but are not required at the table to reach consensus agreement
- task groups or technical experts: stakeholders who have a specific interest or expertise and can be engaged in a more focused way
- other:
    - stakeholders from whom feedback on management actions is sought, which may include potential implementers or those potentially impacted
    - members of the public who may be engaged

Appendix II: Project Membership List

CASA would like to thank all the project team and task group members who generously contributed their time and expertise to this project.

2018 EFR PROJECT TEAM

Name	Organization Name	Title
Afrooz Farjoo	Alberta Energy	Alternate
Ahmed Idriss	Capital Power	Member
Ana Maria Radu	TC Energy	Member
Cameron Stonestreet	TransAlta	Member
Colin Robb	Capital Power	Member (Phase 1 only)
Dan Moore	Alberta Newsprint Company	Member
Darion Byerly	TC Energy	Alternate
David Spink	Prairie Acid Rain Coalition	Member (Phase 1 only)
Gabriel John	Alberta Energy	Member
Garth Gettle	TransAlta	Alternate
Greg Moffatt	CIAC	Corresponding Member
James Brown	Dow Chemicals (CIAC)	Corresponding Member
Jennifer Perron	TC Energy	Alternate
Jim Hackett	Heartland Generation	Member/Co-Chair
Laurie Cheperdak	Alberta Health	Member
Matthew Davies	TC Energy	Member
Mark McGillivray	ENMAX Corporation	Member
Martin Van Olst	Environment and Climate Change Canada	Corresponding Member
Mike Mellross	City of Edmonton	Corresponding Member
Natasha Rowden	MEG Energy (CAPP)	Member (Phase 1 only)
Randy Dobko	Alberta Environment and Parks	Member/Co-Chair
Rekha Nambiar	Suncor (CAPP)	Member
Riley Georgsen	TransAlta	Alternate
Ruth Yanor	Mewassin Community Council	Member
Saeed Kaddoura	Pembina	Member (Phase 1 only)
Salima Loh	Inter Pipeline (CIAC)	Member
Sean Mercer	Imperial Oil Ltd. (CAPP)	Member (Phase 2 only)
Shane Lamden	NOVA Chemicals (CIAC)	Corresponding Member
Shaun McNamara	Maxim	Member
Siobain Quinton	TransAlta	Member (Phase 1 only)
Sushmitha Gollapudi	Alberta Environment and Parks	Member
Wayne Ungstad	Notinto Sipiy Conservation Authority	Member/Co-Chair

HEAT Group

Name	Organization Name	Title
Afrooz Farjoo	Alberta Energy	Member
Anne Vigneau	Heartland Generation	Member
Laurie Cheperdak	Alberta Health	Member
Ruth Yanor	Mewassin Community Council	Member
Sushmitha Gollapudi	Alberta Environment and Parks	Member

CASA Project Managers

Katie Duffett, Alec Carrigy, Lauren Hall, Matt Dance, Candice Sawchuk

Appendix III: Recommendation Implementation Status

TABLE 5: IMPLEMENTATION STATUS OF 2003 FRAMEWORK RECOMMENDATIONS

No.	Recommendation	Implementation Status
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).	**2008**: Alberta Environment has implemented this through its approvals process. **2013:** No update. **2018:** Implementation continues to this time.
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 the 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 Environmental 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 Environmental approval for coal-fired units, or within five years of receiving its Alberta Environmental approval for gas-fired units.	**2008:** Alberta Environment has implemented this through its approvals process. **2013:** No update. **2018:** Implementation continues to this time.
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.	**2008:** Alberta Environment has implemented this through its approvals process. **2013:** No update. **2018:** Implementation continues to this time.

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.	**2008:** Alberta Environment has implemented this through its approvals process. **2013:** No update. **2018:** There are no operating units that are still considered transitional.
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 power purchase agreement (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 50 years from the date of commissioning, whichever is greater.	**2008:** Alberta Environment has implemented this through its approvals process. **2013:** No update. **2018:** Implementation continues to this time. The Wabamun facility has been permanently closed, decommissioned, and removed from site. Coal-fired generation in Alberta will be phased out by 2023.
6	**NO_x and SO_2 Standards for New Thermal Generation Units** Effective January 1, 2006, the SO_2 and NO_x BATEA standards for new coal-fired units be 0.80 kg/MWh for SO_2; and 0.69 kg/MWh for NO_x. Effective January 1, 2006, the NO_x 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.	**2008:** The Alberta Air Emissions Standards for Electricity Generation (AAESEG) became effective January 1, 2006 and sets out the minimum emission requirements that thermal electric power plants are required to achieve, in addition to any other limits specified in the plant's EPEA approval. AAESEG covers nitrogen oxides, sulphur dioxide, and primary particulate matter. For further information, see Alberta Air Emissions Standards for Electricity Generation. **2013:** No update. **2018:** This standards document has not been updated since it

		was first released. Coal-fired generation in Alberta will be phased out by 2023.
7	**NO_x and SO_2 Standards for Transitional Coal-Fired Units** Transitional units be **expected**[7] 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 NO_x by December 31, 2015. Before December 31 ,2015, the deemed threshold for NO_x credit generation will be the 2001 Alberta standard. After this date, the deemed credit threshold for NO_x will be 90% of the 2006 BATEA level.	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** There are no operating units that are still considered transitional.
8	**NO_x and SO_2 Emissions Management Approach** The Electricity Project Team (EPT) recommends adoption of a baseline and credit Emissions Trading System at this time for SO_2 and NO_x. To manage SO_2 and NO_x 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 12 months of being certified.	**2008:** The Emissions Trading System Recommendations (Nos. 8 and 9) are intended to provide incentives and rewards for better than required or expected performance, encourage early shutdown of older units, and encourage implementation of new emissions controls at existing units. Alberta Environment (AENV) has implemented these recommendations through the Emissions Trading Regulation and electronic data submission of monitoring systems. **2013:** No update. **2018:** The Emissions Trading System continues to be in place through a regulation. A limited number of trades have occurred, several electricity generation facilities continue to generate credits, and credits are used to meet more stringent SO_2

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

	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 NO_x 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, no. 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 year's 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 the 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.	and NO_x limits after a unit reaches EoDL.

	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 No. 10.	
9	**Implementation of the Management Approach for NO_x 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 NO_x/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/NO_x trading system should also be examined at that time. Future consideration be given to converting the NO_x/SO_2 emissions management system for the electricity sector to a cap and trade system.	**2008:** This recommendation included the possibility of expanding the Emissions Trading System for other industries and also to consider a cap-and-trade system for the electricity sector. Therefore, this recommendation should not be considered implemented because the multi-stakeholder committee should continue to advise on any adjustments that may be needed to achieve the original intent of the recommendation. **2013:** No update. **2018:** No further work has been done on expanding the ETR to other industrial sectors.
10	**Existing Gas-Fired Units** At the end of the 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 update 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 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 No. 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.	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** All identified gas-fired units whose design life was reached before 2010 submitted implementation plans as required. These units have all met the new criteria or have shut down.

	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 environmental approval where the co-generation facility does not operate under its own Alberta Environment approval, it is recommended that the NO_x limits for these co-generation units continue to be incorporated into the allowable NO_x 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.	
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 and 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 Alberta Environment approval, it is recommended that the NO_x emissions limits for these co-generation units continue to be incorporated into the allowable NO_x 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.	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** There are a limited number of identified co-generation units in Alberta being fired by other fuels (only biogas), and these are being regulated through the EPEA approval process.
11	**Peaking Units** The emissions cap for NO_x 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).	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** Specific requirements for peaking units have been discussed in the various five-year reviews but are considered part of the non-consensus recommendations associated

	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.	with NO_x emission standards for gas-fired electricity generation.
12	**Reciprocating Engines** Emissions from reciprocating engines, excluding standby 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.	**2008:** The overall installed capacity of reciprocating engines for power generation is decreasing. Therefore, it was felt that reciprocating engines could continue to be addressed on an approval basis and compared to the BATEA level of the day. **2013:** No update. **2018:** The issue of installed capacity of reciprocating engines for electricity generation is increasing and has been a topic of discussion during the second and third five-year reviews. Additionally, more stringent emission standards for reciprocating engines have been set in the federal Multi-Sector Air Pollutants Regulations. The banking of several reciprocating engines for electivity generation purposes is an emerging issue and is being dealt with during the EPEA approval process.
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.	**2008:** The purpose of these recommendations (13 to 18, 43, and 44) was to reduce mercury emissions from coal-fired power plants. These recommendations were also used to inform the CCME process for standards and monitoring protocol for mercury. The mercury control and

		technology in the 2003 EPT report was based on carbon injection and fabric filters. To achieve these, AENV introduced the following: • Mercury Regulation, which was developed through consultation and input from a multi-stakeholder advisory group. • The mercury control program, which is being implemented through Regulation 34/2006, found in the Alberta Gazette of March 15, 2006. It requires the operators of coal-fired power plants to submit plans for mercury reduction to Alberta Environment by March 31, 2007. All operators have submitted their plans. These plans must capture at least 70% of the mercury in the coal and will be subject to ongoing review and refinement, with the goal of capturing at least 80% by 2013. • The mercury monitoring protocol, which was completed in 2007. Alberta will use the CCME monitoring protocol to ensure the CCME requirements will be met. **2013:** No update. **2018:** Mercury emissions in Alberta continue to be reported to the CCME and have substantially decreased. As coal-fired generation in Alberta will be phased out by 2023, mercury

		emissions from this sector will be virtually eliminated.
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 No. 17. b) the BATEA level for mercury be reviewed in 2005 by a multi-stakeholder group consisting of representatives from industry, government, non-governmental organization 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 No. 29 and, to the extent possible, also include the Alberta parties involved in the Canada-wide standards 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 No. 17 for shutdown; and d) PPA buyers and generators commit to conclude these discussions by December 31, 2006.	**2008:** See Recommendation No. 13. **2013:** No update. **2018:** While there was a limited BATEA review done, there were no recommendations on further reduction requirements being necessary.
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.	**2008:** See Recommendation No. 13. **2013:** No update. **2018:** While there was a limited BATEA review done, there were no recommendations on further reduction requirements being necessary.
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	**2008:** See Recommendation No. 13. **2013:** No update. **2018:** While there was a limited BATEA review done, there were no recommendations on further reduction requirements being

	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, the shutdown dates for units identified in Recommendation No. 17 for shutdown; and e) PPA buyers and generators commit to conclude these discussions by December 31, 2006.	necessary. The issue about improvements to primary particulate control and the co-benefit realized through installation of fabric filter baghouses has been an issue discussed in all subsequent five-year reviews.
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 Lucar'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 No. 16 by December 31, 2005, 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 2009, consistent with Recommendation No. 16. These commitments and deadlines are to be incorporated into the relevant approvals for all units.	**2008:** See Recommendation No.13. **2013:** No update. **2018:** All operating coal-fired units installed mercury controls with the exception of one unit that was considered a low emitter. This unit has now been shutdown.
18	**Alberta's Position on Addressing Mercury from Coal-fired Power Plants**	**2008:** See Recommendation No. 13.

	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.	**2013:** No update. **2018:** Mercury emission controls were implemented on all coal-fired units in Alberta.
19	**Primary PM Standard** Effective January 1, 2006, the primary particulate matter standard for new coal-fired units be 0.095 kg/MWh.	**2008:** The purpose of these recommendations (19 to 22, 42, and 45) was to develop management approaches for PM. The recommendations were addressed by AENV in the following policies that were implemented in the approval process: • Air Emissions Standards for Electricity Generation • Electronic data submission of monitoring information being implemented. In 2003, it was anticipated that the application of mercury control technology would include activated carbon and compact bag houses (COHPAC), which was expected to have the co-benefit of significantly reducing PM emissions. The initial challenges with the development of COHPAC technology were not overcome, and it was found that advanced sorbent technology allows a higher mercury capture rate with existing particulate control technology (electrostatic precipitators). The use of enhanced activated carbon sorbents and electrostatic precipitators, in conjunction with existing electrostatic precipitators, became the preferred technology for

		mercury removal and, therefore, the expected co-benefits of mercury control for PM will not be realized. The Framework anticipated potential issues with achieving the co-benefits of mercury control, and Recommendation No. 22 indicates that if mercury control does not provide the co-reduction of PM, then the 2008 EFR should develop a primary PM management system for existing units. The team has developed terms of reference to guide the work of the task group that will develop a PM management system. **2013:** No update. **2018:** The issue about improvements to primary particulate control and the co-benefit realized through installation of fabric filter baghouses has been an issue discussed in all subsequent five-year reviews. Coal-fired generation in Alberta will be phased out by 2023.
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.	**2008:** See Recommendation No. 19. **2013:** No update. **2018:** The issue about improvements to primary particulate control and the co-benefit realized through installation of fabric filter baghouses has been an issue discussed in all subsequent five-year reviews.

		Coal-fired generation in Alberta will be phased out by 2023.
21	**Five-Year Review** Every five years, commencing in 2008, the technology be reviewed to determine BATEA levels of the day for primary particulate matter, as part of the process described in Recommendation No. 29.	**2008:** See Recommendation No. 19. **2013:** No update. **2018:** A BATEA review has been done at all subsequent five-year reviews. While updated emission standards for coal-fired units have been agreed upon, there have been non-consensus recommendations about updated emission standards for gas-fired generation. Improvements to primary particulate control and the co-benefit realized through installation of fabric filter baghouses has been an issue discussed in all subsequent five-year reviews.
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.	**2008:** See Recommendation No. 19. **2013:** There may be an outstanding issue related to how existing coal units at the end of design life are treated in terms of PM limits. The PM Task Group is working on this issue, which will remain outstanding if consensus cannot be reached on a PM Management Plan. **2018:** Improvements to primary particulate control and the co-benefit realized through installation of fabric filter baghouses has been an issue discussed in all subsequent five-year reviews. Coal-fired generation in Alberta will be phased out by 2023.

23	**Thermal Generation Greenhouse Gas Intensity Target –** Under discussion	**2008:** In July 2007, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year were required to reduce their emission intensity by 12% under the *Climate Change and Emissions Management Act*. Facilities are able to make their reductions through improvements to their operations, by purchasing Alberta-based credits, or by contributing to the Climate Change and Emissions Management Fund. Moreover, clean fuel technologies, energy efficiency and conservation, and renewable sources of energy have been emphasized. Alberta is committed to alignment with evolving federal policy and with the rest of North America as an integrated carbon market advances. The federal government is continuing to develop the domestic framework for industrial greenhouse gas emissions and intends to put the regulatory framework into law in the near future. The government remains committed to reducing Canada's total greenhouse gas emissions by 20% from 2006 levels by 2020 and has already made significant progress in introducing measures to reduce greenhouse gas emissions. In addition, the federal government has set the objective that 90% of Canada's electricity needs to be provided by non-emitted sources, such as hydro, nuclear, clean coal, or

		wind power by 2020. To further this goal, the government will continue to provide support for biofuels, wind, and other energy alternatives. **2013:** GHG emissions-related recommendations under CASA (23 to 28 and 47) have been superseded by both the Specified Gas Emitters Regulation and the federal GHG regulations for coal-fired power plants. **2018:** Climate change policy in Alberta has changed multiple times subsequent to the initial implementation of the Framework and is no longer being implemented as part of this Framework.
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.[8]	**2008:** See Recommendation No. 23. **2013:** See Recommendation No. 23. **2018:** See Recommendation No. 23.
25	**New Coal Unit Natural Gas Combined Cycle Offset Requirement** The Alberta government continue to apply its Natural Gas Combined Cycle (NGCC) offset policy[9] 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	**2008:** See Recommendation No. 23. **2013:** See Recommendation No. 23. **2018:** See Recommendation No. 23.

[8] It is further recognized that the issue of financial additionality is to be resolved in another forum.
[9] *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.

	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.	
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.	**2008:** See Recommendation No. 23. **2013:** See Recommendation No. 23. **2018:** See Recommendation No. 23.
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.	**2008:** See Recommendation No. 23. **2013:** See Recommendation No. 23. **2018:** See Recommendation No. 23.
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).	**2008:** See Recommendation No. 23. **2013:** See Recommendation No. 23. **2018:** See Recommendation No. 23.

	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.	
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;[10] 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 Nos. 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-governmental 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	**2008:** At the request of Alberta Environment, CASA established a project team in 2007 to lead the first five-year multi-stakeholder review of the Framework. The purpose of the review is to keep the Framework current and foster continuous improvement of environmental performance in the electricity sector. Tasks completed during the review included the following: • development of emissions standards for facilities approved after January 1, 2001 • a review of BATEA • completion of an emission forecast for projected generation to 2030 • a review of recent literature related to the health and environmental effects of emissions from electricity generation • public consultations, including community meetings and opportunities to provide written feedback **2013:** No update. **2018:** Five-year reviews have been done during the period subsequent to the original framework being adopted. The

[10] See section 6.1 of the original framework document for a fuller discussion.

	recommends that no further work is necessary or undertakes a detailed review of either element 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.	reviews have all taken considerably longer than the one-year timeframe originally agreed upon.
30	**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.	**2008:** See Recommendation No. 29. **2013:** No update. **2018:** See Recommendation No. 29.
31	**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.	**2008:** See Recommendation No. 29. **2013:** Even though Recommendations Nos. 6, 7, and 9 from the 2010 report were agreed to by consensus, they are only being used informally by ESRD and have not been formally incorporated into standards. No new coal plants have been approved. This situation could potentially create problems for new plants and for credit generation because it is uncertain which standards apply (see the team's new Recommendation No. 1). **2018:** AEP has implemented consensus-based recommendations from the five-year reviews as appropriate.
32	**Identifying Hotspots** For the purposes of this management framework, that an area will be defined as a hotpot if, due to its location relative to, or its proximity to, one or more electricity generation facilities, one of a, b, or c applies:	**2008:** A group was formed to provide advice on a draft of the Hot Spots Protocol document. Its input proved valuable in keeping the focus of the

	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 emission 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."[11] 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.	document on the important issues that were addressed by the recommendations. In November 2005, Alberta Environment developed the document Guide for Responding to Potential "Hot Spots" Resulting from Air Emissions from the Thermal Electric Power Generation Sector. This guide outlines both the internal and external processes for identifying and managing potential hot spots caused or potentially caused by air emissions from thermal electrical generation facilities. The guide specifies key stakeholders and agencies, including Alberta Health and Wellness, Alberta Sustainable Resource Development, the (Alberta) Energy and Utilities Board (now called the Alberta Utilities Commission), regional health authorities, local airshed zones, local municipalities, environmental non-government organizations, stakeholder groups, and federal departments. The guide is considered thorough and appropriate but has not yet been tested because no "hot spot" has been identified. Therefore, it is difficult to assess the guide's effectiveness at this time.

[11] 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.

		2013: Sectors other than electricity generation are contributing to this issue in the Capital Region, and the hotspots protocol is not solely confined to the Electricity Framework. The protocol is being managed by ESRD. **2018:** To date, no stakeholder has brought forth a "hot spot" issue.
33	**Addressing Hotspots** a) 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. b) Where a framework does not exist for dealing with a specific type of hotspot, that the following steps be taken: o A multi-stakeholder team, consisting of representatives from industry, government, non-governmental 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. o Alberta Environment use the EPT framework, legislation, standards, and approvals as appropriate to implement the plan. o When a hotspot has been identified, an economic, health and environmental analysis will be part of the plan developed to address it.	**2008:** See Recommendation No. 32. **2013:** No update. **2018:** See Recommendation No. 32.
34	**Emissions Growth Review Trigger** During the five-year review, if the updated emissions forecast for any of NO_x, 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 the substance should be reviewed.	**2008:** See Recommendation No. 29. **2013:** Lessons learned regarding the implementation of this recommendation are addressed by the Base Case Working Group. **2018:** To date, this growth trigger has not been exceeded.
35	**Economic Review Trigger**	**2008:** See Recommendation No. 29.

	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.	**2013:** No update. **2018:** To date, this growth trigger has not been exceeded.
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 that they reflect the new emission management mechanisms and the intent to reward performance "beyond compliance" or to deter non-compliance.	**2008:** No update. **2013:** No update. **2018:** Current compliance principles continue to be implemented, and these are discussed on an ongoing basis at the five-year reviews.
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 an SO_2 Emissions Trading System.	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** AEP is updating the Continuous Emissions Monitoring System Code to ensure quality-assured data continue to be submitted and has moved to electronic reporting of emissions trading data.
38	**NO_x 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 NO_x monitoring and tracking system that can support a NO_x Emissions Trading System.	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** See Recommendation No. 37.
39	**Public Availability of SO_2 and NO_x Monitoring Data** Alberta Environment and the electricity sector continue to ensure that SO_2 and NO_x emission monitoring data from electricity generation units remains available to the public.	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** AEP has moved to electronic reporting of emissions trading data.
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.	**2008:** See Recommendation No. 6. **2013:** No update.

	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.	**2018:** AEP has moved to electronic reporting of emissions trading data and has a public facing website with all available data.
41	**Public Availability of NO_x Emission Trading Information** a) Alberta Environment and the electricity sector ensure that information on NO_x emission trading associated with achieving the NO_x emission management targets in the 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 NO_x credits and that this information be public.	**2008:** See Recommendation No. 6. **2013:** No update. **2018:** See Recommendation No. 40.
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.	**2008:** See Recommendation No. 19. **2013:** No update. **2018:** AEP has moved to electronic reporting of emissions trading data.
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*.	**2008:** See Recommendation No. 13. **2013:** It is assumed that mercury emission data from coal-fired power plants will continue to be available through AESRD and possibly the Alberta Environmental Monitoring, Evaluation and Reporting Agency in the future. **2018:** Mercury emissions data are publicly available from the CCME.
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.	**2008:** See Recommendation No. 13. **2013:** No update. **2018:** Mercury emission data continues to be monitored through CCME protocols and continuous emission monitoring

		as developed by a mercury monitoring task team.
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.	**2008:** S See Recommendation No. 10. **2013:** No update. **2018:** AEP has moved to electronic reporting of emissions trading data.
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.	**2008:** See Recommendation No. 23. **2013:** No update. **2018:** See Recommendation No. 23.
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.	**2008:** See Recommendation No. 23. **2013:** See Recommendation No. 23. **2018:** See Recommendation No. 23.
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.	**2008:** In implementing the recommendations in the 2003 Emissions Management Framework for the Alberta Energy Sector, the Alberta government worked closely with stakeholders and provided several opportunities for the public to learn about the framework and provide comment on the implementation of the recommendations. In addition to meetings with implementation and/or advisory groups, the following opportunities for public information and input were provided:

		• meeting with Wabamun community members (Dec. 14, 2004) • overall implementation meetings held in Stony Plan (March 19, 2005) and Calgary (April 16, 2005) • meeting on emissions trading in Calgary (June 20, 2005) • mercury meeting held in Edmonton (June 22, 2005) • baseline workshops for industry held in Edmonton (March 13, 2006) and Calgary (March 14, 2006). ***Public Involvement in Developing any Emissions Trading System*** The Emissions Trading Regulation is managed under the EPEA. Alberta Environment has established a public registry to track the creation, transfer, and retirement of credits. Companies and individuals can buy and sell credits privately, and the registry records the transfer of credits between companies and individuals. Clauses are inserted into approvals, authorizing the use of credits to meet the new emissions limits in Alberta. The framework provides industry with the flexibility to meet new standards for nitrogen oxides and sulphur dioxide emissions and encourages early emissions reductions and early shutdown of older units. ***Emissions Trading Technical Advisory Group***

		This group consisted of a small group of stakeholders and government staff, as well as people with expertise in market design and emissions trading systems. The group worked diligently over a number of months to complete their task, which was to examine the possible expansion of the Emissions Trading System and its conversion to a cap-and-trade system. The overall system was designed in conjunction with this stakeholder advisory group. **2013:** No update. **2018:** Stakeholder input has been received through ongoing five-year reviews. Public input into the framework has mostly been through stakeholder groups involved in the review process.
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 construction public participation.	**2008:** See Recommendation No. 48. **2013:** The team agreed this recommendation is no longer its responsibility because it has no control over implementation. **2018:** See Recommendation No. 48.
50	**Public Involvement in Developing any Emissions Trading System** Public input and involvement be part of Alberta Environment's development of any emissions 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	**2008:** See Recommendation No. 48. **2013:** No update. **2018:** See Recommendation No. 48.

	c) Incorporating minimum provisions to ensure transparency in the operation and evaluation of the regime.	
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.	**2008:** See Recommendation No. 48. **2013:** No update. **2018:** Stakeholder input has been received through ongoing five-year reviews. Public input into the framework has mostly been through stakeholder groups involved in the review process. Further public and stakeholder input to intergovernmental processes, such as the BLIERs process, was through those forums.
52	**Public Access to Intergovernmental Agreements** 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.	**2008:** See Recommendation No. 48. **2013:** No update. **2018:** Public access to any intergovernmental agreements (existing or being developed) has mostly been through stakeholder groups involved in the five-year review process. Further public and stakeholder access to intergovernmental processes, such as the BLIERs process, was through those forums.
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.	**2008:** See Recommendation No. 48. **2013:** No update. **2018:** See Recommendation No. 48.
54	**Transparency** Alberta Environment give to the public ready and timely access to information relating to air emissions from the electricity sectors, subject	**2008:** See Recommendation No. 48. **2013:** No update.

	to necessary access restrictions to ensure protection of proprietary and confidential information relating to legitimate business interests.	**2018:** See Recommendation No. 48.
55	**The Provincial Target for Renewable and Alberta 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.	**2008:** ***Net Metering and Net Billing*** On February 1, 2008, the GoA enacted the Micro-Generation Regulation allowing Albertans to connect to the grid and operate their own micro-generation facilities. This innovative policy will allow Albertans to generate their own environmentally friendly electricity and receive credit for any power they do not use and send into the electricity generation grid. The Alberta Utilities Commission is overseeing the implementation of the regulation and has developed processes to simplify approvals and interconnection between customers and service providers. ***Renewable and Alternative Energy Project Team*** Following the recommendations made in the EPT's 2003 report, CASA's Renewable and Alternative Energy Project Team worked to identify mechanisms to increase Alberta's supply of renewable and alternative electrical energy. Ultimately, members decided it would be more appropriate for the GoA to develop such a framework, and the team agreed to forward the results of its thinking and discussions to the GoA for consideration. The team released their report, *Recommendations for a* Renewable and Alternative

		Electrical Energy Framework for Alberta in March 2007. Alberta Energy led the development of a Provincial Energy Strategy that was announced on December 11, 2008. Recommendations from the Renewable and Alternative Energy Project Team were considered in the development of the strategy. The successful implementation of these recommendations relies on the successful implementation of the Renewable and Alternative Energy Project Team's recommendations. **2013:** No update. **2018:** See Recommendation No. 23.
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.	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.
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 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	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.

	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.	
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)	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.
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 renewables 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.	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.
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; • 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.	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.
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	**2008:** See Recommendation No. 55.

	renewable and alternative electricity, as defined in recommendation 57, as a means of reducing their greenhouse gas emissions.	**2013:** See Recommendation No. 23. **2018:** See Recommendation No. 23.
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.	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.
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.	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.
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 are 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 describe din this report, might be augmented and integrated in Alberta's renewable and alternative energy sector. f) Seeking means by which consumer engagement mechanisms as describe din this report could be funded and implemented.	**2008:** See Recommendation No. 55. **2013:** No update. **2018:** See Recommendation No. 23.

	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, NGOs, 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.	
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 is 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 development 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 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 currently available. 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 exposing the 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.	**2008:** ***Electrical Efficiency and Conservation (EEC) Project Team*** The EEC Project Team was formed in January 2004 t with the goal of implementing the efficiency and conservation recommendations found in the EPT's report, with the aim of increasing electrical efficiency and expanding conservation efforts within Alberta. A significant item within these recommendations was to develop an energy efficiency target for the province. The team was also asked to identify the resources required to implement the various programs recommended to meet the provincial target. The members of the team agreed that an overarching energy efficiency framework was needed in order to make progress on the team's tasks. Five recommendations were developed to establish an effective and much needed energy conservation and efficiency framework in Alberta. Alberta Energy led the development of a Provincial Energy Strategy that was announced on December 11,

	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 usable 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.	2008. Recommendations from the EEC Project Team were considered in the development of the strategy. The non-governmental organizations feel that Recommendations Nos. 67 and 68 need further work and should be referred to the appropriate implementation agency. The implementation of the remainder of the recommendations relies on the successful implementation of the EEC team's recommendations. **2013:** No update. **2018:** See Recommendation No. 23.
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.	**2008:** See Recommendation No. 65. **2013:** No update. **2018:** See Recommendation No. 23.

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.
		2008: See Recommendation No. 65.
		
		2013: Climate Change Central previously had responsibility for these functions. Climate Change Central no longer exists, and the GoA has not yet made a decision as to which agency will assume these activities.
		
		2018: See Recommendation No. 23.

	provide a resource in which information about the various government programs all levels and funding options be made available.	
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.	**2008:** See Recommendation No. 65. **2013:** See Recommendation No. 67. **2018:** See Recommendation No. 23.
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.	**2008:** The materials developed throughout the course of the CASA EPT are on file with Alberta Environment, in both electronic and hard copy versions. **2013:** No update. **2018:** The CASA Secretariat has posted electronic versions of relevant information and reports on its public website.
70	**Water Vapour** The water vapour concerns noted in this report be addressed through existing site-specific regulator 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.	**2008:** See Recommendation No. 29. **2013:** No update. **2018:** No further assessment of issues arising from water vapour emissions from electricity generation facilities has been done.
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 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 consider both new and existing scientific information, with reference to the following diagram.	**2008:** See Recommendation No. 29. **2013:** No update. **2018:** Future substance reviews have been conducted at each subsequent five-year review.

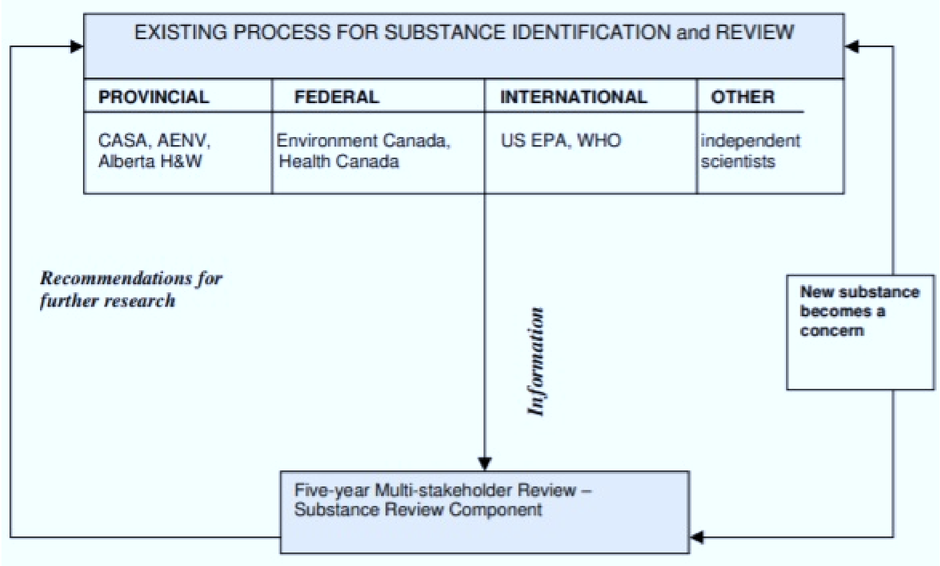


TABLE 6: IMPLEMENTATION STATUS OF THE FIRST (2008) FIVE-YEAR REVIEW RECOMMENDATIONS

No.	Recommendation	Implementation Status
1	**Implementation Status of Emissions Trading Recommendations** In 2013, the next five-year review team should complete a detailed evaluation of the implementation of Recommendations Nos. 8 and 9 of the 2003 Framework, regarding the Emissions Trading System.	**2013:** Implemented as envisioned, but unclear whether the regulation is as effective as intended. **2018:** Implemented. No update needed.
2	**Public Availability of Monitoring, Reporting and Compliance Data** Alberta Environment ensure that monitoring, reporting, and compliance data is made available to the public in an easily accessible manner, and that this be considered a high priority in Alberta Environment's Integrated Monitoring and Reporting Framework expected to be completed by March 31, 2010.	**2013:** Information is available and accessible and should continue to be so, with further improvements as opportunities arise. The new Alberta Environmental Monitoring and Reporting Agency may also have a role. **2018:** Implemented. No update needed.
3	**Recommendations from CASA Renewable and Alternative Energy Project Team and Electrical Efficiency and Conservation Project Team** The CASA Board review the status of implementation of the recommendations made by the Renewable and Alternative Energy Project Team and the Electrical Efficiency and Conservation Project Project Team by the end of 2009.	**2013:** This remains an outstanding item for the CASA Board. The team notes, however, that the GoA is undertaking policy development and renewal in two areas related to this recommendation, and a net

		billing policy has been implemented. **2018:** Climate change policy in Alberta has changed multiple times subsequent to the initial implementation of the framework and is no longer being implemented as part of this framework.
4	**Health and Environmental Effects Information** No additional work or revisions to the Framework are required at this time based on new or additional health and environmental effects information.	**2013:** The current Health and Ecological Assessment Task Group completed a review to determine if further work is needed. **2018:** Implemented. No update needed.
5	**Analysis of Health and Environmental Effects Research** For future five-year reviews, a multi-stakeholder group with appropriate representation be struck to oversee a study to identify any new and relevant studies or research findings regarding potential environmental or health effects from air emissions from electricity generation, and that an independent peer review be completed on the results.	**2013:** The current Health and Ecological Assessment Task Group completed its literature review. A peer review was deemed unnecessary because the group had sufficient expertise to draw conclusions from the reviews and communicate conclusions to non-expert readers. **2018:** Implemented. No update needed.
6	**Source Standards for New Coal-Fired Thermal Generation Units** The following standards apply to coal-fired boiler generating units without carbon capture technology that are approved on January 1, 2011 or later: <u>Nitrogen Oxides (NO_x)</u> Emission standard: 0.47 kg/MWh net Design specification: 0.40 kg/MWh net (Note: In addition to requiring compliance with the NO_x emission standards, the environmental approval will include a condition that requires the proponent to design the NO_x control equipment with the capability to reduce emissions to 0.40 kg/MWh net, or less.) <u>Sulphur Dioxide (SO_2)</u> Emission standard: 0.65 kg/MWh net or 90% removal, whichever is less stringent.	**2013:** The consensus recommendations are being used informally by ESRD but have not been formally incorporated into standards, in part because no new plants have been approved since January 1, 2011. **2018:** As the original standards document has not been revised, these requirements have been implemented through EPEA approval processes as necessary.

	Particulate Matter (filterable) 6.4 ng/J of heat input (~0.066 kg/MWh) Mercury 75% capture design target Optimization plans to meet 80% capture by 2013 The standards are conditional on emissions during start-ups and shutdowns (using best practices) excluded from compliance measurement and reasonable flexibility by Alberta Environment during new technology commissioning period.	Coal-fired generation in Alberta will be phased out by 2023.
7	**NOx and SO_2 Credit Generation Thresholds** The following deemed credit thresholds for the 2011 BATEA standards be applied to new coal-fired and gas-fired units: A. NO_x (coal-fired) – 0.38 kg/MWh net B. SO_2 – 0.55 kg/MWh net C. NO_x (gas-fired) – "A" factor = 0.07 kg/MWh net and "B" factor = 0.008 kg/GJ Non-Peaking Standard Formula: NO_x (kg/h) = [Net Power Output (MW net) x A] + [Heat Output (GJ/h) x B]	**2013:** GoA has not formally adopted recommendations related to coal-fired generation, and no new coal plants have been approved since January 1, 2011. No consensus was reached on gas-fired NO_x standards. **2018:** Coal-fired generation in Alberta will be phased out by 2023.
8	**Credit for Early Action on Mercury Capture** The initiative on Credit for Early Action on Mercury Capture be implemented as follows: • The Credit for Early Action on Mercury initiative will enable operators to gain recognition for past and upcoming Mercury capture before the regulation deadline. • Operators will earn credits for kilograms of Mercury captured (as a result of mercury control activity demonstration, early installation of mercury control equipment and other combustion process modifications). • Credits can only be used on a site-basis (no trading) and only when plants experience upset conditions impacting their ability to achieve target removal requirements. • The credits for early action recognition cannot be used to delay installation of mercury control equipment. • January 1, 2011 is the compliance date. Companies will earn credits for mercury capture rates greater than 75% before January 1, 2011. • Between January 1, 2011 and January 1, 2013, companies will earn credits for mercury capture rates greater than 80%. • All credits will be earned at a discount value of 50%. • All credits will expire on December 31, 2015.	**2013:** Credit for early action was available and some companies did initiate their mercury control systems early, but this early action was not formally tracked. The use and need for these credit provisions was examined as part of the current five-year review. **2018:** Implemented. No update needed.

9	**Source Standards for New Gas-Fired Non-Peaking Thermal Generation Units** No consensus. Details of non-consensus recommendation are available in section 5.4 of the report.	**2013:** No update. **2018:** No consensus was reached and no further clarification has been made by GoA.
10	**Pre-Consultation Phase for the Next Five-Year Review** The working group formed to develop terms of reference and timelines for the next five-year review build in a pre-consultation phase that would involve focused public outreach about CASA as well as the Electricity Framework and progress in its implementation.	**2013:** See Recommendation No. 2.
11	**Higher Profile for the Electricity Management Framework** CASA maintain a website that is updated twice a year with information about the framework and its implementation.	**2013:** The website has been updated regularly with relevant information. Links should be checked periodically. **2018:** Implemented. No update needed.

Appendix IV: Presentations on SCR Received by the Project Team

Alberta Newsprint Company SCRs

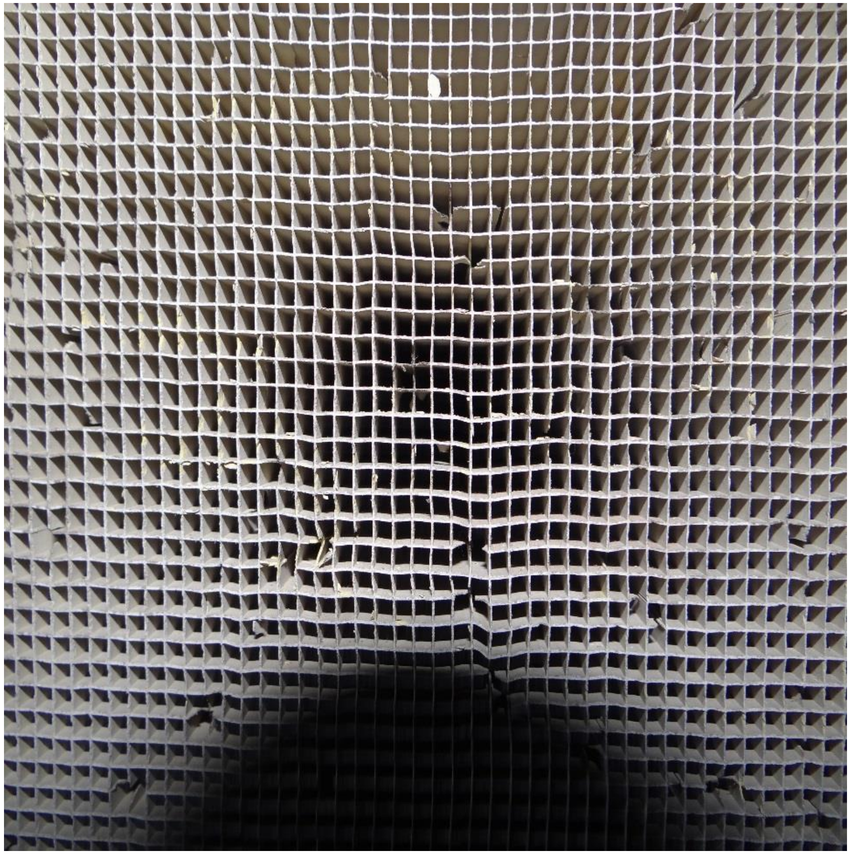
- 10 – 6.3 MW CAT power Generation units
- Reciprocating Engines
- Peaking Plant
- Each unit has an SCR
- Dual layer of bricks
- Urea – 42%
- Total Plant uptime in 2015, 2016 & 2017 - ~14%
- 0.21 g/s limit per unit

Operational Issues

- Urea Nozzle plugging
- Catalyst bricks degrade over time
- Blown seals in SCR – results in brick plugging
- Housing warping
- Inconsistent fuel quality being supplied – impacts engine performance
- Poor control system – not user friendly

Operational Considerations

- SCRs are static in design, surface area specific to expected raw influent exhaust to unit
- Narrow operating range if engines not running to spec due to engine issues or fuel quality
- Take time to warm up – only operate at >300C
- Have to replace bricks at 25000 hours operation – high cost



CASA EFR Team

Info Session :

Emissions Control Technology

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CASA Workgroup Information Only

August 9, 2018

SCR Plants

- Shepard Energy Centre (SEC)
  - 860 MW
  - NGCC
  - East Calgary
  - Aqueous Ammonia SCR

- Calgary Energy Centre (CEC)
  - 320 MW
  - NGCC
  - North East Calgary
  - Aqueous Ammonia SCR

Operations

- Shepard Energy Centre (SEC)
  - JV with Capital Power
  - JV results in running more like a baseload but no operational requirement to remain online
  - Duct fire in high prices
  - Capacity Market (??)

- Calgary Energy Centre (CEC)
  - Operates as needed
  - Daily decision – on/off
  - Duct fire in high prices
  - Capacity Market (??)

SCR Experience

- Shepard Energy Centre (SEC)
  - No issues
  - Truck in Ammonia
  - NH_3 slip minimal
  - SCR worse performance with ducts

- Calgary Energy Centre (CEC)
  - No issues
  - Truck in Ammonia
  - NH_3 slip minimal
  - SCR worse performance with ducts and ramping

Selective Catalytic Reduction

Presentation to the Clean Air Strategic Alliance

August 9, 2018

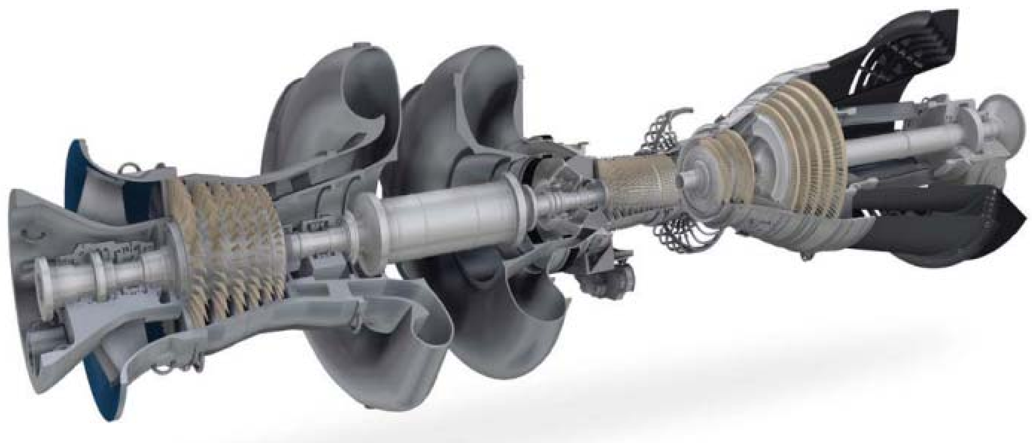
Clover Bar Energy Centre

- Clover Bar Energy Centre is a natural-gas-fired simple-cycle power generation facility located on the eastern edge of the City of Edmonton
- The facility consists of one 48-megawatt (MW) General Electric (GE) LM6000 turbine commissioned in 2008 and two 101 MW GE LMS100 turbines commissioned in September and December 2009
- The cost of all three units was about $263 million
- Three highly-efficient natural-gas turbines power up from standstill to full load in 10 minutes to give Capital Power flexibility to respond to sudden changes in supply and demand.

Source: Capital Power Clover Bar Energy Centre Backgrounder (Updated January 2018)

CBEC Unit 2/3

- GE LMS100 (two units)
- 101 MW
- Installed 2009
- Both units run SCRs
- Reach full load in <10min
- Min stable generation ~35MW due to SCR operational requirements
- Used for peaking operations (CF ~15-30%)



Source: GE LMS100 Brochure

SCR Operations

- Ammonia
  - Aqueous (~19%); not a "*dangerous good*" under the *Dangerous Goods Transportation and Handling Regulation*
  - Storage onsite
  - Standard monitoring and operating procedures for safe handling
- Slippage & Operations
  - Minimal ammonia slippage
  - Slippage is an indicator that the catalyst requires maintenance
- Cost
  - CAPEX ~ $5 million per turbine
  - Ammonia costs $0.30-0.60 /MWh
  - Ongoing maintenance and replacement of catalyst (5-10 years)
- Operations
  - Temperature and minimum load impacts

Appendix V: Communications Plan

CASA EFR Team Communications Plan

Scope:

The EFR Project Team has received direction from the CASA Board based on both budget limitations and AEP's perspective on the extent of consultation required.

The EFR Project Team's communications plan will be focused on informing and increasing stakeholder awareness and understanding of this work.

Target Audience:

EFR team members, including government, industry, and NGO partners. These messages are for the stakeholders and their constituents who may not understand what CASA is and what CASA does.

Communication Strategy:

Objective 1: Develop and implement a strategy and action plan for communicating the work of the project team and information about the electricity generation sector and its impact on air quality.

Potential Deliverables:

- CASA EFR Fact Sheet
    - The fact sheet will include the following:
        - information about CASA
        - information about the consensus process
        - information about the EFR project scope
        - "Frequently Asked Questions" – our key messages and lessons learned from the project, including information on electricity generation and its impact on air quality
    - fact sheets are ideal because they provide key information on a specific topic in an easy and quick to read format
    - communication best practices include the following:
        - keep messages simple, include only the basics
        - format information clearly—people need facts, which are best communicated at a level that recognizes people's general knowledge and understanding of basic science

        - ensure that the messaging addresses information that is frequently missing or misrepresented and identify questions that need addressing
- Effective use of CASA website and social media
    - posting of EFR Fact Sheet
    - sharing relevant articles and information taken from industry and government on CASA social media platforms
- Effective use of existing partnerships
    - collection of existing fact sheets, policies, programs, and vehicle emissions data from GoA and industry partners
    - use of partners' social media to share EFR Fact Sheets where appropriate
- Presentations and briefing notes
    - will be developed by the CASA Secretariat in accordance with usual project communication process for use in board updates, CASA newsletters, and stakeholder communications

Appendix VI: Continuous Improvement Report

CONTINUOUS IMPROVEMENT REPORT

2018 ELECTRICITY FRAMEWORK REVIEW

CLEAN AIR STRATEGIC ALLIANCE

March 19, 2020

1. EXECUTIVE SUMMARY

The contribution of priority air emissions from Alberta's electricity sector has been decreasing for several years. From 2013 to 2018, the period for this review, the electricity sector mass emissions of nitrogen oxides decreased by 27%, sulphur dioxide decreased 35%, particulate matter decreased 26%, mercury decreased 55% and greenhouse gases are down 14%. These significant reductions have been accomplished while meeting the need for a 10% increase in electricity demand to accommodate Alberta's growing economy. Reduced operation of higher emitting units, retirement of older units, additions of new low-emitting generation, and emissions reduction efforts undertaken by electricity sector participants have contributed to achieving the emissions reductions. The mix of resource types that provide electricity generation has shifted from a majority coal-fired generation mix to one with increased natural gas-fired and renewable generation and an aggressive phase-out of coal-fired generation. The transformation of the electricity sector in Alberta and progression of climate change policy drivers is expected to influence future generation development, load growth and continue to deliver emissions reductions.

2. INTRODUCTION

In 2003, the Alberta electricity generators agreed to prepare a continuous improvement report for the Clean Air Strategic Alliance (CASA) stakeholders during the scheduled five-year review of the air management framework. The direction for the report is set out in Recommendation #29, item 6 of the CASA 2003 Electricity Framework report.

This report, the third Continuous Improvement Report (2013 to 2018), summarizes the electricity sector's air emissions profiles and highlights changes in the generation fuel mix during the past five years, and touches upon anticipated trends and continuous improvement opportunities for the future.

The report compares 2013 and 2018 installed capacity, generation and emissions data from the following publicly available sources:

- Generation and installed capacity data is from the Alberta Utilities Commission (AUC) annual electricity data collection process[iii]. The data includes energy generation and installed capacity for Alberta power plants with a 0.5 Megawatts (MW) and greater installed capacity and includes “behind the fence” (electricity for on-site use) generation. Isolated plants generation and interchange energy is not included;
- Emission data for nitrogen oxides (NO_X), sulphur dioxide (SO_2), particulate matter (PM) and mercury (Hg) was obtained from Environment and Climate Change Canada’s (ECCC) National Pollution Release Inventory online data search[i] of facility reported data; and
- Greenhouse gas (GHG) emission data was obtained from ECCC’s Reported Facility GHG Emissions online data search[ii].

Information from the Alberta Electric System Operator (AESO) published forecast reports have also be referenced in this report to provide insight on future growth and trends for Alberta’s electricity sector.

3. ALBERTA ELECTRICITY SECTOR

The electricity industry in Alberta consists of three components to provide reliable electricity to support everyday activities. Generators supply electricity using various fuels and technologies, the transmission component transports electricity via high voltage transmission lines to local substations, and the distribution component transports electricity over lower voltage lines to homes and businesses. Industrial sites may also generate electricity for their own use and sell surplus energy to the electricity grid.

Alberta’s electricity transmission and distribution systems remain fully regulated; rates for these services are set through regulation. A competitive energy-only electricity market has been used for 20 years for generators to supply electricity into the provincial interconnected electricity grid. As the focus of the CASA Electricity Framework Review is to manage source emissions, this summary report will focus on the generation component of the electricity sector.

"Installed capacity" represents the total amount of electricity that theoretically could be produced if all the facilities in Alberta were generating power at their full output. Table 1[iii] presents the total Alberta electric energy installed capacity in Gigawatts (GW) for each of the CASA electricity review milestone years as well as the contribution by each electricity generation resource type. Information presented is net to electricity grid energy based on the maximum continuous rating (MCR) of each generating unit. The installed capacity has increased from 14.6 to 16.2 GW in the 2013 to 2018 period. Based on a percentage of total installed capacity in Alberta, natural gas-fired generation and renewables generation have increased installed capacity; whereas coal-fired capacity has less installed capacity. Wind generation growth over the past decade has resulted in a significant increase in its share of total installed capacity.

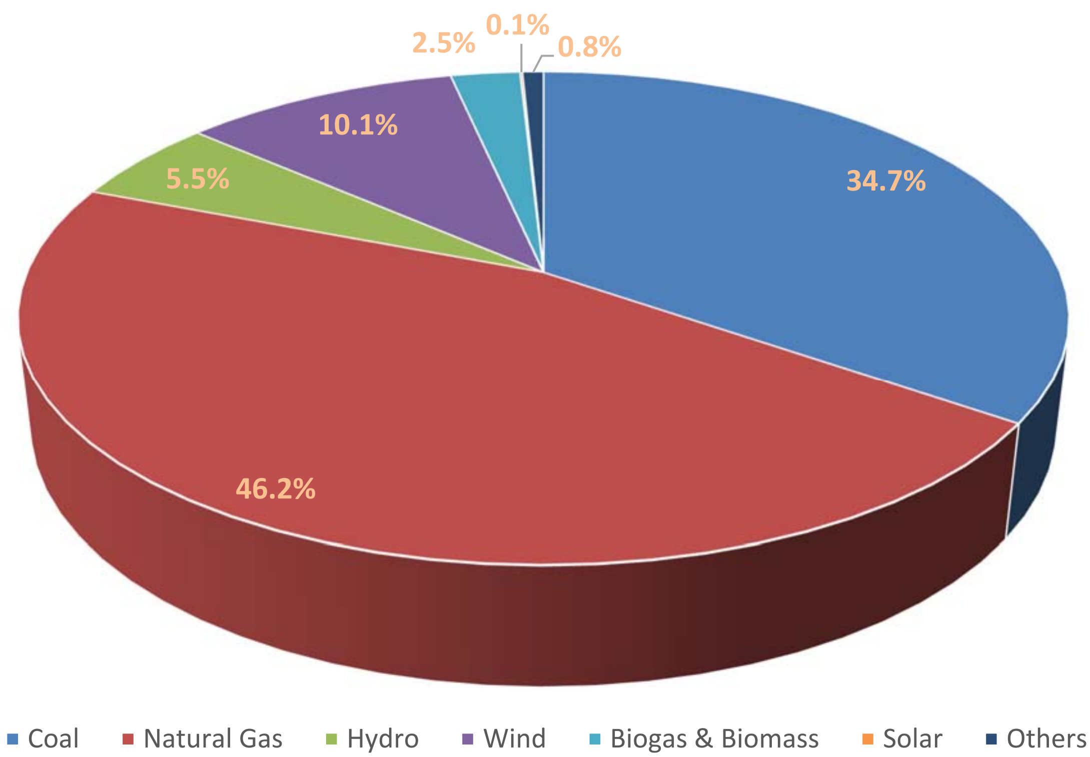
Table 1: Alberta Electric Energy Net Installed Capacity by Resource (% of Total MW)

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	Others (includes oil, diesel & waste heat)	Total Installed Capacity (GW)
2003	47.2%	40.9%	7.6%	1.5%	2.4%	0.0%	0.4%	11.7
2008	47.1%	38.4%	7.2%	4.2%	2.5%	0.0%	0.6%	12.6
2013	42.9%	39.8%	6.2%	7.6%	2.9%	0.0%	0.7%	14.6
2018	35.3%	46.4%	5.7%	9.1%	2.6%	0.1%	0.8%	16.2

*Includes oil, diesel, waste heat

Although not within the review period, Figure 1 is included to illustrate the contribution of the 16.52 GW of installed capacity in 2019 and the continuation of the trend of increasing wind generation and decreasing coal capacity. Note that some coal units have the ability to fire natural gas as a portion of their fuel, but this is still represented as coal capacity in this data.

Figure 1: 2019 Alberta Electric Net Installed Capacity by Resource



The contribution mix of the type of generating unit resources providing actual energy is different than the contribution mix of installed capacity. This is because generating units may not operate at their full capacity or may operate for shorter periods. An example of this would be a wind generator that may not operate all hours of the day depending on whether there is the required wind. Table 2 presents the total Alberta electric generation in Terawatt-hours (TWh) for each of the CASA electricity review milestone years as well as the contribution by each electricity generation resource type. Alberta electricity generation has increased 10% from 76.0 TWh to 83.6 TWh in the 2013 to 2018 period. The type of generating unit resources providing the energy has also changed with an increase in contributions from renewables and natural gas generation. Of note is the significant increase in the contribution of natural gas generation in 2018, which enabled annual natural gas generation to exceed the amount of coal generation for the first time.

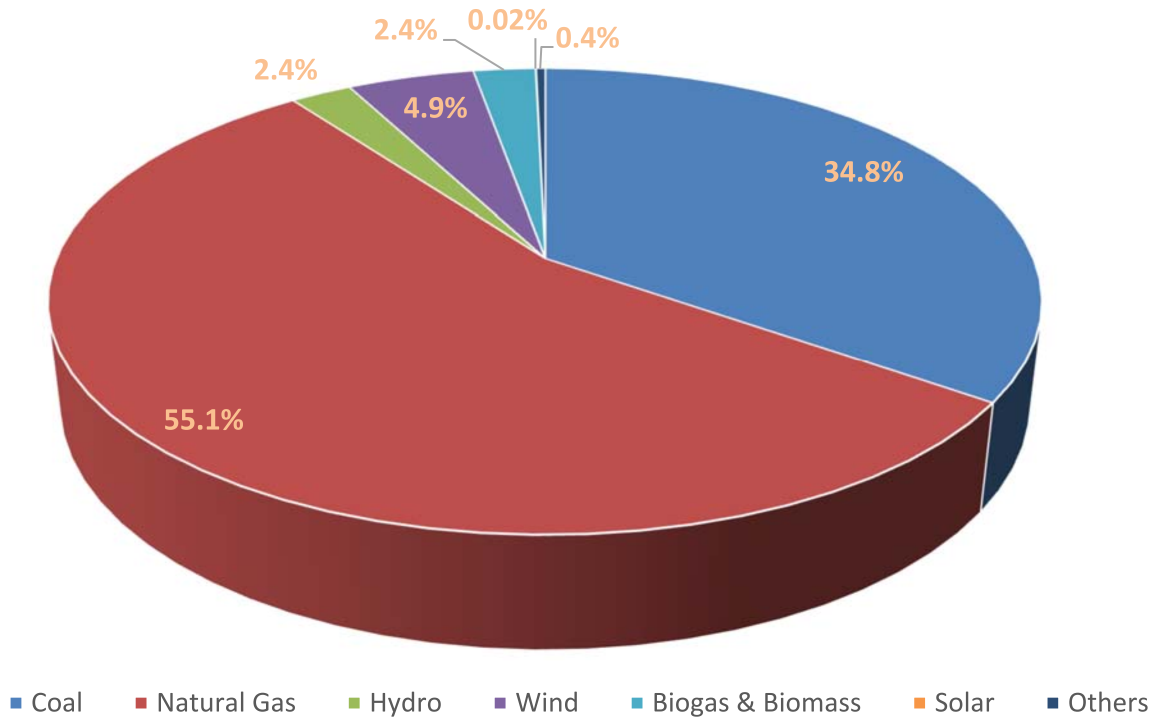
Table 2: Alberta Electric Generation by Resource (% of Total MWh)

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	Others (includes oil, diesel & waste heat)	Total Electric Generation (TWh)
2003	66.5%	27.1%	2.7%	0.6%	2.6%	0.0%	0.4%	63.7
2008	61.4%	30.4%	3.1%	2.1%	2.8%	0.0%	0.2%	69.1
2013	51.6%	38.2%	2.7%	4.1%	3.0%	0.0%	0.5%	76.0
2018	36.7%	53.1%	2.3%	5.0%	2.4%	0.03%	0.5%	83.6

*Includes oil, diesel, waste heat

Although not within the review period, Figure 2 is included to illustrate the generator resource contribution of total electricity generated in 2019 and the continuation of the trend of natural gas generation displacing coal generation. Note that some coal units have the ability to fire natural gas as a portion of their fuel but this is still represented as coal capacity in this data.

Figure 2: 2019 Alberta Electric Generation by Resource



The generation mix in Alberta continues to shift from what was a predominantly coal-based fleet to a natural gas-based fleet. Future generation additions are expected to come from gas-fired combined cycle, cogeneration, wind generation, and small scale renewables. This different mix of generating types providing reliable energy to Albertans and the replacement of retired units with more efficient generating technologies will result in lower electricity sector air emissions, even with expected increases in generation.

4. PRIORITY SUBSTANCE EMISSIONS

The emissions of the five priority substances (NO_X, SO_2, PM, Hg, GHG) from the Alberta electricity sector have reduced significantly over the past five years. The reduction in emissions is due to the change in generation mix, retirements of older units, new low-emitting generation, regulatory initiatives and emissions reduction efforts taken by electricity sector participants.

Climate change policy, at provincial and federal levels, have driven emissions reductions, particularly with respect to coal fired generation. The emissions information, except GHG emissions, presented in this section has been obtained using data searches of the National Pollutant Release Inventory (NPRI). Information was collected for annual total emissions of each air contaminant released from Electric Power Generation (Utilities) in Alberta. Information on GHG emissions was obtained from the Environment and Climate Change Canada (ECCC) GHG reporting program datasets collected for fossil-fuel electricity generation in Alberta. Provincial total emissions were also collected from the two federal databases to allow values for electricity sector contributions to be determined.

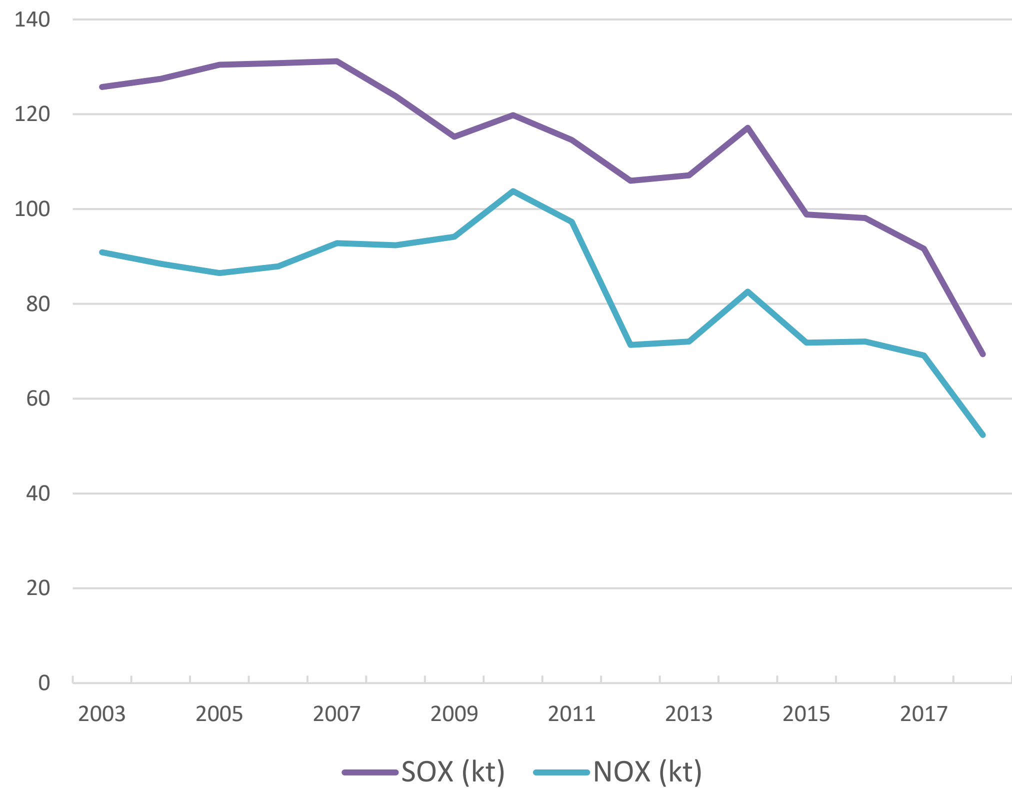
4.1. Nitrogen Oxides (NOx)

In 2018, the electricity sector made up 8.1% of the NO_X mass emissions in Alberta. Electricity sector NO_X emissions have decreased from 72 kilotonnes (kt) in 2013 to 52 kt in 2018, a 27% decrease (see Figure 3). The electricity sector reduction in NOx mass emissions from 2003 levels, when the CASA framework was published, is 42% while delivering 31% more generation MWhs.

4.2. Sulphur Dioxide (SO_2)

In 2018, the electricity sector made up 31% of SO_2 mass emissions in Alberta. The electricity sector's SO_2 emissions have decreased from 107kt in 2013 to 69.4 kt in 2018, a 35% decrease (see Figure 3). Comparing electricity sector reductions to 2003 levels, a 45% reduction in SO2 emissions has been realized with 31% more energy to the grid.

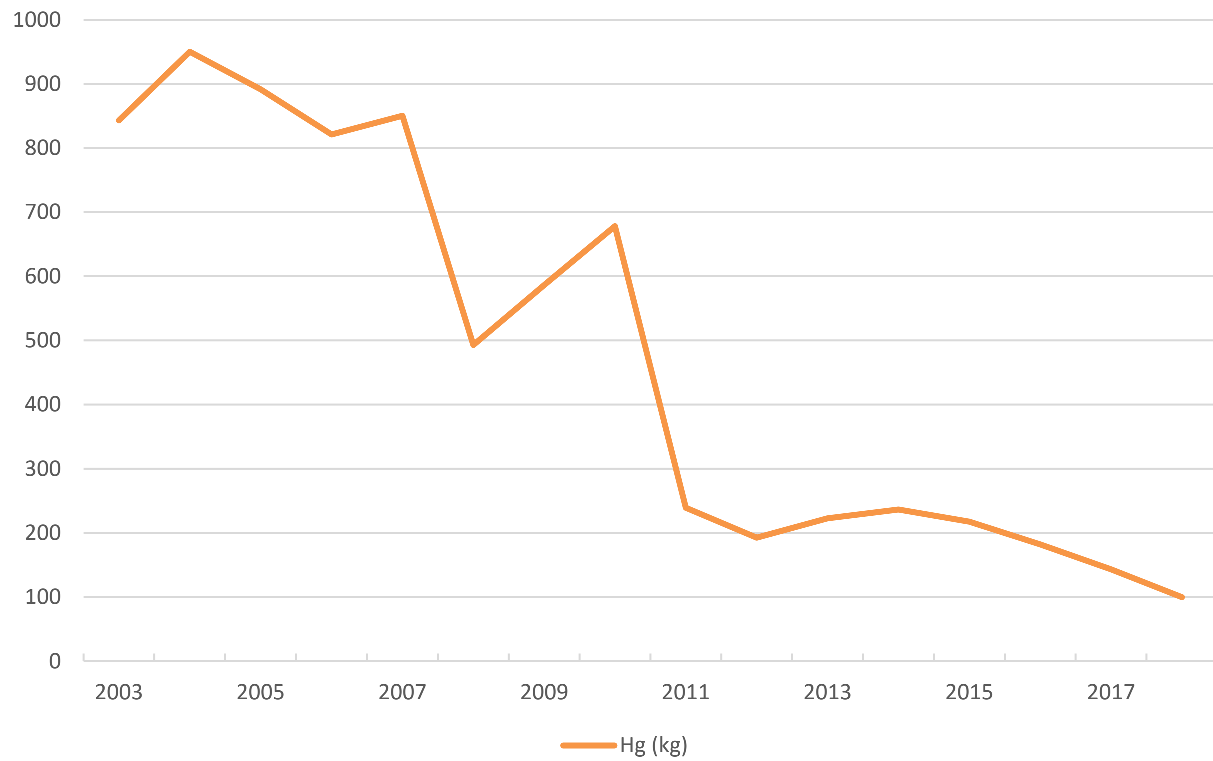
Figure 3 NO_X and SO_2 Mass Emissions



4.3. Mercury

Trace amounts of mercury can be found in coal and when coal is burned, some mercury is released into the atmosphere. In 2018, the electricity sector made up 29% of mercury mass emissions in Alberta. Members of the Alberta electricity sector worked with Government and Environmental Non-Government Organizations through the CASA process to develop a program to reduce mercury. Capture controls were installed at most coal-fired generation plants and continuous improvement actions have been undertaken by the electricity sector to optimize capture efficiency. The electricity sector's mercury emissions have decreased from 223 kilograms in 2013 to 100 kilograms in 2018, a 55% decrease (see Figure 4). Comparing the electricity sector 2003 emissions to 2018 levels has resulted in 88% reduction in mercury mass emissions while increasing generation by 31%. The mercury reduction program demonstrates how successful the CASA multi-stakeholder process can be at tackling difficult issues, bringing innovation forward and delivering great outcomes.

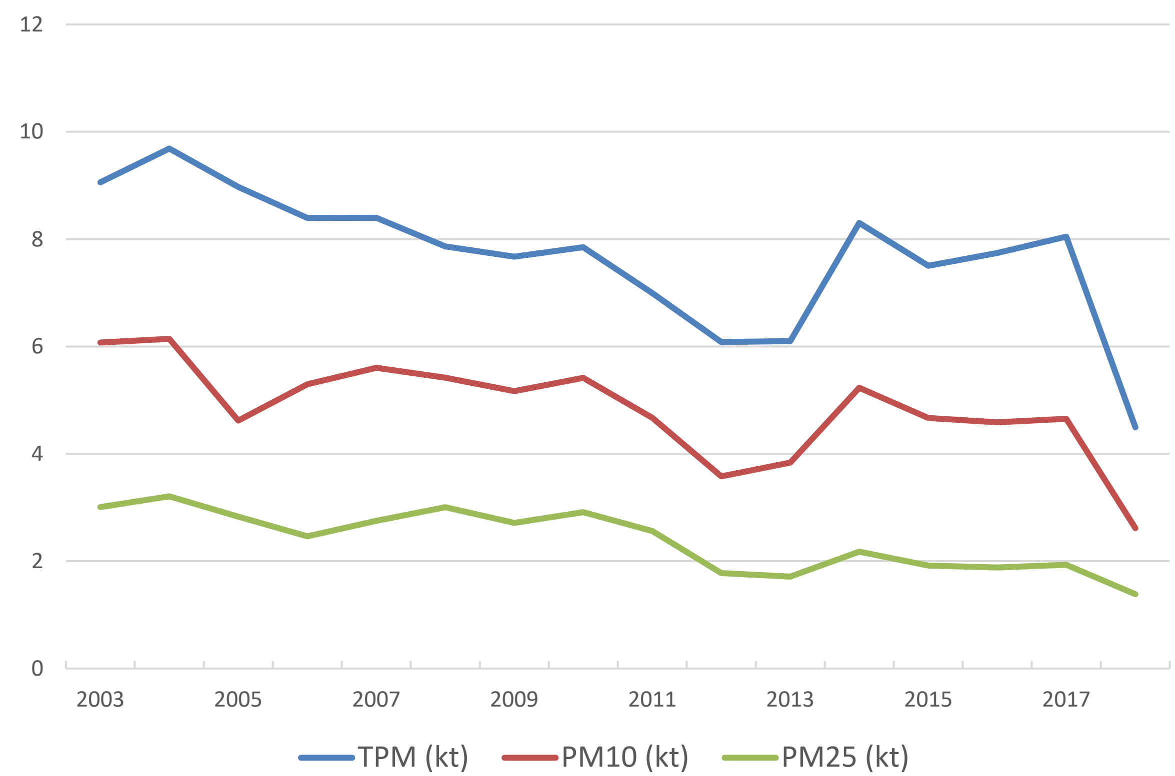
Figure 4 Mercury Mass Emissions



4.4. Particulate Matter

In 2018, the electricity sector made up 4.6% of fine particulate ($PM_{2.5}$) emissions in Alberta excluding open sources (dust, fires and agricultural activities). The electricity sector's primary PM emissions have decreased from 6 Mt in 2013 to 4.5Mt in 2018, a 26% decrease (see Figure 5). Emission of PM_{10} and $PM_{2.5}$ between 2013 and 2018 levels achieved reductions of 32% and 19% respectively. Comparing electricity sector reductions to 2003 levels, a 50% reduction in primary PM emissions has been realized with 31% more energy to the grid. PM_{10} and $PM_{2.5}$ achieved similar reductions of 57% and 54% respectively from 2003 levels.

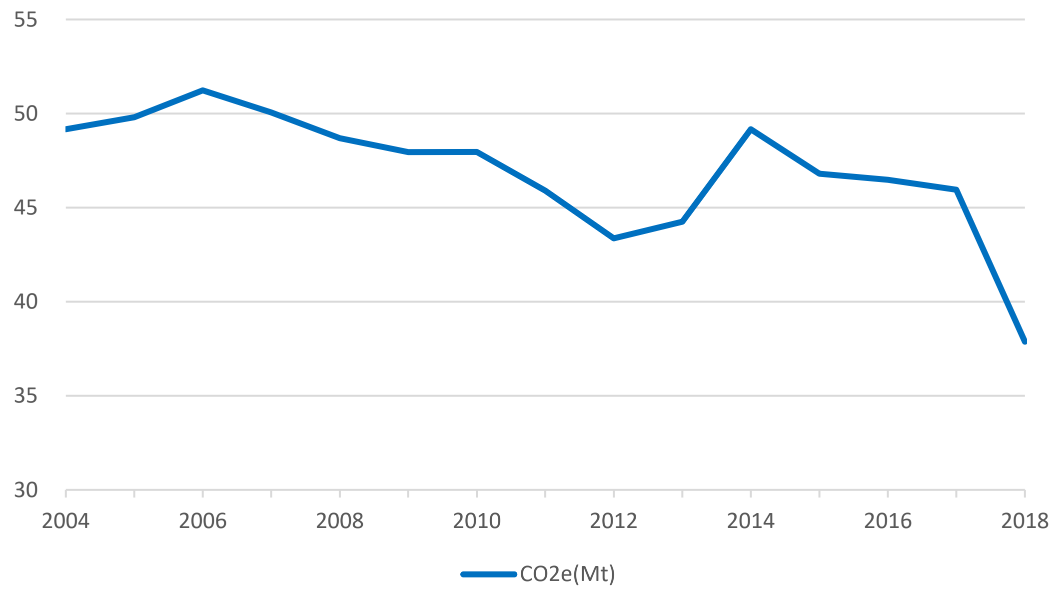
Figure 5 Primary Particulate Matter Mass Emissions



4.5. Greenhouse Gas (GHG)

In 2018, the electricity sector made up 24% of Greenhouse Gases mass emissions in Alberta. The electricity sector's Greenhouse Gases emissions have decreased from 44.3 Mt in 2013 to 37.9 Mt in 2018, a 14% decrease (see Figure 6). The amount of generation increased 10% from 2013 to 2018.

Figure 6 Greenhouse Gases Mass Emissions



At the Conference of the Parties in Paris in December 2015, Canada pledged to reduce GHG emissions by 30% below the 2005 level by 2030. For comparison, in 2018 the Alberta Electricity Sector had reduced GHG mass emissions by 24% from 2005 levels while delivering 26% more energy. With the addition of low and non-emitting generation and phase out of coal-fired emissions that is already underway or planned in the next few years, the Alberta Electricity sector GHG reductions will exceed the 30% target well before 2030.

5. EMISSIONS REDUCTIONS ACTIVITIES DURING 2013 TO 2018

5.1. New and Retired Generation

Between 2013 and 2018, the installed generating capacity of the Alberta electricity system increased by 1,595 megawatt (MW). The change in the generating units that make up the installed capacity has contributed to the overall emissions reductions that have occurred in the 2013 to 2018 period. Most new capacity was provided by low-emitting natural gas generation and non-emitting wind generation. There was also a reduction in coal-fired capacity during the period due to retirements and capacity derates. The change in capacity by resource type is illustrated in Table 3

Table 3 Change in Electricity Generation Installed Capacity

Resource Type	Installed Capacity Change during 2013 to 2018 period (MW)
Coal	-535
Natural Gas	1,705
Hydro	16
Wind	361
Biogas & Biomass	3
Solar	15
Oil, diesel, waste heat	30
Total	**1,595**

In 2018, Sundance coal-fired generating units 1 and 2 (288 MW each) retired. Coal retirements have continued with Battle River unit 3 (149 MW) in 2019 and Sundance unit 3 (359 MW) in 2020.

Natural gas-fired generation has increased and currently contributes the largest portion of generation in Alberta. Natural gas generation additions since 2013 include the following projects:

- The Enmax 860 MW Shepard Energy Centre, commissioned in 2015, is a combined cycle facility that consists of two 240 MW state-of-the-art high efficiency G-class natural gas-fired turbines and one 320 MW steam turbine. The facility uses an advanced emissions control technology that includes a SCR unit that reduces the concentration of NO_X to 3 parts per million and, upon implementation of the carbon capture system, will generate less than half the CO_2 emission per megawatt than a conventional coal-fired plant.
- Several cogeneration projects were added during the period. Cogeneration (combined heat and power) units capture waste heat from electricity production and convert it to useful thermal energy (e.g. steam for use in industrial processes). The overall thermal efficiency of cogeneration units can be very efficient (more than 70%) which results in optimal use of the fuel and also lower emissions than if the electricity is produced by a simple cycle natural gas-fired turbine and heat is produced by a conventional boiler (80% efficiency). Cogeneration projects included:
    - Imperial Oil Kearl phase 1, 84 MW in 2015
    - Cenovus Christina Lake, 100 MW in 2016
    - CNRL Horizon phase 3, 100 MW in 2016
    - Fort Hills, 199 MW in 2017
    - MEG Christina Lake Phase 2B, 110 MW in 2018
- In June 2020, Maxim Power Corp commissioned a 204 MW state-of-the-art natural gas-fired turbine generator at the HR Milner Generating and laid up the existing Milner 1 - 150 MW dual fuel unit. Milner 1 is permitted to run at no more than 9% capacity factor until December 31, 2029
- In October 2020, Imperial Oil commissioned a natural gas cogeneration unit equipped with SCR technology at the Strathcona refinery. Electricity produced by the Strathcona cogeneration unit meets approximately 75 to 80 percent of the refinery's needs, significantly decreasing energy consumptions from the Alberta grid. The unit produces approximately 41 MW of power and reduces province-wide GHG emissions by approximately 112,000 tonnes per year, which is equivalent to taking nearly 24,000 vehicles off the road annually.

Considerable wind generation has been added to the Alberta electrical system in recent years. The growth in this sector has been made possible by advances in wind technology and work to address integration issues to allow wind capacity to increase on the Alberta Interconnected Electricity System (AIES). Wind provides renewable energy with no air emissions. Three-hundred and sixty-one megawatts of wind capacity was added in the 2013 to 2018 period. The Canadian Wind Energy Association (CanWEA) has reported that Alberta is the third largest wind market in Canada. In December 2019 Alberta had 38 projects, 957 wind turbines, with an installed capacity of 1685 MW.

5.2. Emission Improvements Activities

Members of the Alberta electricity sector have taken steps to reduce emissions of existing facilities.

In 2018, the Heartland Generation Battle River Generating Station Unit 4 increased the ability to supplement coal with natural gas firing up to 50% of the units generating capacity. Natural gas firing reduces emissions of SO2, NOx, PM, mercury and GHG.

Several Alberta coal units have completed gas conversion work with more to be undertaken in the near term. This voluntary early action is well ahead of the regulated phase-out for coal generation. Companies with coal-fired generation have made the following announcements:

- December 3, 2020 - Capital Power announced operations will be off coal in 2023. Genesee units 1 and 2 to be repowered using natural gas combined cycle technology and dual-fuel upgrades at Genesee 3, which will be 100% natural gas-fueled by 2023.
- November 4, 2020 - TransAlta announced effective Jan. 1, 2022, the Company will cease coal-fired generation in Canada
- Heartland Generation Ltd. began the transition from coal-to-gas in 2018 and will be complete no later than the end of 2022.

6. FUTURE OUTLOOK

6.1. Proposed New Generation

To provide for the increased electricity demand, generation developers have announced intentions to construct several new power generation projects. These projects include:

- Kineticor Resources Cascade Power Project is 900 MW of combined cycle natural gas generation located SW of Edson. Expected in service date is October 2022.
- Capital Power repowering of Genesee units 1 and 2 (560 MW). Expected in service date is 2024.

6.2. Generation and Transmission Outlook

The Alberta Electric System Operator (AESO) publishes a Long-term Transmission Plan (LTP) and a Long-term Outlook (LTO) every two years. The LTP is the AESO's 20-year forward-looking view of how the transmission system needs to be developed and the LTO is a 20-year forecast of generation and load.

The 2019 LTO serves as the basis for the 2020 LTP. It used five scenarios to forecast the range of potential future states associated with evolving policies, technologies, fuel sources, and social and economic drivers. This approach helps to mitigate the forecasting variability caused by the uncertainty in this period of transformation of Alberta's electricity industry. Changes in economics, government policies, technology, and the way power is produced and consumed can significantly impact load growth and development of generation. The key highlights of the reference case are as follows:

- Load is forecast to grow at a compound annual growth rate of 0.9 per cent until 2039, approximately half the rate of growth experienced in the previous 20 years.
- Approximately 13,000 MW of new generation capacity is expected by 2039 with natural gas-fired generation as the predominant source.
- 5,275 MW of coal-fired generation will co-fire or convert to gas beginning in 2021.

- 1,050 MW of wind and 100 MW in solar by 2030
- Incremental 550 MW of wind and 250 MW of solar by 2039

In addition to the Reference Case, the AESO LTO included scenarios for high oilsands cogeneration growth, high renewable energy growth, high economic growth, low economic growth, and a diversification scenario shifting Alberta's economy away from oil and gas. The next AESO LTO will be undertaken in 2021.

Since the last Electricity Framework Review period, the outlook for economic growth within the province has been revised downward, primarily in response to changes in the price outlook for crude oil, and results in lower load growth than anticipated in previous AESO LTPs.

The 2020 LTP identifies 20 transmission developments proposed over the next five years valued at approximately $1.4 billion. Each of these developments will require detailed needs analysis and regulatory approvals prior to proceeding.

In 2018 the AESO published a Transmission Capability Assessment for Renewables Integration (2018 Capability Assessment). The study determined the capability of the existing transmission system to integrate renewables generation within central east and southern Alberta, and included the projects selected in Round 1 of the Renewable Electricity Program (REP). An update was completed in 2019 as the REP Rounds 2 and 3 progressed. These capability assessments provide useful information on where capability is available and optimal areas to situate projects to connect to the system.

The electricity sector in Alberta is in a state of transformation, due in part to evolving technology, policies, and social and economic drivers that affect future generation development and load growth. The electricity system reliance on coal-fired generation is changing and recent announcements from coal-fired generation operators have aggressively accelerated the phase-out of coal. The future is expected to have an increase in gas-fired and renewable generation however, the continued transformation of the electricity sector may take some new paths.

6.3. Regulatory Influences

Since 2013, there have been numerous changes to regulatory policy direction that have influenced the electricity sector and that will ultimately reduce emissions. One of the more notable regulatory influences during this time has been the progression of climate change policy. A conventional coal-fired generating unit faced a carbon cost of $1.80/MWh in 2015 which has become $25/MWh in 2021 and is proposed to be over $110/MWh by 2030 according to Canada's renewed climate plan. The increasing carbon price places higher costs on using fossil fuels and encourages lower and non-emitting generation technologies. In addition to carbon price, the introduction of stringent performance standards and other broad regulatory initiatives will also drive emissions reductions. The objective to achieve net zero GHG emissions by 2050 will challenge the electricity sector to continue to drive change and reduce emissions. The climate change policy initiatives generally also have a co-benefit of reducing of emissions of other air contaminants in addition to GHG emissions.

7. CONCLUSION

During 2013 to 2018, the period of the 3rd CASA five-year review, the Alberta electricity sector has increased electricity generation by 10% while reducing emissions of the five CASA priority substances (reductions: 27% NO_X, 35% SO_2, 55% Hg, 26% PM and 14% CO_2). Reduced operation of higher emitting units, retirement of older units, additions of new low-emitting generation, and emissions reduction efforts undertaken by electricity sector participants have contributed to achieving the emissions reductions. The mix of resource types that provide electricity generation has shifted from a majority coal-fired generation mix to one with increased natural gas-fired and renewable generation and an aggressive phase-out of coal-fired generation. The transformation of the electricity sector in Alberta and progression of climate change policy drivers is expected to influence future generation development, load growth and continue to deliver significant emissions reductions.

APPENDIX 2: ABBREVIATIONS

AESO	Alberta Electric System Operator
AIES	Alberta Integrated Electrical System
AUC	Alberta Utilities Commission
CASA	Alberta Clean Air Strategic Alliance
CCS	Carbon capture and storage
CEMS	Continuous emissions monitoring system
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DLE	Dry low NO_X emissions
GHG	Greenhouse gases
GWh	Gigawatt-hour
Hg	Mercury
kg	Kilogram
LTO	Long Term Outlook
LTP	Long-term Transmission Plan
MW	Megawatt
MWh	Megawatt-hour
NAICS	North American Industry Classification System
NO_X	Nitrogen oxides
NPRI	National Pollution Release Inventory
PM	Particulate matter
REP	Renewable Electricity Program
SAGD	Steam-assisted gravity drainage
SCR	Selective catalytic reduction
SNCR	Selective non catalytic reduction
SO_2	Sulphur dioxide

References:

[i]Environment Canada; National Pollutant Release Inventory available at tps://open.canada.ca/data/en/dataset/40e01423-7728-429c-ac9d-;.

The data was sorted by substance, Alberta, NAICS code Fossil-fuel Electric Power Generation (221112), and total releases to air.

[ii] Environment Canada; Greenhouse Gas Emissions in Canada available at https://open.canada.ca/data/en/dataset/a8ba14b7-7f23-462a-bdbb-83b0ef629823

GHG emissions data was obtained from Environment Canada’s reported facility GHG emissions online data search by sorting for Alberta and NAICS code 221112.

[iii] AUC, Alberta Electric Energy Net Installed Capacity by Resource; available at https://www.auc.ab.ca/pages/annual-electricity-data.aspx

Installed capacity and total generation data tables may be downloaded.

[Iv] Alberta Electric System Operation (AESO) Long Term Outlook (LTO) and Long-term Transmission Plan (LTP) are available on the AESO website at https://www.aeso.ca/grid/forecasting/

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