Report of the Electricity Project Team – Greenhouse Gas Allocation Subgroup

Prepared by the
Electricity Project Team – Greenhouse Gas Allocation Subgroup
for the
Clean Air Strategic Alliance
Board of Directors

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By consensus, the CASA board of directors approved this report and the recommendations within on July 15, 2004.

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About CASA

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

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

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Acronyms and Abbreviations

AERI	Alberta Energy Research Institute
BAU	Business as usual
CASA	Clean Air Strategic Alliance
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
EDC	Energy Demand Consulting Associates
EPG	Electric Power Generation
EPT	Electricity Project Team
EUB	(Alberta) Energy and Utilities Board
GDP	Gross Domestic Product
GHG(s)	Greenhouse Gas(es)
GWh	Gigawatt-hour
LFE(s)	Large Final Emitter(s)
Mt	Megatonne
MWh	Megawatt-hour
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen oxides (also oxides of nitrogen)
NRCan	Natural Resources Canada
PM	Particulate Matter
PPA(s)	Power Purchase Arrangement(s)
R&A	Renewable and Alternative (energy)
R&D	Research and Development
SO_2	Sulphur dioxide
TIC	Technology Investment Credit
TWh	Terawatt-hour
UA	Unit Age
WPPI	Wind Power Production Incentive

See also the glossary in Appendix A.

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Message to the Reader

The GHG Allocation Subgroup of the Electricity Project Team has developed a conceptual framework for the Alberta electric power generation sector to manage greenhouse gases within Alberta and within the context of Canada's response to the Kyoto Protocol. This framework and process has the potential to a) provide an environmentally effective and economically efficient response to these policy initiatives as well as b) providing valuable guidance for similar efforts in other sectors.

It is important to recognize that this framework envisions several key elements that are interdependent but which have not been fully developed or agreed upon by the subgroup. This framework is thus a "work in progress." Ongoing stakeholder support for the framework is contingent on the resolution of these details.

In developing this conceptual framework, the subgroup invested considerable effort in examining a broad range of management options and assessing their potential impacts on the sector's emission profile, costs and power prices. This analytical work, including the development of modeling tools, has facilitated improved stakeholder understanding of the value of and linkages between these management options.

Consensus on these framework elements was not reached due to uncertainties about larger national and international policy issues and, in some cases, differences of perspective among stakeholders. These included:

- Uncertainty about whether the Kyoto Protocol will come into force, and the federal government's response to that outcome
- Uncertainty about the federal policy for greenhouse gas management for LFEs
- Differing views of the appropriate level of reductions under the framework and whether to provide credits for generation operating below specified intensity limits
- Differences over what offsets should qualify (for example, pre-2008 offsets, technology investment credits), and the need to reconcile these with federal targeted measures
- Differing views about whether renewables and alternative generation should be included in or excluded from electricity sector targets
- Uncertainty regarding the emission targets that would be applied against the cogeneration heat host emissions
- Lack of clarity about the portion of total and unit cost of the electricity sector package (including management of NO_x, SO_2, mercury and primary particulate matter), which will be recovered by generators and/or PPA holders
- Differing interests and perceptions of climate change policy risk exposures of stakeholders.

The subgroup worked diligently, in good faith and without prejudice to develop a conceptual framework, recognizing that further details remain to be worked out. Final stakeholder approval of the overall package is subject to these details being developed. The subgroup nevertheless believes that its conceptual framework should guide the approaches the provincial and federal governments take with respect to managing greenhouse gases from the Alberta electricity sector. Further, the subgroup encourages both orders of government to coordinate their efforts to avoid regulatory duplication and overlap.

1 Executive Summary

In 2002, Minister of Environment, Hon. Lorne Taylor asked the Clean Air Strategic Alliance to develop a new framework for managing emissions from Alberta's electricity sector, including greenhouse gases. CASA's Electricity Project Team (EPT) presented its report to the CASA board in November 2003,[1] and the Government of Alberta subsequently adopted the framework as policy and has begun the process of implementation.

However, due to the complexity of the issues associated with greenhouse gases and the evolving climate change policy landscape in Canada and internationally, the EPT was unable to complete its work in this area. In November 2003, the Greenhouse Gas Allocation Subgroup was formed by the EPT to continue the analysis and recommend an approach for reducing greenhouse gas emissions from Alberta's electricity sector. It was understood that the outcome of the subgroup's work would guide the Government of Alberta in its greenhouse gas reduction discussions and negotiations with the federal government, and consensus recommendations would be adopted as part of the path forward to achieve Alberta's greenhouse gas reduction target for 2020.

The mandate of this group was to recommend:

1. A greenhouse gas emissions reduction target or approach for the thermal generation sector;
2. if and how renewables,[2] energy efficiency and conservation, and the new coal unit NGCC offset requirement would be part of the greenhouse gas reduction target or approach;
3. how the target would be allocated between coal and gas-fired electricity emission intensity;
4. whether emissions from cogeneration are included in the target and, if so, how the emissions would be allocated between the host (steam) and power (electricity); and
5. offset credit details and criteria if offsets are part of the target or the approach.

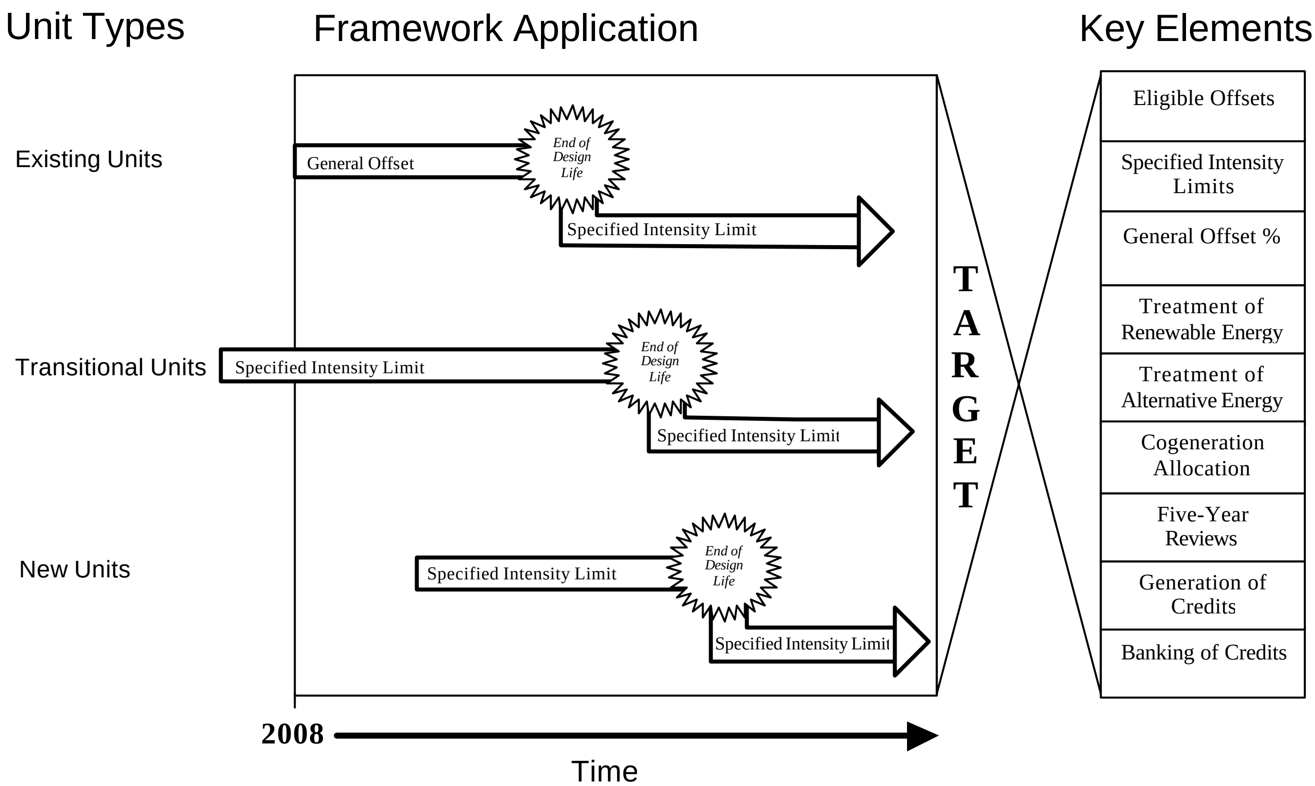
The subgroup has developed a conceptual framework for managing greenhouse gas emissions from Alberta's electricity sector. The framework has two components: a Unit Age component that requires a full offset to a specified intensity limit, and a General Offset component that requires a percentage reduction from a unit's actual emissions intensity. It affects all generation units in different ways at different points in time, but no unit will be affected by both components at the same time. The two components combined make this a robust framework that can be adjusted using the size of the general offset and the specified intensity limits to achieve a wide range of targets.

The following figure illustrates the conceptual framework and its various elements.

[1] The report entitled *An Emissions Management Framework for the Alberta Electricity Sector: Report to Stakeholders*, is available online at http://casahome.org/electricity/index.asp or upon request to CASA.

[2] The subgroup understood the term "renewables" to include alternative energy, and has considered both renewable and alternative energy in this report.

Greenhouse Gas Conceptual Framework



The Unit Age Component
The Unit Age component of the conceptual framework applies to new thermal units at the start of commercial operation, to thermal units at the end of their Design Life, and to transition coal units at the start of commercial operation. Consistent with existing provincial policy for coal-fired units, the Unit Age component of this framework applies immediately to new and transition coal-fired units. For new gas-fired units and for units at the end of their Design Life, the Unit Age component would be effective January 1, 2008.[3] The subgroup recognizes that this effective date is two years later[4] than that recommended for NO_x, SO_2, mercury and PM in the report of the Electricity Project Team but does not believe this would create any difficulties in implementing either framework. The Unit Age component requires a full offset to specified intensity limits for affected units.

As proposed in the EPT framework for other substances, the specified intensity limits would be reviewed every five years, beginning in 2008. New and transitional coal-fired units, new gas-fired units, and all other new units would not be affected by the new intensity limits until they reach the end of Design Life. It is recognized that future national or international greenhouse gas reduction commitments could result in additional management obligations. At the end of Design Life, all units would be required to meet the updated intensity limits as determined by the Five-Year Review.

[3] The Unit Age component could come into effect sooner than January 1, 2008 for both new gas-fired units and gas-fired units at the end of their Design Life; this detail has not been finalized.
[4] This time frame was chosen because it aligns with the first federal Kyoto commitment period.

The General Offset Component

The General Offset component of the conceptual framework would apply to all existing thermal units and would come into effect on January 1, 2008. All affected units except those whose emissions intensities are below their specified intensity limits would be required to reduce their emissions intensity by between 0 and 15%, with this percentage yet to be determined. The specified intensity limit would act as a floor so no unit would be required to go beyond that floor intensity level.

At the present time, all generation units in the province excluding Genesee 3 are affected by this component. The percentage reduction required by the general offset would be reassessed every five years as part of the Five-Year Review.

The application of the conceptual framework to various generation units is shown in the following table.

Application of the Conceptual Greenhouse Gas Management Framework Components to Generation Units in Alberta [a]

	Unit Age Component				General Offset Component
Framework Component	**New and transition coal-fired units**	**Coal-fired units at end of Design Life** [b]	**New gas-fired and all other units** [c]	**Gas-fired and all other units at end of Design Life** [c]	**Existing thermal units**
Effective date for policy	In place	As in EPT Recommendation #25	January 1, 2008 OR earlier [d]	January 1, 2008 OR earlier [d]	January 1, 2008
Effective date for compliance for units	At start of commercial operation	Immediately after reaching end of Design Life	At start of commercial operation	Immediately after reaching end of Design Life	January 1, 2008
Intensity limit [e]	0.418 t/MWh [f]	0.418 t/MWh [f]	0.375 t/MWh	0.375 t/MWh	Must reduce GHG emission intensity by 0-15% [g]
Impact of Five-Year Review	Not affected until reach end of Design Life	Updated intensity standards applied in subsequent five year period	Not affected until reach end of Design Life	Updated intensity standards applied in subsequent five year period	New offset percentage will be applied in subsequent five-year period

[a] The numerical values in this table must be finalized and are subject to agreement on the whole package.

[b] The same requirements apply to non-gas-fired cogeneration units.

[c] "All other units" refers to all thermal units not specifically addressed in this table or its footnotes.

[d] Effective date could be before January 1, 2008; this aspect has not yet been finalized.

[e] The numbers in this row were used in the calculations and modeling by the subgroup.

[f] Depending on offset eligibility.

[g] However, no reductions would be required below a "floor" that is consistent with the specified intensity limits for coal or gas.

Offsets and Credits

Offsets are a critical part of achieving compliance with the framework. Prior to 2008, Alberta's Transition Principles (see Appendix D) define how offsets will be applied and what offsets will count against the 0.418 t/MWh intensity requirement; the subgroup did not reach agreement on eligible offsets that would apply after 2008. The subgroup discussed a range of eligible offsets that included all credits that qualify under federal regulations still under development, as well as credits for early shutdown (effective January 1, 2008), credits for renewable and alternative energy generation, and technology investment credits described in this report. However, there were differing views on both the definition and consequent eligibility of these last three options. The subgroup was unable to agree on whether credits would be provided under the framework for those emitters performing below the specified intensity limit or deemed credit threshold, as applicable. The subgroup also recognized that the future consideration of other verifiable offsets is not precluded.

Renewable and Alternative Energy

The subgroup recognized the role that renewable and alternative (R&A) energy generation could play in achieving GHG targets by reducing the overall intensity of Alberta's EPG sector. There were, however, strong and divergent views about whether R&A should be covered under the framework as part of the EPG sector or whether it should be excluded from the calculation of sectoral intensity. This decision would affect both the level of reduction required by thermal units as well as the economics of R&A generation. The subgroup felt it did not have sufficient information about the linkages between offsets, credits, allowances and other mechanisms to thoroughly consider the advantages and disadvantages of including R&A. There were also differing views on the treatment of R&A in the context of federal plans for targeted measures.

Cogeneration

The subgroup agreed in principle to include the electricity output-related emissions from cogeneration units within the electricity sector, subject to the details of the full framework. It also agreed in principle on a methodology that proportionately divides the emissions from natural gas-fired cogeneration units using reference efficiencies of a stand-alone electricity generation unit and a stand-alone steam boiler unit. The subgroup was unable to reach agreement on whether credits would be provided to cogeneration units with calculated emissions intensity, using the agreed methodology, below the specified intensity limit for gas units. The allocation of emissions from cogeneration units that are fired by fuels other than natural gas would be determined on a unit-by-unit basis and, where appropriate, would be consistent with the principles used for allocating emissions of a conventional natural gas-fired cogeneration unit.

Five-Year Review

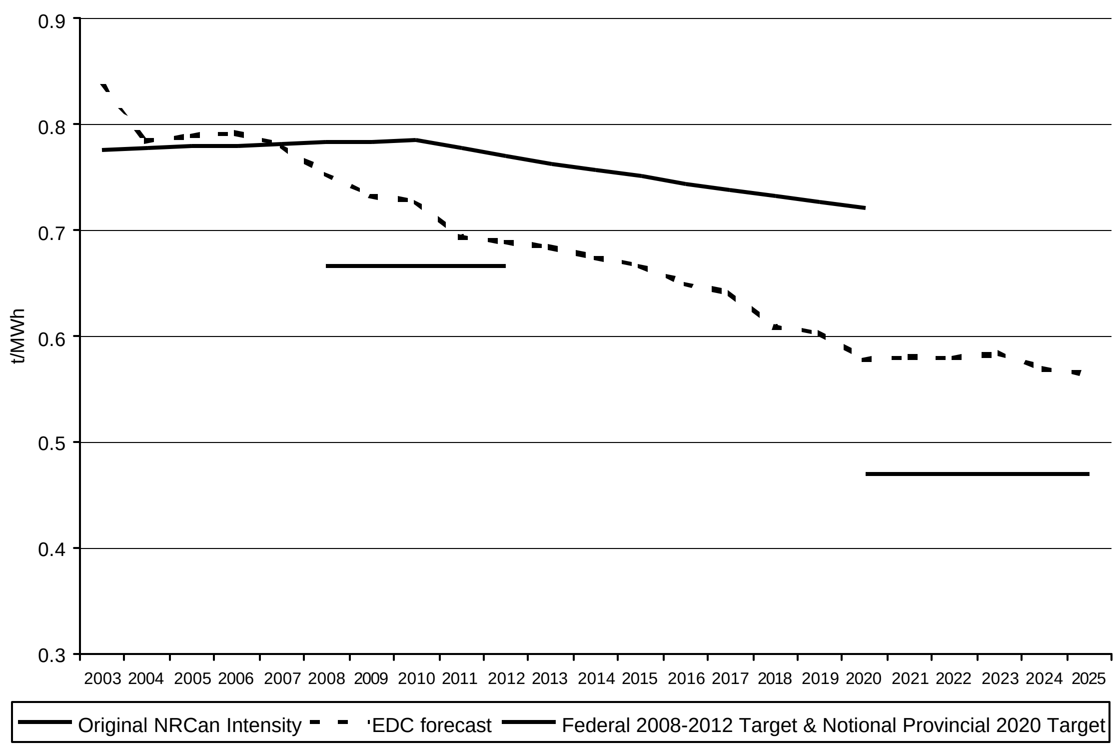
The subgroup agreed that, at minimum, specified intensity limits and the general offset percentage reduction should be subject to a five-year review cycle. It further recognized the benefits of synchronizing review of the GHG framework with the Five-Year Reviews prescribed by the EPT beginning in 2008, as this provides greater certainty to industry for investment and planning purposes. However, it also recognized that future national or international GHG reduction commitments by Canada could result in the need for additional GHG management obligations. These external drivers could require review of all or part of the GHG framework at a different time interval, separate from the larger EPT Five-Year Review. National and international policy drivers should also be taken into consideration when establishing the effective dates for any required revisions to the framework elements.

Impacts of the Framework

The group completed in-depth analysis of the emissions, intensity, cost and price impacts of the proposed conceptual framework. The differences between the federal NRCan business as usual forecast and the forecast used by the EPT were examined. Because of different forecast assumptions and inputs related to unit intensities, predicted coal-fired generation and future demand, Alberta's business as usual forecast can be characterized in different ways.

The subgroup engaged EDC Associates to complete analysis work on the emissions and intensity impacts of a number of reduction scenarios based on EDC's forecast. Federal targets for 2010 were defined as 15% below the federal business as usual. The figure below shows the federal NRCan intensity forecast and the EDC reference forecast, the federal intensity target for the 2008-2012 period and the notional provincial target for 2020 expressed in terms of the total electricity sector in Alberta.

Business as usual Intensities and Targets



The cost impacts to generators were examined on an annual and an aggregate cost basis. The costs per MWh were analyzed on a sector wide basis as well as at the unit level. The unit costs were used by EDC Associates to determine the impact of the framework on the price of electricity and the economic viability of generation in the province. EDC's modeling predicts that the implementation of the framework would not cause any generation in the province to become uneconomic. Wholesale price impact was predicted to be within a range of $0.41/MWh to $1.16 between 2010 to 2019 and approximately $3.00/MWh 2020 and 2025. The difference in wholesale price impacts of the various reduction scenarios was relatively small. EDC's analysis did not measure the cost impact on individual PPA holders, nor did it assess the impacts of the framework on the price of electricity purchased directly through commercial contractual arrangements.

The Benefits of the Conceptual Framework

The conceptual framework described in this document provides a variety of benefits. It:

- is a "made-in-Alberta" approach that reflects the unique structure of the electricity industry in Alberta;
- can achieve meaningful reductions in greenhouse gas emissions intensity in the 2010 timeframe and further, more significant, reductions in the long term to 2020 and beyond;
- balances environmental and economic objectives by:
    - providing public policy signals to reduce GHG emissions intensity, and
    - recognizing investments made in existing thermal generation units and capital stock turnover;
- can provide for a fair and equitable distribution of costs across all generation units;
- includes a flexible range of compliance tools including incentives for industry to take actions that will contribute meaningful long-term reductions;
- can be calibrated to achieve desired policy objectives; and
- includes Five-Year Reviews that allow adjustments needed to reflect changing external developments and policy objectives and emerging best available control technology.

Further Work

The subgroup worked diligently and in good faith to fulfill its mandate, but greater certainty is required in the national and international policy environment before substantial further progress can occur. Recommendations on approval of the conceptual framework and next steps are as follows:

Recommendation 1 – Conditional Approval of Conceptual GHG Management Framework and Next Steps

Approval-in-principle of the conceptual framework conditional on:

a) Future satisfactory resolution of all integral framework elements, including:

- Percentage reduction of general offset
- Definition of eligible offsets, including banking
- Specified intensity limits
- Treatment of pre-2008 offsets
- Treatment of renewable and alternative generation
- Treatment of cogeneration
- Credit for units performing below specified intensity limits.

b) Government strategies and approaches continuing to develop within the range of current stakeholder understanding.

Recommendation 2 – Framework to Guide Government Approaches

This conceptual framework guide the approaches the provincial and federal governments take with respect to managing greenhouse gases from the Alberta electricity sector.

Recommendation 3 – Use of CASA Process

Consideration be given to resolving the outstanding elements of the framework through CASA.

Recommendation 4 – Further Work

That the CASA executive committee determine if and when there is an opportunity for CASA to further the resolution of the framework elements and, if so, to initiate a process in a timely manner to develop draft terms of reference for a project team that includes clear direction on deliverables, timelines and team composition for consideration by the CASA board of directors.

2 Background

In 2002, Minister of Environment, Hon. Lorne Taylor asked the Clean Air Strategic Alliance (CASA) to develop a new framework for managing emissions from Alberta's electricity sector, including greenhouse gases. CASA's Electricity Project Team (EPT) presented its report to the CASA board in November 2003,[5] and the Government of Alberta subsequently adopted the framework as policy and has begun the process of implementation.

The report included recommendations pertaining to greenhouse gas (GHG) management,[6] but work in several important areas could not be completed by the fall of 2003 due to the complexity of the issues coupled with the evolving climate change policy landscape in Canada. The EPT's final report further acknowledged that two of the five GHG recommendations could be amended by the GHG Allocation subgroup based on the outcome of its discussions related to GHG reduction targets and allocation mechanisms.

To continue the greenhouse gas analysis, the GHG Allocation subgroup was established in November 2003.[7] Members of this multi-stakeholder subgroup are listed in Appendix B. The mandate of the group was to recommend:

1. a greenhouse gas emissions reduction target or approach for the thermal generation sector;
2. if and how renewables,[8] energy efficiency and conservation, and the new coal unit NGCC offset requirement would be part of the greenhouse gas reduction target or approach;
3. how the target would be allocated between coal and gas-fired electricity emission intensity;
4. whether emissions from cogeneration are included in the target and, if so, how the emissions would be allocated between the host (steam) and power (electricity); and
5. offset credit details and criteria if offsets are part of the target or the approach.[9]

It was understood that the outcome of the subgroup's work would guide the Government of Alberta in its greenhouse gas reduction discussions and negotiations with the federal government, and would be adopted as part of the path forward to achieve Alberta's greenhouse gas reduction target for 2020.

[5] The report entitled *An Emissions Management Framework for the Alberta Electricity Sector: Report to Stakeholders*, is available online at http://casahome.org/electricity/index.asp or upon request to CASA.
[6] These were recommendations 24-28 in the EPT's final report. These recommendations and the caveat at the beginning of the section on greenhouse gases can be found in Appendix C.
[7] The GHG subgroup presented this conceptual framework to the EPT on June 1, 2004, where it was approved in principle by consensus (see Recommendation 1). The framework was then presented by the EPT to the CASA Board at its June 17, 2004 meeting.
[8] The subgroup understood the term "renewables" to include alternative energy, and has considered both renewable and alternative energy in this report.
[9] GHG Allocation Subgroup Report to the CASA Board, March 2004.

3 Design Considerations

The subgroup recognized that different targets have been proposed and discussed by the provincial and federal governments. Members also recognized that although Canada has ratified the Kyoto Protocol, thus accepting an international obligation to reduce its national average greenhouse gas emissions by six percent below 1990 levels, there continues to be uncertainty on whether the Protocol will enter into force. If it does, Canada will be subject to strict international targets and rules. If the Kyoto Protocol does not enter into force, Canada will have more latitude and flexibility in designing its GHG management systems.

Many of the same considerations that guided the EPT also provided important context for the GHG Allocation subgroup. The management system should:[10]

- Encourage meaningful reductions in greenhouse gas emissions, below business as usual.
- Provide policy certainty over the long term.
- Encourage energy efficiency in the generation of electricity.
- Give consideration to capital stock turnover.
- Maintain flexibility and balance in the provincial fuel supply.
- Maintain the structure of the electricity sector.
- Ensure the impact on cost of electricity to consumers is acceptable.
- Incorporate advances in technology within a reasonable time frame.
- Consider the current PPA structure.

The subgroup worked within the structure of the existing recommendations of the EPT. The subgroup agreed to base its framework on intensity, consistent with the EPT framework, the Alberta climate change action plan and federal direction to large final emitters (LFEs). The relevant EPT recommendations appear in Appendix C.

[10] Adapted from the report of the Electricity Project Team, pp 25-26.

4 Federal and Provincial Climate Change Plans

4.1 The Federal Climate Change Plan

The federal government's climate change plan[11] requires Canada's large final emitters (LFEs), which includes the electricity sector, to achieve a reduction of 55 megatonnes, or 15% below business as usual (BAU) projections in the 2008-2012 period. This translates to total annual greenhouse gas emissions of 48.5 megatonnes for the electricity sector in Alberta. Three reduction options for the electricity sector, expressed in terms of greenhouse gas emissions per unit of electricity generated, have been proposed to achieve compliance with the overall LFE target:[12]

1. National standard: Establishing a single national emissions intensity standard for all thermal production based on forecast BAU emissions in 2010, less 15%. This standard would be 0.558 t/MWh.
2. Provincial Standard: Establishing separate standards by province and territory, based on the individual 2010 BAU emissions intensity less 15%. This option would be equivalent to an emissions intensity of 0.691 t/MWh for the thermal sector in Alberta and 0.667 t/MWh for the total electricity sector in Alberta.
3. Vintage Standard: Establishing a best technology intensity standard for new thermal plants to motivate clean new generation and for near end-of-life plants to accelerate capital turnover. This standard would be 0.370 t/MWh for new plants and for plants older than 35 years.

More recently, the federal government indicated its intentions to develop and support a clean power program for Canada. It is a matter of speculation as to what offsets, if any, would be eligible to meet its targets beyond those that already comply with the offset rules and conditions in the Kyoto Protocol should it come into force.[13] The federal climate change plan also contains the option of developing equivalency agreements with the provinces; with such an agreement, Alberta would negotiate or be assigned a reduction target and the province would be responsible for administering the agreement and achieving the target.

[11] *Climate Change Plan for Canada*, online at http://www.climatechange.gc.ca/plan_for_canada/plan/index.html

[12] From Natural Resources Canada's discussion paper, *Key Issues for Large Final Emitters in the Electricity Sector*, online at http://www.nrcan-rncan.gc.ca/lfeg-ggef/English/electricity_emissions_en.pdf

[13] See the discussion paper published by Natural Resources Canada, *Treatment of Clean Energy Investments under the Large Final Emitters Policy*, online at http://www.nrcan-rncan.gc.ca/lfeg-ggef/English/clean_energy_en.pdf.

4.2 The Alberta Approach

Alberta's climate change action plan[14] takes a different approach and time frame; it proposes a 50% reduction in GHG emissions intensity from 1990 levels by 2020, based on GDP. For the purposes of this group's work, this target has been equated to a notional intensity target of 0.470 t/MWh for the total electricity sector, which is one-half of the 1990 intensity of 0.94 t/MWh. The notional target is 0.490 t/MWh when adjusted to reflect the thermal electricity sector only. Full details on how this target would be achieved have not yet been developed, but some policies are already in place. For example, Transition Principles developed by the Alberta Government require new and transition coal-fired units to offset their intensity to the level of a new NGCC unit, equal to 0.418 t/MWh (see Appendix D). Starting in 2005, Genesee 3 will be the first plant to comply with this requirement. In addition, the EPT recommended that existing coal-fired units be required to offset their intensity to 0.418 t/MWh at the end of their Design Life. The Transition Principles can be changed by CASA consensus recommendations by the Alberta government.

The Requirement for New Coal Units

Alberta requires new coal-fired units to reduce or offset greenhouse gas emissions intensity to 0.418 tonnes of CO_2 equivalent per megawatt-hour. This number represents the commitment volunteered by EPCOR in its application for the new Genesee 3 plant. An intensity of 0.418 t/MWh is the sum of the burner tip intensity of a new NGCC unit (0.375 t/MWh) plus all associated upstream production emissions for the fuel.*

This intensity limit is subject to the Five-Year Review.

* For more information, see *Full Fuel Cycle Emissions Analysis of Existing and Future Electric Generation Options in Alberta, Canada.* 1995.

4.3 Forecasts of Emissions and Intensities

As part of its discussions with provinces and emitting sectors, the federal government has developed forecasts of GHG emissions and emissions intensity ("NRCan forecast"). Energy Demand Consulting (EDC) Associates, the modeling consultant engaged by the EPT and by the GHG subgroup, has developed forecasts as well ("EDC forecast"). The assumptions, timelines and other inputs to these forecasts differed (see section 7), and were analysed by the subgroup as it developed its conceptual framework.

The fundamental differences between the two forecasts are the total generation forecasts, the type of new generation predicted (coal- or gas-fired), and the unit intensities used. Between 2003-2020 the NRCan forecast assumes a growth of electricity generation in the province of 1.7% per year while the EDC forecast assumes a growth rate in generation of 2.4% per year. The EDC forecast assumes no new coal-fired generation beyond a 450 MW unit commissioned in 2005 and that new generation is made up primarily of natural gas-fired cogeneration. The NRCan forecast includes the equivalent of 900 MW additional coal-fired generation by 2010. The NRCan forecast also assumes that existing coal-fired units will be replaced by new coal-fired units whereas EDC's forecast assumes that existing coal-fired generation would be replaced by gas-fired cogeneration. The EDC forecast was derived using the unit intensities gathered by the GHG subgroup. The NRCan forecast used average intensities for each generation type, which are on average 7% lower than the unit intensities gathered by the subgroup. Figure 1 shows the NRCan and EDC forecasts relative to the federal emissions target for 2010. The federal target of 48.5 Mt is superimposed on the graph.

[14] See *Albertans & Climate Change: Taking Action*, online at http://www3.gov.ab.ca/env/climate/actionplan/index.html

Figure 1: NRCan and EDC Emissions Forecasts

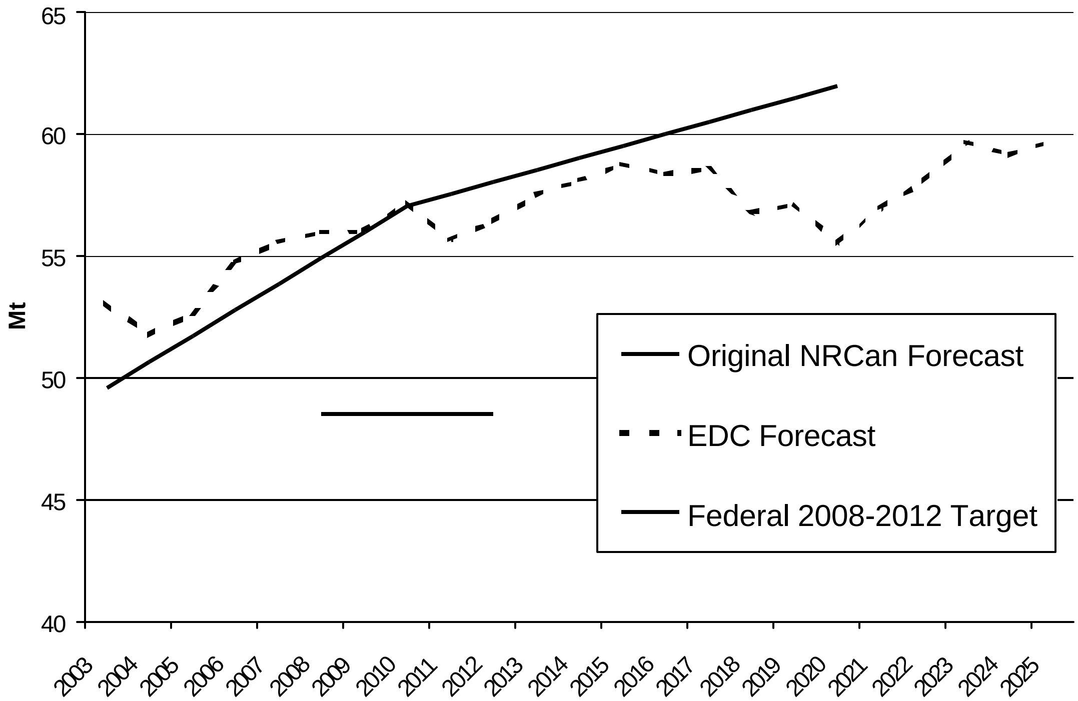
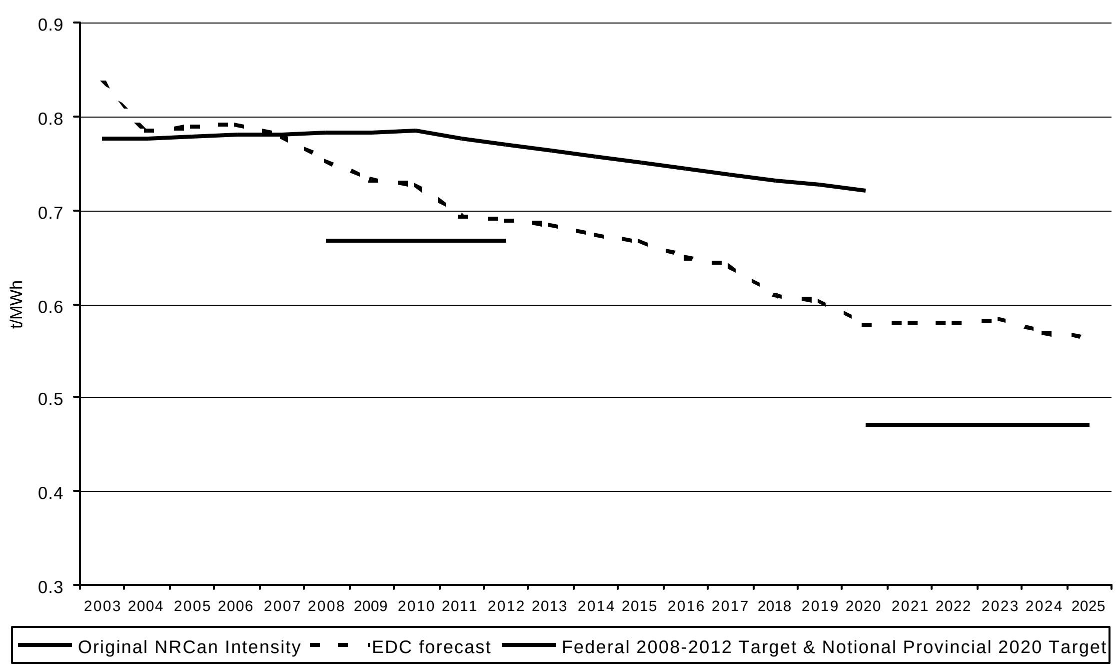


Figure 2 shows the same forecasts as described for Figure 1, for intensity rather than emissions. Again the federal target of 0.667 t/MWh for the 2008-2012 period is shown on the graph. In addition, the notional provincial intensity target of 0.47 t/MWh by 2020 is shown for the years 2020-2025.

Figure 2: NRCan and EDC Forecasts of Emissions Intensity



5 Conceptual Framework for Reducing the Greenhouse Gas Intensity of Alberta's Electricity Sector

This section describes the conceptual framework developed by the subgroup. As members were unable to finalize elements of the framework for various reasons, stakeholder support for the overall framework remains subject to reaching agreement on the details inherent in it.

The federal government is currently negotiating reduction strategies with the provinces and with key sectors of the economy, including large final emitters (LFEs), which includes the electricity sector. Within this broader context, and without prejudice, the subgroup assessed three main approaches for achieving the necessary emissions reductions:

1. **The Unit Age Component,** which requires new units and units that reach the end of a specified lifetime to reduce or offset their emissions to a specified intensity limit.
2. **A General Offset** applied to all thermal units in Alberta. The group considered two approaches, one based on reductions from a unit's actual intensity, the other based on percentage reductions from a unit's actual intensity relative to an intensity limit.
3. **A combination** of the Unit Age component plus the General Offset component.

The subgroup recognized that the Unit Age component described in this report would not be sufficient to meet federal targets in 2008-2012 and may not be sufficient to meet provincial targets[15] depending on subsequent intensity limits arising from the Five-Year Reviews. Thus it has developed a conceptual framework that combines two main components: a Unit Age component[16] and a General Offset component. The framework affects all units in different ways at different points in time but no unit will be affected by both components at the same time. The current policy direction at both the federal and provincial levels is towards an intensity-based approach as a way to meet whatever targets might eventually be identified, and this framework supports that direction. The two components combined make this a robust framework that can be adjusted through the percentages applied in the General Offset component to achieve a wide range of targets.

The framework builds on the Alberta Government's Transition Principles[17] and on recommendations from the EPT that require existing units to reduce or offset their emissions to a specified limit at the end of their Design Life, and for new units to meet this limit immediately. The General Offset component further requires all thermal generation units operating within their Design Life to reduce their emissions intensity by a specified percentage. This conceptual framework would come into effect January 1, 2008.

Figure 3 illustrates the conceptual framework and its elements, and Section 6 describes the elements in more detail. Appendix G provides examples of how the framework could be applied.

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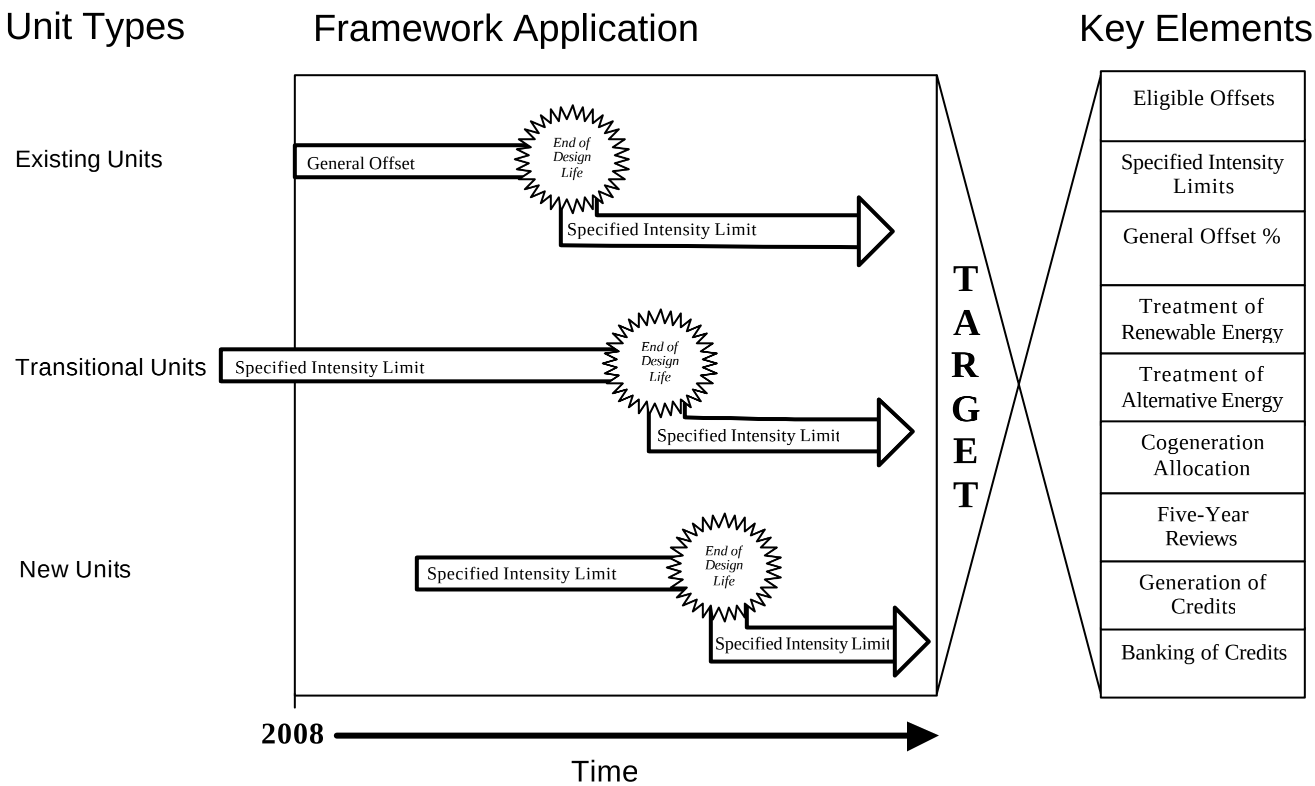
[15] The notional provincial target is described in Section 4.2

[16] The "Unit Age" component embeds the concept of Design Life, which was an important element of the Electricity Project Team's management framework. The Design Life of a unit generally refers to the time period that would allow a reasonable economic return on investment, after which the unit would be expected to meet emission or intensity limits of the day or shut down. Design Life is defined precisely in the context of this report in Appendix C.

[17] See Appendix D.

Figure 3: Conceptual Framework for Managing Greenhouse Gases from Alberta's Electricity Sector



5.1 The Unit Age Component

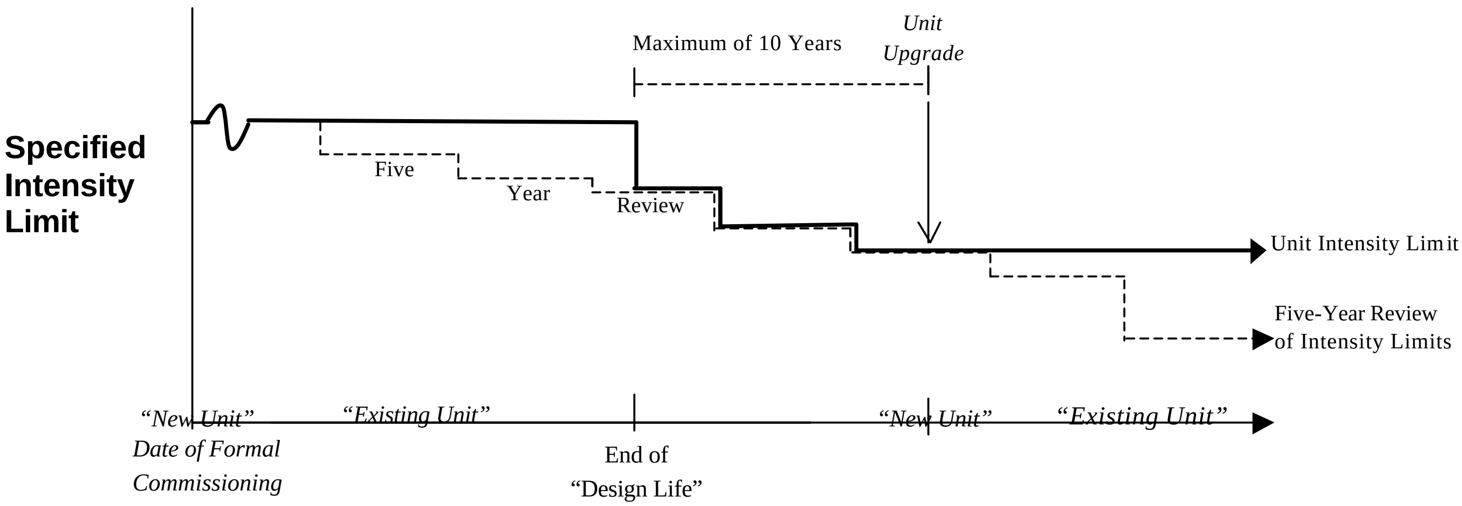
The Unit Age component of the conceptual framework applies to all new thermal units at the start of commercial operation, to thermal units at the end of their Design Life, and to transition coal-fired units. Consistent with existing provincial policy for coal-fired units, the Unit Age component of this framework applies immediately to new and transition coal-fired units. For new gas-fired units and for units at the end of their Design Life, the Unit Age component would be effective January 1, 2008.[18] The subgroup recognizes that this effective date is two years later[19] than that recommended for NO_x, SO_2, mercury and PM in the report of the Electricity Project Team but does not believe this would create any difficulties in implementing either framework. The Unit Age component requires a full offset to specified intensity limits for affected units.

As proposed in the EPT framework for other substances, the specified intensity limits would be reviewed every five years, beginning in 2008. New and transitional coal-fired units, new gas-fired units, and all other new units would not be affected by the new intensity limits until they reach the end of Design Life. It is recognized that future national or international greenhouse gas reduction commitments could result in additional management obligations. At the end of Design Life, all units would be required to meet the updated intensity limits as determined by the most recent Five-Year Review.

[18] The Unit Age component could come into effect sooner than January 1, 2008 for gas-fired units at the end of their Design Life; this detail has not been finalized.
[19] This time frame was chosen because it aligns with the first federal Kyoto commitment period.

Figure 4 illustrates how revisions to the intensity limit would be applied to a generic generation unit.

Figure 4: Application of Intensity Limit Revisions to a Generic Unit



5.2 The General Offset Component

The General Offset component of the conceptual framework would apply to all existing thermal units and would come into effect on January 1, 2008. All affected units except those whose emissions intensities are below their specified intensity limits would be required to reduce their emissions intensity by between 0 and 15%, with this percentage yet to be determined. The specified intensity limit would act as a floor so no unit would be required to go beyond that floor intensity level. The subgroup also explored the application of a benchmark approach, further details of which are provided in Section 6.2.3.

At the present time, all generation units in the province are affected by this component with the exception of Genesee 3. The percentage reduction required would be subject to a Five-Year Review (see Section 5.7).

Table 1 summarizes the application of the conceptual framework components to thermal generation units in Alberta.

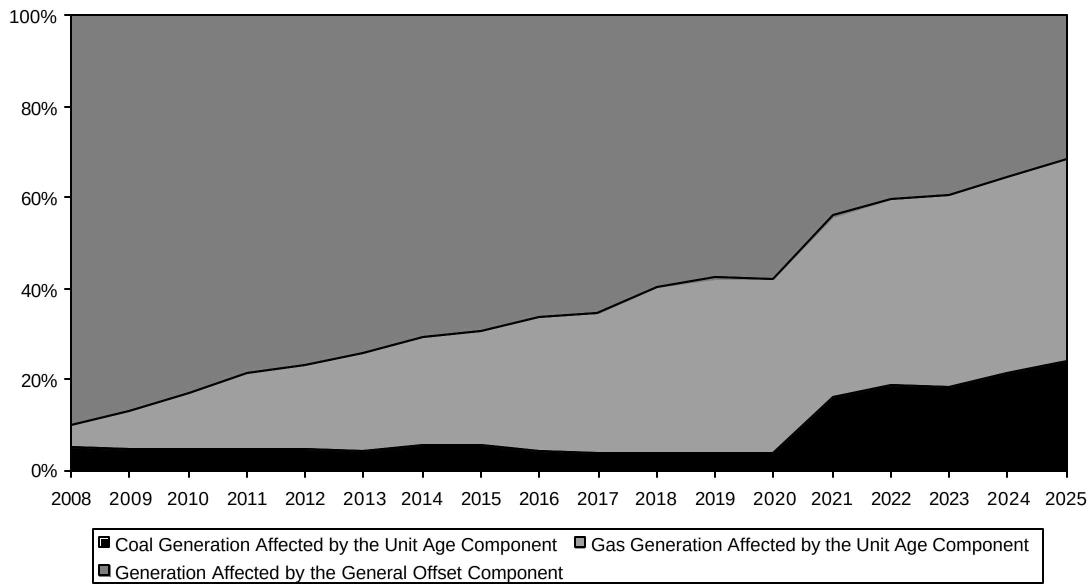
Table 1: Application of the Conceptual Greenhouse Gas Management Framework Components to Thermal Generation Units in Alberta [a]

	Unit Age Component				General Offset Component
Framework Component	**New and transition coal-fired units**	**Coal-fired units at end of Design Life** [b]	**New gas-fired and all other units** [c]	**Gas-fired and all other units at end of Design Life** [c]	**Existing thermal units**
Effective date for policy	In place	As in EPT Recommendation #25	January 1, 2008 OR earlier [d]	January 1, 2008 OR earlier [d]	January 1, 2008
Effective date for compliance for units	At start of commercial operation	Immediately after reaching end of Design Life	At start of commercial operation	Immediately after reaching end of Design Life	January 1, 2008
Intensity limit [e]	0.418 t/MWh[f]	0.418 t/MWh	0.375 t/MWh	0.375 t/MWh	Must reduce GHG emission intensity by 0-15% [g]
Impact of Five-Year Review	Not affected until reach end of Design Life	Updated intensity standards applied in subsequent five year period	Not affected until reach end of Design Life	Updated intensity standards applied in subsequent five year period	New offset percentage will be applied in subsequent five-year period

[a] The numerical values in this table must be finalized and are subject to agreement on the whole package.
[b] The same requirements apply to non-gas-fired cogeneration units.
[c] "All other units" refers to all thermal units not specifically addressed in this table or its footnotes.
[d] Effective date could be before January 1, 2008; this aspect has not yet been finalized.
[e] The numbers in this row were used in the calculations and modeling by the subgroup.
[f] Depending on offset eligibility
[g] However, no reductions would be required below a "floor" that is consistent with the specified intensity limits for coal or gas.

Figure 5 shows the percentage of generating units captured under each component of the framework over time.

Figure 5 Percentage of Generation Affected by the General Offset and Unit Age Components Over Time



5.3 Eligible Offsets

Offsets are a critical part of achieving compliance with the framework. Until 2008, Alberta's Transition Principles define how offsets will be applied for transitional coal-fired units and what offsets can be used to meet the 0.418 t/MWh intensity requirement; the subgroup did not reach agreement on eligible offsets that would apply after 2008.

Those in favour of a wider range of eligible offsets and credits believe the GHG management framework should provide incentives for industry to take actions that contribute to the public policy objective of reducing the overall intensity of the electricity sector in both the short and long term. The subgroup discussed a range of eligible offsets that included all credits that qualify under federal regulations, as well as credits for early shutdown (effective January 1, 2008), credits for renewable and alternative energy generation, and technology investment credits described in this report. However, there were differing views on both the definition and consequent eligibility of these last three options. The issue of eligible offsets is a key aspect of the conceptual framework. The range of offsets discussed by the subgroup does not preclude future consideration of other offsets that meet the criteria described in Table 2 (Section 6.3.1).

5.4 Renewable and Alternative Energy

The subgroup recognized the role that renewable and alternative (R&A) energy generation could play in the conceptual framework by reducing the overall intensity of the electric power generation (EPG) sector. There were, however, strong and divergent views about whether R&A should be covered under the framework as part of the EPG sector or whether they should be excluded from the calculation of sectoral intensity. This decision would affect both the level of reduction required by thermal units as well as the economics of R&A generation. The subgroup felt it did not have sufficient information about the linkages between offsets, credits, allowances and other mechanisms to thoroughly consider the advantages and disadvantages of including R&A. There were also differing views on the treatment of R&A in the context of federal plans for targeted measures.

5.5 Credits for Performance Below Intensity Limits

The subgroup was unable to agree on whether credits would be provided under the framework for those emitters performing below specified intensity limits, or below a deemed credit threshold, as applicable. Credits are also an important issue for cogeneration as this could affect how emissions are allocated between electricity and the heat host.

5.6 Cogeneration

The subgroup agreed in principle to include the electricity output-related emissions from cogeneration units within the electricity sector subject to the details of the full framework. A number of allocation methodologies to divide the emissions between the electricity sector and the heat host sector were examined. The subgroup reached agreement in principle on a methodology that proportionately divides the emissions from natural gas-fired cogeneration units using reference efficiencies of a stand-alone electricity generation unit and a stand-alone steam boiler unit. The subgroup was unable to reach agreement on whether credits would be provided to cogeneration units with emissions intensity, calculated using the agreed methodology, below the specified intensity limit for gas units. Consequently, a consensus recommendation for the allocation of emissions cannot be made until the credit issue is resolved.

The allocation of emissions from cogeneration units that are fired by fuels other than natural gas would be determined on a unit-by-unit basis and, where appropriate, would be consistent with the principles used for allocating emissions of a conventional natural gas-fired cogeneration. The EPT's recommendations for SO_2 and NO_x for non-natural gas fired cogeneration would continue to apply.

5.7 Five-Year Review

The subgroup agreed that, at minimum, specified intensity limits and the general offset percentage reduction should be subject to a five-year review cycle. It further recognized the benefits of synchronizing review of the GHG framework with the Five-Year Reviews prescribed by the EPT beginning in 2008, as this provides greater certainty to industry for investment and planning purposes. However, it also recognized that future national or international GHG reduction commitments by Canada could result in the need for additional GHG management obligations. These external drivers could require review of all or part of the GHG framework at a different time interval, separate from the larger EPT Five-Year Review. National and international policy drivers should also be taken into consideration when establishing the effective dates for any required revisions to the framework elements. See Section 6.2.4 for more details on the Five-Year Review.

6 Elements of the Framework

This section provides additional details on key elements of the conceptual framework. It is divided into five main sections, which describe the elements in more detail:

6.1 – Definition of new, existing and transitional units

6.2 – Framework elements

6.3 – Compliance tools

6.4 – Treatment of emissions from cogeneration

6.5 – Special issues related to renewable and alternative energy

For some of the detailed elements, several options or approaches were considered. Where the subgroup was unable to converge on a single option or approach, the range is described along with the pros and cons of each.

6.1 Definitions of New, Existing and Transitional Units

Coal-Fired Units

The subgroup used the EPT's definitions of new, existing and transitional units for coal-fired units (see Appendix C).

Gas-Fired Units

Some key differences between the province's gas fleet and coal fleet led some stakeholders to examine whether the EPT's definitions of "new units" and "existing units" should apply to gas-fired units for greenhouse gas management purposes. Specifically, there were concerns that the use of these definitions with the proposed conceptual framework would create an arbitrary split between similarly performing gas-fired units built since 1997. This could result in some units being classified as existing and subject to a general offset, and other, similar-performing units being classified as new and subject to a specified intensity limit for their Design Life. One option is to use January 1, 2008 as the start date for new gas-fired units, while continuing to apply the EPT's definitions of existing and new units.

Cogeneration Units Fired by Other Fuels

Application of definitions for new and existing units was not discussed for cogeneration units fired by other fuels. It was suggested that the Design Life for these units should be considered on case-by-case basis.

6.2 Framework Elements

6.2.1 Targets

General

The Unit Age component of the conceptual framework provides increasing reductions in emissions intensity over time as existing units reach the end of their design lives and become subject to new intensity limits. The General Offset component provides for additional reductions from existing units sufficient to reach a particular target.

The subgroup was unable to reach agreement on 2010 targets, however, it recognized that general offset reduction levels should be informed primarily by an intensity target, and secondarily by actual volumes of emissions. Stakeholders discussed a range of general offset levels from 0% (no general offset) to 15%.

The subgroup recognized that there is an upper limit or “breaking point” for the level of general offset where the conceptual framework can no longer be supported by all stakeholders. Under such circumstances, the preferred approach for some stakeholders would be to impose a general offset on all units and drop the Unit Age component.

The subgroup noted that a timing issue arises with respect to the December 31, 2020 date for achieving the provincial intensity target and the year following the expiry of the PPAs (2021), after which the affected units would be required to offset to the specified intensity limits of the day. With the Unit Age component alone, the timing of PPA expiry results in the Alberta EPG sector being unable to meet any provincial target before December 31, 2020. However, adjustments in the specified intensity limits over time may result in the achievement of the provincial target in the 2021 timeframe and beyond (e.g., lowering the coal-fired Unit Age offset requirement from 0.418 t/MWh to 0.25 t/MWh).

Range of General Offset Levels

The subgroup considered a range of general offset levels from 0% to 15%.

Stakeholders supporting the upper end (i.e., 10-15%) are of the opinion that:

- This level comes closest to achieving the current federal large final emitters (LFE) policy scenario for meeting Canada’s Kyoto Protocol commitments. This is understood as the Alberta EPG sector meeting a *pro-rata* share of the 55 Mt LFE target through a 15% reduction in 2010 BAU intensity and would consist of meeting a 2010 intensity target of 0.691 t/MWh (for thermal only) or 0.667 t/MWh (if based on total sectoral intensity where renewable energy is included)
- The federal government has signaled that it will limit LFE liability for increases in production (i.e., absolute emissions) and that it would limit the cost of purchasing offsets to $15/tonne. Accordingly, any target that is less stringent than the federal intensity target would represent a further transfer of liability from LFEs to taxpayers.

Stakeholders supporting a 0% general offset are of the opinion that:

- At this level, there is less likelihood that PPA change-in-law provisions would be challenged

- An offset of 0% supports a capital stock turnover approach and is therefore the lowest cost approach for meeting provincial targets by 2021
- The costs of GHG offsets are uncertain and the real costs of reductions are not yet well understood. There would be more comfort if a monetary cap were in place
- An interim 2010 target is not needed
- If companies are required to spend money on offsets, it will take away investment opportunities from other things like clean technology investments
- Concerns exist about the unknown cumulative cost of the EPT framework and the GHG conceptual framework.

Stakeholders supporting the middle range are of the opinion that:

- This is a reasonable compromise between competing views
- A credible negotiating package is needed to have reasonable success in creating an Alberta alternative to a federal plan
- The offset needs to be less than 15% because of the impact of the Unit Age component on coal-fired units
- The cost impact to the PPAs would be more manageable in the middle range than the upper limit
- It is the lowest cost option, which is especially important for companies that have operations across Canada and who could be affected by equivalency agreements in various provinces
- This range would provide some GHG reductions from existing thermal units.

6.2.2 Unit Age Elements

Units Affected

The GHG subgroup acknowledges that Alberta's Transition Principles are already in place for new coal-fired units and that the EPT has recommended that the current NGCC requirement be applied to existing units when they reach the end of Design Life. The options discussed in this section are fully compatible with that policy and recommendation and should be considered in light of the definitions provided in Section 6.1. This approach applies to all coal-fired, gas-fired and other thermal generation units, with different requirements for each category.

Formal Commissioning Date

The subgroup agreed that the formal commissioning date should be the month that commercial operations began, if this date is known, based on the EUB's 30-day notice procedures for new units going into commercial operations. If this date is unknown, the date should be December 31 of the year in which the unit began commercial operations.

Design Life

The subgroup agreed to adopt the EPT's definitions of Design Life for coal-fired, natural gas-fired and peaking gas-fired units. It also discussed the treatment of other thermal units such as non-gas-fired cogeneration, cogeneration units producing products in addition to useful heat and electricity, and waste heat recovery, recognizing that, precluding any other options, these types of units may most effectively be dealt with on a case-by-case basis.

Specified Intensity Limits

Alberta requires new coal-fired units to reduce or offset their greenhouse gas emissions intensity to 0.418 tonnes of CO_2 equivalent per megawatt-hour. This number represents the full fuel cycle emissions for a NGCC unit and is the sum of the burner tip intensity of a new NGCC unit (0.375 t/MWh) plus all associated upstream production emissions for the fuel. The group discussed non natural gas-fired cogeneration as being treated in the same manner as coal-fired generation because there are no upstream emissions that need to be accounted for, as there are with gas. This intensity level is in effect now for coal-fired units and will be required at least until the end of 2010.

The subgroup focused its discussions on an intensity limit of 0.375 t/MWh for all gas-fired units and other units such as waste heat recovery, but this does not preclude a different intensity limit being considered in future discussions.

Election for Existing Gas Units

If credits are available to units performing below the specified intensity limits (see Section 6.2.5), it was proposed that existing thermal units be provided with a one-time election to be subject to the Unit Age component of the GHG management framework instead of the General Offset component. Units that make this election could choose one of two options.

Under option one, they would forego credits and "lock in" their existing intensity limits for the remainder of their Design Life. Under option two, they would receive credits for performance below the intensity limits, but would be subject to new intensity limits every five years according to the outcomes of the Five-Year Reviews. The intent of this option is to provide an opportunity for top performing existing units to earn credits, should credits be available under the framework.

6.2.3 General Offsets Elements

Type of General Offset

The subgroup recognized that application of the Unit Age component alone would not reach the federal greenhouse gas reduction objectives. Some members of the subgroup do not support obligations beyond the Unit Age component. Others view additional reductions as required in the form of a partial offset applied to existing units before the end of their Design Lives. This approach requires a percentage reduction from a unit's actual intensity, toward but not below the intensity limit that applies to existing units of that generation type. Thus, natural gas-fired units below the specified intensity limit for gas-fired units would not have an offset requirement. If credits are agreed to, consideration should be given to providing credits for these units (see Section 6.2.5).

The subgroup also considered a variation on this general offset under which the percentage offset applied would be the difference between actual emissions and a unit's specified intensity limit. This variation would require proportionately larger reductions from the highest emitting units and proportionately smaller reductions from the cleanest units.

Affected Units

The general offset would apply to existing units until the end of their Design Lives.

Timing

A general offset reduction requirement would begin January 1, 2008 to coordinate with the first federal commitment period.

Application of a "Floor"

The "floor" would be equivalent to the specified intensity limit for coal- or gas-fired generation or other, as applicable, below which a reduction would not be required. The floor would benefit units operating below the benchmark and would reduce the percentage offset requirement for units operating close to but above the floor. It was recognized that creating a floor would exempt lower-emitting gas-fired units that are already emitting at intensities well below the provincial sectoral average, while shifting a small additional burden to those gas- and coal-fired units that are emitting above the specified intensity limits.

6.2.4 Five-Year Review

The EPT recommended that various components of its framework for managing priority substances be reviewed on a regular basis using a multi-stakeholder process (Recommendation 29). Technology advancements may well result in cost-effective opportunities to reduce intensity limits and these improvements should be assessed and incorporated as appropriate. It was also recognized that future national or international GHG reduction commitments by Canada could result in the need for additional GHG management obligations, resulting in the need for more stringent intensity limits and general offset requirements. For this reason, the subgroup agreed that the following elements of the framework should be part of the EPT's Five-Year Review process beginning in 2008:

- Specified intensity limits for the Unit Age component and floor
- Percentage reduction used for the general offsets
- Renewable intensity limits (if applicable)

To stay aligned with the current timetables for the EPT's Five-Year Review, any changes to specified intensity limits arising from the first Five-Year Review would come into effect on January 1, 2011, or, to coincide with the federal commitment periods, on January 1, 2013. The appropriate timing requires additional discussion.

Consideration was given to having revisions to the general offset percentage reduction and floor intensity limits become effective in 2013, recognizing that this effective date may more appropriately be supported by a special review on these two issues in 2011. Additional discussion is suggested on this point.

For investment and planning purposes, it is desirable to synchronize review of the GHG framework elements with the other elements of the EPT's Five-Year Review. However, because of international and federal policy drivers it may be necessary to review some or all of these GHG framework elements on a different timetable.

Notwithstanding the review provisions already described, all additional elements of the GHG framework subject to the Five-Year Review still need to be identified and agreed upon.

6.2.5 Credit for Performance Below Intensity Limits

The subgroup discussed in detail the reasons for and against providing credits for units operating below specified intensity limits, and was unable to resolve this issue. A number of issues need to be resolved before agreement on credits can be reached:

Reasons for having credits:

- Provides an economic driver within this framework and a policy signal to reduce GHGs and provide an incentive for cleaner generation.
- Rewards most efficient, lower emitting performers.

Reasons not to have credits:

- Because credits generated within the electricity sector are a "zero sum game," providing credits to some units puts a greater reduction burden onto existing units operating above their intensity limits.
- Fuel price is the overwhelming economic consideration for gas-fired generation. This creates a built-in driver to minimize emissions and renders the provision of credits a minor factor influencing investment decisions.
- The intent is to have a framework that is as fuel neutral as possible.

The issue of credits is important to stakeholders with efficient cogeneration units who face GHG reduction targets on both the electricity output and the industrial output. In the absence of credits, cogeneration units operating below the specified intensity limit are unable to transfer the benefits to the industrial site. It was suggested that without credits the deemed allocation methodology could be revised to establish the calculated intensity at a level equal to the specified intensity limit to maximize the benefit.

Deemed Credit Threshold

Recognizing the desirability of encouraging very clean generation, an alternative approach was suggested whereby a deemed credits threshold of 0.21 t/MWh would be established so that very clean thermal generation would get credits. Those units operating between 0.21 t/MWh and 0.375 t/MWh would get no credit and those below 0.21 t/MWh would. This concept requires additional discussion.

6.3 Compliance Tools

Electricity generators can achieve reductions in GHG emissions intensity via internal efficiency improvements and acquisition of offsets. Since internal efficiency improvements alone may not be sufficient to meet reduction requirements, the definition of eligible offsets is therefore a critical component of the overall GHG management framework and of any subsequent agreement on targets, as it will directly affect the cost of GHG reductions. The subgroup also discussed some special issues related to accounting and banking of offsets; these are summarized in Section 6.3.2.

6.3.1 Eligible Offset Credits

General

The subgroup discussed the following categories of offset credits:

- All credits qualifying under current and future federal policies
- Credits for early shutdown of units
- Credits for renewable generation
- Credits for alternative generation
- Credits for qualifying technology investment
- Credits for conservation/energy efficiency
- Credit for early action

Widely accepted principles for offset eligibility are outlined in Table 2.

Table 2: Principles for Offsets Eligibility

Real	• Offsets must be real and demonstrable action that results in the reduction of greenhouse gas emissions to the atmosphere, net of any leakage
Measurable	• Offsets must be measurable against a baseline using transparent and replicable calculation methodologies.
Verifiable	• Offsets used for compliance against a unit's reduction obligation must be verified by a qualified independent third-party auditor.
No double counting	• A particular offset can only be used once to meet a reduction requirement. • A particular offset can only be used by one party. • Joint owners may share an offset and use each portion uniquely. • A particular offset may be used to meet requirements of multiple jurisdictions as long as it is used against the same unit in each jurisdiction.
Clear Ownership	• A particular offset must be owned by the party claiming the benefit.
Banking	• A particular offset established in a year may be banked for use in subsequent years.[20]
Surplus	• Offsets eligible for use as a compliance instrument must be a result of action that was not otherwise required by law at the time the action was initiated.[21]

The Transition Principles in Appendix D include emission reduction equivalencies that do not necessarily meet all the requirements of Table 2, specifically: technology investment credits and credits for renewable and alternative generation, depending on the criteria for the latter. In this

[20] There may be constraints on the eligibility period for which offsets may be banked.
[21] It is further recognized that the issue of financial additionality is to be resolved in another forum.

report, these emission reduction equivalencies are encompassed under the general term "offset equivalencies".

The subgroup reviewed offset equivalencies that are included in the province's Transition Principles but are outside those currently recognized as eligible by the federal government. Those in favour of giving credits for these offset equivalencies believe the GHG management framework should provide incentives for industry to take actions that reduce real net greenhouse gases in the atmosphere and thus contribute to the public policy objective of reducing the overall intensity of the electricity sector in both the short and long term. Including them in the management framework has several potential impacts that must be considered and resolved:

- The contributions of offset credits acquired for compliance with Alberta's 0.418 t/MWh requirement for transition coal-fired units has been included in the sector's reduction contribution. If the offset equivalencies eligible under Alberta's Transition Principles are not counted toward a federal target, it would require additional contributions from the sector to make up the shortfall. This would have a significant impact on the conceptual framework and some stakeholders may no longer support it
- If two separate offset systems are established, then there is a need to resolve how Alberta "carbon currency" will operate within and be fungible[22] within a larger national offset and trading regime
- Given that allocation of some of these offset credits may not result in emission reductions within the 2008-2012 period, there is a concern about transfer of liability to taxpayers for the provision of incremental offset credits in order to deliver the required emission reductions
- The framework design was, in part, premised on offset costs that are manageable. If offset costs are higher than those envisioned by some stakeholders, their support for the framework would be withdrawn.

As a result, there was considerable discussion on the appropriate criteria for certain offset equivalencies. In addition, while an option for credits for renewable and alternative energy is discussed in this section, the unique issues associated with the treatment of renewable and alternative energy as part of or outside of the sector are considered separately in Section 6.5. The subgroup also noted that nothing in the conceptual framework precludes other offsets that meet the criteria described in Table 2.

Credits for Early Shutdown

The subgroup considered credits for early shutdown as set out in the Transition Principles and in EPT recommendation #26, and generally supported including this category of offset equivalencies, subject to: a) changing the effective date in EPT Recommendation #26 from January 1, 2006 to January 1, 2008 to avoid overlap with the province's Transition Principles and to harmonize with the first federal commitment period, and b) amending the Transition Principles to include early shutdown of gas-fired units as well as coal-fired units, to be consistent with EPT's recommendation #26. Another approach discussed by the subgroup would hold that the Transition Principles prevail in the event of a conflict with the EPT's recommendations. It was noted that providing credits for early shutdown may create an incentive for peaking gas-fired units to shut down early, which may not be in the interests of the overall sector.

[22] "Fungible" means "precisely or acceptably replacing or replaceable by another item; mutually interchangeable." (source: *The Canadian Oxford Dictionary*, 1998)

Technology Investment

Technology investments credits (TICs) were viewed as a necessary component of Alberta's GHG management framework, recognizing the importance of supporting domestic efforts to develop cleaner generation technologies. A general conceptual approach to technology investment credits was developed by the subgroup:

> TICs can be created through two mechanisms: 1) payment into a specified public fund for a technology development purpose, or 2) through direct qualifying investment. Investments under either mechanism should meet the following criteria to qualify:

1. Investment must be applied to basic or pre-commercial research, development, and demonstration projects that, if successful, will reduce greenhouse gas emissions or intensity.
2. Investments must be consistent with recognized Canadian research strategies (e.g., the Alberta Energy Research Institute's Strategy) in support of Alberta's climate change action plan *Taking Action*.
3. Ongoing, business as usual efforts to improve greenhouse gas emissions performance do not qualify.
4. Qualifying investments must give up any intellectual property rights that may arise from the work, and all results must be freely available for use in Canada.

Time constraints prevented the group from addressing many of the key details associated with the creation of TICs. Key factors to be considered in the development of a more comprehensive approach are summarized below:

- A pricing mechanism is needed to specify the amount of offset credit earned in relation to the amount of qualifying technology investment
- The pricing mechanisms considered included: (1) a fixed price relationship (e.g., $15 in investment earns a one-tonne GHG credit); (2) a variable price relationship indexed to the prevailing international carbon price; and (3) an auction system where companies would bid competitively for a fixed amount of credits made available by government
- The creation of eligible credits will require a governance and accountability system
- Consideration should be given to designing a system that drives successful projects that lead to real offsets, recognizing that the risk threshold for success may be higher in a Kyoto world. Two opposing views arose on the issue of liability for unsuccessful projects, one in favour of using it as a driver for quality projects and one against because technology development is, by nature, speculative and should not be tied to firm outcomes
- Companies receiving TICs will buy fewer other offsets to comply with their LFE targets. In a strict Kyoto world, this will result in the federal government having a corresponding liability to buy foreign credits, if the reductions for which TICs are given are not achieved in the 2008-2012 timeframe. The investments in technology may result in reductions in later periods, but these reductions do not help Canada comply with its 2008-2012 Kyoto target
- How and when successful technology development is factored into revisions to intensity limits for applicable units
- Double counting issues may arise from qualifying technology investment credits being counted under the federal government's targeted measures programs.

Electrical Energy Efficiency and Conservation

The subgroup recognized the important role of electrical energy efficiency and conservation in reducing greenhouse gas emissions, particularly the potential role that the LFE sector could play. A draft proposal for integrating electricity consumption by LFEs into intensity targets was presented to the subgroup, but time constraints prevented a thorough consideration of the proposal, which is included in Appendix E as input to future discussions. It was also noted that electrical energy efficiency and conservation activities are not restricted to the LFE sector and could include a wide variety of demand side management programs.

Renewable and Alternative Generation

While all subgroup stakeholders support the development of more renewable and alternative (R&A) generation to meet a provincial target of 3.5% renewable and alternative generation, a commonly supported approach to R&A credits proved elusive at this time. It was the view of many in the group that agreement on a common approach could be achieved if the framework elements are resolved.

Two general options for credits were considered. One option creates permits or credits for renewables and alternatives inside the electricity sector, the other enables renewables and alternatives to generate credits outside of the sector. These are described in greater detail below. Key issues and considerations in the group's discussions were:

1. The definition of renewables and alternatives
2. Federal incentives and permits and the need to reconcile these options with the federal plan for targeted measures
3. The level of incentive or credit required to support development of more renewable and alternative generation
4. EPT Recommendation #28 on Green Tag credits for Renewable Energy
5. The approach to renewables set out in Alberta's Transition Principles
6. If renewables and alternatives are allocated credits or permits inside the system, it can create a corresponding burden on the remaining emitters (i.e., a zero sum game). This creates an upper end on the intensity at which credits are provided
7. Current federal directions and options
8. Leakage issues.[23]

Definition of Renewable and Alternative Energy

Two options were considered for the definition of renewables, the first being application of EPT Recommendation #57 on the definition of renewables and alternatives. On the basis that EPT Recommendation #57 was too broad and general for the purposes of crediting renewables, a second option was proposed whereby eligible renewable energy would be EcoLogo™ compatible, generated in Alberta, and have demonstrated clear ownership of the reductions. It also required proof that the proposed energy has not been financed by federal funds, including energy funded under the WPPI program. The definition of alternative energy was also considered. This definition

[23] The concept of leakage generally refers to the allocation of emission offset credits to energy that does not result in the reduction of domestic emissions. For example, increased investments in renewable and alternative energy might displace imports of electricity from the United States with no domestic reduction in emissions. Alternatively, investments in clean energy might result in increased exports, again with no resulting domestic emission reduction.

was based on Recommendation #57 and the proposed recommendation for energy recovered from a process stream (a source of alternative energy only partially captured in Recommendation #57). The subgroup was not able to discuss these definitions in any depth due to time and information constraints, and suggests that progress could occur with additional time.

Greenhouse Gas Credit for Renewable and Alternative Energy

Two options were considered for the treatment of offset credits for renewable and alternative energy. Resolution of this aspect of the framework largely depends on two things: a) greater certainty about federal treatment of renewable and alternative energy and corresponding linkage with its LFE policies, and b) the ability of renewable and alternative generators to rely on more than one form of incentive.

Option 1 – Renewable and Alternative Energy Included in the Electricity GHG Framework

Under this option, electricity generated by renewable and alternative energy would be allocated greenhouse gas permits and its generation would be included in the EPG sector's intensity calculation. The subgroup discussed a range of 0.0-0.691 t/MWh as a rate for allocating permits to renewable and alternative energy. Depending on the conversion rate of permits and the generation displaced, the inclusion of renewable and alternative energy has different effects on the overall sector intensity and therefore on individual unit obligations.

Option 2 – Renewable and Alternative Energy Excluded from the Electricity GHG Framework

Under this option, the conceptual framework would not include power from renewable and alternative energy and its generation would therefore not be included in the sector's intensity calculation. This would allow renewable and alternative energy to seek greenhouse gas credits through other avenues and would mitigate the need to reconcile issues around ownership of greenhouse gas credits, targeted measures, and determination of displaced generation.

Special Issues Related to Renewable and Alternative Generation

Currently, renewable and alternative electricity is a more expensive form of generation and must rely on the value of "green" attributes to make projects economic. In the absence of a formal emissions trading regime, renewable generators are using bilateral contracts to capture the value of those attributes and further their projects. For renewable and alternative electricity an assignment of a low intensity calculation potentially represents a dilution in value of those green attributes. Any dilution in value furthers the reliance on government incentives and programs to make renewable and alternative electricity projects economic. There is a concern that permitting renewable and alternative electricity within the sector framework is premature because it may foreclose other options, incentives or programs or competitive market forces that would effectively support the development of renewable and alternative generation. The subgroup generally recognized that a permit for renewable and alternative energy does not provide sufficient incentive for renewable and alternative electricity development and was supportive of additional options being considered.

6.3.2 Accounting and Banking of Credits

Accounting and banking of credits are aspects of the framework that the subgroup did not discuss in any detail and require additional consideration in future discussions. Nonetheless, some options were proposed, and are described below.

Transitional Unit Offsets (2005-2007)

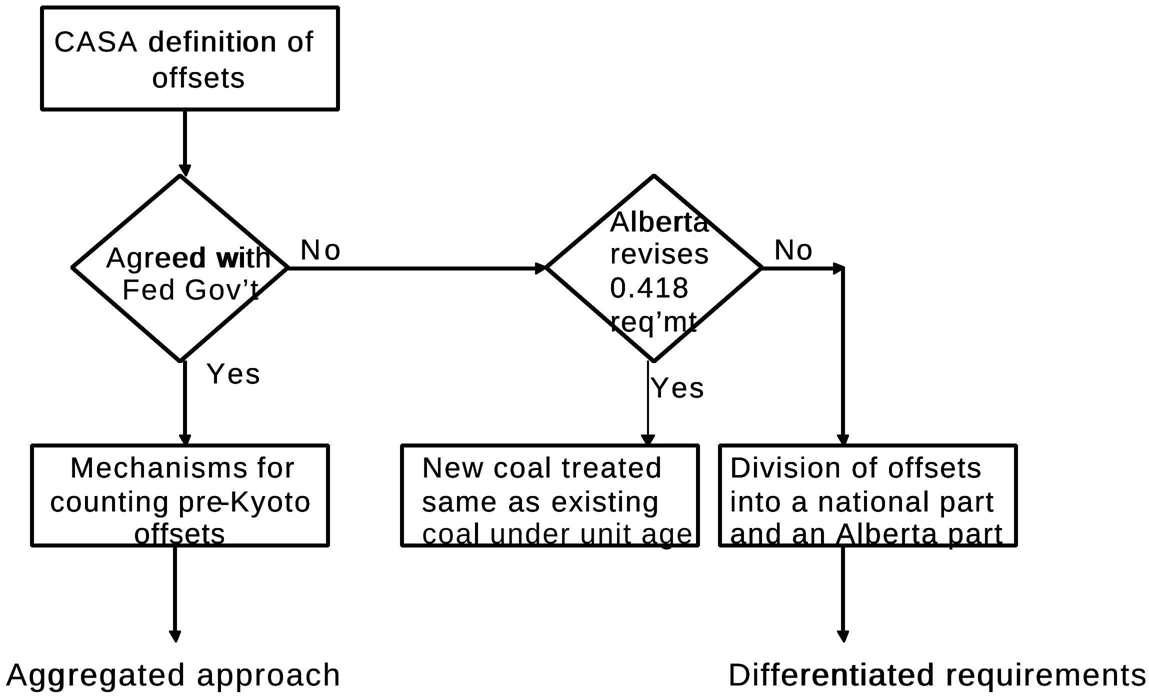
The subgroup addressed accounting of NGCC offsets acquired by transition units in 2005-2007, prior to the first federal commitment period, noting the potential incompatibility between the conceptual framework and Alberta's Transition Principles in terms of how offsets are defined and the years in which they are eligible. The subgroup also noted that without some alteration, Alberta may not be able to count transition unit NGCC offsets for federal purposes because the federal government currently intends to recognize only reductions made during the first Kyoto period. Another concern related to the how the NGCC offsets would be treated after 2012.

Thus, in contemplating an Alberta GHG management system and associated negotiations with the federal government on its equivalency, certain issues arise related to timing and offset obligations for transitional units:

- The federal government policy directions to date have not recognized emission reductions made before 2008 for application within the first federal commitment period
- The Alberta requirement for 0.418 t/MWh is earlier and deeper than any expected from the federal government
- Whether the offsets required for transitional units down to 0.418 t/MWh would be counted as fully contributing to Alberta's reductions in the Kyoto period
- Whether the Alberta definition of qualifying offsets will be used for these and other obligations.

The linkages between the application of 2005-2007 NGCC offsets to the 2008-2012 period and what will be agreed as the definition of eligible offsets as between Alberta and the federal government are critical. This is a two-part question, illustrated in Figure 6 below. Part one is "Can an Alberta definition of offsets be negotiated with the federal government as part of Alberta's equivalency plan during the Kyoto period?" Depending on the answer, one of two options would be preferred.

Figure 6: Options for Accounting for NGCC Offsets Acquired by Transitional Units, 2005-2007



The contribution of Genesee 3 to reductions in the electricity sector is approximately 1.5 Mt per year, this is the reduction achieved if the unit offsets its emissions from its actual intensity to 0.418 t/MWh in any given year. If the reduction obligation of Genesee 3 for the years 2005-2007 is applied over the 2008-2012 period, three years of offsets equal to 4.5 Mt will be spread over the 2008-2012 five-year period, this will result in an additional reduction from that unit of 0.9 Mt per year in this period, for a total reduction of 2.4 Mt per year over the 2008-2012 period

Assuming that Alberta and the federal government agree on a definition of qualifying offsets, several options for counting 2005-2007 offsets were considered. It was suggested that one of two approaches be used:

1. The first would aggregate transitional unit offsets until 2008. Under this option, transition units would acquire offsets from 2005 onward and report progress to the Alberta government, but the tonnes would not be formally verified and delivered until 2008. Thus it would be more consistent with the federal Kyoto timeframe. Benefits are as follows:
   - Pre-Kyoto environmental action is recognized
   - There is no diminishing of environmental benefit from current commitments
   - Alberta's 0.418 t/MWh policy is effectively in place from 2005 on
   - It is least disruptive to Alberta's 0.418 t/MWh policy.
2. The second approach is that pre-2008 offset credits could be used dually – to meet both the Alberta 0.418 t/MWh intensity requirement as well as being eligible in the post-2008

period without being double counted. This is consistent with the basic principles of offset eligibility outlined in Section 6.3.1.

If no agreement occurs with the federal government, then the preferred avenue is a differentiated requirement described below.

Transition units would have an Alberta requirement of 0.418 t/MWh beginning in 2005 until the end of 2007, with offsets defined by the Transition Principles. In the Kyoto period, there would be two components:

1. The transition units would then be treated as any other unit captured under the General Offset component – that is, subject to a certain percentage reduction, with offsets eligibility defined as appropriate. These reductions would count against Alberta's Kyoto period contribution.
2. In addition, in order to achieve the Alberta-only requirement down to 0.418 t/MWh, additional offsets would be required. This incremental amount would be entirely subject to Alberta's definition of offsets, and would not count against the Alberta contribution during the Kyoto period.

Banking of Credits

The proposal discussed by the group stated that all credits may be used in the year they are earned or banked for subsequent use. Concerns were raised about banking of pre-2008 offsets as these may not meet the federal government's eligibility criteria.

There is also a concern about the use of 2008-2012 credits after 2012. The Kyoto Protocol at present does not allow for the use of offsets and credits that are generated outside of the Kyoto timeframe (2008-2012). Only credits that are Kyoto-compliant will be able to be used by the country to true up to international obligations. If international obligations are to be fulfilled and credits not recognized under the Protocol are used for compliance in Canada, then taxpayers will assume the liability for acquiring reductions that are compliant with international rules. For this reason, concern has been expressed around designing banking rules that allow the use of offset credits generated pre-2008 in the 2008-2012 period, as well as the use of credits generated in the 2008-2012 period in years after 2013.

Unit True-Up

It was recognized that a true-up mechanism may be needed to provide some flexibility for units that under- or over-achieve their reduction requirements, especially in regards to being able to carry over surplus credits into subsequent years.

6.4 Treatment of Emissions from Cogeneration

The EPT considered gas-fired cogeneration in its report and established that, at least for the purposes of NO_x management, cogeneration units should be considered part of the Alberta electricity sector. However, for GHG management, the subgroup agreed that division of emissions between electricity and thermal energy is desirable and necessary for establishing an accurate view of the emissions in the electricity sector. Agreement on a particular methodology to divide the emissions is subject to resolution of the credit issues outlined in Section 6.2.5. District energy was not discussed by the subgroup.

6.4.1 Key Considerations for Natural Gas-Fired Cogeneration

The subgroup considered the following in its analysis:

- Cogeneration units represent an efficient use of energy; therefore, emission allocation and reduction approaches should not create a disincentive for investment in or operation of cogeneration.
- The greenhouse gas intensity of electricity from natural gas cogeneration is lower than the electricity sector average. If oil sands and heavy oil development grows as expected, there is potential for an increase of electricity generation from natural gas-fired cogeneration, which would reduce the overall greenhouse gas intensity of the Alberta electricity sector.
- Various commercial arrangements exist for cogeneration units in terms of ownership operation and responsibility for emissions. To the extent practical, GHG management approaches for cogeneration units should not interfere with normal business practices and arrangements.
- Allocating cogeneration emissions between heat and electricity outputs may require the reporting of information that companies may want kept confidential, and this needs to be considered in developing management and reporting approaches for GHG emissions
- The federal government is considering similar options to manage emissions from cogeneration units. The opportunity exists to create consistency between the federal and Alberta approaches.
- GHG emissions from cogeneration units were part of the business as usual emission forecasts used by the federal government to establish its 55 Mt reduction target for large final emitters but there is uncertainty as to exactly how cogeneration units and/or cogeneration emissions were split between the electricity sector and the various heat host sectors.
- Emission allocation methodologies and reduction requirements for cogeneration units should not result in more onerous reduction obligations than those that would result from having stand-alone units producing the equivalent heat or electricity output; otherwise there is a disincentive for cogeneration units.

6.4.2 Allocation of Greenhouse Gas Emissions from Natural Gas-Fired Cogeneration

The subgroup identified and evaluated five allocation methodologies, using actual operating information from cogeneration units in Alberta. The five methodologies are:

1. Energy: simply equates Gigajoules of steam to the energy equivalent in MWh of electricity (i.e., it essentially assumes that steam can be converted to electricity at 100% efficiency).
2. Exergy: an attempt to reflect the relative work potential of the two energy streams by adjusting the work output of the steam produced on the basis of conversion factors.
3. Reference facility for steam, electricity receiving the residual emissions.
4. Component facilities: division of total cogeneration emissions between electricity and steam in proportion to the emissions from the actual facilities (often a simple cycle gas turbine and an industrial boiler) operating on a stand-alone basis. (The boiler would be assumed to burn natural gas in place of using heat recovered from the turbine exhaust.)
5. Stand-alone reference facilities: division of total cogeneration emissions between electricity and steam in proportion to the emissions from reference facilities operating on a

stand-alone basis. The subgroup tested a variety of assumptions about the efficiency of the electricity and steam reference facilities.

The subgroup concluded that method 5 (the stand-alone reference facility approach) has the widest appeal because:

- It divides the efficiency benefits of cogeneration in an even-handed way between electricity and the heat host activity.
- At the present time, this is consistent with what the federal government is proposing for Alberta.
- The reference facilities represent a plausible assumption that, in the absence of the cogeneration, the power producer would build a NGCC plant to sell to direct customers and the wholesale electricity market, and the heat host would build an industrial boiler.
- This particular method reflects the nature of most of the cogeneration industry in Alberta.

The subgroup also agreed to use this method in any subsequent analysis and target setting work.

Further analysis on the efficiency assumptions led the subgroup to conclude that total greenhouse gas emissions from natural gas combustion at cogeneration facilities should be divided based on assigning 50% efficiency to electricity based on combined cycle natural gas turbines, and on assigning 80% efficiency to heat, based on stand-alone industrial natural gas boilers. Details on the method and the formula are provided in Appendix F.

Parties to commercial agreements may negotiate alternative arrangements among themselves for respective responsibilities in relation to any GHG regulations application to cogeneration, including how to treat emissions from duct firing.

6.4.3 Treatment of Cogeneration Using Fuels other than Natural Gas

Presently, most cogeneration comes from natural gas-fired units, but other fuels are likely to be used more in the future. The allocation of greenhouse gas emissions from cogeneration units that use fuels other than natural gas (e.g., coke, hydrogen, diesel, biomass, bitumen) should be determined on a unit-by-unit basis and, where appropriate, should apply the same methodology and efficiency principles used to allocate GHG emission from natural gas-fired generation units. Furthermore, the EPT's recommendations on NO_x and SO_2 reductions for non natural gas-fired cogeneration units would continue to apply.

An immediate case is the generation units integrated with oil sands upgrading facilities. These are part of complex systems of producing process steam, hot water, and electricity and can be fired by a mixture of coke, carbon monoxide, and refinery off-gases, and are sometimes blended with natural gas. The proposed treatment of these units is:

- Emissions attributed to electricity generation are set equal to the intensity limit that applies to new coal-fired units for fuels other than natural gas and new natural gas for natural gas-fired units, with the residual attributed to the host activity (bitumen upgrading)
- The intensity limit that applies to these units after the end of Design Life is the same as what applies to coal or natural gas, depending on the fuel.

The result is that emissions in excess of the intensity limit are addressed under the target for the industrial host and there are no offset requirements for the cogeneration electricity.

7 Emissions and Intensity Modeling

7.1 Background

The Sub-Group undertook two types of analysis:

1. An analysis during the development of the framework of the effects of various policy elements on emission reductions, net emissions and sector emission intensity in the context of the Federal NRCan business as usual (BAU) forecast, focusing on 2010.
2. An analysis of the price, generation and emissions impact of the conceptual framework carried out by Energy Demand Consulting Associates Ltd (EDC Associates).

7.2 Modeling Inputs, Data Sources and Assumptions

The federal NRCan business as usual (BAU) forecast is derived from a 1999 Natural Resources Canada publication entitled *Canada's Emissions Outlook: An Update*, an update of a 1997 forecast of demand, generation and total GHG emissions associated with electricity generation in Alberta. In 2001, the 1999 *Outlook* was further updated to reflect emerging trends in generation. The total demand projection remained the same, but the emissions increased due to a shift in the fuel type of generation from gas to coal. This 2001 *Outlook* is the forecast that the federal government is using as its BAU forecast.

To effectively assess the impacts of the framework and its elements on emissions and intensities, the subgroup gathered data and made several assumptions about the electricity sector in Alberta. These inputs and assumptions were used by EDC to generate price and emissions data and they form the basis for the emissions and intensity analysis of the conceptual framework.

7.2.1 Key Data Inputs

a) Individual unit intensities for coal-fired units and non-cogeneration units were collected from individual companies, Alberta Environment and EDC Associates.

b) Sixteen existing post-1997 natural gas-fired cogeneration unit intensities were calculated using reference plant allocation methodology with efficiency factors of 50% for power and 80% for steam. Based on this data, cogeneration emitting above the specified intensity limits was entered at 0.42 t/MWh and the rest of the existing cogeneration units and generic new cogeneration units were assumed to emit at 0.32 t/MWh.

7.2.2 Key Assumptions

1. In general, coal-fired units were assumed to run to 50 years and gas-fired units to 40 years. There are several exceptions: some coal-fired units are assumed to shut down earlier in accordance with the EPT's mercury recommendations, some behind-the-fence gas-fired and other thermal units were assumed to continue operating until the end of the forecast, and some units shut down early based on EDC's economic analysis.
2. The current Unit Age policy emission limits were used across the forecast period to ensure that the emissions reductions represented a conservative (i.e., lower bound) estimate of future reductions.
3. The provincial renewable and alternative energy target was assumed to be met primarily by wind generation. The analysis assumes that 3.5% of the total power sold through the Power Pool is new renewable generation and that this proportion is held constant over the

forecast period. The target is applied to generation traded through the AESO, which does not include behind the fence generation, when judged against the total generation in the province this target is approximately equal to 2.8%.

7.2.3 The Conceptual Framework for Analysis Purposes

The following analysis examines the achievement of these targets using the conceptual framework, although there is no consensus on certain key policy parameters. For analysis purposes, the following have been assumed:

1. The Unit Age component, which requires new coal-fired units, transition coal-fired units, and coal-fired units that operate after the end of their Design Life to offset their emissions to 0.418 t/MWh. In addition, new gas-fired units, and gas-fired units that have reached the end of their Design Life achieve an intensity of 0.375 t/MWh.
2. Existing units not affected by the Unit Age component are captured under the General Offset component and required to offset their emissions by a percentage of actual emissions. There is a net intensity floor, which means that no unit must offset its intensity below the specified intensity limit for its fuel type.
3. Units operating below their specified intensity limit do not gain credits.
4. Renewable and alternative energy is included in the sector intensity calculations and receives credit at a rate of 0.21 t/MWh generated.

In addition to the reductions achieved by the framework in the following analysis reductions can also achieved through the imposition of a change from the business as usual generation mix, as follows:

- The provincial target for 3.5% new renewable energy by 2008, with the proportion held constant over the forecast
- The replacement by gas-fired generation of projected new coal-fired generation beyond the 450 MW of new coal-fired generation (Genesee 3) planned for 2005.

7.3 Forecasts of Emissions and Intensity

Three major factors contribute to the difference between the EDC and NRCan[24] emissions and intensity forecasts:

1. The emissions intensities assumed for individual units in the province (t/MWh).
2. The technology type of new generation.
3. The total generation in the forecasts (MWh).

7.3.1 Unit Intensities

Based on stakeholder input the subgroup compiled a list of current or predicted intensities for generation units in the province, which were in turn used in the emissions forecasts prepared by EDC.

The NRCan forecast used a top-down approach to unit intensities assuming an average intensity for each generation type. The resulting intensities for coal- and natural gas-fired generation averaged about 7% below the intensities of the actual thermal generation in Alberta.

[24] Natural Resources Canada (NRCan) is the department leading the federal government's GHG forecasting work.

7.3.2 Technology Types for New Generation

The choice of the type of technology, and hence fuel type, for new generation affects the emissions forecasts. The NRCan forecast includes significantly more coal-fired generation than EDC's reference forecast. The EDC forecast assumes no new coal-fired generation beyond a 450 MW unit to be commissioned around 2005; the remainder of new generation is made up primarily of natural gas-fired cogeneration. The NRCan forecast includes the equivalent of 900 MW of additional coal-fired generation. The NRCan forecast assumes that existing coal-fired units would be replaced by new coal-fired units; EDC's forecast assumes that existing coal-fired generation would be replaced by gas-fired generation. Figures 7 and 8 demonstrate these differences.

Figure 7: Natural Resources Canada (NRCan) Forecast

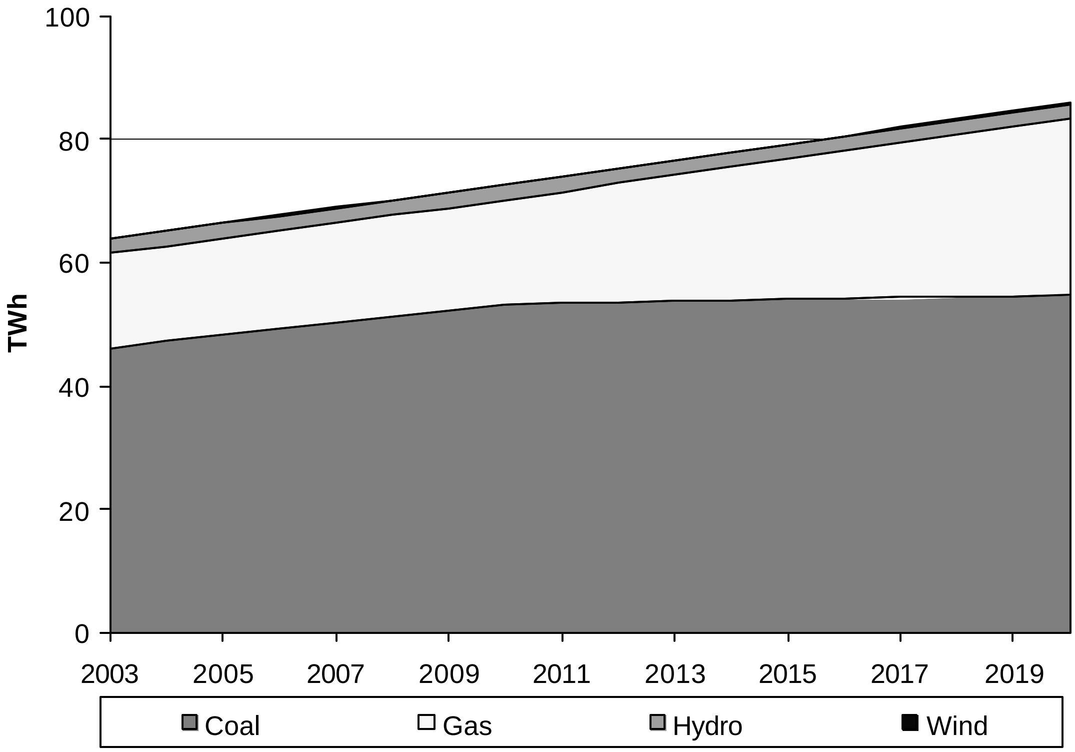
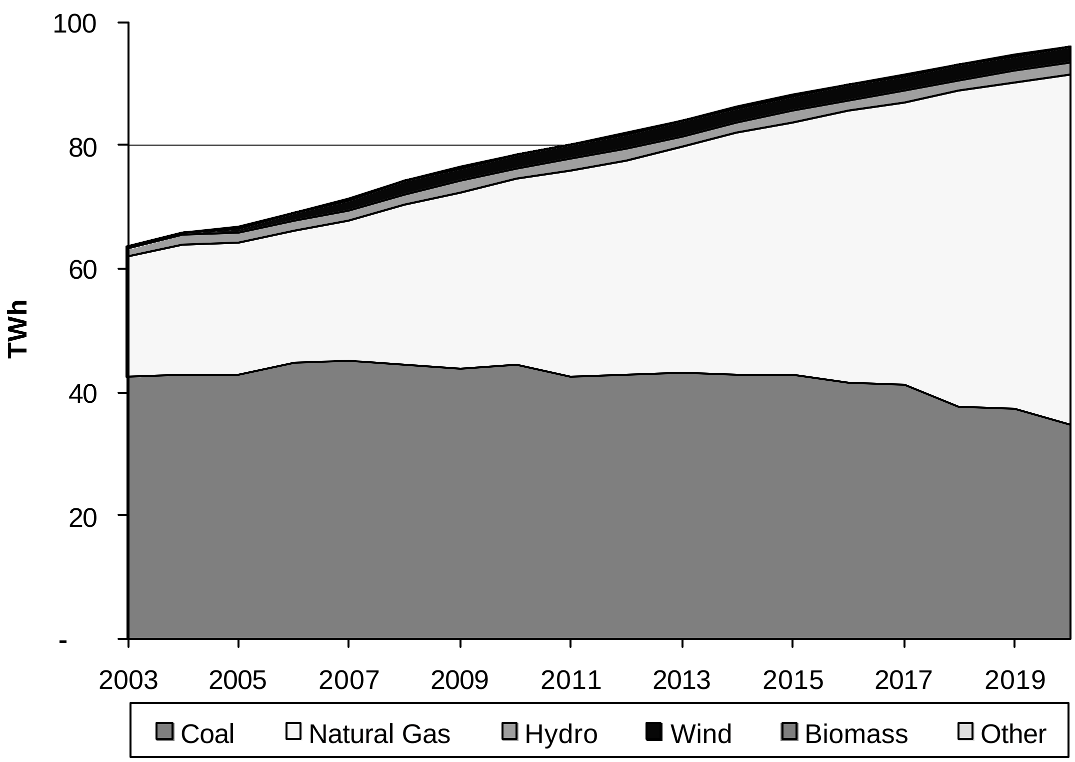


Figure 8: EDC Reference Forecast



There were two views within the GHG Allocations subgroup about the lack of new coal (beyond Genesee 3) in the EDC reference forecast, versus the generation mix in the NRCan forecast:

- The choice of gas is a competitive market outcome independent of climate change policies; OR
- The choice of gas over coal is driven by actual and anticipated future GHG policies that place higher costs on higher emission generation.

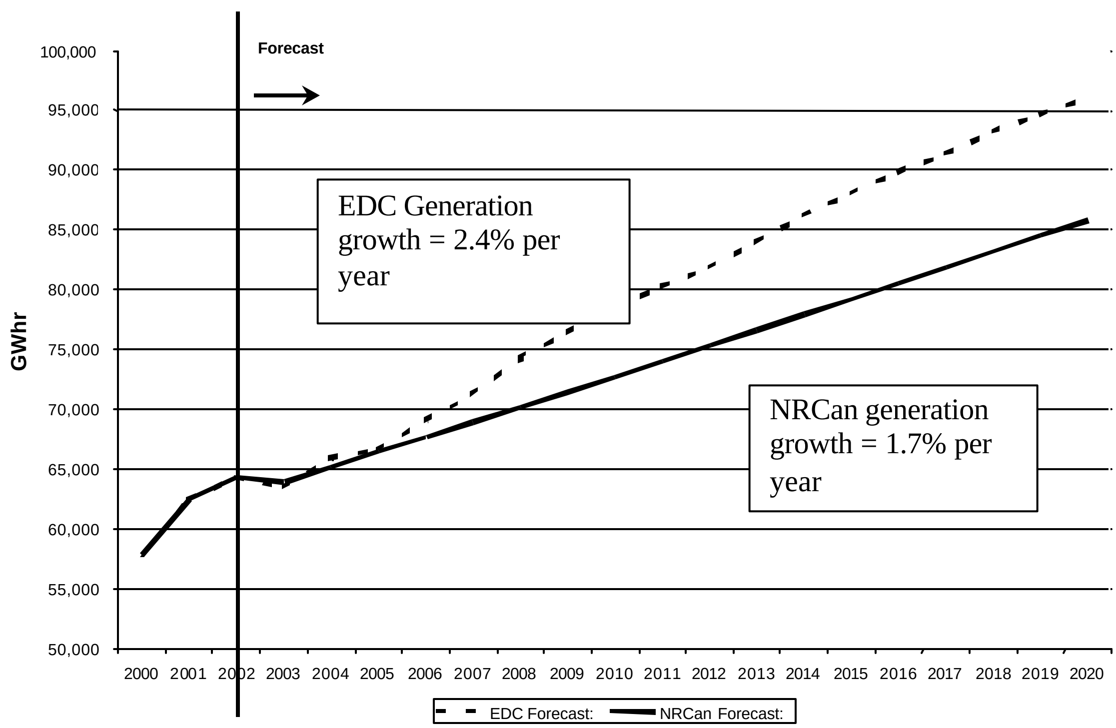
In any case, with the policies in place, the assumption is that no new coal-fired generation is built after Genesee 3.

7.3.3 Total Generation

The total generation included in the forecast affects the emissions and intensity forecasts in different ways. If the total generation in the province is greater than projected, then emissions will be greater. However, if new generation is gas-fired, as predicted by EDC, it will cause a decrease in the intensity of the sector. Conversely, if the total generation in the forecast is less than projected, then the emissions of the sector will be less; if the decrease in generation is due to a decrease in gas-fired generation, then the intensity of the sector will be higher.

Figure 9 shows the NRCan and EDC forecasts of generation from 2003-2020 alongside the electric industry statistics for 2000-2002,

Figure 9: Comparison of NRCan and EDC Generation Forecasts



7.4 Evaluation of Policy Elements in 2010

The NRCan BAU forecast and EDC's reference forecast have important differences. For this reason the the impact of the framework was analyzed using three scenarios:

> **BAU A**: the NRCan forecast, including total demand, unit intensities and technology types of new generation.
>
> **BAU B**: the total generation and technology types of new generation are the same as those in the NRCan forecast, and the unit intensities used were those compiled by the EPT and the GHG subgroup.
>
> **BAU C**: the EDC reference forecast with the renewable energy target displaced by gas-fired generation.

In looking at the effects of policies in achieving a 15% reduction from forecast emissions and intensity, the sector target can be characterized in three ways:

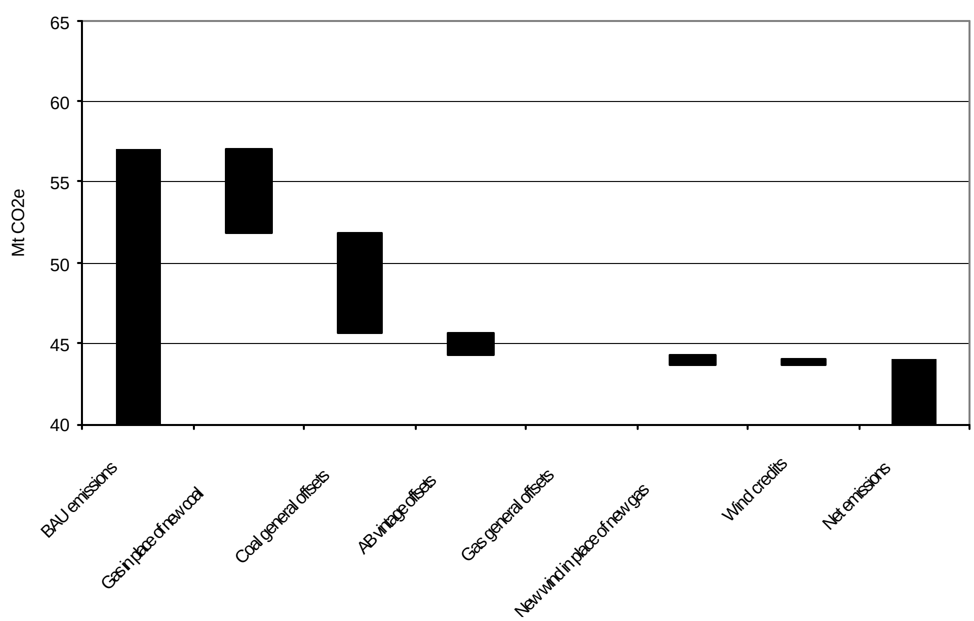
1. 15% below the NRCan emissions forecast (BAU A)
2. 15% below the NRCan intensity forecast (BAU A)
3. 15% below the emission and intensity forecasts of the other scenarios (BAU B or BAU C)

The Alberta Government's climate change plan calls for a 50% reduction in provincial emissions intensity from 1990 levels by 2020. In the absence of a more specific target for the electricity sector, the subgroup agreed to base its work on a notional provincial sectoral intensity target of 0.47 t/MWh by 2020, which is 50% below the 1990 sectoral intensity of 0.94 t/MWh.

7.4.1 The NRCan Forecast

The NRCan forecast predicts emissions of 57 Mt in 2010. Fifteen percent below its BAU emissions and intensity levels is 48.5 Mt. If the actual unit intensities in Alberta were equal to those assumed in the NRCan forecast, a 5% general offset would be needed in addition to the specified intensity limits to achieve this target. Figure 10 shows these reductions.

Figure 10: 2010 NRCan Forecast

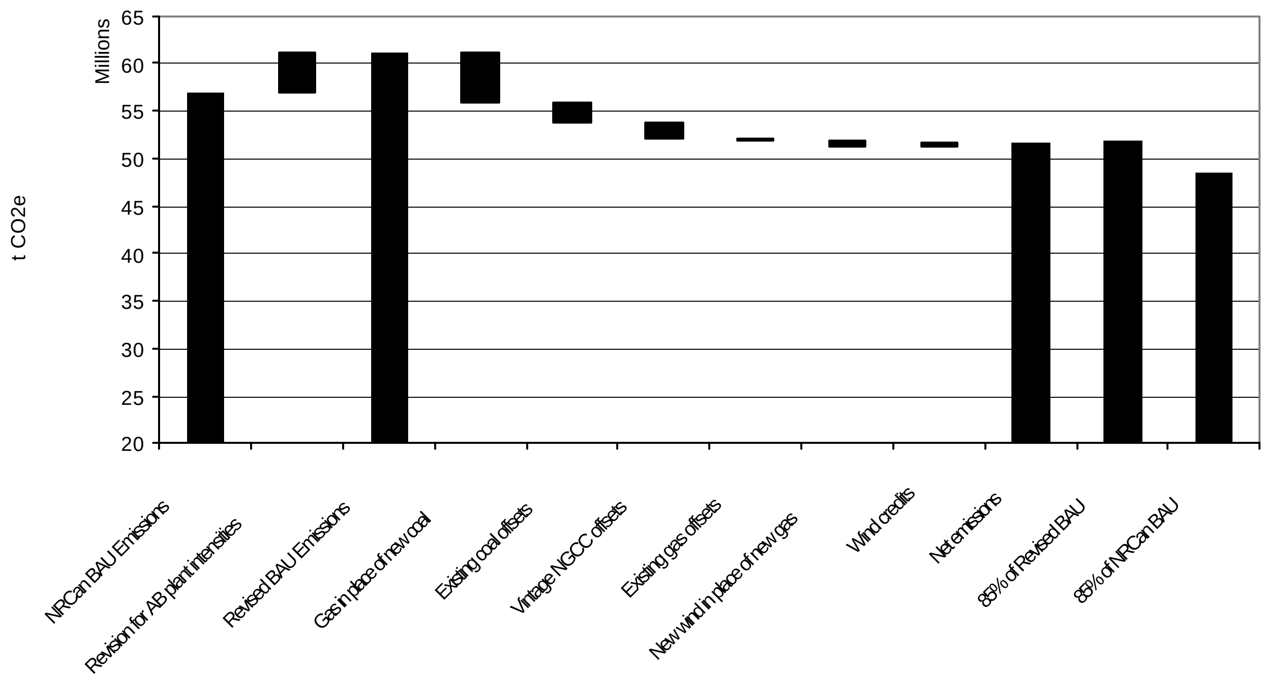


However, since the actual unit intensities are on average 7% higher than assumed in the NRCan forecast, a much higher offset would be required to reach the 48.5 Mt of net emissions if the actual Alberta unit intensities were to be applied.

7.4.2 The NRCan Forecast using Alberta Unit Intensities

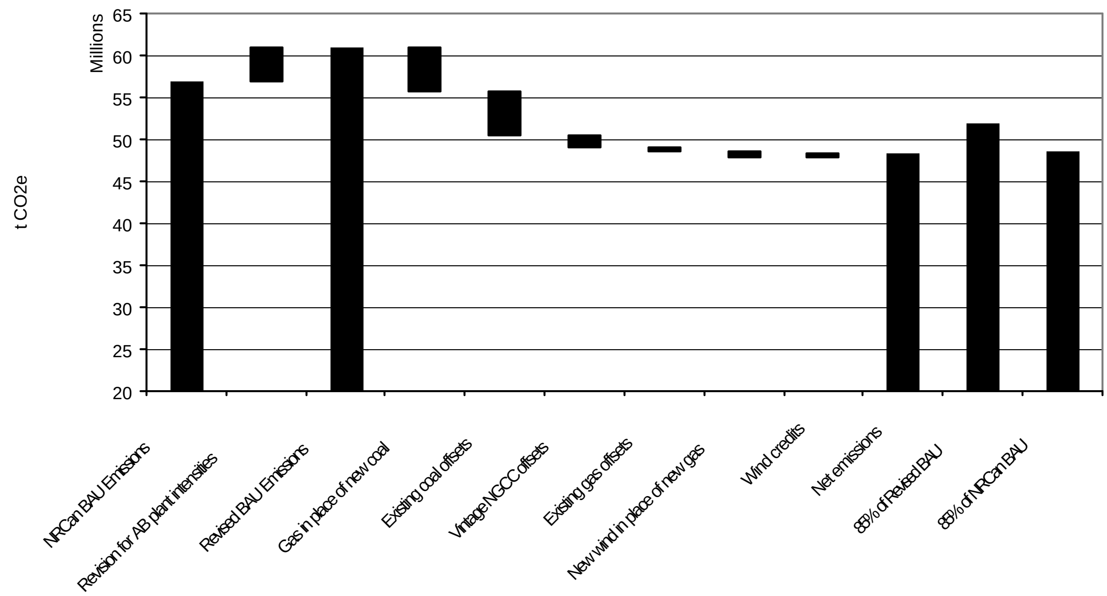
As seen in the previous section, the NRCan forecast emissions in 2010 are 57 Mt. When the unit intensities compiled by the GHG subgroup are inserted into the NRCan forecast, the forecast emissions increase to 61 Mt. To achieve 15% below this new business as usual forecast, a 5% general offset is needed using the conceptual framework. Figure 11 shows the reductions.

Figure 11: 2010 NRCan Forecast with Alberta Unit Intensities & 5% General Offset



To achieve the intensity and emissions target of 15% below the NRCan forecast, a 12% general offset using the conceptual framework is needed. The results are shown in Figure 12.

Figure 12: 2010 NRCan Forecast with Alberta Unit Intensities & 12% General Offset



7.4.3 The EDC Forecast

The EDC reference forecast has more total generation than the NRCan forecast as well as less new coal-fired generation. It assumes that the current economic and regulatory regime remains largely unchanged and does not include the 0.418 t/MWh intensity limit for Genesee 3. In addition the EDC reference case includes the 3.5% target for new renewable energy. For analysis purposes an EDC BAU has been created, this BAU is similar to the reference case, however it assumes that the wind energy in 2001 is held constant over the forecast and that wind energy in the reference case in excess to this is displaced by gas-fired energy.

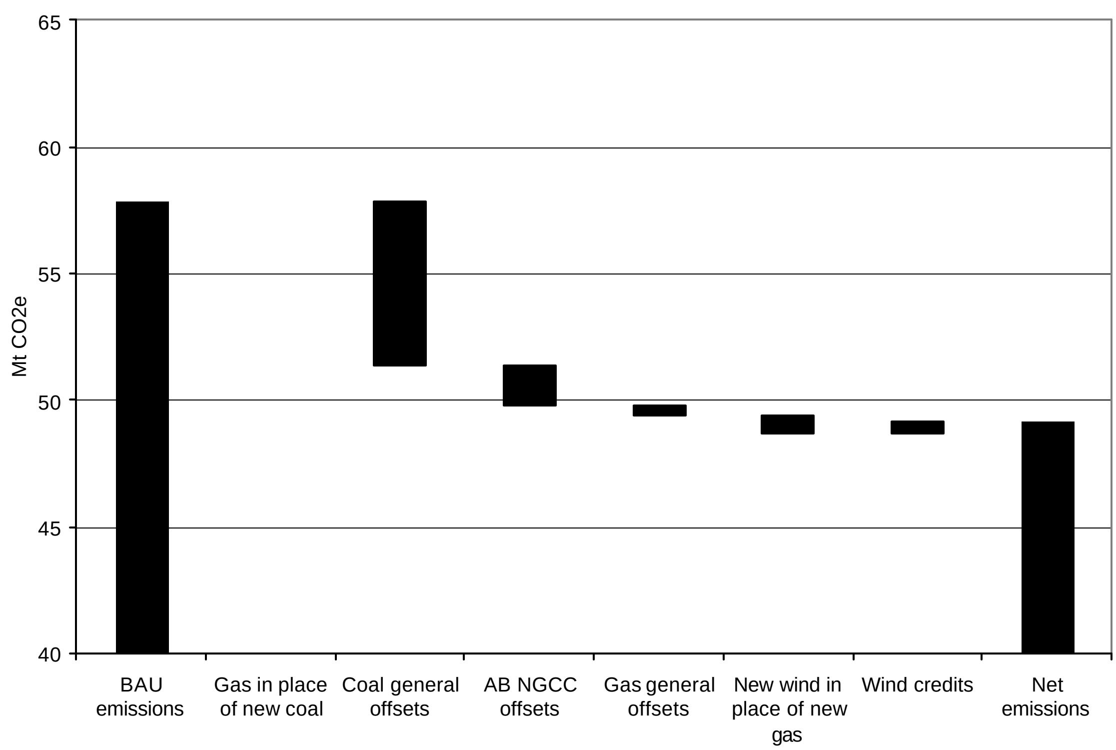
It is important to note that the EDC BAU does not represent an interpretation of a world where the renewable energy target does not exist, wind generation in the province would continue to grow over the forecast in the absence of the target, albeit at a slower rate. The renewable energy target was announced prior to the end of 2001 as part of a government plan to address climate change. This announcement has resulted in increased wind development post 2001 and as such the quantity of generation used to meet this target can be construed as representing a displacement of generation that would have otherwise been built. This can therefore be accounted for as a real reduction in emissions and the BAU is created in order to account for it as such.

The EDC BAU has BAU emissions of 57.9Mt and a BAU intensity of 0.756t/MWh. A 15% reduction would be 49.2Mt and 0.643t/MWh.

- To reach 15% below the EDC forecast *emissions and intensity*, a 15% general offset is needed in addition to the Unit Age policy.
- To reach 15% below the NRCan forecast *emissions (48.5 Mt)*, a 16% general offset would be needed if the Unit Age policy were included.
- To reach 15% below the NRCan forecast *intensity (0.667 t/MWh)*, an 8% general offset would be needed if the Unit Age policy were included.

Figure 13 demonstrates the reductions from the EDC BAU when a 15% general offset is applied in addition to the Unit Age Component.

Figure 13: 2010 EDC BAU with a 15% General Offset



7.4.4 Sensitivity Analysis

The reductions accounted for in each of the figures in this section demonstrate the portion of a given target that will be met by:

1. Replacing any new coal-fired generation beyond Genesee 3 in the forecast with new cogeneration.
2. A Unit Age offset requirement on new and existing units at the end of their Design Life.
3. A General Offset requirement on all thermal units not affected by the Unit Age offset component.
4. Replacing new cogeneration with new wind generation and crediting this power at a rate of 0.21 t/MWh.

In the following sensitivity analysis each of these components is discussed in greater detail in terms of its capacity to achieve reductions. Table 3 shows the emission reduction contribution of the various components using the NRCan forecast and Alberta unit intensities in 2010.

Table 3: Sensitivity of Components

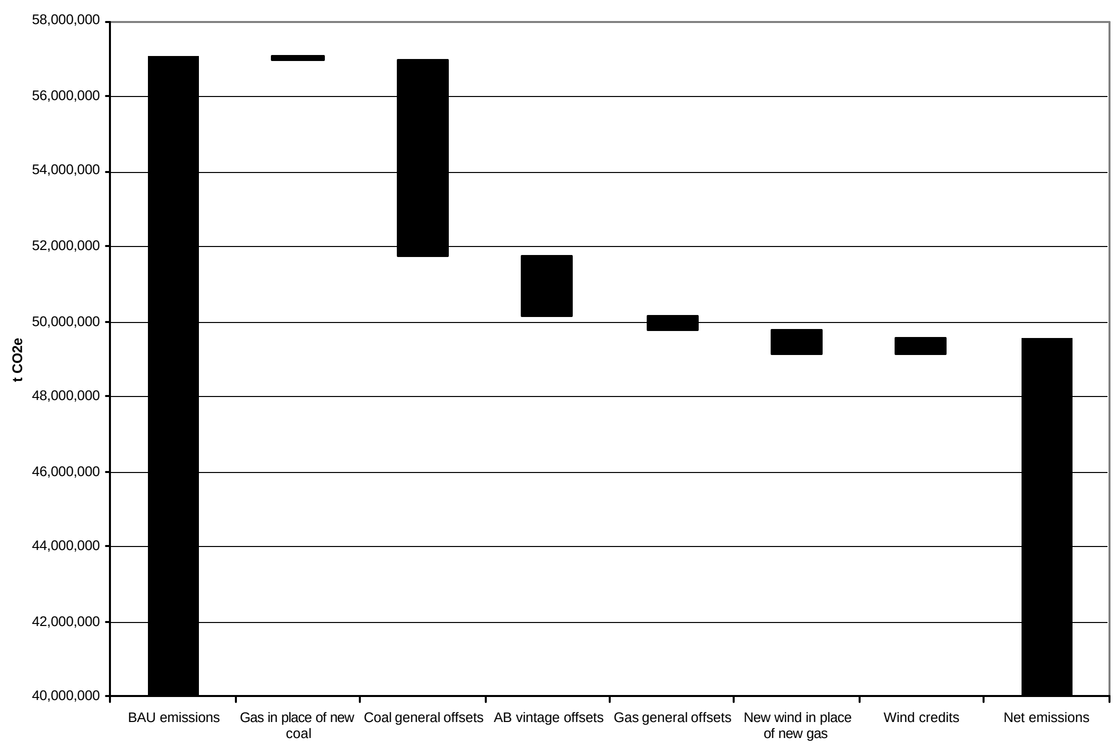
Components	Reductions (Mt)
Gas in place of new coal	5.3
Unit Age offset	1.6
General offset @ 1%	0.49
Renewable contribution @ 0.21t/MWhr	0.22

7.4.5 Gas in Place of New Coal

The NRCan forecast assumes that by 2010, approximately 900 MW of new coal-fired generation will be constructed beyond the proposed Genesee 3 unit. The emissions reductions that result from the displacement of this new coal-fired generation with new cogeneration are approximately 5.3 Mt.

Figure 14 shows the emissions from the NRCan forecast of total generation using Alberta unit intensities, where much of the new coal-fired generation in the original forecast is replaced by new gas-fired generation. In this case, a 12% reduction in addition to the Unit Age component is necessary to meet a target of 15% below the NRCan forecast. The emissions are reduced from 57Mt to 48.5Mt and the contribution to emission reductions of the displacement of coal with gas-fired generation is 0.1Mt.

Figure 14: NRCan Total Generation with Alberta Unit Intensities



7.4.6 Unit Age Component

The Unit Age offset component of the policy contributes 1.6 Mt to the reductions in the system in 2010. These reductions are almost entirely the result of a 1.4 Mt reduction from Genesee 3. The rest of the reduction is due to a few gas-fired units reaching the end of their Design Lives and achieving new emissions intensity limits.

7.4.7 General Offset Component

The General Offset component of this framework requires a percentage reduction of units' actual emissions intensity subject to a floor, which ensures that no unit is required to offset its emissions below its specified intensity limit. The impact of a single percentage point change in the General Offset component is approximately 0.5 Mt in 2010.

7.4.8 Renewable and Alternative Generation

In the preceding analysis the provincial renewable and alternative energy target was assumed to be met by new wind. This energy is included in the calculations of the intensity of the sector and is receiving credit at a rate of 0.21 t/MWh. The emissions reduction contribution of this energy will vary depending on the intensity level of the renewable energy credit. At a credit intensity of 0.32 t/MWh the impact of renewable energy on the sector is zero. This is because new generation in this analysis is assumed to be natural gas-fired cogeneration at an intensity of 0.32 t/MWh. Table 4 shows the contribution of renewables to the emissions reductions in the sector using several different credit intensities.

Table 4: Impact of Renewable Energy on the Electricity Sector Intensities

Emissions in tonnes of renewable energy included at the following credit amounts				
	0 t/MWh	**0.21 t/MWh**	**0.32 t/MWh**	**0.691 t/MWh**
New wind in place of new gas	651,132	651,132	651,132	651,132
Wind credits	-	(427,305)	(651,132)	(1,406,039)
Total Renewable Reductions	**651,132**	**223,827**	**-**	**(754,906)**

Figure 12 shows that a 12% general offset is needed in addition to the Unit Age policy for the total electricity sector to achieve the federal total intensity target in 2010 using the NRCan BAU with Alberta unit intensities. Alternatively, if the federal thermal intensity target is to be met with this BAU, then a 14% general offset in addition to the Unit Age policy would be necessary. This is demonstrated in Table 5.

Table 5: Impact of Removing Renewable Energy on the Electricity Sector Intensities

BAU	Revised NRCan BAU (BAU B) with a 12% general offset	Revised NRCan BAU (BAU B) with a 14% general offset
Net Intensity	0.666	0.654
Thermal Intensity	0.705	0.692

7.5 Evaluation of Long-term Impacts of the Policy Elements

As noted above, in addition to analyzing the effects of the elements of policy included in the framework, the Sub-Group engaged EDC to examine the impact out to 2025 of three general offset cases using the conceptual framework. Figures 15 and 16 show the EDC reference forecast and three general offset cases using the conceptual framework out to 2025. The cases are:

UA1: Unit Age policy only: the general offset percentage is set at zero.

UA2: Unit Age plus 5%: the general offset percentage is set at 5%.

UA3: Unit Age plus 15%: the general offset percentage is set at 15%.

The federal intensity and emissions targets as well as the notional provincial intensity target are shown on the figures.

Figure 15: EDC Emissions

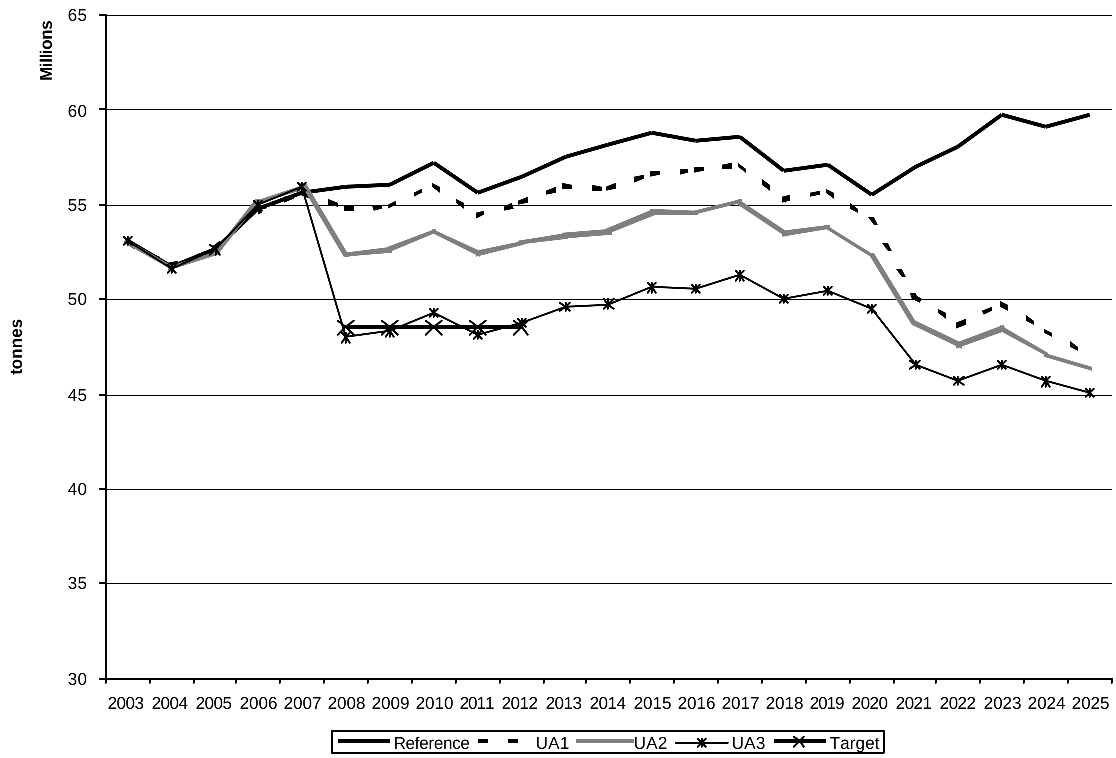
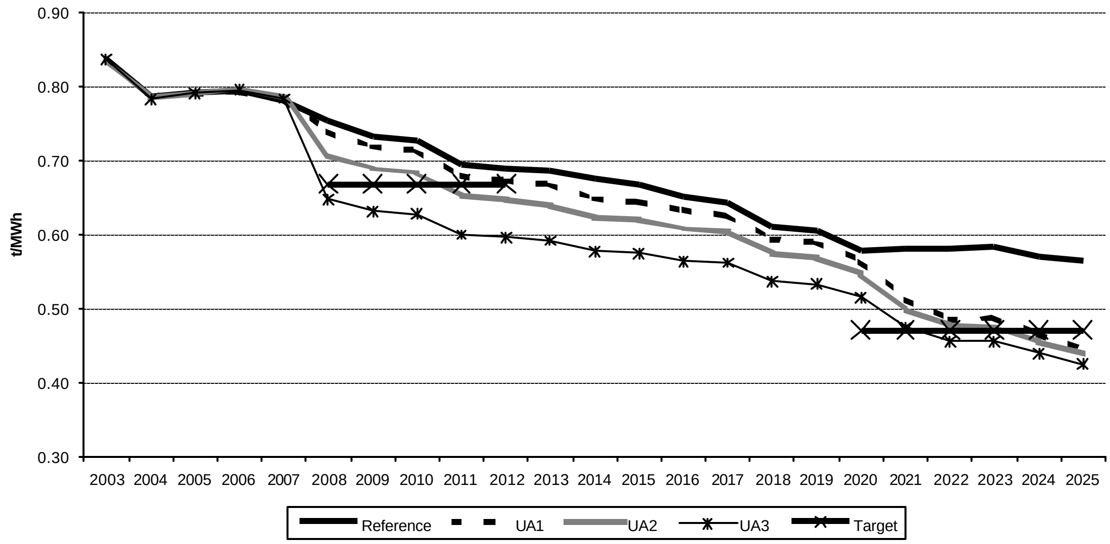


Figure 16: EDC Intensity



The NRCan forecast ends in 2020, so the 2020 to 2025 period can only be analyzed using the EDC forecast, which ends in 2025.

The conceptual framework has two components – a Unit Age component and a General Offset component. The Unit Age component affects existing coal-fired units, but does not significantly reduce provincial emissions intensity until after December 31, 2020 when the PPA terms are finished. Until this time the reductions from this component of the framework are due to the reductions from Genesee 3 and any existing gas-fired and other thermal units reaching the end of their Design Lives. A general offset of 5% allows the provincial target to be met by 2023, and a general offset of 15% allows the target to be met by 2021.

The analysis assumes that the specified intensity limits would remain constant over time. In Table 6, a range of specified intensity limits are examined for their impact on the total sector intensity in 2021. The results are based on a scenario where only the Unit Age component of the framework is applied. The implication is that a specified intensity limit of approximately 0.25t/MWh would be necessary in order for the provincial intensity target to be met in 2021.

Table 6: Variations on 2021 Specified Intensity Limits

Specified Intensity Limit	2021 Net Sector Intensity
0.1 t/MWh	0.451 t/MWh
0.2 t/MWh	0.465 t/MWh
0.3 t/MWh	0.478 t/MWh
0.4 t/MWh	0.492 t/MWh

As part of the modeling exercise, a scenario was developed where new generation was assumed to be primarily coal. The case assumed that the additional coal-fired units required would be built primarily after 2010. The emissions and intensity for the EDC all-coal reference case, along with a case where the Unit Age policy plus a 15% general offset is in place, are shown in Figures 17 and 18.

Figure 17: EDC "All-Coal" Emissions

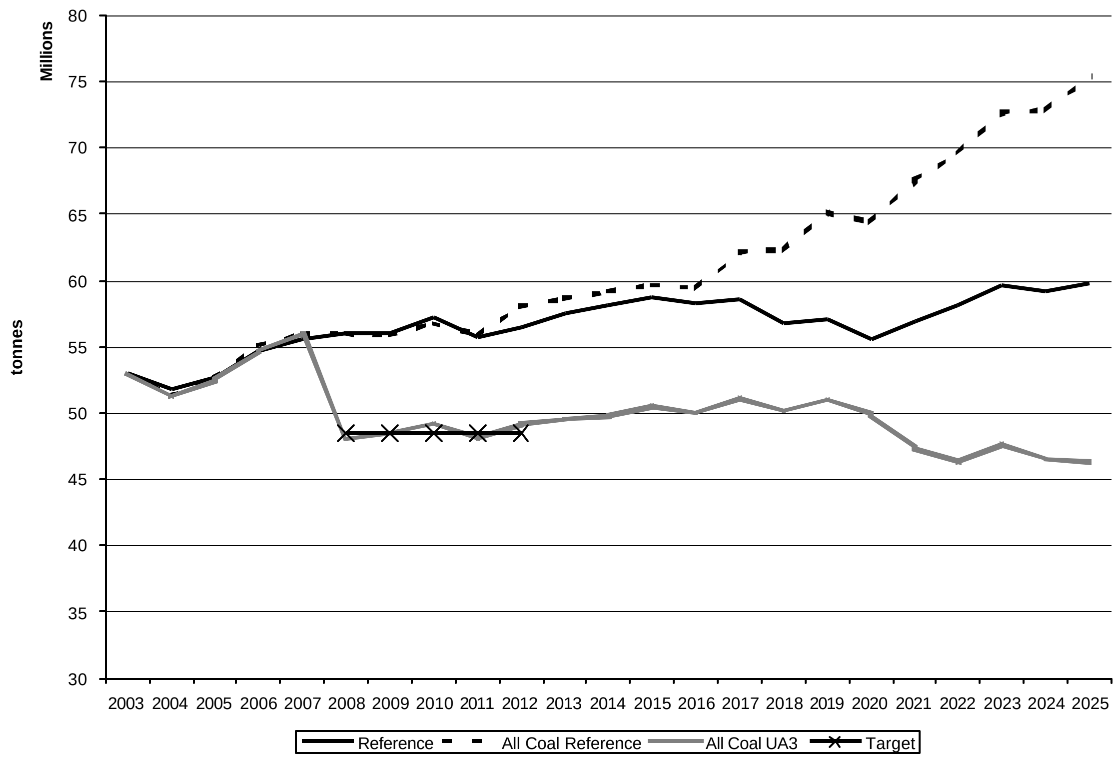
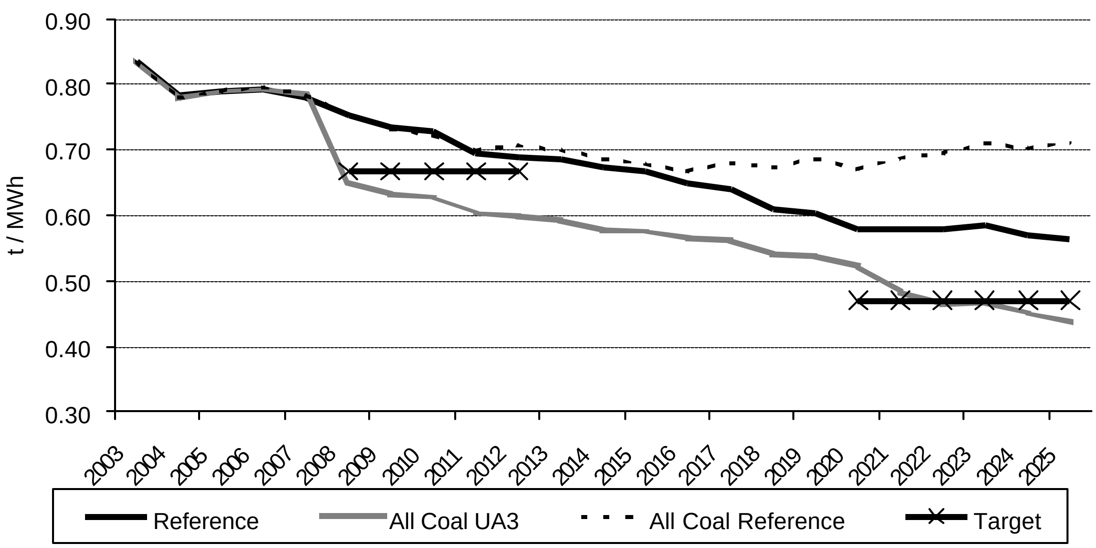


Figure 18: EDC "All-Coal" Intensity



8 Price and Cost Modeling

8.1 Background

The subgroup asked EDC to examine the impacts of the framework on wholesale electricity prices, generation and emissions. Key outputs sought were the effects on the marginal price of wholesale electricity (during both peak and off-peak hours), the energy production by unit (the stacking order), and the emissions forecast for greenhouse gases, for each year from 2003 to 2025. The subgroup also recognized the need to obtain information on any potential unintended ramifications of its emission management recommendations, including impacts on facility design and location, fuel switching and transmission requirements.

The specific objectives of the modeling were:

1. To estimate the incremental impact on the annual average Alberta wholesale electricity price from implementing a proposed emissions management framework, with various options for the timing and scale of emission reductions.
2. To estimate the impact on the supply stacking order from implementing a proposed emissions management framework (and variables) and the impact on particular facilities that are subject to Power Purchase Arrangements.
3. To determine the electricity generation sector's annual aggregate emissions profile by technology type as a result of implementing the proposed emissions management framework and variables.
4. To evaluate the impact on the results of a sensitivity in which coal generation development is extensive. Since coal generation has low variable costs but higher emissions than natural gas fired generation, the amount of coal capacity in the province is an important variable that must be considered when evaluating the impact of proposed GHG policy options.
5. To calculate the estimated financial impact of the GHG policy on fossil fuel generators in Alberta.

8.2 Scenarios

The purposes of the modeling were to:

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

Scenario 1: EDC's Reference Case

This forecast assumes that the current economic and regulatory regime remains largely unchanged. The reference case is driven by the assumption that no specific emission reduction targets are implemented in Alberta, Canada or elsewhere. Thus the energy demand grows and generation additions occur as they naturally would and each generator bids its power into the Alberta market assuming no incremental costs for environmental operating and maintenance requirements or offset purchase or sales. This model of Alberta electricity generation includes demand, generation mix, dispatch order, capacity factors and electricity prices. This forecast also incorporates the emissions reductions and associated costs for NO_x, SO_2, primary particulate matter, and mercury stemming from the EPT's recommendations over the period 2003 to 2025. In addition, this case includes a 3.5% renewable energy target over the forecast period. It does not include the 0.418 t/MWh intensity limit for Genesee 3.

Three cases were run against the reference forecast:

UA1: New coal-fired units and coal-fired units at the end of their Design Lives offset their emissions to 0.418 t/MWh. New gas-fired units and gas-fired units that have reached the end of their Design Lives offset their emissions to 0.375 t/MWh.

UA2: As in 1, with the addition of a general offset. All units not covered by the reductions named above reduce emissions by 5%. A floor on reductions exists such that no unit reduces below its specified intensity limit.

UA3: As in 2, with a percentage reduction of 15%.

The EDC reference forecast assumes only one new 450 MW coal facility will be built. Additional natural gas-fired cogeneration is expected to be developed in Alberta, particularly in conjunction with robust oil sands development, and commensurate with northern transmission capabilities. However, a forecast risk exists if the generation development sequence does not progress as forecast and could have implications on the electricity price and the emissions. For this reason a second reference case was modeled:

Scenario 2: "All Coal" Reference Case

This reference case assumed that new generation is primarily coal-fired; it also incorporates the emissions reductions and associated costs for NO_x, SO_2, primary particulate matter, and mercury according to the CASA EPT recommendations, as well as the renewable energy target over the period 2003 to 2025.

One sensitivity was run against the "all coal" reference case:

UA4: New coal-fired units and coal-fired units at the end of their Design Lives offset emissions to 0.418 t/MWh.New gas-fired units and gas-fired units that have reached the end of their Design Lives offset their emissions to 0.375 t/MWh. All units not covered by the reductions named above reduce emissions by 15%. A floor on reductions exists such that no unit reduces below its specified intensity limit.

8.3 Modeling Inputs, Data Sources and Key Assumptions

8.3.1 Key Data Inputs

Key data inputs for the cost and price modeling were:

1. Unit intensities as discussed in Section 7.
2. The costs of greenhouse gas emissions in nominal Canadian dollars were assumed to be $9/tonne in the 2008-2012 timeframe, $12/tonne in the 2013-2017 timeframe and $15/tonne between 2018-2025.

8.3.2 Key Assumptions

1. The analysis was on a unit basis without consideration of the Power Purchase Arrangements associated with each unit. Omitted from this analysis were the prices paid for the PPA contracts or any hedging decisions that may have been made as a result of the PPA purchase due to competitive confidential requirements. It was assumed that all incremental variable emission costs levied on any generation asset would be bid into the Pool price and therefore reflected in the impact on wholesale electricity prices.
2. Life extension capital of $300/kw to life-extend the coal-fired units to 50 years was included in both the reference case and the optimization scenarios. No additional capital was included to life extend the gas-fired units.
3. Start up and shut down of units was assumed to be December 31 of the relevant year.
4. The current Unit Age specified intensity limits were used across the forecast period to ensure that the emissions reductions represented a conservative estimate of the future.

The complete report from EDC Associates Ltd that describes the results from the EDC modeling is available on the CASA website.[25]

8.4 Wholesale Electricity Price Impacts

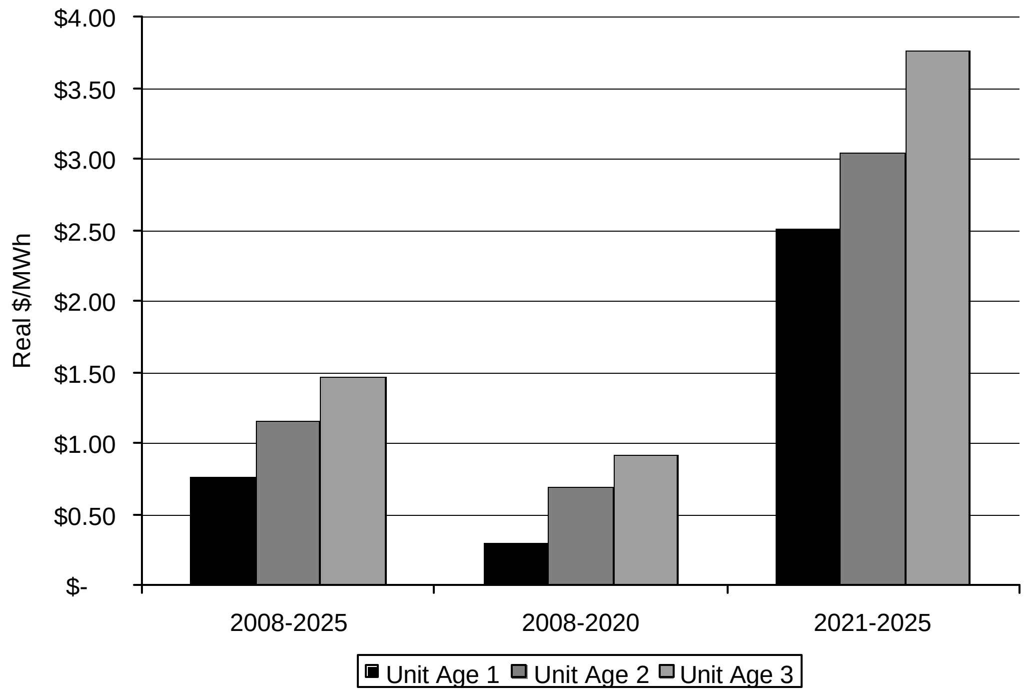
There were three major findings in relation to the framework's impact on wholesale electricity price impacts:

- Only very small differences were identified between the three cases in terms of wholesale electricity prices, dispatch order and electricity production.
- The results suggest that there is not a large difference between the price forecasts of the different cases. Prices are somewhat higher in the three GHG cases than in the reference case. However, the difference is relatively minor because natural gas generators that are typically on the margin setting the power price do not face a large price increase from GHG reductions. The price impacts of the framework in real dollars were roughly $0.30 to $0.90MWh between 2010 and 2019 and approximately $3.00/MWh between 2020 and 2025.
- On the basis of current costs, new wind power requires incentives to justify incremental wind generation.

[25] See http://www.casa-electricity.org.

Figure 19 demonstrates the price impacts of the cases UA1-UA3 relative to the reference case.

Figure 19: Price Impacts of Three Cases



Figures 20 and 21 show a comparison of the average wholesale price impact in nominal dollars of various greenhouse gas scenarios.

Figure 20: Comparison of GHG Cases

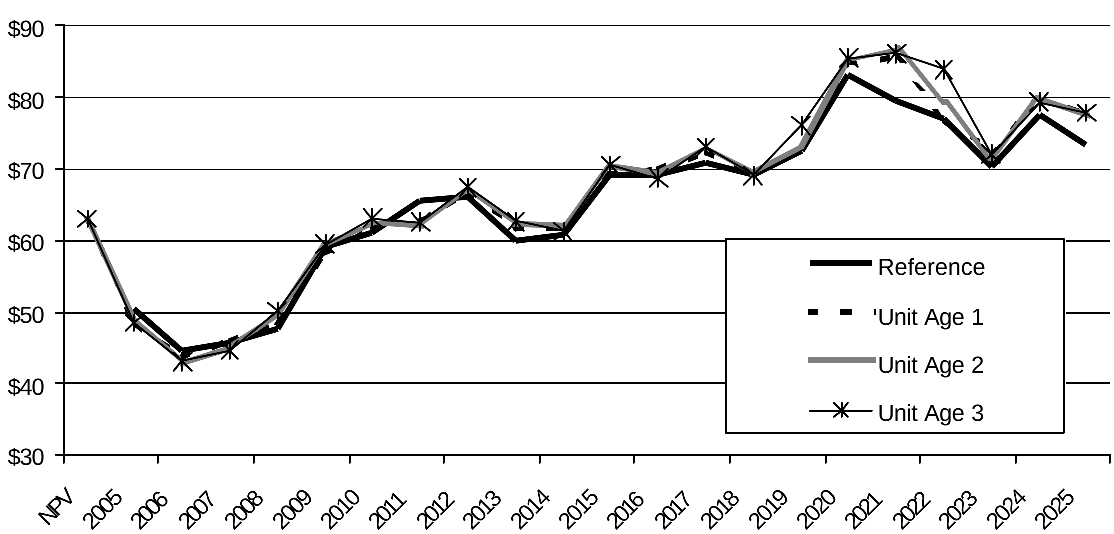
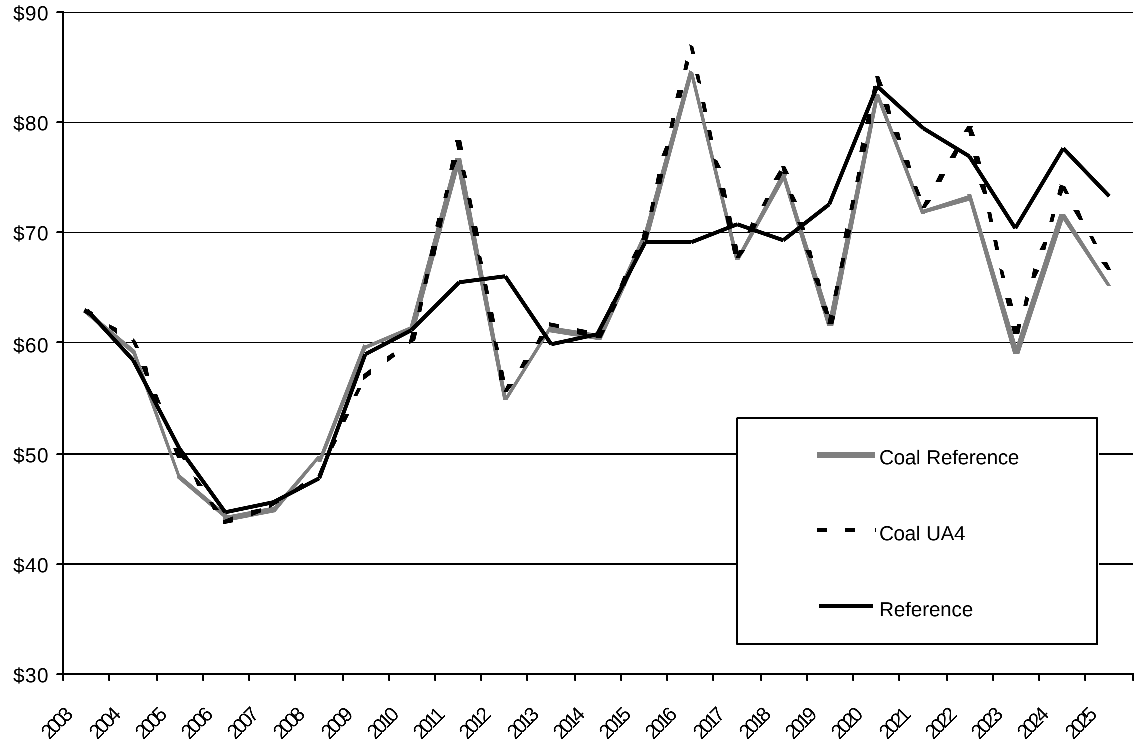


Figure 21: "All-Coal" Reference Case Comparison of GHG Scenarios



8.5 Costs and Impact on Generation

Emission management requirements introduce incremental emission costs to generators in Alberta. In addition to forecasting the impact these costs have on electricity prices, EDC also examined whether or not emission costs rendered the existing generation fleet uneconomic. According to the modeling, none of the existing coal-fired units saw a shift in their capacity factors as a result of incremental emission costs.

Table 7: Cost Impacts to Coal-Fired Generation

	Vintage One	Vintage Two	Vintage Three	Coal & Vintage Three
Cumulative GHG Emission Costs ($000)	$1,132,534	$1,475,243	$2,177,817	$3,502,407
Present Value of GHG Emission Costs ($000)*	$260,458	$382,204	$630,007	$883,172
Levelized GHG Emission Costs per MWh***	$0.61	$0.90	$1.48	$1.86

* Assumes 10% Discount Rate
*** Assumes inflation rate of 2.0% and term of 21 years (2005-2025), starting in 2005

The modeling suggests that coal-fired units will have large aggregate greenhouse gas emission costs that range from $1.1 to $3.5 billion over a 21-year period. When discounted into 2004 dollars the costs range from $0.3 and $0.9 billion. When averaged over the total generation associated with these facilities from 2004-2025, the emission costs expressed as a levelized cost range from $0.61/MWh to $1.86/MWh.

Table 8: Cost Impacts to Gas-Fired Generation

	Vintage One	Vintage Two	Vintage Three	Coal & Vintage Three
Cumulative GHG Emission Costs ($000)	$665	$59,920	$79,260	$67,482
Present Value of GHG Emission Costs ($000)*	$127	$16,245	$22,182	$20,448
Levelized GHG Emission Costs per MWh***	$0.00	$0.04	$0.06	$0.06

* Assumes 10% Discount Rate

*** Assumes inflation rate of 2.0% and term of 21 years (2005-2025), starting in 2005

The modeling suggests that gas-fired units will have aggregate greenhouse gas emission costs that range from $0.6 to $80 million over a 21-year period. When discounted into 2004 dollars the costs range from $0.1 and $22 million. When averaged over the total energy associated with these facilities from 2004-2025, the emission costs expressed as a levelized cost range from approximately $0/MWh to $0.06/MWh.

For individual units, GHG costs will vary based on the unit's age and fuel type. Figures 22 and 23 show the GHG costs of selected units in nominal dollars along with other variable costs associated with achieving UA3 in 2010 and 2025. These variable costs include fuel, operation and maintenance costs, and the cost of meeting emissions requirements for NO_x, SO_2, and mercury. These variable costs represent only a portion of the "all-in" cost of generation, which for a new coal unit is approximately $50-$55/MWh and for a new combined cycle unit is approximately $70-$75/MWh at a natural gas price of $5.15 per gigajoule in 2010 nominal dollars.

Figure 22: Variable Costs of Units in 2010 under UA3

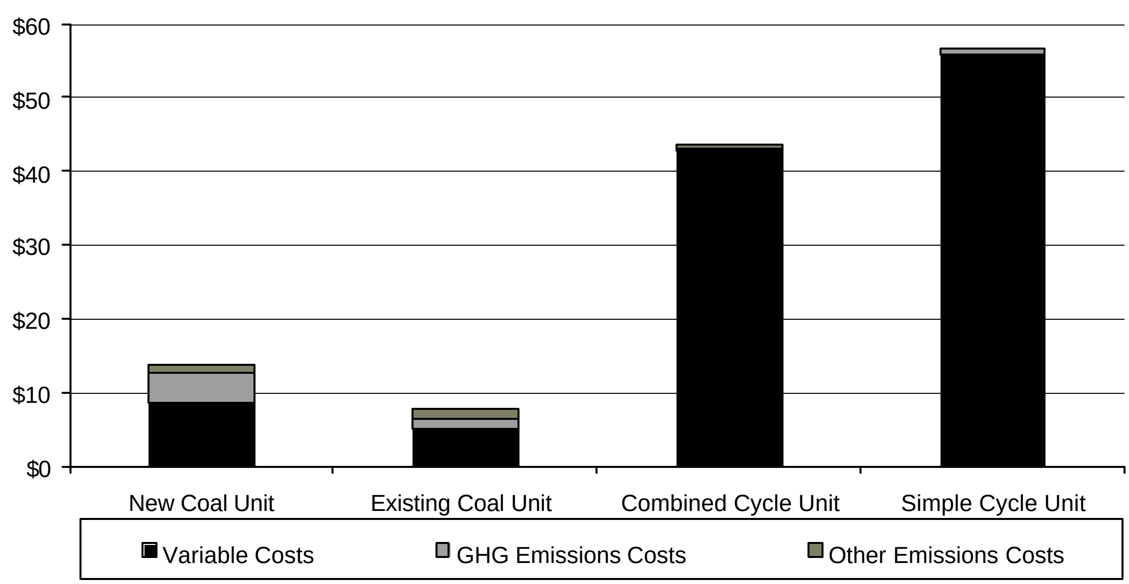
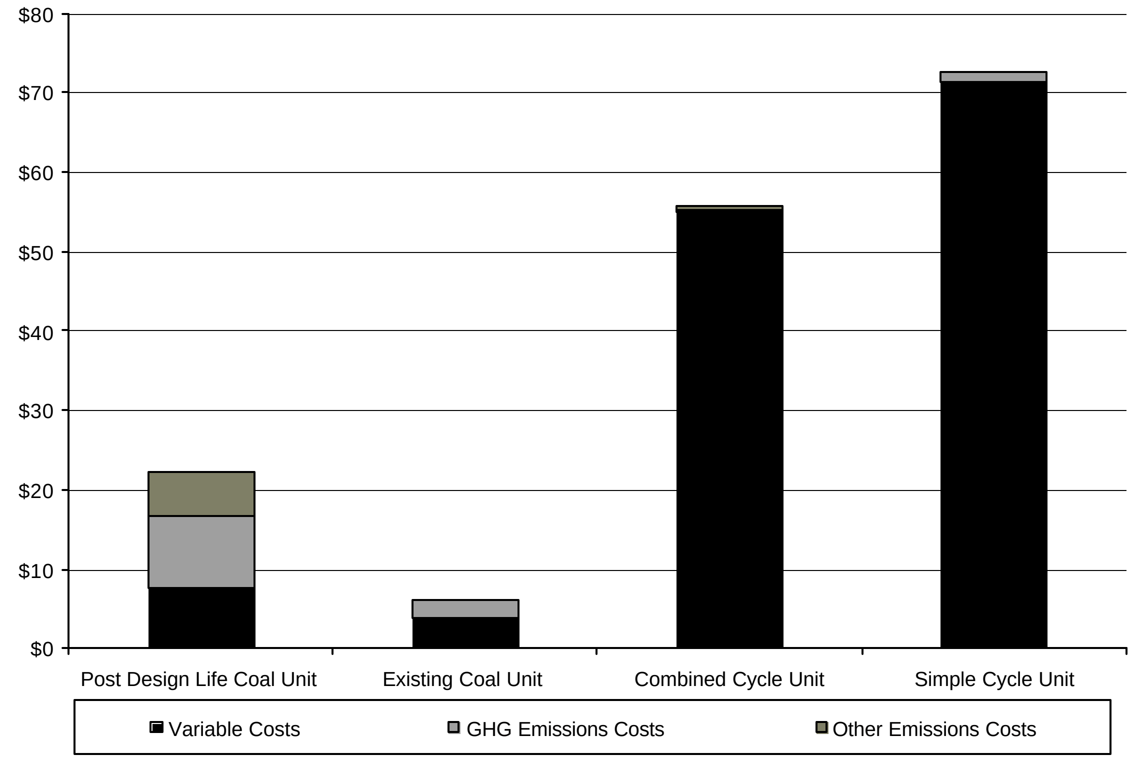


Figure 23: Variable Costs of Units in 2025 under UA3



8.6 Forecast Methodology and Implications

The forecasts presented in this section of the report represent a fundamental approach that reflects the short and long-term costs of producing electricity. Individual generators are expected to behave rationally in the spot market and long-term investment is forecast to proceed in a manner that provides economic returns for new generation. Although the model does reflect generator behaviours that result in short-term economic profits under 'tight' market conditions, potential new behaviours resulting from a GHG policy are not captured. This section explores potential impacts from the policy both in the short and long-term that are not reflected in the forecast results contained in this report.

8.6.1 Potential Short-Term Behaviours

Any change in the market has the potential to result in new generator offer strategies that either inflate or reduce the impact that would be expected from fundamental analysis. This section explores some potential outcomes from the GHG policy from a behavioral perspective rather than from a purely fundamental perspective.

For historical context on the impact a policy change can have on the electricity market, it is useful to look back on the transmission tariff. The transmission tariff change in June 2000 resulted in increased marginal costs for generators of several dollars per MWh because generators faced a direct variable charge for transmission. As with the GHG policy costs, it was expected that this cost would be passed on to consumers via the electricity price to the extent that the marginal generator faced new costs. However, the onset of this policy change coincided with events such as the California power crisis, high natural gas costs and the Wabamun 4 generation outage. As a result, it is impossible to discern whether historical prices show the cost being passed onto the market at an inflated or deflated rate. When this cost disappears in 2006 as per the provincial government's latest transmission directive, it will be interesting to see whether or not electricity prices fall by the amount of the cost reduction.

One factor that may influence generator behaviour is the fact that many companies own interests in multiple generators. For example, some generators have both coal and natural gas generation assets—some participants may be able to develop an offer strategy that allows the higher GHG costs associated with coal units to be passed into the market via the natural gas generation units that face much lower GHG costs. In effect, the participants may try to recover the high costs coal units face by changing the way their natural gas units bid into the market, even though the natural gas generator does not face significant costs itself. This would result in a larger impact on the electricity price forecast than estimated in a purely fundamental model approach.

It is also important to recognize that with a 'commodity' as nebulous as GHG offsets combined with a credit market that is not yet established, it is very difficult to discern the behaviours that will occur in the offset and electricity markets. Given that the offset market will be a market only in the sense that policy and rules create the market and the commodity it trades, it is certainly probable that unpredictable behaviours and strategies will result in the interaction between the two markets. One simple example relates to the time interval over which emission factors and credit requirements will be measured. It is easy to see a situation where a combined cycle natural gas unit will operate both above and below the intensity threshold in the policy for portions of the year based on market conditions as well as ambient weather conditions. If the emission policy is applied over short intervals, this unit would face emission costs but if the time interval is annual, it is possible its annual average emissions would fall below the threshold. Nonetheless, in the periods the unit operates above the threshold, it may very well decide to include a GHG cost in its offer given the uncertainties in how the year will develop, and this potential is not reflected in this report.

8.6.2 Potential Long-Term Behaviours

Long-term behaviours in the electricity market will primarily be reflected in the investment decisions market entrants make over time. A GHG policy alters the relative cost structures of potential generators and may shape the investment decisions in the long-run. For example, given a target of 0.375 t/MWh for natural gas generation, it is likely that new natural gas generators will meet this target in order to avoid the risk of being required to purchase GHG offsets. Further, the choice between natural gas and coal generation additions is substantially altered in the presence of GHG standards.

A typical new coal generator will see its 'all in' costs increase by as much as $9/MWh as a result of the GHG policy. In terms of the investment decision between coal and combined cycle natural gas capacity, this is roughly equivalent to a $1.25/GJ increase in the long-term average price of natural gas.[26] In other words, the unit age GHG policy shifts the relative attractiveness of new generation capacity from coal towards natural gas capacity.

[26] EDC generally assumes that a long-term natural gas price of $5/GJ in real terms results in combined cycle generation costs that are similar to coal costs on an 'all in' basis. The GHG policies examined in this report appear to move this break-even point to over $6/GJ.

Another result of the Unit age Policy is that the relative attractiveness of emission free technology is increased. Wind, hydro and solar power, for example, do not create emissions and will be granted an emission credit of 0.21 t/MWh. This amounts to roughly a $2 - $3/MWh incentive for these technologies, combined with the fact that overall electricity prices are expected to increase by $1 to $2/MWh due to the GHG policy. It is possible that wind technology improvements, for example, will allow wind generation to become cost competitive with coal and/or natural gas generation partially as a result of the GHG policy. In this event, the electricity system will have to come to terms with the impact large-scale wind generation has on system reliability and reserve requirements as wind technology could become the best investment choice on a cost basis.

8.6.3 Constant Market Design

With the wholesale market review currently underway, it is important to note that the analysis in this report assumes the current 'energy only' market design continues in the future. Small changes in this market design such as a day-ahead market would not likely have a substantial impact on the forecast results, but a dramatic change such as a capacity market would alter the results. Without knowing the details of a capacity market, it is not possible to determine exactly how different the results would be, but some basic premises can be stated.

In the current market design, coal capacity cannot generate economic returns unless natural gas generators set the price, i.e. coal generators have marginal costs well below their average costs. In a competitive market dominated by coal capacity, energy prices would gravitate towards the marginal cost of coal generation. Clearly, this is not attractive for coal capacity because it does not allow the units to recover their large capital costs. In essence, coal generators need natural gas generators to set the price for a large amount of the year in order to create a return on capital.

Since a capacity market implies that generators will be compensated for their capital costs outside of the energy market, there will no longer be a legitimate reason for generators to submit offers above their marginal costs into the energy market.[27] If this is the case, coal generators may very well set the price in many hours and still generate fair returns. However, since coal generators face much higher GHG offset costs than natural gas generators under the proposed policies, the impact of the policy would be much greater. In effect, the cost of GHG offsets would be more likely to flow through into the energy price with a capacity market.

There are other potential impacts that could arise from a capacity market design, but the detailed analysis falls outside the scope of this document. For example, it is not clear how a capacity market would change the incentives for fuel efficiency, i.e. lower heat rates. The current market design rewards efficient generators because they are more likely to be in merit and they earn an economic profit in the hours a less efficient generator sets the price. Clearly, this reward for efficiency will be enhanced with GHG offset costs added into the picture for natural gas units that fall below the threshold efficiency as well as all coal units. However, without details in how a capacity market would be implemented, it is not possible to determine whether this same type of incentive would exist.

[27] In the current market design, there is an implicit assumption that marginal generators recover their capital costs during times of shortage when the electricity prices rise well above marginal costs. If a capacity market exists, it will presumably allow generators to recover their capital costs in the secondary market and the energy market should simply reflect production costs.

9 The Benefits of the Conceptual Framework

The conceptual framework described in this document provides a variety of benefits. It:

- is a “made-in-Alberta” approach that reflects the unique structure of the electricity industry in Alberta;
- can achieve meaningful reductions in greenhouse gas emissions intensity in the 2010 timeframe and further, more significant, reductions in the long term to 2020 and beyond;
- balances environmental and economic objectives by
    - providing public policy signals to reduce GHG emissions intensity, and
    - recognizing investments made in existing thermal generation units and capital stock turnover;
- can provide for a fair and equitable distribution of costs across all generation units;
- includes a flexible range of compliance tools including incentives for industry to take actions that will contribute meaningful long-term reductions;
- can be calibrated to achieve desired policy objectives; and
- includes Five-Year Reviews that allow adjustments needed to reflect changing external developments and policy objectives.

This conceptual framework creates a strong foundation and basis for future discussions on the unresolved elements.

10 Recommendation for Further Work

The subgroup worked diligently and in good faith to fulfill its mandate, but for the reasons already outlined, members were unable to finalize key elements of the framework. It is the view of the group that continuing work in the near term could result in some additional refinement of the framework elements, but that greater policy certainty is required in the national and international policy environment before substantial further progress can occur.

Recommendations on approval of the conceptual framework and next steps are as follows:

Recommendation 1 – Conditional Approval of Conceptual GHG Management Framework and Next Steps

Approval-in-principle of the conceptual framework conditional on:

a) Future satisfactory resolution of all integral framework elements, including:
   - Percentage reduction of general offset
   - Definition of eligible offsets, including banking
   - Specified intensity limits
   - Treatment of pre-2008 offsets
   - Treatment of renewable and alternative generation
   - Treatment of cogeneration
   - Credit for units performing below specified intensity limits.

b) Government strategies and approaches continuing to develop within the current range of stakeholder understanding.

Recommendation 2 – Framework to Guide Government Approaches

This conceptual framework guide the approaches the provincial and federal governments take with respect to managing greenhouse gases from the Alberta electricity sector.

Recommendation 3 – Use of CASA Process

Consideration be given to resolving the outstanding elements of the framework through CASA.

Recommendation 4 – Further Work

That the CASA executive committee determine if and when there is an opportunity for CASA to further the resolution of the framework elements and, if so, to initiate a process in a timely manner to develop draft terms of reference for a project team that includes clear direction on deliverables, timelines and team composition for consideration by the CASA board of directors.

Appendix A Glossary

Allowance

(See permit)

Alternative energy

Alternative energy includes generation units less than 5MW whose emissions intensities are less than or equal to a combined cycle gas turbine (0.418 t/MWh)[28] and units that generate power using energy recovered from a process stream whose intensity is less than 0.21 t/MWh, and are not classified as cogeneration as defined in this report.

Behind the fence

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

CO_2 (carbon dioxide)

A greenhouse gas that is produced in the burning of fossil fuels

CO_2 equivalent

The amount of CO_2 that would cause the same effect as a given amount or mixture of other greenhouse gases, based on their global warming potential.

Cogeneration

The simultaneous production of useful heat and electricity.

Compliance Instrument

A mechanism that is used to meet a GHG emissions reduction obligation. It includes offsets, offset equivalencies, permits and credits.

Credit

See Offsets

GHG(s) (greenhouse gas(es))

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

GWh (Gigawatt-hour)

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

Intensity

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

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

[28] As noted in the report of the EPT, available online at http://casahome.org/electricity/index.asp or upon request to CASA

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

kW (kilowatt)

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

MW (Megawatt)

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

MWh (Megawatt-Hour)

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

NGCC (Natural Gas Combined Cycle)

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

Offsets and Credits

Under the electricity target system outlined in this paper, generation units with actual emission intensity in excess of their intensity limit must cover the difference with “credits” or permits. Credits are issued by the government for qualifying and verified reductions in emissions by emitters outside the electricity target system. Such reductions are referred to as offsets because the reduction outside electricity target system “offset” emissions in excess of targets in the target system.

Credits might also be issued to generation units with actual intensity below their intensity limit.

Credits (like permits or allowances) are, in effect, the carbon currency used by generators to true-up to their intensity targets.

Offset equivalency

An emission reduction equivalency in the transition principles or similar mechanism not meeting accepted principles for offsets.

Permit or allowance

A permit is the right to emit one tonne of CO2-e; also referred to as an allowance or gratis allocation and used in some places interchangeably with “credit.”

PPA (Power Purchase Arrangements)

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

Specified intensity limit

The emission intensity limits stipulated under the framework for a) units subject to the Unit Age component, and b) units subject to the floor associated with the general offset component.

Stacking order

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

Thermal unit

An electricity generating unit, excluding units deemed to be renewable or alternative generation.

TWh (Terawatt-hour)

Terawatt-hour is a unit of usage of power usage or generation; i.e., the number of terawatts used or generated in one hour. One terawatt equals 1,000,000 megawatts.

Appendix B GHG subgroup Members

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James Brown	Shell Canada
Ward Christensen	AltaGas
Julia Ciccaglione	Pristine Power
Keith Denman	CASA Secretariat
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Don Wharton	TransAlta

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Former Members:

Christine Macken	CASA Secretariat
David Spink	Alberta Environment

Appendix C EPT Definitions and GHG Recommendations

Definitions

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).

Existing Units

For the purposes of this management framework, an "existing" thermal generation unit be defined as follows:

An existing coal or gas unit is one that, prior to the most recent review and update of the BATEA emission limits,

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

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

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.

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.

Design Life

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

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

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

GHG Recommendations

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

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

- A fair and equitable contribution to the reduction of greenhouse gas emissions from the Alberta electricity sector in keeping with broader multi-sectoral targets
- The projected business as usual emission intensity
- The nature, scope, availability and cost of eligible offsets
- Issues of double counting[29] (see recommendations 23, 24 and 28)
- Investment in innovative technology in Alberta
- Additional flexibility for dealing with Alberta's Natural Gas Combined Cycle offset requirement for new coal-fired units

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

Rules for Offset Credits (Recommendation 24)

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.[30]

New Coal Unit NGCC Offset Requirement (Recommendation 25)

The Alberta government continue to apply its Natural Gas Combined Cycle (NGCC) offset policy[31] 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

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

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

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

the greenhouse gas reduction commitment for the Design Life of the unit. It is recognized that future national or international greenhouse gas reduction commitments may result in additional management obligations.

(Note: Flexibility should be provided to companies in meeting this offset requirement with special consideration given to offsets associated with in-province renewables, energy efficiency and conservation, and technology research, development, and investment. Where agreements do not already exist and government support is involved in the development of an offset credit, it is recognized that apportionment mechanisms must be developed by industry and government for the ownership of these greenhouse gas reductions.)

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

Greenhouse Gas Emission Credits for Early Shutdown (Recommendation 26)

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 cogeneration 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.

Discounting of Greenhouse Gas Emission Credits (Recommendation 27)

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

"Green Tag" Credits for Renewable Energy (Recommendation 28)

A "green tag" program for renewable and alternate energy be established, that is in units of "tonnes of CO_2-equivalent." This program should be developed by 2005 and applied to all renewable and alternate energy developed after December 31, 2001.

Green tag credits, usable for compliance with individual units' greenhouse gas intensity targets, could be made available in addition to the green certificates proposed as part of achieving the 3.5% renewable energy target (see recommendation 59).

This recommendation does not preclude the sale of credits from earlier reductions. It is recognized that the issue of credit for earlier action is to be resolved in another forum.

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

Appendix D Transition Principles

March 2004

TRANSITION PRINCIPLES
Regarding Greenhouse Gas Emission Requirements for New Coal-Fired Electricity Facilities in Alberta

A. BACKGROUND

Late in 2001, Alberta established a policy that new coal-fired power generation must effectively reduce the GHG emission intensity to the same level as a natural gas combined cycle (NGCC) plant. This policy ensures that net GHG emissions from new coal-fired plants will be as low as has already been achieved by stand-alone, large scale gas-fired facilities in Alberta.

Alberta is currently developing a new long-term management framework for air emissions from the electricity sector. A number of initiatives are related to developing this framework, including implementation of Alberta's climate change action plan *Taking Action*; the Clean Air Strategic Alliance Electricity Project Team (CASA-EPT) report; and negotiation of an agreement with the electricity sector respecting greenhouse gas (GHG) emissions.

While the long-term management framework is being developed, industry needs certainty for making investments to reduce or offset GHG emissions associated with new coal-fired power plants subject to the NGCC requirement. These transition principles provide greater certainty for an interim period, and will lead into the post-transition management framework being developed for the electricity sector.

Alberta wants to encourage GHG management practices that reduce net emission intensity and lead to continuous improvement in emissions performance. Alberta is committed to investing in, and encouraging private sector investment in, technology to improve the economic and environmental performance of the province's electricity generation. Alberta has set an objective of increasing power generation provided by low intensity and renewable energy sources. Alberta has a long-standing commitment to allow flexibility in how GHG emission performance targets will be achieved, and also to recognize early action in reducing GHG emissions so that those who take early action are not disadvantaged.

B. TRANSITION PERIOD

1. Period

a) The transition period begins with the commercial start-up of the first new coal-fired power facility subject to the NGCC offset requirement and will be in place for a period of three years.

b) Changes to the provisions included in this document can be made during that time to conform to CASA-EPT recommendations that are subsequently approved by the Alberta government.

2. Greenhouse Gas Emission Requirement

a) New coal-fired power plants must reduce their net GHG emissions intensity to the level of an NGCC plant.

b) The NGCC standard is 0.418 tonnes of CO_2 equivalent per MWh.

3. Recognized Emission Reduction Equivalencies

a) In addition to direct emission reductions via application of power generation technology, the following four types of actions may be used in achieving net GHG emissions requirements: emission offsets, renewable power generation, early shutdown of other power generation facilities, and qualifying investment in technology development.

C. APPLYING EMISSION REDUCTION EQUIVALENCIES DURING THE TRANSITION PERIOD

4. No Double Counting

a) A particular emission reduction equivalency may be used only once to meet GHG emission reduction requirements.

b) A particular emission reduction equivalency may not be used by more than one party.

c) Joint owners may share an emission reduction equivalency and use each portion uniquely.

d) Notwithstanding the provisions above, a particular emission reduction equivalency may be used to meet both the Alberta requirement and the requirement in another GHG management system in a Canadian jurisdiction, as long as they are used only once in each set of calculations.

5. Banking

a) Emission reduction equivalencies established in a year may be banked for use in subsequent years.

6. Ownership

a) Emission reduction equivalencies from offsets, renewables and premature facility shutdowns, as described in this document, must be owned by the party claiming the benefit.

b) Qualifying technology investments, as described in Section 12, must be made by the party claiming the benefit.

c) Jointly owned emission reduction equivalencies must be used in such a way that double counting does not occur.

7. Verification

a) Emissions reduction equivalencies must be verified by a qualified independent third-party auditor.

8. Reporting and Compliance

a) GHG emission requirements will be enforced by Alberta Environment in a manner consistent with the department's compliance assurance principles and programs.

b) An annual GHG emission report must be submitted to Alberta Environment by October of the following year.

c) Regulated parties may be provided up to 3 months following AENV's review of the facility's GHG report to address and correct any shortfall in emission reduction equivalencies before a determination is made on compliance.

9. Offsets

a) Offsets are off-site reductions of GHG emissions or removals of GHGs from the atmosphere.

b) Offsets must be real, measurable and verifiable, and must result from an action that was not otherwise required by law at the time the action was initiated.

c) There are no geographical, jurisdictional or sectoral restrictions on offsets.

d) Information on the geographic location of offset projects will be required for information purposes.

e) Offsets created since the power generator first participated in the Voluntary Challenge & Registry may be used in the year they were established or banked for use in subsequent years.

10. Renewables

a) Renewable power sources in Alberta may be considered in achieving GHG emissions performance requirements by including any emissions from the renewable generation in the numerator and the power generated by the renewable source in the denominator of the GHG emissions intensity calculation for the facility.

b) Alternatively, renewable power projects can be used to establish credits based on the difference between the GHG emission intensity of the renewable project and the emission intensity of the relevant marginal electricity generation unit, to a maximum credit amount of 0.418 tonnes of CO2 equivalent per MWh.

c) Renewable power from sources built since the power generator first participated in the *Voluntary Challenge & Registry* may be used in calculating net emissions intensity in the year the renewable power was generated or banked for use in subsequent years.

11. Early Plant Shutdowns

a) Early shut down occurs when power generation facilities are shut down prior to their normal end of design life and not otherwise in response to a regulatory requirement to shut down.

b) Normal end of life for coal-fired power plants is reached at 40 years of age or at the end of the plant's Power Purchase Arrangement (PPA) agreement, whichever is later.

c) Normal end of life for all units of the Wabamun thermal electric power plant is March 31, 2010.

d) The incremental GHG emission reduction equivalency for a year is calculated by multiplying the difference between the emissions intensity of the shut down facility and the NGCC level of 0.418 tonnes of CO2 equivalent per MWh by the facility's average annual power generation, as defined by the average of the three highest years of generation in the five years prior to shutdown, through to the normal end of life.

e) Early shut downs of power generation facilities after January 1, 2002 in Alberta may be used in achieving GHG emissions performance requirements.

f) Emission reduction equivalencies established under the early shut down provision may be used to meet GHG emission performance requirements for the year or may be banked for use in subsequent years.

12. Investment in Technology Development

a) The contribution of incremental investment in qualifying technology development may be included in achieving the NGCC performance requirement.

b) To qualify, investments must be multi-party in nature and consistent with the Alberta Energy Research Institute (AERI) strategy in support of Alberta’s climate change action plan *Taking Action.*

c) Incremental investment is that amount above the average annual investment in the three calendar years preceding the first year that the benefit is claimed.

d) Investments that might be considered ongoing, business as usual efforts to improve performance would not qualify.

e) Qualifying technology investments will be recognized at a rate of 1 tonne of CO2 equivalent for every $15 of investment.

f) Alberta Environment will provide one year's notice of any rate changes specified in sub-Section e).

g) Qualifying technology investments made since the publication of Alberta's climate change action plan *Taking Action*, October 2002, may be used in the year the investments were made or banked for use in subsequent years.

D. FOLLOWING THE TRANSITION PERIOD

a) Alberta will continue work to develop and implement a framework for long-term management of GHG emissions from Alberta's electricity sector, informed by the continuing CASA process and federal-provincial discussions.

b) The intention is to take the CASA recommendations approved by the Alberta government into consideration for implementation at the earliest practical opportunity. This may result in amendments to the transition principles prior to the end of the 3-year term.

c) The long-term management framework is expected to include an overall GHG intensity performance target for the Alberta generation system or components of it, and definition of eligible offsets and credits for compliance with the GHG performance standards.

d) Emission reduction equivalencies established under the transition principles may be eligible to bank and carry forward into this future provincial framework. At a minimum, these reductions will be fully allowed for purposes of meeting the natural gas combined cycle GHG performance standard. The eligibility of these credits for other purposes will depend on whether they meet the requirements under the rules to be developed for the forthcoming system.

Source: Alberta Environment, online at
http://www3.gov.ab.ca/env/media/news/releases/transition_principles_backgrounder.pdf

Appendix E Integrating Electricity Consumption by LFEs into Intensity Targets[32]

Basic LFE Target Structure

- Non-electricity LFE sectors:
  - LFEs are given a target/allocation equal to their output multiplied by their intensity targets (tonnes CO_2e/unit of output).
- Electricity generation in Alberta:
  - The fundamental element of electricity generation targets is a natural gas combined cycle (NGCC) intensity standard as the reference for setting targets for thermal types of generation.
    - The NGCC standard applies to new thermal generation: 0.418 t/MWh for new coal-fired units and 0.375 t/MWh for new natural gas-fired units.
    - The same specified intensity limits represent net intensity floors for existing thermal generation, which face an offset of **x**% (yet to be determined) of actual emissions.
    - New renewables could receive a credit of 50% (or some other percentage) of the specified intensity limit for new coal.
  - Generators face net intensity targets, so that their absolute targets vary with the MWh amount of generation.
- Indirect emissions from electricity use:
  - From an electricity consumer point of view, indirect emissions associated with the use of electricity from new generation would be the MWh of consumption multiplied by the NGCC intensity standard.
  - For use of electricity from existing units, indirect emissions would be the MWh of consumption multiplied by the target for the generation unit in question.

How could LFEs' electricity consumption and conservation actions be covered by intensity targets?

- LFE emissions could be defined to include direct emissions plus deemed indirect emissions from electricity consumption, based on the NGCC standard.
- Intensity targets could include indirect emission intensity, included at 100%. Intensity targets would be the BAU direct emission intensity minus the required percentage reduction (15% in the current NRCan plan) plus BAU indirect emission intensity (based on electricity intensity multiplied by the NGCC standard).

  e.g., Oil sands mining and upgrading (using round hypothetical numbers):

  Direct emissions intensity:

  BAU: 0.10 t/bbl
  85% target: 0.085 t/bbl

  Electricity consumption and indirect emission intensity:

  BAU: 0.02 MWh/bbl
  Indirect emission intensity = 0.02 MWh/bbl x 0.375 t/MWh = 0.0075 t/bbl

  Total direct and indirect intensity:

  BAU: 0.10 + 0.0075 = 0.1075 t/bbl

[32] This appendix is a proposal put forward by one stakeholder for discussion purposes, but has not been examined in detail by the subgroup.

Target = 0.085 + 0.0075 = 0.0925 t/bbl

- LFE end users of electricity would then have a balanced incentive to reduce direct emissions and electricity use and could use reduced electricity intensity along with reduced direct emission intensity and purchased permits to meet their intensity target.

How does the combination of generation and end use treatment fit together under this approach?

For example, oil sands output held constant at 1 million bbls, while electricity intensity is reduced from 0.02 MWh/bbl to 0.015 MWh/bbl, no other change from BAU numbers above.

Oil sands producer (using numbers above):

BAU

Electricity use: 0.02 MWh/bbl x 1 m bbls = 20,000 MWh

Direct + indirect intensity: 0.1075 t/bbl

Direct + indirect emissions: 1 m bbls x 0.1075 t/bbl = 107,500 t CO_2e

Target: 1 m bbls x 0.0925 t/bbl =92,500 tCO_2e

BAU-Target Gap: 107,500 – 92,500 = 15,000 tCO_2e

Actual

Electricity use: 0.015 MWh/bbl x 1 m bbls = 15,000 MWh

Intensity: 0.10 t/bbl +0 .015 MWh/bbl x 0.375 t/MWh = 0.10 + 0.00565 = 0.10565 t/bbl

Emissions: 1 m bbls x .10565 t/bbl = 105,650 tCO_2e

Actual Gap: = 105,650 – 92,500 = 13,150 tCO_2e

Gap reduced from 15,000 tCO_2e to 13,150 tCO_2e, that is, by 1,850 tCO_2e

Alberta Electricity generators:

New generation subject to NGCC standards: 0.418 t/MWh for coal, 0.375 t/MWh for natural gas.

Existing generation subject to an **x**% offset of actual emissions towards the NGCC standard multiplied by their generation. Existing (cogeneration) units below the standard are assumed to receive credits equal to **x**% of the difference between the standard multiplied by their generation and their emissions. For simplicity, in this example, **x =** 10.

The attached table shows the effect on *net emissions* of an oil sands user of electricity and a generator, for four different types of generation, when the oil sands user reduces consumption by 5,000 MWh and there is a corresponding reduction in generation. Where the intensity target of the generator is above the 0.375 T/MWh used to deem indirect emissions, combined net emissions fall. Where the generation intensity target is equal to the deemed indirect emission intensity, the combined net emissions are unchanged. And where the generation intensity target is less than the deemed indirect emission intensity, the combined net emissions increase.

Impact of Reduced Electricity Consumption on Combined Net Emissions of End User & Generator

Deemed electricity intensity for end use	0.375	Existing generation offset requirement **X**% = 10%

		Direct Emissions		Electricity & Indirect Emissions				Total Emissions		Target		Gap
Hypothetical Oil Sands	Output bbls	t/bbl	tonnes	MWh/bbl	MWh	t/bbl	tonnes	t/bbl	tonnes	t/bbl	tonnes	tonnes
BAU	1,000,000	0.100	100,000	0.020	20,000	0.0075	7,500	0.108	107,500	0.0925	92,500	15,000
Actual	1,000,000	0.100	100,000	0.015	15,000	0.0056	5,625	0.106	105,625	0.0925	92,500	13,125
Change	-	-	-	(0)	(5,000)	(0)	(1,875)	(0)	(1,875)	-	-	(1,875)

Old Coal

		Actual Intensity	Intensity Target		
		1.05	0.9868		
	Generation & Use	Actual Emissions	Target Emissions	Gap	Combined Net Emissions
BAU consumption	20,000	21,000	19,736	1,264	
Reduced consumption	15,000	15,750	14,802	948	
Change	(5,000)	(5,250)	(4,934)	(316)	
End user change in gap				(1,875)	
Combined change		(5,250)		(2,191)	(3,059)

NGCC @ .375

		Actual Intensity	Intensity Target		
		0.375	0.375		
	Generation	Actual Emissions	Target Emissions	Gap	Combined Net Emissions
BAU consumption	20,000	7,500	7,500	-	
Reduced consumption	15,000	5,625	5,625	-	
Change	(5,000)	(1,875)	(1,875)	-	
End user change in gap				(1,875)	
Combined change		(1,875)		(1,875)	-

New Coal

		Actual Intensity	Intensity Target		
		0.86	0.418		
	Generation	Actual Emissions	Target Emissions	Gap	Combined Net Emissions
BAU consumption	20,000	17,200	8,360	8,840	
Reduced consumption	15,000	12,900	6,270	6,630	
Change	(5,000)	(4,300)	(2,090)	(2,210)	
End user change in gap				(1,875)	
Combined change		(4,300)		(4,085)	(215)

Gas Cogen @.35

		Actual Intensity	Intensity Target		
		0.35	0.3525		
	Generation	Actual Emissions	Target Emissions	Gap	Combined Net Emissions
BAU consumption	20,000	7,000	7,050	(50)	
Reduced consumption	15,000	5,250	5,288	(38)	
Change	(5,000)	(1,750)	(1,763)	13	
End user change in gap				(1,875)	
Combined change		(1,750)		(1,863)	113

Appendix F Allocation Methodologies for Emissions from Cogeneration

Stand-alone reference facilities method

The details of method 5 are as follows:

- The cogeneration emissions are divided between electricity generation and the steam host activity in proportion to the relative amounts of natural gas required to produce the electricity in a reference unit and to produce the steam in a stand-alone industrial boiler.
- The proportions will obviously depend on the type and therefore the efficiency of the reference electricity generation and industrial boiler chosen for the allocation.
- The subgroup used as references the efficiencies of a new NGCC plant of the type recently being built in Canada and a corresponding new industrial steam boiler. The subgroup settled on 50% efficiency for the NGCC and 80% efficiency of the boiler as being reasonable assumptions for determining the division of cogeneration emissions, recognizing that arguments could be put forward for minor variations around those numbers, but that such variations do not materially affect the division of emissions.
- The table below gives the division of emissions and emission intensity of electricity and steam that results from applying this method to information on 16 cogeneration facilities in Alberta, ordered from the least to most emission intensive.
- The emission intensity of the electricity generated and the steam produced, and the division of emissions between them depends on the configuration of the cogeneration. The efficiency of most new cogeneration facilities is expected to be greater than the output weighted average of the efficiencies of a 50% efficient NGCC and an 80% efficient boiler. If that is the case, the intensity of cogeneration electricity and steam will each be the same proportion below the intensity of the reference stand-alone facilities. The table shows a fairly wide range in efficiency of the cogeneration units included in the sample, some less efficient than the reference facilities.

Unit	NGCC turbine efficiency 50%		Boiler efficiency 80%	
	Intensity of electricity (t/MWh)	% emissions to electricity	Intensity of steam (t/GJ)	% emissions to steam
1	0.250	77.4%	0.043	22.6%
2	0.289	54.7%	0.050	45.3%
3	0.294	44.7%	0.051	55.3%
4	0.305	50.4%	0.053	49.6%
5	0.325	57.4%	0.056	42.6%
6	0.327	24.7%	0.057	75.3%
7	0.329	51.1%	0.057	48.9%
8	0.350	51.3%	0.061	48.7%
9	0.362	45.8%	0.063	54.2%
10	0.365	78.1%	0.063	21.9%
11	0.384	75.8%	0.067	24.2%
12	0.395	73.1%	0.069	26.9%
13	0.397	78.3%	0.069	21.7%
14	0.405	65.6%	0.070	34.4%
15	0.407	83.5%	0.071	16.5%
16	0.427	81.2%	0.074	18.8%
Minimum	0.250	24.7%	0.043	16.5%
Maximum	0.427	83.5%	0.074	75.3%
Weighted Average	0.354	58.6%	0.059	41.4%
Stand-alone	0.371		0.064	

The division of emissions is based on the following formulas:[33]

- Electricity: $E_e = ET * \left(\frac{\left(\frac{Oe}{0.5}\right)}{\left(\frac{Oe}{0.5}\right) + \left(\frac{Oth}{0.8}\right)} \right)$
- Steam/Heat: $E_{th} = ET * \left(\frac{\left(\frac{Oth}{0.8}\right)}{\left(\frac{Oth}{0.8}\right) + \left(\frac{Oe}{0.5}\right)} \right)$

where: E_e = GHG emissions allocated to electricity production
E_{th} = GHG emissions allocated to steam/heat production
ET = total GHG emissions from facility
O_e= actual net electricity output from facility in MWh
O_{th} = actual net steam/heat energy output from facility in units of MWh

[33] The full formula for the electricity share of emissions (and correspondingly for steam) would show total cogeneration emissions multiplied by the *emissions* from a NGCC unit divided by the sum of emissions from a NGCC unit and a stand-alone industrial boiler. Since the terms in those formulae converting output of electricity and steam into emissions cancel out, we are left with the reduced form formulae as shown.

Appendix G Examples of the Application of the Conceptual Framework

Purpose:
To provide specific examples of how the greenhouse gas management framework would apply given certain assumptions. The examples and assumptions are "without prejudice" to CASA stakeholders and serve as illustrative examples of how the conceptual framework components would work.

Seven examples are provided in this appendix:
- New coal-fired unit
- Transitional coal-fired unit
- Existing coal-fired unit
- New gas-fired unit above specified intensity limit
- Existing gas-fired unit above offset "floor"
- Existing gas-fired unit near offset "floor"
- Existing gas-fired unit at the end of Design Life

Assumptions:
- "New" gas units are those built **after** January 1, 2008
- Specified intensity limits come into effect **three years** after the Five-Year Review
- General offset percentages come into effect **two years** after the Five-Year Review
- Units operating below applicable intensity limits **do not** receive credit
- The specified intensity limit for coal-fired units equals the burner tip intensity for gas-fired units plus upstream emissions associated with natural gas production
- The offset "floor" is equal to the specified intensity limit of the day
- GO = general offset component, UA = Unit Age component

Five-Year Review:
Coal Specified Intensity Limits and General Offset %

Specified Intensity Limits (t/MWh)

2004	0.418
2008	0.400
2013	0.380
2018	0.340

General Offset %

2008	8.0%
2011	15.0%
2016	20.0%
2021	25.0%

Five-Year Review:
Gas Specified Intensity Limits and General Offset %

Specified Intensity Limits (t/MWh)

2004	0.375
2008	0.360
2013	0.340
2018	0.300

General Offset %

2008	8.0%
2011	15.0%
2016	20.0%
2021	25.0%

Example 1. New Coal-Fired Unit

Unit Data

Fuel	Coal
Commercialization Date	Jan. 1, 2014
End of Design Life	Jan. 1, 2054
Upgrade Date	Jan. 1, 2064
Max. Capacity Rating (MW)	450
Capacity Factor	90.0%
Actual Intensity (t/MWh)	0.84
Generation (MWh)	3,547,800
Actual Emissions (t)	2,980,152

	Component	Intensity Limit	Offsets		Component	Intensity Limit	Offsets
2005	n/a	n/a	n/a	**2016**	UA	0.380	1,631,988
2006	n/a	n/a	n/a	**2017**	UA	0.380	1,631,988
2007	n/a	n/a	n/a	**2018**	UA	0.380	1,631,988
2008	n/a	n/a	n/a	**2019**	UA	0.380	1,631,988
2009	n/a	n/a	n/a	**2020**	UA	0.380	1,631,988
2010	n/a	n/a	n/a	**2021**	UA	0.380	1,631,988
2011	n/a	n/a	n/a	**2022**	UA	0.380	1,631,988
2012	n/a	n/a	n/a	**2023**	UA	0.380	1,631,988
2013	n/a	n/a	n/a	**2024**	UA	0.380	1,631,988
2014	UA	0.380	1,631,988	**2025**	UA	0.380	1,631,988
2015	UA	0.380	1,631,988				

In this example a “new” coal unit is built in 2014 and therefore its intensity limit will equal the specified intensity limit of the day. The intensity limit of the day is 0.380 t/MWh, set in the 2008 Five-Year Review, and applies for the unit’s entire Design Life.

Example 2. Transitional Coal-Fired Unit

Unit Data

Fuel	Coal
Commercialization Date	Jan. 1, 2005
End of Design Life	Jan. 1, 2045
Upgrade Date	Jan. 1, 2055
Max. Capacity Rating (MW)	450
Capacity Factor	90.0%
Actual Intensity (t/MWh)	0.86
Generation (MWh)	3,547,800
Actual Emissions (t)	3,051,108

	Component	Intensity Limit	Offsets		Component	Intensity Limit	Offsets
2005	UA	0.418	1,568,128	**2016**	UA	0.418	1,568,128
2006	UA	0.418	1,568,128	**2017**	UA	0.418	1,568,128
2007	UA	0.418	1,568,128	**2018**	UA	0.418	1,568,128
2008	UA	0.418	1,568,128	**2019**	UA	0.418	1,568,128
2009	UA	0.418	1,568,128	**2020**	UA	0.418	1,568,128
2010	UA	0.418	1,568,128	**2021**	UA	0.418	1,568,128
2011	UA	0.418	1,568,128	**2022**	UA	0.418	1,568,128
2012	UA	0.418	1,568,128	**2023**	UA	0.418	1,568,128
2013	UA	0.418	1,568,128	**2024**	UA	0.418	1,568,128
2014	UA	0.418	1,568,128	**2025**	UA	0.418	1,568,128
2015	UA	0.418	1,568,128				

A coal unit is built in 2005 and is classified as a “transitional” unit. For the duration of its Design Life this unit will be required to offset its emissions down to the specified intensity limit of the day, which is 0.418 t/MWh. his limit was established when the unit applied for approval.

Example 3. Existing Coal-Fired Unit

Unit Data

Fuel	Coal
Commercialization Date	Dec. 31, 1975
End of Design Life	Dec. 31, 2015
Upgrade Date	Dec. 31, 2025
Max. Capacity Rating (MW)	450
Capacity Factor	90.0%
Actual Intensity (t/MWh)	1.30
Generation (MWh)	3,547,800
Actual Emissions (t)	4,612,140

	Component	Intensity Limit	Offsets		Component	Intensity Limit	Offsets
2005	n/a	n/a	n/a	**2016**	UA	0.380	3,263,976
2006	n/a	n/a	n/a	**2017**	UA	0.380	3,263,976
2007	n/a	n/a	n/a	**2018**	UA	0.380	3,263,976
2008	GO	1.196	368,971	**2019**	UA	0.380	3,263,976
2009	GO	1.196	368,971	**2020**	UA	0.380	3,263,976
2010	GO	1.196	368,971	**2021**	UA	0.340	3,405,888
2011	GO	1.196	368,971	**2022**	UA	0.340	3,405,888
2012	GO	1.196	368,971	**2023**	UA	0.340	3,405,888
2013	GO	1.105	691,971	**2024**	UA	0.340	3,405,888
2014	GO	1.105	691,821	**2025**	UA	0.340	3,405,888
2015	GO	1.105	691,821	**2026**	Upgrade to "New Unit" or Shutdown		

This unit was built December 31, 1975 and the end of its Design Life is December 31, 2015. Therefore for the years 2008-2015, this unit will be subject to the general offset component. However, at the end of its Design Life this unit will be required to offset its emissions down to the specified intensity limit of the day. The 2016 specified intensity limit, set in 2013, equals 0.380 t/MWh. If the unit upgrades in 2026 it will be re-classified as “new” and subject to the 2026 specified intensity limit for the duration of its new Design Life.

Example 4. New Gas-Fired Unit Above Specified Intensity Limit

Unit Data

Fuel	Natural Gas
Commercialization Date	Jan. 1, 2010
End of Design Life	Jan. 1, 2040
Max. Capacity Rating (MW)	200
Capacity Factor	50.0%
Allocated Intensity (t/MWh)	0.430
Generation (MWh)	876,000
Allocated Emissions (t)	376,680

	Component	Intensity Limit	Offsets		Component	Intensity Limit	Offsets
2005	n/a	n/a	n/a	**2016**	UA	0.375	48,180
2006	n/a	n/a	n/a	**2017**	UA	0.375	48,180
2007	n/a	n/a	n/a	**2018**	UA	0.375	48,180
2008	n/a	n/a	n/a	**2019**	UA	0.375	48,180
2009	n/a	n/a	n/a	**2020**	UA	0.375	48,180
2010	UA	0.375	48,180	**2021**	UA	0.375	48,180
2011	UA	0.375	48,180	**2022**	UA	0.375	48,180
2012	UA	0.375	48,180	**2023**	UA	0.375	48,180
2013	UA	0.375	48,180	**2024**	UA	0.375	48,180
2014	UA	0.375	48,180	**2025**	UA	0.375	48,180
2015	UA	0.375	48,180				

This gas-fired unit is classified as "new" and is therefore required to offset its emissions down to the specified intensity limit of the day. That intensity limit equals 0.375 t/MWh and applies for the duration of the unit's Design Life.

Example 5. Existing Gas-Fired Unit Above Offset "Floor"

Unit Data

Fuel	Natural Gas
Commercialization Date	Dec. 31, 1997
End of Design Life	Dec. 31, 2027
Max. Capacity Rating (MW)	200
Capacity Factor	50.0%
Allocted Intensity (t/MWh)	0.430
Generation (MWh)	876,000
Allocated Emissions (t)	376,680

	Component	Intensity Limit	Offsets		Component	Intensity Limit	Offsets
2005	n/a	n/a	n/a	**2016**	GO	0.366	56,502
2006	n/a	n/a	n/a	**2017**	GO	0.366	56,502
2007	n/a	n/a	n/a	**2018**	GO	0.344	75,336
2008	GO	0.396	30,134	**2019**	GO	0.344	75,336
2009	GO	0.396	30,134	**2020**	GO	0.344	75,336
2010	GO	0.396	30,134	**2021**	GO	0.344	75,336
2011	GO	0.396	30,134	**2022**	GO	0.344	75,336
2012	GO	0.396	30,134	**2023**	GO	0.323	94,170
2013	GO	0.366	56,502	**2024**	GO	0.323	94,170
2014	GO	0.366	56,502	**2025**	GO	0.323	94,170
2015	GO	0.366	56,502				

This unit was built in 1997 and is therefore classified as “existing.” It is subject to the general offset and the offset “floor.” However, it must offset the entire general offset percentage because its allocated intensity minus the general offset is above the offset “floor.”

Example 6. Existing Gas-Fired Unit Near Offset "Floor"

Unit Data

Fuel	Natural Gas
Commercialization Date	Dec. 31, 1997
End of Design Life	Dec. 31, 2027
Max. Capacity Rating (MW)	200
Capacity Factor	50.0%
Actual Intensity (t/MWh)	0.380
Generation (MWh)	876,000
Allocated Emissions (t)	332,880

	Component	Intensity Limit	Offsets		Component	Intensity Limit	Offsets
2005	n/a	n/a	n/a	**2016**	GO	0.340	35,040
2006	n/a	n/a	n/a	**2017**	GO	0.340	35,040
2007	n/a	n/a	n/a	**2018**	GO	0.340	35,040
2008	GO	0.375	4,380	**2019**	GO	0.340	35,040
2009	GO	0.375	4,380	**2020**	GO	0.340	35,040
2010	GO	0.375	4,380	**2021**	GO	0.300	70,080
2011	GO	0.360	17,520	**2022**	GO	0.300	70,080
2012	GO	0.360	17,520	**2023**	GO	0.300	70,080
2013	GO	0.360	17,520	**2024**	GO	0.300	70,080
2014	GO	0.360	17,520	**2025**	GO	0.300	70,080
2015	GO	0.360	17,520				

This unit was built in 1997 and is therefore classified as "existing." It is subject to the general offset and is protected by the offset "floor." Because offsetting the full amount of the general offset would take the unit's intensity below the offset "floor," the intensity limit for this unit is the offset "floor."

Example 7. Existing Gas-Fired Unit at the End of Design Life

Unit Data

Fuel	Natural Gas
Commercialization Date	Dec. 31, 1978
End of Design Life	Dec. 31, 2008
Max. Capacity Rating (MW)	200
Capacity Factor	50.0%
Actual Intensity (t/MWh)	0.470
Generation (MWh)	876,000
Allocated Emissions (t)	411,720

	Component	Intensity Limit	Offsets		Component	Intensity Limit	Offsets
2005	n/a	n/a	n/a	**2016**	UA	0.340	113,880
2006	n/a	n/a	n/a	**2017**	UA	0.340	113,880
2007	n/a	n/a	n/a	**2018**	UA	0.340	113,880
2008	GO	0.432	33,288	**2019**	UA	0.340	113,880
2009	UA	0.375	83,220	**2020**	UA	0.340	113,880
2010	UA	0.375	83,220	**2021**	UA	0.300	148,920
2011	UA	0.360	96,360	**2022**	UA	0.300	148,920
2012	UA	0.360	96,360	**2023**	UA	0.300	148,920
2013	UA	0.360	96,360	**2024**	UA	0.300	148,920
2014	UA	0.360	96,360	**2025**	UA	0.300	148,920
2015	UA	0.360	96,360				

This unit reaches the end of its Design Life on December 31, 2008. Therefore, with respect to greenhouse gases, the unit is subject to the general offset of 8% for the year 2008, and is subject to the Unit Age component from the year 2009 onward.

However, the NO_x and SO_2 framework also affect the determination of applicable greenhouse gas intensity limits. EPT recommendation #10 declares that any gas-fired unit reaching the end of its design life before December 31, 2010 will be given until December 31, 2010 to meet NO_x and SO_2 standards applicable to the age of that unit. From that date on they are given a ten-year period to use emissions trading to comply with NO_x and SO_2 standards, but at the end of that period the unit must physically upgrade to meet the standard. When the unit upgrades it will be redefined as a “new unit” and its Unit Age component intensity limit will be set for the duration of its new Design Life at the specified intensity limit of the day.

For this unit, the ten-year NO_x and SO_2 emissions trading period begins in 2011 and ends in 2020. During that period the unit is subject to any adjustment of the specified intensity limit coming out of the Five-Year Reviews. By December 31, 2020 the unit must physically upgrade, at which time it will be redefined as a “new unit” and its intensity limit will be set at 0.300 t/MWh for the duration of its new Design Life.