Appendix A
Administrative Order 238 Establishing the Alaska Climate Change Sub-Cabinet

Administrative Orders
FROM THE OFFICE OF THE GOVERNOR OF ALASKA

Sarah Palin
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

September 14th, 2007

ADMINISTRATIVE ORDER NO. 238

I, Sarah Palin, Governor of the State of Alaska, under the authority of art. III, secs. 1 and 24 of the Alaska Constitution establish the Alaska Climate Change Sub-Cabinet to advise the Office of the Governor on the preparation and implementation of an Alaska climate change strategy.

BACKGROUND AND FINDINGS

Scientific evidence shows many areas of Alaska are experiencing a warming trend. Many experts predict that Alaska, along with our northern latitude neighbors, will continue to warm at a faster pace than any other state, and the warming will continue for decades. Climate change is not just an environmental issue. It is also a social, cultural, and economic issue important to all Alaskans. As a result of this warming, coastal erosion, thawing permafrost, retreating sea ice, record forest fires, and other changes are affecting, and will continue to affect, the lifestyles and livelihoods of Alaskans. Alaska needs a strategy to identify and mitigate potential impacts of climate change and to guide its efforts in evaluating and addressing known or suspected causes of climate change. Alaska's climate change strategy must be built on sound science and the best available facts and must recognize Alaska's interest in economic growth and the development of its resources. Commercializing Alaska's great natural gas reserves through a new pipeline will improve the nation's energy security while providing a clean, low carbon fuel to help the nation reduce its overall greenhouse gas emissions.

PURPOSE AND DUTIES

The purpose of the Climate Change Sub-Cabinet is to advise the Office of the Governor on the preparation and implementation of an Alaska climate change strategy. This strategy

should include building the state's knowledge of the actual and foreseeable effects of climate warming in Alaska, developing appropriate measures and policies to prepare communities in Alaska for the anticipated impacts from climate change, and providing guidance regarding Alaska's participation in regional and national efforts addressing the causes and effects of climate change.

In view of its purpose, the Climate Change Sub-Cabinet shall develop recommendations on the following:

1. the assembly of scientific research, modeling, and mapping information in ways that will help the public and policymakers understand the actual and projected effects of climate change in Alaska, including the time frames in which those effects are likely to take place;

2. the prioritization of climate change research in Alaska to best meet the needs of the public and policymakers;

3. the most effective means of informing, and generating a dialogue with the public regarding climate change in Alaska;

4. the early assessment and development of an action plan addressing climate change impacts on coastal and other vulnerable communities in Alaska;

5. the policies and measures to reduce the likelihood or magnitude of damage to infrastructure in Alaska from the effects of climate change;

6. the policies and measures addressing foreseeable changes to the marine environment; the quantity, quality, and location of fish and game in Alaska; and the productivity of forests and agricultural lands in Alaska due to climate change;

7. the evaluation and response to the risks of new, or an increase in the frequency or severity of, disease and pests due to climate change in Alaska;

8. the identification of federal and state mechanisms for financing climate change activities in Alaska, including research and adaptation projects;

9. the potential benefits of Alaska participating in regional, national, and international climate policy agreements and greenhouse gas registries;

10. the opportunities to reduce greenhouse gas emissions from Alaska sources, including the expanded use of alternative fuels, energy conservation, energy efficiency, renewable energy, land use management, and transportation planning;

11. aggressive efforts toward development of an Alaska natural gas pipeline to commercialize clean burning, low carbon natural gas reserves;

12. the opportunities to reduce greenhouse gas emissions from the operations of Alaska state government;

13. the opportunities for Alaska to participate in carbon-trading markets, including the offering of carbon sequestration;

14. the identification of economic opportunities for Alaska that might emerge as a result of the growing response to this global challenge;

15. other policies and measures that the Climate Change Sub-Cabinet considers would help achieve the purpose of this Order.

COMPOSITION AND CHAIRPERSON

The Climate Change Sub-Cabinet consists of the commissioners of the Department of Commerce, Community, and Economic Development; Department of Environmental Conservation; Department of Natural Resources; Department of Fish and Game; and Department of Transportation and Public Facilities. The Climate Change Sub-Cabinet shall consult with the President of the University of Alaska or his or her designee and the director of State/Federal Relations and Special Counsel in the Office of the Governor, Washington, D.C., or another representative designated by the governor.

ADMINISTRATIVE SUPPORT

The member agencies shall provide administrative support necessary to carry out this Order. In accordance with law, these agencies may enter into intergovernmental agreements or apply for federal and other grants available to accomplish the purposes of this Order.

OTHER PROVISIONS

The Climate Change Sub-Cabinet shall serve as the executive branch contact to, and a resource for, the Alaska Climate Impact Assessment Commission established by Legislative Resolve 49 (2006).

The Climate Change Sub-Cabinet may form one or more workgroups that include members of the public to assist the sub-cabinet in achieving the purpose of this Order.

At times and locations to be determined by the Climate Change Sub-Cabinet, it shall convene public meetings to present and receive comments on its draft recommendations.

Nothing in this Order is intended to limit or otherwise modify any existing or future statutory or regulatory authority of any state agency.

This Order takes effect immediately.

DATED at Juneau, Alaska, this 14th day of September, 2007.

/s/Sarah Palin
Governor

APPENDIX C
Description of
Alaska Advisory Group Process

This document, excerpted from the contract between the State of Alaska, Department of Environmental Conservation and the Center for Climate Strategies, outlines the work plan for the Alaska Climate Change Strategy Advisory Group Process. Key principles and guidelines, developed from the Governor's Administrative Order #238 and established as part of the contract are defined. The role of citizen participants in this multi-stakeholder process, as well as the purpose and goals of the step-wise progression are described. The excerpt also includes an general agendas for each meeting, an outline of the final report content, overall timing (which was extended by several months at the request of the State) and milestones. Lastly, biographies of the project facilitation team are provided.

Background

Governor Palin created Administrative Order #238 in September, 2007 directing the creation of a Climate Change Strategy (Strategy) for Alaska. A warming climate is having serious and broad scale impacts in Alaska including flooding of villages; increased strength of fall coastal storms that erode the narrow beaches of coastal villages; thawing of permanent soils resulting in subsidence of land and the buildings built upon those land parcels; and a record number of forest fires threatening community and private buildings also resulting in severe air pollution health threats.

The Governor's Administrative Order charged that the Strategy address three purposes: building the state's knowledge on actual or foreseeable effects of climate change (Research); developing appropriate measure and policies to prepare communities (Adaptation); and providing guidance on Alaska's participation in efforts to slow the physical forces that scientists have concluded are causing a warming of the climate (Mitigation).

The Climate Change Sub-Cabinet (CCSC or Sub-Cabinet) created by the Order and charged with developing the Strategy needs expert assistance to develop the Strategy using broad stakeholder processes comprised of advisory and technical work groups. Because the impacts of a changing climate are affecting many aspects of life in Alaska ranging from how we build structures to when and where we harvest resources, the State's Strategy therefore needs to reflect a broad range of personal, business and industrial activities.

Primary Objectives

The Sub-Cabinet decided that developing the Strategy for Alaska must build upon the knowledge, expertise, and concerns of a broad representation of Alaskans because climate change is not just an environmental issue, but one with far-reaching social, cultural and economic consequences of great importance to all Alaskans. The Sub-Cabinet thus requires that the draft recommendations on Adaptation and Mitigation issues must be a product of a deliberative process embracing Alaska concerns and Alaska solutions from Alaska constituencies. The Sub-Cabinet is responsible for making final recommendations that, in

aggregate, comprise the Alaska Climate Change Strategy for the Governor's consideration. The Sub-Cabinet may also choose to undertake statewide public review of the draft Strategy before making recommendations to the Governor. The Sub-Cabinet is the sole convening body of the Adaptation and Mitigation stakeholder processes and as such provides ultimate oversight of them. The Center for Climate Strategies (CCS) will apply a structured process to these deliberative, consensus-building efforts. Staff to the Sub-Cabinet will provide vital assistance throughout, particularly with respect to existing measures and issues, data and analytical assistance, and logistical support.

CCS is responsible for executing the process described in the following pages which will result in draft Strategy recommendations concerning Tasks 9, 10, 12, 13, 14, and 15 of the Governor's Administrative Order.

Overall, and as described more fully on the following pages, CCS is responsible for: providing subject matter technical expertise during advisory and technical work group meetings; providing professional facilitation including a lead Alaska-based facilitator; executing the stakeholder process described below for building consensus among Alaska stakeholders to develop draft recommendations responsive to the appropriate tasks in the Order; provide guidance and knowledge on policy options, costs or savings, benefits, and other metrics for the stakeholders to assess the merits of numerous adaptation and mitigation strategies as learned through the contractor's experience in other states and other nations and as tailored to Alaska's situation; materials and communications necessary to support a successful outcome of the deliberations of the advisory and technical work groups; and written documentation of the final draft recommendations from the Mitigation Advisory Work Group and all processes for the Adaptation Advisory Working Group until August 31, 2008. The State will be responsible for those same functions for the Adaptation Advisory Group and the Oil and Gas Technical Work Group of the Mitigation Advisory Group as of September 1, 2008.

Project Officers

On behalf of the Sub-Cabinet and its Chair, Department of Environmental Conservation (DEC) Commissioner Hartig, Jackie Poston will represent the State as the project officer. Sub-Cabinet Chair Hartig may also direct actions relating to the work of the Advisory Group(s).

Stakeholder Advisory Groups and Technical Work Groups

Two umbrella citizen stakeholder advisory groups are to be established by the Sub-Cabinet with their work products going forward to the Sub-Cabinet for consideration and incorporation in the Strategy.

The Climate Change Adaptation Advisory Group (AAG) comprised of 12 to 25 members as appointed by Sub-Cabinet will work with adaptation issues stemming from the associated topics listed in the Order (Tasks #5, 6, 7, 14 and 15). Four Technical Work Groups (TWG) will be established:

- Public Infrastructure
- Health & Culture

- Natural Systems
- Economic Activities

Members to each TWG will be appointed by the Sub-Cabinet or by DEC on behalf of the Sub-Cabinet.

The Climate Change Mitigation Advisory Group (MAG) comprised of 12 to 25 members as appointed by the Sub-Cabinet will work with mitigation issues stemming from topics listed in the Order (Tasks # 9, 10, 12, 13, 14 and 15). Five Technical Work Groups will be established with members appointed by the Sub-Cabinet. The Technical Work Groups will be designed to address specific sectors of analysis:

- Electrical Supply and Demand (ESD) which includes residential, commercial and industrial energy users;
- Transportation and Land Use (TLU);
- Forestry, Agriculture and Waste Management (FAW);
- Cross-Cutting issues (CC).
- Oil & Gas (OG) which includes the oil and gas exploration, production, pipeline and refining sector

The Technical Work Group process is fully integrated with each respective Advisory Group. TWGs are comprised of members of the Advisory Group members and/or their staff, as well as additional technical members as may be appointed by the CCSC. TWGs serve in an advisory role to each Advisory Group.

In making appointments, the Sub-Cabinet recognizes the balance necessary between private sector interests and public sector interests, from technical or subject matter expertise to policy and legal expertise. Potentially affected sectors in the Alaska economy, communities or resource users will also be given weight in making specific nominations for committee or workgroup membership. While much of the Administrative Order is designed for the future needs of government to plan and manage resources of the state, governmental decisions will affect private sector decisions. In order for the Strategy to succeed, it is not sufficient to only acquire successful governmental actions, but supporting actions by leaders in businesses, industries and private citizens will be required. All of these factors will be considered in making appointments to Advisory Groups and TWGs. Lead agency staff will seek CCS's advice during the nomination review phase as well as advice from other invited persons or entities under the direction or approval of the Sub-Cabinet or its chair.

All meetings of the Advisory and Technical Work Groups are to be public meetings conducted in accord with the Alaska Open Meetings Act. The CCSC may provide additional opportunity for broad public review of the Advisory Groups' recommendations after they are submitted to the CCSC.

Participant Guidelines

Members of Advisory Groups and Technical Work Groups are expected to follow certain codes of conduct during the process, including:

- Participants will not debate the science of climate change, the goals established in the Administrative Order, or the timeline, but will instead provide leadership and vision for how Alaska will rise to the challenges and opportunities of addressing climate change.

- Participants are expected to support the process and its concept fully and, through the group process, in good faith collaborate toward the goals of the advisory and work groups.

- Participants are expected to act as equals during the process to ensure that all members have equal footing during deliberations and decisions.

- Participants must attend meetings and stay current with information provided to the group and the decisions of the group. Alternates are strongly discouraged and must be cleared with the facilitator and Chair. It is expected that alternates will not be routinely utilized. Any alternate who does participate should be current with information developed by the process and able to make decisions.

- Participants are asked not to reconsider decisions made in the stepwise process. Once the Advisory Group reaches a milestone by consensus or vote, it moves to the next step.

- Each participant should speak only about his/her position and refrain from characterizing the views of others when making Advisory Group decisions. Each member must be able to vote or otherwise take a position at the meetings.

- When speaking about the process with the media or in other public settings, each member must make clear they are representing only themselves.

- Participants are expected to provide objective, fact-based comments and alternatives during advisory and work group discussions, and must refrain from personal criticisms.

Climate Change Adaptation Advisory Group

Development of comprehensive adaptation policy recommendations as part of the Alaska Climate Change Strategy supports state climate policy objectives. It will enable Alaska to fully consider state, regional and national policy opportunities as it formulates state at least until September 1, 2008 when the State will assume responsibility for this group. To provide broad perspective, involvement, and support in the development of concrete adaptation policy recommendations for the CCSC's consideration in preparing the Alaska Climate Change Strategy, the CCSC will establish a stakeholder-based Climate Change Adaptation Advisory Group (AAG) to conduct the tasks detailed below.

Alaska is among the initial states to conduct a comprehensive, stakeholder-based climate adaptation process. Other initial state processes have found it effective to establish subcommittee technical working groups (TWGs) to assist the larger stakeholder-based AAG.

The CCSC has already established and named co-chairs for two related but independent subcommittee efforts, the Immediate Action Work Group and the Research Needs Work Group. Four additional TWGs will be appointed and launched under the explicit auspices of the AAG under the oversight of the CCSC. The specific charge of each of these TWGs should be determined following initial exploratory efforts to identify and categorize the greatest climate vulnerabilities Alaska faces.

As indicated below, CCS will provide critical planning and initial facilitation, management, technical support, and analytical activities to the AAG and the TWGs in order to ensure the successful launch of the AAG process. Facilitator Brian Rogers will partner with CCS, and will commit to applying the key principles and guidelines described below. Information Insights' unique contribution to the CCS-led adaptation tasks is to bring local knowledge to the CCS team, including familiarity with Alaska stakeholders, groups and business sector representatives. The CCS team will work in partnership with and under the direction of the DEC as an impartial and expert party throughout the startup of the AAG in developing adaptation policy recommendations for the CCSC.

Specifically, CCS will assist the CCSC with the following advance technical and planning support tasks as appropriate until September 1, 2008:

- Development of a work plan for planning, startup, launch and management of the AAG process, for review and approval.

- Exploration of potential ways to capture and organize traditional knowledge regarding climate impacts already occurring in Alaska.

- Development of a vulnerable sector inventory and adaptation baseline of Alaska's vulnerability to climate impacts in a synthesis review draft format for consideration during the AAG and CCSC processes.

- Within the broad climate impacts identified in the Administrative Order, in consideration of the synthesis vulnerability inventory and baseline, and in consultation with the CCSC, identification of specific categories of climate impacts that the State faces and delineation of a subset of priority categories around which to structure the work of the AAG and its TWGs.

- Identification of an initial list or "catalog" of potential state-level policies and actions to reduce climate vulnerability for consideration by stakeholders within the priority categories of climate impacts identified.

- Identification and assessment of multi-state and national climate adaptation policy issues and options that could affect decisions of the AAG or CCSC.

- Identification of key studies and assessments related to climate change adaptation options in Alaska.

- With the assistance the State, help in the identification of technical experts in Alaska for potential membership in the sector-based subcommittees of the AAG (TWGs).

- Help in the identification of points of contact in state agencies and other institutions to support technical assessments related to the AAG process.

- Assist in the development of communications tools to support the CCSC and AAG processes, including a project website, document templates, and other tools.

- In order to launch and conduct the AAG process, CCS will assist the State with the following management, facilitation and technical support tasks as appropriate until September 1, 2008:

- Launch of the AAG process with the assistance of a well recognized Alaska based facilitator, for two meetings of the AAG and a series of interim meetings of four subcommittee TWGs to develop adaptation policy recommendations for the CCSC's consideration for potential inclusion in the *Alaska Climate Change Strategy*.

- Review and approval by the AAG of the vulnerable sector inventory and adaptation baseline for Alaska.

Climate Change Mitigation Advisory Group

Development of mitigation policy recommendations as part of the *Alaska Climate Change Strategy* supports state and national climate policy objectives and will enable Alaska to fully consider state, regional and national climate change policy opportunities as it formulates comprehensive state mitigation efforts involving energy, transportation, economic development, environmental quality, and civic infrastructure. The process described in the following pages will be used to develop mitigation policy recommendations for consideration by the CCSC and will include regular opportunities for input from the public. To provide broad perspective, involvement, and support in the development of concrete mitigation policy recommendations for the CCSC's consideration in preparing the Alaska Climate Change Strategy, the CCSC will establish a stakeholder-based Climate Change Mitigation Advisory Group (MAG) to conduct the tasks detailed below.

Typically, successful state climate mitigation planning processes have established subcommittee technical working groups (TWGs) to assist the larger stakeholder-based MAG. Generally these TWGs include Energy Supply (ES); Residential, Commercial, and Industrial Energy Demand (RCI); Transportation and Land Use (TLU); Agriculture, Forestry, and Waste Management (AFW); and Cross-Cutting Issues (CC). Alaska's substantial size and diffuse population may give rise to an appropriate reconfiguration of this approach to TWGs, however. The Sub-Cabinet has already established and named co-chairs for an Alternative Energy and Energy Conservation Workgroup. The mission of the Alternative Energy and Energy Conservation Workgroup is quite consistent with, and can generally assume the role of an energy-related TWG contemplated under a stakeholder-based MAG. However, it would be advisable to expand its mandate and membership somewhat going forward.

Five TWGs will be formed to work under the MAG to identify prioritize, and assess mitigation options most appropriate for Alaska. The TLU, AFW, and CC TWGs would operate as noted above. It is anticipated that emissions associated with airborne passenger and freight transport will reflect a greater focus in Alaska than other states, but will still be part of the TLU sector.

With respect to energy production, the predominance of oil and gas industry GHG emissions, particularly in comparison to the electricity sector, augurs for a distinct Oil & Gas TWG (OAG) to address oil and gas GHG emissions including exploration, production, pipelines and refining.

Due to other industry sectors being significant energy users, such as seafood processing and mining, the Alternative Energy and Energy Conservation Workgroup will be expanded to include these industrial based energy users along with residential and commercial energy users and will be called the Energy Supply and Demand (ESD) TWG. Members of TWGs will be appointed and the TWGs' efforts launched under the explicit auspices of the MAG. A local facilitator will be contracted to provide additional guidance, leadership and interface with members.

Also indicated below, CCS will provide critical planning, facilitation, management, technical support, and analytical activities to the MAG and the TWGs in order to ensure the successful results of the MAG process in 2008-09. Facilitator Brian Rogers will partner with CCS, and will commit to applying the key principles and guidelines described below. Information Insights' unique contribution to the CCS-led mitigation tasks is to bring local knowledge to the CCS team, including familiarity with Alaska stakeholders, groups and business sector representatives. The CCS team will work in partnership with and under the direction of the DEC as an impartial and expert party throughout the startup and management of the MAG in developing mitigation policy recommendations for the CCSC. On September 1, 2008, local facilitation will commence for the Oil and Gas TWG and will follow the same process as the rest of the MAG TWGs to ensure consistent results in the final report and aggregated results.

Specifically, CCS will assist the with the following advance technical and planning support tasks:

- Development of a work plan for planning, startup, launch and management of the MAG process, for review and approval.

- Development of cost share from private donors to fully fund the proposed work plan as needed beyond the available state cost share.

- Further refinement and update, based on additional DEC data and stakeholder input, of Alaska's comprehensive inventory and forecast of greenhouse gas emissions (GHGs) from 1990 to 2020 or later in a review draft format for consideration during the MAG and CCSC processes.

- Identification of existing state actions that reduce GHG emissions in Alaska, and assessment of the GHG reduction potential of key actions recently implemented and or formally planned by the state.

- Identification and assessment of multi-state and national climate policy issues and options that could affect decisions of the MAG or CCSC.

- Support in the identification of potential early actions by the state to address climate change policy needs.

- Identification of key studies and assessments related to climate change mitigation options in Alaska.

- In consultation with the State and other State designees, identification of 12-25 appropriate stakeholders (by sector) for potential involvement in the MAG process.

- Assistance in the identification of technical experts in Alaska for potential membership in potential sector-based subcommittees of the MAG (called Technical Work Groups or TWGs) during the MAG process.

- Assistance in the identification of points of contact in state agencies and other institutions to support technical assessments related to the MAG process.

- Assistance in the development of communications tools to support the CCSC and MAG processes, including a project website, document templates, and other tools.

- In order to launch and conduct the MAG process, CCS will assist the State with the following management, facilitation and technical support tasks:

- Launch of the MAG process with the assistance of Information Insights, a well recognized Alaska based facilitator, for seven meetings of the MAG and a series of interim teleconference and in-person meetings of five subcommittee TWGs to develop mitigation policy recommendations for the CCSC's consideration for inclusion in the *Alaska Climate Change Strategy*.

- Development of a comprehensive set of specific policy recommendations by the MAG to reduce GHG emissions and enhance energy and economic opportunity in Alaska by 2020 and beyond, including analyses of GHG reduction potential and cost or cost savings for each recommended measure (some measures may not require quantification, such as reporting or education).

- Review and approval by the MAG of the draft inventory and forecast of Alaska GHG emissions from 1990 to 2020 or later.

- Development and recommendation by the MAG to the CCSC of potential statewide GHG reduction goals and targets.

- Preparation of a final report by CCS to the CCSC reflecting the GHG mitigation recommendations prepared by the MAG.

- Assistance to and consultation with the CCSC as it develops its recommendations to the Governor.

Consensus Building Process Principles

The Climate Change Adaptation Advisory Group (AAG), the Climate Change Mitigation Advisory Group (MAG) and each of the Technical Work Groups (TWG) supporting the advisory groups will use the following key principles and guidelines:

- **The process is fully transparent.** All materials considered by the AAG, MAG and TWGs are posted to the project website, and all meetings are open to the public. For TWG meetings, which will typically be conducted as teleconferences (although some in-person meetings will be possible), the State will arrange for physical locations with a telephone and a telephone monitor so that the public can listen. The evaluation of potential policy options is transparent with respect to data sources, methods, key assumptions, and uncertainties. In addition, policy design parameters and implementation methods for recommended actions are explicit and transparent, including goals, timing, coverage of parties, and implementation mechanisms. The transparency of technical analysis, policy design, and participant viewpoints is critical to the identification and resolution of potential conflicts.

- **The process is inclusive.** A diverse group of AAG, MAG and TWG members are chosen to represent a broad spectrum of interests and expertise in Alaska. The public will be afforded the opportunity to provide meaningful review of and comment upon pending AAG and MAG decisions.

- **The process is stepwise.** Each step of the sequential process builds incrementally on the former toward a final solution. Sufficient time, information, and interaction are provided between steps to ensure comfort with decisions and quality of results. Participants are responsible for staying current with information developed by and decisions taken during the process, as the schedule does not allow decisions to be reconsidered once they have been voted on.

- **The process will seek but not mandate consensus.** Votes will be taken at each of the major milestones in the process in order to advance to the next step. Decisions are requested on individual policy options. Alternatives that address barriers to consensus will be developed by the AAG or the MAG with the assistance of CCS and the State as needed. Voting is conducted by simple request for objection (by show of hands) at the point of decision, followed by resolution of conflicts through discussion and development of alternatives, as needed, in order to proceed. Final votes by the AAG or MAG include support at three levels: Unanimous Consent (no objections), Super Majority (five objections or less), and Majority (less than half object). Typically, the early stages of the process proceed with unanimous consent or super majority approval by the AAG or MAG. Final recommendations may include recommendations at all three support levels, though typically, most final recommendations also enjoy unanimous consent. The final report will document the level of support for individual adaptation policy options recommended by the AAG or MAG, including alternative views as needed.

- **The process is comprehensive.** The AAG will explore solutions in all sectors and across all potential implementation methods, including a variety of voluntary and mandatory implementation mechanisms. Recommendations may include state-level, multi-state actions

(regional and national), and/or international actions. Similarly, all forms of economic development are open for consideration as they relate to potential climate adaptation actions. Significant actions taken by the executive or legislative branches during the process will be included as possible and as necessary in the baseline assessment.

The MAG will explore solutions in all sectors and across all potential implementation methods, including a variety of voluntary and mandatory implementation mechanisms. Recommendations may include state-level, multi-state actions (regional and national), and/or international actions. Mitigation of all six GHGs will be considered. Units will be expressed in million metric tons carbon dioxide equivalent ($MMtCO_2e$). Similarly, all forms of energy supply and use and economic development are open for consideration as they relate to GHG mitigation actions. Significant actions taken by the executive or legislative branches during the process will be included as possible and as necessary in a reference case forecast of emissions.

- **The process is guided by clear decision criteria** for the selection and design of recommended actions. For Adaptation recommendations these include consideration of (1) flexibility; (2) capital intensity; and (3) adaptive capacity. For Mitigation recommendations these include consideration of: (1) GHG reduction potential; (2) cost or cost savings per ton of GHG emissions removed; (3) potential co-benefits, including economic, energy and other improvements; and (4) potential feasibility issues (e.g., technical, economic, political, institutional, etc.).

- **The process is quantitative.** Results of MAG decisions will include explicit descriptions of policy design parameters and results of economic analysis. Recommendations can include both quantified and non-quantified actions, with emphasis on quantification of GHG reduction potential and cost or cost savings for as many recommendations as possible. Additional quantification needs related to co-benefits or feasibility issues will be evaluated on a case-by-case basis pending MAG input and available resources. To the extent possible, quantified metrics will be used for recommendations being considered by the AAG.

- **The process covers short-, medium-, and long-term periods of action.**

  Adaptation - The period of analysis for the vulnerable sector inventory and adaptation baseline will be 1990-2030 with assessment of later periods being subject to available resources. Characterization of adaptation options will cover the present to 2030, with supplemental analysis also possible for longer periods if resources permit.

  Mitigation - The period of analysis for emissions inventories and reference case projections will be 1990-2020 ***(Note: this was subsequently extended to 2025 by mutual agreement),*** with assessment of later periods being optional subject to available resources. Emission reduction options and related energy and economic analysis will cover the present to 2020, with supplemental analysis also possible for longer periods if resources permit.

- **The process is implementation-oriented.** The goal of the process is the ultimate adoption of specific policies by the State of Alaska based on planning recommendations delivered to the Sub-Cabinet by each of the Advisory Groups. Subsequent, more detailed analyses may be appropriate and necessary. Accordingly, recommendations of the AAG and MAG are

intended to guide and support immediate policy adoption, but do not necessarily comprise the level of detail required for final programmatic implementation, rulemaking, institutional design, and feasibility.

Developing Recommendations for Adapting to Climate Change - Adaptation

Process Used by Adaptation Advisory Group

The AAG process will closely resemble the format of several previous successful state climate mitigation planning processes conducted by CCS (details available at *www.climatestrategies.us*). This consensus-building model combines techniques of alternative dispute resolution, community collaborative decision-making, and corporate strategic planning in a combined form of facilitation and technical analysis known as "evaluative facilitation."

The process fully integrates group decisions and technical analysis through open, informed, and collaborative decision-making and self-determination by a broadly representative group of stakeholders (the AAG), with the support of subcommittee TWGs that are comprised of AAG members and others. Activities of the AAG will be transparent, inclusive, stepwise, fact-based, and consensus driven (see key principles and guidelines of the process listed below). The process will *seek but not mandate consensus* on individual policy option recommendations and will use a formally structured voting process to identify potential objections and alternatives.

The AAG process relies on intensive use of information and interaction between facilitators, participants, and technical analysts. The CCS team and its partners will provide close coordination of AAG, TWG, facilitation, and technical support activities. To facilitate learning, collaboration, and task completion by the AAG and its TWGs, CCS will provide a series of discussion and decision templates for each step in the process, including:

A public website for all information and proceedings of the process. The primary web presence for the CCSC and other climate information in Alaska is www.climatechange.alaska.gov. CCS will establish www.akclimatechange.us as a public website for ready posting of emerging materials from the Advisory Groups and Technical Work Group. The CCS website will be compatible in style to that of the State and will be "hot linked" to the State website in a manner that allows browsers to easily and transparently navigate between the two appearing to the casual user as though he/she remains on the State's web site. The State will maintain website materials associated with the AAG on its own website.

Materials to be posted on the AAG and MAG websites, but not limted to:

- Standard meeting documents, including an agenda and notice, discussion Powerpoint, meeting summary, and reference document(s) for each of the AAG and TWG meetings;

- A draft final report, and PowerPoint presentation for review and approval of the Alaska vulnerable sector inventory and adaptation baseline;

- A broad assessment of categories of climate impacts that Alaska faces and identification of specific priority categories that merit the AAG's principal attention in the course of this process.

- An initial "catalog" of state adaptation actions with brief descriptions for each option; suggested ranking criteria; draft rank of potential flexibility, capital intensity, and adaptive capacity for each action; along with indications of related actions recently adopted by Alaska.

AAG Project Timing and Milestones

The work of the AAG should, to the greatest extent practicable, be advised by the conclusions reached by the Immediate Action Work Group (IAWG); the findings contained in the report of the Alaska Joint Climate Impact Assessment Commission; the preliminary analysis and vulnerability synthesis of adaptation issues prepared by the National Commission on Energy Policy, as well as the scientific expertise of the Research Needs Work Group (RNWG). Accordingly, every effort should be made to hold the first meeting of the AAG jointly with the IAWG and the RNWG. Its agenda should include the findings of the IAWG that are likely to pertain to longer-term as well as immediate climate policy responses. In addition, the AAG should dialogue with the RNWG to identify, to the extent possible, crucial questions for which the AAG requires RNWG insights in order to best frame the development of its policy recommendations. Such questions are likely to focus on the nature and extent of likely climate impacts in Alaska for which adaptation and response policies may be necessary and/or appropriate. For its second meeting, the AAG should thus be armed with the pertinent conclusions of the IAWG and initial answers from the RNWG, and should be able to commence its efforts with the benefit of these work groups' insights into the comprehensive policy development process described in this work plan.

Five additional full-day AAG meetings will be held between July 2008 and May 2009, and a final report will be completed by the State by June 2009 in conjunction with the MAG final report. The schedule may be adjusted by DEC. Two or more TWG conference calls by each of the AAG's TWGs will typically be held between each of the AAG meetings. In addition, at the request of the CCSC, CCS would be pleased to brief legislators or legislative committees on the progress of the AAG process. The following reflects a tentative draft calendar:

Prospective AAG Calendar

Date	Action	Notes
May 2008	AAG Startup; 1st AAG meeting	Joint meeting with IAWG to learn of its findings and recommendations and RNWG to determine key questions AAG needs RNWG to address. Visibility opportunity for the CCSC and/or Gov. Palin.
July 2008	2rd AAG meeting	Following this meeting: Opportunity to brief CCSC on targeted TWG sectors, overall process, vulnerability inventory and baseline, and representative categories of policy options being considered by AAG.
September 2008	3rd AAG meeting	Following this meeting: Opportunity to brief CCSC on the universe of policy options being considered by AAG.

Date	Action	Notes
November 2008	4th AAG meeting	Following this meeting: Opportunity to brief CCSC on priority policy options selected by AAG.
February 2008	5th AAG meeting	Following this meeting: Opportunity to brief CCSC on policy designs developed by the AAG.
March 2009	6th AAG meeting	Following this meeting: Opportunity to brief CCSC (and/or Legislators) on initial adaptation policy option costs and effects.
April 2009	7th AAG meeting	Following this meeting: Opportunity to brief CCSC (and/or Legislators) on aggregate adaptation policy option costs and effects.
June 2009	Final AAG report	Following this: Opportunity to consult with CCSC in the development of its adaptation recommendations to Gov. Palin.
Between AAG Meetings	TWG conference calls and meetings	

AAG Meeting Objectives and Agendas

The objectives and agendas for each of the AAG meetings and TWG meetings are listed below, with notes regarding decisions of the AAG.

Meeting #1

Objectives:

- Introduction to the process, presentation of IAWG findings and conclusions, presentation from and discussion with the RNWG to identify crucial scientific questions of importance to the AAG effort, formation of TWGs, next steps.

Agenda:

- Introductions
- Purpose and goals of the AAG process
- Review of the components and ground rules of the AAG process
- Presentation of IAWG findings and conclusions, discussion of impact with respect to AAG process
- Presentation of analysis and recommendations from the National Commission on Energy Policy
- Presentation from and discussion with the RNWG to identify fundamental scientific questions crucial for framing the AAG effort.
- Formation of TWGs, next meeting agenda, time, location, date

- Public input and announcements

Interim TWG calls will cover: (1) discussion and further revision to IAWG and RNWG findings and impacts, and (2) introduction and modifications to the catalog of adaptation policy options.

Meeting #2:

Objectives:

- Introduction to the process, presentation of preliminary fact-finding (vulnerable sector inventory and adaptation baseline; catalog of state actions), formation of TWGs (no votes, but AAG members should be prepared to select one or more work groups for participation), next steps.

Agenda:

- Introductions
- Purpose and goals of the AAG process
- Review of the components and ground rules of the process
- Review of the history and status of state climate risks and related adaptation actions
- Review of the draft Alaska vulnerable sector inventory and adaptation baseline
- Review of the draft catalog of existing state climate adaptation actions, including Alaska actions
- Formation of TWG's, next meeting agenda, time, location, date
- Public input and announcements

Interim TWG calls will cover: (1) suggested revisions to the draft vulnerable sector inventory and adaptation baseline, and (2) review and suggested modifications to the catalog of adaptation policy options.

Developing Recommendations to Reduce the Causal Forces of Climate Change - Mitigation

Process Used by Mitigation Advisory Group

The MAG process will adhere to the format of several previous successful state climate mitigation planning processes conducted by CCS (details available at *www.climatestrategies.us*). This consensus-building model combines techniques of alternative dispute resolution, community collaborative decision-making, and corporate strategic planning in a combined form of facilitation and technical analysis known as "evaluative facilitation."

The process fully integrates group decisions and technical analysis through open, informed, and collaborative decision-making and self-determination by a broadly representative group of stakeholders (the MAG), with the support of subcommittee TWGs that are comprised of MAG members and others. Activities of the MAG will be transparent, inclusive, stepwise, fact-based, and consensus driven (see key principles and guidelines of the process listed below). The process will *seek but not mandate consensus* on individual policy option recommendations and will use formal voting (described below) to identify potential objections and alternatives.

The MAG process relies on intensive use of information and interaction between facilitators, participants, and technical analysts. The CCS team provides close coordination of MAG, TWG, facilitation, and technical support activities. To facilitate learning, collaboration, and task completion by the MAG and its TWGs, CCS will provide a series of discussion and decision tools and templates for each step in the process, including:

- A public website for all information and proceedings of the process. The primary web presence for the CCSC and other climate information in Alaska is www.climatechange.alaska.gov. CCS will establish www.akclimatechange.us as a public website for ready posting of emerging materials from the Advisory Groups and Technical Work Group. The CCS website will be compatible in style to that of the State and will be "hot linked" to the State website in a manner that allows browsers to easily and transparently navigate between the two appearing to the casual user as though he/she remains on the State's web site;

- Standard meeting documents, including an agenda and notice, discussion PowerPoint, meeting summary, and reference document(s) for each of the MAG and TWG meetings;

- A draft final report, PowerPoint presentation, and series of worksheets for review and approval of the Alaska GHG emissions inventory and forecast;

- An initial "catalog" of state GHG reduction actions with brief descriptions for each option, suggested ranking criteria, draft rank of potential GHG reductions and costs or cost savings of each action, along with indications of major related actions recently adopted in Alaska;

- An assessment of the emissions savings and other impacts of actions recently adopted in Alaska;

- A balloting form for identification of initial priorities for analysis for each of the sector-based TWGs;

- A policy option template for the drafting and analysis of individual mitigation policy recommendations;

- A principles and guidelines document for quantification of policy options in each of the TWGs;

- Analysis materials, including documentation of key data sources, assumptions, models, methods, and printouts of worksheets as needed; and

- A final MAG report format with summary chapters and technical appendices.

MAG Project Timing and Milestones

The first meeting of the MAG will be held in May 2008 with five additional meetings by June 2009 and a final report to be completed by June 2009. The schedule may be adjusted by DEC. Two or more TWG conference calls by each of the five TWGs will typically be held between each of the MAG meetings according to the following tentative draft calendar:

Prospective MAG Calendar

Date	Action	Notes
May 2008	MAG Startup; 1st MAG meeting	At this meeting: Visibility opportunity for the CCSC and/or Gov. Palin.
July 2008	2nd MAG meeting	Following this meeting: Opportunity to brief CCSC on the universe of policy options being considered by MAG.
September 2008	3rd MAG meeting	Following this meeting: Opportunity to brief CCSC on priority policy options selected by MAG.
November 2008	4th MAG meeting	Following this meeting: Opportunity to brief CCSC on policy designs developed by the MAG.
February 2008	5th MAG meeting	Following this meeting: Opportunity to brief CCSC (and/or Legislators) on initial quantification of GHG reductions and costs/savings.
March 2009	6th MAG meeting	Following this meeting: Opportunity to brief CCSC (and/or Legislators) on aggregate GHG reductions and costs/savings.
April/May 2009	7th MAG meeting	Following this meeting: Opportunity to brief CCSC (and/or Legislators) on aggregate GHG reductions and costs/savings.
June 2009	Final MAG report	Following this: Opportunity to consult with CCSC in the development of its recommendations to Gov. Palin.
Between MAG Meetings	TWG conference calls and meetings	

MAG Meeting Objectives and Agendas

The objectives and agendas for each of the MAG meetings and TWG meetings are listed below, with notes regarding decisions of the MAG.

Meeting #1:

Objectives:

Introduction to the process, presentation of preliminary fact-finding (inventory and forecast of emissions, Catalog of state actions), formation of TWGs (no votes, but MAG members should be prepared to select one or more work groups for participation), next steps.

Agenda:

- Introductions
- Purpose and goals of the MAG process
- Review of the components and ground rules of the process
- Review of the history and status of state climate mitigation and related energy and commerce actions
- Review of the draft Alaska emissions inventory & forecast
- Review of the draft catalog of existing state climate mitigation actions, including Alaska actions
- Formation of TWG's, next meeting agenda, time, location, date
- Public input and announcements

Interim TWG calls will cover: (1) suggested revisions to the draft inventory and reference case projections, and (2) review and suggested modifications to the catalog of policy options.

Meeting #2:

Objectives:

Addition of potential actions to the draft catalog of state actions (by vote); identification of potential revisions to the draft emissions inventory and forecast (by vote if/as needed)

Agenda:

- Review and recommended updates to the draft emissions inventory and forecast
- Review and approval of additional actions to the catalog of possible Alaska actions

- Discussion of the process for identifying initial policy option priorities for TWG analysis
- Next meeting agenda, time, location, date
- Public input and announcements

Interim TWG calls will cover: (1) suggested revisions to the emissions inventory and reference case projections, as needed; and (2) early ranking of options in the catalog and balloting for initial priority policy options.

Meeting #3:

At the request of DEC, this meeting met the objectives below for only one of the five Technical Working Groups. Meeting #4 targets these objectives for the remaining TWGs.

Objectives:

Review and approval of available TWG-identified initial priority policies for further analysis (by vote); review and approval of revisions to the emissions inventory and forecast (by vote if/as needed)

Agenda:

- Agreement on inventory forecast revisions, with modifications as needed
- Review and approval of TWG lists of initial policy priorities for analysis, with modifications as needed
- Discussion of process for developing straw policy design proposals for analysis of priority policy options
- Briefing on quantification methods for draft policy options
- Next meeting agenda, time, location, date
- Public input and announcements

Interim TWG calls will cover: (1) development of straw proposals for design parameters for individual options, and (2) next steps for analysis of options.

Meeting #4:

Objectives:

Review and approval of initial priorities for analysis of TWG identified policy options (by vote); review and approve any straw proposals prepared from previously approved policy options; review and approval of revisions to the emissions inventory and forecast (by vote if/as needed)

Agenda:

- Agreement on inventory forecast revisions, with modifications as needed
- Review and approval of TWG lists of initial policy priorities for analysis, with modifications as needed
- Discussion of process for developing straw policy design proposals for analysis of priority policy options
- Briefing on quantification methods for draft policy options
- Next meeting agenda, time, location, date
- Public input and announcements

Interim TWG calls will cover: (1) development of straw proposals for design parameters for individual options, and (2) next steps for analysis of options.

Meeting #5:

Objectives:

Review and approval of TWG suggested straw proposals for policy design (goals, timing, coverage of parties) (by vote); review and approval of any additions to the list of priority policy options for analysis, if/as needed (by vote); preparation for quantification phase of the process (briefing and discussion)

Agenda:

- Review and approval of straw proposals for policy design, with modifications as needed
- Discussion and approval of additional priority policy options for analysis, if/as needed
- Discussion of quantification principles and guidelines, key assumptions for TWG analysis of priority policy options
- Next meeting agenda, time, location, date
- Public input and announcements

Interim TWG calls will cover: (1) review of proposed quantification procedures for individual options, including proposed data sources, methods, assumptions; (2) review of first round of quantification results, identification of needs for revision as needed; and (3) identification of potential early consensus options to recommend for MAG approval.

Meeting #6:

Objectives:

Review and approval of consensus policy recommendations (by vote); identification of specific barriers to consensus, and potential alternatives for non-consensus policy options (discussion).

Agenda:

- Review of the draft pending policy options list, with results of analysis and cumulative emissions reductions potential
- Identification of early consensus policy options
- Identification of barriers and alternatives for remaining options, with guidance for additional work on options to TWGs
- Review of final report progress and plans
- Next meeting agenda, time, location, date
- Public input and announcements

Interim TWG calls will cover: (1) final revisions to alternative policy design and implementation mechanisms as needed, (2) final analysis of options and alternatives, and (3) final steps on formulation of cross cutting policy options and mechanisms.

Meeting #7:

Objectives:

Review and approval of final policy option recommendations (by vote); review of final report procedures.

Agenda:

- Review of the draft pending policy options list, with results of analysis and cumulative emissions reductions potential
- Review and final approval of draft pending policy options, with revisions as needed
- Summary of the process, review of next steps for completion and transmittal of the final report
- Public input and announcements

Final Report

At the conclusion of the MAG process, CCS will provide a final report to the State for the CCSC that compiles and summarizes the final mitigation policy recommendations of the MAG and covers the following areas:

- Executive Summary
- History and Status of State Actions
- Inventory and Forecast of Alaska GHG Emissions
- Recommended Policy Actions by Sector:
    - Oil and Gas
    - Energy Supply and Demand
    - Transportation and Land Use
    - Agriculture, Forestry and Waste Management
    - Cross-Cutting Issues, including Emissions Reporting, Registries, Goals, and Education
- Other Technical Appendices

Participants' Roles and Responsibilities

Alaska DEC and the Climate Change Sub-Cabinet

As chair of the CCSC and on behalf of it, the DEC convenes the two Advisory Group processes; receives nonbinding recommendations from the Advisory Groups through a report from CCS; and transmits recommendations to the CCSC for its consideration prior to adopting final recommendations for the Strategy to the Governor. The DEC/Sub-Cabinet also appoints: (1) chairs of the AAG and MAG (each possibly a member of the CCSC); (2) members of the AAG and MAG, recognizing the importance of outside stakeholders to the effective functioning of these processes; and (3) members of the respective TWGs of the AAG and MAG, recognizing that state, federal and local agencies have a wealth of knowledge and data that may contribute to TWG deliberations. DEC and other State agency representatives may recommend nonbinding policy options for the consideration of the AAG and MAG in the normal course of its policy development process. Finally, the DEC appoints a facilitation and technical support team (CCS and Information Insights) to conduct and manage the processes. DEC, jointly with other state agencies as appropriate, staffs and provides logistical support for meetings, public notice, meeting summaries, and technical review and input to TWG meetings.

The Adaptation Advisory Group will consider a full range of potential adaptation and mitigation options and recommended statewide goals, and approve a final Alaska vulnerable sector inventory and adaptation baseline. CCS and Information Insights facilitate all AAG activities, including its votes, in an open group format until September 1, 2008. CCS and Information

Insights will work with the State to ensure timely and orderly completion of tasks, good faith participation and resolution of issues by AAG members. In coordination with CCS and Information Insights, the DEC or other designated State representative enforces ground rules and opens and closes AAG meetings.

The Mitigation Advisory Group will consider a full range of potential mitigation options and recommended statewide goals, and approve a reference case Alaska GHG emissions inventory and forecast. The final report of the MAG will include the affects of implementing its policy recommendations upon Alaska's reference case GHG emissions forecast. CCS and Information Insights facilitate all MAG activities, including its votes, in an open group format. CCS and Information Insights will work with the State to ensure timely and orderly completion of tasks, good faith participation and resolution of issues by MAG members. In coordination with CCS, the DEC or other designated State representative enforces ground rules and open and close MAG meetings.

Center for Climate Strategies, its team and sub-contractors

CCS designs and conducts the Advisory Group processes, and provides facilitation and technical support as an impartial and expert party. CCS manages and facilitates meetings and votes during meetings, schedules Advisory meetings in coordination with the DEC, develops meeting agendas, and produces documents for Advisory and TWG consideration, including technical analysis.

CCS abides by the Model Standards of Conduct for Mediators approved by the American Arbitration Association, the Litigation Section, and the Dispute Resolution Section of the American Bar Association, and the Society of Professionals in Dispute Resolution. As described more fully elsewhere, CCS also ensures that adequate funding exists to successfully complete the process through private sources.

CCS project team members

Note: By mutual agreement CCS and DEC may alter the team configuration based on need during the process.

Initial Adaptation Team

Project Management Team: Ken Colburn, Brian Rogers, Tom Peterson, Gloria Flora

Facilitation Team: Ken Colburn, Brian Rogers, Gloria Flora

Technical Work Group Facilitators and Consultants: To be determined pending sector/impact orientation of Adaptation TWGs

Mitigation

Project Management Team: Ken Colburn, Brian Rogers, Tom Peterson, Gloria Flora

Facilitation Team: Ken Colburn, Brian Rogers, Gloria Flora

Inventory and Forecast Team: Randy Strait, Steven Roe, Dan Wei, Maureen Mullen, Holly Lindquist

Technical Work Group Facilitators and Consultants

- **Cross Cutting Issues:** Nancy Tosta, Amy Wheeless
- **Energy Supply and Demand:** Christopher James, Jeremy Fisher, Dick LaFever
- **Forestry, Agriculture, and Waste Management**: Steve Roe, Brad Strode, Rachel Anderson
- **Oil and Gas:** Alison Bailie (until September 1, 2008), Dick LaFever
- **Transportation and Land Use:** Jeff Ang-Olson, Frank Gallivan

Biographies of Project Facilitation Team

Brian Rogers, Principal Consultant and Chief Financial Officer, Information Insights, Inc.; Acting Chancellor, University of Alaska - Fairbanks

Mr. Rogers has over 30 years of public policy experience in Alaska, working with a wide variety of Alaska constituencies. His work with Information Insights in the past 12 years has included significant public stakeholder facilitation on the major issues facing Alaska. He facilitated policy summits on early learning, fisheries, subsistence and the Alaska permanent fund for the current and past two governors; led strategic planning efforts for the Denali Commission, state agencies, local governments, tribes, non-profit organizations and Alaska Native corporations; mediated environmental conflicts at the Pogo Mine between miners and environmentalists; facilitated successful negotiated rulemaking processes involving motorized oil transport and cruise ship wastewater discharge; and facilitated dozens of stakeholder processes for state and federal agencies, including DEC's water quality permit process mapping, the air permit regulations work group, and solid waste program changes, EPA's tribal voice on contaminants, and USDA Rural Development's sustainable rural utilities work group. Rogers is currently facilitating the Tongass Futures Roundtable, a stakeholder process designed to resolve long-standing issues of logging, preservation and community use in the Tongass National Forest. Rogers led Information Insights research teams on economic impact analyses for the Alaska Department of Revenue, the Department of Transportation and Public Facilities, the Alaska Oil and Gas Association, the North Slope Borough, and a consortium of Fairbanks-area Alaska Native organizations. Rogers is a former state legislator, serving in the Alaska House of Representatives from 1978 - 1982. He served as budget director and vice president for finance at the University of Alaska system, and later served as a member of the UA Board of Regents, including three years as chair. He has served on dozens of civic and professional boards and commissions, chairing the State of Alaska Long-Range Financial Planning Commission and the Alaska Statehood Commission, and serving on the Governor's Task Force on Jobs and the Economy. He holds a Master's degree in Public Administration from Harvard's Kennedy School of Government.

Kenneth A. Colburn, Senior Consultant, CCS. Project Director and Facilitator.
Mr. Colburn served as Executive Director of the Northeast States for Coordinated Air Use Management (NESCAUM) from 2002-2005. Before joining NESCAUM in 2002, Mr. Colburn led the Air Resources Division of the New Hampshire Department of Environmental Services (NHDES), helping to make that state a leader in reducing air pollution with the nation's first "4-pollutant" bill for power plants and the first greenhouse gas emissions reduction registry law. Prior to joining NHDES in 1995, Mr. Colburn was vice president of the Business & Industry Association of New Hampshire (BIA), representing the state's business community on environmental, energy, and telecommunications matters in legislative and regulatory forums. Mr. Colburn represented the states at annual Conferences of the Parties (COPs) to the United Nations Framework Convention on Climate Change (UNFCCC) for a decade, including in Kyoto, served on the US delegation to G8 Environmental Ministers meetings, and was a commissioner on the Ozone Transport Commission. Colburn has testified before Congress on air quality and climate issues several times, and is frequently called upon to speak on these topics domestically and internationally. Mr. Colburn holds a BS in Mathematics from M.I.T. and MBA and MEd degrees from the University of New Hampshire.

Gloria Flora, Executive Director, Sustainable Obtainable Solutions; Climate Change Consultant, CCS.
Ms. Flora established and directs Sustainable Obtainable Solutions, an organization dedicated to the sustainability of public lands and of the plants, animals and communities that depend on them. With her 30 years of experience, she consults on sustainable plans and practices for forests, energy and climate change, especially pertaining to public lands. Gloria also speaks and writes on ecosystem management; people's relationships to landscapes - cultural, historical, social, and psychological; biomimicry (innovations from nature); and on leadership in changing times. Gloria's prior position was Forest Supervisor of the largest national forest in the continental U.S. In her 23-year career with the U.S. Forest Service, she became nationally known for her cutting-edge work in ecosystem management and the integration of the human dimension into environmental policy. She has extensive experience leading interdisciplinary collaborative groups in the development of forest plans and major projects from concept to environmental study through implementation and monitoring. For her courageous stewardship of public lands, she's received many awards from conservation, educational, policy and civic organizations including the Natural Resources Council of America. Her work has been featured in *Sunset Magazine, Vanity Fair, Audubon,* NPR, NOW with Bill Moyers and in numerous newspapers, documentaries and books. She also appears in Leonardo DiCaprio's film on the environment, *The 11th Hour.* Gloria holds a BS in Landscape Architecture from Penn State University.

Appendix C
Members of MAG Technical Work Groups

The Alaska Climate Change Mitigation Advisory Council (MAG) was advised by five Technical Work Groups (TWGs), comprised of 75 representatives from Alaska's business community, utilities, petroleum producers and other key industries, environmental organizations, public interest groups, universities and research institutions, military installations, state, local, and tribal government and MAG members. The Governor's Office selected the following individuals to serve on the Alaska Climate Change Technical Work Groups:

Cross Cutting Issues

Maria Gladziszewski, Assistant Director, Alaska Department of Fish and Game
Doug O'Harra, Editor, Online News & Far North Science
Scott Sloane, Mobile Air Sources, Alaska Department of Environmental Conservation (DEC)
Rev. Paul Klitzke , Pastor, St. David's Episcopal Church & Chair, Interfaith Light & Power
Katharine Heumann, Information Officer, DEC
Jack Hébert, Director, Cold Climate Housing Research Center; Owner, Hébert Homes
Kate Troll, Director, Alaska Conservation Alliance
Aubrey Baure, Regional Environmental Officer for Department of Defense Region 10

The following individuals were also selected by the Governor's Office and served on the Cross Cutting TWG for a portion of its tenure:

Scott Anaya, Director, Alaska Building Science Network
Jeanne Carlson, Recycling Coordinator, Solid Waste, Municipality of Anchorage & Green Star
Scott Deveau, Field Office Manager, General Services Administration
Lori Hanemann, Northern Alaska Environmental Center
Mike Heatwole, Director of Corporate Communications, Alyeska Pipeline
James Hornaday, Mayor of Homer
Scott Waterman, State Energy Programs Manager, Alaska Housing Finance Corporation, Research & Rural Development
John Rubini, Owner, JL Properties
Sean Skaling, Director, Green Star
Randy Virgin, Director of Sustainability, Economic and Community Development, Municipality of Anchorage

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Nancy Tosta, Technical Work Group Facilitator and Analyst
Amy Wheeless, Technical Work Group Analyst

Energy Supply and Demand

Peter Crimp, Program Manager, Alternative Energy, Alaska Energy Authority
Meera Kohler, Executive Director, Alaska Village Electric Cooperative
Marilyn Leland, Executive Director, Alaska Power Association
Tom Lovas, Energy Economist & Research Coordinator, National Rural Electric Cooperative Association
Jim Posey, Executive Director, Municipal Light & Power
Sean Skaling, Executive Director, Green Star
Steve Colt, Economist, University of Alaska – Anchorage (UAA) Institute for Social & Economic Research
Steve Denton, Vice President, Business Development, Usibelli Coal Mine
Kate Lamal, Vice President for Power Supply, Golden Valley Electric Association, Inc.
Greg Peters, Manager, Environmental Compliance, Alyeska Seafoods
Chris Rose, Director, Renewable Energy Alaska Project
Dan White, Director, Institute of Northern Engineering, University of Alaska – Fairbanks (UAF)

The following individuals were also selected by the Governor's Office and served on the ESD TWG for a portion of its tenure:

David Benton, Executive Director, Marine Conservation Alliance
Charlie Boddy, Director of Governmental Affairs, Usibelli Coal Mine
Clint Farr, Area Source Section Manager, Air Quality, DEC
Scott Goldsmith, Economist, UAA Institute for Social & Economic Research
Wayne Hall, Senior Environmental Coordinator, Teck Cominco Alaska, Inc., Red Dog Mine
Gwen Holdmann, Organizational Director, Alaska Center for Energy & Power, UAF
Jodi Mitchell, CEO & General Manager, Inside Passage Electric Coop
Christopher Nye, Volcanologist, Alaska Department of Natural Resources (DNR)

Center for Climate Strategies

Dick LaFever, Technical Work Group Facilitator
Jeremy Fisher, Technical Work Group Analyst
Chris James, Technical Work Group Analyst

Forestry, Agriculture and Waste Sectors

Doug Buteyn, Environmental Program Manager, DEC Env Health, Solid Waste
Charles Knight, Manager, DNR Division of Agriculture
Chris Maisch, State Forester, Director, DNR Division of Forestry
Donna Mears, Recycling Coordinator for Solid Waste, Municipality of Anchorage
Rick Rogers, Vice President, Lands, Resources, and Tourism, Chugach Alaska Corporation
Ron Wolfe, Corporate Forester & Manager, Office of Natural Resources, Sealaska Corporation

The following individuals were also selected by the Governor's Office and served on the FAW TWG for a portion of its tenure:

Steve Gilbert, Manager, Alaska Projects, enXco Development, Inc.
Jeff Riley, Chief Operating Officer, Alaska Waste
Rick Harris, Vice President, Sealaska Corporation
Kathie Wasserman, Director, Alaska Municipal League

Center for Climate Strategies

Stephen Roe, Technical Work Group Facilitator and Analyst
Jackson Schreiber, Technical Work Group Analyst
Brad Strode, Technical Work Group Analyst

Oil and Gas Sector

Janet Bounds, Legislative & Regulatory Affairs, Chevron
Russ Douglass, Director, Environmental Affairs, Doyon Drilling
David Hite, Petroleum Geologist and Consultant, Hite Consulting
Kip Knudsen, Government Affairs, Tesoro
Louis Kozisek, Petroleum Engineer, Joint Pipeline Office
Sean Lowther, Air Quality, DEC
Jim Pfeiffer, Environmental Advisor, Air Quality, BP
Brad Thomas, Senior Environmental, Coordinator, Air Programs, ConocoPhillips

The following individuals were also selected by the Governor's Office and served on the OG TWG for a portion of its tenure:

Jim Calvin, Economist, McDowell Group
Jeff Cook, Government Affairs, Flint Hills Resources
Brian Davies, Board Chair, The Nature Conservancy - Former Vice President, BP
Claire Fitzpatrick, Chief Financial Officer, BP Alaska
John Norman, Commissioner, Alaska Oil and Gas Conservation Commission
Bob Swenson, Division Director, Oil and Gas, DNR, State Geologist; Sub-Cabinet member
Jeff Walker, Regional Director, Minerals Management Service

The following individuals contributed time and expertise although they were not official members:

David Clarke, BPXA (*quantification assistance*)
John Colloggi, ConocoPhillips (*quantification assistance*)
Carl Rutz, Alyeska Pipeline
Diane Shellenbaum, Petroleum Geophysicist/DNR -Division of Oil (*Alternate for Bob Swenson*)
Jane Williamson, Alaska Oil and Gas Conservation Commission; now with DNR, Division of Oil and Gas) (*Alternate for John Norman*)

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Dick LaFever, Technical Work Group Facilitator
Fran Sussman, Technical Work Group Analyst
Brian Gillis, Technical Work Group Analyst

Transportation and Land Use Sector

Alison Bird, Manager, Environmental Engineering, FedEx (*Alternate for Karen Ellis*)
Rob Bosworth, Director, Southeast Alaska Programs, The Nature Conservancy
Bruce Carr, Director, Strategic Planning, AK Railroad
John Duffy, Manager, Mat-Su Borough
Luke Hopkins, Fairbanks North Star Borough Assembly member
Jeff Ottesen, Division Director, Alaska Department of Transportation
Curt Stoner, Sales Manager, Totem Ocean
Charles W. "Chip" Treinen, United Fishermen of Alaska
Lance Wilber, Director, Traffic, Municipality of Anchorage
Aves Thompson, President, Alaska Trucking Associaton

The following individuals were also selected by the Governor's Office and served on the TLU TWG for a portion of its tenure:

Karen Ellis, Director, Environmental Management, FedEx Express
David van den Berg, Executive Director, Northern Alaska Environmental Center
Jamie Spell, Chief, Asset Management, Flight, 3rd Wing Elmendorf Air Force Base
Stan Stephens, Owner, Stan Stephens Charters

Center for Climate Strategies

Jeffrey Ang-Olson, Technical Work Group Facilitator and Analyst
Frank Gallivan, Technical Work Group Analyst

Final Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990-2025

Center for Climate Strategies
July 2009

Principal Authors: Maureen Mullen, Stephen Roe, Randy Strait, Alison Bailie, Holly Lindquist, Alison Jamison

Comment [kmp1]: Are these names correct?

DRAFT

CENTER FOR CLIMATE STRATEGIES

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Executive Summary

The Center for Climate Strategies (CCS) prepared the first draft of this report for the Alaska Department of Environment Conservation (DEC) under an agreement with the Western Governors' Association. The report presented an assessment of the State's greenhouse gas (GHG) emissions and anthropogenic sinks (carbon storage) from 1990 to 2025. The preliminary draft inventory and forecast estimates served as a starting point to assist the State, as well as the Alaska Climate Change Mitigation Advisory Group (MAG) and Technical Work Groups (TWGs), with an initial comprehensive understanding of Alaska's current and possible future GHG emissions, and thereby informed the identification and analysis of policy options for mitigating GHG emissions.[1] The MAG and TWGs have reviewed, discussed, and evaluated the draft inventory and methodologies as well as alternative data and approaches for improving the draft GHG inventory and forecast. The inventory and forecast as well as this report have been revised to address the comments provided and approved by the MAG

Emissions and Reference Case Projections (Business-as-Usual)

Alaska's anthropogenic GHG emissions and sinks (carbon storage) were estimated for the period from 1990 to 2025. Historical GHG emission estimates (1990 through 2005)[2] were developed using a set of generally accepted principles and guidelines for state GHG emission estimates, with adjustments by CCS to provide Alaska-specific data and inputs when it was possible to do so. The reference case emission projections (2006-2025) are based on a compilation of various existing projections of electricity generation, fuel use, and other GHG-emitting activities for Alaska, along with a set of transparent assumptions described in the appendices of this report.

The inventory and projections cover the six types of gases included in the US Greenhouse Gas Inventory: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Emissions of these GHGs are presented using a common metric, CO_2 equivalence (CO_2e), which indicates the relative contribution of each gas, per unit mass, to global average radiative forcing on a global warming potential- (GWP-) weighted basis.[3]

Table ES-1 provides a summary of historical (1990, 2000 and 2005) and reference case projection (2010, 2020, and 2025) GHG emissions for Alaska. Activities in Alaska accounted for approximately 50.6 million metric tons (MMt) of *gross*[4] carbon dioxide equivalent (CO_2e)

[1] "Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990-2020," prepared by the Center for Climate Strategies for the Alaska Department of Environmental Conservation, July 2007.
[2] The last year of available historical data varies by sector; ranging from 2000 to 2005.
[3] Changes in the atmospheric concentrations of GHGs can alter the balance of energy transfers between the atmosphere, space, land, and the oceans. A gauge of these changes is called radiative forcing, which is a simple measure of changes in the energy available to the Earth-atmosphere system (IPCC, 2001). Holding everything else constant, increases in GHG concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth), See: Boucher, O., et al. "Radiative Forcing of Climate Change." Chapter 6 in *Climate Change 2001: The Scientific Basis*. Contribution of Working Group 1 of the Intergovernmental Panel on Climate Change Cambridge University Press. Cambridge, United Kingdon. Available at: http://www.grida.no/climate/ipcc_tar/wg1/212.htm.
[4] Excluding GHG emissions removed (e.g., CO_2 sequestered) in forestry and other land uses.

emissions in 2005, an amount equal to about 0.7% of total U.S. gross GHG emissions. Alaska's gross GHG emissions grew at a faster rate than those of the nation as a whole (gross emissions exclude carbon sinks, such as forests). Alaska's gross GHG emissions increased 30% from 1990 to 2005, while national emissions rose by 16% during this period. The growth in Alaska's emissions from 1990 to 2005 is primarily associated with the transportation and the industrial fuel use/fossil fuel (FF) industry sectors.

Estimates of carbon sinks within Alaska's forests have also been included in this report. Estimates of carbon dioxide sequestered in Alaska's managed forests are -1.4 $MMtCO_2$/yr ("managed forests" consist of the coastal maritime forests in Alaska; see Appendix H). This leads to *net* emissions of 49.2 $MMtCO_2e$ in Alaska in 2005.

Figure ES-1 illustrates the State's emissions per capita and per unit of economic output. On a per capita basis, Alaskans emitted about 79 metric tons (Mt) of CO_2e in 2005, higher than the national average of 24 $MtCO_2e$ in 2005. The higher per capita emission rates in Alaska are driven by emissions from the industrial fuel use/FF industry and transportation sectors, which are much higher than the national average. Per capita emissions in Alaska have increased somewhat from 1990 to 2005, while economic growth exceeded emissions growth throughout the 1990-2005 period (leading to declining estimates of GHG emissions per unit of state product). From 1990 to 2005, emissions per unit of gross product dropped by 26% nationally, and by 17% in Alaska.

The principal source of Alaska's GHG emissions is the industrial fuel use/FF industry sector, accounting for 49% of total State gross GHG emissions in 2005. The industrial sector includes fossil fuel combustion at industrial sites as well as fossil fuel industry emissions associated with natural gas production, processing, transmission and distribution (T&D), flaring, and pipeline fuel use, as well as with oil production and refining and coal mining emission releases. The next largest contributor to total gross GHG emissions is the transportation sector, which accounted for 35% of the total State gross GHG emissions in 2005.

As illustrated in Figure ES-2 and shown numerically in Table ES-1, under the reference case projections, Alaska's gross GHG emissions continue to grow, and are projected to climb to 62.7 $MMtCO_2e$ per year by 2025, 61% above 1990 levels. As shown in Figure ES-3, emissions associated with industrial fuel use/FF industry sector are projected to be the largest contributor to future emissions growth, followed by emissions from the transportation sector.

Emissions of aerosols, particularly "black carbon" (BC) from fossil fuel combustion, could have significant climate impacts through their effects on radiative forcing. Estimates of these aerosol emissions on a CO_2e basis were developed for Alaska based on 2002 data and 2018 projected data from the Western Regional Air Partnership (WRAP). Estimated BC emissions for the year 2002 were a total of 3.0 $MMtCO_2e$, which is the mid-point of a range of estimated emissions (1.9 – 4.0 $MMtCO_2e$). Based on an assessment of the primary contributors, it is estimated that BC emissions will decrease by 2018 after new engine and fuel standards take effect in the onroad and nonroad diesel engine sectors. Details of this analysis are presented in Appendix I to this report. These estimates are not incorporated into the totals shown in Table ES-1 below because a

global warming potential for BC has not yet been assigned by the Intergovernmental Panel on Climate Change (IPCC).

Some data gaps exist in this analysis, particularly for the reference case projections. Key tasks for future GHG inventory work in Alaska include review and revision of key emissions drivers. These include electricity, fossil fuel production, and transportation fuel use growth rates and future electricity generation source mix, which will be major determinants of Alaska's future GHG emissions. Appendices A through H provide the detailed methods, data sources, and assumptions for each GHG sector. Also included are descriptions of significant uncertainties in emission estimates or methods and suggested next steps for refinement of the inventory. Appendix J provides background information on GHGs and climate-forcing aerosols.

GHG Reductions from Recent Actions[5]

The federal Energy Independence and Security Act (EISA) of 2007 was signed into law in December 2007. This federal law contains several requirements that will reduce GHG emissions as they are implemented over the next few years. During the MAG process, sufficient information was identified (e.g., implementation schedules) to estimate GHG emission reductions associated with implementing the Corporate Average Fuel Economy (CAFE) requirements in Alaska. The MAG also identified recent actions that Alaska has undertaken to control GHG emissions while at the same time conserving energy. One recent action related to weatherization bonding was identified for which data were available to estimate the emission reductions of the action relative to the business-as-usual reference case projections. Weatherization bonding reduced emissions relative to the BAU reference case projections slightly. This program is only funded from 2010 to 2014, and would account for a reduction of about 0.07 $MMtCO_2e$ in 2010. Future reductions were not quantifiable, since the program would be terminated after 2014. The GHG emission reductions projected to be achieved by the CAFE program are summarized in Table ES-2. This table shows a total reduction of about 0.7 $MMtCO_2e$ in 2025 from the business-as-usual reference case emissions, or a 1.1% reduction from the business-as-usual emissions in 2025 for all sectors combined.

[5] Note that actions recently adopted by the state of Alaska have also been referred to as "existing" actions.

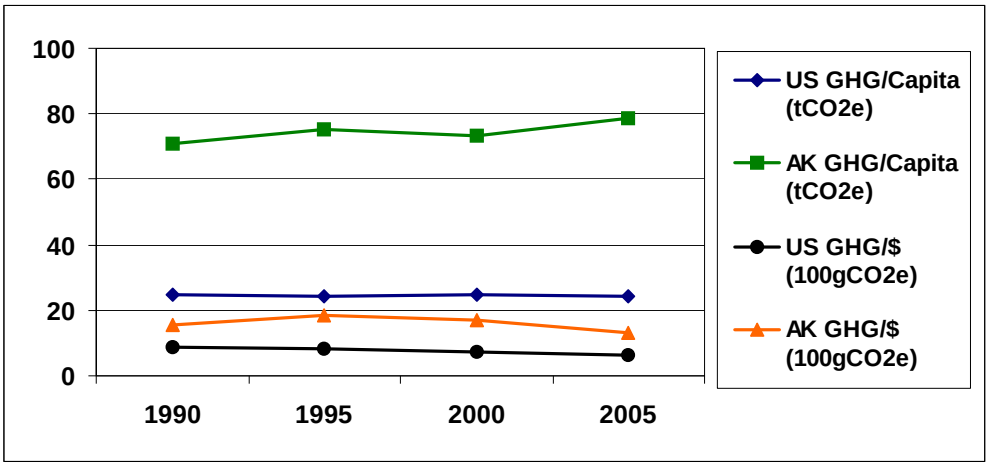
Table ES-1. Alaska Historical and Reference Case GHG Emissions, by Sector (MMtCO2e)[a]

$MMtCO_2e$	1990	2000	2005	2010	2020	2025	Explanatory Notes for Projections
Energy Use (CO_2, CH_4, N_2O)	**38.6**	**45.3**	**49.6**	**52.5**	**58.7**	**60.8**	
Electricity Use (Consumption)	**2.76**	**3.19**	**3.20**	**3.58**	**3.74**	**4.02**	
Electricity Production (in-state)	2.76	3.19	3.20	3.58	3.74	4.02	See electric sector assumptions
Coal	*0.40*	*0.42*	*0.48*	*0.50*	*0.79*	*0.79*	in appendix A.
Natural Gas	*2.00*	*2.29*	*2.14*	*2.22*	*2.36*	*2.36*	
Oil	*0.37*	*0.48*	*0.57*	*0.86*	*0.58*	*0.86*	
Imported/Exported Electricity	0.00	0.00	0.00	0.00	0.00	0.00	
Residential/Commercial Fuel Use	**3.77**	**4.33**	**3.88**	**3.91**	**4.12**	**4.07**	
Coal	*0.76*	*0.79*	*0.70*	*0.69*	*0.67*	*0.66*	*Based on US DOE regional projections*
Natural Gas	*1.79*	*2.22*	*1.87*	*1.91*	*2.09*	*2.13*	*Based on US DOE regional projections*
Petroleum	*1.21*	*1.30*	*1.29*	*1.29*	*1.34*	*1.26*	*Based on US DOE regional projections*
Wood (CH_4 and N_2O)	*0.012*	*0.013*	*0.023*	*0.023*	*0.023*	*0.023*	*Based on US DOE regional projections*
Industrial Fuel Use/Fossil Fuel Industry	**20.5**	**22.9**	**24.7**	**26.5**	**30.8**	**31.6**	
Coal/Coal Mining	*0.009*	*0.010*	*0.009*	*0.009*	*0.009*	*0.010*	*Based on US DOE regional projections*
Natural Gas/Natural Gas Industry	*13.4*	*17.7*	*19.2*	*20.5*	*25.0*	*26.0*	*Based on US DOE regional projections*
Petroleum/Oil Industry	*7.10*	*5.18*	*5.57*	*5.98*	*5.78*	*5.60*	*Based on US DOE regional projections*
Wood (CH_4 and N_2O)	*0.012*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*Based on US DOE regional projections*
Transportation	**11.5**	**14.9**	**17.8**	**18.5**	**20.1**	**21.1**	
Aviation	*7.15*	*10.6*	*12.9*	*13.1*	*13.4*	*13.7*	*FAA aircraft operations forecasts*
Marine Vessels	*0.83*	*0.48*	*0.61*	*0.72*	*1.00*	*1.17*	*DEC commercial marine growth factors*
On-road Vehicles	*3.41*	*3.71*	*4.19*	*4.55*	*5.57*	*6.20*	*WRAP inventory VMT projections*
Rail and Other	*0.082*	*0.075*	*0.056*	*0.057*	*0.062*	*0.063*	*Historical trends and USDOE regional projections*
Industrial Processes	**0.051**	**0.20**	**0.33**	**0.45**	**0.75**	**0.96**	
Limestone and Dolomite Use (CO_2)	0.000	0.000	0.008	0.008	0.009	0.009	Alaska manufacturing employment growth
Soda Ash (CO_2)	0.006	0.006	0.006	0.006	0.007	0.007	National projections for 2004-2009 (USGS)
ODS Substitutes (HFC, PFC)	0.001	0.17	0.30	0.42	0.72	0.94	EPA 2004 ODS cost study report
Electric Power T&D (SF_6)	0.044	0.025	0.024	0.017	0.010	0.008	Based on national projections (USEPA)
Waste Management	**0.32**	**0.53**	**0.63**	**0.52**	**0.73**	**0.86**	
Solid Waste Management	0.26	0.46	0.56	0.45	0.65	0.78	Projected based on 1995-2005 trend
Wastewater Management	0.057	0.067	0.068	0.071	0.076	0.079	Projected based on population
Agriculture	**0.053**	**0.054**	**0.053**	**0.056**	**0.066**	**0.073**	
Manure Management	0.001	0.002	0.004	0.005	0.009	0.012	USDA livestock projections
Enteric Fermentation	0.013	0.015	0.020	0.023	0.029	0.034	USDA livestock projections
Agricultural Soils	0.039	0.037	0.030	0.029	0.028	0.028	Projected based on historical trend
Gross Emissions (Consumption Basis)	**39.0**	**46.1**	**50.6**	**53.5**	**60.2**	**62.7**	
increase relative to 1990		*18%*	*30%*	*37%*	*55%*	*61%*	
Emissions Sinks	**-0.3**	**-1.4**	**-1.4**	**-1.4**	**-1.4**	**-1.4**	
Forestry and Land Use	-0.3	-1.4	-1.4	-1.4	-1.4	-1.4	Projections held constant at 2000 level
Net Emissions (Consumption Basis) (Including Forestry and Land Use Sinks))	**38.7**	**44.7**	**49.2**	**52.1**	**58.8**	**61.3**	
increase relative to 1990		*15%*	*27%*	*35%*	*52%*	*58%*	

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; CH_4 = methane; CO_2 = carbon dioxide; N_2O = nitrous oxide; ODS = ozone-depleting substance; HFC = hydrofluorocarbon; PFC = perfluorocarbon; SF_6 = sulfur hexafluoride; T&D = transmission and distribution.

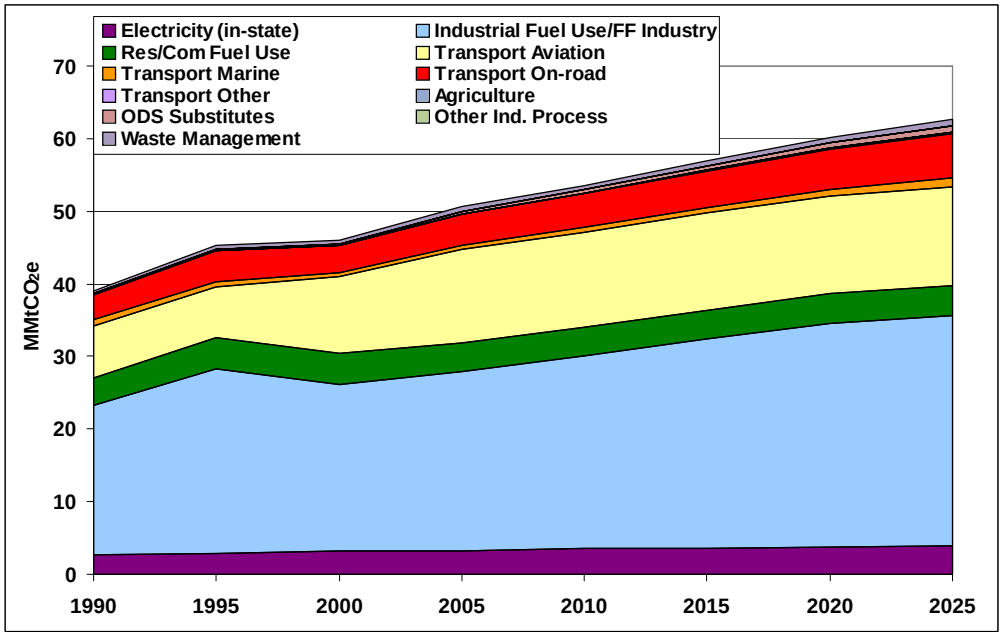
[a] Totals may not equal exact sum of subtotals shown in this table due to independent rounding.

Figure ES-1. Historical Alaska and U.S. GHG Emissions, Per Capita and Per Unit Gross Product



AK = Alaska; g = gram; GHG = greenhouse gas; tCO2e = metric tons of carbon dioxide equivalent; g = grams.

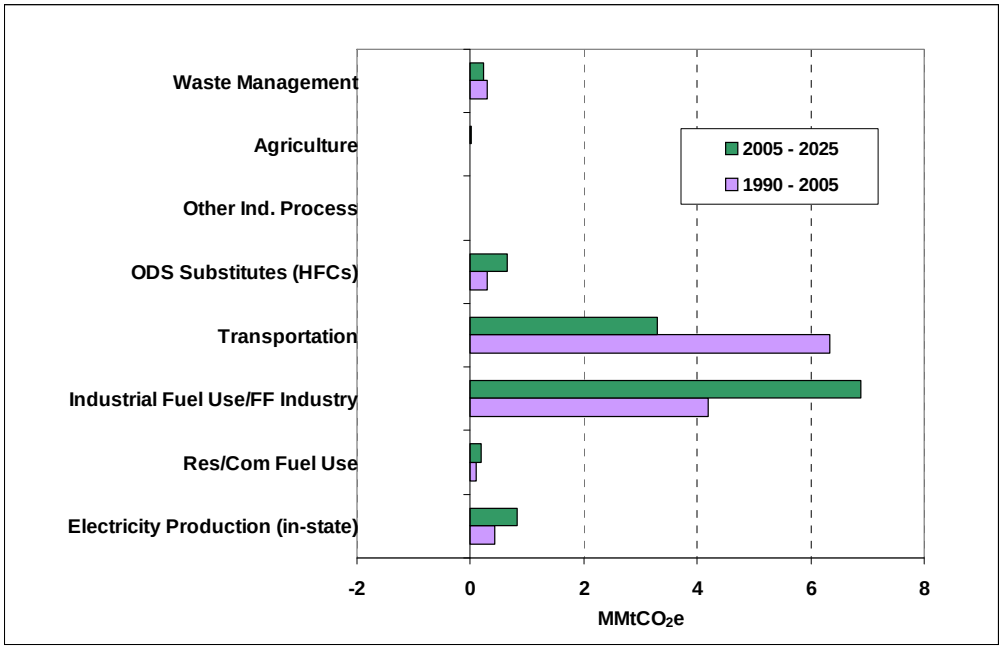
Figure ES-2. Alaska Gross GHG Emissions by Sector, 1990-2025: Historical and Projected



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; FF=fossil fuel; Res/Com = direct fuel use in the residential and commercial sectors; ODS = ozone-depleting substance; Ind. = industrial. The Industrial Fuel Use/FF Industry category accounts for direct fuel combustion in the industrial sector as well as fugitive

methane that occurs from leaks and venting during the production, processing, transmission, and distribution of fossil fuels.

Figure ES-3. Sector Contributions to Emissions Growth in Alaska, 1990-2025: Reference Case Projections



$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; Ind. = industrial; ODS = ozone-depleting substance; HFCs = hydrofluorocarbons; FF= fossil fuel; Res/Com = residential and commercial sectors.

Table ES-2. Emission Reduction Estimates Associated with the Effect of Recent Actions in Alaska (Consumption-Basis, Gross Emissions)

Sector/Recent Action	GHG Reductions ($MMtCO_2e$)		GHG Emissions ($MMtCO_2e$)	
			Business as Usual	With Recent Actions
	2015	2025	2025	2025
Residential/Commercial/Industrial (RCI) Fuel Use/Fossil Fuel Industry				
Weatherization Bonding	0	0	35.7	35.7
Transportation and Land Use (TLU)				
Federal Corporate Average Fuel Economy (CAFE) Requirements	0.22	0.73	21.1	20.4
Total (RCI + TLU Sectors)			**56.8**	**56.1**
Alaska Total (All Sectors)			**62.7**	**62.0**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

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Acronyms and Key Terms

AEO – *Annual Energy Outlook*

Ag – Agriculture

ADEC – Alaska Department of Environmental Conservation

bbls – Barrels

BC – Black Carbon

Bcf – Billion cubic feet

BLM – United States Bureau of Land Management

BOC – Bureau of Census

BTU – British thermal unit

C – Carbon

$CaCO_3$ – Calcium Carbonate

CBM – Coal Bed Methane

CCS – Center for Climate Strategies

CFCs – chlorofluorocarbons

CH_4 – Methane*

CO_2 – Carbon Dioxide*

CO_2e – Carbon Dioxide equivalent*

CRP – Federal Conservation Reserve Program

EC – Elemental Carbon

eGRID – U.S. EPA's Emissions & Generation Resource Integrated Database

EIA – U.S. DOE Energy Information Administration

EIIP – Emissions Inventory Improvement Project (US EPA)

FIA – Forest Inventory Analysis

GHG – Greenhouse Gases*

GSP – Gross State Product

GWh – Gigawatt-hour

GWP - Global Warming Potential*

HFCs – Hydrofluorocarbons*

HNO_3 – Nitric acid

HWP – Harvested Wood Products

IPCC – Intergovernmental Panel on Climate Change*

kWh – Kilowatt-hour

LFGTE – Landfill Gas Collection System and Landfill-Gas-to-Energy

LMOP – Landfill Methane Outreach Program

LNG – Liquefied Natural Gas

LPG – Liquefied Petroleum Gas

Mg – Megagrams (equivalent to one metric ton)

Mt - Metric ton (equivalent to 1.102 short tons)

MMt – Million Metric tons

MPO – Metropolitan Planning Organization

MSW – Municipal solid waste

MW – Megawatt

N – Nitrogen

N_2O – Nitrous Oxide*

NO_2 – nitrogen dioxide*

NAICS – North American Industry Classification System

NASS – National Agricultural Statistics Service

NO_x – Nitrogen oxides

NSCR – Non-selective catalytic reduction

ODS – Ozone-Depleting Substances

OM – Organic Matter

PADD – Petroleum Administration for Defense Districts

PFCs – Perfluorocarbons*

PM – Particulate Matter

ppb – parts per billion

ppm – parts per million

ppt – parts per trillion

PV – Photovoltaic

RCI – Residential, Commercial, and Industrial

RPA – Resources Planning Act Assessment

RPS – Renewable Portfolio Standard

SAR – Second Assessment Report

SCR- Selective catalytic reduction

SED – State Energy Data

SF_6 – Sulfur Hexafluoride*

SGIT – State Greenhouse Gas Inventory Tool

Sinks – Removals of carbon from the atmosphere, with the carbon stored in forests, soils, landfills, wood structures, or other biomass-related products.

TAR – Third Assessment Report

T&D – Transmission and Distribution

TWh – Terawatt-hours

UNFCCC – United Nations Framework Convention on Climate Change

U.S. EPA – United States Environmental Protection Agency

U.S. DOE – United States Department of Energy

USDA – United States Department of Agriculture

USFS – United States Forest Service

USGS – United States Geological Survey

VMT – Vehicle-Miles Traveled

WAPA – Western Area Power Administration

WECC – Western Electricity Coordinating Council

W/m^2 – Watts per Square Meter

WMO – World Meteorological Organization*

WRAP – Western Regional Air Partnership

* - See Appendix I for more information.

Acknowledgements

Comment [kmp2]: Please review to ensure that all names are included. - KP

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Summary of Findings

Introduction

The Center for Climate Strategies (CCS) prepared the first draft of this report for the Alaska Department of Environment Conservation (DEC) under an agreement with the Western Governors' Association. The report presented an assessment of the State's greenhouse gas (GHG) emissions and anthropogenic sinks (carbon storage) from 1990 to 2020. The preliminary draft inventory and forecast estimates served as a starting point to assist the State, as well as the Alaska Climate Change Mitigation Advisory Group (MAG) and Technical Work Groups (TWGs), with an initial comprehensive understanding of Alaska's current and possible future GHG emissions, and thereby informed the identification and analysis of policy options for mitigating GHG emissions.[6] The MAG and TWGs have reviewed, discussed, and evaluated the draft inventory and methodologies as well as alternative data and approaches for improving the draft GHG inventory and forecast. The inventory and forecast as well as this report have been revised to address the comments provided and approved by the MAG

Emissions and Reference Case Projections (Business-as-Usual)

Historical GHG emissions estimates (1990 through 2005)[7] were developed using a set of generally accepted principles and guidelines for state GHG emissions inventories, as described in the "Approach" section below, relying to the extent possible on Alaska-specific data and inputs. The initial reference case projections (2006-2025) are based on a compilation of various existing projections of electricity generation, fuel use, and other GHG-emitting activities, along with a set of simple, transparent assumptions described in the appendices of this report.

This report covers the six gases included in the U.S. Greenhouse Gas Inventory: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Emissions of these GHGs are presented using a common metric, CO_2 equivalence (CO_2e), which indicates the relative contribution of each gas to global average radiative forcing on a Global Warming Potential- (GWP-) weighted basis.[8] The final appendix to this report provides a more complete discussion of GHGs and GWPs. Emissions of black carbon were also estimated. Black carbon (BC) is an aerosol species with a positive climate forcing potential (that is, the potential to warm the atmosphere, as GHGs do); however, black carbon currently does not have a GWP defined by the IPCC due to uncertainties in both the direct and indirect effects of BC on atmospheric processes (see Appendices H and I for more details). Therefore, except for Appendix H, all of the summary tables and graphs in this report cover emissions of just the six GHGs noted above.

[6] "Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990-2020," prepared by the Center for Climate Strategies for the Alaska Department of Environmental Conservation, July 2007.
[7] The last year of available historical data varies by sector; ranging from 2000 to 2005.
[8] Changes in the atmospheric concentrations of GHGs can alter the balance of energy transfers between the atmosphere, space, land, and the oceans. A gauge of these changes is called radiative forcing, which is a simple measure of changes in the energy available to the Earth-atmosphere system (IPCC, 1996). Holding everything else constant, increases in GHG concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth), http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm.

It is important to note that the emission estimates for the electricity sector reflect the *GHG emissions associated with the electricity sources used to meet Alaska's demands*, corresponding to a *consumption-based* approach to emissions accounting (see "Approach" section below). Another way to look at electricity emissions is to consider the *GHG emissions produced by electricity generation facilities in the State.* Because Alaska has very limited electricity imports or exports, the GHG emissions on a production-basis are the same as GHG emissions from a consumption-basis. CCS introduces this concept of consumption- versus production-based emissions, since in other states, electricity imports and exports are an important issue.

Alaska Greenhouse Gas Emissions: Sources and Trends

Table 1 provides a summary of GHG emissions estimated for Alaska by sector for the years 1990, 2000, 2005, 2010, 2020, and 2025. Details on the methods and data sources used to construct these estimates are provided in the appendices to this report**.** In the sections below, we discuss GHG emission sources (positive, or *gross*, emissions) and sinks (negative emissions) separately in order to identify trends, projections and uncertainties for each.

The next section of the report provides a summary of the historical emissions (1990 through 2005) followed by a summary of the reference case projection year emissions (2006 through 2025), key uncertainties, and suggested next steps. We also provide an overview of the general methodology, principles, and guidelines followed for preparing the inventories. Appendices A through G provide the detailed methods, data sources, and assumptions for each GHG sector.

Appendix H provides information on 2002 and 2018 BC estimates for Alaska. CCS estimated that BC emissions in 2002 ranged from 1.9 – 4.0 $MMtCO_2e$ with a mid-point estimate of 3.0 $MMtCO_2e$. A range is estimated based on the uncertainty in the global modeling analyses that serve as the basis for converting BC mass emissions into their carbon dioxide equivalents (see Appendix I for more details). Since the IPCC has not yet assigned a global warming potential for BC, CCS has excluded these estimates from the GHG summary shown in Table 1 below. Based on an assessment of 2018 forecasted emissions for the primary BC contributors from the Western Regional Air Partnership (WRAP), it is estimated that BC emissions will decrease by 2018 after new engine and fuel standards take effect in the onroad and nonroad diesel engine sectors. Appendix I contains a detailed breakdown of emissions contribution by source sector.

Appendix I provides background information on GHGs and climate-forcing aerosols.

Table 1. Alaska Historical and Reference Case GHG Emissions, by Sector (MMtCO2e)a

$MMtCO_2e$	1990	2000	2005	2010	2020	2025	Explanatory Notes for Projections
Energy Use (CO_2, CH_4, N_2O)	**38.6**	**45.3**	**49.6**	**52.5**	**58.7**	**60.8**	
Electricity Use (Consumption)	**2.76**	**3.19**	**3.20**	**3.58**	**3.74**	**4.02**	
Electricity Production (in-state)	2.76	3.19	3.20	3.58	3.74	4.02	See electric sector assumptions
Coal	*0.40*	*0.42*	*0.48*	*0.50*	*0.79*	*0.79*	in appendix A.
Natural Gas	*2.00*	*2.29*	*2.14*	*2.22*	*2.36*	*2.36*	
Oil	*0.37*	*0.48*	*0.57*	*0.86*	*0.58*	*0.86*	
Imported/Exported Electricity	0.00	0.00	0.00	0.00	0.00	0.00	
Residential/Commercial Fuel Use	**3.77**	**4.33**	**3.88**	**3.91**	**4.12**	**4.07**	
Coal	*0.76*	*0.79*	*0.70*	*0.69*	*0.67*	*0.66*	*Based on US DOE regional projections*
Natural Gas	*1.79*	*2.22*	*1.87*	*1.91*	*2.09*	*2.13*	*Based on US DOE regional projections*
Petroleum	*1.21*	*1.30*	*1.29*	*1.29*	*1.34*	*1.26*	*Based on US DOE regional projections*
Wood (CH_4 and N_2O)	*0.012*	*0.013*	*0.023*	*0.023*	*0.023*	*0.023*	*Based on US DOE regional projections*
Industrial Fuel Use/Fossil Fuel Industry	**20.5**	**22.9**	**24.7**	**26.5**	**30.8**	**31.6**	
Coal/Coal Mining	*0.009*	*0.010*	*0.009*	*0.009*	*0.009*	*0.010*	*Based on US DOE regional projections*
Natural Gas/Natural Gas Industry	*13.4*	*17.7*	*19.2*	*20.5*	*25.0*	*26.0*	*Based on US DOE regional projections*
Petroleum/Oil Industry	*7.10*	*5.18*	*5.57*	*5.98*	*5.78*	*5.60*	*Based on US DOE regional projections*
Wood (CH_4 and N_2O)	*0.012*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*Based on US DOE regional projections*
Transportation	**11.5**	**14.9**	**17.8**	**18.5**	**20.1**	**21.1**	
Aviation	*7.15*	*10.6*	*12.9*	*13.1*	*13.4*	*13.7*	*FAA aircraft operations forecasts*
Marine Vessels	*0.83*	*0.48*	*0.61*	*0.72*	*1.00*	*1.17*	*DEC commercial marine growth factors*
On-road Vehicles	*3.41*	*3.71*	*4.19*	*4.55*	*5.57*	*6.20*	*WRAP inventory VMT projections*
Rail and Other	*0.082*	*0.075*	*0.056*	*0.057*	*0.062*	*0.063*	*Historical trends and USDOE regional projections*
Industrial Processes	**0.051**	**0.20**	**0.33**	**0.45**	**0.75**	**0.96**	
Limestone and Dolomite Use (CO_2)	0.000	0.000	0.008	0.008	0.009	0.009	Alaska manufacturing employment growth
Soda Ash (CO_2)	0.006	0.006	0.006	0.006	0.007	0.007	National projections for 2004-2009 (USGS)
ODS Substitutes (HFC, PFC)	0.001	0.17	0.30	0.42	0.72	0.94	EPA 2004 ODS cost study report
Electric Power T&D (SF_6)	0.044	0.025	0.024	0.017	0.010	0.008	Based on national projections (USEPA)
Waste Management	**0.32**	**0.53**	**0.63**	**0.52**	**0.73**	**0.86**	
Solid Waste Management	0.26	0.46	0.56	0.45	0.65	0.78	Projected based on 1995-2005 trend
Wastewater Management	0.057	0.067	0.068	0.071	0.076	0.079	Projected based on population
Agriculture	**0.053**	**0.054**	**0.053**	**0.056**	**0.066**	**0.073**	
Manure Management	0.001	0.002	0.004	0.005	0.009	0.012	USDA livestock projections
Enteric Fermentation	0.013	0.015	0.020	0.023	0.029	0.034	USDA livestock projections
Agricultural Soils	0.039	0.037	0.030	0.029	0.028	0.028	Projected based on historical trend
Gross Emissions (Consumption Basis)	**39.0**	**46.1**	**50.6**	**53.5**	**60.2**	**62.7**	
increase relative to 1990		*18%*	*30%*	*37%*	*55%*	*61%*	
Emissions Sinks	**-0.3**	**-1.4**	**-1.4**	**-1.4**	**-1.4**	**-1.4**	
Forestry and Land Use	-0.3	-1.4	-1.4	-1.4	-1.4	-1.4	Projections held constant at 2000 level
Net Emissions (Consumption Basis) (Including Forestry and Land Use Sinks))	**38.7**	**44.7**	**49.2**	**52.1**	**58.8**	**61.3**	
increase relative to 1990		*15%*	*27%*	*35%*	*52%*	*58%*	

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; CH_4 = methane; CO_2 = carbon dioxide; N_2O = nitrous oxide; ODS = ozone-depleting substance; HFC = hydrofluorocarbon; PFC = perfluorocarbon; SF_6 = sulfur hexafluoride; T&D = transmission and distribution.

[a] Totals may not equal exact sum of subtotals shown in this table due to independent rounding.

Historical Emissions

Overview

In 2005, activities in Alaska accounted for approximately 50.6 million metric tons (MMt) of *gross*[9] CO_2e emissions, an amount equal to 0.7% of total U.S. gross GHG emissions. Alaska's gross GHG emissions grew at a faster rate than those of the nation as a whole (gross emissions exclude carbon sinks, such as forests). Alaska's gross GHG emissions increased 30% from 1990 to 2005, while national emissions rose by 16% during this period. The growth in Alaska's emissions from 1990 to 2005 is primarily associated with the transportation and the industrial sectors.

Figure 1 illustrates the State's emissions (metric tons) per capita and per dollar of economic output. On a per capita basis in 2005, Alaska activities emitted about 79 metric tons (Mt) of CO_2e annually; significantly higher the national average of 24 $MtCO_2e$. The higher per capita emission rates in Alaska are driven by emissions from the industrial fuel combustion and transportation sectors, which are much higher than the national average. Figure 1 also shows that per capita emissions have increased somewhat in Alaska through the 1995-2005 period. Like the nation as a whole, Alaska's economic growth exceeded emissions growth throughout the 1990-2005 period (leading to declining estimates of GHG emissions per unit of state product). From 1990 to 2005, emissions per unit of gross product dropped by 26% nationally, and by 17% in Alaska.[10] .

[9] Excluding GHG emissions removed due to forestry and other land uses and excluding GHG emissions associated with exported electricity.

[10] Based on real gross domestic product (millions of chained 2000 dollars) that excludes the effects of inflation, available from the US Bureau of Economic Analysis (http://www.bea.gov/regional/gsp/). The national emissions used for these comparisons are based on 2005 emissions from the 2008 version of EPA's GHG inventory report. (http://www.epa.gov/climatechange/emissions/usinventoryreport.html).

Figure 1. Alaska and US Gross GHG Emissions, Per Capita and Per Unit Gross Product

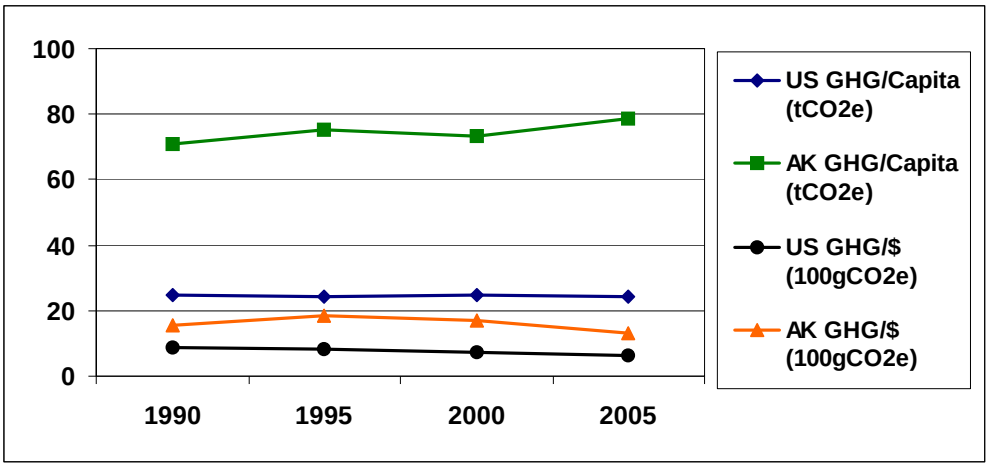
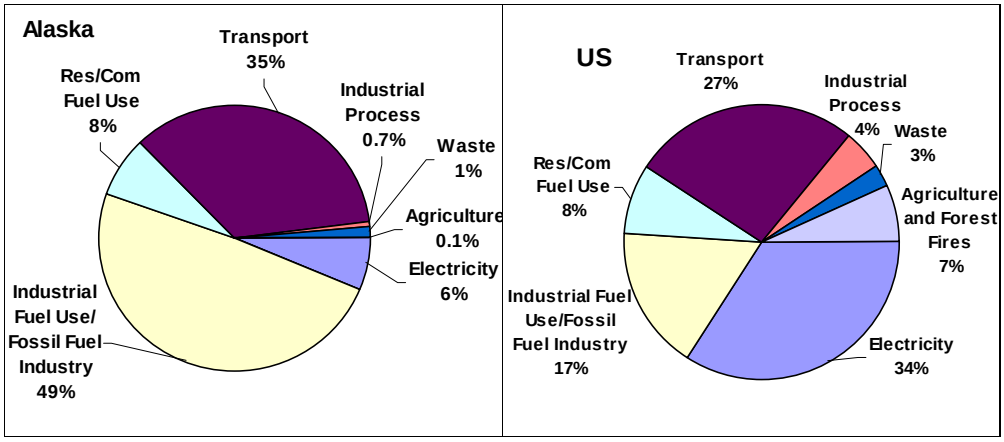


Figure 2 compares the contribution of gross GHG emissions by sector estimated for Alaska to emissions for the U.S. for year 2005. The principal sources of Alaska's GHG emissions in 2005 are the industrial and transportation sectors, accounting for 49% and 35% of Alaska's gross GHG emissions, respectively. The industrial sector includes fossil fuel combustion at industrial sites as well as fossil fuel industry emissions associated with natural gas production, processing, transmission and distribution (T&D), flaring, and pipeline fuel use, as well as with oil production and refining and coal mining emission releases. The next-largest contributor is the combustion of fossil fuel by the residential and commercial sectors, accounting for 8% of gross GHG emissions in 2005. Electricity production accounted for 6% of gross GHG emissions in 2005. The remaining sectors—agriculture, landfills and wastewater management facilities, and industrial processes—accounted for about 2% of the state's emissions in 2005. Industrial process emissions comprised only 0.7% of state GHG emissions in 2005, but these emissions are rising due to the increasing use of HFCs as substitutes for ozone-depleting chlorofluorocarbons.[11] Other industrial process emissions result from CO_2 released during soda ash, limestone, and dolomite use. In addition, SF_6 is released due to the use of electric power T&D equipment.

Forestry activities in Alaska are estimated to be net sinks for GHG emissions. Forested lands are a net sink of about 1.4 $MMtCO_2e$ in 2005.

[11] Chlorofluorocarbons are also potent GHGs. However, they are not included in GHG estimates because of concerns related to implementation of the Montreal Protocol on Substances That Deplete the Ozone Layer. See Appendix J in the Final Inventory and Projections report for Alaska, available at http://www.akclimatechange.us/Inventory_Forecast_Report.cfm.

Figure 2. Gross GHG Emissions by Sector, Alaska and US – 2005 Data



Notes: Res/Com = Residential and commercial fuel use sectors. Emissions for the residential and commercial fuel use sectors are associated with the direct use of fuels (natural gas, petroleum, coal, and wood) to provide space heating, water heating, process heating, cooking, and other energy end uses. The commercial sector accounts for emissions associated with the direct use of fuels by, for example, hospitals, schools, government buildings (local, county, and state), and other commercial establishments.

The industrial fuel use/fossil fuel industry sector accounts for direct fuel combustion in the industrial sector as well as fugitive methane that occurs from leaks and venting during the production, processing, transmission, and distribution of fossil fuels. The industrial processes sector accounts for emissions associated with manufacturing and excludes emissions included in the industrial fuel use/fossil fuel industry sector.

The transportation sector accounts for emissions associated with fuel consumption by all on-road and non-highway vehicles. Non-highway vehicles include jet aircraft, gasoline-fueled piston aircraft, railway locomotives, boats, and ships. Emissions from non-highway agricultural and construction equipment are included in the industrial sector.

Electricity = Electricity generation sector emissions on a consumption basis. In Alaska, the electricity consumed is assumed to be the same as the electricity produced in the state.

A Closer Look at the Two Major Sources: Industrial Sector and Transportation

Industrial Sector

As shown in Figure 2, the industrial sector, comprised of industrial fuel combustion as well as emissions associated with the production, processing, transmission, and distribution of fossil fuels, accounted for 49% of Alaska's gross GHG emissions in 2005 (about 25 $MMtCO_2e$), which was much higher than the national average share of emissions from the industrial sector (17%). Activities in the industrial[12] sector produce GHG emissions when fuels are combusted to provide space heating, process heating, and other applications. This sector also includes emissions released during the production, processing, transmission, and distribution of fossil fuels. Known as fugitive emissions, these are methane and carbon dioxide gases released via leakage and venting at coal mines, oil and gas fields, processing facilities, and pipelines. A majority of the industrial sector emissions resulted from the use of natural gas and the natural gas industry (19.2

[12] The industrial sector includes emissions associated with agricultural energy use and fuel used by the fossil fuel production industry.

$MMtCO_2e$). Industrial oil combustion and the oil industry together contributed 5.6 $MMtCO_2e$ of GHG emissions in 2005. An insignificant amount of the industrial sector emissions was contributed by coal use and coal mining. GHG emissions for the industrial sector (excluding those associated with electricity consumption) are expected to increase by 28% between 2005 and 2025, reaching 31.6 $MMtCO_2e$ by 2025.[13]

Transportation Sector

The transportation sector accounted for 35% (17.8 $MMtCO_2e$) of Alaska's gross GHG emissions in 2005. Emissions are projected to increase to 21.1 $MMtCO_2e$ (34% of gross GHG emissions) in 2025. Jet fuel consumption accounts for the largest share of transportation GHG emissions. Emissions from jet fuel consumption increased by about 84% from 1990 to 2005 to account for 72% of total transportation emissions in 2005. Emissions from onroad gasoline grew by 15% between 1990 and 2005 and onroad diesel grew by 37% during this period. In 2005, onroad gasoline and diesel accounted for 14% and 10% of total transportation emissions, respectively. GHG emissions from marine fuel consumption decreased by 44% from 1990 to 2005, and in 2005 accounted for 3% of GHG emissions from the transportation sector. Emissions from all other categories combined (aviation gasoline, locomotives, natural gas and LPG, and oxidation of lubricants) contributed slightly over 0.3% of total transportation emissions in 2005.

From 2005 to 2025, emissions from transportation fuels are projected to rise by 0.85% per year. This leads to an increase of 3.3 MMtCO2e in transportation emissions from 2005 to 2025, for a total of 21.1 $MMtCO_2e$ in 2025. The largest percentage increase in emissions over this time period is seen in onroad diesel fuel consumption, which is projected to increase by 92% from 2005 to 2025.

It is important to note that the jet fuel emissions include fuel that is purchased in-state but is not necessarily consumed within Alaska's airspace. This accounting issue is also present in the inventories of other states prepared by CCS, where international passenger and cargo transportation emissions are concerned. On the other hand, fuel purchased outside of the state for aircraft that enter the state are not included in the emission estimates presented in this report. The size of the contribution from the transportation - aviation sector shown in Figure 3 reflects the importance of this industry in Alaska.

Reference Case Projections (Business as Usual)

Relying on a variety of sources for projections, as noted below and in the appendices, we developed a simple reference case projection of GHG emissions through 2025. Figure 3 provides both the historical and projected gross emission estimates for all source sectors. Figure 4 is a chart showing the contribution for each sector to emissions growth both historically (1990-2005) and for the reference case forecast (2005-2025). As illustrated in Figure 3 and shown

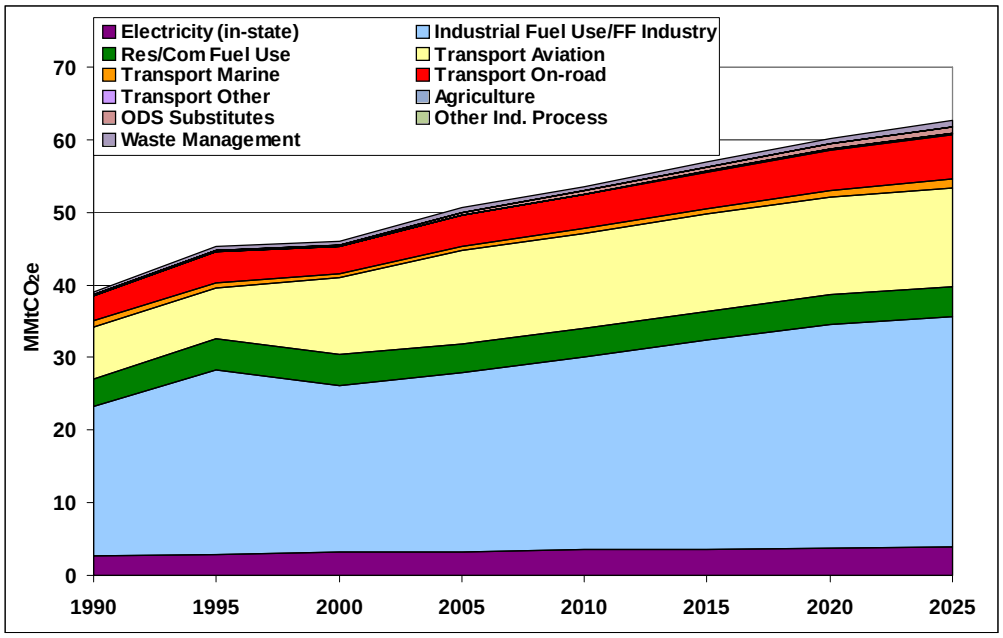
[13] See Appendix B for more details. Given the forecasted decline in non-combustion emissions for the fossil fuel industry, the increase in the industrial fossil fuel consumption seems odd; however, DEC contacts indicate that natural gas combustion is expected to increase significantly in future years, since more fuel is consumed to extract oil and gas as the production in existing fields declines. This is an area that should be investigated further during future work. The industrial fossil fuel consumption projections are based on the regional Energy Information Administration *Annual Energy Outlook 2006* forecast data for the Pacific Region (http://www.scag.ca.gov/rcp/pdf/publications/1_2006AnnualEnergyOutlook.pdf).

numerically in Table 1, under the reference case projections, Alaska gross GHG emissions continue to grow steadily, climbing to 62.7 $MMTCO_2e$ by 2025, 61% above 1990 levels. This equates to an annual growth rate of 1.1% per year from 2005 to 2025. Relative to 2005, the share of emissions associated with the industrial sector, industrial processes, and waste management all increase slightly to 50%, 1.5%, and 1.4%, respectively, in 2025. The shares of emissions from the transportation and residential and commercial fuel use sectors both decrease slightly by 2025, relative to 2005, to 34% and 6%, respectively. The share of emissions from the electricity and the agricultural sectors both remain the same in 2025 as their shares in 2005.

As shown in Figure 4, both the industrial and transportation sectors are important contributors to emissions growth, both historically and in the future projected emissions. Emissions associated with the industrial sector are projected to be the largest contributor to future GHG emissions growth, with a total increase in GHG emissions from 2005 to 2025 of 7.0 $MMtCO_2e$, as shown in Figure 4. The next-largest source of emissions growth in this time period is the transportation sector, with an increase of 3.3 $MMtCO_2e$. Other sources of future emissions growth include the electricity production, ozone-depleting substance substitutes, waste management, residential and commercial fuel use, and agriculture sectors. Details on the assumptions used to estimate future GHG emissions are provided in the applicable technical appendices to this report.

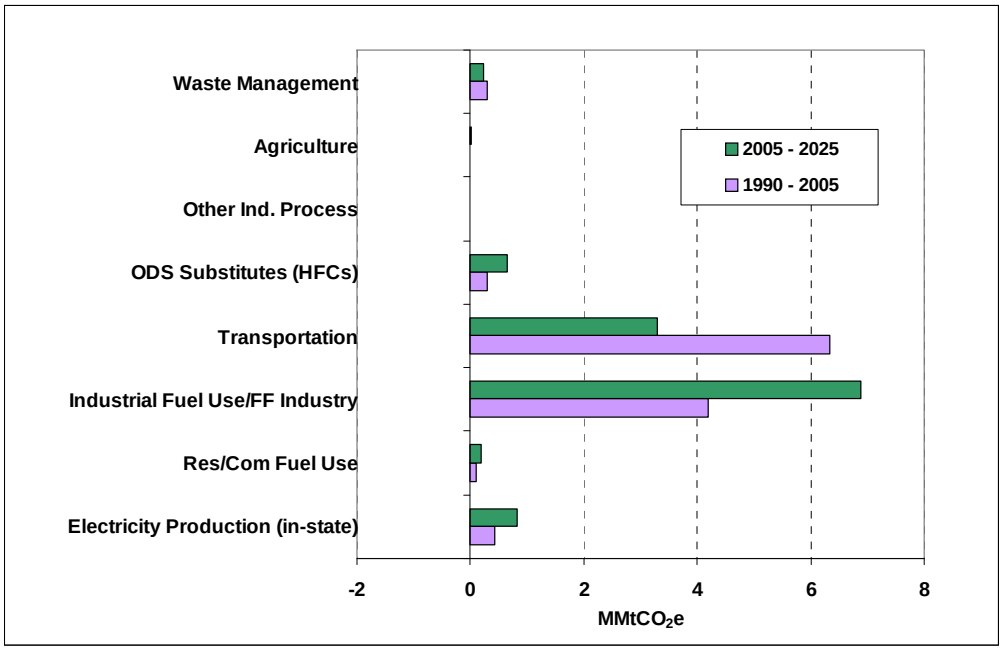
Table 2 summarizes the growth rates that drive the growth in the Alaska reference case projections as well as the sources of these data.

Figure 3. Alaska Gross GHG Emissions by Sector, 1990-2025: Historical and Projected



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; FF=fossil fuel; Res/Com = direct fuel use in the residential and commercial sectors; ODS = ozone-depleting substance; Ind. = industrial. The Industrial Fuel Use/FF Industry category accounts for direct fuel combustion in the industrial sector as well as fugitive methane that occurs from leaks and venting during the production, processing, transmission, and distribution of fossil fuels.

Figure 4. Sector Contributions to Emissions Growth in Alaska, 1990-2025: Historical and Reference Case Projections



$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; Ind. = industrial; ODS = ozone-depleting substance; HFCs = hydrofluorocarbons; FF= fossil fuel; Res/Com = residential and commercial sectors.

Table 2. Key Annual Growth Rates for Alaska, Historical and Projected

Key Parameter	1990-2005	2005-2025	Sources
Population	1.0%	0.6%	Alaska Department of Labor and Workforce Development
Employment Goods Services	 2.1% 1.7%	 0.9% 1.1%	Alaska Department of Labor and Workforce Development, 2004-2014 Forecast trend assumed to continue through 2025
Electricity Sales	2.2%	0.8%	Historic rates are from EIA data, projections are CCS assumptions as described in Appendix A.
Vehicle Miles Traveled	1.7%	1.3%	Alaska Department of Transportation and Public Facilities, Western Region Air Partnership (WRAP) Mobile Source Inventory

* Population and employment projections for Alaska were used together with the U.S. Department of Energy's Energy Information Administration *Annual Energy Outlook 2006* projections of changes in fuel use per capita and per employee, as relevant for each sector (http://www.scag.ca.gov/rcp/pdf/publications/1_2006AnnualEnergyOutlook.pdf). For instance, growth in Alaska's residential natural gas use is calculated as the Alaska population growth times the change in per-capita natural gas use for the Pacific region.

EIA = Energy Information Administration; CCS = Center for Climate Strategies.

Mitigation Advisory Group Revisions

Following are the revisions that the MAG made to the inventory and reference case projections, thus explaining the differences between this final Inventory and Projections report and the initial assessment completed in July 2007:

All Sectors

The initial assessment included GHG emission projections to 2020. This was revised to extend the GHG projections to 2025 for all sectors.

Electric Supply

The Energy Supply and Demand TWG generated forecasts for RCI fuel and electricity consumption for the purposes of deriving sub-sector emission reductions from various policies. Historical RCI uses, growing at regional rates, were used to estimate future non-oil and gas use. Electricity-sector emissions were designed to be consistent with the current fuel mix in Alaska, as well as specific expected changes in the fuel mix based on expert opinion in the TWG. It is expected that, in absence of new infrastructure, new demand in the future would be met through petroleum combustion. The 60-megawatt Healy Clean Coal Project is expected to be brought on line in 2013 (displacing natural gas), and Fairbanks is expected to obtain natural gas delivery service by 2019 (displacing petroleum consumption), according to panel experts.

Transportation

The Transportation and Land Use TWG recommended that the marine emissions inventory exclude emissions from vessels that pass through Alaskan waters but do not call on Alaskan ports. This approach is consistent with the treatment of aviation emissions, which exclude emissions from aircraft that pass through Alaskan airspace but do not stop in Alaska. It was estimated that the offshore marine emissions previously calculated consisted largely of emissions from vessels that do not call on Alaska ports. Approximately 1%–2% of ships passing through Alaska's Exclusive Economic Zone, which extends 200 miles from the shore, actually stop at an Alaska port. In addition, some of those offshore emissions are already accounted for in the nearshore emissions component. As a result, the offshore emissions have been removed from the GHG I&F. Historical fuel consumption data and vehicle miles traveled through 2005 were added, where available. In addition, several minor errors were corrected, including the baseline on-road fuel economy values.

Waste Management

The Forestry, Agriculture, and Waste Management (FAW) TWG recommended that open-burning emissions be assumed to occur based on 50% of all waste received at Class III landfills. In addition, open-burning emissions were removed from the controlled burning category. Controlled burning was then updated based on input from DEC. The 2005 and future year emission totals for the controlled burning category were also adjusted to account for the fact that Juneau no longer used controlled burning as a waste management practice. For municipal solid waste (MSW) landfills, the total tonnage disposed of in Class II and Class III landfills was adjusted based on the population of the areas served by those landfills and an assumed 5.9 pounds MSW/person/day. The initial I&F overestimated the number of Class III landfills by 78

and the number of Class II landfills by 36. The allocation of potential landfill gas emissions among uncontrolled, flared, and landfill-gas-to-energy (LFGTE) landfills was adjusted, based on TWG input that the Anchorage and Juneau landfills began flaring in 2006 and 2008, respectively, and the Anchorage Regional Landfill will begin an LFGTE project in 2015. All revised landfill data were provided by members of the FAW TWG.

Reference Case Projections with Recent Actions[14]

The federal Energy Independence and Security Act (EISA) of 2007 was signed into law in December 2007. This federal law contains several requirements that will reduce GHG emissions as they are implemented over the next few years. During the MAG process, sufficient information was identified (e.g., implementation schedules) to estimate GHG emission reductions associated with implementing the Corporate Average Fuel Economy (CAFE) requirements in Alaska.

The MAG also identified recent actions that Alaska has undertaken to control GHG emissions while at the same time conserving energy. One recent action related to weatherization bonding was identified for which data were available to estimate the emission reductions of the action relative to the business-as-usual reference case projections.

The GHG emission reductions projected to be achieved by these recent State and Federal actions are summarized in Table 3. This table shows a total reduction of about 0.7 $MMtCO_2e$ in 2025 from the business-as-usual reference case emissions, or a 1.1% reduction from the business-as-usual emissions in 2025 for all sectors combined.

The following provides a brief summary of the component of the EISA that was analyzed as a recent federal action.

Federal Corporate Average Fuel Economy Requirements: Subtitle A of Title I of EISA imposes new CAFE standards beginning with the 2011 model year vehicles. The average combined fuel economy of automobiles will be at least 35 mpg by 2020, with separate standards applying to passenger and non-passenger automobiles. The standard will be phased in, starting with the 2011 model year, so that the CAFE increases each year until the average fuel economy of 35 mpg is reached by 2020.

The following provides a brief summary of the Alaska recent action.

Weatherization Bonding: Weatherization bonding reduced emissions relative to the BAU reference case projections slightly. This program is only funded from 2010 to 2014, and would account for a reduction of about 0.07 $MMtCO_2e$ in 2010. Future reductions were not quantifiable, since the program would be terminated after 2014.

[14] Note that actions recently adopted by the state of Alaska have also been referred to as "existing" actions.

Table 3. Emission Reduction Estimates Associated with the Effect of Recent Actions in Alaska (Consumption-Basis, Gross Emissions)

Sector/Recent Action	GHG Reductions ($MMtCO_2e$)		GHG Emissions ($MMtCO_2e$)	
			Business as Usual	With Recent Actions
	2015	2025	2025	2025
Residential/Commercial/Industrial (RCI) Fuel Use/Fossil Fuel Industry				
Weatherization Bonding	0	0	35.7	35.7
Transportation and Land Use (TLU)				
Federal Corporate Average Fuel Economy (CAFE) Requirements	0.22	0.73	21.1	20.4
Total (RCI + TLU Sectors)			**56.8**	**56.1**
Alaska Total (All Sectors)			**62.7**	**62.0**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Key Uncertainties and Next Steps

Some data gaps exist in this inventory, and particularly in the reference case projections. Key tasks that should be performed in future updates include review and revision of key drivers, such as the industrial and transportation fuel use growth rates that will be major determinants of Alaska's future GHG emissions (See Table 2). These growth rates are driven by uncertain economic, industrial, demographic, and land use trends (including growth patterns and transportation system impacts), all of which deserve closer review and discussion.

Perhaps the variables with the most important implications for the State's GHG emissions are the assumptions on air travel and industrial sector growth. Finally, uncertainty remains regarding the estimates for historic GHG sinks from forestry, and projections for these emissions may affect the net GHG emissions in Alaska.

Emissions of aerosols, particularly black carbon from fossil fuel combustion, could have significant impacts in terms of radiative forcing (that is, climate impacts). Methodologies for conversion of black carbon mass estimates and projections to global warming potential involve significant uncertainty at present, but CCS has developed and used a recommended approach for estimating black carbon emissions based on methods used in other States. Current estimates suggest a 6% CO_2e contribution overall from BC emissions, as compared to the CO_2e contributed from the gases (see Appendix I).

Approach

The principal goal of compiling the inventories and reference case projections presented in this document is to provide the State, with a general understanding of Alaska's historical, current, and projected (expected) GHG emissions. The following explains the general methodology and the general principles and guidelines followed during development of these GHG inventories for Alaska.

General Methodology

CCS prepared this analysis in close consultation with Alaska agencies, in particular, with the DEC staff. The overall goal of this effort is to provide simple and straightforward estimates, with an emphasis on robustness, consistency and transparency. As a result, we rely on reference forecasts from best available state and regional sources where possible. Where reliable forecasts are lacking, we use straightforward spreadsheet analysis and linear extrapolations of historical trends rather than complex modeling.

In most cases, we follow the same approach to emissions accounting for historical inventories used by the US EPA in its national GHG emissions inventory[15] and its guidelines for States.[16] These inventory guidelines were developed based on the guidelines from the Intergovernmental Panel on Climate Change, the international organization responsible for developing coordinated methods for national GHG inventories.[17] The inventory methods provide flexibility to account for local conditions. The key sources of activity and projection data are shown in Table 4. Table 4 also provides the descriptions of the data provided by each source and the uses of each data set in this analysis.

General Principles and Guidelines

A key part of this effort involves the establishment and use of a set of generally accepted accounting principles for evaluation of historical and projected GHG emissions, as follows:

- **Transparency:** We report data sources, methods, and key assumptions to allow open review and opportunities for additional revisions later based on input from others. In addition, we will report key uncertainties where they exist.

- **Consistency:** To the extent possible, the inventory and projections were designed to be externally consistent with current or likely future systems for state and national GHG emission reporting. We have used the EPA tools for state inventories and projections as a starting point. These initial estimates were then augmented and/or revised as needed to conform with state-based inventory and base-case projection needs. For consistency in

[15] *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*, April 15, 2008, US EPA #430-R-08-005, (http://www.epa.gov/climatechange/emissions/usinventoryreport.html).
[16] http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateInventoryGuidance.html.
[17] http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

making reference case projections[18], we define reference case actions for the purposes of projections as those *currently in place or reasonably expected over the time period of analysis*.

- **Priority of Existing State and Local Data Sources:** In gathering data and in cases where data sources conflicted, we placed highest priority on local and state data and analyses, followed by regional sources, with national data or simplified assumptions such as constant linear extrapolation of trends used as defaults where necessary.

- **Priority of Significant Emissions Sources:** In general, activities with relatively small emissions levels may not be reported with the same level of detail as other activities.

- **Comprehensive Coverage of Gases, Sectors, State Activities, and Time Periods.** This analysis aims to comprehensively cover GHG emissions associated with activities in Alaska. It covers all six GHGs covered by U.S. and other national inventories: CO_2, CH_4, N_2O, SF_6, HFCs, and PFCs and black carbon. The inventory estimates are for the year 1990, with subsequent years included up to most recently available data (typically 2002 to 2005), with projections to 2010, 2020, and 2025.

- **Use of Consumption-Based Emissions Estimates:** To the extent possible, we estimated emissions that are caused by activities that occur in Alaska. For example, we reported emissions associated with the electricity consumed in Alaska. The rationale for this method of reporting is that it can more accurately reflect the impact of State-based policy strategies such as energy efficiency on overall GHG emissions, and it resolves double counting and exclusion problems with multi-emissions issues. This approach can differ from how inventories are compiled, for example, on an in-state production basis, in particular for electricity. *As mentioned previously, since there are no significant electricity imports to or exports from Alaska, the production-based estimates are the same as the consumption-based estimates.*

[18] "Reference case" refers to a projection of the current or "base year" inventory to one or more future years under business-as-usual forecast conditions (for example, existing control programs and economic growth).

Table 4. Key Sources for Alaska Data, Inventory Methods, and Growth Rates

Source	Information provided	Use of Information in this Analysis
US EPA State Greenhouse Gas Inventory Tool (SIT)	US EPA SIT is a collection of linked spreadsheets designed to help users develop State GHG inventories. US EPA SIT contains default data for each State for most of the information required for an inventory. The SIT methods are based on the methods provided in the Volume 8 document series published by the Emissions Inventory Improvement Program (http://www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html)	Where not indicated otherwise, SIT is used to calculate emissions from residential/commercial/industrial fuel combustion, industrial processes, transportation, agriculture and forestry, and waste. We use SIT emission factors (CO_2, CH_4 and N_2O per British thermal unit (Btu) consumed) to calculate energy use emissions.
US DOE Energy Information Administration (EIA) State Energy Data (SED)	EIA SED source provides energy use data in each State, annually to various historical years (2002-2005).	EIA SED is the source for most energy use data. Emission factors from US EPA SIT are used to calculate energy-related emissions.
US DOE Energy Information Administration Annual Energy Outlook 2006 (AEO2006)	EIA AEO2006 projects energy supply and demand for the US from 2005 to 2030. Energy consumption is estimated on a regional basis. Alaska is included in the Pacific Census region (AK, CA, HI, OR, and WA)	EIA AEO2006 is used to project changes in per capita (residential) and per employee (commercial/industrial) energy consumption
US DOE Energy Information Administration Annual Energy Outlook 2009 (AEO2009)	EIA AEO2009 provides estimates of historical and projected electricity generation and consumption of electricity by end use sector.	EIA 2009 is used to project electricity generation for Alaska
American Gas Association – Gas Facts	Natural gas transmission and distribution pipeline mileage.	Pipeline mileage from Gas Facts used with SGIT to estimate natural gas transmission and distribution emissions.
US EPA Landfill Methane Outreach Program (LMOP)	LMOP provides landfill waste-in-place data.	Waste-in-place data used to estimate annual disposal rate, which was used with SGIT to estimate emissions from solid waste, with additional data from ADEC staff.
US Forest Service	Data on forest carbon stocks for multiple years.	Data are used to calculate CO_2 flux over time (terrestrial CO_2 sequestration in forested areas).
USDS National Agricultural Statistics Service (NASS)	USDA NASS provides data on crops and livestock.	Crop production data used to estimate agricultural residue and agricultural soils emissions; livestock population data used to estimate manure and enteric fermentation emissions

If DEC decides to refine this analysis, they may also consider estimating other sectoral emissions on a consumption basis, such as accounting for emissions from combustion of transportation fuel used in Alaska, but purchased out-of-state. In some cases this can require venturing into the relatively complex terrain of life-cycle analysis. In general, CCS recommends considering a consumption-based approach where it will significantly improve the estimation of the emissions impact of potential mitigation strategies. [For example re-use, recycling, and source reduction can lead to emission reductions resulting from lower energy requirements for material production (such as paper, cardboard, and aluminum), even though production of those materials, and emissions associated with materials production, may not occur within the State.]

Details on the methods and data sources used to construct the inventories and forecasts for each source sector are provided in the following appendices:

- Appendix A. Electricity Use and Supply.
- Appendix B. Residential, Commercial, and Industrial Fossil Fuel Combustion and Fossil Fuel Industries.
- Appendix C. Transportation Energy Use.
- Appendix D. Industrial Processes.
- Appendix E. Agriculture.
- Appendix F. Waste Management.
- Appendix G. Forestry.

Appendix H contains a discussion of the inventory and forecast for black carbon. Appendix I provides additional background information from the US EPA on greenhouse gases and global warming potential value.

Appendix A. Electricity

This Appendix describes Alaska's electricity sector and the historical greenhouse gas (GHG) emissions associated with this sector from 1990 to the present. The assumptions used to develop the reference case projections are also described and the resulting GHG emissions are summarized.

As noted in the main report, a key question for many States to consider when developing GHG inventories is how to treat GHG emissions that result from generation of electricity that is produced outside the State to meet electricity needs in the State – or the opposite case of electricity produced in the State to provide electricity for customers in other states. In other words, should the State consider the GHG emissions associated with the State's electricity consumption, with its electricity production, or with some combination of the two? This issue is not as important for Alaska, since its electric sector is stand-alone. All emissions presented here are consumption-based. However, in the case of Alaska, production-based emissions would be equivalent to these consumption-based estimates.

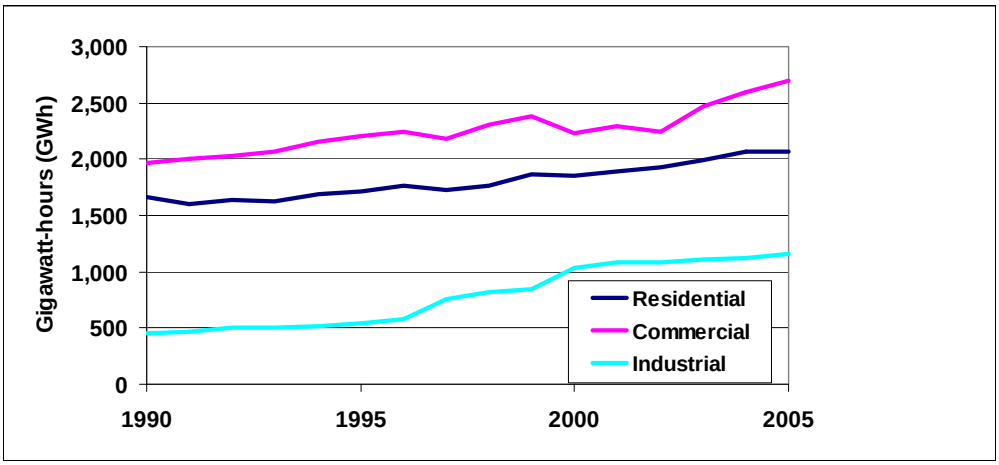
Electricity Consumption

At about 8,800 kilowatt-hours (kWh) per capita per year based on 2004 data, Alaska has relatively low electricity consumption for its population. By way of comparison, the per capita consumption for the U.S. was about 12,000 kWh per year.[19] Many factors influence a state's per capita electricity consumption, including the impact of weather on demand for cooling and heating, the size and type of industries in the State, and the type and efficiency of equipment in use in the residential, commercial and industrial sectors.

As shown in Figure A1, electricity sales in Alaska's residential and commercial sectors have generally increased modestly from 1990 through 2005. The industrial sector electricity sales are characterized by strong growth from 1997 to 2000, but limited growth in other time periods. Overall, total electricity consumption increased at an average annual rate of 2.2 percent from 1990 to 2005, which can be compared with the average population growth rate of 1.0 percent per year and gross state product increases averaging about 3.1 percent per year over the same period.[20]

[19] US Census Bureau for US population, Energy Information Administration for electricity sales.
[20] Population from Alaska Department of Labor and Workforce Development, "Workforce Information," Home (http://almis.labor.state.ak.us/), Population & Census, Estimates & Projections, Population Data Tables "Alaska Population Estimates 2000-2005,". Gross State Production from Bureau of Economic Analysis. http://bea.gov/bea/newsrelarchive/2006/gsp1006.xls.

Figure A1. Electricity Consumption by Sector in Alaska, 1990-2005[21]



Source: EIA State Energy Data (1990-2002) and EIA Electric Power Annual (2003-2005).

Electricity Generation – Alaska's Power Plants

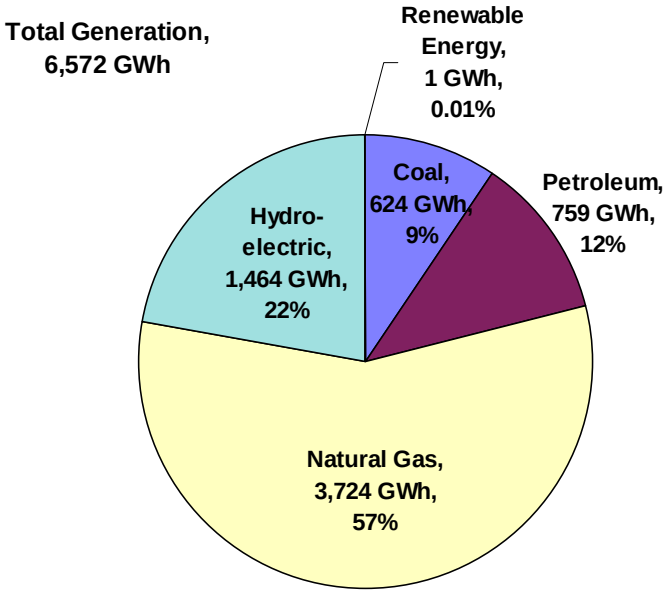
The following section provides information on GHG emissions and other activity associated with power plants in Alaska. As displayed in Figure A2, natural gas figures prominently in electricity generation and accounts for 67 percent of the GHG emissions from power plants in Alaska in 2005. Hydroelectric and petroleum-fired plants also provided significant electricity generation.

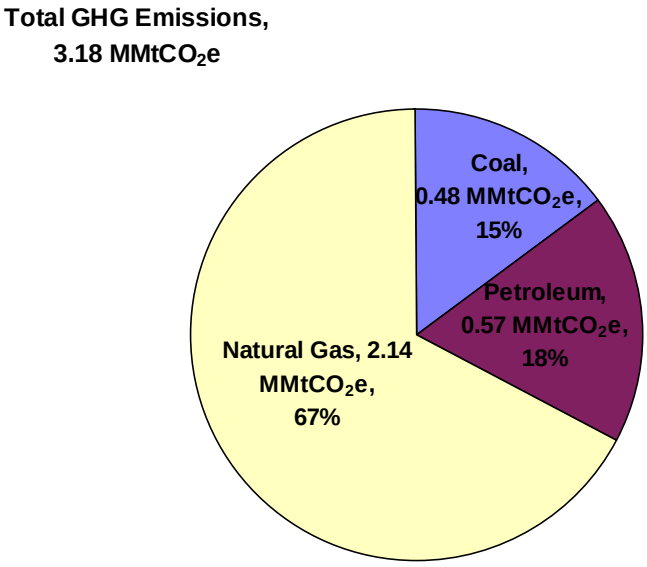
As discussed above, we assumed that Alaska electricity consumption is exclusively served by in-state Alaska generation. Generation is assumed to exceed consumption by 7%, accounting for losses from transmission and distribution. The historical fuel mixes for current and historical Alaska RCI electric sector consumption were derived from the EIA Electric Power Monthly publication.[22]

[21] Note from 1990-2002, the EIA data includes a category referred to as "other," which included lighting for public buildings, streets, and highways, interdepartmental sales, and other sales to public authorities, agricultural and irrigation sales where separately identified, electrified rail and various urban transit systems (such as automated guideway, trolley, and cable). To report total electricity in Figure A1, the sales from the "other" category are included with the commercial sector. The decision to include these with commercial rather than the other sectors is based on comparing the trends of electricity sales from 2000-2002 with 2003 sales.

[22] Electric Power Monthly, available online at http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html

Figure A2. Electricity Generation and CO2 Emissions from Alaska Power Plants, 2005





Source: Generation data from EIA Electric Power Annual 2007, GHG emissions calculated from EIA data on fuel consumption and eGRID 2005 emission factors.

Table A1 shows the growth in generation by fuel type between 1990 and 2006 from power plants in Alaska. Overall generation grew by 19% percent over the 16 year period. Petroleum-fired generation has had particularly strong growth, more than doubling between 1990 and 2005. Hydroelectric generation also grew significantly during this period. Natural gas-fired generation grew more slowly but remains the dominant source of electricity in Alaska.

Table A1. Growth in Electricity Generation in Alaska 1990-2006

	Generation (GWh)		
Fuel Type	**1990**	**2006**	**Growth**
Coal	511	617	21%
Petroleum	497	768	54%
Natural Gas	3,466	4,058	17%
Hydroelectric	975	1,224	26%
Renewable Energy	151	1	-99%
Total	**5,600**	**6,668**	**19%**

Source: EIA Electric Power Annual 2007

Emission rates by fuel type were based on rates from existing generators in Alaska, as obtained from eGRID (2005).[23] Emission rates estimated for carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) are shown in Table A2. These rates were applied to calculate both historical and future emissions. GHG emission estimates were calculated by multiplying the energy consumption by the GHG emission factors for each type of fuel consumed.

Table A2. Emissions Rates for Electric Generators in AK (lbs/MWh), based on 2005 eGRID.

	Emission Rate (lbs/MWh)		
Fuel Type	**CO_2**	**N_2O**	**CH_4**
Coal	1,697	0.0304	0.0212
Petroleum	1,647	0.0143	0.0713
Natural Gas	1,269	0.0025	0.0252

Source: eGRID 2005 (see reference 7)

[23] US Environmental Protection Agency, 2005. eGRID 2007 (2005 data). Available online at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html

Future Generation Growth

In Alaska, more than 70 different entities provide electricity to consumers. In 2004, the State had 21 Investor-owned utilities, 34 public entities and 18 electric co-operatives. These entities are not required to submit planning reports to the Regulatory Commission of Alaska, or to any other source. Collecting information from each utility was beyond the resources of this project, and may not even be feasible since many utilities are unlikely to have such plans. Other potential sources for electricity sales projections, such as the Institute of Social and Economic Research (ISER) at the University of Alaska and the documents from the Alaska Energy Task Force, had not completed state-wide projections recently.[24] Representatives from both ISER and the Alaska Energy Authority suggested future growth is likely to follow historic trends.[25]

Based on input from the Alaska Climate Change Mitigation Action Group's Energy Supply and Demand (ESD) technical working group, forecasts of electricity generation in Alaska were developed based on (1) historical energy consumption data and (2) growth rates of energy consumption available in the U.S. DOE's Annual Energy Outlook (AEO) 2009.[26] The data sources for the historical energy consumption data are gathered from the Energy Information Administration (EIA) for electricity.[27]

To forecast electricity consumption through 2025, growth rates from the Pacific Region of AEO 2009 were applied to the historical electricity consumption in order to forecast energy consumption, as shown in Table A3. The growth rates were broken down into four time periods so as to provide a level of granularity showing recent economic changes.

Table A3. Annual Growth Rates in Electricity Consumption by End Use and Time Period

End Use	2007-2010	2010-2015	2015-2020	2020-2025
Residential Electricity	0.09%	-0.61%	0.62%	0.83%
Commercial Electricity	1.20%	1.51%	1.56%	1.32%
Industrial Electricity	0.16%	0.98%	0.24%	0.42%

Source: AEO2009, Pacific Region data

Future Generation Mix

The future mix of plants in Alaska remains uncertain as the trends in type of new builds are influenced by many factors. Recently, new power plants in Alaska have been a mix of wind, geothermal, hydroelectric and naphtha. Given the many factors affecting electricity-related emissions and a diversity of assumptions by stakeholders within the electricity sector, developing a "reference case" projection for the most likely development of Alaska's electricity sector is particularly challenging. Future changes in the fuel mix for this reference case forecast were

[24] Email from Scott Goldsmith, ISER, January 10, 2007.
[25] Email from Scott Goldsmith, ISER, January 10, 2007, personal communication with Peter Crimp, Alaska Energy Authority, January 16, 2007. Also, personal communication, Mark Foster, Mark A Foster & Associates (MAFA).
[26] U.S. EIA AEO2009 with Projections to 2030, (http://www.eia.doe.gov/oiaf/aeo/index.html).
[27] "Current and Historical Monthly Retail Sales, Revenues and Average Revenue per Kilowatthour by State and by Sector (Form EIA-826)", available at http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

derived from expert advice from the ESD technical working group members. Major assumptions that were incorporated into the reference case projections included the following:

- No substantial increases will occur from the baseline hydroelectric generation;
- Healy Clean Coal Project (HCCP) will be brought online in 2010, achieving full operational capacity by 2013; the plant would displace natural gas consumption on the railbelt.[28]
- Approximately 60 MW of natural gas capacity will become available in Fairbanks in 2019, displacing petroleum consumption.[29]
- All additional required energy needs will be met with petroleum.
- The eGRID emission rates that were applied for the historical emissions calculations were also applied in the reference case projections.

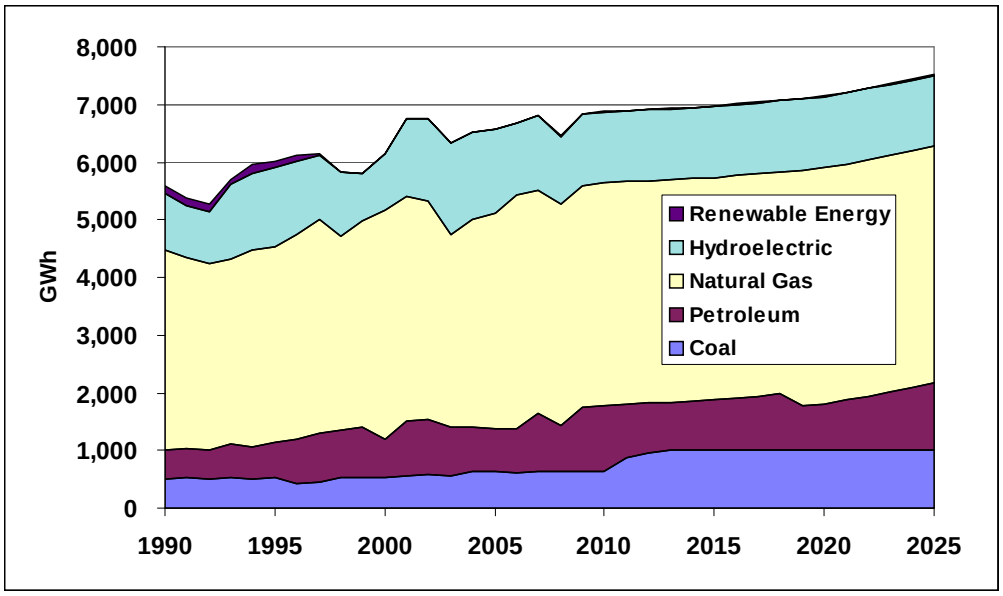
Summary of Reference Case Projections

Figure A3 shows the resulting historical electricity generation in the state by fuel source, along with projections to the year 2025 based on the assumptions described above. Based on the assumptions for new generation, Alaska's electricity continues to be delivered from a mix of resources, with natural gas-fired generation accounting for the largest share (55% in 2025). Overall electricity generation grows at 0.67% annually from 2005 to 2025. Although hydroelectric generation is the second largest fuel source of generation in Alaska in both 2005 and 2025, the share of generation from this source drops from 22% in 2005 to 16% in 2026. The share of generation from coal and petroleum powered sources both increase to 14% and 15%, respectively, of total generation in 2025.

[28] HCCP is already built but not in operation. The 50 MW plant is located in Healy, AK on the railbelt. It is assumed that at full capacity, the plant would operate at a nominal 85% capacity factor (including outages), producing ~372 GWh per year.

[29] It is assumed that new natural gas capacity in Fairbanks would displace current distillate and residual fuel oil combustion and that new gas capacity would have a capacity factor similar to existing generators in AK. As of 2005, there were 896 MW of natural gas capacity online in AK (EPA eGRID, 2007) with an average capacity factor of 47.41%. The new assumed 60 MW of capacity in Fairbanks would produce ~250 GWh per year.

Figure A3. Alaska Electricity Generation by Fuel Type 1990-2025

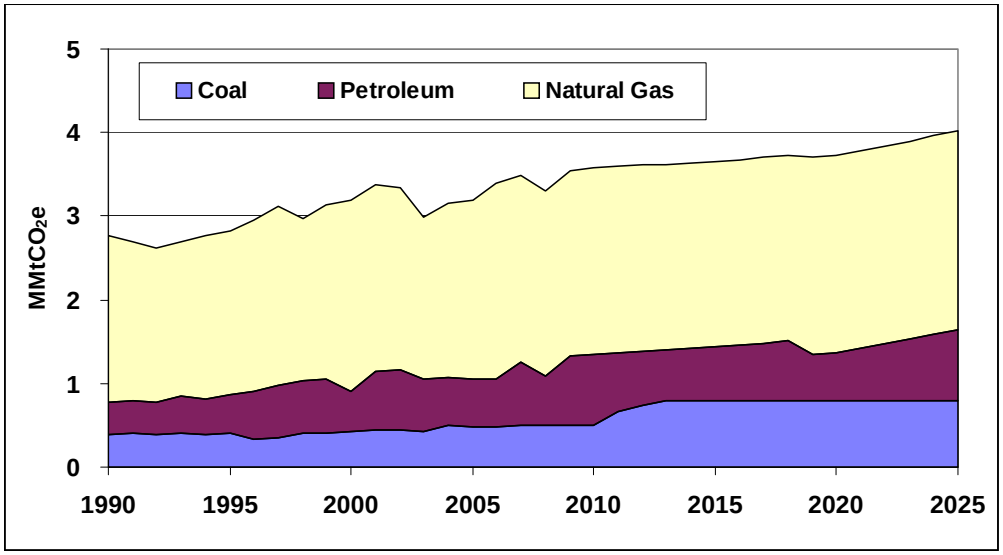


Sources: 1990-2006, Electric Power Annual 2007; 2007 and 2008 from EIA Electric Power Monthly; and ESD technical work group input for post-2007 fuel mix.

Figure A4 illustrates the GHG emissions associated with the mix of electricity generation shown in Figure A3. From 2005 to 2025, total GHG emissions from Alaska electricity generation are projected to grow at 1.1 percent per year. The annual growth rate of GHG emissions from coal-powered sources from 2005 to 2025 is 2.5%, primarily due to the addition of the HCCP, as mentioned above. In contrast, this HCCP project is assumed to replace generation from natural gas, leading to an annual increase in GHG emissions of only 0.5% per year from natural gas sources. The emission intensity (GHG emissions per MWh) of Alaska electricity is expected to increase from 0.49 metric tons (Mt) CO_2e/MWh in 2005 to 0.53 $MtCO_2$/MWh in 2025. This is due to the decreasing share of generation from hydroelectric sources and the increasing share of generation from coal and oil from 2005 to 2025.

Table A4 summarizes the GHG emissions for Alaska's electric sector from 1990 to 2025. During this time period, emissions are projected to increase by 45 percent. As mentioned at the beginning of this Appendix, the issue of whether to report GHG emissions based on the electricity consumed in the State (consumption-basis) or to report emissions based on the electricity produced in the State is a key question for many states. This is not important for Alaska because the GHG emission estimates are the same from either basis, since Alaska has very limited electricity imports.

Figure A4. Alaska GHG Emissions Associated with Electricity Production



Source: CCS calculations based on approach described in text.

Table A4. Alaska GHG Emissions from Electric Sector, 1990-2025 ($MMtCO_2e$)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025
Coal	0.40	0.41	0.42	0.48	0.50	0.79	0.79	0.79
Petroleum	0.37	0.47	0.48	0.57	0.86	0.64	0.58	0.86
Natural Gas	2.00	1.95	2.29	2.14	2.22	2.22	2.36	2.36
Hydroelectric	0	0	0	0	0	0	0	0
Renewable Energy	0	0	0	0	0	0	0	0
Total	**2.76**	**2.82**	**3.19**	**3.20**	**3.58**	**3.65**	**3.74**	**4.02**

Because Alaska has very limited electricity imports or exports, the GHG emissions on a production-basis are the same as GHG emissions on a consumption-basis.

Appendix B. Residential, Commercial, and Industrial - Fossil Fuel Combustion and Fossil Fuel Industries

Overview

Activities in the residential, commercial, and industrial (RCI) fossil fuel combustion sectors produce carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions when fuels are combusted to provide space heating, process heating, and other applications. Carbon dioxide accounts for over 99% of these emissions on a million metric tons (MMt) of CO_2 equivalent (CO_2e) basis in Alaska. In addition, since these sectors consume electricity, one can also attribute emissions associated with electricity generation to these sectors in proportion to their electricity use.[30]

This appendix also reports the GHG emissions that are released during the production, processing, transmission, and distribution of fossil fuels. Known as fugitive emissions, these are methane and carbon dioxide gases released via leakage and venting at coal mines, oil and gas fields, processing facilities, and pipelines. Nationally, fugitive emissions from natural gas systems, petroleum systems, and coal mines accounted for 2.8% of total US greenhouse gas emissions in 2004.[31]

Excluding emissions from the generation of the electricity they consume, RCI fossil fuel combustion and the fossil fuel industry combined are the largest source of gross greenhouse gas (GHG) emissions in Alaska. Direct use of oil, natural gas, coal, and wood in the RCI sectors along with emissions from the fossil fuel industry accounted for an estimated 28.6 $MMtCO_2e$ of gross GHG emissions in 2005.[32] The RCI and fossil fuel industry sectors are combined in this appendix due to the strong correlation between the industrial sector fuel consumption and the fossil fuel industry as well as the importance of considering both the fuel combustion emissions and the fossil fuel industry emissions when evaluating industrial GHG mitigation options.

Fossil Fuel Combustion

Emissions for direct fuel use were estimated using the United States Environmental Protection Agency's (US EPA's) State Greenhouse Gas Inventory Tool (SIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for RCI fossil fuel combustion.[33] The default data used in SIT for Alaska are from the United States Department of Energy (US DOE) Energy Information Administration's (EIA's) *State Energy Data* (SED). The SIT default data for Alaska were revised using the most recent data available,

[30] One could similarly allocate GHG emissions from transport-related GHG sources to the RCI sectors based on their direct use of gas and other fuels, but we have not done so here due to the relatively small level of emissions from these sources.
[31] "The US Inventory of Greenhouse Gas Emissions and Sinks", US EPA, 2005.
[32] Emissions estimates from wood combustion include only N_2O and CH_4. Carbon dioxide emissions from biomass combustion are assumed to be "net zero", consistent with US EPA and IPCC methodologies, and any net loss of carbon stocks due to biomass fuel use should be accounted for in the forestry analysis.
[33] GHG emissions were calculated using SIT, with reference to *EIIP, Volume VIII*: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004; and Chapter 2 "Methods for Estimating Methane and Nitrous Oxide Emissions from Stationary Combustion", August 2004.

which includes: (1) 2002 SED information for all fuel types;[34] (2) 2003 SED information for coal, and wood and wood waste;[35] (3) 2004 SED information for natural gas;[6] (4) 2003 and 2004 SED information for petroleum (distillate oil, kerosene and liquefied petroleum gas) consumption;[6] (5) 2004 electricity consumption data from the EIA's *State Electricity Profiles*;[36] and (6) 2005 natural gas consumption data from the EIA's *Natural Gas Navigator*.[37]

Note that the EIIP methods for the industrial sector exclude from CO_2 emission estimates the amount of carbon that is stored in products produced from fossil fuels for non-energy uses. For example, the methods account for carbon stored in petrochemical feedstocks, and liquefied petroleum gas (LPG), and natural gas used as feedstocks by chemical manufacturing plants (i.e., not used as fuel), as well as carbon stored in asphalt and road oil produced from petroleum. The carbon storage assumptions for these products are explained in detail in the EIIP guidance document.[38] The fossil fuel categories for which the EIIP methods are applied in the SIT software to account for carbon storage include the following categories: asphalt and road oil, coking coal, distillate fuel, feedstocks (naphtha with a boiling point of less than 401 degrees Fahrenheit), feedstocks (other oils with boiling points greater than 401 degrees Fahrenheit), LPG, lubricants, miscellaneous petroleum products, natural gas, pentanes plus,[39] petroleum coke, residual fuel, still gas, and waxes. Data on annual consumption of the fuels in these categories as chemical industry feedstocks were obtained from the EIA SED.

Reference case emissions from direct fuel combustion were estimated based on fuel consumption forecasts from EIA's *Annual Energy Outlook 2006* (AEO2006),[40] with adjustments for Alaska's projected population[41] and employment growth. Alaska employment data for the manufacturing (goods producing) and non-manufacturing (commercial or services providing) sectors were obtained from the Alaska Department of Labor and Workforce Development.[42] Regional employment data for the same sectors were obtained from EIA for the EIA's Pacific region.[43]

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[34] EIA *State Energy Data 2002*, Data through 2002, released June 30, 2006, (http://www.eia.doe.gov/emeu/states/state.html?q_state_a=co&q_state=ALASKA).
[35] EIA *State Energy Data 2003 revisions for all fuels and first release of 2004 information for natural gas and petroleum*, (http://www.eia.doe.gov/emeu/states/_seds_updates.html).
[36] EIA *Electric Power Annual 2005 - State Data Tables*, (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html).
[37] EIA *Natural Gas Navigator* (http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SAK_a.htm).
[38] EIIP, Volume VIII: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004.
[39] A mixture of hydrocarbons, mostly pentanes and heavier fractions, extracted from natural gas.
[40] EIA AEO2006 with Projections to 2030, (http://www.eia.doe.gov/oiaf/aeo/index.html).
[41] Population data from the Alaska Department of Labor and Workforce Development, "Workforce Information," Home (http://almis.labor.state.ak.us/), Population & Census, Estimates & Projections, Population Data Tables. Data for 1990 through 2000 found in "Alaska Population Estimates 2000-2005," under Historical Estimates (at bottom of page), Select "Borough and Census Area 1990-2000," in Excel file named "02T2-1a.xls." Data for 2001 through 2005 found in "Alaska Population Estimates 2000-2006," under Vintage 2005 Estimates, Borough, and Census Area Estimates, "Population by Labor Market Area, Borough and Census Area, and Components of Change, 1990-2005" in Excel file named "05t2-1.xls." Data for 2006 through 2029 found in "Alaska Population Projections (2005-2029)," under "February 2005 issue of Alaska Economic Trends," in PDF file named "feb05.pdf" (Projections for Alaska population 2005–2029, Table 5. Population Growth Projections Alaska 2005–2029, Medium Population Values in Table 5 used for forecast).
[42] Alaska Department of Labor and Workforce Development, "Workforce Information," Home (http://almis.labor.state.ak.us/), Industry Forecasts, Under Ten-Year Industry Employment Forecasts, Ten-year

Table B1 shows historical and projected growth rates for electricity sales by sector. Table B2 shows historical and projected growth rates for energy use by sector and fuel type.

For the residential sector, the rate of population growth is expected to increase by about 0.61% annually between 2005 and 2025; this demographic trend is reflected in the growth rates for residential fuel consumption. Based on the Alaska Department of Labor and Workforce Development's forecast (2004 to 2014), commercial and industrial employment are projected to increase at compound annual rates of 1.09% and 0.95%, respectively, and these growth rates are reflected in the growth rates in energy use shown in Table B2 for the two sectors. These estimates of growth relative to population and employment reflect expected responses of the economy — as simulated by the EIA's National Energy Modeling System — to changing fuel and electricity prices and changing technologies, as well as to structural changes within each sector (such as shifts in subsectoral shares and in energy use patterns).

Table B1. Electricity Sales Annual Growth Rates, Historical and Projected

Sector	1990-2004[a]	2004-2025[b]
Residential	1.6%	0.33%
Commercial	2.0%	1.1%
Industrial	6.6%	0.61%
Total	**2.2%**	**0.74%**

[a] 1990-2004 compound annual growth rates calculated from Alaska electricity sales by year from EIA state electricity profiles (Table 8), (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html).

[b] 2004-2025 compound annual growth rate for total for all three sectors taken from forecast for the energy supply sector (see Appendix A).

industry employment forecasts for Alaska published in the November 2006 issue of Alaska Economic Trends (extracted data from file named "nov06ind.pdf.").

[43] AEO2006 employment projections for EIA's Pacific region obtained through special request from EIA (dated September 27, 2006).

Table B2. Historical and Projected Average Annual Growth in Energy Use in Alaska, by Sector and Fuel, 1990-2025

	1990-2005[a]	2005-2010[b]	2010-2015[b]	2015-2020[b]	2020-2025[b]
Residential					
natural gas	2.1%	0.7%	0.7%	0.3%	-0.2%
petroleum	0.2%	0.6%	-0.3%	1.4%	-2.0%
wood	4.4%	0.6%	-0.1%	0.0%	-0.3%
coal	-4.1%	0.6%	-1.0%	-1.1%	-1.4%
Commercial					
natural gas	-1.2%	-0.3%	1.8%	1.2%	1.0%
petroleum	0.6%	-0.9%	0.6%	0.2%	0.0%
wood	8.8%	-0.4%	0.1%	-0.3%	-0.3%
coal	-0.2%	-0.6%	0.1%	-0.3%	-0.3%
Industrial					
natural gas	2.3%	1.4%	2.0%	2.3%	0.8%
petroleum	2.2%	3.2%	1.7%	1.1%	1.3%
wood	-28.8%	3.4%	2.7%	2.6%	2.9%
coal	-13.9%	2.4%	0.4%	0.9%	0.8%

[a] Compound annual growth rates calculated from EIA SED historical consumption by sector and fuel type for Alaska. Latest year for which EIA SED information was available for each fuel type is 2003 for coal and wood/wood waste, 2004 for petroleum (distillate oil, kerosene, and LPG), and 2005 for natural gas. Petroleum includes distillate fuel, kerosene, and LPG for all sectors plus residual oil for the commercial and industrial sectors. Industrial coal consumption for 1990 through 2002 was zero; growth rate for industrial coal is calculated from EIA SED consumption reported for 1993 through 2003.

[b] Figures for growth periods starting after 2005 are calculated from AEO2006 projections for EIA's Pacific region, adjusted for Alaska's projected population for the residential sector, non-manufacturing employment for the commercial sector, and manufacturing employment for the industrial sector.

Oil and Gas Production

Alaska currently ranks second in crude oil production among US states, totaling 864,000 barrels (bbls) per day and accounting for about 17% of US production.[44] Proved crude oil reserves sit at 4,327 million barrels, which is 17% of US totals. Oil production in the state peaked in 1988 at 2.017 million bbls per day.[45] Alaska has six petroleum refineries, with a combined crude oil distillation capacity of 373,500 barrels per day.[46]

Alaska has two main oil production fields: the Cook Inlet and the North Slope.[47] While natural gas production is prevalent in Alaska, most of the gas extracted never makes it to U.S. consumers or foreign markets. Of the 3.451 Bcf of natural gas produced on the North Slope in 2005, 92% was re-injected for enhanced oil recovery.[48]

[44] "Petroleum Profile: Alaska", US DOE Energy Information Administration website, January 2007, Accessed at http://tonto.eia.doe.gov/oog/info/state/ak.html.
[45] "Petroleum Navigator", US DOE Energy Information Administration website, January 2007, Accessed at http://tonto.eia.doe.gov/dnav/pet/hist/mcrfpak2a.htm.
[46] "Petroleum Profile: Alaska", US DOE Energy Information Administration website, January 2007, Accessed at http://tonto.eia.doe.gov/oog/info/state/ak.html.
[47] Personal communication with Brian Havelock, Alaska DNR Oil and Gas Division, January 22, 2007.
[48] Alaska Department of Natural Resources: Division of Oil & Gas, Annual Report 2006, Accessed at http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm

Alaska's potential coal resources are estimated to be 5.5 trillion short tons and may contain up to 1,000 TCF (Trillion cubic feet) of natural gas.[49] Since drilling the first exploratory coal bed methane (CBM) well in 1994, the state of Alaska has leased over 300,000 acres in the Cook Inlet for coal bed methane development.[50] While there is continued evaluation of drill sites, including the collection and analysis of coal samples for their methane potential, any CBM development in Alaska faces the challenges of extreme climate and difficult drill rig access. Currently, there is no viable CBM production in Alaska and reserves remain unproven.[51]

Oil and Gas Industry Emissions

Emissions of methane (CH_4) and entrained carbon dioxide (CO_2) can occur at many stages of production, processing, transmission, and distribution of oil and gas. With over 2,300 active gas and oil wells in the state[52], 8 operational gas processing plants, 6 oil refineries, and almost 4,000 miles of gas pipelines[53], there are significant uncertainties associated with estimates of Alaska's GHG emissions from this sector. This is compounded by the fact that there are no regulatory requirements to track CO_2 or CH_4 emissions. Therefore, estimates based on actual emissions measurements in Alaska are not possible at this time.

The SIT facilitates the development of a rough estimate of state-level greenhouse gas emissions.[54] Methane emission estimates are calculated by multiplying emissions-related activity levels (e.g. miles of pipeline, number of compressor stations) by aggregate industry-average emission factors. Key information sources for the activity data are the US DOE EIA[55] and the American Gas Association's annual publication *Gas Facts*.[56] Methane emissions were estimated using SIT, with reference to the EPA Emissions Inventory Improvement Program (EIIP) guidance document.

Projections of methane emissions from oil and gas systems are developed based on the following key drivers:

- Natural Gas Consumption – See Appendix A (Electricity Sector), and this appendix (RCI fossil fuel combustion) for assumptions used in projecting natural gas consumption in Alaska. Based on those assumptions, Alaska's natural gas consumption is projected to grow at an average rate of 2.0% annually from 2005 until 2025.
- Production – Projections for crude oil and natural gas production were pulled from the Alaska Department of Natural Resources Oil and Gas Annual Report 2006. While

[49] Alaska Department of Natural Resources, Division of Oil & Gas, January 2007, Accessed at http://www.dog.dnr.state.ak.us/oil/products/publications/coal_meth/coalbed_methane.htm.
[50] Coal Bed Methane Drilling in the MatSu Valley, January 2007, Accessed at http://www.gasdrillingmatsu.org/laws.html.
[51] IBID.
[52] Energy Information Administration, Oil & Gas Well Distribution, Accessed at http://www.eia.doe.gov/pub/oil_gas/petrosystem/ak_table.html.
[53] Data from EIA and Gas Facts.
[54] Methane emissions were calculated using SIT, with reference to EIIP,Volume VIII: Chapter. 5. "Methods for Estimating Methane Emissions from Natural Gas and Oil Systems", March 2005.
[55] "Petroleum Navigator" and "Natural Gas Navigator", US DOE Energy Information Administration website, November 2006, Accessed at http://www.eia.doe.gov.
[56] American Gas Association "Gas Facts, A Statistical Record of the Gas Industry" Referenced annual publications from 1992 to 2004.

projected crude oil production varies from year to year, decline rates averaged at 1.3% annually between 2006 and 2015, and increased to 5.4% annually between 2016 and 2025.[57] Natural gas production is projected to decrease at an average rate of 13% annually from 2005 to 2025. Simple assumptions were made for processing and transport growth rates.

Table B3 provides an overview of data sources and approach used to project future emissions.

Table B3. Approach to Estimating Historical and Projected Methane Emissions from Natural Gas and Oil Systems.

	Approach to Estimating Historical Emissions		**Approach to Estimating Projections**
Activity	***Required Data for SIT***	***Data Source***	***Projection Assumptions***
Natural Gas Drilling and Field Production	Number of wells	EIA	Emissions estimated from Alaska DNR natural gas production forecasts, with an average annual decline of 13%.[58]
	Number of offshore platforms	Alaska DNR Oil and Gas[59]	
	Miles of gathering pipeline	Gas Facts[60]	
Natural Gas Processing	Number of gas processing plants	EIA[61]	Emissions follow trend of natural gas processing, which is estimated to decline 1.4% annually until 2025.[62]
Natural Gas Transmission	Miles of transmission pipeline	Gas Facts[19]	Emissions follow trend of State gas processing, as above.[63]
	Number of gas transmission compressor stations	EIIP[64]	
	Number of gas storage compressor stations	EIIP[65]	

[57] Alaska Department of Natural Resources: Division of Oil & Gas, Annual Report 2006, Tables III.7 and III.8, Accessed at http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm. Crude oil proved reserves in Alaska have been declining at an average of almost 3% annually since 1990, as reported by the EIA.
[58] Assumption based on gas production forecasts from the Alaska DNR Oil and Gas Division Annual Report 2006 for the Cook Inlet and the North Slope, with an average annual decline rate of 13% between 2006 and 2025. Projected emissions calculations use the annual growth or decline rate for each year.
[59] Personal communication, Will Nebesky, Alaska DNR Division of Oil and Gas. January 16, 2007.
[60] No Gas Facts available for 1991 and 1993, so a linear relationship was assumed to extrapolate from the previous and subsequent year.
[61] EIA reported data for 2004, and personal communication with Brian Havelock, Alaska DNR, January 22, 2007.
[62] Decline rate based on EIA gas processing data reported for Alaska, average annual decline of 1.39% in gas processing volume between 2000 and 2004.
[63] It is considered a very low likelihood that an Alaskan natural gas pipeline would be operational prior to 2025, if at all. Personal communication, Brian Havelock, Alaska Department of Natural Resources, Oil and Gas Division, January 22, 2007. Projected emissions from natural gas transmission is assumed to follow gas processing trend as it is processed prior to reinjection in enhanced oil recovery.
[64] Number of gas transmission compressor stations = miles of transmission pipeline x 0.006 EIIP. Volume VIII: Chapter 5. March 2005.
[65] Number of gas storage compressor stations = miles of transmission pipeline x 0.0015 EIIP. Volume VIII: Chapter 5. March 2005.

	Approach to Estimating Historical Emissions		Approach to Estimating Projections
Activity	***Required Data for SIT***	***Data Source***	***Projection Assumptions***
	Number of LNG storage compressor stations	Unavailable, assumed negligible.	
Natural Gas Distribution	Miles of distribution pipeline	Gas Facts[60]	Distribution emissions follow State gas consumption trend - annual average growth of 2.0% until 2025.[66]
	Total number of services	Gas Facts	
	Number of unprotected steel services	Ratio estimated from 2002 data[67]	
	Number of protected steel services	Ratio estimated from 2002 data[24]	
Oil Production	Annual production	EIA[68]	Emissions estimated from Alaska DNR oil production forecasts, with an average annual decline rate of 3.4%.[69]
Oil Refining	Annual amount refined	EIA[70]	Emissions projected to follow recent trend in State oil refining of 1.5% annual growth.[71]
Oil Transport	Annual oil transported	Unavailable, assumed oil produced = oil transported	Emissions follow trend of State oil production, as above.

Note that potential improvements to production, processing, and pipeline technologies resulting in GHG emissions reductions have not been accounted for in this analysis.

A potentially significant source of CO_2, not currently included in this inventory, is that of 'entrained' CO_2 in raw gas emerging from the ground. In some areas entrained CO_2 can be significantly above pipeline specifications, and must be separated out at gas processing facilities. Depending on the level of entrained CO_2 in any current natural gas production or future production of Alaskan coal bed methane, emissions of entrained CO_2 may be significant.

[66] Based on US DOE regional projections and electric sector growth assumptions (see Appendix A and B).
[67] Gas Facts reported unprotected and protected steel services for 2002, but only total services for other years. Therefore the ratio of unprotected and protected steel services in 2002 was assumed to be the ratio for all other years (0.4891 for protected services and 0.0045 for unprotected services). This yields more congruent results than the EIIP guidance of using multipliers of 0.2841 for protected steel services, and 0.0879 for unprotected steel services.
[68] Data extracted from the EIA Petroleum Supply Annual for each year.
[69] Assumption based on crude oil production forecasts from the Alaska DNR Oil and Gas Division Annual Report 2006 for the Cook Inlet and the North Slope. Average annual decline rate of 3.4% between 2005 and 2025. Projected emissions calculations use the annual growth or decline rate for each year.
[70] Refining assumed to be equal to the total input of crude oil into the Petroleum Administration for Defense District (PADD) V (West Coast) times the ratio of Alaska's refining capacity to PADD V's total refining capacity. No data for 1995 and 1997, so linear relationship assumed from previous and subsequent years.
[71] Based on EIA data, average growth in crude refined annually was 1.5% between 2000 and 2004.

Coal Production Emissions

Methane occurs naturally in coal seams, and is typically vented during mining operations for safety reasons. Coal mine methane emissions are usually considerably higher, per unit of coal produced, from underground mining than from surface mining.

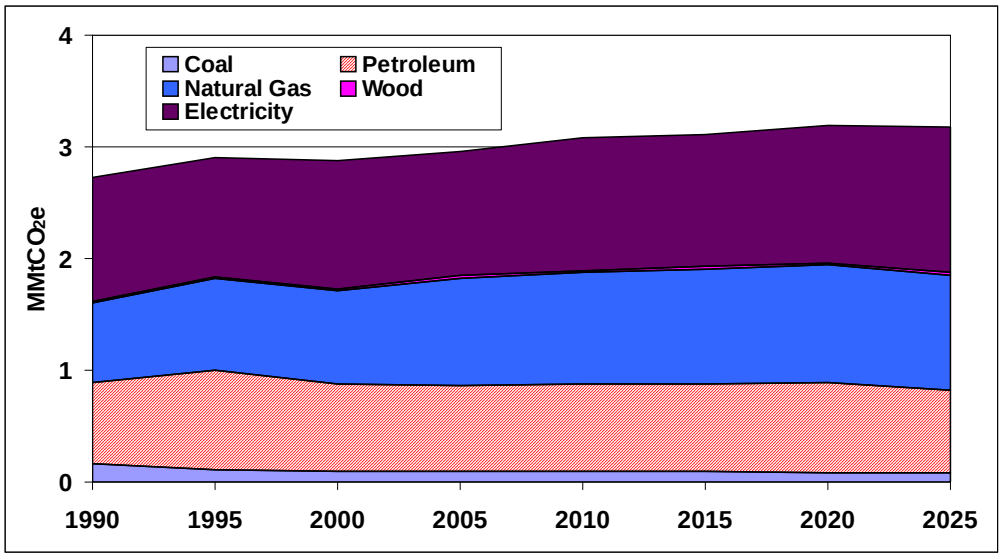
Alaska has one operational surface coal mine, which produced almost 1.5 million short tons of coal in 2005.[72] As reported in this inventory, methane emissions from coal mines are as reported by the EPA, and include emissions from surface coal mines and post-mining activities.[73]

Methane emissions from coal mining have remained fairly steady with an average annual increase in methane emissions of 0.4% between 1990 and 2004. As an initial and simple estimate, coal mine methane emissions are projected to continue to increase at 0.4% annually until 2025.

Results

Figures B1 and B2 and Tables B4 and B5 show historical and projected emissions for the residential and commercial fuel consumption sectors in Alaska from 1990 through 2025. These figures show the emissions associated with the direct consumption of fossil fuels and, for comparison purposes, show the share of emissions associated with the generation of electricity consumed by each sector.

Figure B1. Residential Sector GHG Emissions from Fuel Consumption



Note: Emissions from electricity generation are allocated here for illustrative purposes. In the front of this report, the electricity emissions are attributed to the Electricity Production sector.

[72] EIA Coal Data Accessed at http://www.eia.doe.gov/cneaf/coal/page/acr/table1.html.
[73] Emissions from EPA *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004* (April 2006) Accessed at http://epa.gov/climatechange/emissions/usinventoryreport.html

Table B4. Residential Sector GHG Emissions from Fuel Consumption ($MMtCO_2e$)

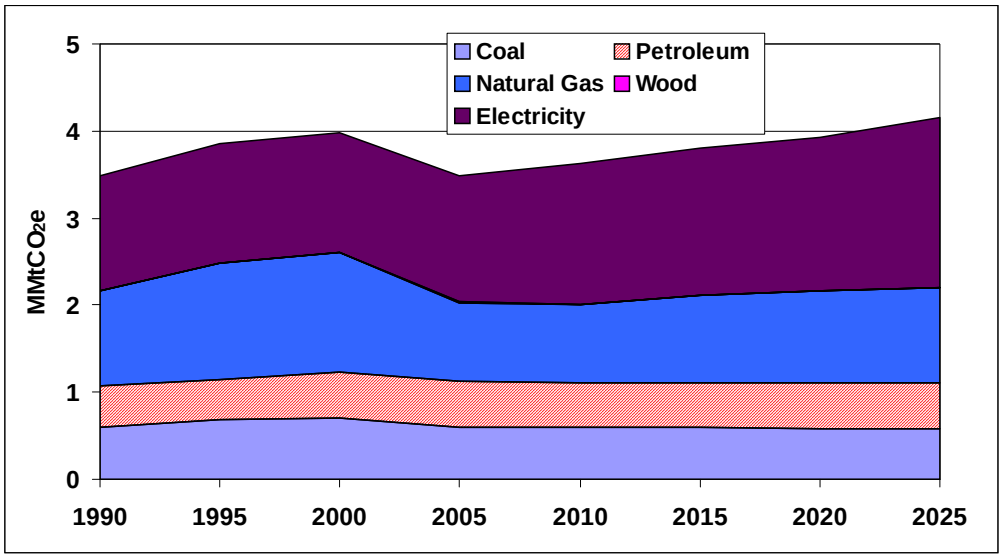
	1990	1995	2000	2005	2010	2015	2020	2025
Coal	0.160	0.110	0.092	0.095	0.096	0.092	0.087	0.081
Petroleum	0.730	0.895	0.783	0.761	0.777	0.779	0.807	0.735
Natural Gas	0.709	0.811	0.834	0.968	1.004	1.036	1.047	1.035
Wood	0.011	0.013	0.011	0.019	0.020	0.020	0.020	0.019
Electricity	1.115	1.079	1.150	1.115	1.187	1.182	1.235	1.313
Total	**2.725**	**2.908**	**2.870**	**2.959**	**3.084**	**3.107**	**3.196**	**3.183**

Note: Emissions from electricity generation are allocated here for illustrative purposes. In the front of this report, the electricity emissions are attributed to the Electricity Production sector.

For the residential sector, emissions from electricity and direct fossil fuel use in 1990 were about 2.7 $MMtCO_2e$, and are estimated to increase to about 3.2 $MMtCO_2e$ by 2025. Emissions associated with the generation of electricity to meet residential energy consumption demand accounted for about 41% of total residential emissions in 1990, decreasing to 38% of total residential emissions in 2005, and then increasing back to 41% of total residential emissions by 2025. In 1990, natural gas consumption accounted for about 26% of total residential emissions, about 33% of residential emissions in 2005, and about 33% of total residential emissions by 2025. Residential-sector emissions associated with the use of petroleum accounted for about 27% of total residential emissions in 1990, 26% of residential emissions in 2005, and about 23% of residential emissions in 2025. Residential-sector emissions associated with the use of coal and wood in 1990 were about 0.17 $MMtCO_2e$ combined, and accounted for about 6.3% of total residential emissions in 1990. By 2025, emissions associated with the consumption of these two fuels are estimated to be 0.10 $MMtCO_2e$ and to account for 3.1% of total residential sector emissions.

For the 20-year period 2005-2025, residential-sector GHG emissions associated with the use of electricity and natural gas are expected to increase at average annual rates of about 0.8% and 0.3%, respectively. Emissions associated with the use of wood are expected to remain relatively constant, and emissions associated with the use of coal and petroleum are expected to annually decline by about -0.8% and -0.2%, respectively. Total GHG emissions for this sector increase by an average of about 0.4% annually over the 20-year period.

Figure B2. Commercial Sector GHG Emissions from Fuel Consumption



Notes: Emissions associated with wood combustion too small to be seen on this graph. Emissions from electricity generation are allocated here for illustrative purposes. In the front of this report, the electricity emissions are attributed to the Electricity Production sector.

Table B5. Commercial Sector GHG Emissions from Fuel Consumption ($MMtCO_2e$)

	1990	1995	2000	2005	2010	2015	2020	2025
Coal	0.604	0.695	0.703	0.603	0.590	0.591	0.582	0.574
Petroleum	0.477	0.453	0.521	0.527	0.512	0.526	0.530	0.530
Natural Gas	1.082	1.330	1.382	0.903	0.910	0.990	1.047	1.097
Wood	0.001	0.002	0.002	0.004	0.004	0.004	0.004	0.003
Electricity	1.317	1.375	1.379	1.457	1.618	1.697	1.771	1.942
Total	**3.481**	**3.855**	**3.986**	**3.494**	**3.634**	**3.807**	**3.933**	**4.147**

Note: Emissions from electricity generation are allocated here for illustrative purposes. In the front of this report, the electricity emissions are attributed to the Electricity Production sector.

For the commercial sector, emissions from electricity and direct fuel use in both 1990 and 2005 were about 3.5 $MMtCO_2e$ and emissions are estimated to increase to about 4.1 $MMtCO_2e$ by 2025. Emissions associated with the generation of electricity to meet commercial energy consumption demand accounted for about 38% of total commercial emissions in 1990, about 42% of total commercial emissions in 2005, and are estimated to increase to about 47% of total commercial emissions by 2025. In 1990, natural gas consumption accounted for about 31% of total commercial emissions, decreasing to 26% of commercial sector emissions in 2005, and increasing slightly to about 27% of total commercial emissions by 2025. Commercial-sector emissions associated with the use of coal accounted for about 17% of total commercial emissions in 1990 and 2005, and are estimated to decline to about 14% of total commercial emissions by 2025. Commercial-sector emissions associated with the use of petroleum accounted for about

14% of total commercial emissions in 1990, 15% of commercial sector emissions in 2005, and about 13% of total commercial emissions by 2025. Commercial-sector emissions associated with the use of wood accounted for about 0.03% of total commercial emissions in 1990 and about 0.1% of commercial emissions in 2005 and 2025.

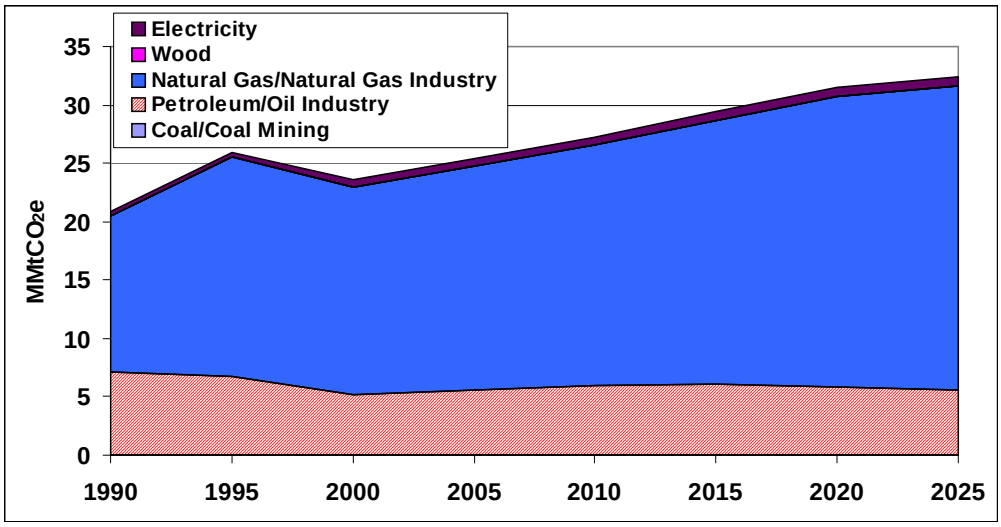
For the 20-year period 2005 to 2025, commercial-sector GHG emissions associated with the use of electricity, natural gas, and petroleum are expected to increase at average annual rates of about 1.4%, 1.0%, and 0.02%, respectively. Emissions associated with the use of coal and wood are expected to decline annually by about -0.24% and -0.22%, respectively. Total GHG emissions for this sector increase by an average of about 0.86% annually over the 20-year period.

Figure B3 and Table B6 show historical and projected emissions from industrial fuel consumption as well as from the fossil fuel industry in Alaska from 1990 through 2025. This figures show the emissions associated with the direct consumption of industrial fossil fuels and the fossil fuel industry by fuel type and, for comparison purposes, shows the share of emissions associated with the generation of electricity consumed by the industrial fuel use sector.

For the industrial fuel use/fossil fuel industry sector, emissions in 1990 were about 21 $MMtCO_2e$, and are estimated to increase to about 25 $MMtCO_2e$ in 2005 and to 32 $MMtCO_2e$ in 2025. Emissions associated with the generation of electricity to meet industrial energy consumption demand accounted for about 1.6% of total industrial emissions in 1990 and are estimated to increase to about 2.5% of total industrial emissions by 2025 and then decrease to about 2.3% of total industrial emissions by 2025. In 1990, natural gas consumption accounted for about 64% of total industrial emissions, about 76% of total industrial emissions in 2005, and about 80% of total industrial emissions by 2025. Industrial-sector emissions associated with petroleum accounted for about 34% of total industrial sector emissions in 1990, 22% of industrial emissions in 2005, and are projected to decline to about 18% of total industrial emissions by 2025. Industrial-sector emissions associated with coal and wood combined are about 0.1% or less of total industrial sector emissions throughout the 1990-2025 period.

For the 20-year period 2005 to 2025, industrial sector GHG emissions associated with petroleum and natural gas are expected to increase at average annual rates of about 0.02% and 1.5%, respectively. Emissions associated with the use of coal, electricity, and wood are expected to increase annually by about 0.4%, 1.0%, and 2.9%, respectively. Total GHG emissions for this sector increase by an average of about 1.2% annually over the 20-year period.

Figure B3. GHG Emissions from Industrial Sector Fuel Consumption and from the Fossil Fuel Industry



Note: Emissions from electricity generation are allocated here for illustrative purposes. In the front of this report, the electricity emissions are attributed to the Electricity Production sector.

Table B6. GHG Emissions from Industrial Sector Fuel Consumption and from the Fossil Fuel Industry ($MMtCO_2e$)

	1990	1995	2000	2005	2010	2015	2020	2025
Coal/Coal Mining	0.009	0.009	0.010	0.009	0.009	0.009	0.009	0.010
Petroleum/Oil Industry	7.10	6.76	5.18	5.57	5.98	6.03	5.78	5.60
Natural Gas/Natural Gas Industry	13.42	18.72	17.72	19.15	20.53	22.66	24.97	26.01
Wood	0.012	0.011	0.000	0.000	0.000	0.000	0.000	0.000
Electricity	0.33	0.37	0.66	0.63	0.77	0.77	0.73	0.76
Total	**20.88**	**25.87**	**23.57**	**25.36**	**27.29**	**29.47**	**31.49**	**32.38**

Key Uncertainties

Key sources of uncertainty underlying the estimates above are as follows:

- Population and economic growth are the principal drivers for electricity and fuel use. The reference case projections are based on regional fuel consumption projections for EIA's Pacific modeling region scaled for Alaska population and employment growth projections. Consequently, there are significant uncertainties associated with the projections. Future work should attempt to base projections of GHG emissions on fuel consumption estimates specific to Alaska to the extent that such data become available.
- The AEO2006 projections assume no large long-term changes in relative fuel and electricity prices, relative to current price levels and to US DOE projections for fuel prices. Price changes would influence consumption levels and, to the extent that price trends for competing fuels differ, may encourage switching among fuels.

- The current levels of fugitive emissions are based on industry-wide averages, and until estimates are available for specific facilities, significant uncertainties remain.
- The degree to which the SIT emission factors are applicable to the fossil fuel industry in Alaska is somewhat uncertain.
- The fossil fuel industries are difficult to forecast, as they are affected by a mix of drivers, including: economics, resource supply, fuels demand, technology development, and the status of regulations applying to the industry, among others. The ADNR Oil & Gas projections are considered to be fairly conservative estimates,[74] and may not include any significant changes in energy prices, relative to today's prices. Large price swings, resource limitations, or changes in regulations could significantly change future production and the associated GHG emissions.
- Future natural gas transmission lines to transport Alaskan North Slope natural gas to Canada or the lower 48 states would cause increases in the natural gas emission from the natural gas industry .[75]
- Other significant uncertainties include the fraction of entrained CO_2 in any current natural gas production or future CBM production and potential emissions reducing improvements in oil and gas production, processing, and pipeline technologies.

[74] Personal communication, Brian Havelock, Alaska Department of Natural Resources, Oil and Gas Division, January 22, 2007.
[75] It is considered a very low likelihood that an Alaskan natural gas pipeline would be operational prior to 2025, if at all. Personal communication, Brian Havelock, Alaska Department of Natural Resources, Oil and Gas Division, January 22, 2007.

Appendix C. Transportation Energy Use

Overview

The transportation sector is one of the largest sources of GHG emissions in Alaska – accounting for 35% of Alaska's gross GHG emissions in 2005. Carbon dioxide accounts for about 99% of transportation GHG emissions from fuel use in 2005. Most of the remaining GHG emissions from the transportation sector are due to N_2O emissions from gasoline and jet engines.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2005 were estimated using SIT and the methods provided in the EIIP guidance document for the sector.[76,77] For onroad vehicles, the CO_2 emission factors are in units of lb/MMBtu and the CH_4 and N_2O emission factors are both in units of grams/VMT. Key assumptions in this analysis are listed in Table C1. The default data within SIT were used to estimate emissions, with the most recently available fuel consumption data (2005) from EIA SED added.[78] The default VMT data in SIT were replaced with state-level annual VMT from Alaska Department of Transportation and Public Facilities (ADOT&PF).[79] State-level VMT was allocated to vehicle types using the default vehicle mix data in SIT.

Onroad gasoline and diesel emissions were projected based on VMT projections from the WRAP mobile source inventory[80] and growth rates developed from national vehicle type VMT forecasts reported in EIA's *Annual Energy Outlook 2008* (AEO2008). The VMT projections taken from the WRAP inventory show an average annual growth rate in total state VMT of 1.3%. The AEO2008 data were incorporated because they indicate significantly different VMT growth rates for certain vehicle types. The procedure first applied the AEO2008 vehicle type-based national growth rates to 2005 Alaska estimates of VMT by vehicle type. These data were then used to calculate the estimated proportion of total VMT by vehicle type in each year. Next, these proportions were applied to the projected state-total VMT for each year to yield the vehicle-type compound annual average growth rates are displayed in Tables C2.

[76] CO_2 emissions were calculated using SIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 1. "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004.
[77] CH_4 and N_2O emissions were calculated using SIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 3. "Methods for Estimating Methane and Nitrous Oxide Emissions from Mobile Combustion", August 2004.
[78] Energy Information Administration, State Energy Consumption, Price, and Expenditure Estimates (SED), http://www.eia.doe.gov/emeu/states/_seds.html
[79] David Phillips, Research Analyst, Alaska Department of Transportation & Public Facilities
[80] WRAP Mobile Source Emission Inventories Update, Western Regional Air Partnership, http://www.wrapair.org/forums/ef/UMSI/index.html

Table C1. Key Assumptions and Methods for the Transportation Inventory and Projections

Vehicle Type and Pollutants	Methods
Onroad gasoline, diesel, natural gas, and LPG vehicles – CO_2	**Inventory (1990 – 2005)** EPA SIT and fuel consumption from EIA SED **Reference Case Projections (2006 – 2025)** Gasoline and diesel fuel projected using VMT projections from the WRAP, adjusted by fuel efficiency improvement projections from EPA. Other onroad fuels projected using Pacific Region fuel consumption projections from EIA AEO2008 adjusted using state-to-regional ratio of population growth.
Onroad gasoline and diesel vehicles – CH_4 and N_2O	**Inventory (1990 – 2005)** EPA SIT, onroad vehicle CH_4 and N_2O emission factors by vehicle type and technology type within SIT were updated to the latest factors used in the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003.* State total VMT replaced with VMT provided by ADOT&PF, VMT allocated to vehicle types using default data in SIT. **Reference Case Projections (2006 – 2025)** VMT projections from WRAP.
Non-highway fuel consumption (jet aircraft, gasoline-fueled piston aircraft, boats, locomotives) – CO_2, CH_4 and N_2O	**Inventory (1990 – 2005)** EPA SIT and fuel consumption from EIA SED. Commercial marine fuel consumption estimates from DEC and allocation from national fuel consumption estimates. **Reference Case Projections (2003 – 2020)** Aircraft projected using aircraft operations projections from FAA and jet fuel efficiency improvement projections from AEO2008. Commercial marine projected using growth factors from DEC inventory.

Table C2. Alaska Vehicle Miles Traveled Compound Annual Growth Rates

Vehicle Type	2005-2010	2010-2015	2015-2020	2020-2025
Heavy Duty Diesel Vehicle	2.92%	2.67%	2.54%	2.28%
Heavy Duty Gasoline Vehicle	1.75%	1.95%	2.28%	2.13%
Light Duty Diesel Truck	6.27%	9.98%	11.54%	10.32%
Light Duty Diesel Vehicle	6.27%	9.98%	11.54%	10.32%
Light Duty Gasoline Truck	1.05%	0.94%	0.77%	0.63%
Light Duty Gasoline Vehicle	1.05%	0.94%	0.77%	0.63%
Motorcycle	1.05%	0.94%	0.77%	0.63%

Onroad gasoline and diesel fuel consumption was forecasted by developing a set of growth factors that adjusted the VMT projections to account for improvements in fuel efficiency. Fuel efficiency projections were taken from EPA data. These projections suggest onroad fuel consumption growth rates of 0.7% per year for gasoline and 3.3% per year for diesel between 2005 and 2025.

Gasoline consumption estimates for 1990-2005 were adjusted by subtracting ethanol consumption. While the historical ethanol consumption suggests continued growth, projections for ethanol consumption in Alaska were not available. Therefore, ethanol consumption was assumed to remain at the 2005 level (1.7% of total gasoline) in the reference case projections. Biodiesel and other biofuel consumption were not considered in this inventory because historical and projection data were not available.

For the aircraft sector, emission estimates for 1990 to 2005 are based on SIT methods and fuel consumption from EIA. State-level fuel consumption projections for aviation fuels are not available; therefore, jet fuel and aviation gasoline emissions were projected from 2005 to 2025 using 2006 through 2025 aircraft operations forecasts from the Federal Aviation Administration's Terminal Area Forecast System (TAF).[81] A base-year of 2006 was used because the TAF data for 2005 were developed using a different scenario and were not consistent with the 2006-2025 data. The growth rate from 2005 to 2006 was assumed to be the same as the 2006-2010 average annual growth rate. Jet fuel emissions were projected using the sum of itinerant aircraft operations from air carrier, air taxi/commuter, general aviation, and military aircraft. The post-2005 commercial aircraft estimates were adjusted to reflect the projected increase in national aircraft fuel efficiency (indicated by increased number of seat miles per gallon), as reported in AEO2008. General aviation emissions were projected based on local general aviation aircraft operations forecasts. These projections resulted in the compound annual growth rates shown in Table C3.

Table C3. Alaska Jet Fuel and Aviation Gasoline Compound Annual Growth Rates

Vehicle Type	2005-2010	2010-2015	2015-2020	2020-2025
Jet Fuel	0.30%	0.26%	0.19%	0.30%
Aviation Gasoline	0.24%	0.25%	0.27%	0.29%

[81] Terminal Area Forecast, Federal Aviation Administration, http://www.apo.data.faa.gov/main/taf.asp.

Commercial marine fuel consumption was estimated using activity data and brake-specific fuel consumption factors (in units of gallons/kW-hr) from the commercial marine criteria pollutant inventory recently developed for DEC.[82] This inventory covers nine major ports in Alaska. Fuel consumption for the remaining ports was developed by allocating 1990-2005 national diesel and residual oil vessel bunkering fuel consumption estimates obtained from EIA.[83] Marine vessel fuel consumption was allocated to each area using the marine vessel activity allocation methods/data compiled to support the development of EPA's National Emissions Inventory (NEI). [84] In keeping with the NEI, 75 percent of each year's distillate fuel and 25 percent of each year's residual fuel were assumed to be consumed within the port area (remaining consumption is assumed to occur while ships are underway). National port area fuel consumption was allocated to these areas based on year-specific freight tonnage data reported in "Waterborne Commerce in the United States Waterways and Harbors".[85] Freight tonnage for the nine major ports covered by the DEC inventory was subtracted from the state total freight tonnage to give the remainder. Offshore CO_2 emissions and fuel consumption for the Alaska's exclusive economic zone (EEZ) were considered for inclusion in the inventory. Data are available from a study by Corbett for the Commission for Environmental Cooperation in North America (CEC).[86] These emissions were ultimately not included in the inventory because only a very small percentage (1-2%) of ships passing through Alaska's EEZ actually call at Alaskan ports. 2002 fuel consumption from the DEC inventory was scaled to other years using freight tonnage data. Emissions were then estimated from fuel consumption estimates using SIT emissions factors for marine diesel and residual fuels. Emissions were projected using growth factors from the DEC inventory.

For rail and marine gasoline, 1990 – 2005 estimates are based on SIT methods and fuel consumption from EIA. For rail, the historic data show no significant positive or negative trend; therefore, no growth was assumed for this sector. Marine gasoline projections were based on the 1994-2004 historical trend. Marine gasoline consumption estimates for 1990-1993 were significantly higher than subsequent years; therefore, these years were not included in the trend analysis.

Fuel consumption data from EIA includes nonroad gasoline and diesel fuel consumption in the commercial and industrial sectors. Therefore, nonroad emissions are included in the RCI emissions in this inventory (see Appendix B). Table C2 shows how EIA divides gasoline and diesel fuel consumption between the transportation, commercial, and industrial sectors.

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[82] Commercial Marine Inventories for Select Alaskan Ports, prepared by E.H. Pechan & Associates, prepared for the Alaska Department of Environmental Conservation, June, 2005.

[83] U.S. Department of Energy, Energy Information Administration, "Petroleum Navigator" (diesel data obtained from http://tonto.eia.doe.gov/dnav/pet/hist/kd0vabnus1a.htm; residual data obtained from http://tonto.eia.doe.gov/dnav/pet/hist/kprvatnus1a.htm).

[84] See methods described in ftp://ftp.epa.gov/EmisInventory/2002finalnei/documentation/mobile/2002nei_mobile_nonroad_methods.pdf

[85] Waterborne Commerce Statistics Center, http://www.iwr.usace.army.mil/ndc/wcsc/wcsc.htm.

[86] Estimate, Validation, and Forecasts of Regional Commercial Marine Vessel Inventories, submitted by J. Corbett, prepared for the California Air Resources Board, California Environmental Protection Agency, and Commission for Environmental Cooperation in North America, http://coast.cms.udel.edu/NorthAmericanSTEEM/.

Table C2. EIA Classification of Gasoline and Diesel Consumption

Sector	Gasoline Consumption	Diesel Consumption
Transportation	Highway vehicles, marine	Vessel bunkering, military use, railroad, highway vehicles
Commercial	Public non-highway, miscellaneous use	Commercial use for space heating, water heating, and cooking
Industrial	Agricultural use, construction, industrial and commercial use	Industrial use, agricultural use, oil company use, off-highway vehicles

Results

As shown in Figure C1 and table C3, jet fuel consumption accounts for the largest share of transportation GHG emissions. Emissions from jet fuel consumption increased by about 84% from 1990 to 2005 to account for 72% of total transportation emissions in 2005. Emissions from onroad gasoline grew by about 15% from 1990 to 2005 and onroad diesel grew by 37% during this period. In 2005, onroad gasoline and diesel accounted for 14% and 10% of total transportation emissions, respectively. GHG emissions from marine fuel consumption decreased by 44% from 1990 to 2005, and in 2005 accounted for 3.5% of GHG emissions from the transportation sector. Emissions from all other categories combined (aviation gasoline, locomotives, natural gas and LPG, and oxidation of lubricants) contributed slightly 0.9% of total transportation emissions in 2005. Total transportation emissions increased 55% from 1990 to 2005, from 11.5 $MMtCO_2e$ to 17.8 $MMtCO_2e$.

GHG emissions from jet fuel are projected to increase by an additional 5% between 2005 and 2025. Emissions resulting from onroad gasoline consumption are projected to increase by about 16%, and emissions from onroad diesel consumption are expected to increase by 92% between 2005 and 2025. Emissions from boats and ships are projected to increase by 21% during this period. Overall, total transportation GHG emissions are expected to increase to 21.1 $MMtCO_2e$ in 2025, an increase of 18% over the 2005 Alaska transportation emissions.

Figure C1. Transportation GHG Emissions by Fuel, 1990-2020

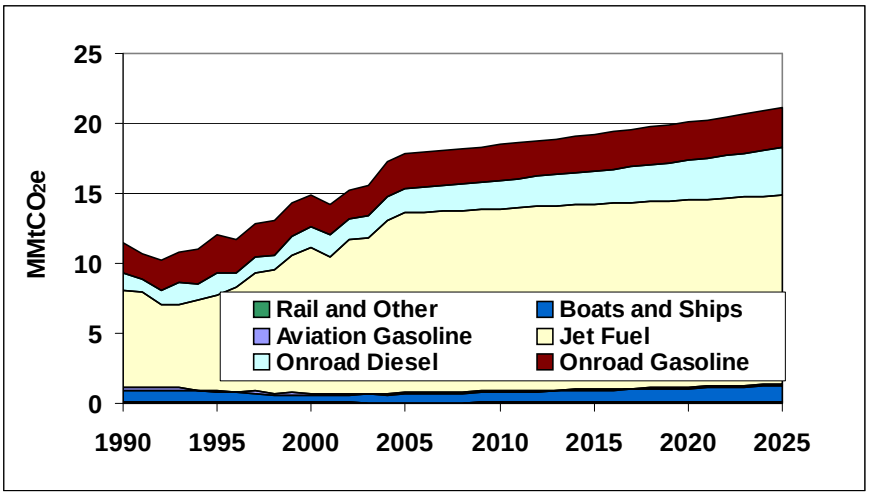


Table C3. Transportation Emissions Inventory and Reference Case Projections ($MMtCO_2e$)

Subsector	1990	1995	2000	2005	2010	2015	2020	2025
Onroad Gasoline	2.12	2.65	2.22	2.43	2.52	2.63	2.73	2.81
Onroad Diesel	1.29	1.59	1.49	1.76	2.03	2.38	2.84	3.39
Jet Fuel	6.98	6.80	10.41	12.84	13.04	13.21	13.33	13.54
Aviation Gasoline	0.174	0.138	0.184	0.098	0.102	0.106	0.110	0.113
Boats and Ships	0.828	0.745	0.476	0.614	0.723	0.850	0.999	1.174
Rail and Other	0.082	0.065	0.075	0.056	0.057	0.060	0.062	0.063
Total	**11.47**	**11.99**	**14.86**	**17.80**	**18.47**	**19.23**	**20.07**	**21.09**

Source: CCS calculations based on approach described in text.

Key Uncertainties

Projections of Vehicle Miles of Travel (VMT) and Biofuels Consumption

One source of uncertainty is the future year vehicle mix, which was calculated based on national growth rates for specific vehicle types. These growth rates may not reflect vehicle-specific VMT growth rates for the state. Also, onroad gasoline and diesel growth rates may be slightly overestimated because increased consumption of biofuels between 2005 and 2020 was not taken into account (due to a lack of data).

Uncertainties in Aviation Fuel Consumption

The consumption of international bunker fuels included in jet fuel consumption from EIA is another uncertainty. This fuel consumption associated with international air flights should not be included in the state inventory (as much of it is actually consumed out of state); however, data were not available to subtract this consumption from total jet fuel estimates. Another uncertainty

associated with aviation emissions is the use of national seat miles per gallon data to adjust for increases in commercial aircraft fuel efficiency.

Appendix D. Industrial Processes

Overview

Emissions in the industrial processes category span a wide range of activities, and reflect non-combustion sources of greenhouse gas (GHG) emissions from several industrial processes. The industrial processes that exist in Alaska, and for which emissions are estimated in this inventory, include the following:

- Carbon Dioxide (CO_2) from:
  - Consumption of limestone, dolomite, and soda ash;
- SF_6 from transformers used in electric power transmission and distribution (T&D) systems; and
- HFCs and PFCs from consumption of substitutes for ozone-depleting substances (ODS) used in cooling and refrigeration equipment.

Other industrial processes that are sources of GHG emissions but are not found in Alaska include the following:

- Carbon Dioxide (CO_2) from:
  - Production of cement, lime, and soda ash
- Nitrous oxide (N_2O) from nitric and adipic acid production;
- Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) from semiconductor manufacture;
- PFCs from aluminum production;
- HFCs from HCFC-22 production; and
- SF_6 from magnesium production and processing.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2005 were estimated using the State Greenhouse Gas Inventory Tool (SIT) and the methods provided in the Emissions Inventory Improvement Project (EIIP) guidance document for this sector.[87] Table D1 identifies for each emissions source category the information needed for input into SIT to calculate emissions, the data sources used, and the historical years for which emissions were calculated based on the availability of data. Table D2 lists the data sources used to quantify activities related to industrial process emissions, the annual compound growth rates implied by estimates of future activity used, and the years for which the reference case projections were calculated.

[87] GHG emissions were calculated using SIT, with reference to the Emission Inventory Improvement Program, Volume VIII: Chapter. 6. "Methods for Estimating Non-Energy Greenhouse Gas Emissions from Industrial Processes", August 2004. This document is referred to as "EIIP" below.

Table D1. Approach to Estimating Historical Emissions

Source Category	Time Period	Required Data for SIT	Data Source
Limestone and Dolomite Consumption	1994 - 2002	Consumption of limestone and dolomite by industrial sectors.	For default data, the state's total limestone consumption (as reported by USGS) is multiplied by the ratio of national limestone consumption for industrial uses to total national limestone consumption. Additional information on these calculations, including a definition of industrial uses, is available in Chapter 6 of the EIIP guidance (see footnote 1 for reference to EIIP guidance document).
Soda Ash	1990 - 2002	Consumption of soda ash used in consumer products such as glass, soap and detergents, paper, textiles, and food. Emissions based on state's population and estimates of emissions per capita from the US EPA national GHG inventory.	*USGS Minerals Yearbook, 2004: Volume I, Metals and Minerals*, (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/). For population data, see references for ODS substitutes.
ODS Substitutes	1990 - 2002	Based on state's population and estimates of emissions per capita from the US EPA national GHG inventory.	-- Population data from the Alaska Department of Labor and Workforce Development, "Workforce Information," Home (http://almis.labor.state.ak.us/), Population & Census, Estimates & Projections, Population Data Tables: ---- Data for 1990 through 2000 found under Alaska Population Estimates 2000-2006, Historical Estimates (at bottom of page), Select Borough and Census Area 1990-2000, in Excel file named "02T2-1a.xls." ---- Data for 2001 through 2005 found under Alaska Population Estimates 2000-2006, Vintage 2005 Estimates, Borough and Census Area Estimates, Population by Labor Market Area, Borough and Census Area, and Components of Change, 1990-2005 in Excel file named "05t2-1.xls." -- Data for 2006 through 2029 found under Alaska Population Projections (2005-2029), February 2005 issue of Alaska Economic Trends, in PDF file named "feb05.pdf" (Projections for Alaska population 2005–2029, Table 5. Population Growth Projections Alaska 2005–2029, Medium Population Values in Table 5 used for forecast). -- US 1990-2000 population from US Census Bureau (http://www.census.gov/popest/archives/EST90INTERCENSAL/US-EST90INT-01.html). -- US 2000-2005 population from US Census Bureau (http://www.census.gov/population/projections/SummaryTabA1.xls).
Electric Power T&D Systems	1990 - 2002	Emissions from 1990 to 2002 based on the national emissions per kilowatt-hour (kWh) and state's electricity use.	National emissions per kWh from US EPA *2005 Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003* (http://www.epa.gov/climatechange/emissions/usgginv_archive.html).

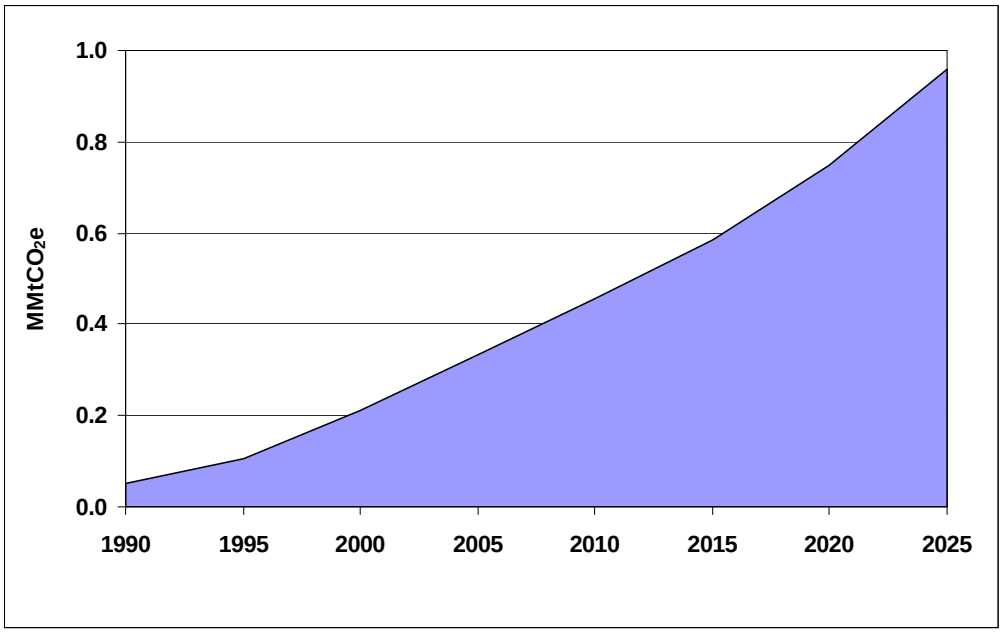
Table D2. Approach to Estimating Projections

Source Category	Time Period	Projection Assumptions	Data Source	Annual Growth Rates (%)			
				2000 to 2005	2005 to 2010	2010 to 2015	2015 to 2025
Limestone and Dolomite Consumption	2003 - 2020	Compound annual growth rate for Alaska's employment projections for goods-producing sector (2004-2014). Assumed growth is same for 2015 – 2020 as in previous periods.	Alaska Department of Labor and Workforce Development, "Workforce Information," Industry Forecasts (http://almis.labor.state.ak.us/).	0.95	0.95	0.95	0.95
Soda Ash Consumption	2003 - 2020	Growth between 2004 and 2009 is projected to be about 0.5% per year for US production. Assumed growth is same for 2010 – 2020.	*Minerals Yearbook, 2005: Volume I, Soda Ash*, (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/soda_myb05.pdf).	0.5	0.5	0.5	0.5
ODS Substitutes	2003 - 2020	Based on national growth rate for use of ODS substitutes.	EPA, 2004 ODS substitutes cost study report (http://www.epa.gov/ozone/snap/emissions/TMP6si9htnvca.htm).	15.8	7.9	5.8	5.3
Electric Power T&/D Systems	2003 - 2020	National growth rate (based on aggregate for all stewardship program categories provided in referenced data source).	U.S. Department of State, *U.S. Climate Action Report*, May 2002, Washington, D.C., May 2002 (Table 5-7). (http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/SHSU5BNQ76/$File/ch5.pdf).	3.3	-6.2	-9.0	-2.8

Results

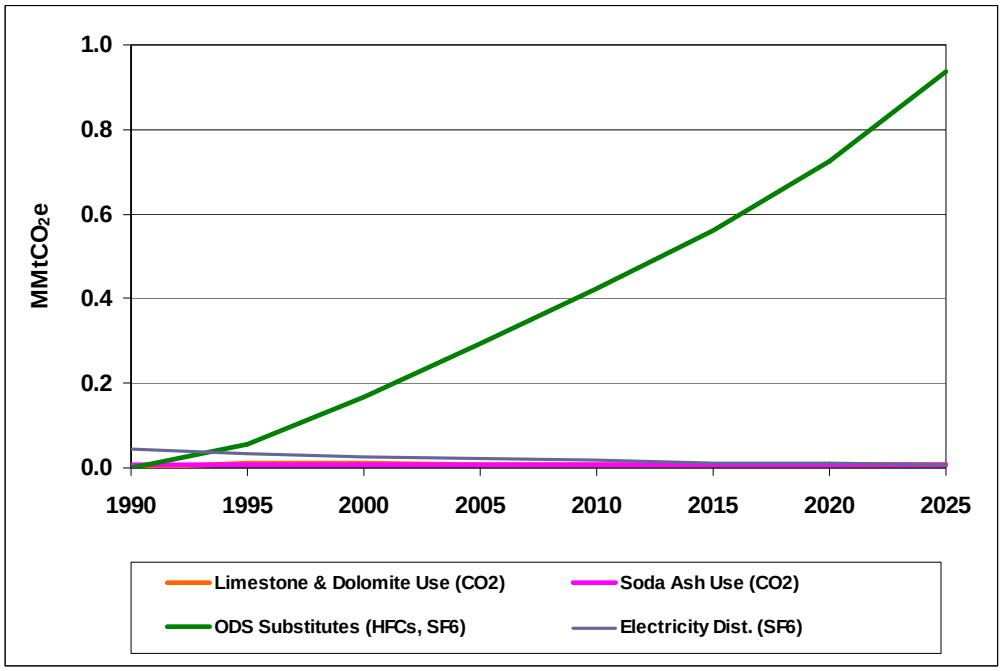
Figures D1 and D2 and Table D3 show historic and projected emissions for the Alaska industrial processes sector from 1990 to 2025. Total gross GHG emissions were about 0.33 million metric tons (MMt) of carbon dioxide equivalent (CO_2e) in 2005 (0.7% of gross Alaska GHG emissions in 2005), rising to about 0.96 $MMTCO_2e$ in 2025 (1.5% of gross Alaska GHG emissions in 2025). Emissions from the overall industrial processes category are expected to grow rapidly, as shown in Figures D1 and D2, with emissions growth almost entirely due to the increasing use of HFCs and PFCs in refrigeration and air conditioning equipment.

Figure D1. GHG Emissions from Industrial Processes, 1990-2025



Source: CCS calculations based on approach described in text.

Figure D2. GHG Emissions from Industrial Processes, 1990-2025, by Source



Source: CCS calculations based on approach described in text.

Table D3. Industrial Processes Emissions Inventory and Reference Case Projections ($MMtCO_2e$)

Source Category	1990	1995	2000	2005	2010	2015	2020	2025
Limestone & Dolomite Use (CO_2)	-	0.0126	-	0.0077	0.0080	0.0084	0.0088	0.0092
Soda Ash Use (CO_2)	0.0060	0.0062	0.0059	0.0060	0.0062	0.0063	0.0065	0.0067
ODS Substitutes (HFCs, SF6)	0.0007	0.0548	0.1668	0.2951	0.4236	0.5597	0.7237	0.9358
Electricity Distribution (SF_6)	0.0443	0.0333	0.0247	0.0238	0.0168	0.0112	0.0097	0.0084
Total	**0.0511**	**0.1069**	**0.1974**	**0.3326**	**0.4547**	**0.5857**	**0.7488**	**0.9601**

Substitutes for Ozone-Depleting Substances (ODS)

HFCs and PFCs are used as substitutes for ODS, most notably CFCs (CFCs are also potent warming gases with global warming potentials on the order of thousands of times that of CO_2 per unit of emissions) in compliance with the *Montreal Protocol* and the *Clean Air Act Amendments*

of 1990.[88] Even low amounts of HFC and PFC emissions, for example, from leaks and other releases associated with normal use of the products, can lead to high GHG emissions on a carbon-equivalent basis. Emissions from the use of ODS substitutes in Alaska were calculated using the default methods in SIT (see dark green line in Figure D2). Emissions have increased from 0.0007 $MMtCO_2e$ in 1990 to about 0.30 $MMtCO_2e$ in 2005, and are expected to increase at an average rate of 5.9% per year from 2000 to 2025 due to increased substitutions of these gases for ODS. The projected rate of increase for these emissions is based on projections for national emissions from the US EPA report referenced in Table D2.

Electricity Distribution

Emissions of SF_6 from electrical equipment have experienced declines since the early nineties (see gray line in Figure D2), mostly due to voluntary action by industry. SF_6 is used as an electrical insulator and interrupter in electricity T&D systems. Emissions for Alaska from 1990 to 2005 were estimated based on the estimates of emissions per kilowatt-hour (kWh) from the US EPA GHG inventory and on Alaska's electricity consumption estimates provided in SIT. The *US Climate Action Report* shows expected decreases in these emissions at the national level, and the same rate of decline is assumed for emissions in Alaska. The decline in SF_6 emissions in the future reflects expectations of future actions by the electric industry to reduce these emissions.

Limestone and Dolomite Consumption

Limestone and dolomite are basic raw materials used by a wide variety of industries, including the construction, agriculture, chemical, glass manufacturing, and environmental pollution control industries, as well as in metallurgical industries such as magnesium production.[89] Recent historical data for Alaska were not available from the USGS; consequently, the default data provided in SIT were used to calculate emissions for Alaska (see orange line in Figure D2). The employment growth rate for Alaska's goods-producing sector (i.e., 0.95% annual) was used to project emissions to 2025. Relative to total industrial non-combustion process emissions, emissions associated with limestone and dolomite consumption are low (about 0.008 $MMtCO_2e$ in 2005 and 0.009 $MMtCO_2e$ in 2025), and therefore, appear near the bottom of the graph in Figure D2. Note that for this sector, SIT did not contain default consumption data for Alaska for 1990 through 1994 and for 2000.

Soda Ash Consumption

Commercial soda ash (sodium carbonate) is used in many consumer products such as glass, soap and detergents, paper, textiles, and food. CO_2 is also released when soda ash is consumed (see footnote 1 for reference to EIIP guidance document). SIT estimates historical emissions (see dark pink line in Figure D2) based on the state's population and national per capita emissions from the

[88] As noted in EIIP Chapter 6, ODS substitutes are primarily associated with refrigeration and air conditioning, but also many other uses including as fire control agents, cleaning solvents, aerosols, foam blowing agents, and in sterilization applications. The applications, stocks, and emissions of ODS substitutes depend on technology characteristics in a range of equipment. For the US national inventory, a detailed stock vintaging model was used, but this modeling approach has not been completed at the state level.

[89] In accordance with EIIP Chapter 6 methods, emissions associated with the following uses of limestone and dolomite are not included in this category: (1) crushed limestone consumed for road construction or similar uses (because these uses do not result in CO_2 emissions), (2) limestone used for agricultural purposes (which is counted under the methods for the agricultural sector), and (3) limestone used in cement production (which is counted in the methods for cement production).

US EPA national GHG inventory. According to the USGS, this industry is expected to grow at an annual rate of 0.5% from 2004 through 2009 for the U.S. as a whole. Information on growth trends for years later than 2009 was not available; therefore, the same 0.5% annual growth rate was applied for estimating emissions to 2025. Relative to total industrial non-combustion process emissions, emissions associated with soda ash consumption are low (about 0.006 $MMtCO_2e$ in 1990 and 0.007 $MMtCO_2e$ in 2025).

Key Uncertainties

Key sources of uncertainty underlying the estimates above are as follows:

- Since emissions from industrial processes are determined by the level of production in and the production processes of a few key industries, and, in some cases, of a few key plants, there is relatively high uncertainty regarding future emissions from the industrial processes category as a whole. Future emissions depend on the competitiveness of Alaskan manufacturers in these industries, and the specific nature of the production processes used in plants in Alaska.
- The projected largest source of future industrial emissions, HFCs and PFCs used in cooling applications, is subject to several uncertainties as well. First, historical emissions are based on national estimates; Alaska-specific estimates are currently unavailable. For example, emissions will be driven by future choices regarding mobile and stationary air conditioning technologies and the use of refrigerants in commercial applications, for which several options currently exist.
- Historical consumption estimates for limestone and dolomite and for soda ash are highly uncertain. Future work should include efforts to improve the historical consumption estimates.
- Greenhouse gases are emitted from several additional industrial processes that are not covered in the EIIP guidance documents, due in part to a lack of sufficient state data on non-energy uses of fossil fuels for these industrial processes. These sources include:
    - Iron and Steel Production (CO_2 and CH_4);
    - Ammonia Manufacture and Urea Application (CO_2, CH_4, N_2O);
    - Aluminum Production (CO_2);
    - Titanium Dioxide Production (CO_2);
    - Phosphoric Acid Production (CO_2);
    - CO_2 Consumption (CO_2);
    - Ferroalloy Production (CO_2);
    - Petrochemical Production (CH_4); and
    - Silicon Carbide Production (CH_4).

The CO_2 emissions from the above processes (those listed as CO_2 sources—with the exception of CO_2 consumption and phosphoric acid production) result from the non-energy use of fossil fuels.

Although the US EPA estimates emissions for these industries on a national basis, US EPA has not developed methods for estimating the emissions at the state level due to data limitations. If state-level data on non-energy uses of fuels become available, future work should include an assessment of emissions for these source categories.

Appendix E. Agriculture

Overview

The emissions discussed in this appendix refer to non-energy methane (CH_4) and nitrous oxide (N_2O) emissions from enteric fermentation, manure management, and agricultural soils. Emissions and sinks of carbon in agricultural soils are also covered. Energy emissions (combustion of fossil fuels in agricultural equipment) are included in the residential, commercial, and industrial (RCI) fuel consumption sector estimates.

There are two livestock sources of greenhouse gas (GHG) emissions: enteric fermentation and manure management. Methane emissions from enteric fermentation are the result of normal digestive processes in ruminant and non-ruminant livestock. Microbes in the animal digestive system breakdown food and emit CH_4 as a by-product. More CH_4 is produced in ruminant livestock because of digestive activity in the large fore-stomach. Methane and N_2O emissions from the storage and treatment of livestock manure (e.g., in compost piles or anaerobic treatment lagoons) occur as a result of manure decomposition. The environmental conditions of decomposition drive the relative magnitude of emissions. In general, the more anaerobic the conditions are, the more CH_4 is produced because decomposition is aided by CH_4 producing bacteria that thrive in oxygen-limited conditions. Under aerobic conditions, N_2O emissions are dominant. Emissions estimates from manure management are based on manure that is stored and treated on livestock operations. Emissions from manure that is applied to agricultural soils as an amendment or deposited directly to pasture and grazing land by grazing animals are accounted for in the agricultural soils emissions.

The management of agricultural soils can result in N_2O emissions and net fluxes of carbon dioxide (CO_2) causing emissions or sinks. In general, soil amendments that add nitrogen to soils can also result in N_2O emissions. Nitrogen additions drive underlying soil nitrification and de-nitrification cycles, which produce N_2O as a by-product. The emissions estimation methodologies used in this inventory account for several sources of N_2O emissions from agricultural soils, including decomposition of crop residues, synthetic and organic fertilizer application, manure application, sewage sludge, nitrogen fixation, and histosols (high organic soils, such as wetlands or peatlands) cultivation. Both direct and indirect emissions of N_2O occur from the application of manure, fertilizer, and sewage sludge to agricultural soils. Direct emissions occur at the site of application and indirect emissions occur when nitrogen leaches to groundwater or in surface runoff and is transported off-site before entering the nitrification/denitrification cycle. Methane and N_2O emissions also result when crop residues are burned. Methane emissions occur during rice cultivation; however, rice is not grown in Alaska.

The net flux of CO_2 in agricultural soils depends on the balance of carbon losses from management practices and gains from organic matter inputs to the soil. Carbon dioxide is absorbed by plants through photosynthesis and ultimately becomes the carbon source for organic matter inputs to agricultural soils. When inputs are greater than losses, the soil accumulates carbon and there is a net sink of CO_2 into agricultural soils. In addition, soil disturbance from the cultivation of histosols releases large stores of carbon from the soil to the atmosphere. Finally, the practice of adding limestone and dolomite to agricultural soils results in CO_2 emissions.

Emissions and Reference Case Projections

Methane and Nitrous Oxide

GHG emissions for 1990 through 2005 were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SIT) and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for the sector.[90] In general, the SIT methodology applies emission factors developed for the US to activity data for the agriculture sector. Activity data include livestock population statistics, amounts of fertilizer applied to crops, and trends in manure management practices. This methodology is based on international guidelines developed by sector experts for preparing GHG emissions inventories.[91]

Data on crop production in Alaska from 1990 to 2005 and the number of animals in the state from 1990 to 2002 were obtained from the United States Department of Agriculture (USDA), National Agriculture Statistical Service (NASS) and incorporated as defaults in SIT.[92] Future reference case emissions from enteric fermentation and manure management were estimated based on the annual growth rate in emissions (million metric ton [MMt] carbon dioxide equivalent [CO_2e] basis) associated with historical livestock populations in Alaska for 1990 to 2002. The default data in SIT accounting for the percentage of each livestock category using each type of manure management system was used for this inventory. Default SIT assumptions were available for 1990 through 2002.

Data on fertilizer usage came from *Commercial Fertilizers*, a report from the Fertilizer Institute. Data on crop production in Alaska from 1990 to 2005 from the USDA NASS were used to calculate N_2O emissions from crop residues and CH_4 emissions from agricultural residue burning through 2005. Emissions for the other agricultural crop production categories (i.e., synthetic and organic fertilizers) were calculated through 2002. Production data from NASS was available for only two (i.e., barley and oats) of the types of crops included in SIT, and these crops do not use nitrogen; therefore, N_2O emissions were not estimated for crops that use nitrogen (i.e., nitrogen fixation). Also, data were not available to estimate nitrogen released by the cultivation of histosols (i.e., the number of acres of high organic content soils). In addition,

[90] GHG emissions were calculated using SIT, with reference to EIIP, Volume VIII: Chapter 8. "Methods for Estimating Greenhouse Gas Emissions from Livestock Manure Management", August 2004; Chapter 10. "Methods for Estimating Greenhouse Gas Emissions from Agricultural Soil Management", August 2004; and Chapter 11. "Methods for Estimating Greenhouse Gas Emissions from Field Burning of Agricultural Residues", August 2004.
[91] Revised 1996 1ntergovermental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories, published by the National Greenhouse Gas Inventory Program of the IPCC, available at http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm; and Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, published in 2000 by the National Greenhouse Gas Inventory Program of the IPCC, available at: http://www.ipcc-nggip.iges.or.jp/public/gp/english/.
[92] USDA, NASS (http://www.nass.usda.gov/Statistics_by_State/Alaska/index.asp).

net carbon fluxes from agricultural soils are not reported in the US Inventory of Greenhouse Gas Emissions and Sinks[93] and the US Agriculture and Forestry Greenhouse Gas Inventory.

There is some agricultural residue burning conducted in Alaska. The SIT methodology calculates emissions by multiplying the amount (e.g., bushels or tons) of each crop produced by a series of factors to calculate the amount of crop residue produced and burned, the resultant dry matter, and the carbon/nitrogen content of the dry matter. For Alaska, the default SIT method was used to calculate emissions because activity data in the form used in the SIT were not readily available. Future work on this category should include an assessment to refine the SIT default assumptions.

Table E1 shows the annual growth rates applied to estimate the reference case projections by agricultural sector. Emissions from enteric fermentation and agricultural soils were projected based on the annual growth rate in historical emissions ($MMtCO_2e$ basis) for these categories in Alaska for 1990 to 2002 (1990 to 2005 for crop residues and nitrogen fixing crops). For crop residues, data for 1990 through 1993 were not available; therefore, the annual growth rate is based on the last 11 years for which historical emissions were calculated. Note that during 2000, weather conditions caused a significant decline in barley and oat production (both the number of acres harvested and yields); however, production of these crops recovered to typical levels in 2001 through 2005.[94]

Table E1. Growth Rates Applied for the Agricultural Sector

Agricultural Category	Growth Rate	Basis for Annual Growth Rate*
Enteric Fermentation	2.7%	Historical emissions for 1990-2002.
Manure Management	6.1%	Historical emissions for 1997-2002.
Agricultural Burning	0.0%	Assumed no growth.
Agricultural Soils – Direct Emissions		
Fertilizers	-4.3%	Historical emissions for 1990-2002.
Crop Residues	2.0%	Historical emissions for 1994-2005.
Nitrogen-Fixing Crops	0.0%	No historical data available.
Histosols	0.0%	No historical data available.
Livestock	2.1%	Historical emissions for 1990-2002.
Agricultural Soils – Indirect Emissions		
Fertilizers	-4.3%	Historical emissions for 1990-2002.
Livestock	2.4%	Historical emissions for 1990-2002.
Leaching/Runoff	-2.8%	Historical emissions for 1990-2002.

* Except for manure management and crop residues, compound annual growth rates shown in this table were calculated using the growth rate in historical emissions ($MMtCO_2e$ basis) from 1990 through the most recent year of data. These growth rates were applied to forecast emissions from the latest year of data to 2020. For crop residues, data for 1990 through 1993 were not available; therefore, the annual growth rate is based on the last 11 years for which historical emissions were calculated. For manure management, the growth rate is based on emissions calculated for 1997-2002 (see text for explanation).

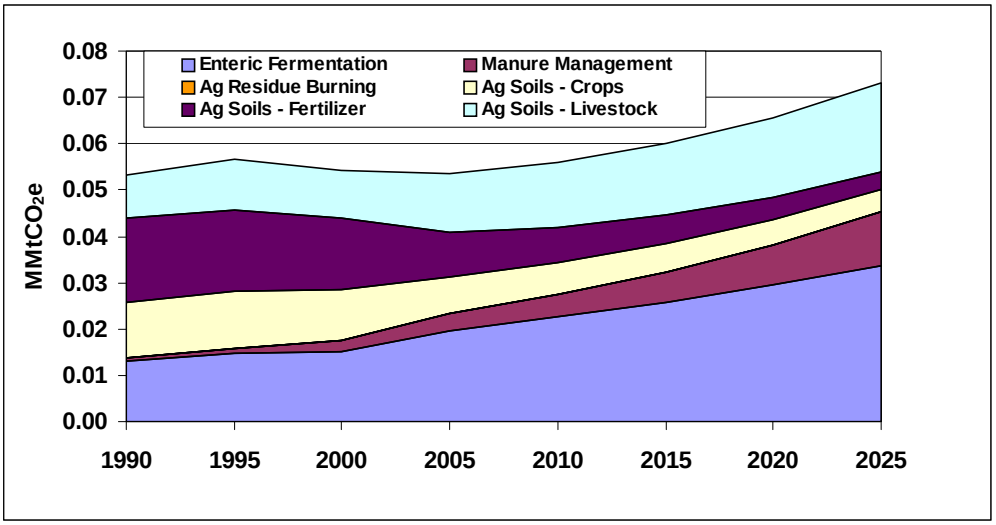
[93] US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004 (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006. Available at: http://www.epa.gov/climatechange/emissions/usinventoryreport.html.
[94] Alaska Agricultural Statistics 2001, prepared by Alaska Agricultural Statistics Service, USDA, Palmer, Alaska.

For manure management, the 12-year historical growth rate is 15.4% and the 5-year growth rate (based on 1997 through 2002 emissions) is 6.1%. The high 12-year growth rate is driven by changes in the SIT assumptions on the types of manure management systems applied for dairy cattle and heifers. For dairy cattle and heifers, the proportion of manure managed in systems that yield higher GHG emissions (e.g., anaerobic lagoons and liquid slurry) than other systems (e.g., pasture) increased from 0% in 1990 to over about 70% for 1997 through 2002. For this analysis, the 5-year growth rate was assumed to be more representative of future manure management practices in Alaska and was used to forecast emissions from 2002 to 2025.

Results

As shown in Figure E1 and Table E2, gross GHG emissions from agricultural sources range between about 0.053 and 0.073 $MMtCO_2e$ from 1990 through 2025, respectively. In 1990, enteric fermentation accounted for about 25% (0.013 $MMtCO_2e$) of total agricultural emissions and is estimated to account for about 46% (0.034 $MMtCO_2e$) of total agricultural emissions in 2025. The manure management category, which shows the highest rate of growth relative to the other categories, accounted for 1% (0.001 $MMtCO_2e$) of total agricultural emissions in 1990 and is estimated to account for about 16% (0.012 $MMtCO_2e$) of total agricultural emissions in 2025. The agricultural soils category shows declining growth, with 1990 emissions accounting for 74% (0.039 $MMtCO_2e$) of total agricultural emissions and 2025 emissions estimated to be about 38% (0.028 $MMtCO_2e$) of total agricultural emissions.

Figure E1. Gross GHG Emissions from Agriculture



Source: CCS calculations based on approach described in text.

Notes: Ag Soils – Crops category includes crop residues (no cultivation of histosols estimated); emissions for agricultural residue burning are too small to be seen in this chart.

Table E2. Agriculture Sector Emissions Inventory and Reference Case Projections ($MMtCO_2e$)

Subsector	1990	1995	2000	2005	2010	2015	2020	2025
Enteric Fermentation	0.013	0.015	0.015	0.020	0.023	0.026	0.029	0.034
Manure Management	0.001	0.001	0.002	0.004	0.005	0.006	0.009	0.012
Ag Residue Burning	0.00001	0.00002	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001
Ag Soils - Crops	0.012	0.012	0.011	0.008	0.007	0.006	0.005	0.005
Ag Soils - Fertilizer	0.018	0.017	0.016	0.009	0.008	0.006	0.005	0.004
Ag Soils - Livestock	0.009	0.011	0.010	0.013	0.014	0.015	0.017	0.019
Total	**0.053**	**0.057**	**0.054**	**0.053**	**0.056**	**0.060**	**0.066**	**0.073**

Agricultural burning emissions were estimated to be very small based on the SIT activity data (<0.00001 $MMtCO_2e$/yr from 1990 to 2002). This agrees with the USDA Inventory which also reports a low level of residue burning emissions (0.02 $MMtCO_2e$).

The standard IPCC source categories missing from this report are CO_2 emissions from limestone and dolomite application and CO_2 fluxes in agricultural soils. Estimates for Alaska were not available; however, the USDA's national estimate for soil liming is about 9 $MMtCO_2e$/yr.[7] As mentioned above the USDA national estimates for soil carbon do not include Alaska.

Key Uncertainties

Emissions from enteric fermentation and manure management are dependent on the estimates of animal populations and the various factors used to estimate emissions for each animal type and manure management system (i.e., emission factors which are derived from several variables including manure production levels, volatile solids content, and CH_4 formation potential). Each of these factors has some level of uncertainty. Also, animal populations fluctuate throughout the year, and thus using point estimates introduces uncertainty into the average annual estimates of these populations. In addition, there is uncertainty associated with the original population survey methods employed by USDA. The largest contributors to uncertainty in emissions from manure management are the emission factors, which are derived from limited data sets.

As mentioned above, data for Alaska were not available for estimating emissions associated with changes in agricultural soil carbon levels and limestone and dolomite application. When newer data are released by the USDA, these should be reviewed to represent current conditions as well as to assess trends.

Alaska has reindeer husbandry operations which are not included in SIT. The number of head of reindeer in Alaska has declined in recent years (from 24,000 head in 1998 to 15,000 in 2005).[95] Future work should consider developing data for estimating emissions associated with reindeer husbandry operations if this category is determined to be important.

[95] Alaska Agricultural Statistics 2006, prepared by Alaska Field Office, USDA NASS, Palmer, Alaska.

Another contributor to the uncertainty in the emission estimates is the projection assumptions. This inventory assumes that the average annual rate of change in future year emissions will follow the historical average annual rate of change from 1990 through the most recent year of data. For example, the historical data show a decline in the use of fertilizers; however, there may be a leveling-off in fertilizer use trends due to recent efficiency gains that my be close to reaching their full technical potential.

Appendix F. Waste Management

Overview

GHG emissions from waste management include:

- Solid waste management – CH_4 emissions from municipal and industrial solid waste landfills (LFs), accounting for CH_4 that is flared or captured for energy production (this includes both open and closed landfills);
- Solid waste combustion – CH_4, CO_2, and N_2O emissions from the combustion of solid waste in incinerators or waste to energy plants; and
- Wastewater management – CH_4 and N_2O from municipal wastewater and CH_4 from industrial wastewater (WW) treatment facilities.

Inventory and Reference Case Projections

Solid Waste Management
For solid waste management, CCS used the U.S. EPA SIT and the U.S. EPA Landfill Methane Outreach Program (LMOP) landfills database[96] as starting points to estimate emissions. The LMOP data serve as input data to estimate annual waste emplacement for each landfill needed by SIT. SIT then estimates CH_4 generation for each landfill site. Additional post-processing outside of SIT to account for controls is then performed to estimate CH_4 emissions.

The LMOP database contained limited information on 6 Class I landfills. CCS also contacted DEC staff to gather additional information on solid waste landfills and other solid waste management issues, including waste combustion.[97] DEC provided estimates of waste emplacement rates for 7 Class I landfills, 14 Class II landfills, and 222 Class III landfills. For the Class III sites, half of the waste accepted is assumed to be open burned (these emissions are addressed under the Solid Waste Combustion section below). Also, half of the waste estimated for Barrow (Class II landfill) was assumed to be burned at the Barrow Incinerator. The date of landfill opening was available for 5 of the Class I landfills. All other landfills were assumed to have been in operation since the 1960s, if not earlier.

Three landfills in AK are currently controlled. The Merrill Field landfill, which closed in 1987, is partially flared. The Anchorage and Juneau landfills began flaring in 2006 and 2008, respectively. The Anchorage Regional Landfill will begin a landfill gas to energy (LFGTE) project in 2015. The Class III, Class II, and remaining Class I sites were combined for the purposes of emissions modeling. The Class II and Class III disposal estimates provided by DEC were based on 2000 population data for the communities served and per capita generation rates

[96] LMOP database is available at: http://www.epa.gov/lmop/proj/index.htm. Updated version of the database provided by Rachel Goldstein, Program Manager, EPA Landfill Methane Outreach Program, October 2006. The only AK site represented in the database was the Anchorage Regional LF.
[97] Doug Buteyn and Ed Emswiler, DEC, Solid Waste Division, personal communications with S. Roe, CCS, December 2006 – January 2007; additional revisions to data and assumptions provided by D. Buteyn in October 2008.

(6.6 lb/person/day). These estimates were back-cast to 1960 and forecast to 2005 based on growth in rural population in AK. Table F1 provides a summary of the data used as input to SIT for modeling emissions.

Table F1. Summary of Municipal Solid Waste Landfill Data

Site Name	Operating Years	Average Waste Emplacement Rate (tons/yr)	Control
Anchorage Regional LF	1987 - Present	352,203	Flare (beginning 2006)
Juneau LF[a]	2004 - Present	29,428	Flare (beginning 2008)
Anchorage Merrill Field LF	1960-1987	104,942	Flare (partial coverage)
Other Class I LFs (5 sites)	Varies - Present	197,556	None
Class II LFs (14 sites)[b]	1960's - Present	31,480	None
Class III LFs (222 sites)[b]	1960's - Present	37,004	None

[a] Prior to 2004, combustible waste was incinerated and is accounted for under the waste combustion sector. A collection and flare system is in place; however, currently the methane is mostly being vented.
[b] Waste emplacement is for 2000, rates are back-cast and forecast based on rural population growth (0.81%/year for 1960-1990, 1.89% for 1990-2000, -0.05% for 2000-2005)

The estimated average annual disposal rates for each landfill were used in SIT for all years that the landfills were operating (Class II and III landfills were both collectively modeled as individual units at a state level). CCS performed 4 different runs of SIT to estimate emissions from municipal solid waste (MSW) landfills: (1) Anchorage; (2) Juneau; (3) Merrill Field; (4) uncontrolled. The other landfill category that CCS commonly models is sites with landfill gas to energy (LFGTE) plants. There are none of these currently operating in Alaska.

After obtaining the methane generation data from SIT, CCS performed post-processing of the methane emissions to account for landfill gas controls (flared sites) and to project the emissions through 2025. For Anchorage, Juneau, and Merrill Field, CCS projected uncontrolled emission levels by assuming continuation of the current emplacement rates. Controls were then applied in the appropriate year. CCS assumed that the overall methane collection and control efficiency is 75%.[98] Of the methane not captured by a landfill gas collection system, it is further assumed that 10% is oxidized before being emitted to the atmosphere (consistent with the SIT default). This assumption for oxidation is also used for the methane emitted from uncontrolled sites. Growth rates for uncontrolled landfills were estimated using the historic (1995-2005) growth rates of emissions (4.5%/year).

For industrial waste landfills, SIT calculates emissions based on an assumption that industrial waste is emplaced at industrial landfill sites and that the methane emissions are 7% of the methane generated at MSW sites (this default is based on national data). Due to the lack of a substantial industrial base in Alaska, CCS assumed that any industrial waste emplaced in solid waste landfills is captured in the MSW emplacement estimates described above. Hence, there are no emissions estimated specifically for the industrial waste landfills sector.

[98] As per EPA's AP-42 Section on Municipal Solid Waste Landfills: http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf.

Solid Waste Combustion
Information from DEC contacts was used to construct estimates from municipal solid waste combustion.[99] Solid waste combustion addressed here includes both the controlled combustion of MSW in incinerators, as well as open MSW combustion occurring at community landfills. For controlled combustion, 2002 estimates of combustion at incinerators provided by DEC were used to represent 2002 and 2003 activity; while 2004 and 2005 activity were estimated by subtracting the throughput for the Juneau facility, which closed in 2004. Controlled combustion estimates were back-cast from 2002 to 1990 based on AK population growth for 1990-2002 (1.4%/year). Open burning estimates were based on the assumption that half of the waste received at Class III landfills was burned on site.

The mass of controlled waste combustion was added to the estimate described under the landfills section above for open burning at Class III landfill sites to estimate total waste combustion emissions. Table F2 shows the total waste mass estimates per year.

Table F2. Summary of Municipal Solid Waste Combustion Data (tons)

Combustion Category	1990	1995	2000	2005
Controlled Burning	29,668	31,820	34,128	14,139
Open Burning	21,839	23,730	26,062	25,995
Totals	**51,508**	**55,550**	**60,190**	**40,133**

SIT does not use different methods (emission factors) for open and controlled burning. Therefore, the total waste estimates above were used as input to SIT to estimate emissions. DEC also provided some data for sewage sludge incineration. Most of the carbon in sewage sludge is of biological origin, and therefore the associated CO_2 emissions would not be incorporated into this GHG inventory. While CCS would expect some emissions of methane and nitrous oxide from these sources, CCS believes that the emissions would be negligible.

Emissions for the solid waste combustion sector were forecast based on Alaska's forecasted population growth from 2005-2025 (0.61%/yr).[100]

Wastewater Management
GHG emissions from municipal and industrial wastewater treatment were also estimated. For municipal wastewater treatment, emissions are calculated in EPA's SIT based on state population, assumed biochemical oxygen demand (BOD) and protein consumption per capita, and emission factors for N_2O and CH_4. The key SIT default values are shown in Table F3 below. Emissions for the municipal wastewater management sector were forecast based on Alaska's forecasted population growth from 2005-2020 (0.69%/yr).

[99] Controlled burning - Alice Edwards, DEC, personal communication and data file provided to S. Roe, CCS, January 2007. Open burning – Doug Buteyn, DEC, personal communication with S. Roe, CCS, December 2006 with additional follow-up in October 2008.
[100] Alaska Department of Labor and Workforce Development, "Workforce Information," Home, Population & Census, Estimates & Projections, Population Data Tables, "Alaska Population Projections (2005-2029)," Select "February 2005 issue of Alaska Economic Trends," in PDF file named "feb05.pdf"(Projections for Alaska population 2005–2029, Table 5. Population Growth Projections Alaska 2005–2029, Medium Population Values in Table 5 used for forecast).

For industrial wastewater emissions, SIT provides default assumptions and emission factors for three industrial sectors: Fruits & Vegetables, Red Meat & Poultry, and Pulp & Paper. According to DEC contacts and the Dun & Bradstreet database, there currently are no large operations in these industry sectors that would be expected to have their own treatment systems. According to the contact at the Alyeska Valdez Marine terminal, the Valdez ballast water treatment facility does not emit CH_4 emissions.[101]

Emissions of methane are also expected to occur from fish processing waste dumped at sea.[102] Again, CCS attempted to gather information on this issue; however no emissions-related information was identified. Presumably, methane emissions would also occur from waste treatment conducted on-shore; however, CCS is not aware of any data or emissions estimation methods to address this potential source category.

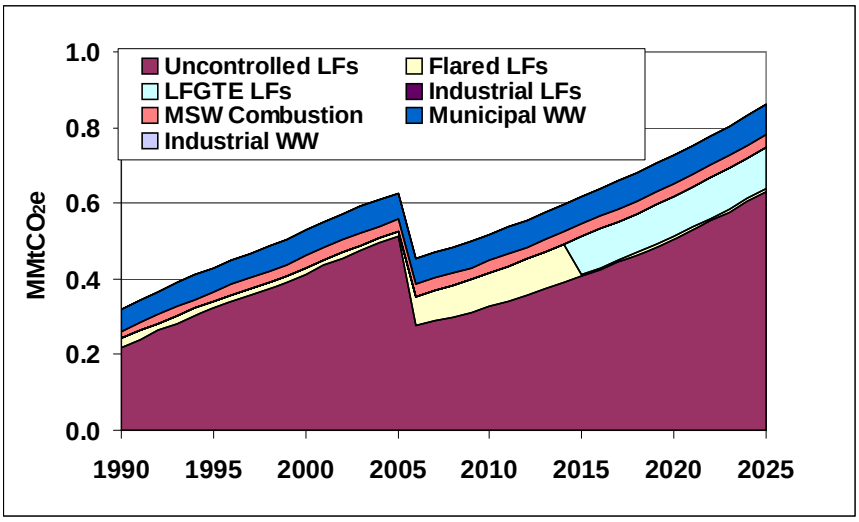
Table F3. SIT Key Default Values for Municipal Wastewater Treatment

Variable	Value
BOD	0.065 kg /day-person
Amount of BOD anaerobically treated	16.25%
CH_4 emission factor	0.6 kg/kg BOD
Alaska residents not on septic	75%
Water treatment N_2O emission factor	4.0 g N_20/person-yr
Biosolids emission Factor	0.01 kg N_2O-N/kg sewage-N
Source: U.S. EPA State Inventory Tool – Wastewater Module; methodology and factors taken from U.S. EPA, Emission Inventory Improvement Program, Volume 8, Chapter 12, October 1999: www.epa.gov/ttn/chief/eiip/techreport/volume08/.	

Figure F1 and Table F4 show the emission estimates for the waste management sector. Overall, the sector accounts for 0.6 $MMtCO_2e$ in 2005. By 2025, emissions are expected to grow to 0.9 $MMtCO_2e$/yr. Uncontrolled landfills account for the majority of waste management emissions, accounting for an estimated 81% of waste management emissions in 2005 and expected to account for 73% of Alaska's waste management emissions in 2025. Flared landfills accounted for an estimated 2% of waste management emissions in 2005 and are expected to account for 1% of waste management emissions in 2025. The significant drop in emissions seen in 2006 is due to the start of flaring at the Anchorage landfill. Before flaring began, the Anchorage landfill was the largest contributor to landfill emissions, accounting for about 44% of landfill emissions in 2005. After flaring began in 2006, the Anchorage landfill only contributed 10% to total landfill emissions. Flared landfill emissions drop significantly in 2015, when the Anchorage landfill is assumed to begin operating LFGTE technology.[103]

[101] Brad Thomas, Alyeska Valdez Marine Terminal, personal communication with Steve Roe, CCS, January, 2007. It is unclear whether this facility would also not emit any N_2O.
[102] An estimate from the early 1990's is that about 1.7 million metric tons of fish waste is generated in Alaska. The amount generated and treated on-shore versus at sea was not provided (*Pollution Prevention Opportunities in the Fish Processing Industry*, Pacific Northwest Pollution Prevention Research Center, 1993).
[103] Input from D. Mears of the FAW TWG.

Figure F1. Alaska GHG Emissions from Waste Management



Notes: LF – landfill; WW – wastewater; LFGTE – landfill gas to energy. Sources of information to estimate emissions for the industrial WW treatment category could not be obtained for incorporation into this assessment.

Table F4. Waste Management Emissions Inventory and Reference Case Projections ($MMtCO_2e$)

Subsector	1990	1995	2000	2005	2010	2015	2020	2025
Uncontrolled LFs	0.22	0.32	0.41	0.51	0.33	0.41	0.51	0.63
Flared LFs	0.023	0.19	0.15	0.012	0.090	0.006	0.006	0.009
LFGTE LFs	0	0	0	0	0	0.10	0.10	0.11
Industrial LFs	0	0	0	0	0	0	0	
MSW Combustion	0.020	0.025	0.033	0.031	0.032	0.033	0.034	0.35
Municipal WW	0.057	0.063	0.067	0.068	0.071	0.073	0.076	0.078
Industrial WW	0	0	0	0	0	0	0	0
Total	**0.32**	**0.43**	**0.53**	**0.63**	**0.52**	**0.62**	**0.73**	**0.86**

Source: CCS calculations based on approach described in text.

Waste combustion is estimated to contribute 5% of waste management emissions in 2005 and is expected to contribute about 4% of waste management emissions in 2025. The wastewater treatment sector is estimated to contribute 11% of the sector emissions in 2005 and about 0% of the total waste management emissions by 2025 (note that the wastewater estimates currently only include the municipal wastewater treatment sector). Data and methods were not identified to incorporate industrial wastewater treatment emissions into this assessment (including ballast water treatment and fish processing waste). The remaining emissions for the waste management sector emissions are contributed by solid waste landfilling – about 84% of waste management emissions in 2005 and 87% of waste management emissions in 2025, with an initial decline after 2005 and then steadily climbing through 2025.

Key Uncertainties

The methods used to project landfill emissions do not account for uncontrolled sites that will need to apply controls during the period of analysis due to triggering requirements of the federal New Source Performance Standards/Emission Guidelines. As noted above, the available data do not cover all of the open and closed landfills in Alaska. Rough estimates were developed for 14 Class II and 222 Class III landfills in the state. Also, many small landfills in Alaska are frozen for as much as half the year and would not be expected to contribute emissions during that time. Hence, the estimates presented here should be viewed as order of magnitude estimates.

The waste combustion estimates should also be viewed as order of magnitude estimates given the availability of data. The estimates are based on assumptions that 50% of the waste in Class III sites is open burned. National default waste composition profiles are used to estimate the CO_2e emissions for this activity, which might not adequately reflect the types of waste being open burned (i.e. paper/wood versus plastic/other composite fractions). No significant changes in controlled waste burning (in municipal waste combustors) are assumed for the future. Growth overall in waste combustion emissions is assumed to track population growth.

For the wastewater sector, the key uncertainties are associated with the application of SIT default values for the municipal wastewater treatment parameters listed in Table F1 above (e.g. fraction of the Alaska population on septic; fraction of BOD which is anaerobically decomposed). The SIT defaults were derived from national data.

For industrial wastewater treatment, data and estimation methods were lacking for this assessment. Emissions are expected from ballast water treatment and the treatment of fish processing waste; however no information was identified to develop emission estimates.

Overall for the waste management sector, it is important to note that the emissions presented here are associated with the end of life waste management practices in Alaska. This is consistent with the “production-based” estimates of emissions provided for the other GHG sectors. A consumption-based approach to emissions estimation would factor in the life-cycle GHG emissions associated with the production, transport, and final waste management practice for the wastes being managed in the State. For example, the emissions associated with the production of a plastic bottle, its transport to a distributor and end user, and its final disposal method (e.g. landfill or combustion). While this method of consumption-basis emissions accounting can be useful for understanding the full impacts of GHG mitigation policies implemented in Alaska, the reductions would largely occur outside of the State.

Appendix G. Forestry

Overview

Forestland emissions refer to the net carbon dioxide (CO_2) flux[104] from forested lands in Alaska, which account for about 35% of the state's land area.[105] About 10% of Alaska's forests are temperate coastal forests with the remainder being the interior boreal forests. Sitka spruce, hemlock and cedar are the dominant species in the southeast and south-central coastal parts of the state, while white spruce, black spruce, black cottonwood, aspen, and paper birch are found in the interior forests.

Forestlands are net sinks of CO_2 in Alaska. Through photosynthesis, CO_2 is taken up by trees and plants and converted to carbon in biomass within the forests. CO_2 emissions occur from respiration in live trees and decay of dead biomass. In addition, carbon is stored for long time periods when forest biomass is harvested for use in durable wood products. CO_2 flux is the net balance of CO_2 removals from and emissions to the atmosphere from the processes described above.

CCS has also included information on methane emissions from Alaskan ecosystems. These emissions are considered natural sources of methane that may be indirectly influenced by climate change. The estimated emissions documented below are not included within the summary tables presented in the body of this report, since they are considered natural sources.

Inventory and Reference Case Projections

CO_2 Flux in Alaska's Forests

For over a decade, the United State Forest Service (USFS) has been developing and refining a forest carbon modeling system for the purposes of estimating forest carbon inventories. The methodology is used to develop national forest CO_2 fluxes for the official US Inventory of Greenhouse Gas Emissions and Sinks.[106] The national estimates are compiled from state-level data. Unfortunately, the USFS has not yet developed estimates for Alaska due to a lack of comprehensive survey data for the State needed to develop these estimates.

Alaska is unique because a large fraction of the land base is essentially untouched, pristine forestland. GHG inventories principally account for *anthropogenic* emissions and sinks. In the forestry sector, experts have determined that a practical approach to quantifying anthropogenic emissions and sinks is to inventory carbon fluxes and non-CO2 emissions on "managed" forestland only. The USFS forest carbon accounting system incorporates these principles to a large degree because the Forest Inventory and Analysis survey (FIA) upon which they are based

[104] "Flux" refers to both emissions of CO_2 to the atmosphere and removal (sinks) of CO_2 from the atmosphere.
[105] Alaska Forest Association, http://www.akforest.org/facts.htm, reports 129 million acres of forested lands. The total land area in AK is 365 million acres (http://www.netstate.com/states/geography/ak_geography.htm). Data used in this appendix from UAF are based on geographic information indicating that AK has about 162 million acres of forested lands (about 23 million acres are in the temperate (coastal) maritime forest).
[106] *US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004* (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006. Available at: http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

targets managed forestlands (although all forested lands are included in the carbon flux estimates).

CCS used research studies provided by experts from the University of Alaska to construct estimates of the forest carbon flux in Alaska that are comparable in principle to the standard USFS inventory approach. The methods and results presented here cover both the entire forestland base in AK, as well as the temperate (coastal) maritime forests. The coastal maritime forests are where much of Alaska's productive forests are and where most the management has occurred historically. For the purposes of this analysis, CCS considers these to represent the State's "managed" forests.

Yarie and Billings provided estimates for Alaska's boreal forests that indicated annual sequestration rates of about -35 $MMtCO_2$.[107] Boreal forests represent about one-third of the forests in Alaska. University of Alaska Fairbanks (UAF) researchers also provided recent estimates for carbon flux based on forest ecosystem modeling.[108] Carbon flux in Alaska's forests was modeled from 1950 through 2002. These carbon flux estimates are based on UAF's Terrestrial Ecosystem Model (TEM), which estimates net primary productivity for forest ecosystems and take into account carbon flux both forest biomass and soils. The effects of climate, fires, and CO_2 levels are evaluated within the modeling. Model runs were performed with and without the effects of fertilization from higher CO_2 levels. Figures G1a and b provide a summary of the modeling results.

The data shown in Figure G1a show the variation in carbon flux for all of Alaska's forests over the period of analysis. The average sequestration rate over the period of analysis is -10 $MMtCO_2$/yr and the range is from -94 to 143 $MMtCO_2$/yr (CCS converted the values in the figures from units of carbon to CO_2 to show these estimates). [Note: negative numbers used in this report represent sequestration; the only exception is Figures G1 and G2, where positive numbers were used in the UAF reports. Also, for this analysis, CCS reports the UAF modeling results for carbon flux without CO_2 fertilization effects for consistency with standard inventory approaches]. The large range in flux values is largely related to wildfire activity--years with net emissions are those where significant wildfire activity occurred. The summary statistics show that these data are negatively skewed, so the median value (-25 $MMtCO_2$/yr) is probably a better estimate of central tendency in the data.

Figure G1b shows similar estimates covering only the coastal maritime forests (primarily those in the Chugach and Tongass National Forests). Based on the mean and median of these annual estimates, the historical carbon flux for these forests has been about -1.2 to -1.3 $MMtCO_2e$/yr (as with the data for Figure G1a, CCS converted carbon to CO_2 to report these estimates).

[107] Yarie, J. and S. Billings, "Carbon balance of the taiga forest within Alaska: present and future", *Canadian Journal of Forestry Research*, 32: 757–767 (2002).
[108] D. McGuire and M. Balshi, UAF, personal communication and data file provided to S. Roe, CCS, January 2007. Documentation is included within a manuscript currently under review by the Journal of Geophysical Research.

Figure G1a. Statewide Forest Carbon Flux

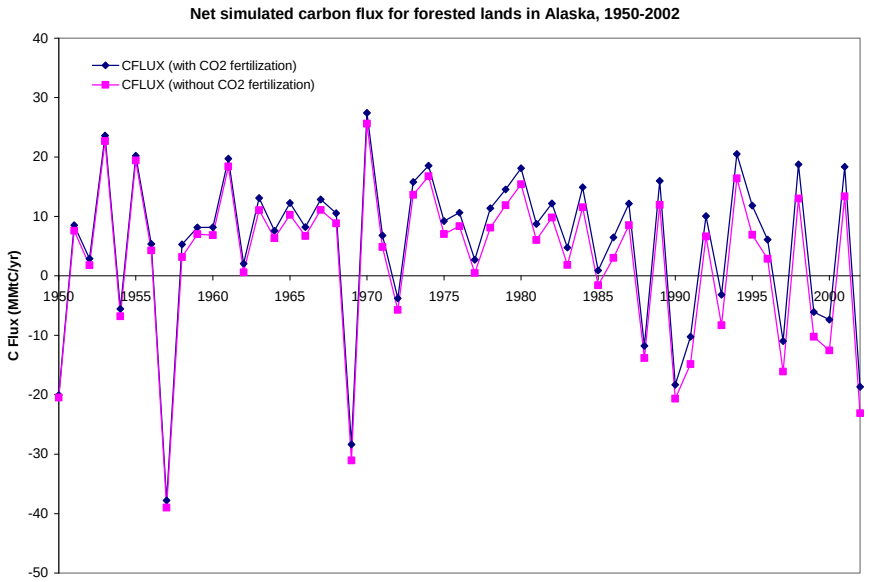
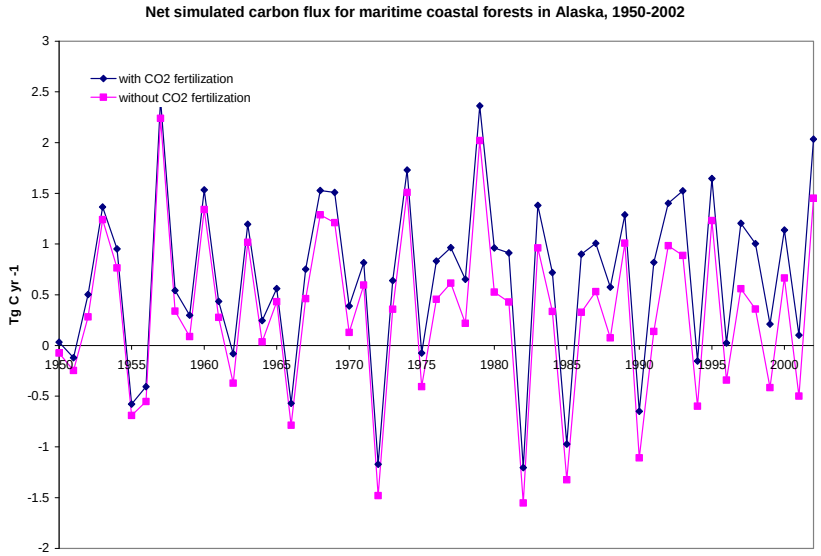


Figure G1b. Forest Carbon Flux in Coastal Maritime Forests



Note: Positive values in these graphs represent annual net sequestration. Source: M. Balshi, UAF, unpublished manuscript.

Figures G2a and b show the same modeling data from UAF as ten year averages of CO_2 sequestration in Alaska's forests. Ten year averages were selected to provide a comparison of sequestration rates in other western states.[109] An assessment of longer term averages also provides a sense of the sequestration potential of Alaskan forests during a typical year (a year that is not strongly influenced by large wildfire activity or no wildfire activity). The data in Figure G2a show that since the 1970s, average sequestration potential has decreased significantly. Historically, average sequestration rates were -20 to -30 $MMtCO_2$/yr. In recent decades, net sequestration has turned into net emissions of over 10 $MMtCO_2$/yr. Data for the 2000 time-frame were available through 2002. It appears that due to increased wildfire activity, Alaska's forests have entered into a period of net CO_2 emission during an average year.[110] Figure G3 provides ten year averages for statewide wildfire acres burned. The figure shows the upward trend in acres burned since the 1960's.[111]

Figure G2b shows the ten year averages of CO_2e flux for coastal maritime forests. The data show that the net sequestration rates have stayed fairly constant over time, at around -1.4 $MMtCO_2e$/yr. According to UAF researchers, since there was no significant wildfire activity in the 1990's time-frame, the lower sequestration rates shown for that period are probably due to climate factors (additional analysis would be needed to confirm this and the specific factors involved).

The statewide results from UAF show a trend where the CO_2 sequestration rate approaches zero and transition to a net emission rate as a result of high fire activity. This finding is consistent with a 2006 study published in *Science*.[112] This study indicated an increasing frequency of wildfire activity in the western US since the mid-1980s driven by a longer fire season and higher average temperatures.

[109] In other western states assessed by CCS, the US Forest Service uses Forest Inventory and Analysis survey data to estimate carbon in forest carbon pools; the period between surveys is typically about 10 years. The ten year averages shown in Table G2 represent the 10 year period bracketing the year indicated (for example, the 1990 average is derived from the estimates for 1985-1994; 1995-2002 were used for the 2000 average).

[110] According to M. Balshi of UAF, the area burned during the period 2000-2005 (UAF simulations only go through 2002 due to climate data restraints) already exceeds that of every decade on record.

[111] S.K. Todd and H.A. Jewkes, *Wildland Fire in Alaska: A History of Organized Fire Suppression and Management in the Last Frontier*, Agricultural and Forestry Experiment Station Research Bulletin #114, University of Alaska, Fairbanks, March 2006. These rough estimates assume similar fuel loading/acre as used to develop the WRAP's 2002 fire estimates. As with the ten year carbon dioxide flux averages mentioned in the footnote above, CCS used 1985-1994 to represent the 1990 ten year average, etc. For the 2000 average, data for 1996-2004 were used.

[112] Westerling, A.L. et al, "Warming and Earlier Spring Increases Western US Forest Wildfire Activity", *Sciencexpress*, July 6, 2006.

Figure G2a. Ten-Year Average Forest CO_2 Flux in Statewide Forests

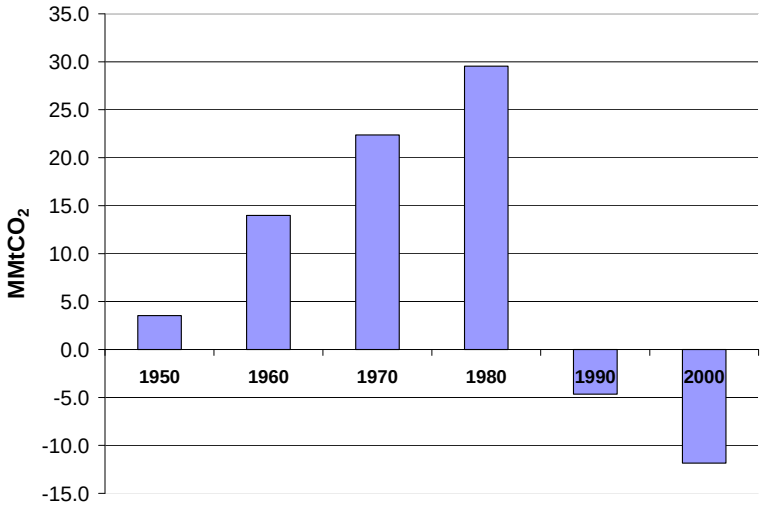
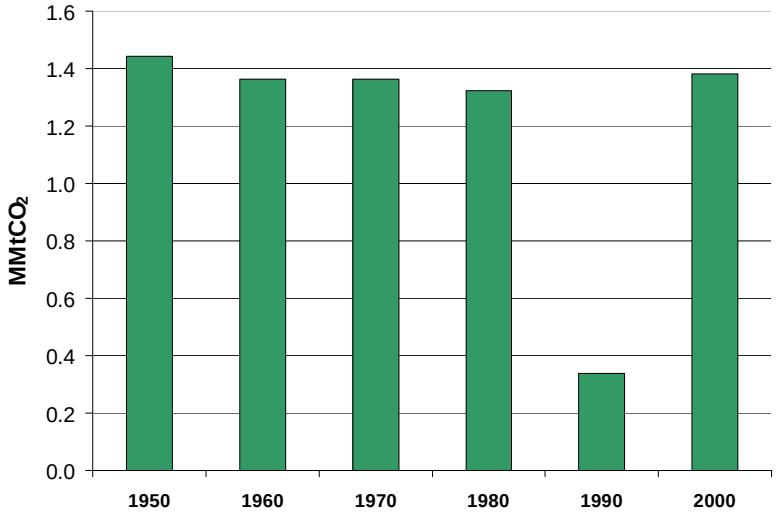
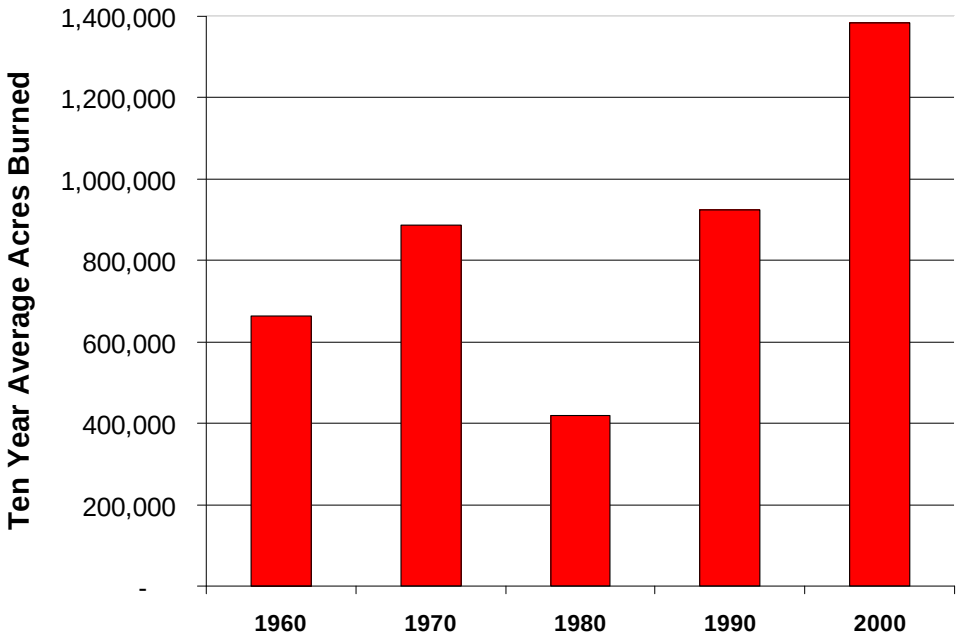


Figure G2b. Ten-Year Average Forest CO_2 Flux in Coastal Maritime Forests



Note: Positive values in these graphs represent annual net sequestration. Based on data from M. Balshi, UAF, unpublished manuscript.

Figure G3. Ten Year Averages of Statewide Wildfire Acres



Non-CO_2 Emissions from Wildfires

The UAF modeling of carbon flux described above included total carbon emissions, which would include CO_2, carbon monoxide, and methane (CH_4). In order to provide an estimate of CO_2e emissions for CH_4 and a more comprehensive understanding of GHG sources/sinks from the forestry sector, CCS developed rough estimates of state-wide emissions for methane (in CO_2 equivalents) and nitrous oxide (N_2O, in CO_2 equivalents) from wildfires and prescribed burns.[113] A separate estimate was also made for "managed" (coastal maritime) forests.

CCS used 2002 emissions data developed by the Western Regional Air Partnership (WRAP) to estimate CO_2e emissions for wildfires and prescribed burns.[114] The CO_2e from CH_4 emissions from this study were added to an estimate of CO_2e for N_2O to estimate a total CO_2e for fires. The nitrous oxide estimate was made assuming that N_2O was 1% of the emissions of nitrogen oxides (NO_x) from the WRAP study. The 1% estimate is a common rule of thumb for the N_2O content of NO_x from combustion sources.

[113] As with the CO_2 flux estimates for non-managed forests, the non-CO_2 emissions associated with fires on non-managed lands could also be considered non-anthropogenic (since wildfires are a natural occurrence). For the purposes of this study and for comparison to other state inventories prepared by CCS, these emissions are being provided at the state level as well as in "managed" forests.

[114] *2002 Fire Emission Inventory for the WRAP Region Phase I – Essential Documentation*, prepared by Air Sciences, Inc., June 2004.

The results for 2002 are that fires contributed 10.0 $MMtCO_2e$ of CH_4 and NO_x from about 1.95 million acres burned (2002 was a fairly high wildfire activity year in Alaska and the western US). About 95% of the CO_2e was contributed by CH_4. For the purposes of comparison, another 2002 estimate was made using emission factors from a 2001 global biomass burning study[115] and the total tons of biomass burned from the 2002 WRAP fires emissions inventory. This estimate is about 11.8 $MMtCO_2e$ showing good agreement with the estimate above; however, there were about equal contributions from methane and nitrous oxide on a CO_2e basis.

In order to estimate non-CO_2 GHG emissions for other years, CCS used wildfire acreage estimates for Alaska compiled in a recent report by UAF researchers.[116] For years other than 2002, the emission estimate was made by multiplying the 2002 estimate described above (10 $MMtCO_2e$ by a ratio of the acres burned in each year to those burned in 2002. The fire acreages and emission estimates for 1985-2002 are presented in Table G1 below. For comparison to the CO_2 flux estimates, ten year averages are 4.7 $MMtCO_2e$/yr in 1990 and 4.9 $MMtCO_2e$/yr in 2000.[117]

UAF provided wildfire acreage estimates for managed forests in each year. As was done to estimate the statewide emissions, the ratio of these acreages to the acreage for 2002 was used to estimate emissions of the non-CO_2 gases. There was very limited wildfire activity in the coastal maritime forests: about 500 acres in 1996; and about 1,500 acres in 2001.

Table G2 provides a summary of the CO_2 flux estimates for Alaska's forests. The table provides both a state-wide estimate as well as an estimate for managed forests in the state (coastal maritime forests). Estimates of managed forestlands are developed and used within this report of state-wide emissions to maintain consistency with IPCC guidelines for national GHG reporting. Additional explanatory notes are included at the end of this appendix. Post-2000 flux estimates are assumed to remain constant at the 2000 levels.

CH_4 Emissions from Alaskan Ecosystems

Alaska's ecosystems are expected to experience earlier and more drastic changes from global warming compared with lower latitude ecosystems.[118] The projected changes are consistent with changes that have been observed in recent decades, which include increases in mean annual air temperatures, thawing of permafrost, and longer growing seasons. Changes in climate, plant and soil conditions will have implications for CH_4 dynamics and carbon storage in Alaska's soils.

[115] M. O. Andreae and P. Merlet, "Emission of trace gases and aerosols from biomass burning", *Global Biogeochemical Cycles*, Vol. 15, No. 4, pp. 955-966, December 2001.

[116] S.K. Todd and H.A. Jewkes, *Wildland Fire in Alaska: A History of Organized Fire Suppression and Management in the Last Frontier*, Agricultural and Forestry Experiment Station Research Bulletin #114, University of Alaska, Fairbanks, March 2006. These rough estimates assume similar fuel loading/acre as used to develop the WRAP's 2002 fire estimates.

[117] The ten year average stated for 2000 is based on data from 1995-2002. If data through 2004 were available, the estimated emissions would be larger due to high fire activity through 2004.

[118] Zhuang, Q., J. M. Melillo, A.D. McGuire, D.W. Kicklighter, R.G. Prinn, P.A. Steudler, B.S. Felzer, and S. Hu. 2007. "Net land-atmosphere exchanges of CH_4 and CO_2 in Alaska: Implications for the region's greenhouse gas budget", *Ecological Applications*, in press.

Table G1. Statewide Non-CO_2 GHG Emissions Estimates from Wildfires

Year	Acreage	Non-CO_2 Emissions ($MMtCO_2e$)	Year	Acreage	Non-CO_2 Emissions ($MMtCO_2e$)
1985	407,300	2.1	1994	265,722	1.4
1986	477,455	2.4	1995	43,946	0.2
1987	169,145	0.9	1996	599,267	3.1
1988	2,134,539	11	1997	2,026,899	10
1989	64,810	0.3	1998	120,752	0.6
1990	3,189,078	16	1999	1,005,427	5.2
1991	1,667,950	8.6	2000	756,296	3.9
1992	150,006	0.8	2001	216,039	1.1
1993	712,869	3.7	2002	1,950,000[a]	10[a]

[a] Acreage and emissions estimates based on the WRAP's 2002 Fire Inventory.

Table G2. Forestry CO_2e Flux Estimates for Alaska

Source	CO_2e Flux ($MMtCO_2e$)[a]					
	1990	2000	2005	2010	2020	
State-Level Forest Flux						
CO_2 Flux	4.6	12	12	12	12	12
Non-CO_2 Gases from Fire	4.5	4.9	4.9	4.9	4.9	4.9
CH_4 Flux[b]	16	21	24	26	31	36
Total State-Level	**25**	**38**	**41**	**43**	**48**	**53**
Flux for Managed Forests[c]						
CO_2 Flux	-0.3	-1.4	-1.4	-1.4	-1.4	-1.4
Non-CO_2 Gases from Fire	0.0	<0.01	<0.01	<0.01	<0.01	<0.01
CH_4 Flux	n/a	n/a	n/a	n/a	n/a	n/a
Total – Managed Forests	**-0.3**	**-1.4**	**-1.4**	**-1.4**	**-1.4**	**-1.4**

Positive values represent net CO_2e emissions. Non-CO_2 gases are methane and nitrous oxide.
[a] Values reported are ten year averages of annual data surrounding the year reported (e.g., 1990 average is the average of data for 1985-1994). For 2000, data only available through 2002. After 2000, flux estimates are assumed to remain constant.
[b] UAF estimate for the 1980-1996 period used for 1990. UAF growth rate of 0.5 $MMtCO_2e$/yr used for forecast years. See Section on CH_4 emissions from Alaskan ecosystems.
[c] Managed forests are the coastal maritime forests of the state. CH_4 flux estimates were not available for managed forests.

Further, according to UAF researchers, one-third of the global soil carbon stocks are located in the Arctic. The fate of this stored soil carbon under altered climate is a major question, since microbes can respond quickly to temperature changes in high latitude ecosystems. Soil microbial activity includes organic matter decomposition under aerobic conditions that releases CO_2 to the atmosphere. Under anaerobic conditions, warming and changes in hydrology could trigger rapid CH_4 emissions in response to the early spring thawing in sub-arctic mire ecosystems. Methane

dynamics are also influenced by the increase in the depth to which permafrost thaws each summer and any changes in the water table of northern peatlands that may result from changes in the water cycle. While CH_4 flux is considered to be non-anthropogenic, estimates are provided in this appendix for information purposes, given the influence of climate change.

UAF has conducted studies using its TEM model of CH_4 flux from Taiga (interior forests) and Tundra (treeless) ecosystems in Alaska. These ecosystems are estimated to be net sources of CH_4. Net emissions of 3.1 $MMtCH_4$/yr (65 $MMtCO_2e$/yr) estimated for the period of 1980-1996 are expected to almost double to 5.7 $MMtCH_4$/yr (120 $MMtCO_2e$/yr) by the 2080-2099 period. The growth rate in emissions is estimated at 0.026 $MMtCH_4$/yr (0.5 $MMtCO_2e$/yr). Of the 3.1 $MMtCH_4$/yr emitted in the 1980-1996 period, 0.76 $MMtCH_4$/yr is emitted in the Taiga ecosystem (16 $MMtCO_2e$/yr). These estimates were incorporated into the statewide estimates presented in Table G2. Note that these emissions do not include the previously-described CH_4 emissions that occur as a result of fire. No data were available for methane flux from coastal forest ecosystems.

Key Uncertainties

Both the estimates of forest CO_2e flux and ecosystem CH_4 flux presented here should be viewed as preliminary estimates based on process-based modeling of Alaska's ecosystems. For CH_4 flux, UAF comparisons against site-specific measurements suggest that the uncertainty around the flux estimate is probably plus or minus 50% overall. As described above, from year to year, CO_2 flux in forested lands varies dramatically depending on the level of wildfire activity. Years with high wildfire activity result in large net emissions of CO_2 to the atmosphere, while, in years with low activity, a significant level of CO_2 sequestration occurs. To provide a better sense of changes that are occurring in net carbon flux over time as well as a data set for comparison to other states, CCS has provided results in ten year averages.

The issue of what constitutes managed forests in Alaska may need further consideration and refinement (see additional notes on this issue from IPCC guidance below). Although fire suppression has occurred throughout state forests in previous decades, it is questionable whether the level of suppression was significant enough to designate much of the State's forests to be "managed". For the purposes of this initial assessment, CCS assumed that managed forests are those in the coastal maritime forests of Alaska (primarily those in the Chugach and Tongass National Forests). These coastal forests have much different net CO_2 flux from Alaska's interior forests (due to both sequestration potential and fire occurrence). It is possible that some of the interior forests have received sufficient intervention to be considered managed forests (e.g., those surrounding communities, productive forests).

CCS estimates that the estimates that uncertainty in the non-CO_2 emissions from wildfires is +/- a factor of two. This is based on comparisons with estimates in a recent paper from French et al on the uncertainty in GHG emissions from boreal forests.[119] The estimates provided here for non-CO_2 data made by extrapolating the WRAP's 2002 fire estimates are higher than those reported in this study by over a factor of two. One primary difference is that the estimates

[119] French, N.H.F., P. Goovaerts, E.S. Kasichke, "Uncertainty in estimating carbon emissions from boreal forest fires", *Journal of Geophysical Research*, vol. 19, D14S08, 2004.

reported here include N_2O, while the French et al paper included carbon-containing compounds only. There is a lot of uncertainty specifically on the issue of N_2O emissions from wildfires; however it could contribute substantially to the total CO_2e emissions for fires. The other main issues are the emission factors used in either the WRAP or French et al study for methane, as well as fuel loading factors, handling of emissions from different phases of wildfires (especially smoldering), and possibly other factors. A more in-depth analysis of the differences in these studies was beyond the scope of this initial assessment.

Forecasting of forest carbon flux is particularly challenging. UAF is currently engaged in developing forecasts of carbon flux, and these data should be reviewed for incorporation when available. Although the statewide trend appears to be moving in the direction of increased CO_2e emissions, the sequestration rates in the managed forests have remained fairly constant over time. For the purposes of this assessment, CCS assumes that the flux rates will stay constant at the 2000 levels.

A considerable uncertainty in both the previous and projected GHG estimates is the exclusion of CH_4 and CO_2 from melting permafrost. Sufficient information was not identified to develop estimates for these areas. In addition, just like with the boreal forest, it is not clear whether these emissions should be treated as coming from anthropogenic or natural sources.

Additional Notes: IPCC Guidelines for Agriculture, Forestry, and Other Land Uses (AFOLU)
The AFOLU Sector has some unique characteristics with respect to developing inventory methods. There are many processes leading to emissions and removals of greenhouse gases, which can be widely-dispersed in space and highly variable in time. The factors governing emissions and removals can be both natural and anthropogenic (direct and indirect) and it can be difficult to clearly distinguish between causal factors. While recognizing this complexity, inventory methods need to be practical and operational. The 2006 IPCC Guidelines are designed to assist in estimating and reporting national inventories of anthropogenic greenhouse gas emissions and removals. For the AFOLU Sector, anthropogenic greenhouse gas emissions and removals by sinks are defined as all those occurring on 'managed land'. Managed land is land where human interventions and practices have been applied to perform production, ecological or social functions. All land definitions and classifications should be specified at the national level, described in a transparent manner, and be applied consistently over time. Emissions/removals of greenhouse gases do not need to be reported for unmanaged land. However, it is good practice for countries to quantify, and track over time, the area of unmanaged land so that consistency in area accounting is maintained as land-use change occurs.

The use of managed land as a proxy for anthropogenic effects is in use in the present IPCC guidelines. The key rationale for this approach is that the preponderance of anthropogenic effects occurs on managed lands. By definition, all direct human-induced effects on greenhouse gas emissions and removals occur on managed lands only. While it is recognized that no area of the Earth's surface is entirely free of human influence (e.g., CO_2 fertilization), many indirect human influences on greenhouse gases (e.g., increased N deposition, accidental fire) will be manifested predominately on managed lands, where human activities are concentrated. Finally, while local and short-term variability in emissions and removals due to natural causes can be substantial (e.g., emissions from fire), the natural 'background' of greenhouse gas emissions and removals by

sinks tends to average out over time and space. This leaves the greenhouse gas emissions and removals from managed lands as the dominant result of human activity.

Specific Guidance for Forests: Countries should consistently apply national definitions of managed forests over time. National definitions should cover all forests subject to human intervention, including the full range of management practices from protecting forests, raising plantations, promoting natural regeneration, commercial timber production, non-commercial fuel wood extraction, and abandonment of managed land.

Appendix H. Inventory and Forecast for Black Carbon

This appendix summarizes the methods, data sources, and results of the development of an inventory and forecast for black carbon (BC) emissions in Alaska. Black carbon is an aerosol (particulate matter or PM) species with positive climate forcing potential but currently without a global warming potential defined by the IPCC (see Appendix I for more information on BC and other aerosol species). BC is synonymous with elemental carbon (EC), which is a term common to regional haze analysis. An inventory for 2002 was developed based on inventory data from the Western Regional Air Partnership (WRAP) regional planning organization and other sources.[120] This appendix describes these data and methods for estimating mass emissions of BC and then transforming the mass emission estimates into CO_2 equivalents (CO_2e) in order to present the emissions within a GHG context.

In addition to the PM inventory data from WRAP, PM speciation data from EPA's SPECIATE database were also used: these data include PM fractions of EC (also known as BC) and primary organic aerosols (also known as organic material, or OM). These data come from the US Environmental Protection Agency's latest release of its SPECIATE database (Version 4.0).[121] As will be further described below, both BC and OM emission estimates are needed to assess the CO_2e of BC emissions. While BC and OM emissions data are available from the WRAP regional haze inventories, CCS favored the newer speciation data available from EPA for the purposes of estimating BC and OM for most source sectors (BC and OM data from the WRAP were used only for the nonroad engines sector). In particular, better speciation data are now available from EPA for important BC emissions sources (including most fossil fuel combustion sources).

After assembling the BC and OM emission estimates, the mass emission rates were transformed into their CO_2e estimates using information from recent global climate modeling. This transformation is described in later sections below.

Development of BC and OM Mass Emission Estimates

The BC and OM mass emission estimates were derived by multiplying the emissions estimates for particulate matter with an aerodynamic diameter of less than 2.5 micrometers ($PM_{2.5}$) by the appropriate aerosol fraction for BC and OM. The aerosol fractions were taken from Pechan's ongoing work to update EPA's SPECIATE database as approved by EPA's SPECIATE Workgroup members.

After estimating both BC and OM emissions for each source category, we used the BC estimate as described below to estimate the CO_2e emissions. Also, as described further below, the OM emission estimate was used to determine whether the source was likely to have positive climate forcing potential. The mass emission results for 2002 are shown in Table H1.

[120] Tom Moore, Western Regional Air Partnership, data files provided to Steve Roe, CCS, December 2006; Corbett, J., *Estimation, Validation, and Forecasts of Regional Commercial Marine Vessel Emissions, Tasks 1 and 2: Baseline Inventory and Ports Comparison, Final Report*, May 3, 2006.
[121] US EPA, Version 4.0 of the SPECIATE database and report, released January 2007: http://www.epa.gov/ttn/chief/software/speciate/index.html#related.

Development of CO_{2e} for BC+OM Emissions

We used similar methods to those applied previously in Maine and Connecticut for converting BC mass emissions to CO_2e.[122] These methods are based on the modeling of Jacobson (2002)[123] and his updates to this work (Jacobson, 2005a).[124] Jacobson (2005a) estimated a range of 90:1 to 190:1 for the climate response effects of BC+OM emissions as compared to CO_2 carbon emissions (depending on either a 30-year or 95-year atmospheric lifetime for CO_2). It is important to note that the BC+OM emissions used by Jacobson were based on a 2:1 ratio of OM:BC (his work in these papers focused on fossil fuel BC+OM; primarily diesel combustion, which has an OM:BC ratio of 2:1 or less).

For Maine and Connecticut, ENE (2004) applied climate response factors from the earlier Jacobson work (220 and 500) to the estimated BC mass to estimate the range of CO_2e associated with BC emissions. Note that the analysis in the northeast was limited to BC emissions from onroad diesel exhaust. An important oversight from this work is that the climate response factors developed by Jacobson (2002, 2005a) are on the basis of CO_2 carbon (not CO_2). Therefore, in order to express the BC emissions as CO_2e, the climate response factors should have been adjusted upward by a factor of 3.67 to account for the molecular weight of CO_2 to carbon (44/12).

For this inventory, we started with the 90 and 190 climate response factors adjusted to CO_2e factors of 330 and 697 to obtain a low and high estimate of CO_2e for each sector. An example calculation of the CO_2e emissions for 10 tons of PM less than 2.5 microns ($PM_{2.5}$) from onroad diesel exhaust follows:

BC mass = (10 short tons $PM_{2.5}$) x (0.613 ton EC/ton $PM_{2.5}$) = 6.13 short tons BC

Low estimate CO_2e = (6.13 tons BC) (330 tons CO_2e/ton BC+OM) (3 tons BC+OM/ton BC) (0.907 metric ton/ton) = 5,504 metric tons CO_2e

High estimate CO_2e = (6.13 tons BC) (697 tons CO_2e/ton BC+OM) (3 tons BC+OM/ton BC) (0.907 metric ton/ton) = 11,626 metric tons CO_2e

NOTE: The factor 3 tons BC+OM/ton BC comes directly from the global modeling inputs used by Jacobson (2002, 2005a; i.e., 2 tons of OM/ton of BC).

For source categories that had an OM:BC mass emissions ratio >4.0, we zeroed out these emission estimates from the CO_2e estimates. The reason for this is that the net heating effects of

[122] ENE, 2004. Memorandum: "Diesel Black Carbon Calculations – Reductions and Baseline" from Michael Stoddard, Environment Northeast, prepared for the Connecticut Stakeholder Dialog, Transportation Work Group, October 23, 2003.
[123] Jacobson, 2002. Jacobson, M.Z., "Control of fossil-fuel particulate black carbon and organic matter, possibly the most effective method of slowing global warming", *Journal of Geophysical Physical Research*, volume 107, No. D19, 4410, 2002.
[124] Jacobson, 2005a. Jacobson, M.Z., "Updates to 'Control of fossil-fuel particulate black carbon and organic matter, possibly the most effective method of slowing global warming", *Journal of Geophysical Research Atmospheres*, February 15, 2005.

OM are not currently well understood (overall OM is thought to have a negative climate forcing effect or a net cooling effect). Therefore, for source categories where the PM is dominated by OM (e.g., biomass burning), the net climate response associated with these emissions is highly uncertain and could potentially produce a net negative climate forcing potential. Further, OM:BC ratios of 4 or more are well beyond the 2:1 ratio used by Jacobson in his work.

Results and Discussion

We estimate that BC mass emissions in Alaska total about 3.0 $MMtCO_2e$ in 2002. This is the mid-point of the estimated range of emissions. The estimated range is 1.9 – 4.0 $MMtCO_2e$ (see Table H1). The primary contributing sectors in 2002 were commercial marine vessels (37%)[125], aircraft (14%), nonroad diesel (12%), onroad diesel (8%), residential/commercial/industrial (RCI) coal combustion (6%), electricity generating unit (EGU) oil combustion (6%), nonroad gasoline engines (5%), RCI "other" combustion (mainly large diesel engines; 4%), and EGU coal combustion (4%).

The nonroad diesel sector includes exhaust emissions from construction/mining, industrial and agricultural engines, as well as recreational equipment. Construction and mining engines contributed about 72% of the diesel nonroad total, while the rest of the emissions were spread across remaining engine categories. For nonroad gasoline engines, 64% of the emissions were contributed by recreational equipment, and the remaining emissions were spread across the remaining engine categories.

Wildfires and miscellaneous sources such as fugitive dust from paved and unpaved roads contributed a significant amount of PM and subsequent BC and OM mass emissions (see H1); however the OM:BC ratio is >4 for these sources, so the BC emissions were not converted to CO_2e.

CCS also performed an assessment of the primary BC contributing sectors from the 2018 WRAP forecast. A drop in the future BC emissions for the onroad and nonoad diesel sectors is expected due to new engine and fuels standards that will reduce particulate matter emissions. For the nonroad diesel sector the estimated 0.3 $MMtCO_2e$ in 2002 drops to 0.09 $MMtCO_2e$ in 2018. For the onroad diesel sector, 0.2 $MMtCO_2e$ was estimated for 2002 dropping to 0.03 $MMtCO_2e$ in 2018 (Note: as with the other estimates described above, these represent the mid-point in the estimated range of emissions). No significant reductions are expected in the other emission sectors. The development of emission estimates for the remaining source sectors was beyond the scope of this analysis.

While the state of science in aerosol climate forcing is still developing, there is a good body of evidence supporting the net warming impacts of BC. Aerosols have a *direct* radiative forcing because they scatter and absorb solar and infrared radiation in the atmosphere. Aerosols also

[125] Particulate matter emissions, from the Corbett et al (2006) study referenced in the footnote above, were used as the starting point for estimating CMV emissions. These include in-port as well as underway emissions within 200 miles from shore (the Exclusive Economic Zone). The BC and OM fractions from the same speciation profiles used in the WRAP inventory (also referenced above) were applied to estimate BC and OM mass emissions, which were then transformed into their CO2 equivalents.

alter the formation and precipitation efficiency of liquid water, ice and mixed-phase clouds, thereby causing an *indirect* radiative forcing associated with these changes in cloud properties (IPCC, 2001).[126] There are also a number of other indirect radiative effects that have been modeled (see, for example, Jacobson, 2002, as noted in the footnote of the previous page).

The quantification of aerosol radiative forcing is more complex than the quantification of radiative forcing by GHGs because of the direct and indirect radiative forcing effects, and the fact that aerosol mass and particle number concentrations are highly variable in space and time. This variability is largely due to the much shorter atmospheric lifetime of aerosols compared with the important GHGs (i.e., CO_2). Spatially and temporally resolved information on the atmospheric concentration and radiative properties of aerosols is needed to estimate radiative forcing.

The quantification of indirect radiative forcing by aerosols is especially difficult. In addition to the variability in aerosol concentrations, some complicated aerosol influences on cloud processes must be accurately modeled. For example, the warm (liquid water) cloud indirect forcing may be divided into two components. The first indirect forcing is associated with the change in droplet concentration caused by increases in aerosol cloud condensation nuclei. The second indirect forcing is associated with the change in precipitation efficiency that results from a change in droplet number concentration. Quantification of the latter forcing necessitates understanding of a change in cloud liquid-water content. In addition to warm clouds, ice clouds may also be affected by aerosols.

To put the radiative forcing potential of BC in context with CO_2, the IPCC estimated the radiative forcing for a doubling of the earth's CO_2 concentration to be 3.7 watts per square meter (W/m^2). For BC, various estimates of current radiative forcing have ranged from 0.16 to 0.42 W/m^2 (IPCC, 2001). These BC estimates are for direct radiative effects only. There is a higher level of uncertainty associated with the direct radiative forcing estimates of BC compared to those of CO_2 and other GHGs. There are even higher uncertainties associated with the assessment of the indirect radiative forcing of aerosols.

[126] IPCC, 2001. Climate Change 2001: The Scientific Basis, Intergovernmental Panel on Climate Change, 2001.

Table H1. 2002 BC Emission Estimates

Sector	Subsector	Mass Emissions			CO_2 Equivalents		Contribution to CO_2e (%)
		BC	OM	BC + OM	Low	High	
		Metric Tons			Metric Tons		
Electric Generating Units (EGUs)	Coal	79	113	191	78,045	164,841	4.1
	Oil	109	37	146	107,709	227,494	5.6
	Gas	0	168	168	0	0	0.0
	Other[a]	30	10	40	29,972	63,304	1.6
Non-EGU Fuel Combustion (Residential, Commercial, and Industrial)							
	Coal	120	172	292	118,955	251,247	6.2
	Oil	14	8	22	14,085	29,750	0.7
	Gas	0	1,501	1,501	0	0	0.0
	Other[a]	318	1,194	1,512	81,499	172,136	4.3
Onroad Gasoline (Exhaust, Brake Wear, & Tire Wear)		17	65	81	7,048	14,886	0.4
Onroad Diesel (Exhaust, Brake Wear, & Tire Wear)		161	67	228	143,337	302,745	7.5
Aircraft		272	354	627	269,392	568,988	14.1
Railroad[b]		27	9	35	26,288	55,523	1.4
Commercial Marine Vessels		721	234	955	713,790	1,507,611	37.3
Other Energy Use	Nonroad Gas	101	284	385	99,983	211,176	5.2
	Nonroad Diesel	222	56	279	220,187	465,061	11.5
	Other Combustion[c]	0	4	4	0	0	0.0
Industrial Processes		1	42	43	0	0	0.0
Agriculture[d]		2	205	207	0	0	0.0
Waste Management	Landfills	0	0	0			0.0
	Incineration	1	1	2	1,071	2,262	0.1
	Open Burning	35	455	490	0	0	0.0
	Other	0	0	0			0.0
Wildfires/Prescribed Burns		49,185	494,471	543,655	0	0	0.0
Miscellaneous[e]		18	294	312	0	0	0.0
Total		**51,434**	**499,742**	**551,176**	**1,911,360**	**4,037,023**	**100**

[a] Primarily large stationary diesel engines/turbines.

[b] Railroad includes Locomotives and Railroad Equipment Emissions.

[c] Other Combustion includes Motor Vehicle Fire, Structure Fire, and Aircraft/Rocket Engine Fire & Testing Emissions.

[d] Agriculture includes Agricultural Burning, Agriculture/Forestry and Agriculture, Food, & Kindred Spirits Emissions.

[e] Miscellaneous includes Paved/Unpaved Roads and Catastrophic/Accidental Release Emissions.

Appendix I. Greenhouse Gases and Global Warming Potential Values: *Excerpts from the Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2000*

Original Reference: Material for this Appendix is taken from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2000*, U.S. Environmental Protection Agency, Office of Atmospheric Programs, EPA 430-R-02-003, April 2002 (www.epa.gov/globalwarming/publications/emissions). Michael Gillenwater directed the preparation of this appendix.

Introduction

The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and removals for the years 1990 through 2000. The estimates are presented on both a full molecular mass basis and on a Global Warming Potential (GWP) weighted basis in order to show the relative contribution of each gas to global average radiative forcing.

The Intergovernmental Panel on Climate Change (IPCC) has recently updated the specific global warming potentials for most greenhouse gases in their Third Assessment Report (TAR, IPCC 2001). Although the GWPs have been updated, estimates of emissions presented in the U.S. *Inventory* continue to use the GWPs from the Second Assessment Report (SAR). The guidelines under which the *Inventory* is developed, the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) and the United Nations Framework Convention on Climate Change (UNFCCC) reporting guidelines for national inventories[127] were developed prior to the publication of the TAR. Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. This excerpt of the U.S. *Inventory* addresses in detail the differences between emission estimates using these two sets of GWPs. Overall, these revisions to GWP values do not have a significant effect on U.S. emission trends.

Additional discussion on emission trends for the United States can be found in the complete Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000.

What is Climate Change?

Climate change refers to long-term fluctuations in temperature, precipitation, wind, and other elements of the Earth's climate system. Natural processes such as solar-irradiance variations, variations in the Earth's orbital parameters, and volcanic activity can produce variations in climate. The climate system can also be influenced by changes in the concentration of various gases in the atmosphere, which affect the Earth's absorption of radiation.

The Earth naturally absorbs and reflects incoming solar radiation and emits longer wavelength terrestrial (thermal) radiation back into space. On average, the absorbed solar radiation is balanced by the outgoing terrestrial radiation emitted to space. A portion of this terrestrial radiation, though, is itself absorbed by gases in the atmosphere. The energy from this absorbed terrestrial radiation warms the Earth's surface and atmosphere, creating what is known as the "natural greenhouse effect." Without the natural heat-trapping properties of these atmospheric gases, the average surface temperature of the Earth would be about 33°C lower (IPCC 2001).

Under the UNFCCC, the definition of climate change is "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in

[127] See FCCC/CP/1999/7 at <www.unfccc.de>.

addition to natural climate variability observed over comparable time periods." Given that definition, in its Second Assessment Report of the science of climate change, the IPCC concluded that:

> *Human activities are changing the atmospheric concentrations and distributions of greenhouse gases and aerosols. These changes can produce a radiative forcing by changing either the reflection or absorption of solar radiation, or the emission and absorption of terrestrial radiation (IPCC 1996).*

Building on that conclusion, the more recent IPCC Third Assessment Report asserts that "[c]oncentrations of atmospheric greenhouse gases and their radiative forcing have continued to increase as a result of human activities" (IPCC 2001).

The IPCC went on to report that the global average surface temperature of the Earth has increased by between 0.6 ± 0.2°C over the 20th century (IPCC 2001). This value is about 0.15°C larger than that estimated by the Second Assessment Report, which reported for the period up to 1994, "owing to the relatively high temperatures of the additional years (1995 to 2000) and improved methods of processing the data" (IPCC 2001).

While the Second Assessment Report concluded, "the balance of evidence suggests that there is a discernible human influence on global climate," the Third Assessment Report states the influence of human activities on climate in even starker terms. It concludes that, "[I]n light of new evidence and taking into account the remaining uncertainties, most of the observed warming over the last 50 years is likely to have been due to the increase in greenhouse gas concentrations" (IPCC 2001).

Greenhouse Gases

Although the Earth's atmosphere consists mainly of oxygen and nitrogen, neither plays a significant role in enhancing the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide, and other trace gases in the atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 1996). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans. A gauge of these changes is called radiative forcing, which is a simple measure of changes in the energy available to the Earth-atmosphere system (IPCC 1996). Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth).

Climate change can be driven by changes in the atmospheric concentrations of a number of radiatively active gases and aerosols. We have clear evidence that human activities have affected concentrations, distributions and life cycles of these gases (IPCC 1996).

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). Because CFCs, HCFCs, and halons are stratospheric ozone depleting substances, they are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty; consequently these gases are not included in national greenhouse gas inventories. Some other fluorine containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas inventories.

There are also several gases that, although they do not have a commonly agreed upon direct radiative forcing effect, do influence the global radiation budget. These tropospheric gases—referred to as ambient air pollutants—include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and

tropospheric (ground level) ozone (O_3). Tropospheric ozone is formed by two precursor pollutants, volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of ultraviolet light (sunlight). Aerosols—extremely small particles or liquid droplets—often composed of sulfur compounds, carbonaceous combustion products, crustal materials and other human induced pollutants—can affect the absorptive characteristics of the atmosphere. However, the level of scientific understanding of aerosols is still very low (IPCC 2001).

Carbon dioxide, methane, and nitrous oxide are continuously emitted to and removed from the atmosphere by natural processes on Earth. Anthropogenic activities, however, can cause additional quantities of these and other greenhouse gases to be emitted or sequestered, thereby changing their global average atmospheric concentrations. Natural activities such as respiration by plants or animals and seasonal cycles of plant growth and decay are examples of processes that only cycle carbon or nitrogen between the atmosphere and organic biomass. Such processes—except when directly or indirectly perturbed out of equilibrium by anthropogenic activities—generally do not alter average atmospheric greenhouse gas concentrations over decadal timeframes. Climatic changes resulting from anthropogenic activities, however, could have positive or negative feedback effects on these natural systems. Atmospheric concentrations of these gases, along with their rates of growth and atmospheric lifetimes, are presented in Table I1.

Table I1. Global Atmospheric Concentration (ppm Unless Otherwise Specified), Rate of Concentration Change (ppb/year) and Atmospheric Lifetime (Years) of Selected Greenhouse Gases

Atmospheric Variable	CO_2	CH_4	N_2O	SF_6[a]	CF_4[a]
Pre-industrial atmospheric concentration	278	0.700	0.270	0	40
Atmospheric concentration (1998)	365	1.745	0.314	4.2	80
Rate of concentration change[b]	1.5[c]	0.007[c]	0.0008	0.24	1.0
Atmospheric Lifetime	50-200[d]	12[e]	114[e]	3,200	>50,000

Source: IPCC (2001)
[a] Concentrations in parts per trillion (ppt) and rate of concentration change in ppt/year.
[b] Rate is calculated over the period 1990 to 1999.
[c] Rate has fluctuated between 0.9 and 2.8 ppm per year for CO_2 and between 0 and 0.013 ppm per year for CH4 over the period 1990 to 1999.
[d] No single lifetime can be defined for CO_2 because of the different rates of uptake by different removal processes.
[e] This lifetime has been defined as an "adjustment time" that takes into account the indirect effect of the gas on its own residence time.

A brief description of each greenhouse gas, its sources, and its role in the atmosphere is given below. The following section then explains the concept of Global Warming Potentials (GWPs), which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H_2O). Overall, the most abundant and dominant greenhouse gas in the atmosphere is water vapor. Water vapor is neither long-lived nor well mixed in the atmosphere, varying spatially from 0 to 2 percent (IPCC 1996). In addition, atmospheric water can exist in several physical states including gaseous, liquid, and solid. Human activities are not believed to directly affect the average global concentration of water vapor; however, the radiative forcing produced by the increased concentrations of other greenhouse gases may indirectly affect the hydrologic cycle. A warmer atmosphere has an increased water holding capacity; yet, increased concentrations of water vapor affects the formation of clouds, which can both absorb and reflect solar and terrestrial radiation. Aircraft contrails, which consist of water vapor and other aircraft emittants, are similar to clouds in their radiative forcing effects (IPCC 1999).

Carbon Dioxide (CO_2). In nature, carbon is cycled between various atmospheric, oceanic, land biotic, marine biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. In the atmosphere, carbon predominantly exists in its oxidized form as CO_2. Atmospheric carbon dioxide is part of this global

carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. Carbon dioxide concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 367 ppmv in 1999, a 31 percent increase (IPCC 2001). The IPCC notes that "[t]his concentration has not been exceeded during the past 420,000 years, and likely not during the past 20 million years. The rate of increase over the past century is unprecedented, at least during the past 20,000 years." The IPCC definitively states that "the present atmospheric CO_2 increase is caused by anthropogenic emissions of CO_2" (IPCC 2001). Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of carbon dioxide.

In its second assessment, the IPCC also stated that "[t]he increased amount of carbon dioxide [in the atmosphere] is leading to climate change and will produce, on average, a global warming of the Earth's surface because of its enhanced greenhouse effect—although the magnitude and significance of the effects are not fully resolved" (IPCC 1996).

Methane (CH_4). Methane is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit CH_4, as does the decomposition of municipal solid wastes. Methane is also emitted during the production and distribution of natural gas and petroleum, and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of methane have increased by about 150 percent since pre-industrial times, although the rate of increase has been declining. The IPCC has estimated that slightly more than half of the current CH_4 flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use and waste disposal (IPCC 2001).

Methane is removed from the atmosphere by reacting with the hydroxyl radical (OH) and is ultimately converted to CO_2. Minor removal processes also include reaction with Cl in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of methane reduce the concentration of OH, a feedback which may increase methane's atmospheric lifetime (IPCC 2001).

Nitrous Oxide (N_2O). Anthropogenic sources of N_2O emissions include agricultural soils, especially the use of synthetic and manure fertilizers; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater treatment and waste combustion; and biomass burning. The atmospheric concentration of nitrous oxide (N_2O) has increased by 16 percent since 1750, from a pre industrial value of about 270 ppb to 314 ppb in 1998, a concentration that has not been exceeded during the last thousand years. Nitrous oxide is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere.

Ozone (O_3). Ozone is present in both the upper stratosphere, where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere, where it is the main component of anthropogenic photochemical "smog." During the last two decades, emissions of anthropogenic chlorine and bromine-containing halocarbons, such as chlorofluorocarbons (CFCs), have depleted stratospheric ozone concentrations. This loss of ozone in the stratosphere has resulted in negative radiative forcing, representing an indirect effect of anthropogenic emissions of chlorine and bromine compounds (IPCC 1996). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover, with detection of such recovery not expected to occur much before 2010 (IPCC 2001).

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the third largest increase in direct radiative forcing since the pre-industrial era, behind CO_2 and CH_4. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds mixing with nitrogen oxides (NO_x) in the presence of sunlight. Ozone, carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_2) and particulate matter are included in the category referred to as "criteria pollutants" in the

United States under the Clean Air Act and its subsequent amendments. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable.

Halocarbons, Perfluorocarbons, and Sulfur Hexafluoride (SF_6). Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine—chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), methyl chloroform, and carbon tetrachloride—and bromine—halons, methyl bromide, and hydrobromofluorocarbons (HBFCs)—result in stratospheric ozone depletion and are therefore controlled under the Montreal Protocol on Substances that Deplete the Ozone Layer. Although CFCs and HCFCs include potent global warming gases, their net radiative forcing effect on the atmosphere is reduced because they cause stratospheric ozone depletion, which is itself an important greenhouse gas in addition to shielding the Earth from harmful levels of ultraviolet radiation. Under the Montreal Protocol, the United States phased out the production and importation of halons by 1994 and of CFCs by 1996. Under the Copenhagen Amendments to the Protocol, a cap was placed on the production and importation of HCFCs by non-Article 5 countries beginning in 1996, and then followed by a complete phase-out by the year 2030. The ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC.

Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. HFCs—primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process—currently have a small aggregate radiative forcing impact; however, it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2001). PFCs and SF_6 are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium casting. Currently, the radiative forcing impact of PFCs and SF_6 is also small; however, they have a significant growth rate, extremely long atmospheric lifetimes, and are strong absorbers of infrared radiation, and therefore have the potential to influence climate far into the future (IPCC 2001).

Carbon Monoxide (CO). Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH_4 and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH_4 and tropospheric ozone. Carbon monoxide is created when carbon-containing fuels are burned incompletely. Through natural processes in the atmosphere, it is eventually oxidized to CO_2. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides (NO_x). The primary climate change effects of nitrogen oxides (i.e., NO and NO_2) are indirect and result from their role in promoting the formation of ozone in the troposphere and, to a lesser degree, lower stratosphere, where it has positive radiative forcing effects. Additionally, NO_x emissions from aircraft are also likely to decrease methane concentrations, thus having a negative radiative forcing effect (IPCC 1999). Nitrogen oxides are created from lightning, soil microbial activity, biomass burning – both natural and anthropogenic fires – fuel combustion, and, in the stratosphere, from the photo-degradation of nitrous oxide (N_2O). Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Nonmethane volatile organic compounds include compounds such as propane, butane, and ethane. These compounds participate, along with NO_x, in the formation of tropospheric ozone and other photochemical oxidants. NMVOCs are emitted primarily from transportation and industrial processes, as well as biomass burning and non-industrial consumption of organic solvents. Concentrations of NMVOCs tend to be both short-lived in the atmosphere and spatially variable.

Aerosols. Aerosols are extremely small particles or liquid droplets found in the atmosphere. They can be produced by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. They affect radiative forcing in both direct and indirect ways: directly by scattering and absorbing solar and thermal infrared radiation; and indirectly by increasing droplet counts that modify the formation, precipitation efficiency, and radiative properties of clouds. Aerosols are removed from the atmosphere relatively rapidly by precipitation. Because aerosols generally have short atmospheric lifetimes, and have concentrations and compositions that vary regionally, spatially, and temporally, their contributions to radiative forcing are difficult to quantify (IPCC 2001).

The indirect radiative forcing from aerosols is typically divided into two effects. The first effect involves decreased droplet size and increased droplet concentration resulting from an increase in airborne aerosols. The second effect involves an increase in the water content and lifetime of clouds due to the effect of reduced droplet size on precipitation efficiency (IPCC 2001). Recent research has placed a greater focus on the second indirect radiative forcing effect of aerosols.

Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulphates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning.

The net effect of aerosols is believed to produce a negative radiative forcing effect (i.e., net cooling effect on the climate), although because they are short-lived in the atmosphere—lasting days to weeks—their concentrations respond rapidly to changes in emissions. Locally, the negative radiative forcing effects of aerosols can offset the positive forcing of greenhouse gases (IPCC 1996). "However, the aerosol effects do not cancel the global-scale effects of the much longer-lived greenhouse gases, and significant climate changes can still result" (IPCC 1996).

The IPCC's Third Assessment Report notes that "the indirect radiative effect of aerosols is now understood to also encompass effects on ice and mixed-phase clouds, but the magnitude of any such indirect effect is not known, although it is likely to be positive" (IPCC 2001). Additionally, current research suggests that another constituent of aerosols, elemental carbon, may have a positive radiative forcing (Jacobson 2001). The primary anthropogenic emission sources of elemental carbon include diesel exhaust, coal combustion, and biomass burning.

Global Warming Potentials

Global Warming Potentials (GWPs) are intended as a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas. It is defined as the cumulative radiative forcing—both direct and indirect effects—integrated over a period of time from the emission of a unit mass of gas relative to some reference gas (IPCC 1996). Carbon dioxide (CO_2) was chosen as this reference gas. Direct effects occur when the gas itself is a greenhouse gas. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The relationship between gigagrams (Gg) of a gas and Tg CO_2 Eq. can be expressed as follows:

$$\text{Tg CO}_2\text{ Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1{,}000\ \text{Gg}}\right)$$

where,

Tg CO_2 Eq. = Teragrams of Carbon Dioxide Equivalents
Gg = Gigagrams (equivalent to a thousand metric tons)
GWP = Global Warming Potential
Tg = Teragrams

GWP values allow policy makers to compare the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of roughly ±35 percent, though some GWPs have larger uncertainty than others, especially those in which lifetimes have not yet been ascertained. In the following decision, the parties to the UNFCCC have agreed to use consistent GWPs from the IPCC Second Assessment Report (SAR), based upon a 100 year time horizon, although other time horizon values are available (see Table I2).

> *In addition to communicating emissions in units of mass, Parties may choose also to use global warming potentials (GWPs) to reflect their inventories and projections in carbon dioxide-equivalent terms, using information provided by the Intergovernmental Panel on Climate Change (IPCC) in its Second Assessment Report. Any use of GWPs should be based on the effects of the greenhouse gases over a 100-year time horizon. In addition, Parties may also use other time horizons. (FCCC/CP/1996/15/Add.1)*

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. he short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, other ambient air pollutants (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and black carbon), however, vary spatially, and consequently it is difficult to quantify their global radiative forcing impacts. GWP values are generally not attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table I2. Global Warming Potentials (GWP) and Atmospheric Lifetimes (Years) Used in the Inventory

Gas	Atmospheric Lifetime	100-year GWP[a]	20-year GWP	500-year GWP
Carbon dioxide (CO_2)	50-200	1	1	1
Methane (CH_4)[b]	12±3	21	56	6.5
Nitrous oxide (N_2O)	120	310	280	170
HFC-23	264	11,700	9,100	9,800
HFC-125	32.6	2,800	4,600	920
HFC-134a	14.6	1,300	3,400	420
HFC-143a	48.3	3,800	5,000	1,400
HFC-152a	1.5	140	460	42
HFC-227ea	36.5	2,900	4,300	950
HFC-236fa	209	6,300	5,100	4,700
HFC-4310mee	17.1	1,300	3,000	400
CF_4	50,000	6,500	4,400	10,000
C_2F_6	10,000	9,200	6,200	14,000
C_4F_{10}	2,600	7,000	4,800	10,100
C_6F_{14}	3,200	7,400	5,000	10,700
SF_6	3,200	23,900	16,300	34,900

Source: IPCC (1996)
[a] GWPs used here are calculated over 100 year time horizon
[b] The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Table I3 presents direct and net (i.e., direct and indirect) GWPs for ozone-depleting substances (ODSs). Ozone-depleting substances directly absorb infrared radiation and contribute to positive radiative forcing; however, their effect as ozone-depleters also leads to a negative radiative forcing because ozone itself is a potent greenhouse gas. There is considerable uncertainty regarding this indirect effect; therefore, a range of net GWPs is provided for ozone depleting substances.

Table I3. Net 100-year Global Warming Potentials for Select Ozone Depleting Substances*

Gas	Direct	Net_{min}	Net_{max}
CFC-11	4,600	(600)	3,600
CFC-12	10,600	7,300	9,900
CFC-113	6,000	2,200	5,200
HCFC-22	1,700	1,400	1,700
HCFC-123	120	20	100
HCFC-124	620	480	590
HCFC-141b	700	(5)	570
HCFC-142b	2,400	1,900	2,300
$CHCl_3$	140	(560)	0
CCl_4	1,800	(3,900)	660
CH_3Br	5	(2,600)	(500)
Halon-1211	1,300	(24,000)	(3,600)
Halon-1301	6,900	(76,000)	(9,300)

Source: IPCC (2001)

* Because these compounds have been shown to deplete stratospheric ozone, they are typically referred to as ozone depleting substances (ODSs). However, they are also potent greenhouse gases. Recognizing the harmful effects of these compounds on the ozone layer, in 1987 many governments signed the *Montreal Protocol on Substances that Deplete the Ozone Layer* to limit the production and importation of a number of CFCs and other halogenated compounds. The United States furthered its commitment to phase-out ODSs by signing and ratifying the Copenhagen Amendments to the *Montreal Protocol* in 1992. Under these amendments, the United States committed to ending the production and importation of halons by 1994, and CFCs by 1996. The IPCC Guidelines and the UNFCCC do not include reporting instructions for estimating emissions of ODSs because their use is being phased-out under the *Montreal Protocol*. The effects of these compounds on radiative forcing are not addressed here.

The IPCC recently published its Third Assessment Report (TAR), providing the most current and comprehensive scientific assessment of climate change (IPCC 2001). Within that report, the GWPs of several gases were revised relative to the IPCC's Second Assessment Report (SAR) (IPCC 1996), and new GWPs have been calculated for an expanded set of gases. Since the SAR, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2 response function (presented in WMO 1999). The GWPs are drawn from WMO (1999) and the SAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated. Because the revised radiative forcing of CO_2 is about 12 percent lower than that in the SAR, the GWPs of the other gases relative to CO_2 tend to be larger, taking into account revisions in lifetimes. However, there were some instances in which other variables, such as the radiative efficiency or the chemical lifetime, were altered that resulted in further increases or decreases in particular GWP values. In addition, the values for radiative forcing and lifetimes have been calculated for a variety of halocarbons, which were not presented in the SAR. The changes are described in the TAR as follows:

New categories of gases include fluorinated organic molecules, many of which are ethers that are proposed as halocarbon substitutes. Some of the GWPs have larger uncertainties than that of others, particularly for those gases where detailed laboratory data on lifetimes are not yet available. The direct GWPs have been calculated relative to CO_2 using an improved calculation of the CO_2 radiative forcing, the SAR response function for a CO_2 pulse, and new values for the radiative forcing and lifetimes for a number of halocarbons.

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Appendix E
Quantification Methods and Assumptions

The Center for Climate Strategies
Helping States and the Nation Tackle Climate Change

www.climatestrategies.us

Quantification Memorandum

Date: October 31, 2008

To: Alaska Climate Change Mitigation Advisory Group (MAG)

From: The Center for Climate Strategies

Subject: Quantification of Climate Mitigation Policy Options

This memo summarizes key elements of the recommended methodology for estimating reductions in GHG emissions and the cost effectiveness in achieving these reductions for those draft policy options amenable to such quantification. The quantification process is intended to support custom design and analysis of draft policy options, and provide both consistency and flexibility. Feedback is encouraged.

Key guidelines include:

- Focus of analysis: **Net GHG reduction potential** in physical units of million metric tons (MMt) of carbon dioxide equivalent (CO_2e) and **net cost per metric ton reduced** in units of dollars per metric ton of carbon dioxide equivalent ($/t$CO_2e$). Where possible, full life cycle analysis is used to evaluate the net energy (and emissions) performance of actions (taking into account all energy inputs and outputs to production). Net analysis of the effects of carbon sequestration is conducted where applicable.
- Cost-effectiveness: Because monetized dollar values of GHG reduction benefits are not available, physical benefits are used instead, measured as dollars per metric ton of carbon dioxide equivalent ($/t$CO_2e$) (i.e., cost or savings per ton) or "cost effectiveness" evaluation. Both positive costs and cost savings ("negative costs") are estimated in the course of the cost effectiveness analysis.
- Geographic inclusion: Measure GHG impacts of activities that occur within the state, regardless of the actual location of emissions reductions. For instance, a major benefit of recycling is the reduction in material extraction and processing (e.g., aluminum production). While a policy option may increase recycling in Alaska, the reduction in emissions may occur where this material is produced. Where significant emissions impacts are likely to

occur outside the state, this will be clearly indicated. These emissions reductions are counted towards the achievement of the state's emission goal, since they result from actions taken by or within the state.

- Direct vs. indirect effects: "Direct effects" are those borne by the entities implementing the policy recommendation. Direct costs are net of any financial benefits or savings to the entity. "Indirect effects" are defined as those borne by entities other than those implementing the policy recommendation. Indirect effects will be quantified on a case-by-case basis depending on magnitude, importance, time and resources available, need, and availability of data. (See additional discussion and examples below.)

- Non-GHG impacts and costs: The recommended quantification process allows for an "apples to apples" comparison among different policy options for reducing GHG emissions. This is important in identifying meaningful and efficient options. However, it is beyond the scope of this quantification to assess broader economic impacts, which could be material, or distributional effects that implementing certain policy options could have on particular businesses, business sectors or regions of Alaska. The quantification of GHG impacts can be supplemented by describing in qualitative terms potential material non-GHG impacts, and where deemed important, these potential non-GHG impacts can be quantified on a case-by-case basis provided the necessary time, resources, and data are available. Follow-on efforts to evaluate broader economic and/or non-GHG impacts could be done before the MAG makes its final recommendations on policy options to the Climate Change Sub-Cabinet, or by the Sub-Cabinet before it determines its final recommendations. Further, the MAG could include in its policy recommendations a description of additional, supplemental assessment of non-GHG impacts it believes necessary before a final decision is reached concerning implementation of particular mitigation policies.

- Discounting and annualizing: Discount a multi-year stream of net costs (or savings) to arrive at the "net present value" of the cost of implementing a policy option. Discount costs to constant 2007 dollars using a 5% annual real discount rate for the project period of 2009 through 2020 (unless otherwise specified for the particular policy option). Capital investments are represented in terms of annualized or amortized costs through 2020. Create a levelized cost per ton by dividing the present value cost or cost savings by the cumulative reduction in tons of GHG emissions.

- Time period of analysis: Count the impacts of actions that occur during the project time period and, using annualized emissions reduction and cost analysis, report emissions reductions and costs for specific target years of 2015 and 2020. Where additional GHG reductions or costs occur beyond the project period as a direct result of actions taken during the project period, show these to the extent practicable for comparison and potential inclusion.

- Aggregation of cumulative impacts of policy options: In addition to "stand alone" results for individual policy options, estimate the cumulative impacts of all policy options combined. This aggregation avoids double-counting of GHG reductions and costs that would occur were emission reductions and costs associated with all of the policy recommendations simply added together. In doing so, interactive effects between policy recommendations are noted and estimated as appropriate using analytical methods where significant overlap or equilibrium effects are likely.

- Policy design specifications and other key assumptions: Explicit goal levels, timing, implementing parties, type of implementation mechanism, and other key assumptions are as determined by the Alaska Mitigation Advisory Group (MAG) and included in the individual policy option descriptions.
- Transparency: Specific policy design choices (as noted above) as well as data sources, methods, key assumptions, and key uncertainties are as approved by the MAG and recorded transparently in the policy options document. Data and comments provided by the MAG reflecting its members' expertise and knowledge ensure the use of best available data sources, methods, and key assumptions to address specific issues in Alaska. Any modifications are made through facilitated decisions by the MAG.

For additional reference, see the economic analysis guidelines developed by the Science Advisory Board of the US EPA available at: http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/Guidelines.html.

Examples of Direct/Indirect Net Costs and Savings

Note: These examples are meant to be illustrative, not exhaustive nor determinative.

Residential, Commercial, and Industrial (RCI) Energy Demand Sectors

Direct Costs and/or Savings

- Net capital costs (or incremental costs relative to standard practice) of improved buildings, appliances, equipment (e.g., cost of higher-efficiency refrigerator versus refrigerator of similar features that meets standards)
- Net operation and maintenance (O&M) costs (relative to standard practice) of improved buildings, appliances, equipment, including avoided/extra labor costs for maintenance (e.g., less changing of compact fluorescent lights (CFL) or light-emitting diodes (LED) in lamps relative to incandescent bulbs)
- Net fuel (gas, electricity, biomass, etc.) costs (typically as avoided costs from a societal perspective)
- Cost/value of net water use/savings
- Cost/value of net materials use/savings (e.g., raw materials savings via recycling, or lower/higher cost of low-global warming potential (GWP) refrigerants)
- Direct improved productivity as a result of industrial measures, measured as change in cost per unit output (e.g., for an energy/GHG-saving improvement that also speeds up a production line or results in higher product yield)

Indirect Costs and/or Savings

- Re-spending effect on economy
- Net value of employment impacts
- Net value of health benefits/impacts
- Value of net environmental benefits/impacts (e.g., value of damage by air pollutants on structures, crops, etc.)
- Net embodied energy of materials used in buildings, appliances, equipment, relative to standard practice
- Improved productivity as a result of an improved working environment, such as improved office productivity through improved lighting (though the inclusion of this as indirect might be argued in some cases)

Energy Supply (ES) Sector

Direct Costs and/or Savings

- Net capital costs (or incremental costs relative to reference case technologies) of renewables or other advanced technologies resulting from policies

- Net O&M costs (relative to reference case technologies) of renewables or other advanced technologies resulting from policies
- Avoided or net fuel savings (gas, coal, biomass, etc.) of renewables or other advanced technologies relative to reference case technologies resulting from policies
- Total system costs (net capital + net O&M + avoided/net fuel savings + net imports/exports + net transmission and distribution (T&D) costs) relative to reference case total system costs

Indirect Costs and/or Savings

- Re-spending effect on economy
- Higher cost of electricity reverberating through economy
- Value of improved energy security
- Net value of employment impacts
- Net value of health benefits/impacts
- Value of net environmental benefits/impacts (e.g., value of damage by air pollutants on structures, crops, etc.)

Agriculture, Forestry, and Waste Management (AFW) Sectors

Direct Costs and/or Savings

- Net capital costs (or incremental costs relative to standard practice) of facilities or equipment (e.g., manure digesters and associated infrastructure, generator; ethanol production facility)
- Net O&M costs (relative to standard practice) of equipment or facilities
- Net fuel (gas, electricity, biomass, etc.) costs or avoided costs
- Cost/value of net water use/savings

Indirect Costs and/or Savings

- Net value of employment impacts
- Net value of human health benefits/impacts
- Net value of ecosystem health benefits/impacts (e.g., wildlife habitat; reduction in wildfire potential; etc.)
- Value of net environmental benefits/impacts (e.g., value of damage by air or water pollutants on structures, crops, etc.)
- Net embodied energy of water use in equipment or facilities relative to standard practice
- Reduced VMT and fuel consumption associated with land use conversions (e.g., as a result of forest/rangeland/cropland protection policies)

Transportation and Land Use (TLU) Sector

Direct Costs and/or Savings

- Incremental cost of more efficient vehicles net of fuel savings
- Incremental cost of implementing "Smart Growth" programs, net of saved infrastructure costs
- Incremental cost of mass transit investment and operating expenses, net of saved infrastructure costs (e.g., roads)
- Incremental cost of alternative fuel, net of any change in maintenance costs

Indirect Costs and/or Savings

- Health benefits of reduced air and water pollution.
- Ecosystem benefits of reduced air and water pollution.
- Value of quality-of-life improvements.
- Value of improved road safety.
- Value of improved energy security
- Net value of employment impacts

Appendix F
Cross-Cutting Issues
Policy Recommendations

Summary List of Alaska Climate Change Mitigation Policy Recommendations

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million 2005$)	Cost-Effective-ness ($/$tCO_2e$)	Level of Support
		2015	2020	2025	Total 2015–2025			
CC-1	Establish an Alaska Greenhouse Gas Emission Reporting Program	*Not Quantified*						Unanimous, but on hold
CC-2	Establish Goals for Statewide GHG Emission Reduction	*Not Quantified*						Majority
CC-3	Identify and Implement State Government Mitigation Actions	*Not Quantified*						Unanimous
CC-4	Integrate Alaska's Climate Change Mitigation Strategy With the Alaska Energy Plan	*Not Quantified*						Unanimous
CC-5	Explore Various Market-Based Systems to Manage GHG Emissions	*Not Quantified*						Unanimous
CC-6	Coordinate Implementation of Alaska's Efforts to Address Climate Change	*Not Quantified*						Super-majority

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

CC-1. Establish an Alaska Greenhouse Gas Emissions Reporting Program

The following policy is not being recommended to the Sub-Cabinet at this time. On March 10, 2009, the U.S. Environmental Protection Agency (EPA) released a draft greenhouse gas (GHG) reporting rule that would require mandatory reporting of GHG emissions from large sources (those emitting at least 25,000 metric tons of carbon dioxide equivalent [tCO_2e]). Based on action at the federal level, the policy will need to be re-examined in light of requirements that may be established for state reporting.

Policy Description

This climate change mitigation policy describes the basic legislative, fiscal, administrative, reporting, and database elements necessary to establish and support an Alaska GHG Reporting Program. The program will be responsible for establishing and administering Alaska's mandatory and voluntary GHG emissions reporting program. It will collect, verify, and analyze GHG emissions data to establish a baseline of anthropogenic (human-caused) GHG emissions for Alaska, and identify the types and magnitude of anthropogenic GHG emission sources in Alaska and their relative contributions. These data will be used to inform state leaders and the public on statewide GHG emission trends, identify opportunities for reducing GHG emissions, and enable the assessment of Alaska's climate change mitigation efforts over time. Pending the approval of the Climate Change Sub-Cabinet, implementation of this policy would also require legislative and executive branch (including departmental) approval. The development of this program would be in conjunction with, but not duplicative of, any federally mandated climate change or GHG reporting legislation or regulations.

Policy Design

Goals:

- Establish a GHG Reporting Program for Alaska that ensures publicly accessible, accurate, verifiable, and transparent reporting of GHG emissions data using well-documented mandatory and voluntary GHG emissions reporting and verification procedures.
- Develop an "energy database" for Alaska that will track commercial, residential, industrial, and transportation energy consumption, GHG emissions, and climate change mitigation actions throughout the state.
- Develop and publish the Alaska GHG Inventory and Forecast (I&F) every 3 years. Use this information to communicate the results of climate change mitigation efforts, and to modify Alaska's climate change mitigation strategy as needed.

To establish an Alaska GHG Reporting Program, the state will have to establish new climate change statutes and regulations, as well as allocate funds for the personnel and infrastructure required to administer the program. The following sections describe some of the legislative, fiscal, administrative, reporting, and database elements that are essential for establishing and administering this program.

Legislative & Fiscal Requirements: The State of Alaska and the Climate Change Sub-Cabinet will have to decide on a legislative pathway and the level of funding necessary for establishing and administering Alaska's GHG Reporting Program. Does the state wish to wait for federal climate change legislation or develop Alaska-specific climate change legislation ahead of any federal initiative? It is anticipated that a national, economy-wide, carbon cap-and-trade or tax program will be promulgated by federal law in the near future. Congress may decide to draft new federal climate change legislation outside of the Clean Air Act (CAA) to allow EPA to promulgate GHG mandatory reporting regulations and a carbon cap-and-trade program (e.g., Climate Security Act of 2008[1]).[2] In the event of new federal climate change legislation, Alaska may need to prepare a climate change bill with a fiscal note, new statutes and regulations, and a fee study. This will be a multi-year (2–5 year) legislative process.

If Alaska decides to proceed with climate change legislation, it could be modeled after California's Global Warming Solutions Act of 2006[3] and Oregon's Climate Integration Act of 2007.[4] The Global Warming Solutions Act authorized the California Air Resources Board (CARB) to establish a mandatory GHG reporting regulation[5] and funding to establish CARB's mandatory GHG reporting program. This legislation also authorized CARB to establish California's 1990 GHG emissions baseline and a publicly approved 2020 GHG emissions cap.[6] Oregon's Climate Change Integration Act,[4] which relates to an emergency, established Oregon's GHG reduction goals in statute (e.g., by 2020 reduce GHG levels to 10% below 1990 levels), and provided funding for establishing Oregon's mandatory GHG reporting rule.[7] The Oregon Department of Environmental Quality's 2008 legislative package requested more than $900,000 for 10 positions to establish a new GHG Reporting Program within its Division of Air Quality.[8] These positions will be dedicated to administering Oregon's GHG reporting rule, developing and implementing a cap-and-trade program, entering and verifying data, and identifying GHG mitigation opportunities.

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[1] U.S. Senate, "Lieberman-Warner Climate Security Act of 2008," S.3036, 110th Congress, 2nd Session, May 21, 2008. Available at: http://thomas.loc.gov/cgi-bin/query/z?c110:S.3036:.

[2] On March 10, 2009, U.S. EPA released a draft GHG emission reporting rule. Available at: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

[3] State of California, "California Global Warming Solutions Act of 2006," Assembly Bill 32. Available at: http://cliamtechange.ca.gov/publications/legislation.html.

[4] State of Oregon, House Bill (HB) 3543, "Climate Change Integration Act of 2007," 74th Oregon Legislative Session, June 2007. Available at: http://www.leg.state.or.us/07orlaws/sess0900.dir/0907.htm.

[5] California Air Resources Board, "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions," in Title 17 of California's Code of Regulations. Available at: http://www.arb.ca.gov/regact/2007/ghg2007/froghg.pdf.

[6] California Air Resources Board, *California 1990 Greenhouse Gas Emission Level and 2020 Emission Limit,* Staff Report, publicly released November 16, 2007. Available at: http://www.arb.ca.gov/cc/inventory/1990level/1990level.htm.

[7] Oregon Department of Environmental Quality, "GHG Reporting Rule," Oregon Administrative Rule 340-215-0010. Available at: http://www.deq.state.or.us/aq/climate/docs/FinalGHGRule.pdf.

[8] Scott Sloane, Alaska Department of Environmental Conservation, personal communication with Margaret Oliphant, Oregon Department of Environmental Quality, August 19, 2008.

Administrative Requirements: The Alaska Department of Environmental Conservation (DEC) Division of Air Quality's Air Permitting Program currently administers CAA Title V and Title I air discharge permits, conducts air pollution emission inventories using its AIRTOOLS database, and reports these data electronically to EPA. One option for Alaska's future GHG Reporting Program would have that program work closely with DEC's Air Permitting Program because of the need to track GHG emissions as well as cap-and-trade allowances for large permitted industries. Therefore, the design of this policy assumes that at least a portion of Alaska's future GHG Reporting Program be hosted by DEC because most of the necessary permitting, database, and reporting tools for administering the program are already in place. Other state agencies will also play a role in Alaska's GHG Reporting Program. The Alaska Energy Authority (AEA) developed Alaska's Energy Plan, released in January 2009.[9] As this plan is enacted, close coordination between AEA and DEC will be necessary to track energy consumption and climate change mitigation efforts throughout Alaska. The University of Alaska (UA) will also play a large role in climate change mitigation and adaptation research and implementation. Alaska's GHG Reporting Program could eventually be composed of several state agencies with different functions.

To administer a mandatory GHG reporting and carbon cap-and-trade program, the state will need to have sufficient administrative resources to ensure that all GHG emissions reporting occurs on schedule, that these data are audited each year (both centrally and through targeted site audits), and that the public can access emissions data on the Internet.[10] Under a future cap-and-trade program, "accurate measurement and reporting of all GHG emissions will be necessary to assure accountability, establish the integrity of allowances, and sustain confidence in the market. The *regulatory agency* responsible for the program must track emissions to ensure that (1) emissions match allowances at particular sources and (2) overall emissions match overall allowances."[11] The state will also be responsible for providing certainty through well-recognized civil and criminal penalties.[12]

Alaska's future GHG Reporting Program staff would be tasked to:

- Develop and draft statutes, regulations, fiscal notes, fee studies, position papers, guidance documents, policies, procedures, and standards as necessary to establish and implement federal and state climate change legislation.
- Develop and draft GHG emission reporting and verification protocols, procedures, methods, forms, and reporting guidance documents for regulated industries in Alaska.
- Develop and draft GHG mitigation and reduction goals, priorities, inventories, schedules, and performance measures related to mitigating climate change in Alaska.

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[9] Alaska Energy Authority. *Alaska Energy Report*. January 2009. Available at: http://www.aidea.org/AEA/PDF%20files/AK%20Energy%20Final.pdf.

[10] "*Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California.*" Recommendations of the Market Advisory Committee to the California Air Resources Board, June 30, 2007. Available at: http://climatechange.ca.gov/market_advisory_committee/index.html.

[11] Ibid.

[12] Ibid.

- Establish Alaska's GHG emissions baseline and compare it to Alaska's GHG mitigation goals.
- Conduct and publish Alaska's GHG emission inventory every 3 years.
- Allocate and track carbon emission allowances for facilities permitted under a future federal cap-and-trade program.
- Provide information on climate change mitigation technology and regulatory guidance to industry and the public.
- Coordinate the Sub-Cabinet's climate change mitigation policy efforts with Alaska's Energy Plan, the Alaska Municipal League, industry, the Western Climate Initiative (WCI), and others.
- Conduct compliance and enforcement activities.

GHG Reporting & Verification Requirements: Once its GHG Reporting Program is in place, Alaska may then establish a standard protocol for mandatory and voluntary GHG emissions reporting and verification. The state would be primarily responsible for developing these written protocols with assistance from private contractors.

All of the necessary reporting and verification procedures can be obtained from other state and regional GHG reporting rules and initiatives. The California Climate Action Registry's *General Reporting Protocol*[13] and The Climate Registry's (TCR's) *General Reporting Protocol*[14] are good templates for Alaska's GHG reporting program. Both of these protocols use an online reporting database that provides transparent, consistent, written reporting procedures for industry, as well as third-party verified data for public consumption. It is likely that EPA's future GHG mandatory reporting protocol will be similar to TCR's *General Reporting Protocol*. TCR hosts a national climate database. It is anticipated that, under a future national cap-and-trade program, states will be responsible for reporting these data to a centralized national database, such as TCR's. Most western states are also members of WCI, which is currently developing its *Essential Requirements of Mandatory Reporting for the Western Climate Initiative*.[15] Alaska could choose to join TCR and WCI now to gain familiarity with their reporting and verification procedures and to allow for a more efficient transition of data reporting once a federal GHG reporting rule is promulgated. Essential reporting requirements for Alaska's future GHG reporting program may include (but are not limited to) the following:

- *GHG Pollutants*—The following GHGs would be included: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Other newly described GHGs, like nitrogen trifluoride, may also be included under Alaska's mandatory GHG reporting rule.

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[13] California Climate Action Registry, *General Reporting Protocol*, Version 3.0, April 2008. Available at: http://www.climateregistry.org.

[14] The Climate Registry, *General Reporting Protocol*, Version 1.1, May 2008. Available at: http://www.theclimateregistry.org.

[15] Western Climate Initiative, *Essential Requirements of Mandatory Reporting for the Western Climate Initiative*, second draft dated September 30, 2008. Available at: http://www.westernclimateinitiative.org/.

- *Emission Source Categories*—These categories include electricity generation; industrial processes, such as oil and gas process emissions (including vented, flared, fugitive, and accidental emissions); and commercial, industrial, residential, and transportation fuel combustion above the reporting threshold. An Alaska GHG Reporting Program would include industries in Alaska with a Title V permit, but could also include mobile sources, such as marine and aviation fleets, and other transportation sources above the reporting threshold.
- *Reporting Thresholds*—Alaska's GHG reporting threshold will have to be as stringent as any future federal reporting requirement. The Climate Security Act of 2008[16] captured GHG sources emitting >10,000 tCO_2e per year (yr) of GHGs, California's mandatory GHG reporting rule captures sources that emit ≥25,000 CO_2e/yr,[17] and Oregon's proposed mandatory GHG reporting program captures sources that emit ≥2,500 tCO_2e/yr.[18]
- *Point of Regulation*—For industrial facilities, the point of regulation is the point of emission. For electricity sources in Alaska, the point of regulation would also be the point of emission, since electricity is not currently distributed or sold out of state. For transportation sources, the point of regulation could be the point at which fuels enter commerce at the terminal rack, final blender, or distributor.

Database Requirements: It is recommended that Alaska develop a statewide "Energy Database" that will enable it to record and monitor the following:

- Residential, commercial, industrial, and transportation fossil fuel energy consumption and production;
- Alternative energy consumption and production;
- Mandatory and voluntary reporting of energy-related GHG emissions;
- GHG emission reductions due to energy-related climate change mitigation actions; and
- Carbon emission allowances and their monetary value under a future cap-and-trade program.

To track Alaska's energy-related GHG emissions and their abatement, it will be necessary to establish an Energy Database that will monitor statewide residential, commercial, industrial, and transportation fossil fuel energy consumption and production in energy units. The common energy unit used in international reports of GHG emissions is the joule or terajoule (TJ), which is equal to 10^{12} joules, while the customary U.S. energy unit is the British thermal unit (Btu). Electric utilities often report their emissions per kilowatt-hour (kWh) or megawatt-hour (MWh), which are interchangeable with TJ and Btu. Knowing both the higher heating values of various fuels (e.g., million [MM] Btu per cubic foot of natural gas) and their carbon content (e.g., teragrams [Tg] of carbon per Btu) allows us to convert a facility's or fleet's energy consumption

[16] See Section 4 in U.S. Senate, "Lieberman-Warner Climate Security Act of 2008," S.3036, 110th Congress, 2nd Session, May 21, 2008. Available at: http://thomas.loc.gov/cgi-bin/query/z?c110:S.3036:.

[17] California Air Resources Board, *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, in Title 17 of California's Code of Regulations. Available at: http://www.arb.ca.gov/regact/2007/ghg2007/froghg.pdf.

[18] Oregon Department of Environmental Quality, *GHG Reporting Rule*, Oregon Administrative Rule 340-215-0010. Available at: http://www.deq.state.or.us/aq/climate/docs/FinalGHGRule.pdf.

(Btu, TJ, kWh) to GHG emissions in Tg (1 Tg = 10^{12} grams) of carbon, or million metric tons of CO_2 equivalents ($MMtCO_2e$).[19] Alaska's Energy Database should be able to record and monitor facility- and fleet-specific energy consumption and production in the form of TJ, Btu, kWh, calories, or other energy unit and easily convert these to GHG emissions in Tg of carbon or $MMtCO_2e$.

In addition to tracking energy (Btu, kWh, TJ), this new or modified database may also have to issue and track carbon emission allowances and have banking capabilities. Carbon emissions or energy units will have a monetary value under a future federal carbon cap-and-trade or tax program. It is anticipated that large industries in Alaska will be regulated as "capped sources" in the near future.[20] These large industries are already permitted by DEC's Air Permitting Program through their Title V permit, and are required to report their stack emissions and fuel consumption data. DEC's AIRTOOLS database currently tracks emissions from these large industries and periodically transmits these data electronically to EPA. AIRTOOLS could be enhanced and used for tracking and reporting GHG emissions under a future mandatory GHG reporting rule and cap-and-trade program. However, this database is currently insufficient to monitor statewide energy consumption and production, carbon emission allowances, and potentially the flow of money. The state agency eventually responsible for issuing and tracking carbon allowances may need access to and familiarity with a well-secured, state-insured banking database. Preferably, this database would serve multiple functions and have the statewide capability to accurately and securely monitor the following:

Energy ‹› GHG Emissions ‹› U.S. Currency
[Btu, kWh, TJ] ‹› [Tg of carbon or $MMtCO_2e$] ‹› [$$$]

It will also be important for Alaska to track and mitigate GHG emissions from residential, commercial, light industrial, and transportation sources that are not included under a future cap-and-trade program (uncapped sources). The Center for Climate Strategy's *Alaska GHG Inventory & Reference Case Projections, 1990–2020*[21] estimated that transportation sources in Alaska accounted for approximately 35% of the gross GHG emissions in 2000, while residential and commercial sources accounted for another 9%. Combined, these sources accounted for almost 45% of the total GHG emissions in Alaska for 2000. These GHG emission sources may not be captured under a future mandatory GHG reporting rule or cap-and-trade program. Alaska's climate change mitigation strategy will need to account for both mandatory (capped) and voluntary (uncapped) GHG emission sources, so that all GHG emissions can be tracked as climate change mitigation activities are enacted across the state.

Currently, there is no energy database in Alaska that tracks commercial, residential, light industrial, and transportation energy consumption and production throughout the state.[22] Both

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[19] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990–2006,* Annexes 1–8, EPA-430-R-08-005, 2005. Available at: http://www.epa.gov/climatechange/emissions/usgginventory.html.

[20] U.S. Senate, "Lieberman-Warner Climate Security Act of 2008," S.3036, 110th Congress, 2nd Session, May 21, 2008. Available at: http://thomas.loc.gov/cgi-bin/query/z?c110:S.3036:.

[21] Center for Climate Strategies, *Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990–2020,* July 2007. Available at: www.climatechange.alaska.gov/doc-links.htm.

[22] Scott Sloane, DEC, personal communication with Peter Crimp, AEA, December 5, 2008.

the State of California and TCR use an online reporting tool for mandatory and voluntary reporting of GHG emissions, which are third-party verified and accessible to the public. The State of Alaska may need to develop a similar new, or modified database and online reporting tool that would enable the state to track energy, carbon emissions, and potentially the flow of money. This new or modified database will play an integral part in tracking Alaska's GHG emissions and energy-related climate change mitigation efforts. AEA may be the agency to house a portion of Alaska's new or modified database, since it is responsible for implementing Alaska's Energy Plan.

Timing: The following timeline provides an estimated time frame for establishing Alaska's GHG Reporting Program, including legislation, regulations, and related efforts:

- *2009–2011:* The Alaska Department of Law (ADOL) and other appropriate state departments, in consultation with the Climate Change Sub-Cabinet, develop a climate change bill and a fiscal note to obtain legislative approval and monies for establishing Alaska's GHG Reporting Program.
- *2010–2012:* ADOL and other appropriate state departments, in consultation with the Climate Change Sub-Cabinet, develop statutes and regulations to establish Alaska's mandatory GHG emissions reporting program, and carbon cap-and-trade program.
- *2010–2012:* Alaska develops a database to track energy consumption and energy-related climate change mitigation efforts throughout Alaska.
- *2009:* Alaska joins TCR and WCI to gain familiarity with their GHG reporting and verification procedures and infrastructure.
- *2012:* Covered entities will be required to begin reporting to the state on their GHG emissions for 2011. Thereafter, reporting will occur annually.
- *2012:* The State of Alaska publishes Alaska's GHG emissions I&F. This report will be published every 3 years to guide Alaska's climate protection efforts.

Parties Involved: The State of Alaska, in conjunction with the Climate Change Sub-Cabinet, will be primarily responsible for writing Alaska's climate change bill, statutes, and regulations. The state will be primarily responsible for writing the fiscal note, establishing and implementing the mandatory and voluntary components of Alaska's GHG emissions reporting program, and publishing a statewide GHG I&F every 3 years. AEA may play a role in tracking voluntary reporting of energy consumption, energy production, and energy-related climate change mitigation efforts. Close coordination between state agencies, including DEC, AEA, and UA will be required to design and implement energy-related GHG mitigation efforts.

Other: None.

Implementation Mechanisms

The Climate Change Sub-Cabinet would need legislative approval from both houses in the form of a bill prior to moving ahead with developing Alaska-specific climate change statutes and regulations. Alaska's climate change bill could be modeled after California's Global Warming

Solutions Act of 2006[23] and Oregon's Climate Change Integration Act of 2007.[24] State departments would co-write Alaska's climate change bill in conjunction with the Climate Change Sub-Cabinet and ADOL. As part of this legislative approval process, affected state agencies would have to prepare fiscal notes that reflect the costs of a multi-year process, during which the state would hire staff to develop the statutory and regulatory framework for administering a mandatory GHG reporting program and carbon cap-and-trade program. The state would be primarily responsible for developing, writing, and submitting the fiscal note, along with Alaska's climate change bill. The fiscal note would include monies for hiring GHG Reporting Program personnel, developing reporting and verification procedures, and developing a database as presented in this mitigation policy. Obtaining both senate and house approval of Alaska's climate change legislation and fiscal note could take multiple legislative sessions (1–3 years).

Once Alaska's climate change legislation is approved, the fiscal note would provide the monies necessary for the state to hire staff to develop a GHG Reporting Program, climate change statutes and regulations, GHG reporting and verification procedures, and a database. ADOL would be primarily responsible for developing Alaska-specific climate change statutes and regulations in conjunction with the Sub-Cabinet. The state would be primarily responsible for developing a GHG mandatory reporting rule, by amending and adopting GHG reporting regulations developed in other states. The state would develop the GHG reporting and verification protocols and regulatory guidance documents for industry, with assistance from private contractors. The state would be solely responsible for conducting a fee study to determine the monetary fees associated with administering its mandatory GHG reporting rule. It is anticipated that any new positions would eventually be funded through fees generated via the implementation of Alaska's GHG mandatory reporting rule and carbon cap-and-trade program.

One of the primary implementation tasks will be developing a database, new or modified, that tracks energy and carbon allowances. Carbon emissions will have a monetary value under a future carbon cap-and-trade program. The state agency eventually responsible for issuing and tracking these carbon allowances will need access to and familiarity with a well-secured, state-insured banking database. AEA may be the agency to house a portion of Alaska's new or modified database, since it is responsible for implementing Alaska's Energy Plan.

Related Policies/Programs in Place

- **Federal Climate Change Initiatives:** EPA has released a draft GHG emissions reporting rule. This draft rule, as written, would regulate large sources of GHG emissions ($\geq$25,000 tCO_2e), including those not currently regulated by EPA. The rule is currently under discussion.
- **Regional Climate Change Initiatives:** TCR maintains a national climate database. It is likely that future federal GHG mandatory reporting legislation will include methods very

[23] State of California, "Global Warming Solutions Act of 2006," Assembly Bill 32. Available at: http://cliamtechange.ca.gov/publications/legislation.html.

[24] State of Oregon, "Climate Change Integration Act of 2007," House Bill 3543, 74th Oregon Legislative Session, June 2007. Available at: http://www.leg.state.or.us/07reg/measpdf/hb3500.dir/hb3543.en.pdf.

similar to TCR's *General Reporting Protocol* because most U.S. states and Canadian provinces belong to TCR and already employ its reporting and verification procedures. Alaska could join TCR now to gain familiarity with TCR's reporting and verification procedures. Alternatively, Alaska could develop state-specific reporting and verification procedures or wait for federal GHG legislation and adopt the federal GHG reporting and verification procedures.

- **State Climate Change Initiatives:** The western states of California, Oregon, and Washington have already promulgated or are in the process of developing a GHG mandatory reporting rule. Under California's and Oregon's GHG reporting rules, covered entities are industries that produce, consume, transport, or manufacture $\geq$25,000 and $\geq$2,500 tCO_2e, respectively. EPA will likely employ GHG reporting and verification procedures similar to those developed by California, TCR, and WCI.
- **Alaska Climate Change Initiatives:** AEA has developed an Energy Plan for Alaska, published in January 2009.[25] The Climate Change Sub-Cabinet could work with AEA and the Alaska Municipal League to integrate these organizations' alternative energy plans into Alaska's Climate Change Mitigation Strategy. To integrate Alaska's Energy Plan and Climate Change Mitigation Strategy, a new or modified database that can track energy and carbon will need to be developed for the state.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

A key uncertainty regarding development of a GHG Reporting Program for Alaska is coordination and interaction with EPA regulations. Previous federal attempts at climate change legislation gave a 2% emission allowance for states with GHG reporting programs that exceed federal GHG emission reduction targets (see section 3302 Climate Security Act[26]), though the current draft of EPA's rule does not provide this allowance.

Another key uncertainty centers on developing an Energy Database for Alaska. Where will this database be housed and who will develop it? What data elements are required? Close coordination between affected state agencies, AEA, and UA will be required to develop this database. This coordination process should begin immediately following the climate change bill and fiscal note approval. A list of policy questions follows:

- Should an Alaska GHG Reporting Program include both mandatory and voluntary reporting of GHG emissions, and what emission sources and thresholds should be included?

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[25] Alaska Energy Authority, *Alaska Energy Report.* January 2009. Available at: http://www.aidea.org/AEA/PDF%20files/AK%20Energy%20Final.pdf.

[26] See Section 3302 in U.S. Senate, "Lieberman-Warner Climate Security Act of 2008," S.3036, 110th Congress, 2nd Session, May 21, 2008. Available at: http://thomas.loc.gov/cgi-bin/query/z?c110:S.3036:.

- Should Alaska develop an Energy Database to track GHG emissions, carbon allowances, and energy-related climate change mitigation efforts throughout the state?
- Should Alaska join TCR and WCI now to gain familiarity with their reporting and verification procedures, or wait for future federal mandatory reporting requirements?
- Does Alaska have existing statutory authority to implement a GHG cap-and-trade program, or do new statutes and regulations have to be developed prior to implementing this program?
- Does Alaska have the monetary resources to hire additional staff as needed to develop and manage a GHG Reporting Program?

Additional Benefits and Costs

Benefits

Establishing a GHG Reporting Program in Alaska would allow the state to ascertain an accurate, verifiable, and transparent baseline of GHG emissions for Alaska, and subsequently develop a technically feasible GHG mitigation goal. This program could collect, verify, and analyze GHG emissions data to establish a baseline of anthropogenic (human-caused) GHG emissions for Alaska, and identify the types and magnitude of anthropogenic GHG emission sources in Alaska and their relative contributions. These data could be used to inform state leaders and the public on statewide GHG emission trends, identify opportunities for reducing GHG emissions, and enable the assessment of Alaska's climate change mitigation efforts over time.

Costs

The estimated 5-year (fiscal years [FY] 2010–2014) operating expenditures for establishing and administering Alaska's GHG Reporting Program are presented in Table F-l.1. Personnel salary and benefit funds are presented for five full-time positions, including one Environmental Program Specialist (EPS) IV, three EPS III, and one Analyst Programmer.

Table F-1. GHG Reporting Program 5-year estimated operating expenditures

Operating Expenditures	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
Personnel Salary & Benefits for 5 Full-Time Positions	$425,000	$425,000	$425,000	$425,000	$425,000
Travel	$25,000	$25,000	$25,000	$25,000	$25,000
Equipment	$25,000	$25,000	$25,000	$25,000	$25,000
Contractual					
ADOL	$100,000	$100,000	$100,000	$0	$0
Reporting/Guidance Documents	$100,000	$100,000	$100,000	$0	$0
Energy Database Development	$100,000	$100,000	$100,000	$0	$0
Database Maintenance				$50,000	$50,000
Totals	**$775,000**	**$775,000**	**$775,000**	**$525,000**	**$525,000**

ADOL = Alaska Department of Law; GHG = greenhouse gas.

During the first 3 years of this transition period (FY 2010–2012), $300,000 is allocated as follows: $100,000 for ADOL to develop a climate change bill, statutes, and regulations; $100,000 for private contractors to develop mandatory GHG reporting and verification procedures and other regulatory guidance documents; and $100,000 for developing an Energy Database. Over the 2010–2014 transition period, annual program receipts from routine fees associated with administering the GHG Reporting Program are expected to increase. The state will have to conduct a fee study to ascertain the fee structure necessary to pay for the increased level of effort associated with administering a mandatory GHG reporting program, the carbon cap-and-trade program, and compliance and enforcement activities. It is anticipated that eventually most of the personnel salary and benefit costs will be paid for by permit fees and the trading of carbon under a future cap-and-trade program. Final cost estimates may differ from those presented above, depending on the final options for and design of a state GHG Reporting Program.

Feasibility Issues

In developing an Alaska-specific reporting program, the feasibility issues to note are how it would interface with any federal or regional program, and where and how funding would be available for the staff positions and infrastructure required.

Status of Group Approval

The Mitigation Advisory Group (MAG) has agreed that this effort may be needed, but recommends no action until the status of federal legislation is known.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-2. Establish Goals for Statewide GHG Emission Reductions

Policy Description

Alaska should set goals that recognize both the state's unique emissions profile and the emerging dynamics of a federal GHG emission regulatory program. In addition, the state should set a baseline of emissions that will help measure progress toward these goals. This policy recommends that the state adopt a goal starting now to reduce emissions, with reductions of 20% below 1990 levels by 2020, and 80% below 1990 levels by 2050.

Countries, regions, states, cities, counties, and companies worldwide committed to reversing the effects of climate change have set goals or targets as a mechanism to ensure that emission reductions are achieved. Many of these governmental and corporate entities have done so in response to the United Nations' Intergovernmental Panel on Climate Change (IPCC), which has determined that an 80% reduction below 1990 levels in GHG emissions by 2050 is necessary to keep CO_2 levels below 450 parts per million and avoid major irreversible damage.

Almost half of all U.S. states have established state-specific goals and targets to reduce their emissions, with many setting aspirational goals of reducing emissions by up to 80% below 1990 levels by 2050.[27] In the federal budget released in February 2009 for fiscal year 2010, the Obama Administration proposed a 14% reduction in emissions below 2005 levels by 2020.[28] [29] One hundred and fifty-two members of Congress have signed a letter expressing strong support for these same levels of emission reductions. In addition, the American Clean Energy and Security Act of 2009, commonly referred to as the Waxman-Markey bill, proposes a number of measures related to U.S. climate policy, including the establishment of nationwide goals associated with a cap-and-trade system. The current language proposed in the bill calls for a 20% reduction in GHG emissions below 2005 levels by 2020, a 42% reduction by 2030, and an 80% reduction by 2050.[30]

In Alaska, the Center for Climate Strategies found that, as of 2005, Alaskan sources most likely generate over 50 million metric tons (MMt) of gross GHG emissions. More than 40% of these emissions result from burning carbon-based fuels at industrial sites. Another major finding of

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[27] States with state-specific goals and targets include Arizona, California, Colorado, Connecticut, Oregon, Florida, New Mexico, Illinois, Minnesota, Utah, and Washington. At this time, California is the only state with a mandatory economy-wide emissions cap that includes enforceable penalties. The Pew Center's Global Climate Change Web site contains detailed information on emission targets and other activities at the state level. See: www.pewclimate.org/what_s_being_done/in_the_states/state_action_maps.cfm.

[28] U.S. Office of Management and Budget, *A New Era of Responsibility: Renewing America's Promise—Budget for Fiscal Year 2010.* Available at: http://www.whitehouse.gov/omb/assets/fy2010_new_era/a_new_era_of_responsibility2.pdf.

[29] U.S. Office of Management and Budget, *A New Era of Responsibility: Renewing America's Promise—Budget for Fiscal Year 2010.* Available at: http://www.whitehouse.gov/omb/assets/fy2010_new_era/a_new_era_of_responsibility2.pdf.

[30] American Clean Energy and Security Act of 2009. Available at: http://energycommerce.house.gov/Press_111/20090331/acesa_discussiondraft.pdf.

the report is that nearly 40% of the statewide GHG emissions come from the transportation sector, mostly from jet fuel consumption. Of the remaining 20%, about 7% is non-combustion-related emissions from the fossil fuel industries, and 7% is from electricity consumption/generation (for all uses). The remainder is divided between commercial and residential (non-electrical) energy needs. On a per-capita basis, Alaska activities emit about 82 tCO_2 annually, significantly higher than the national average of 25 tCO_2 per year.

Given that almost half of Alaska's emissions are a result of fossil fuel industrial activity, it is important to note that BP America, ConocoPhillips, and Shell Oil have all issued strong statements regarding climate change and emission goals. For example:

- Robert Malone, President of BP America, noted before the House Select Committee on Energy and Global Warming (April 2008) that "Congress should set climate policy goals and allow the market to decide which technologies best deliver upon the objectives it sets."[31]
- In 1998, BP America set a target to cut emissions from operations to 10% below 1990 levels by 2010—a target reached 9 years early.[32]
- Jim Mulva, Chairman and Chief Executive Officer of ConocoPhillips, noted in his remarks at an energy conference (February 2008) that "the industry must also recognize that the ways it provides energy must change. For example: in the near term, we should reduce the carbon intensity of our own energy consumption. We can do this by continually improving efficiency and using more low-carbon and renewable fuels."[33]
- Shell Oil notes on its Web site that Shell was one of the first energy companies to acknowledge the threat of climate change; to call for action by governments, its industry, and energy users; and to take action itself.[34] Shell America has reduced its GHG emissions by nearly 25% compared to 1990.

It is also important to note the following indisputable facts:

- Alaska is a premier energy state and the only Arctic state.
- Alaska is experiencing the effects of climate change more than other states.
- Alaska's major industry and source of GHG emissions supports policy goals to begin reducing GHG emissions by 2012, with reductions of up to 10% by 2017 and incremental goals thereafter that reduce GHG emissions by 60%–80% below 1990 levels by 2050.

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[31] Robert Malone, BP America, written testimony to U.S. Congress, April 1, 2009. Available at: http://globalwarming.house.gov/tools/assets/files/0456.pdf.

[32] BP America, *BP Sustainability Report 2001*, April 2002. Available at: http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/E/Environmental_and_social_report_2001.pdf.

[33] Jim Mulva, Chairman & CEO, ConocoPhillips. CERAWeek Energy Security and Climate Change Speech. "Energy Security and Climate Change: The Case for Engagement," February 12, 2008. Available at: http://www.conocophillips.com/newsroom/other_resources/CERA_speech.htm.

[34] Royal Dutch Shell, "Responding to Climate Change: Responsible Energy." Available at: http://www.shell.com/home/content/responsible_energy/environment/climate_change/.

- There is a strong likelihood that national legislation will contain similar goals, and that Alaska will strive to be part of the national solution.

Alaska should set goals that recognize both its unique emissions profile and the emerging dynamics of a federal GHG emission regulatory program. "Goals" in this context is meant as an aspiration for the state as a whole and does not imply that the goals should become mandatory. It should be noted that these goals (1) will be reviewed after waste energy audits have been completed for Alaska's major emission sources, and (2) do not account for emissions that may be added as a result of the operation of the natural gas pipeline. Once the emission effects of the natural gas pipeline are known, then these goals will be modified to account for this important energy project.

In addition, obtaining an accurate baseline of GHG emissions or energy consumption in Alaska will be necessary to measure Alaska's success in combating climate change and meeting its GHG emission reduction goals. Under any future carbon cap-and-trade program, carbon emission allowances may be allocated based on the GHG emissions baseline established. It will be crucial to have accurate data when establishing a cap-and-trade program to "avoid over-allocation of carbon allowances and to create the necessary market scarcity."[35]

Policy Design

Goals:

- The state adopts a goal starting now to reduce emissions, with reductions of 20% below 1990 levels by 2020, and 80% below 1990 levels by 2050. The 2050 goal is the recommendation of the IPCC.

- The state establishes a GHG emissions baseline and refines it based on updates from any mandatory reporting program and GHG inventories to measure progress on goals.

Timing: It is expected that the Sub-cabinet will review this policy and either recommend the MAG-recommended goal, develop their own, or determine an appropriate implementation mechanism.

Parties Involved: MAG, Climate Change Sub-Cabinet, other stakeholders as deemed necessary.

Other: None.

Implementation Mechanisms

This policy could be implemented either through legislation or as an executive order. In Oregon, the Climate Change Integration Act established the state's GHG reduction goals in a statute (e.g., by 2020, reduce GHG levels to 10% below 1990 levels), as well as provided funding for

[35] *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*. Recommendations of the Market Advisory Committee to the California Air Resources Board, June 30, 2007. Available at: http://www.climatechange.ca.gov/.../2007-06-01_MAC_DRAFT_REPORT.PDF.

establishing Oregon's mandatory GHG reporting rule.[36] In Washington, the state's GHG reduction goal was established in 2007 when Governor Gregoire issued Executive Order 02-07.

Related Policies/Programs in Place

See the Policy Description section for goals that have been set by other U.S. states, organizations, and members of industry in Alaska.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

The key uncertainty associated with this policy is how it could interface with any federal legislation that may occur in the near future. It is possible that the U.S. Congress will pass legislation that would require a GHG emission cap across all states. If this were to happen, Alaska would decide whether to meet the cap as a minimum or set a goal for further reductions.

Additional Benefits and Costs

Benefits

By setting GHG emission goals, Alaska would be on par with many other U.S. states. Working to meet these goals could put Alaska in a more advantageous position if and when national rules on emission reductions are enacted.

Costs

The costs of adopting this policy could be zero if the MAG and Sub-Cabinet agree to these proposed goals. If additional work is needed to help stakeholders agree to goals for GHG emission reductions, there would be some moderate costs ($10,000–$50,000) to facilitate a workgroup of these stakeholders and develop a decision.

Feasibility Issues

These goals should be evaluated against other MAG recommendations for reducing GHG emissions to ensure the goals are feasible for the state to undertake.

Status of Group Approval

Approved.

Level of Group Support

Majority.

[36] Oregon Department of Environmental Quality, *GHG Reporting Rule*, Oregon Administrative Rule 340-215-0010. Available at: http://www.deq.state.or.us/aq/climate/docs/FinalGHGRule.pdf.

Barriers to Consensus

Of the fourteen MAG members in attendance at the final meeting, six objected to and eight supported the setting of a numeric goal for reducing GHG emissions in Alaska. Objections to setting a specific goal included:

- Many of Alaska's emissions come from activities that are not in its control, such as fuel and airplane emissions from refueling and overflights. Further, some activities are under federal—not state—control, including military base operations.
- Some MAG members stated that this policy should not include specific goals but, rather, that the Sub-Cabinet should recommend a specific aspirational goal.

CC-3. Identify and Implement State Government Mitigation Actions

Policy Description

Alaska can lead by example in responding to climate change and reducing GHG emissions by identifying potential GHG reduction activities and implementing specific and tangible changes in its operations. Leadership on the part of the state to both identify and implement these early actions[37] will accomplish two primary goals:

- Alaska can quickly make reductions in GHG emissions.
- The demonstrated success of state action can be an incentive for private citizens, businesses, nongovernmental organizations (NGOs), and local governments to take action. Identifying early actions and then acting on them is the essence of "leading by example" and a necessary first step for more ambitious goals. Initial successes can also help convince the public and state legislature to move forward with actions that may require more significant changes in behavior, regulation, and public funding.

Policy Design

Goals:

- Lead by example by implementing no-cost and low-cost early actions that can be taken without new funding or legislative approval in the immediate future to reduce the state's GHG emissions, and actions that must be completed as a first step toward state implementation of more complex and expensive goals.
- Publicize successes quickly through a "Report Card" to encourage others to act and to generate political momentum.

The objective of this policy is for state agencies to implement actions within their purview and authority, with a priority toward immediate and meaningful reductions in GHG emissions by changes in day-to-day state activity. To facilitate this, the MAG developed a preliminary matrix (Table F-2) outlining potential lead-by-example actions, time frames, needed resources and authorities, potential GHG reductions, and potential savings. In developing this list of actions, Alaska can learn from the examples of other state governments that have taken steps to reduce their GHG emissions.

The list of early actions that the state should pursue includes:

- Require the establishment of audiovisual conferencing facilities and their use by state employees to reduce the economic and GHG emission costs associated with state employee airline travel.
- Convert state-owned fleets to use lower-carbon fuels and/or have more energy-efficient vehicles.

[37] Actions that can be taken without new funding or legislative approval.

- Develop expansive incentives for environmentally friendly commuting and comprehensive telecommuting policies for state employees.
- Develop an environmentally preferred purchasing program for state procurement.
- Conduct an energy audit and implement identified changes to improve energy efficiency for the Governor's mansion and other key government buildings (require that all state computers be set at "sleep" mode or switched off when not in use for long periods of time, use light-emitting diode (LED) holiday lights on state-owned buildings and venues rather than conventional lights, switch to more energy-efficient lighting, etc.).[38]
- Encourage creative ideas from state employees by offering incentives for energy conservation recommendations in state facilities.

Alaska will establish an annual Report Card to describe the GHG reduction goals and the progress that each state agency is making toward these goals[39] (related to CC-1 and CC-2). In addition, to publicize success and encourage a culture of energy conservation, state agencies will release Web updates and public service announcements when undertaking GHG emission reduction measures.

Timing: State lead-by-example activity should be implemented as soon as possible after the Sub-cabinet approves it as part of the Alaska Climate Change Strategy.

Parties Involved: DEC would take the lead initially to communicate and implement the immediate actions, using ideas and feedback from other state climate offices and relevant NGOs. If any state climate change program or coordinating body is established, it would take over the function of implementing and coordinating state lead-by-example actions, including identifying, tracking, and implementing more complex and expensive actions.

Other: None.

Implementation Mechanisms

- DEC should initiate activity through the Climate Change Sub-Cabinet, identifying those actions to address immediately. The Sub-Cabinet can agree to specific activities and recommend to the Governor's Office issuance of executive orders or other administrative mechanisms to implement immediate actions pertaining to specific departments. Funding may be needed in some instances to achieve early action goals, though it is assumed that these policies would have a short energy payback period.
- If any state climate change program or coordinating body is established, it would take on the responsibility of communicating, educating, and providing resources for state agencies to continue to reduce their GHG emissions.

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[38] For examples, see California Environmental Protection Agency Air Resources Board, "Expanded List of Early Action Measures to Reduce Greenhouse Gas Emissions in California," October 17, 2007. Available at: http://www.arb.ca.gov/cc/ccea/reports/reports.htm.

[39] For example, see California Environmental Protection Agency Air Resources Board, "State Agency Greenhouse Gas Reduction Report Card," 2007. Available at: http://www.arb.ca.gov/cc/cc.htm.

- Identifying early actions—and then implementing them—will serve as the catalyst for many other policies and goals identified in Alaska's Climate Change Strategy.
- Using "lessons learned," the state can work with municipalities (boroughs, cities, and villages), possibly through the Alaska Municipal League, to develop their GHG mitigation plans. The state can also look for opportunities to apply and expand the work developed at the municipal level to the state level (e.g., expanding the City of Homer's climate change plan).

Additional implementation approaches may be developed based on specific actions.

Related Policies/Programs in Place

None noted.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

The ability of Alaska state agencies to implement GHG reduction policies that may require additional funding or time is unknown. The amount of funding and time required will vary by action.

Additional Benefits and Costs

Benefits

Changes in state procedures or employee behavior could significantly reduce GHG emissions in Alaska. Successful implementation at the state level can also set the stage for citizens and businesses to follow. Both leading by example and taking "first-step" actions will create momentum that can launch the state's entire Climate Change Program.

Costs

The costs of developing and implementing these actions will vary, depending on the specific actions. The intent of these actions is that they be relatively low cost to implement and/or will create cost savings over some period of time. Additional work is needed to determine the specific costs of the initial actions outlined in this policy, and not-yet-developed policies will require some amount of staff time to scope and cost for inclusion in this effort.

Feasibility Issues

For each action, feasibility issues will vary. For developing further ideas for early action, there may be some need for staff time, though most actions that would fit in this policy should be relatively simple to implement, thus not requiring a great deal of staff time.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

Table F-2. Initial list of lead-by-example actions

#	Action	Timing	Needed Resources	Implementation Needs	GHG Savings	Cost or Cost Savings	Question/ Notes
1	Require the use of audiovisual (A/V) teleconferencing between state employees.	Immediate implementation using available resources; increased use as more A/V centers are made available.	Some A/V resources are already available; Increased facilities needed; may need education/training.	Educate state employees about available resources; establish new A/V centers.	Elimination of air or ground travel GHG emissions.	Elimination of cost of air or ground travel; cost of increased use of A/V resources.	Is there any education related to Alaska's current A/V resources? Are there additional barriers to use that should be considered?
2	Convert state-owned fleets to use lower-carbon fuels and/or have more energy-efficient vehicles.	Phased implementation: older vehicles are replaced with more efficient vehicles or those that can use lower-carbon fuels.	New, more energy-efficient vehicles; lower-carbon fuels.	Develop purchasing protocol to identify fleet vehicles for replacement and direct appropriate conversion.	GHG savings as a result of using lower-emission fuels and/or vehicles.	Initial higher cost of upgrading vehicles to more efficient models; likely decreased costs over the life of the vehicle, depending on the cost of fuel.	How many state vehicles are there? Does Alaska have an obligation to purchase cars from American companies? Is there a central purchasing authority that this policy should be tailored toward?
3	Develop expansive incentives for environmentally friendly commuting and comprehensive telecommuting policies for state employees.	Immediate implementation.	Incentives for carpooling and transit; increased infrastructure to support telecommuting.	Develop incentives for carpooling and use of transit, such as transit passes or preferred parking; develop telecommuting policies.	State employees commuting less or more efficiently reduces GHG emissions.	Decreased driving could reduce parking lot needs and costs. Increased telecommuting can decrease office space needs.	Does Alaska have a telecommuting policy for any state employees?
3a	State managers will immediately authorize certain employees to telecommute.	Immediate implementation.	Infrastructure to support telecommuting.	Develop telecommuting policy; identify priority employees for telecommuting (e.g., those who commute more than 5 miles, those who do not have regular field or customer work).	State employees commuting less or more efficiently reduces GHG emissions.	Decreased driving could reduce parking lot needs and costs. Increased telecommuting can decrease office space needs.	Does Alaska have a telecommuting policy for any state employees?

#	Action	Timing	Needed Resources	Implementation Needs	GHG Savings	Cost or Cost Savings	Question/ Notes
3b	State sets up satellite work sites for those who commute long distances, but are unable to telecommute, such as in the Mat Su Borough.	Few months to years.	Property and services for satellite work sites.	Identify locales that would be best served by satellite work sites (e.g., Mat Su Borough).	State employees commuting less reduces GHGs.	Cost of setting up satellite work sites; could be offset by having less employees in central location	May be more long-term
3c	State provides or subsidizes commuter buses from park-and-ride sites in far suburbs from metropolitan areas.	Almost immediate.	Buses or bus service to provide commuter service; parking lots.	Identify locales that would be best served by commuter buses.	State employees commuting more efficiently (e.g., fewer single-occupancy vehicles) reduces GHG.	Cost of buses or alternate transportation; reduced cost of parking for employees	Could there be enough voluntary use to make the system pay for itself? Would particular amenities encourage ridership?
4	Develop an environmentally preferred purchasing program for state procurement, including energy-efficient products.	Implementation following development of program and policies.	Time needed for developing new policy.	Develop new policy on procurement of environmentally preferable products.	Reduced environmental footprint, including GHG emissions, in the purchase of environmentally preferable products.	Reduced operational costs of using more energy-efficient products; some products may have higher costs than conventional counterparts.	See MA: http://tinyurl.com/9qcfnr. Are there any policies in Alaska about environmentally responsible purchasing? What is the appropriate implementation vehicle?
5a	Conduct an energy audit and implement identified changes to improve energy efficiency for key government buildings.	Immediate energy audit; phased implementation of identified changes.	Resources for making identified changes to government buildings.	Identify buildings for energy audit; implement energy audit.	Minor and major GHG savings, depending on buildings that were audited and upgraded; high-profile building could encourage energy audits among the public.	Initial cost of making identified changes in buildings, though many of the changes (insulation, lighting upgrades, etc.) will have a short payback period.	Who will have primary responsibility? What resources/tools do they need?

#	Action	Timing	Needed Resources	Implementation Needs	GHG Savings	Cost or Cost Savings	Question/ Notes
5b	Encourage creativity and new ideas by soliciting energy conservation ideas from state employees and providing an incentive for the best ones (e.g., paid time off).	Immediate.	No resources needed.	Identify incentives for proposing good ideas.	Employees are often aware of the best places to make energy conservation changes, so providing a goal could encourage large savings in GHG emissions.	Costs would depend on incentive. Cost savings could be significant, depending on energy conservation measures suggested and implemented.	

GHG = greenhouse gas.

CC-4. Integrate Alaska's Climate Change Mitigation Strategy With the Alaska Energy Plan

Policy Description

This climate change mitigation policy describes the basic strategy and reporting tools necessary to integrate Alaska's Climate Change Mitigation Strategy with the Alaska Energy Plan to accomplish the triple objective of maintaining climate integrity, energy security, and economic prosperity for Alaska.

In January 2009, AEA released a plan for managing Alaska's energy resources in local communities to support the goals of energy independence, economic vitality, and energy conservation. This plan is built on past AEA energy plans and provides specific information for local communities interested in developing new energy projects or improving existing ones.[40]

Both the Center for Climate Strategy's *Alaska GHG Inventory and Reference Case Projections, 1990–2020,*[41] and DEC's *Refinements to the Alaska GHG Emission Inventory*[42] reports concluded that the majority of Alaska's anthropogenic GHG emissions are due to the consumption of energy as fossil fuels to power industry and transportation. Those industries in Alaska combusting, producing, refining, storing, and transporting the most fossil fuel had the highest GHG emission estimates and can be grouped into Alaska's energy sector. "The energy sector is mainly comprised of exploration and exploitation of primary energy sources; conversion of primary energy sources into more useable energy forms in refineries and power plants; transmission and distribution of fuels; use of fuels in stationary and mobile applications."[43]

Starting in 2010, pending the approval of the Climate Change Sub-Cabinet, it is recommended that Alaska's Energy Plan and Climate Change Mitigation Strategy be combined into one plan to achieve Alaska's stated climate change mitigation goals guided by a 10-year energy plan. Integrating Alaska's Climate Change Mitigation Strategy with Alaska's Energy Plan is good policy for achieving the stated objectives. Both plans will include the development of energy efficiency, energy conservation, co-generation, fuel switching, and renewable energy measures. It would not make sense to develop a climate change mitigation strategy that calls for a reduction in Alaska's GHG emissions, while at the same time enact an energy plan that calls for developing Alaska's coal, oil, and natural gas resources without considering the carbon footprint.

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[40] Alaska Energy Authority, *Alaska Energy Report,* January 2009. Available at: http://www.aidea.org/AEA/PDF%20files/AK%20Energy%20Final.pdf.

[41] Center for Climate Strategies, *Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990–2020,* July 2007. Available at: www.climatechange.alaska.gov/doc-links.htm.

[42] DEC, *Summary Report of Improvements to the Alaska Greenhouse Gas Emission Inventory,* January 2008. Available at: http://www.climatechange.alaska.gov/doc-links.htm.

[43] Simon Eggleston et al., eds., *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Energy,* prepared by the IPCC National Greenhouse Gas Inventories Programme. IGES, Japan, 2006. Available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm.

It is also recommended that Alaska's 10-year integrated Climate Protection & Energy Plan include all fossil fuel (coal, oil, natural gas, coal-bed methane) resource extraction and production potential in Alaska projected through the year 2020, because these estimates influence the rate at which GHGs are produced in Alaska. A major component of this integrated Climate Protection & Energy Plan will be the development of an Energy Database for Alaska, as briefly described below.

Finally, it is recommended that Alaska's integrated Climate Protection & Energy Plan be updated periodically to guide Alaska's climate change mitigation objectives and energy consumption goals through time and across various state administrations.

This mitigation policy does not provide the detailed, industry-by-industry energy policies necessary for achieving Alaska climate change mitigation objectives because these have been addressed in other sectors and by the AEA. This climate change mitigation policy addresses GHGs from fossil fuels (CO_2, CH_4, and N_2O), but does not address high-global-warming-potential GHGs containing bromine, chlorine, or fluorine.

Policy Design

Goals:

- Starting in 2010, Alaska will begin to develop its 10-year Climate Protection & Energy Plan to achieve the state's climate change mitigation strategy objectives and energy consumption goals through 2020.
- Starting in 2010, Alaska will begin to develop an Energy Database that will track commercial, residential, industrial, and transportation energy consumption and production, GHG emissions, and climate change mitigation actions throughout Alaska.

Establish Energy (GHG Emissions) Baseline: As referenced previously, the majority of Alaska's anthropogenic GHG emissions are due to the consumption of energy as fossil fuels to power industry and transportation.[44] Obtaining an accurate baseline of GHG emissions or energy (fossil fuel) consumption in Alaska will be necessary to measure Alaska's success in combating climate change. The Alaska Cold Climate Housing Research Center's (CCHRC) report states that "most significantly, energy conservation and policy effectiveness cannot be measured without establishing a current baseline. Collecting baseline data is the first step in launching a meaningful energy-related efficiency program."[45] Alaska's GHG emissions or energy consumption baseline is the starting point from which we account for how well the state's climate change mitigation strategy is working. Also, under a future carbon cap-and-trade program, carbon emission allowances may be allocated based on the GHG emissions baseline established in Alaska's GHG inventory. It will be crucial to have accurate data when establishing a cap-and-trade program to "avoid over-allocation of carbon allowances and to

[44] Center for Climate Strategies, *Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990–2020,* July 2007. Available at: www.climatechange.alaska.gov/doc-links.htm.

[45] C. Lister, B. Rogers, and C. Ermer, *Alaska Energy Efficiency Program and Policy Recommendations*, Final Report to the Cold Climate Housing Research Center, June 12, 2008. Available at: http://www.akenergyauthority.org/.

create the necessary market scarcity."[46] Therefore, through the Climate Change Mitigation Strategy, the MAG should strive to establish a publicly approved energy or GHG emissions baseline for Alaska.

Establish Energy (GHG Emissions) Reduction Goals: In addition to establishing a GHG emissions or energy baseline for Alaska, the final Climate Change Mitigation Strategy should include a statewide GHG emission reduction goal (i.e., reduce Alaska's GHG emissions by 20% below 1990 levels by 2020 and 80% below 1990 levels by 2050).

Alaska's GHG emissions baseline and GHG reduction goal can be used as "goalposts" for achieving Alaska's desired climate change mitigation objectives. For example, assume, as presented on page 3 of the *Alaska Greenhouse Gas Inventory,*[47] that Alaska's GHG emissions baseline is approximately 50 $MMtCO_2e$. Also assume that Alaska's stated GHG reduction goal is reducing Alaska's baseline of GHG emissions by 30% by 2020. This would imply that Alaska would have to reduce its GHG emissions by 15 $MMtCO_2e$ over the next 10 years, equivalent to an annual reduction of 1.5 $MMtCO_2e$. The alternative energy-related measures that have been developed in other sectors (Energy, Oil & Gas, etc.) include a combination of fuel switching, cogeneration, flare-reduction, energy efficiency, and energy conservation measures. All of these energy-related measures can be used to achieve Alaska's 1.5 $MMtCO_2e$ annual GHG reduction goal, and overall GHG reduction goal (i.e., reduce Alaska's GHG emissions by 20% below 1990 levels by 2020 and 80% below 1990 levels by 2050).

Use Energy Plans to Achieve Alaska's GHG Reduction Goals: Alaska's Climate Change Mitigation Strategy objectives and desired GHG mitigation goals can be achieved by integrating these objectives with Alaska's Energy Plan. In addition to the alternative energy policies developed by AEA and the MAG, there are many newly developed alternative energy blueprints that Alaska can incorporate to achieve its GHG mitigation goals. California's *Climate Change Proposed Scoping Plan*[48] provides numerous examples of state-led alternative energy initiatives. The U.S. Department of Energy (DOE) and EPA recently released their cooperative *National Action Plan for Energy Efficiency, Vision for 2025: A Framework for Change.*[49] The U.S. House of Representatives' Select Committee on Energy Independence and Global Warming *Final Staff Report for the 110th Congress*[50] also provides many energy-related measures to combat climate change. The Alaska CCHRC's report includes several examples of voluntary residential and commercial energy measures that can be used to achieve a portion of Alaska's desired GHG

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[46] *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*. Recommendations of the Market Advisory Committee to the California Air Resources Board, June 1, 2007. Available at: http://www.climatechange.ca.gov/events/2007-06-12_mac_meeting/2007-06-01_MAC_DRAFT_REPORT.PDF.

[47] Center for Climate Strategies, *Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990–2020,* July 2007. Available at: www.climatechange.alaska.gov/doc-links.htm.

[48] California Air Resources Board, *Climate Change Proposed Scoping Plan*, October 2008, prepared for the State of California. Available at: http://www.arb.ca.gov/cc/cc.htm.

[49] U.S. Department of Energy and U.S. Environmental Protection Agency, *National Action Plan for Energy Efficiency, Vision for 2025: A Framework for Change*, November 2008. Available at: http://www.epa.gov/eeactionplan.

[50] U.S. House of Representatives, Select Committee on Energy Independence & Global Warming,, *Final Staff Report for the 110th Congress*, October 31, 2008. Available at: http://globalwarming.house.gov.

mitigation goals. All of the energy-related measures can be used to accomplish the triple objective of maintaining climate integrity, energy security, and economic prosperity for Alaska through the integration of its Climate Change Mitigation Strategy and Energy Plan.

Establish Energy or Carbon Database: "Because there will be monetary value to carbon credits, there is an even greater incentive to establish carbon data management systems that work."[51] In the near future, carbon emissions will have a monetary value under a national carbon cap-and-trade or carbon tax program. Therefore, it would be financially beneficial if Alaska could track fossil fuel energy consumption and production throughout the state. Currently, there is no single statewide database that tracks residential, commercial, industrial, and transportation fossil fuel energy consumption and production. Separate state and federal agencies track energy consumption and production for their individual agency missions. For example, DEC tracks fuel consumption for its Title V permits, the Alaska Housing Finance Corporation (AHFC) tracks residential energy consumption, and DOE's Energy Information Administration (EIA) tracks energy production and consumption in Alaska.

To track Alaska's energy-related GHG emissions and their abatement, it will be necessary to establish an Energy Database that will monitor statewide residential, commercial, industrial, and transportation fossil fuel energy consumption and production in energy units. The common energy unit used in international reports of GHG emissions is the joule or terajoule (TJ = 10^{12} joules), while the customary U.S. energy unit is the Btu. Electric utilities often report their emissions per kWh or MWh, which are interchangeable with TJ and Btu. Knowing both the higher heating values of various fuels (e.g., million Btu per cubic foot of natural gas) and their carbon content (e.g., Tg of carbon per Btu) allows us to convert a facility's or fleet's energy consumption (Btu, TJ, kWh) to GHG emissions in Tg of carbon, or $MMtCO_2e$.[52] Alaska's Energy Database should be able to record and monitor facility- and fleet-specific energy consumption and production in the form of TJ, Btu, kWh, calories, or other energy units and easily convert these to GHG emissions in Tg of carbon or $MMtCO_2e$.

In addition to tracking energy (Btu, kWh, TJ), this new or modified database may have to track carbon emission allowances and have banking capabilities. Carbon emissions will have a monetary value under a future federal carbon cap-and-trade, cap-and-dividend, or tax program. It is anticipated that large industries in Alaska will be regulated as "capped sources" in the near future.[53] The state agency eventually responsible for issuing and tracking carbon allowances will need access to and familiarity with a well-secured, state-insured banking database. Preferably, this database will serve multiple functions and have the statewide capability to accurately and securely monitor the following:

Energy ←→ GHG Emissions ←→ U.S. Currency

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[51] National Association of Clean Air Agencies, *Defining the Role of States and Localities in Federal Global Warming Legislation*, Conference Proceedings, June 2008. Available at: http://www.4cleanair.org/TopicDetails.asp?parent=16.

[52] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990–2006*, Annexes 1-8, EPA-430-R-08-005, 2005. Available at: http://www.epa.gov/climatechange/emissions/usgginventory.html.

[53] U.S. Senate, "Lieberman-Warner Climate Security Act of 2008," S.3036, 110th Congress, 2nd Session, May 21, 2008. Available at: http://thomas.loc.gov/cgi-bin/query/z?c110:S.3036:.

Btu, kWh, TJ ←→Tg of carbon or $MMtCO_2e$ ← → $$$

It will also be important for Alaska to track and mitigate GHG emissions from residential, commercial, light industrial, and transportation sources that are not included under a future cap-and-trade program (uncapped sources). The Center for Climate Strategy's *Alaska GHG Inventory and Reference Case Projections, 1990–2020* estimated that transportation sources in Alaska accounted for approximately 35% of the gross GHG emissions in 2000,[54] while residential and commercial sources accounted for another 9%. Combined, these sources accounted for almost 45% of the total GHG emissions in Alaska for 2000. These GHG emission sources may not be captured under a future mandatory GHG reporting rule or cap-and-trade program. Alaska's climate change mitigation strategy will need to account for both mandatory (capped) and voluntary (uncapped) GHG emission sources, so that all GHG emissions can be tracked as climate change mitigation activities are enacted across the state. It will also be important to track Alaska's alternative energy consumption and production (e.g., hydroelectric, solar, wind, tidal, geothermal), because the rate at which these technologies is implemented corresponds directly with the decrease of GHG production in Alaska.

Timing:

- Beginning in 2010, pending approval from the Climate Change Sub-Cabinet, Alaska will work to develop its 10-year Climate Protection & Energy Plan. This plan will include the Sub-Cabinet's final climate change mitigation objectives; the future fossil fuel (coal, oil, natural gas, coal-bed methane) resource extraction and production potential in Alaska projected through 2020; and the alternative energy measures developed by the MAG and AEA. The plan will be updated every 2 years to guide Alaska's energy consumption and climate change mitigation efforts. Alaska's natural gas will be developed where possible to replace high-density carbon fuels (e.g., coal and oil).
- Beginning in 2010, pending approval from the Climate Change Sub-Cabinet,, Alaska will work to develop an Energy Database, which will enable the state to record and monitor the following:
  - Residential, commercial, industrial, and transportation fossil fuel energy consumption and production;
  - Mandatory and voluntary reporting of energy-related GHG emissions;
  - GHG emission reductions due to alternative energy-related climate change mitigation actions; and
  - Carbon emission allowances and their monetary value under a future cap-and-trade or tax program.

Parties Involved: Climate Change Sub-Cabinet, AEA, relevant state agencies.

Other: None.

[54] Center for Climate Strategies, *Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990–2020*, July 2007. Available at: www.climatechange.alaska.gov/doc-links.htm.

Implementation Mechanisms

See Policy Design section.

Related Programs/Policies in Place

Other related efforts include the following:

- DEC collects fuel consumption and emissions data for large (Title V) industries and submits emissions inventory data to EPA through its Consolidate Emissions Reporting program.
- AHFC collect data on residential energy consumption.
- EIA collects data on energy consumption and production in Alaska.
- Alaska's 10-year Climate Protection & Energy Plan should integrate the energy and climate protection plans currently being developed by the members of the Alaska Municipal League.
- Both the State of California and TCR use online reporting tools for mandatory and voluntary reporting of GHG emissions, which are third-party verified and accessible to the public. Alaska may need to develop a similar, new or modified, database or online reporting tool that would enable the state to track energy consumption and production, carbon emissions, and potentially the flow of money. This new or modified database will play an integral part in tracking Alaska's GHG emissions and energy-related climate change mitigation efforts.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

- How will Alaska track energy-related GHG emissions and their abatement?
- What kind of carbon trading system will be developed by the federal government (e.g., carbon cap-and-trade versus carbon tax and dividend), and what kind of database will be required to track carbon emissions and their monetary value?
- Who will be responsible for establishing and administering Alaska's Energy Database, how much will it cost, and where will it be located?

This mitigation strategy recommends, starting in 2010, that Alaska begin to develop its 10-year integrated Climate Protection & Energy Plan and its Energy Database. By 2011, it is anticipated that a federal carbon cap-and-trade or carbon tax program will be in place. The agency responsible for administering Alaska's Energy Database, its exact location, structure (e.g., reporting requirements), and costs will be determined based on the federal program about to be promulgated. It appears that the federal government is leaning toward developing a national carbon cap-and-trade program. Less talked about is the possibility of developing a carbon tax-and-dividend program. In either case, carbon emissions will likely have a monetary value in the

near future. Therefore, it would be beneficial for Alaska to start developing its own carbon or Energy Database now in anticipation of the federal program.

Additional Benefits and Costs

Benefits

Integrating Alaska's climate protection and energy policies will allow the state to achieve its GHG mitigation goals, and will result in a profitable, less volatile, fixed-price, carbon-based economy. Alaska is rich in carbon-based fuels and should benefit from a future GHG cap-and-trade program.[55,56]

Costs

Alaska will accrue costs for developing and managing a state Energy Database. Estimated development costs range from $300,000 to $500,000, depending on whether the state can modify an existing database or must develop a completely new one. Funds could come from AEA's existing Alternative Energy Fund to develop and administer this database.

Feasibility Issues

The feasibility issues associated with this policy are how to ensure that those working on the Alaska Energy Plan and those working on the Climate Change Strategy will coordinate their efforts to develop an integrated plan. Further, for the development of the Energy Database, the funding mechanism is not yet known.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

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[55] Steve Colt, Institute for Social and Economic Research, "Comments on the Lieberman-Warner Climate Security Act and Lieberman-Warner Proposed Legislation," April 11, 2008. Available at: www.iser.uaa.alaska.edu/Publications/Colt_ACCF-NAM_Ak2.pdf.

[56] EIA, *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007*, SR-OIAF/2008/01, April 2008. Available at: http://www.eia.doe.gov/oiaf/servicerpt/s2191/index.html.

CC-5. Explore Various Market-Based Systems to Manage GHG Emissions

Policy Description

Many organizations and governmental entities are exploring and implementing market-based programs for managing GHG emissions. For example, the European Union Emissions Trading Scheme and the Northeast Regional Greenhouse Gas Initiative are being implemented. WCI is developing a regional cap-and-trade system among western states (Alaska is an observer to WCI). The U.S. Congress is also developing and considering market-based systems that would be enacted nationwide if adopted, with varying scopes on industry. Details of these proposals vary, as do their potential impacts on Alaska.

Alaska has many issues to be addressed as it considers developing a state climate policy. Alaska is a major producer of oil and natural gas, which makes up a large portion of its economy and GHG footprint. Any market-based system adopted by Alaska or the United States could have significant effects on the nationwide demand for oil and gas. In general, any efforts to put a price on carbon will increase the wellhead value of both gas and crude oil from the North Slope. According to the Institute for Social and Economic Research (ISER), "natural gas contains 55% as much CO_2 per unit energy as coal. Switching from coal to natural gas is one sure way for electric utilities to reduce GHG emissions. Economic theory predicts that the more stringent is the cap on emissions, the more the demand for natural gas will be stimulated."[57] The projections contained in this ISER analysis of the Lieberman-Warner bill show an additional $4–$9 billion per year of wellhead value, translating into an additional $1–$2 billion per year of gas revenue to the state treasury under Lieberman-Warner.

This policy recommends that a study be commissioned to explore the implications to Alaska of participating in the various market-based approaches for managing GHG emissions, including cap-and-trade programs, carbon taxes, and cap-and-dividend programs. The study would include investigation into the experiences of those who have implemented market-based systems, such as the European Union and the U.S. Northeast. The study could further make a recommendation on the type of market-based system that would be most beneficial to Alaska or the type of system that the state should prepare for. An appropriately designed market-based program can help ensure that GHG emissions are achieved as cost-effectively as possible. Revenues generated from the market-based program can be used to cover program costs, generate jobs, establish loan or grant programs, or offset impacts.

[57] Steve Colt, Institute for Social and Economic Research, "Comments on the Lieberman-Warner Climate Security Act and Lieberman-Warner proposed legislation," April 11, 2008 (www.iser.uaa.alaska.edu/Publications/Colt_ACCF-NAM_Ak2.pdf); and Steve Colt, Scott Goldsmith, and Peter Larson, ISER, "Analysis of National Greenhouse Gas (GHG) Control Legislation on Alaska Energy Prices and Consumer Costs," July 2007 (www.iser.uaa.alaska.edu/presentations/Bingaman_update_V2.pdf).

Policy Design

Market-based initiatives to manage carbon are under development.[58] Exploring the impact on Alaska of the various market-based systems in detail requires rigorous economic inquiry. This policy recommends that research be conducted to explore different market-based initiatives and their potential impacts on Alaska.

Goals:

- Examine how a market-based program interacts with existing and proposed emission reduction measures, including regulations, performance-based standards, price subsidies, tax credits, and other technology-promoting initiatives.
- Examine how to oversee and manage revenues generated by any future market-based program, and determine whether changes to existing laws will be needed.
- Parallel to and in coordination with this study, participate in federal and regional discussions on and implementation of a market-based program for Alaska.

The three major types of market-based systems under debate are carbon taxes, a carbon cap-and-trade program, and a carbon cap-and-dividend program. The advisability and costs and benefits of these approaches for Alaska need further investigation. A brief description of these market-based systems follows:

- A *carbon tax* is a pollution tax on CO_2 and other GHG emissions, levied on the production, distribution, or use of a fossil fuel. The government would set a price for GHG emissions and translate that price into a tax on covered entities, such as the electric power industry, based on the amount of GHG emitted from fossil fuels. Because this tax would make energy more expensive to produce, it would encourage more energy conservation from both producers and consumers.[59]
- A *carbon cap-and-trade program* would set a cap on the amount of allowable GHG emissions. The program would grant a certain number of allowances to entities (by geographic area or by industry). Entities that emit fewer GHG emissions than their allowances could sell their unused allowances on the market to entities that exceed their allowances, thereby putting a price on carbon that would encourage covered entities to reduce their GHG emissions. Some cap-and-trade programs propose a "safety valve"—if the price of a GHG allowance becomes too high, entities would be able to purchase additional allowances at some fixed price. The cap would lower over time, affecting the costs of carbon and decreasing emissions.[60]
- A *carbon cap-and-dividend program* establishes permits for emitting CO_2 that are auctioned to potential emitters, with the revenues being returned to citizens in the form of dividends,

[58] See www.pewclimate.org/federal/analysis/congress/110/cap-trade-bills for a table summarizing the Economy-Wide Cap & Trade Proposals in the 110th Congress prepared by the Pew Center on Global Climate Change. See www.westernclimateinitiative.org/ewebeditpro/items/O104F19865.PDF for the WCI design recommendations.

[59] Pew Center on Global Climate Change, "Tax Policies to Reduce Greenhouse Gas Emissions." Available at: http://www.pewclimate.org/DDCF-Briefs/Taxes.

[60] Ibid.

based on specific criteria for distribution (e.g., equal distribution or need). This could be modeled after the Alaska Permanent Fund.[61] Similar to a cap-and-trade program, the cap would lower over time, and the price of carbon would rise. Dividends would rise as the price of carbon rises.[62]

Timing: In 2009, the Climate Change Sub-Cabinet would commission a research study to engage Alaska professionals in an Alaska-specific analysis of the impacts of participating in various market-based proposals, and recommend the future path for Alaska.

Parties Involved: Climate Change Sub-Cabinet, commissioned researcher.

Other: None.

Implementation Mechanisms

The Climate Change Sub-Cabinet would commission a study on market-based options, potentially by leveraging existing funding and contracting mechanisms.

Related Programs/Policies in Place

ISER has conducted some economic analyses of the potential effects of carbon market legislation on Alaska (http://www.iser.uaa.alaska.edu/Home/ResearchAreas/climatechange.htm).

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

The time frame for developing a federal market-based program to manage GHG emissions is unknown. Recent discussions in Congress and announcements from President Obama suggest that a GHG cap-and trade-program may be on the horizon. The pace of development of this federal legislation could affect the need for a study. Mandatory requirements could be developed before Alaska evaluates options and engages in discussions.

Additional Benefits and Costs

Benefits

The results of this analysis could help inform Alaska's participation in some market-based system, such as WCI.

[61] For more information, see: https://www.pfd.state.ak.us/.

[62] Cap and Dividend. "How Cap and Dividend Works." Available at: http://www.capanddividend.org/?q=readfirst.

Costs

The costs of this policy will be the costs of commissioning a study, which will vary, depending on the final scope of the study. Initial estimates range between $25,000 and $50,000.

Feasibility Issues

It is unclear who would conduct this analysis, although ISER is well positioned given its past work on climate change legislation and the resulting impacts on the Alaskan economy. Further, the mechanism for funding and overseeing this study is not yet known.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-6. Coordinate Implementation of Alaska's Efforts to Address Climate Change

Policy Description

Responding to climate change and reducing GHG emissions will require a dedicated and coordinated effort. Better coordination can promote efficiencies and effectiveness in the following areas:

- Tracking climate change efforts across state agencies in Alaska;
- Communicating between Alaska's efforts and other efforts (e.g., federal activities);
- Proactively interacting with and responding to expected federal initiatives on climate change;
- Providing access to information and education resources; and
- Improving outreach to citizens and businesses on climate change.

To achieve the above, a coordinating entity is needed. This coordinating entity could be an Alaska Climate Change Coordinating Committee under the Sub-Cabinet or a designated person or office that brings together representatives of state agencies. It is recommended that the Sub-Cabinet ensure coordination of the work already started through the Advisory Committee process. If a committee or lead office is not identified, the Sub-Cabinet should authorize a task force to continue to identify ways to ensure coordination among state agencies, especially on policy and strategy coordination and responses to federal inquiries and reporting requirements. With a strong coordination effort, resources and funding can be identified, secured, and leveraged to further Alaska's climate change policies and goals.

Policy Design

Goals:

- Provide focus to state agency efforts as recommendations of the Sub-Cabinet are implemented.
- Ensure the coordination of state agency development of position papers, guidance documents, policies, procedures, and standards to establish and implement federal and state climate change programs.
- Provide outreach and consistent information on climate change mitigation technology and regulatory guidance to industry and the public.
- Ensure the Sub-Cabinet's Climate Change Strategy efforts are coordinated with the Alaska Energy Plan (see CC-4), the Alaska Municipal League, industry, WCI, and advisory groups working on climate change efforts in Alaska.
- Provide a primary point of contact for federal agencies addressing climate change in Alaska.

Activities

- Support a GHG emission reporting program and associated inventories (see CC-1) as mandated by federal or state policies.
- Develop state government partnerships with private citizens, businesses, and local governments.
- Promote actions for state agencies to take to address climate change (see CC-3).
- Provide outreach and access to information by continuing to support the Alaska Climate Change Strategy Web site. (Consider evolution to a portal to provide additional information and functionality as a clearinghouse of climate change information, resources, and education materials among state agencies.)

Timing: This coordination effort should be initiated as soon as possible after approval by the Climate Change Sub-Cabinet.

Parties Involved: Key to the success of the effort will be identifying and maximizing partnerships within state agencies, and with federal, private, and public programs. The Governor and the Governor's Office, the Office of Management and Budget, the Climate Change Sub-Cabinet, and representatives of key state departments, including DEC, Alaska Department of Fish and Game, Alaska Department of Natural Resources, and Alaska Department of Commerce, Community, and Economic Development should be involved. In 2009, the Sub-Cabinet should assess current resources and identify lead staff. Resources and staff should be committed by the end of 2009 to address the coordination goals and activities listed above.

Many groups will be partners and beneficiaries of this coordinating body, including the state legislature, Climate Change Sub-Cabinet, state and federal agencies, Alaska Municipal League, tribes, AEA, UA, state public elementary and secondary schools, communities and local government, and industry.

Other: None.

Implementation Mechanisms

To establish an Alaska Climate Change Coordinating Program, the Sub-Cabinet must provide authorization to an entity to lead the effort. Additionally, funding for activities may be required. The Sub-Cabinet should submit legislative or budget documentation necessary to procure the resources and authority to charter this coordination effort. DEC will continue to have responsibilities for permitting, database, and reporting tools for administering a GHG Reporting Program (see CC-1). Appropriate tools and skills must be put in place to support coordination and outreach efforts, including technology and training as necessary.

Related Programs/Policies in Place

Creating a coordinating function with the mission of tracking climate change and coordinating the state's response will help to ensure the success of the other policies in the Alaska Climate Change Strategy. Staff tasked with this effort can also serve as key liaisons and resources for the private sector if or when the state enacts regulations governing GHG emissions or reporting. A Web portal would serve as an information hub to provide outreach for preparing for and responding to climate change, and for efforts to monitor, measure, and research climate change.

Many state agencies already have existing staff who deal with climate change issues and outreach. This policy would not fund these positions or create new ones within these agencies; rather, it would serve to coordinate and complement these activities.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

Challenges include engaging all agencies with responsibilities for addressing climate change, establishing clear responsibilities for coordinating roles, identifying needed funding to carry out the coordination, organizing information to present to the public, and identifying processes to maintain and update a Web site.

Additional Benefits and Costs

Benefits

Creating a coordination function is essential to track and provide some cohesion to the state's response to the Sub-Cabinet recommendations. It will also facilitate state agencies' efforts to educate businesses, agencies, and individuals seeking knowledge about climate change programs and policies, thus improving overall understanding of climate change issues. Finally, it will provide a means for state agencies to share climate change information and coordinate interactions with the federal government.

Costs

Costs primarily entail resources for personnel to provide the point of coordination, including salaries and benefits, potentially contracting costs to develop materials and support a Web portal, and training costs to ensure staff have the skills needed to provide outreach and education.

Feasibility Issues

Key feasibility issues include identifying a funding source and appropriately coordinating across existing programs. In addition, the effort needs to be flexible and generate sufficient political will to be effective and sustained.

Status of Group Approval

Approved.

Level of Group Support

Supermajority.

Barriers to Consensus

Two MAG members present at the final MAG meeting objected to this option, stating that it duplicated existing efforts, that a new agency should not be created, and that there is not a need to expend funds on coordination.

Appendix G
Energy Supply and Demand Policy Recommendations

Summary of List of Alaska Climate Change Mitigation Policy Recommendations

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)	Level of Support
		2015	2020	2025	Total 2010-2025			
ESD-1a	Rural Village-to-Village Transmission	0.00	0.00	0.01	0.05	$44	$897	Unanimous
ESD-1b	Renewable Energy Grants for Transmission Upgrades	0.06	0.08	0.09	1.06	–$2	–$2	Unanimous
ESD-1	Transmission Optimization and Expansion (Total a & b)	0.07	0.08	0.09	1.11	$42	$38	Unanimous
ESD-2	Energy Efficiency for Residential and Commercial Customers	*Quantified with ESD-2/4/6*						*See below*
ESD-2/4/6	Energy Efficiency for Residential, Commercial, and Industrial Customers, 2% per year	0.34	1.07	1.84	12.41	–$728	–$59	Unanimous
ESD-3	Implementation of Renewable Energy	1.99	2.35	3.86	32.52	$297	$9	Unanimous
ESD-4	Building Standards/Incentives	*Quantified with ESD-2/4/6*						*See above*
ESD-5	Efficiency Improvements for Generators	*Moved to Research Needs Work Group*						
ESD-6	Energy Efficiency for Industrial Installations	*Quantified with ESD-2/4/6*						*See above*
ESD-7	Implementation of Small-Scale Nuclear Power	*Moved to Research Needs Work Group*						
ESD-8	Research and Development for Cold-Climate Renewable Technologies	*Moved to Research Needs Work Group*						
ESD-9	Implementation of Advanced Supply-Side Technologies	*Moved to Research Needs Work Group*						
	Sector Total After Adjusting for Overlaps*	**1.93**	**2.77**	**4.67**	**37.51**	**–$19.46**	**–$4.24**	
	Reductions From Recent Actions				**0.34**			
	Sector Total Plus Recent Actions	**1.93**	**2.77**	**4.67**	**37.85**	**–$19.46**	**–$4.24**	

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent. Note: Sector Total is indicative of potential savings, see note in chapter.

ESD-1. Transmission Optimization and Expansion

Policy Description

A policy of transmission optimization and expansion in Alaska will offset sources of greenhouse gases (GHGs) by linking load centers with both existing and new renewable energy, and improving the efficiency of rural generators by increasing capacity-sharing capabilities. This policy is directed toward establishing improvements in the electrical network of Alaska that will:

- Improve opportunities for renewable resource utilization;
- Enhance coordination between electricity end users and energy providers; and
- Promote the reduction of electric energy losses associated with inadequate and aging infrastructure.

The best renewable resources may not be near existing transmission lines. New transmission, as well as upgrades to existing transmission lines, may be needed to accommodate extensive deployment of renewable generation capacity.

Energy Supply and Demand (ESD)-1 is intended to target transmission projects with established scopes and budgets submitted and accepted for seed funding by the Alaska Energy Authority's (AEA's) Renewable Energy Fund, as well as broadly defined transmission systems between remote rural areas. While addressing the need for improved optimization and the desirability of smart-grid features, ESD-1 does not provide the costs and benefits of incremental grid improvements or a systematic overhaul.

Policy Design

The policy would be implemented through the adoption and revision of existing programs, as well as financial and logistical coordination with electric cooperatives and utilities throughout Alaska. While no specific funding mechanism is currently proposed to implement either transmission expansion or optimization projects, a number of mechanisms could be used in part or in whole:

- A revolving-door mechanism financed by the state via either the AEA revolving loan fund or the Power Cost Equalization (PCE) Endowment Fund for project development;
- A public benefit fund (PBF) in concert with ESD-2, used to fund generator efficiency via village-to-village transmission upgrades;
- State revenues generated by auctioning carbon allowances under a national cap-and-trade policy (or alternately, funding from a carbon tax under a similar framework);
- Power project loans from the AEA to qualified entities for constructing, improving, and expanding transmission and distribution (T&D) facilities;
- Department of Revenue Permanent Fund or other state tax revenues;
- Utilities including transmission operation and maintenance (O&M) in rates.

Goals:

- Interconnection of major generation facilities within the applicable regions of Alaska.
- Access to identified hydroelectric, wind, tidal, and other non-fossil-fired generation resources.
- Displacement of less efficient industrial and commercial electrical generation facilities (including Alyeska Pipeline pump stations, North Slope production facilities, Cook Inlet production facilities, fish processing generation, and others).
- Improved access for combined heat and power production facilities at industrial locations.
- Reduced diesel-fired generation in remote locations.
- Electricity access for resource development, such as mining, tourism, fisheries, and others in remote locations.
- Regional or micro grids supplied by specialized resources (e.g., geothermal facilities).

Timing: To meet anticipated national GHG goals, transmission projects that effectively reduce GHG emissions would need to begin implementation by 2015; interties applying for AEA Renewable Energy (RE) Funds are scheduled to start operation between 2010 and 2013.

Parties: Electric transmission facilities, while primarily owned and/or operated by utility organizations, are subject to regulatory oversight by a host of state and federal agencies. As transmission facilities are notably visible and by their very nature have a wide range of ecological impacts, numerous non-governmental organizations also participate in various ways on transmission system issues. The primary participants in implementation of a statewide policy of transmission optimization and expansion are:

- The AEA and the Alaska Industrial Development and Export Authority (AIDEA), which are currently charged with distributing state funding for RE and PCE-related funding.
- The electric utilities of Alaska—private, municipal, cooperative, and joint-action agencies and various operating organizations among utilities.
- The Denali Commission.
- The Regulatory Commission of Alaska (RCA).
- The Alaska Department of Natural Resources (DNR).
- The U.S. Department of Agriculture's Rural Utilities Service.
- The U.S. Fish and Wildlife Service.
- The U.S. Army Corp of Engineers.
- Statewide commercial and industrial enterprise owners.

Other: None identified.

Implementation Mechanisms

A statewide policy promoting enhancement of the state's transmission system will be implemented through regulatory polices of the state to reduce barriers to development and to establish, for example, a structural framework for providing low-cost funds for financing system expansion and technological improvements. The Denali Commission and AIDEA/AEA would be the agencies of significance in providing financial and technology support.

Legislation could create a new transmission authority, charged with (1) funding improvements in the electric transmission infrastructure and developing energy storage technologies; (2) facilitating the transmission and use of renewable energy by financing or planning, acquiring, maintaining, and operating electric transmission facilities, storage facilities, and related infrastructure; and (3) facilitating and guiding the transmission siting process among utilities, municipalities, cooperatives and electric authorities, villages, and commercial entities. Such an entity could be funded through one or more of the mechanisms described above.

Related Policies/Programs in Place

The State of Alaska and the Denali Commission have had programs in place to enhance the transmission system. Alaska's AIDEA/AEA has developed transmission facilities, retaining ownership while delegating maintenance and operation to utility participants. AIDEA/AEA includes transmission system development as a component of expanded access to renewable resources by utilities. The federal government has supported improved transmission, for example, by authorizing the various components of the Southeast Alaska Intertie system, which has benefited from periodic contributions of appropriated funds for design and construction by various electric utility organizations.

Seed monies for scoped transmission projects are currently provided by the AEA under the umbrella of the Renewable Energy Fund, while other transmission projects have obtained direct state appropriations.

Type(s) of GHG Reductions

Types: Carbon dioxide (CO_2) and nitrous oxide (N_2O).

Negative Impacts: Loss of CO_2 sink in forests displaced by transmission lines; fuel used in construction and maintenance of transmission lines.

Table G-1. Estimated GHG reductions and net costs of or cost savings from ESD-2/4/6 under 2% scenario

Policy No.	Policy	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million 2008$)	Cost-Effectiveness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
ESD-1a	Rural Village-to-Village Transmission	0.00	0.00	0.01	0.05	$44	$897
ESD-1b	Renewable Energy Grants for Transmission Upgrades	0.06	0.08	0.09	1.06	-$2	-$2
ESD-1	**Transmission Optimization and Expansion**	**0.07**	**0.08**	**0.09**	**1.11**	**$42**	**$38**

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

The two analyses under this policy are designed to quantify, separately, the benefits from a rural transmission program and a renewable energy access program. In both cases, proxy cases are included as examples to assist in the quantification of the cost-effectiveness of these two GHG reduction mechanisms. "Rural Transmission" explores the costs of connecting 200 villages with dispersed microgrids, easing load-following requirements for small-scale generators. Higher efficiency results in reduced fuel consumption and GHG emissions. "RE Access Transmission" tests the net value of implementing transmission to existing renewable energy sources. This analysis does not include the marginal GHG savings associated with reducing line losses along established grid networks or the fuel efficiencies gained by connecting remote industries and Alyeska pump stations to the existing grid.

Estimated GHG Reductions and Net Costs or Cost Savings

The analysis of this policy is based on two sub-scenarios, which are analyzed under a separate construct. Detailed assumptions can be found in at the end of the policy descriptions. Data sources, quantification methods, and key assumptions are explained briefly below for each of the two sub-scenarios:

Rural Village-to-Village Transmission (ESD-1a)

Data Sources: The quantification is an exercise in village-to-village connectivity, assuming a fixed number of villages in rural Alaska (northern, southwestern, and Kodiak) that are not currently connected. Village generators reduce fuel use when connected to another village.

Quantification Methods: This is a simple spreadsheet model, based on a scenario designed by the ESD Technical Work Group (TWG), and using data inputs from Alaska Power Statistics. Using 2001 statistics, 161 villages were identified that generated power only from diesel oil combustion turbines and were not connected to either a central power grid or other towns or villages. The total power generated from these villages was recorded, and their approximate location (latitude and longitude) as determined with Google Maps. The absolute straight-line distance between each village pairing was determined (in miles). Every village pairing within a 60-mile threshold was considered a viable transmission pairing; 31 villages fit this criterion,

serving 102,667 megawatt-hours (MWh) of diesel-fired generation in 2003, or 1.6% of Alaska load in 2009. The average distance between the nearest villages within this grouping is 30 miles.

Transmission projects were assumed to begin in 2012 and end in 2020, with three to four villages being connected each year.

Input assumptions included a $300,000 per linear mile cost of transmission, a 15% savings in fuel consumption by connecting two villages, a 20-year economic life of transmission lines, and a 5% discount rate. The capital costs of transmission lines were amortized over the 20-year period; no cost was assumed for O&M or new generators (assumed to be replaced as transmission is built).

Key Assumptions: The model is highly sensitive to the distances between villages, the expected fuel efficiency savings from connecting two villages, as well as the average energy use per village. The total number of villages involved (161), as well as the average energy use per village was determined from the *Alaska Electric Power Statistics* (2003) data set. Communities in this analysis were those that were listed as using internal combustion generation (assumed diesel) and were not obviously connected to a larger community with other energy sources already available. The analysis is sensitive to the assumed expected fuel savings and the threshold distance for connecting villages. Because actual linear distances were calculated, and each village serves a different amount of load, the savings and costs on a village-by-village basis are quite different. This analysis did not attempt to distinguish the most cost-effective set of villages (i.e., those that both are near to each other and serve significant load, where significant savings might be realized). However, we did conduct a sensitivity analysis on the threshold distance and possible savings from connecting two villages. Table G-1 shows the results of this sensitivity as a function of the threshold distance and fuel savings expectation.

Table G-2. Carbon cost efficacy of village-to-village interties, depending on expected fuel savings from connecting two villages and maximum distance threshold between two villages

Threshold Distance (miles)	Villages in Analysis	Average Distance (miles)	Load Served (MWh)	Cost-Effectiveness (2008$/t$CO_2$e) at Interconnection Fuel Savings		
				5%	15%*	25%
20	9	11.8	9,096	$3,489	$969	$464
50*	29	28.3	74,149	$3,274	$897	$422
100	51	49.2	174,717	$4,350	$1,255	$637
200	109	104.2	319,538	$11,188	$3,535	$2,004

GHG = greenhouse gas; MMtCO_2e = million metric tons of carbon dioxide equivalent; $/t$CO_2$e = dollars per metric ton of carbon dioxide equivalent; MWh = megawatt-hour.

*Default value

Renewable Energy Grants for Transmission Upgrades (ESD-1b)

The transmission for renewable energy access shares a similar quantification structure with the ESD-3 analysis of the implementation of renewable energy projects.

Data Sources: This quantification assumes that projects submitted for seed funding from the AEA Renewable Energy Fund are implemented. Only five projects that focus exclusively on

transmission to renewable energy are included in this analysis: (1) Metlakatla–Ketchikan intertie, (2) North Prince of Wales intertie, (3) Kake–Petersburg intertie, (4) transmission and control infrastructure (for wind in Nome), and (5) the Lake and Peninsula Borough wind/hydro intertie.

Program descriptions and data for quantifying emission reductions were obtained from the following sources:

- Alaska Energy Authority, *Renewable Energy Fund Applications and Analysis: Round 1 and Round 2 Project Summaries and AEA Evaluations*. Available at: http://www.akenergyauthority.org/RE_Fund_Applications.html.
- *Distributing Alaska's Power: A Technical and Policy Review of Electric Transmission in Alaska*, September 4, 2008. Prepared for the Denali Commission. http://denali.gov/
- Institute of Social and Economic Research, University of Alaska, Anchorage (November 2003), *Alaska Electric Power Statistics (with Alaska Energy Balance): 1960–2001*, Prepared for the Alaska Energy Authority, Regulatory Commission of Alaska, and Denali Commission.
- Governor Palin's press conference at Alaska Energy Authority: "Palin Unveils Energy Goals for Cities, Villages," *Fairbanks Daily News-Miner*, January 16, 2009. http://www.newsminer.com/news/2009/jan/16/palin-unveils-energy-goals-cities-villages/
- U.S. Energy Information Administration (EIA) (2009), *Assumptions for the Annual Energy Outlook 2009: With Projections to 2030*. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/index.html.
- Alaska Energy Authority (January 2009), *Alaska Energy: A First Step Toward Energy Independence*. Available at: http://www.akenergyauthority.org/

Quantification Methods: The model is structured from standard analyses conducted by the AEA to determine which RE Fund projects could obtain seed funding. Each project lists (among other variables) annual expected renewable generation that would be accessed, O&M costs, avoided fossil fuel use, local expected prices for fuels, and capital costs. Capital costs are amortized across the expected lifetime of the project (also given by the AEA), starting from the first year of generation. The net present value (NPV) is determined from the discounted costs (including amortized capital costs) and benefits through 2025. Avoided fuel use is translated into avoided CO_2 emissions. Total cost -effectiveness is calculated as the cumulative carbon avoided (to 2025) divided by the NPV.

Key Assumptions: Costs, avoided costs, timing, and avoided fuel uses assumed by the AEA and partners in the RE Fund analysis (see ESD-3 quantification for details). Carbon emission coefficients are extracted from the AEA analysis.

Key Uncertainties

Transmission for Renewable Energy: If projects are the only feasible interties available; if the implementation of new medium- to large-scale renewable energy projects would spur interest or need for new transmission connections to a central grid.

Rural interties analysis: Distances between villages, number of villages impacted or participating, direct connection from village to village, efficiency gains expected by connection of two or more villages, cost of transmission, expected start and end of transmission projects, feasibility of connecting multiple villages per year, and avoided costs of diesel (currently from AEA RE Grants program, Round 1, project 110—Kong Wind)

National climate policy and both world oil and natural gas markets will influence the cost-effectiveness of future projects.

Additional Benefits and Costs

Increased transmission and access to renewable generation will produce several co-benefits for Alaska. These include:

- Lower electricity costs and increased reliability in rural areas and villages.
- Reduced environmental damage and costs associated with cleanup of diesel fuel spills in rural villages and along watercourses.
- Reduced criteria and toxic air pollutant emissions from diesel generators.

Feasibility Issues

Transmission infrastructure is often costly and difficult to site based on property, environmental, and line operation and ownership considerations. The siting process requires the participation of large groups of stakeholders with diverse interests and conflicts. In addition, transmission lines in remote areas may be difficult to service, and in Alaska are prone to icing, treefall, landslides, and other disturbances.

Statewide GHG benefits will be greatest if this policy is coordinated and integrated with ESD-2/4/6 (Energy Efficiency for Residential, Commercial, and Industrial Customers, 2% per year) However, avoided fuel costs and displaced carbon will be lower than calculated when combined with energy efficiency.

Fossil fuel use may be avoided in large part if distributed-generation renewable energy projects (i.e., ESD-3) are implemented on a village scale. Village-to-village transmission may still be beneficial for reliability purposes, but will displace less fossil fuel if renewable resources are used instead.

Status of Group Approval

Approved.

Level of Group Approval

Unanimous.

Barriers to Consensus

None.

ESD-2/4/6. Energy Efficiency for Residential, Commercial, and Industrial Customers, 2% per year

Policy Description

This policy seeks to reduce electricity, natural gas, and fuel oil consumption in the residential, commercial, and industrial sectors through energy efficiency and demand-side management (DSM) measures using a variety of programs and policies, including state and utility efficiency programs, appliances standards, and building codes. Details of these programs and policies are provided under the Implementation Mechanisms section, below. This policy involves a variety of stakeholders, including state agencies, utilities, fuel distributors, advocacy groups, energy service companies, and local governments. The potential funding sources for this policy option include (but are not limited to) state funding through legislative actions, a system benefit charge, and a state-capitalized end-use efficiency endowment.

Energy efficiency reduces energy consumption required by appliances and heating and cooling equipment, while maintaining or improving the quality of energy services. Providing strong programs for energy efficiency and conservation in Alaska is one of the most cost-effective and fastest methods to reduce energy use and GHG emissions. The Interior Issues Council's Cost of Energy Task Force report, *Fairbanks Energy*,[1] states:

"Conservation and efficiency increases are by far the most effective means of reducing cost, reducing emissions and reducing fuel usage. The beauty of increasing efficiency is we can start today."

A recent report by the Cold Climate Housing Research Center[2] agrees with this view and states:

"To be sure, supply side solutions are necessary in Alaska, but efficiency measures should be step one in any energy plan—they are the single least expensive way to decrease demand and save energy."

Indeed, energy efficiency has been acknowledged across the nation and by the federal government as the least expensive energy solution. A growing number of states are requiring states and/or utilities to tap into cost-effective energy efficiency measures first before developing supply-side solutions. Contrary to these notions, Alaska has implemented few energy efficiency programs for more than a decade. This means that Alaska has significant untapped energy efficiency resources compared to other states.

The articulation of an energy efficiency vision by the Governor, and the ensuing design and implementation of a comprehensive set of energy efficiency and conservation programs could rapidly set in motion a significant energy use reduction for all sectors in the state: commercial, industrial, institutional, and residential. In 2008, the state invested significant funding toward

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[1] Fairbanks Economic Development Corporation. (2007). Fairbanks Energy: Strategic Business Plan. Available at: *http://www.investfairbanks.com/documents/FairbanksEnergyExecutiveSummary.pdf*

[2] Cold Climate Housing Research Center (2008). *Alaska Energy Efficiency Program and Policy Recommendations*. Prepared for the Alaska Energy Authority and Alaska Housing Finance Corporation. Available at: *http://www.cchrc.org/alaska+energy+efficiency+program+and+policy+recommendations.aspx.*

residential weatherization. Similar levels of support for the other sectors and for residential electrical efficiency are now needed to reduce both energy use and the energy costs in these homes and buildings.

Policy Design

Goals: Energy efficiency programs and policies to reduce energy consumption for electricity, natural gas, and fuel oil, and increase annual incremental energy savings to 1% of retail energy sales by 2015 and 2% by 2020 (Table G-3).

Table G-3. Annual incremental savings and expected savings below baseline load growth with 2% energy efficiency per year

2% Energy Efficiency by 2020	2010	2015	2020	2025
Annual incremental savings	0.2%	1.0%	2.0%	2.0%
Annual cumulative savings below baseline	0.2%	3.4%	10.8%	17.8%

Timing: Early action to begin with increased funding in current state programs in 2009.

Parties Involved: AEA, RCA, electric utilities, Alaska Housing Finance Corporation (AHFC), tribal governments, municipal and local governments, industrial partners, AIDEA, and possible third-party efficiency operators.

Implementation Mechanisms

Design and fund a comprehensive set of state and utility energy efficiency programs that will encourage the installation of energy efficient equipment and encourage the conservation of energy in all sectors. These programs would include:

- Public education.
- Comprehensive whole-building energy audits and retrofits for all sectors.
- Rebates and incentives to end users for installing energy-efficient equipment.
- Village retrofit and weatherization programs, including possibly an expanded whole-village retrofit program prior to re-sizing local power plants.
- An energy efficiency program for new and existing schools.
- Incentives for vendors, retailers, and contractors for selling or installing energy-efficient equipment and for optimizing the size of heating, ventilation, and air conditioning (HVAC) equipment.
- Low-cost loans for energy efficiency improvements.
- Training of related professionals (such as commercial energy auditors, HVAC maintenance staff, and retail sales staff).
- Performance incentives for program administrators (e.g., utility and/or third party).
- Energy savings measurement and verification studies.

- Other programs, such as a new construction program, a whole-building program for retrofit, a refrigerator trade-in and recycling program, pilot testing of smart meter installations, and research and development (R&D) testing of energy-efficient equipment in Alaska's climatic conditions.

In addition to the programs, certain other actions are recommended to knock down barriers to the implementation of energy efficiency measures, including:

- Establish energy efficiency building codes for residential and commercial properties statewide (to avoid Alaska's current problem of older buildings with very poor energy performance and high energy costs);
- Establish aggressive appliance standards;
- Change the rate structure of energy utilities to encourage their participation in providing aggressive energy efficiency and conservation programs. Alternatively, allow the utilities to pay a certain customer charge into the statewide energy efficiency delivery office(s), which will provide the above programs, incentives, rebates, loans, and trainings. This model is working exceptionally well in Oregon and avoids the internal conflict that utilities face regarding efficiency programs' detrimental effect on their sales revenues;
- Review the PCE program to determine if energy efficiency incentives can be effectively built in to encourage, rather than discourage, energy efficiency measures for these communities.

New or increased funding is necessary for engaging in most of the programs and policies mentioned above. The potential short-term funding source is state funding through legislative appropriation. The potential long-term funding source is a utility system benefit charge (e.g., a few mills per kilowatt-hour [kWh] for every ratepayer) or a state-capitalized end-use efficiency endowment (when a system benefit charge is politically difficult to establish).

Most of these elements of the policies and programs are outlined in the 2008 *Alaska Energy Efficiency Program and Policy Recommendations* report.[3] That report is the culmination of a significant project to determine future program and policy needs in Alaska related to energy efficiency, and serves as the roadmap and menu of needed actions.

Related Policies/Programs in Place

The Energy Independence and Security Act of 2007 has three titles particularly relevant to this policy: Title III: Appliance and Lighting Efficiency, Title IV: Energy Savings in Building and Industry, and Title V: Energy Savings in Government and Public Institutions.

- **The Weatherization Program:** Targeted at Alaskan residents with incomes below the state median. Funding increased in 2008 from ~$6 million to $300 million. Administered by AHFC.
- **The Home Energy Rebate Program:** Targeted at homeowners who do not qualify for the Weatherization Program. Provides rebates for high-efficiency home upgrades exceeding AHFC standards. Administered by AHFC.

[3] Ibid.

- **Second Mortgage Program for Energy Conservation:** Targeted at homeowners to make cost-effective energy improvements.[4] Administered by AHFC.

Type(s) of GHG Reductions

Reduction in GHG emissions (largely CO_2) from avoided electricity production or on-site fuel combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

The MAG evaluated two energy efficiency scenarios: (1) achieving 1% energy efficiency per year by 2015 and (2) reaching further to achieve 2% energy efficiency by 2020. Evaluating the economics and assessing current actions taken in other states, the MAG determined that the savings that could be achieved with 2% energy efficiency improvements each year would be an appropriate goal. Table G-4 presents results from the selected 2% energy efficiency goal, but additional charts and tables demonstrate and estimate savings for both the 1% and the 2% scenarios.

Table G-4 presents the estimated GHG reductions and net costs of or costs savings from implementing the 2% scenario. The table is broken down by electricity use, natural gas use (for residential, commercial, and industrial (RCI) purposes), and oil use. RCI end uses are not displaced but underlie the calculations summarized here. Figures G-1, G-2, and G-3 present the projected total energy consumption for all RCI sectors for electricity, natural gas, and fuel oil under the 1% and 2% scenarios, as well as the baseline energy consumption by sector in the background.

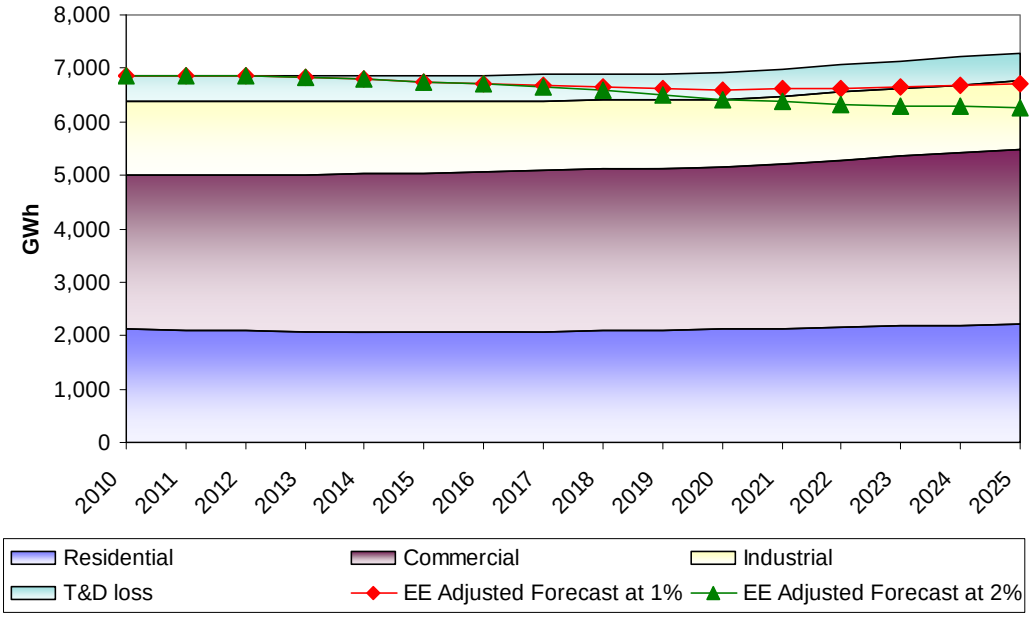
Table G-4. Estimated GHG reductions and net costs of or cost savings from ESD-2/4/6 under 2% scenario

Policy No.	Policy	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effectiveness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
ESD-2/4/6a	2% EE, Electric	0.16	0.50	0.88	5.86	–$246	–$42
ESD-2/4/6b	2% EE, Natural Gas	0.11	0.35	0.61	4.09	–$155	–$38
ESD-2/4/6c	2% EE, Oil	0.07	0.21	0.35	2.45	–$327	–$134
ESD-2/4/6	**2% EE, Total**	**0.34**	**1.07**	**1.84**	**12.41**	**–$728**	**–$59**

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

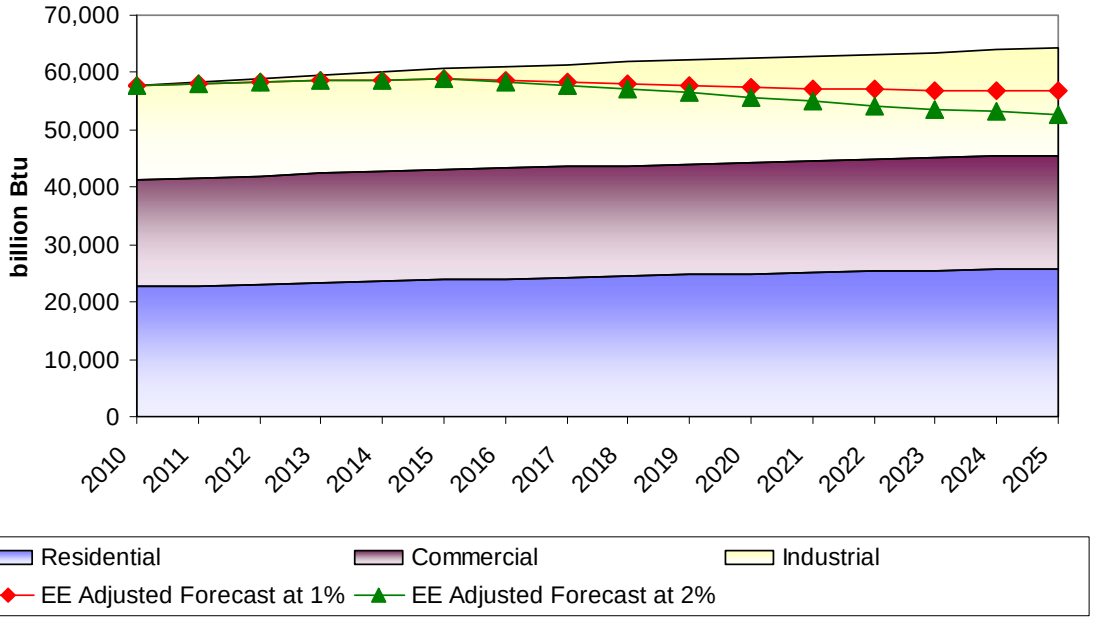
[4] Alaska Housing Finance Corporation. *Home Energy Rebate, Weatherization, and Loan Programs.* Updated 04/22/09. Available online at: http://www.ahfc.state.ak.us/energy/weatherization_rebates.cfm.

Figure G-1. Electricity demand forecast with/without energy efficiency scenarios



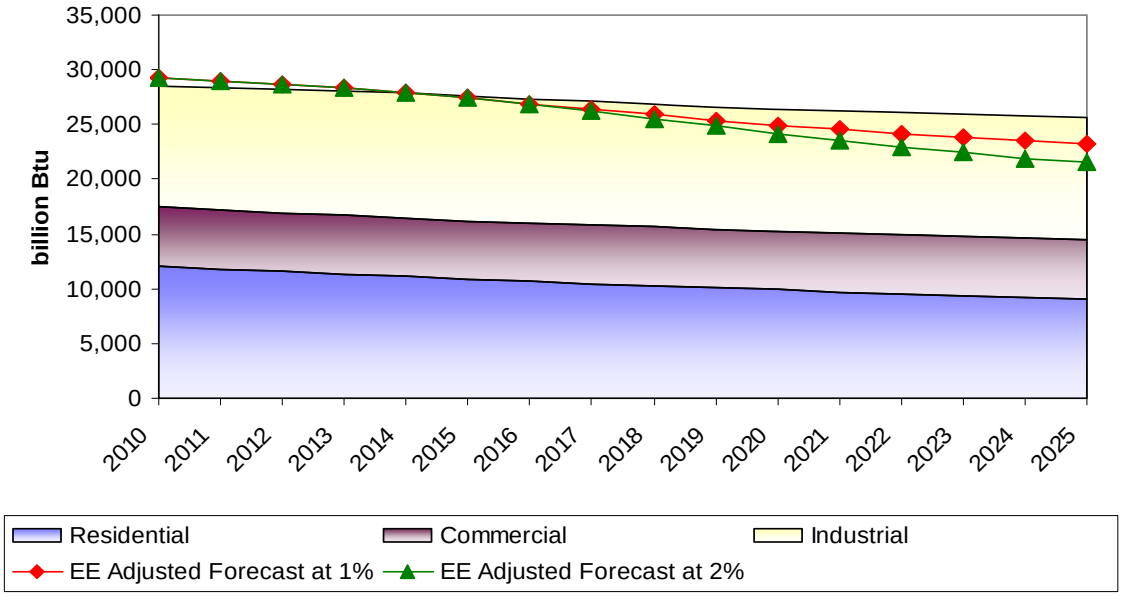
EE = energy efficiency; GWh = gigawatt-hours; T&D = transmission and distribution.

Figure G-2. Natural gas demand forecast with/without energy efficiency scenarios



Btu = British thermal units; EE = energy efficiency.

Figure G-3. Fuel oil demand forecast with/without energy efficiency scenarios



Btu = British thermal units; EE = energy efficiency.

Data Sources:

Experience in Other States on Cost of Energy Efficiency:

- U.S. Environmental Protection Agency (EPA) and U.S. Department of Energy (DOE) (July 2006), *National Action Plan for Energy Efficiency*, p. ES-4. Available at: http://www.epa.gov/cleanrgy/documents/napee/napee_exsum.pdf.
- Synapse Energy Economics (August 2008). *Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts*, prepared for the Northeast Energy Efficiency Council. Available at: http://www.synapse-energy.com/Downloads/SynapsePresentation.2008-08.0.Sustainability-and-Costs-of-Efficiency-Impacts.S0051.pdfUH.
- K. Takahashi and D. Nichols (2008), "The Sustainability and Costs of Increasing Efficiency Impacts: Evidence From Experience to Date," proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings, pp. 8-363–8-375. Available at: http://www.synapse-energy.com/Downloads/SynapsePresentation.2008-08.0.Sustainability-and-Costs-of-Efficiency-Impacts.S0051.pdf
- Bill Prindle (2007), "Energy Efficiency: The First Fuel in the Race for Clean and Secure Energy," presentation at the National Action Plan for Energy Efficiency Southeast Energy Efficiency Workshop on September 28, 2007. Available at: http://www.epa.gov/cleanenergy/documents/southeast-meeting/prindle_new_napee_presentation_atlanta_9_28_07.pdf.
- Martin Kushler, Dan York, and Patti White (April 2004), *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, Washington, DC:

American Council for an Energy Efficient Economy. Available at: http://www.aceee.org/pubs/u041.htm.

WGA 2006—Energy Efficiency Task Force Report to the Clean and Diversified Energy Advisory Committee of the Western Governors' Association (January 2006), *The Potential for More Efficient Electricity Use in the Western United States*, Denver, CO: Western Governors' Association. Available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-text.pdf

Cost of Saved Natural Gas:

- Southwest Energy Efficiency Project (2006), *Natural Gas Demand-Side Management Programs: A National Survey*. Available at: www.swenergy.org.

Cost of Saved Fuels and Measure Lifetime:

- U.S. DOE, Office of Energy Efficiency and Renewable Energy (2007), "Industrial Assessment Centers (IAC) Database." Available at: http://www.iac.rutgers.edu/database/.
- Suzanne Tegen and Howard Geller (January 2006), *Natural Gas Demand-Side Management Programs: A National Survey*, Boulder, CO: Southwest Energy Efficiency Project. Available at: www.swenergy.org.
- U.S. EPA and U.S. DOE (July 2006), *National Action Plan for Energy Efficiency*, p. ES-4, Available at: http://www.epa.gov/cleanrgy/documents/napee/napee_exsum.pdf.
- Martin Kushler, Dan York, and Patti White (January 2005), *Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest*, Washington, DC: American Council for an Energy Efficient Economy. Available at: http://www.aceee.org/pubs/u051.htm.
- Southwest Energy Efficiency Project (SWEEP) (January 2006), *Natural Gas Demand-Side Management Programs: A National Survey*. Available at www.swenergy.org.
- Optimal Energy, Inc., et al. (October 31, 2006), Natural Gas Energy Efficiency Resource Development Potential in New York, prepared for the New York State Energy Resource and Development Authority. Available at: http://www.nyserda.org/Energy_information/otherdocs.asp.

Quantification Methods:

- Base project energy savings on the stated energy savings (electricity, natural gas, and oil) target based on two scenarios: (1) a 1% per year annual incremental reduction in total annual consumption by 2015; and (2) further increasing the reduction to 2% per year by 2020. Adjust annual consumption each year based on the previous year's DSM impacts.
- Include all sectors in the analysis, including RCI.
- Estimate the total cost of energy savings using state-specific or region-specific data on the cost of saved energy from energy efficiency measures.
- Estimate the GHG emission reductions through the energy efficiency measures.

Key Assumptions:

Discount Rate: 5% real.

Avoided Cost of Electricity: 9.5 cents/kWh as the population-weighted average cost of avoided electricity in different regions:

- Railbelt: 6 cents/kWh based mainly on the cost of natural gas power plants.
- Southeast: zero due to hydro dominant energy sources in the region.
- Rural: 22 cents/kWh based on oil-based electricity and $96/barrel of oil (2008$/barrel), as the levelized price of oil price for lower 48 oil price over the study period. The oil data are obtained from the U.S. EIA's *Annual Energy Outlook 2009* (AEO 2009).
- The conversion rate between oil and electricity is based on the range of electricity price from 12 to 30 cents/kWh for $50 to $147/barrel of oil, obtained from the ESD TWG members.

Avoided Cost of Natural Gas: $5.28/million British thermal units (MMBtu) (2008$), the levelized cost of projected natural gas prices. The natural gas avoided cost was projected using (1) the average Alaska city gate price of natural gas in 2008 and (2) the trend in projected natural gas prices in the AEO 2009 for the Pacific region.

Avoided Cost of Fuel Oil: $20.11/MMBtu (2008$) (placeholder assumption), levelized price of distillate fuel oil for the Pacific region (AEO 2009 between 2009 and 2025).

T&D Loss: 7% for electricity, 0% for natural gas, 0% for fuel oil.

Cost of Electric Energy Efficiency Measures: 5 cents/kWh for electricity—inflated from the "typical" price of energy efficiency in the lower 48 states. The utility cost of saved energy (CSE) for electric energy efficiency programs (that does not include participants' costs of efficiency measures) is 1–5 cents/kWh saved, with the average about 2.4 cents/kWh saved based on experience in other states (CSE). These data are presented in Table G-5 and Figure G-4. Assuming the cost split between utilities and participants is about 60%/40%, the total cost of energy efficiency programs would be about 4 cents/kWh on average. This estimate was then inflated by 25% to take into account higher costs of products and services in Alaska.

Table G-5. Utility cost of saved energy[5]

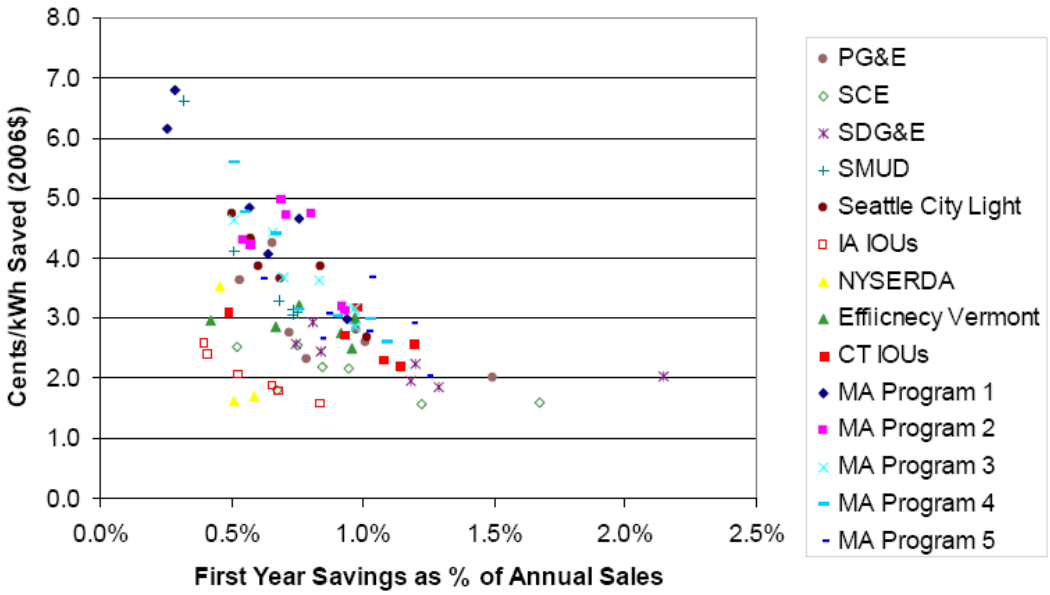
Entity	State	CSE (cents/kWh)
Austin Energy	TX	3
Bonneville Power Administration	ID, MT, OR, WA	3
California Utilities	CA	1
Connecticut Utilities	CT	1
Efficiency Vermont	VT	2
Massachusetts Utilities	MA	3
Minnesota Electric and Gas Investor-Owned Utilities	MN	1

[5] U.S. DOE, Office of Energy Efficiency and Renewable Energy (2007), "Industrial Assessment Centers (IAC) Database. Available at: http://www.iac.rutgers.edu/database/.

Entity	State	CSE (cents/kWh)
Nevada	NV	3
New York State Energy Research and Development Authority	NY	2
Seattle City Light	WA	2
Sacramento Municipal Utility District	CA	3
Wisconsin Department of Administration	WI	5
Average		**2.4**

CSE = cost of saved energy; DOE = U.S. Department of Energy; EPA = U.S. Environmental Protection Agency; KWh = kilowatt-hour.

Figure G-4. Utility cost of saved energy for multiple utilities over multiple years[6]



Cost of Saved Natural Gas: $ $2.99/MMBtu for natural gas—inflated from average the cost of saved natural gas (SWEEP 2006). The natural gas savings per dollar of program investment is 72,700 million cubic feet per year per million dollars, based on the average cost of a number of gas DSM programs reported in Tegen and Geller (2006). The RCI TWG will estimate the cost of saved natural gas per MMBtu based on (1) the natural gas savings per program investment above, (2) a 12-year average measure lifetime, and (3) a real discount rate of 5%.

Costs of Saved Fuel Oil and Propane: For residential and commercial uses, these costs are assumed to be the same as the cost of saved natural gas in terms of $/MMBtu. For the industrial sector, data available at DOE's IAC database might be useful.[7]

[6] Synapse Energy Economics (August 2008), *Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts*, prepared for the Northeast Energy Efficiency Council. This study concluded that the utility cost of energy efficiency programs tends to decrease as the scale of energy efficiency increases.

[7] U.S. DOE, Office of Energy Efficiency and Renewable Energy (2007, "Industrial Assessment Centers (IAC) Database." Available at: http://www.iac.rutgers.edu/database/

Utility cost of saved energy: The utility cost of saved energy (including incentives, marketing, and administrative costs) is assumed to be 60% of the total cost of energy efficiency. This cost does not include costs paid by participants. Utility costs of saved energy were obtained and adjusted upward to estimate the total costs using the 60%/40% cost split.

Energy Efficiency Measure Lifetime: 12 years on average.

Displaced Emissions for Electricity: 0.655 metric tons of carbon dioxide (tCO_2)/MWh as the population-weighted average emissions in different regions:

- Railbelt: 0.7468 tCO_2/MWh—a typical emission rate for natural gas power plants. Input from the TWG members. The data are obtained from EPA's Emissions & Generation Resource Integrated (eGRID) database.
- Southeast: Zero due to hydro-dominant energy sources in the region. Input from the TWG members.
- Rural: 0.5754 tCO_2/MWh. A typical emission rate for oil power plants. Input from the TWG members. The data are obtained from EPA's eGRID database.

Displaced emissions for natural gas: 0.0528 tCO_2/MMBtu.

Displaced emissions for natural gas: 0.0724 tCO_2/MMBtu based on the emission rate of distillate fuel.

Key Uncertainties

The source of funding to implement the aggressive DSM program envisioned here is uncertain.

There are few data on the cost of saved fuel oil. For this analysis, it was assumed that the costs of saved fuel oil equal the cost per MMBtu saved for natural gas. To the extent that oil appliances are similar to natural gas appliances, the costs will be similar among fuel-saving measures per MMBtu saved. While there are similar applications among all fuels (e.g., water heating, cooking), the similarities between specific appliances running on different fuels are less clear. On the other hand, given that there has not been any significant effort to promote oil-efficient appliances in the United States, there may be more “low-hanging fruit” in energy efficiency measures for oil that is not realized in this quantification.

Two scenarios were initially explored in this analysis. The MAG selected the more ambitious 2% energy efficiency scenario. However, results from both scenarios are shown in Table G-6 and Table G-7 for comparative purposes.

Table G-6. Annual incremental and cumulative savings from 1% and 2% energy efficiency programs

Energy Efficiency Scenarios	2010	2015	2020	2025
1% Energy Efficiency by 2020				
Annual incremental savings	0.2%	1.0%	1.0%	1.0%
Annual cumulative savings below baseline	0.2%	3.4%	8.1%	11.4%
2% Energy Efficiency by 2020				
Annual incremental savings	0.2%	1.0%	2.0%	2.0%
Annual cumulative savings below baseline	0.2%	3.4%	10.8%	17.8%

Table G-7. Estimated GHG reductions and net costs of or cost savings from ESD-2/4/6 under 1% and 2% scenarios

Policy No.	Policy	GHG Reductions ($MMtCO_2e$) 2015	2020	2025	Total 2010–2025	Net Present Value 2010–2025 (Million $)	Cost-Effectiveness ($/tCO_2e$)
ESD-2/4/6a	1% EE, Electric	0.16	0.38	0.56	4.35	–$187	–$43
ESD-2/4/6b	1% EE, Natural Gas	0.11	0.26	0.39	3.03	–$117	–$39
ESD-2/4/6c	1% EE, Oil	0.07	0.16	0.23	1.85	–$252	–$137
ESD-2/4/6	**1% EE, Total**	**0.34**	**0.80**	**1.18**	**9.22**	**–$557**	**–$60**
ESD-2/4/6a	2% EE, Electric	0.16	0.50	0.88	5.86	–$246	–$42
ESD-2/4/6b	2% EE, Natural Gas	0.11	0.35	0.61	4.09	–$155	–$38
ESD-2/4/6c	2% EE, Oil	0.07	0.21	0.35	2.45	–$327	–$134
ESD-2/4/6	**2% EE, Total**	**0.34**	**1.07**	**1.84**	**12.41**	**–$728**	**–$59**

EE = energy efficiency; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Additional Benefits and Costs

- Indoor comfort and air quality improvements, with related improvements in health and productivity.
- Savings to consumers and businesses on energy bills. Benefits to low-income populations from reduced utility costs.
- Electricity system benefits: reduced peak demand, reduced capital and operating costs, improved utilization and performance of electricity system.
- Reduced risk of power shortages.
- Reduced pollutants from emissions, improved health from fewer pollutants and particulates, and reduced water use for cooling.
- Green-collar employment expansion and economic development.
- Reduced dependence on imported fuel sources.
- Reduced energy price increases and volatility.

Feasibility Issues

None known.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ESD-3. Implementation of Renewable Energy

Policy Description

Renewable energy systems can directly offset fossil fuel use. This is especially true in Alaska's rural villages, which rely on expensive diesel fuel for electricity generation. Renewable energy systems include wind, biomass, hydro, geothermal, solar photovoltaic, solar thermal, and other systems relying on energy flows driven directly or indirectly by solar radiation or geothermal heat. The purpose of this policy is to reduce the use of fossil fuels by establishing an economic and regulatory environment that will allow and encourage utilities and individuals to install capital-intensive renewable energy systems. Electricity generation is likely to be a promising sector for early actions.

Policy Design

This policy focuses on encouraging renewable energy development through implementation of legislation passed by the Alaska legislature in 2008, and the recent AEA report on energy independence.[8] To achieve the policy goals, the State of Alaska will:

- Aggressively publicize, pursue, and monitor progress toward the target of 50% of electricity generation from renewable sources by 2025.
- Set benchmark targets for renewable energy use until 2025.
- Follow through with the existing Renewable Energy Fund process and consider additional funding to support more projects.
- Shift priorities in the PCE Endowment Fund to reward utility, co-op, and village investment in renewable systems; transfer funds from reimbursements to infrastructure.
- Remove or reduce existing legal barriers to renewable energy systems, such as land use laws, land leasing requirements, or school funding formulas that might reduce reimbursements if a school or community invests in a wind turbine to reduce utility bills.
- Change the utility regulatory system—by statute if necessary—to provide for reasonable and predictable returns on utility investments in cost-effective renewable systems.
- Change the utility regulatory system – by statute if necessary – to provide for reasonable and predictable treatment of small-scale renewable systems installed by individuals and connected to the electric grid.
- Provide access to capital for cost-effective renewable energy investments through a combination of grants, rebates, loans, loan guarantees, tax incentives, and other means.

Goals

- 50% of all electricity in Alaska is generated from renewable sources by 2025.

[8] Alaska Energy Authority (January 2009), *Alaska Energy: A First Step Toward Energy Independence*. Available at: http://www.akenergyauthority.org/

- Maximum cost-effective implementation of renewable energy systems for direct heating, where "cost-effective" includes a monetized value of avoided GHG emissions, as determined by prevailing national or state policy.

Timing: This policy is already underway through the Governor's goal statement and the Renewable Energy Fund. Implementation will need to continue through 2025, with an aggressive push toward statutory and regulatory changes during the next 2 years.

Parties Involved: The entire apparatus of state government must be engaged to ensure that renewable systems are promoted and not stifled. For round 1 and 2 Renewable Energy Fund projects, House Bill (HB) 152 designated the AEA as the lead agency. The Renewable Energy Fund is to be administered by the Department of Revenue. HB 152 also states that the AEA is to coordinate project review with the Alaska DNR. Other agencies and organizations that are anticipated to be involved in policy implementation are:

- Governor
- Legislature
- Alaska Office of Management and Budget (OMB)
- RCA
- Renewable Energy Alaska Project
- Electric utilities
- Tribal governments
- Municipal and local governments

Other: None identified.

Implementation Mechanisms

The AEA has been designated the lead agency to implement renewable energy projects. The AEA has completed its review of projects submitted under Rounds 1 and 2. The AEA is also the lead agency designated to design, develop, and implement the *Alaska Energy: A First Step Towards Energy Independence* report. Additional policy, regulations, and statutory requirements may be required to fully achieve the report's goals and objectives.

The AEA is also involved in energy efficiency programs. Coordination between ESD-2/4/6 and ESD-3 will help to increase the level of GHG savings and their cost-effectiveness.

Overall, the scope for GHG reductions is:

- ESD-3a & 3b: All projects submitted, reviewed, and approved by the AEA, as part of the implementation of Renewable Energy Grant Program Rounds 1 and 2 of HB 152.
- ESD-3c: Hydroelectric projects that include each of the identified Susitna locations (Watana, Low Watana, Watana/Devil Canyon, Staged Watana/Devil Canyon, and Devil Canyon).

Related Policies/Programs in Place

Major programs in place that should be continued are:

- Renewable Energy Fund (per HB 152).
- Railbelt electricity grid coordination efforts.

Type(s) of GHG Reductions

Types: CO_2 and N_2O.

Negative Impacts: Increased use of concrete for hydroelectric dams, loss of carbon-sink forests from reservoirs and transmission lines, transportation for servicing remote wind turbine sites and hydroelectric dams.

Estimated GHG Reductions and Net Costs or Cost Savings

Costs and greenhouse gas reductions were estimated for three separate programs, the AEA Renewable Energy Grants Program Round 1 and Round 2 applications, and building a large hydroelectric facility connected to the railbelt grid. The expected carbon reductions, as well as the net present value (NPV) of these programs are summarized in table G-8. The estimated fuel mix serving Alaska electrical needs (not including North Slope oil & gas operations) as projects allocated seed funding from the renewable energy grants program are implemented is displayed in Figure G-5. The estimated fuel mix resulting from the building of a large grid-connected hydroelectric facility is displayed in Figure G-6. Finally, the expected renewable energy portfolio for both grid and village electricity generation before and after policy implementation is shown in Figure G-7.

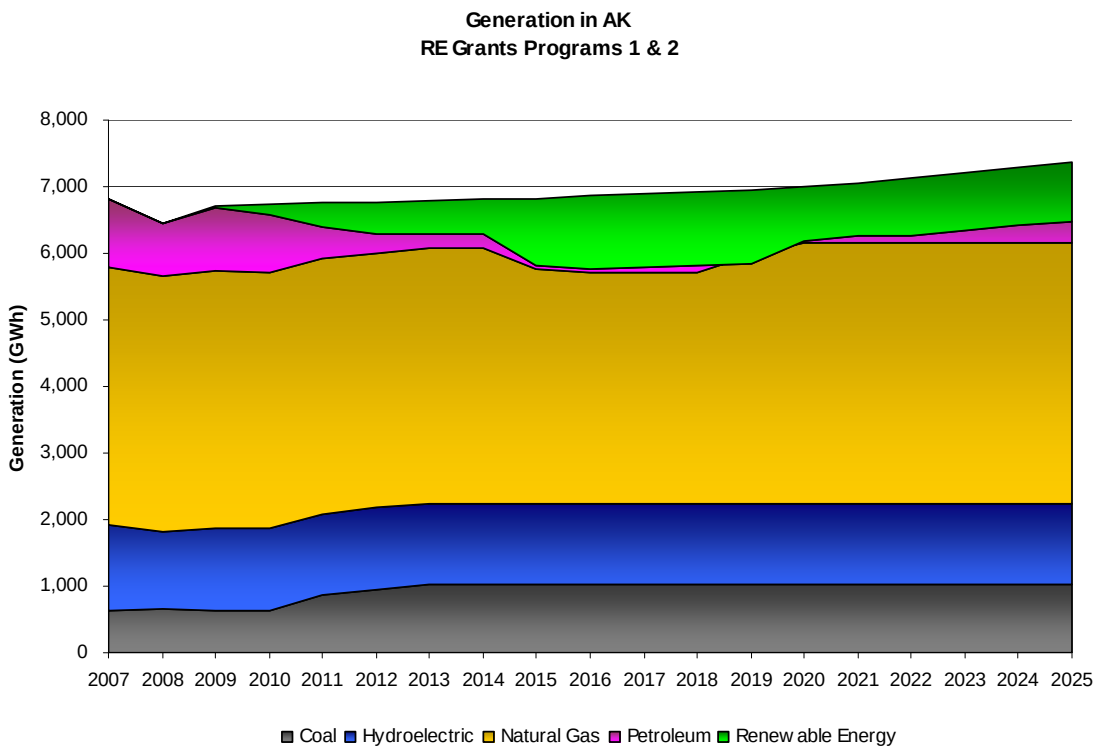
Table G-8. Estimated GHG reductions and net costs of or cost savings from the implementation of renewable energy

Policy No.	Policy	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million 2008$)	Cost-Effectiveness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
ESD-3a	Renewable Energy Grants, Round 1	0.58	0.71	0.84	9.33	–$414	–$44
ESD-3b	Renewable Energy Grants, Round 2	1.41	1.64	1.64	18.80	–$485	–$26
ESD-3c	Large Hydroelectric	0.00	0.00	1.38	4.39	$1,196	$273
ESD-3	**Implementation of Renewable Energy**	**1.99**	**2.35**	**3.86**	**32.52**	**$297**	**$9**

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

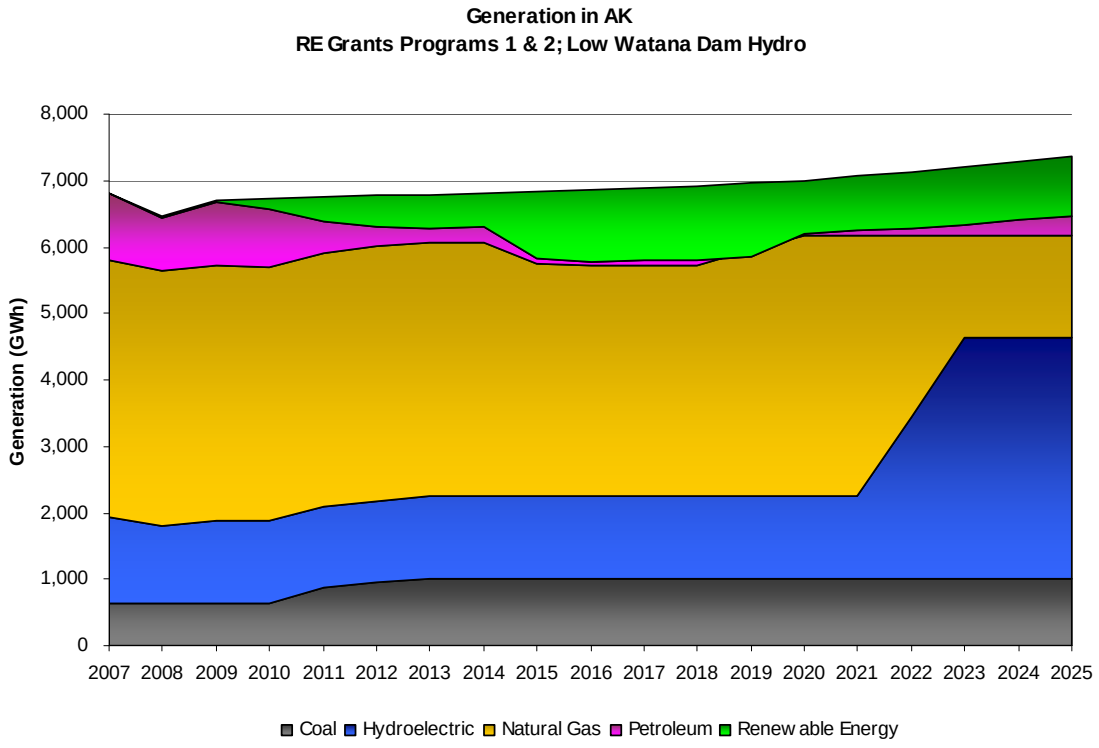
Note: Total cost effectiveness is calculated as total net present value ($297 million 2008$) per cumulative CO_2 emissions (32.52 $MMTCO_2e$) and is not additive between categories.

Figure G-5. Fuel mix through 2025 with full implementation of AEA Renewable Energy Grant programs (limited to those selected for seed grant funding)



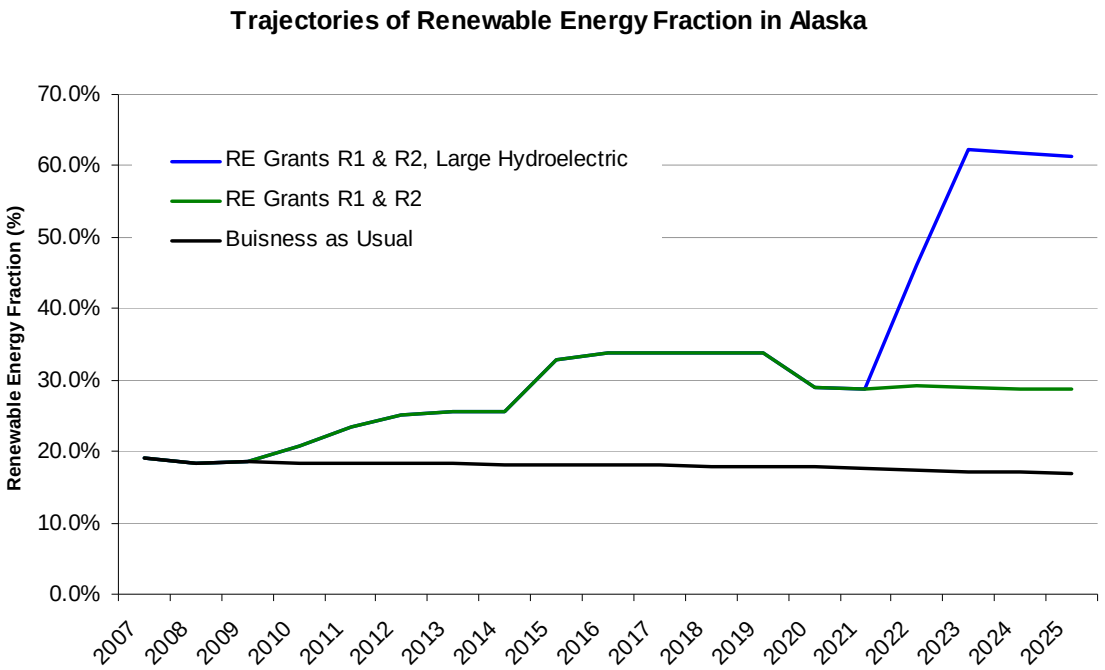
AEA = Alaska Energy Administration; AK = Alaska; GWh = gigawatt hours; RE = renewable energy.

Figure G-6. Fuel mix through 2025 with full implementation of AEA Renewable Energy Grant programs and large hydroelectric project (Low Watana dam equivalent)



AEA = Alaska Energy Administration; AK = Alaska; GWh = gigawatt hours; RE = renewable energy.

Figure G-7. Trajectories of renewable energy fraction in Alaska: business as usual (no additional renewable energy or hydroelectric projects implemented); implementation of selected AEA renewable energy programs; implementation of large hydroelectric project (Low Watana dam equivalent)



AEA = Alaska Energy Administration; RE = renewable energy.

Data Sources: The program description and estimates of emission reductions were obtained from the following sources:

- Alaska Energy Authority (January 2009), *Alaska Energy: A First Step Toward Energy Independence*. Available at: http://www.akenergyauthority.org/
- Alaska Energy Authority (March 16, 2009). Susitna Hydroelectric Project: Project Evaluation (Interim Memorandum, Final). Available at: http://www.aidea.org/aea/SusitnaFiles/Susitna_Hydroelectric_Project_Project_Evaluation_wo_appendices.pdf
- Alaska Energy Authority (2008), *Renewable Energy Fund Applications and Analysis*. . Available at: http://www.akenergyauthority.org/RE_Fund_Applications.html.
- Governor Palin press conference at Alaska Energy Authority, January 16, 2009: *Palin Unveils Energy Goals for Cities, Villages*. Available at: http://www.newsminer.com/news/2009/jan/16/palin-unveils-energy-goals-cities-villages/.
- Energy Information Administration, 2009. *Assumptions for the Annual Energy Outlook 2009: with Projections to 2030*. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/index.html.

- House Bill 152, Approved February 17, 2009, 25th Legislature. Available at: www.legis.state.ak.us.

Quantification Methods: The model is structured from standard analyses conducted by the AEA to determine which Renewable Energy Fund projects could obtain seed funding. Each of the Round 1 and 2 projects approved by the AEA were analyzed using AEA assumptions. Projects accepted for seed funding (partial or complete) were included. Rejected projects were excluded from the analysis.

- Each project lists (among other variables) annual expected renewable generation that would be accessed, O&M costs, avoided fossil fuel use, local expected prices for fuels, and capital costs. Capital costs were amortized across the expected lifetime of the project (also given by the AEA), starting from the first year of generation. The NPV is determined from the discounted costs (including amortized capital costs) and benefits through 2025.
- Avoided CO_2 emissions are calculated from avoided use of natural gas and diesel.
- Total cost-effectiveness is calculated as the cumulative carbon avoided (to 2025) divided by the NPV.
- The quantity of energy and capacity provided by each approved Round 1 and 2 project was calculated, and then aggregated. The quantity was compared to that of the Alaska goal of 50% renewable generation by 2025 against a business-as-usual load-growth scenario.
- Hydroelectric energy was added to meet the Alaska renewable energy goal of 50% by 2025, using the Susitna Low Watana dam option as a proxy project. Grid-connected hydroelectric energy was assumed to displace natural gas.

Key Assumptions:

- Diesel is the main fuel being displaced by the Round 1 and 2 projects; each project lists the expected displaced fuel and rate accordingly. Only current or projected electric demand is displaced (not conversions from fossil heat to electric heat).
- The rate of new renewable energy generation was assumed to continue until the 50% renewable energy goal was attained in 2025.
- Different prices were used for the avoided costs of electricity and fuel at each renewable energy project site, according to AEA estimations and projections. The price of avoided electricity on the grid was determined from AEA analyses, using proxy prices for the railbelt, south of the Alaska Range.
- It is assumed that the renewable energy projects proposed in Rounds 1 and 2 are the only renewable energy projects that will be implemented over the study period. Additional requirements for renewable energy to meet a 50% target by 2025 are assumed to be met by new, large-scale hydroelectric generation.
- It is assumed that proposed and accepted renewable energy projects do not overlap—i.e. they do not propose to displace the same fossil fuel sources.

Key Uncertainties

There are several uncertainties regarding this analysis and the ability of Alaska to achieve its goal of 50% renewable generation by 2025:

- National climate policy and world oil and natural gas markets will influence the cost-effectiveness of future projects.
- According to this analysis, Alaska can meet the 50% renewable energy goal by building a large, grid-connected hydroelectric facility. However, the cost of this project for both equivalent carbon reductions and on a cost-of-energy basis appears to be more expensive than the distributed projects proposed for AEA Renewable Energy Grants. The smaller projects are chosen (partly) based on cost-effectiveness, while the large hydroelectric project is not.
- Continued funding and/or development of funding mechanisms are necessary to ensure that the 50% renewable goal is reached by 2025.
- The eligibility of Alaska for revenue from the proceeds of federal carbon allowance auctions and the application of these funds to renewable energy projects is uncertain.

Additional Benefits and Costs

Increased renewable generation will produce several co-benefits for Alaska. These include:

- Lower electricity costs, and increased reliability, especially in rural areas and villages;
- Reduced environmental damage and costs associated with cleanup of diesel fuel spills in rural villages and along watercourses; and
- Reduced criteria and toxic air pollutant emissions from diesel generators.

Increased renewable generation will require additional infrastructure in Alaska. In many cases, these are small-scale projects with relatively contained footprints, such as:

- Wind
- Local timber for wood-fired co-generation, and
- Small hydroelectric facilities.

In some cases, however, they may have significant environmental impacts, such as:

- Flooding of forests and wildlands for large hydroelectric reservoirs and associated downstream impacts, and
- New transmission infrastructure and cleared corridors through protected lands.

Feasibility Issues

Statewide GHG benefits will be greatest if this policy is coordinated and integrated with ESD-2/4/6 (Energy Efficiency for Residential, Commercial, and Industrial Customers, 2% per year).

Status of Group Approval

Approved.

Level of Group Approval

Unanimous.

Barriers to Consensus

None.

DRAFT

ESD-5. Efficiency Improvements for Generators

Policy Description

This policy is intended to increase the efficiency of electricity generators. Originally developed to estimate the efficacy of tuning, improving, or replacing current generating units, it was envisioned that these marginal improvements could save anywhere from 3% to 30% of fuel in any given unit simply by upgrading to more efficient equipment. However, it was decided that these improvements would, in the absence of direct state subsidies to support capital improvements, fall under the purview of actions taken and funded by utilities.[9] Instead, the policy was restructured as an Research and Development encouragement policy to create highly efficiency next-generation generators.

Members of the MAG opted to move this policy to the Research Needs Working Group, and unanimously supported a non-quantified policy to encourage utility operators to invest in currently available efficient generators.

[9] Utility operators noted that any generator improvements are intrinsically a utility cost-based decision. Capital costs for improvements and savings from reduced fuel use are passed through to utility ratepayers. Ultimately, if efficiency upgrades resulted in a net benefit for consumers, utilities would undergo these improvements, regardless of GHG implications.

ESD-7. Implementation of Small-Scale Nuclear Power

Policy Description

This policy was conceived to develop technologies for small-scale nuclear generation in outlying rural areas. A series of low-maintenance, low-running cost nuclear generators could reduce the need to import fuel to small villages and towns and reduce emissions from diesel engines. There are currently no small-scale nuclear units available on the market (or that have passed federal regulatory hurdles); thus, this policy could not be quantified for costs or potential benefits. The significant research agenda required to implement this policy rendered it appropriate as a research need.

Members of the MAG opted to move this policy to the Research Needs Working Group.

ESD-8. Research and Development for Cold-Climate Renewable Technologies

Policy Description

This policy was conceived to recognize that Alaska's unique climatic conditions render some technologies difficult or impossible to deploy. The policy seeks to create one or more centers of expertise on cold-climate-compatible renewable energy in Alaska. The significant research agenda required to implement this policy rendered it appropriate as a research need.

Members of the MAG opted to move this policy to the Research Needs Working Group.

ESD-9. Implementation of Advanced Supply-Side Technologies

Policy Description

This policy was conceived to examine Alaska's capacity for significant improvements in generation technology, and look to develop and implement new or emerging forms of energy supply. Research in this area would focus on biomass gasification, coal-to-liquids, carbon capture and storage, and enhanced geothermal systems, among others. The significant research agenda required to implement this policy rendered it appropriate as a research need.

Members of the MAG opted to move this policy to the Research Needs Working Group.

ESD Annex 1: Current Action: Weatherization Program Appropriation

At the time of this analysis, the AEA and AHFC had received a $300 million state and federal appropriation of funds for a residential weatherization improvement program and low-income household weatherization program. Two-thirds of the program funds were directed toward the low-income program. Because there is a potential for significant emission savings from these weatherization funds, these savings should be deducted from the baseline expected emissions.

The OMB released an estimate of weatherization funds expected without the additional appropriation, spanning 2010–2014.[10] Over this period, it is expected that $8 million would be used each year. We assumed that the additional $200 million of funding would be equally divided over this same period at $40 million per year, replacing and exceeding the $8 million annual expected funding from the OMB. Thus, the "current action" additional funding would result in $32 million per year from 2010 to 2014. Similar weatherization and efficiency programs typically require a minimum of 20% administrative costs (advertising and marketing, consumer questions and concerns, coordination of contractors, etc.), which were deducted from the total available funding pool. Using the average historical cost per house for low-income weatherization ($6,518) and the estimated CO_2 reductions per weatherized household (34,962 pounds per house),[11] it was estimated that the weatherization program would result in 0.07 million tons per year of annual CO_2 reductions, or a cumulative 0.34 million tons over the course of the program.

It should be noted that low-income weatherization programs are typically considered social equity and poverty reduction programs, rather than energy efficiency programs. These programs do not necessarily target the most cost-effective energy or emission savings, but rather are structured to alleviate energy bills for low-income residents.

[10] Alaska Housing Finance Corporation (2008). AHFC Weatherization Program, FY2010 Appropriation Request: Brief Statement and Summary of Need. Available online at: http://omb.alaska.gov/10_omb/budget/Rev/enacted/2010proj6332.pdf.

[11] Report by Information Insights, Inc. (June 5, 2008). *Alaska Energy Efficiency Program and Policy Recommendations*. Prepared for Cold Climate Housing Research Center. Available at: http://www.cchrc.org/App_Content/files/08-2_EEP_Draft_Final.pdf.

Appendix H
Forestry, Agriculture, and Waste Management Policy Recommendations

Summary List of Alaska Climate Change Mitigation Policy Recommendations

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million 2005$)	Cost-Effective-ness ($/$tCO_2e$)	Level of Support
		2015	2020	2025	Total 2010–2025			
FAW-1	Forest Management Strategies for Carbon Sequestration							
	A. Coastal Forest Management Pre-Commercial Thinning	Included under FAW-2, along with all options using biomass in other sectors						Unanimous
	B. Boreal Forest Mechanical Fuels Treatment Projects							Unanimous
	C. Community Wildfire Risk Reduction Plans							Unanimous
	D. Boreal Forest Reforestation After Fire or Insect and Disease Mortality	0.09	0.12	0.15	1.6	$150	$92	Unanimous
FAW-2	Expanded Use of Biomass Feedstocks for Energy Production							
	A. Biomass Feedstocks to Offset Heating Oil Use	0.01	0.03	0.04	0.3	$27	$90	Unanimous
	B. Biomass Feedstocks for Electricity Use	0.07	0.12	0.18	1.5	$59	$38	Unanimous
	C. Biomass Feedstocks to Offset Fossil Transportation Fuels	0.03	0.06	0.09	0.8	$41	$52	Unanimous
FAW-3	Advanced Waste Reduction and Recycling	0.27	0.45	0.65	5.3	–$43	–$8	Unanimous
	Sector Total Before Adjusting for Overlaps	0.47	0.78	1.11	9.5	$234	$25	
	Sector Total After Adjusting for Overlaps	0.47	0.78	1.11	9.5	$234	$25	
	Reductions From Recent Actions (CAFE standards)	N/A	N/A	N/A	N/A	N/A	N/A	
	Sector Total Plus Recent Actions	0.47	0.78	1.11	9.5	$234	$25	

CAFE = corporate average fuel economy; FAW = Forestry, Agriculture, and Waste Management (Technical Work Group); GHG = greenhouse gas; $MM = million dollars; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Note that negative costs represent a monetary savings.

Also included in this appendix after FAW-3 is a policy that was considered by the Alaska Natural Systems Adaptation Group. This policy has been moved to this appendix because of the overlap between it and FAW-1 and FAW-2. This policy is mostly concerned with fostering the growth and management of healthy forests in Alaska, and getting the most possible benefits from Alaska's forestland. While the greenhouse gas (GHG) benefits of adaptation policies are

not quantified, this policy nonetheless can provide additional insight into issues of forest health. It is being included to assist in the future implementation of forestry-related GHG mitigation approaches for the Alaska process.

FAW-1 elements A–C all have the potential to produce biomass that can be used for fuel feedstocks under FAW-2. Note that for FAW-1A, the Alaska Climate Change Advisory Group recognizes that the costs to collect, process, and transport most of the biomass generated from coastal forest thinning projects will be too costly to use as an energy source. The biomass feedstocks generated from the FAW-1 elements were added to the FAW biomass supply assessment (see the next section of this appendix). The GHG reductions for using the biomass from FAW-1 or other sources were quantified under FAW-2.

There are no overlaps between the FAW biomass policies and the policies in the Energy Supply and Demand (ESD) or Transportation and Land Use (TLU) appendices. Biomass demand from ESD-3 has been accounted for in the biomass availability analysis shown in the next section.

Biomass Resource Supply and Demand Assessment

This section provides a preliminary assessment of biomass availability in Alaska. These estimates were taken from readily available sources or updates from the Forestry, Agriculture, and Waste Management (FAW) Technical Work Group (TWG). The source for each value indicated is provided in the notes section. Information on biomass availability is needed to assess the viability of the goals for policy recommendation FAW-2, as well as any biomass-related recommendations considered in other TWGs (e.g., Energy Supply and Demand [ESD] and Transportation and Land Use [TLU]).

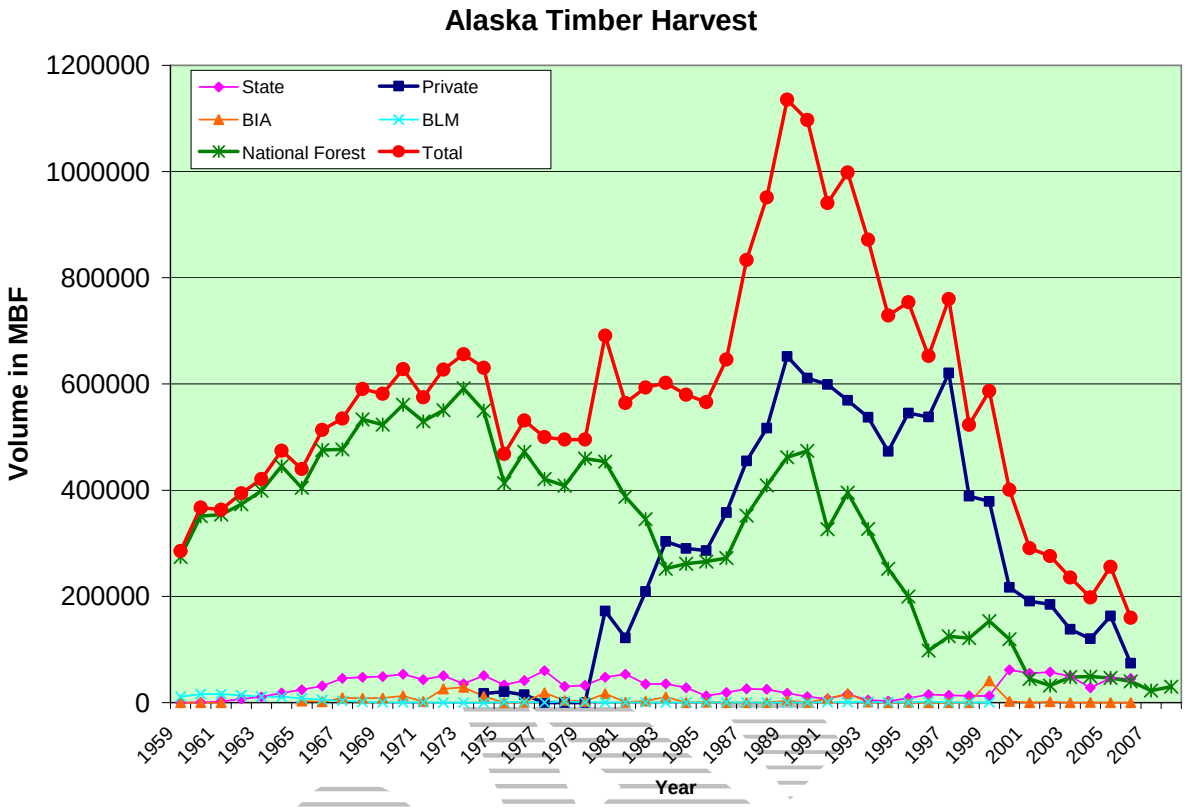
An assessment of biomass resources available to meet the feedstock requirements of the Alaska Climate Change Mitigation Advisory Group (MAG) policies is presented in Table H-1 on the following pages. Table H-2 presents the annual biomass demand that would result from MAG recommendations. Except for the final four entries, Table H-1 presents a total potential availability of biomass in dry tons based on business as usual (BAU) in Alaska across the forestry, agriculture, and waste management sectors. The final four entries represent the values resulting from full implementation of FAW-1 and FAW-3, as mentioned in the notes column. For the purpose of defining a reference point, the stated potential assumes all constraints can be lifted and does not consider economic conditions limiting supply (e.g., distance to end user).

Location and distance issues are paramount in assessing the feasibility of biomass as a resource. Because of this, it is impossible to accurately express all of the cost inputs involved in assessing delivered biomass cost/ton in a single number. The assumption was made that biomass could be delivered within a 180-mile radius. If this is not possible, delivery costs will be higher. A more detailed, community-based biomass assessment would be more effective at determining both biomass availability and biomass costs. This information would allow for location-specific analysis to be possible, and provide an additional level of accuracy. This could be an effort to pursue in the future to expand Alaska's biomass utilization. The Alaska Energy and Power Authority published locationally dependent costs. Although this information could not be used in this particular analysis, it is possible that it will be valuable for any future assessment of biomass costs.

After the analysis of recommendations from all TWGs is complete, the annual biomass demand for 2025 will be calculated in order to assess whether sufficient biomass supply exists to achieve the goals set forth in the policy recommendations made by the MAG.

The Alaska timber harvest is outlined in Figure H-1. As can be seen, the total timber harvest has declined significantly since the mid-1980s. It is possible that the supply estimates for the logging industry (logging residue, primary/secondary mill residue) are somewhat high, because most of the forest sector supply estimates for this analysis are from 2002. However, most of the declines in harvest volume had already taken place by 2001. Thus, while choosing any single year to represent overall timber harvest is difficult, 2002 may be a reasonable choice for a representative near-term year to form a baseline.

Figure H-1. Alaska timber harvest: 1959–2007



MBF = thousand board-feet.

Table H-1. Potential annual biomass resource supply

Biomass Resource	Annual Biomass Supply (dry tons)	Delivered Cost[1] ($2005/dry ton)	Notes
Logging Residue	669,502	$100	Biomass supply based on 2005 NREL report.[2] Derived from the USDA Forest Service's Timber Product Output database for 2002. Delivered cost from a 2000 TSS study on ethanol feedstock production in SE AK (estimated range is $80–$100).[3] Cost estimate is likely only valid in SE AK. Converted from tonnes to short tons. Delivered costs are variable and may change significantly due to location and available transportation infrastructure.

[1] Delivered cost is expressed in units of $/dry ton. However, the FAW TWG reports that deliveries of biomass may sometime be reported in green tons. Although this uncertainty exists, the delivered cost for dry tons is assumed to be correct, for the purpose of this analysis.

[2] A. Milbrandt. *A Geographic Perspective on the Current Biomass Resource Availability in the United States.* Technical Report NREL/TP-560-39181. Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory, December 2005. Available at: www.nrel.gov/docs/fy06osti/39181.pdf.

[3] TSS Consultants. *Southeast Alaska Biomass-to-Ethanol Project Feedstock Supply Plan Final Report*, June 20, 2000. Available at: http://www.p2pays.org/ref/40/39064.pdf.

Biomass Resource	Annual Biomass Supply (dry tons)	Delivered Cost[1] ($2005/dry ton)	Notes
Primary Mill Residue (Unused)	118,841	$13 (low) $30 (high)	2005 NREL report. Derived from the USDA Forest Service's Timber Product Output database for 2002, includes mill residues burned as waste or landfilled. This value agrees well with an estimate of 100,000–150,000 BDT provided in the TSS ethanol feedstock report cited above. Costs are based on TSS estimate assuming transport by barge to end user within a ~180-mile radius of Klawock. High estimate is based on end use at a distant end user adding another 200 miles to the radius (e.g., Juneau). R. Harris of the FAW TWG provided a 2008 estimate for 5 SE AK mills of ~53,000 BDT.[4] Converted from tonnes to short tons.
Secondary Mill Residue	1,814	$13 (low) $30 (high)	2005 NREL report. Derived from data on the number of businesses from the U.S. Census Bureau, 2002 County Business Patterns. Includes wood scraps and sawdust from woodworking shops—furniture factories, container and pallet mills, and wholesale lumberyards. Same cost source and assumptions as above. Converted from tonnes to short tons.
Urban Wood Waste	58,967	$36	2005 NREL report. Includes utility tree trimming and/or private tree companies and construction/demolition wood.[5] Based on information compiled by DOE EIA.[6] Assumes a cost of $12/wet ton for collection and processing (at 50% moisture) and $12/dry ton for transport to a local end user (50-mile radius). Converted from tonnes to short tons.
Coastal Forest: Pre-Commercial Thinning Residue	84,700	$300	Assumes full implementation of FAW-1 Element A. Costs include thinning plus collection and delivery. $300 cost is based on personal communication between Jackson Schreiber and Chris Maisch, 4/29/09. As noted under FAW-1, removal of PCT biomass is unlikely to occur due to high delivery costs and potential damage to the stand from biomass removal equipment.
Boreal Forest: Mechanical Fuel Reduction	11,500	$75	Assumes full implementation of FAW-1 Element B. 40-mile distance to end user. $75 dollar cost is based on estimates from a personal communication between Jackson Schreiber and Chris Maisch, 4/29/09.
Boreal Forest Community Wildfire Reduction Plans	58,000	$75	Assumes full implementation of FAW-1 Element C. 40-mile distance to end user. New community plans would need to begin after 2025 to maintain this level of biomass removal. $75 cost is based on Tok estimates from a personal communication between Jackson Schreiber and Chris Maisch, 4/29/09.

[4] R. Harris, Sealaska, FAW TWG, personal communication with S. Roe, Center for Climate Strategies (CCS), November 2008.

[5] CCS reviewed the methodology used in the 2005 National Renewable Energy Laboratory (NREL) report to estimate urban wood waste biomass availability. For the state of Alaska, NREL's data source for the municipal solid waste (MSW) wood component of urban wood waste did not provide the necessary source data to make the calculations used by NREL to estimate biomass availability from MSW wood waste. Therefore, CCS assumed that the urban wood waste component of NREL's biomass availability study does not include MSW wood waste for the state of Alaska.

[6] U.S. Department of Energy, Energy Information Administration, *Biomass for Electricity Generation*. Accessed 2/18/2009 at http://www.eia.doe.gov/oiaf/analysispaper/biomass/.

Biomass Resource	Annual Biomass Supply (dry tons)	Delivered Cost[1] ($2005/dry ton)	Notes
Municipal Solid Waste (MSW) Fiber	296,643	$36	Total biomass supply for the year 2025, assuming full implementation of FAW-3. Without implementation of FAW-3, the total biomass supply would be 383,938 dry tons. Same cost source/assumptions as above for urban wood waste.
Yard and Landscape Waste Debris	7,570	$36	Total biomass supply for the year 2025, assuming full implementation of FAW-3. Without implementation of FAW-3, the total biomass supply would be 119,217 dry tons. Same cost source/assumptions as above for urban wood waste.
Total Annual Biomass Supply	1,222,838		Excludes PCT biomass.
Total Annual Biomass Supply Available at <40$/ton	483,835		
Total Annual Biomass Supply Available at <100$/ton	1,153,337		Excludes PCT biomass.

AK = Alaska; BDT = bone dry ton; DOE = U.S. Department of Energy; EIA = Energy Information Administration; FAW = Forestry, Agriculture, and Waste Management (Technical Work Group); MSW = municipal solid waste; NREL= National Renewable Energy Laboratory; PCT = pre-commercial thinning; SE = southeast; TSS = TSS Consultants; USDA = U.S. Department of Agriculture.

Table H-2. 2025 annual biomass demand from MAG recommendations

Biomass Requirement	2025 Annual Biomass Demand (dry tons)	Notes
FAW-2. Element A. Biomass Heating	50,000	See FAW-2 quantification.
FAW-2. Element B: Biomass for Electricity Production	345,000	See FAW-2 quantification.
FAW-2. Element C: Biomass for Liquid Fuels Production	124,000	See FAW-2 quantification.
ESD TWG Biomass Needs	8,000	Based on personal communication with Jeremy Fischer, Energy Supply and Demand Technical Work Group. Represents demand for biomass from ESD-3. Assumed white spruce for heat content conversion of cordwood.
TLU Biomass Needs	0	No TLU options had biomass requirements.
Total	**527,000**	

MAG = Mitigation Advisory Work Group; ESD = Energy Supply and Demand; FAW = Forestry, Agriculture, and Waste Management; TLU = Transportation and Land Use; TWG = Technical Work Group.

FAW-1. Forest Management Strategies for Carbon Sequestration

Policy Description

Alaska forests can play a unique role in both preventing and reducing greenhouse gas (GHG) emissions, while providing for a wide range of social and environmental benefits. These benefits include clean air and water, wildlife habitat, recreation, subsistence activities, forest products, and a host of other uses and values. Carbon is stored in the above-ground biomass and in the organic and mineral components of the soil. Permafrost soils add an additional dimension and complication to the role soils play in the boreal, subarctic, and arctic ecosystems, and the potential impacts of increased wildland fire in these regions have wide-ranging implications. Additionally, the state has two distinct forest ecosystems—the boreal and coastal forests—and the types of forest management activities that may apply to each from a carbon management perspective may also differ.

Coastal Forest Options

- Increase the amount of durable wood products produced from managed forests. Durable wood products produced as part of the timber harvest can serve to effectively sequester carbon for extended periods. Examples of management practices could be:
  - Extended rotations;
  - Pre-commercial thinning (PCT)[7] or commercial thinning (CT)[8] of young-growth stands of timber;
  - Fertilization treatments; and
  - Other silvicultural treatments that would meet the intent of this policy recommendation.
- Another concept to consider is the lower energy intensity of wood product manufacture when compared with other building products. Wood substitution prevents GHG emissions because it is typically less carbon intensive in production compared with wood substitutes.

Boreal Forest Options

- Implement fuel-reduction projects that utilize both prescribed fire and mechanical treatments to reduce fuel loads and burn intensity and overall GHG emissions in a wildland fire event.
- Complete Community Wildfire Protection Plans (CWPPs) to identify fuel types and community risks to aid in prioritization of fuel treatment work.
- Rapidly reforest sites impacted by fire or by insect and disease outbreaks to ensure full stocking and a quick return to forest cover.

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[7] PCT is the removal of trees not for immediate financial return but to reduce the stocking to concentrate growth on the more desirable trees. PCT is generally done between the ages of 15 and 25 years in southeast Alaska, with the ages being lower in the more productive southern half of the forest.

[8] CT is any type of thinning producing merchantable material at least equal to the value of the direct costs of harvesting. The age range for conducting CT on highly productive lands is considered 55–60 years.

Policy Design

Goals: Direct the maximum economically feasible biomass from the following policy elements to energy use. (The MAG does not believe that a significant amount of biomass from these elements could be directed to durable wood products.) The goal levels listed below include BAU levels of action, which are described under "Other," below.

Element A. Coastal Forest Carbon Management Pre-Commercial Thinning

- By 2010, thin 4,000 acres annually across all ownerships (both public and private).
- By 2015, thin 8,000–10,000 acres annually.
- By 2025, thin 6,000 acres annually.

Element B. Boreal Forest Mechanical Fuels Treatment Projects[9]

- By 2010, treat 1,000 acres annually across all ownerships.
- By 2020, treat 2,000 acres annually.
- By 2025, treat 2,500 acres annually.

Element C. Community Wildfire Risk Reduction Plans

- By 2010, complete 15 plans.
- By 2015, complete 25 additional plans.
- By 2025, complete 35 additional plans.

Element D. Boreal Forest Reforestation After Fire or Insect and Disease Mortality

- By 2010, reforest 5% of high-site-class lands.[10]
- By 2015, reforest 15% of high-site-class lands.
- By 2025, reforest 25% of high-site-class lands.

Timing: As specified in the goals above.

Parties Involved: Alaska Department of Natural Resources (DNR) Division of Forestry (DOF), Alaska Native Corporations (ANCs), University of Alaska (UA), Southeast Conference, Cooperative Extension Service (CES), Natural Resource Conservation Service (NRCS), Resource Development Council (RDC), Alaska Forest Association, U.S. Forest Service (USFS), state and private forestry, Alaska Board of Forestry, Soil and Water Conservation Districts, National Park Service, U.S. Bureau of Land Management.

Other: Forest thinning in the coastal Tongass National Forest by the USFS in the 1990–2000 time frame was around 4,200 acres per year (yr), and that thinning by Sealaska was around 4,000

[9] The MAG notes that if fire use and prescribed fire treatments are included, the goals could be increased significantly; however, the overall carbon management benefits of these treatments are very difficult to quantify.

[10] High-site-class lands are defined as high-severity burn areas in the quantification.

acres/yr.[11] No additional information was identified on thinning levels on other public lands or private lands in the coastal forest.

DNR indicates that about 535 acres/yr of boreal forest have been mechanically treated on average since 2005.[12] Treatment typically consists of shear-blading flammable black spruce stands during winter and windrow burning of the biomass during the following fall.

Implementation Mechanisms

Forest Carbon Management: Increase funding levels to ramp up the program to meet goals at various increments and establish a viable carbon-trading program to capture the revenue stream from the carbon dioxide (CO_2) sequestration perspective.

Mechanical Fuel Treatment Projects: Based on CWPP recommendations, utilize both mechanical methods and village Type II emergency fire-fighting crews and agency Type I fire crews to complete projects in their communities. Mechanical fuel treatments in Tok and Fairbanks have produced usable biomass for wood energy projects at a competitive rate per ton and will be cheaper than hand crew use in similar forest types. The transportation cost of the biomass is the most sensitive expense for these types of treatments and will greatly influence the freight-on-board cost per green ton to a wood biomass facility. Funding for these projects will be a key aspect, and programs at the national level may help with this need.

Community Wildfire Protection Plans: Establish a statewide coordinator by 2010; conduct training workshops for communities by 2011–2012.

Reforestation: Increase seed collection efforts by 2010–2015, especially when there are good seed years, to ensure enough seed is on hand to meet goals. Funding for this item will be a critical aspect of this element.

For reforestation projects, some work needs to be done on the recommended species mix for conifers. Should lodge pole pine or Siberian larch be considered for a portion of the mix—e.g., white spruce 75% and lodge pole pine 25% per unit area planted (an adaptation measure)?

Research Needs

- Continue work to develop the science and process to better quantify beneficial and negative outcomes of silvicultural treatments from a carbon sequestration perspective. Opportunities in this area are currently limited by the science.
- Develop an accepted protocol for determining the "carbon life" of various forest products. This relates to the current assumption that the point of tree harvest is an emission of CO_2, when in practice much of the CO_2 in harvested timber is stored in durable forest products that have over decades of service lives.

[11] TSS Consultants, *Southeast Alaska Biomass-to-Ethanol Project Feedstock Supply Plan Final Report,* June 20, 2000. Available at: http://www.p2pays.org/ref/40/39064.pdf.

[12] D. Hanson, AK DNR, DOF, personal communication with S. Roe, CCS, 2/18/2009.

A strong timber industry in Alaska will serve to both stabilize and reduce the overall cost of delivered biomass in the state. If increased demand for biomass as a result of GHG policies can serve to strengthen the market for timber, then it is possible there could be cost benefits in the future.

Related Policies/Programs in Place

None identified.

Types(s) of GHG Reductions

Enhanced forest management, including reforestation, has the potential to increase levels of carbon sequestration, thereby increasing the CO_2 removed annually by Alaska's forests. Forest management that includes wildfire hazard reduction lowers the potential for catastrophic wildfires, thereby protecting existing carbon stocks and sequestration levels. Biomass removed from the forest that is put to use as an energy source can offset GHG emissions from fossil fuel combustion. Biomass removed from the forest and used to produce durable wood products can sequester carbon over decades.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2020, 2025 (MMtCO_2e):

Element A: Captured under FAW-2 and biomass utilization recommendations in other sectors (dry tons produced are provided in the Biomass Supply and Demand Assessment at the front of this appendix). The suggestion was made to incorporate the reductions shown in Table H-5 under this recommendation. Capturing the benefits of this recommendation under FAW-2 may not be viable because of the implementation items listed, such as the economics and feasibility of removing the biomass without unacceptable residual damage to the stand.

Element B: Captured under FAW-2 and biomass utilization recommendations in other sectors (dry tons produced are provided in the Biomass Supply and Demand Assessment at the front of this appendix).

Element C: Captured under FAW-2 and biomass utilization recommendations in other sectors (dry tons produced are provided in the Biomass Supply and Demand Assessment at the front of this appendix).

Element D: 0.09, 0.12, 0.15, respectively, in 2015, 2020, and 2025.

Net Cost per tCO_2e (metric ton of CO_2 equivalent):

Element A: Not applicable (delivered biomass cost per ton is provided in the Biomass Supply and Demand Assessment at the front of this appendix).

Element B: Not applicable (delivered biomass cost per ton is provided in the Biomass Supply and Demand Assessment at the front of this appendix).

Element C: Not applicable (delivered biomass cost per ton is provided in the Biomass Supply and Demand Assessment at the front of this appendix).

Element D: $92.

Data Sources: Data sources are specified or footnoted in the following Quantification Methods section.

Quantification Methods: The GHG reductions and costs for each element of FAW-1 are provided below.

Element A. Coastal Forest Carbon Management—Silviculture Pre-Commercial Thinning and Commercial Thinning

There are two GHG-related benefits for this element. The first comes from the beneficial re-use of silviculture removals as an energy source, which would offset fossil-based energy use. The second relates to the additional timber that would be available for use in durable wood products as a result of the PCT activity. Information from the TWG indicates that there would be additional timber suitable for carbon durable products available following a 70-year rotation, as compared with a BAU scenario, where no silviculture is performed. Each of these benefits is addressed separately below. For the second benefit, the annual GHG benefit (additional CO_2 sequestered for future timber harvest) is not included in the summary of benefits above, since these reductions will only be realized at the time of harvest (70 years or more into the future).

Business as Usual. BAU for the coastal temperate rainforest of southeast Alaska was defined by the two 50-year long-term timber contracts between the Tongass National Forest (TNF) and the two pulp companies in the late 1950s and early 1960s. BAU evolved into a treatment of even-aged regeneration harvest—i.e., clear cutting, with no subsequent silviculture treatments. This model is designed to produce fiber for pulp production in the most cost-effective manner. Natural regeneration stocking following this harvest is typically thousands of trees per acre, and the TNF in accordance with national forest policy established rotation age[13] at approximately 90 years in accordance with the National Forest Management Act requirements that harvest not occur prior to the culmination of mean annual increment (CMAI).[14] The Alaska Native Claims Settlement Act (ANCSA) was passed in 1971 and authorized formation of Alaska Native Corporations (ANCs). Southeast Alaska ANC began receiving entitled ANCSA lands in the 1980s, and soon thereafter commenced timber harvest operations. Even-aged regeneration harvest was practiced exclusively on these lands until the 1990s, and the BAU model did not prescribe any subsequent silviculture. But rotation age for these lands was not constrained by CMAI, and was driven by the economic rotation. Under this circumstance, rotation age is shorter, approximately age 50.

Re-use of Silviculture Removals for Energy. Silviculture removals are divided between biomass from PCT and biomass from CT due to differential costs and practical and technical constraints associated with recovery of this material and different outcomes.

[13] Rotation age is the time it takes to grow the next crop of trees—in other words, the time between the first harvest and the next harvest.

[14] Culmination of mean annual increment is the age at which the rate of growth among a stand of trees peaks, and after which annual growth remains level or declines.

Pre-commercial Thinning. For PCT, the estimated theoretical biomass removed in 2025 through implementation of this policy was noted in Table H-1 at the front of this appendix. For use in policy recommendations that require biomass, including FAW-2, the TWG assumes that the biomass would only be available at an extraordinarily high cost. The policy design calls for 4,000 acres of PCT in 2010; 8,000–10,000 acres annually by 2015; and then maintaining 6,000 acres of PCT annually from 2025 onward. It is assumed that these goals are incremental to any BAU PCT activity in the coastal forest. Table H-3 provides a summary of coastal forest inventory data from the USFS.[15]

Removal of PCT biomass may not be prudent because of damage done to and the resultant condition of the stand after such removal due to the huge amount of PCT slash. Further, it may not be cost-effective due to the extraordinarily high cost of removal.

Table H-3. Alaska coastal forest statistics

Forest Type Group	Ownership Class	Area (10^3 acres)	Total AG Tree Biomass (dry tons)	Total AG Tree Density (dry ton/acre)	Total AG Live 1–5-Inch Trees (dry tons)	1–5-Inch Density (dry tons/acre)	Total AG Dead Trees (dry tons)	Dead Tree Density (dry tons/acre)
Softwood	All	13,557	700,932,159	51.70	19,641,041	0.66	2,913,848	0.21
Softwood	Public	12,402	620,421,874	50.03	15,661,532	0.57	2,565,780	0.21
Softwood	Private	1,155	80,510,285	69.71	3,979,509	1.56	348,068	0.30
Hardwood	All	1,207	16,796,604	13.92	1,352,303	0.51	53,029	0.04
Hardwood	Public	936	11,876,530	12.69	1,062,254	0.51	—	—
Hardwood	Private	271	4,920,074	18.16	290,049	0.49	53,029	0.20
All	**All**	**14,764**	**717,728,763**	**48.61**	**20,993,344**	**1.42**	**2,966,877**	**0.20**

AG = above ground.

Table H-4 provides estimates of the amount of biomass removed as a result of the policy using two different estimates of biomass removal. The first uses the summary data from Table H-3 The biomass density of PCT removals is assumed to include all above ground (AG) biomass in live trees between 1- and 5-inch diameter, plus all AG dead tree biomass. The sum of these factors is around 1.6 dry tons/acre. The second estimate comes from the TSS biomass feedstock report,[16] which referenced a removal rate of 25 dry tons/acre for PCT on second-growth coastal forests. Given the order of magnitude difference in these two estimates, a mid-point estimate is also shown in Table H-4 (roughly 85,000 dry tons/yr in 2025).

The delivered cost per dry ton was estimated to be $122 by 2025. The sources for cost information are cited at the bottom of Table H-4. Note that after this estimate of delivered costs was made, a revised estimate of $300/dry ton was provided by a TWG member as cited in the Biomass Supply and Demand Assessment at the beginning of this appendix. The overall

[15] See http://www.fs.fed.us/pnw/fia/local-resources/pdf/tables/AK_table1-9.pdf, tables dated 08/10/2007, representing 2006 Forest Inventory & Analysis data.

[16] TSS Consultants, *Southeast Alaska Biomass-to-Ethanol Project Feedstock Supply Plan Final Report*, June 20, 2000. Available at: http://www.p2pays.org/ref/40/39064.pdf.

estimate assumes a treatment cost of $417/acre and a collection/processing/delivery cost of $90/dry ton. (It is unclear from the report what the delivery radius would be; however, it is probably safe to assume that it would be <100 miles to the end user.) The thinning costs were escalated using growth in the annual Producer Price Index (PPI) estimates for the logging industry from 2002 to 2007 (about 1.2%/yr). For collection, processing, and delivery, the estimates were not escalated for future years due to the uncertainties in future fuel costs, labor costs, and potential change due to technology advancement or economies of scale.

Table H-4. Theoretical coastal PCT removals and delivered costs

Year	Acres Thinned	Biomass: Low Estimate (dry tons)	Biomass: High Estimate[a] (dry tons)	Biomass: Mid-Point (dry tons)	Thinning Costs[b] ($2005)	Collection, Processing, & Delivery Costs[c] ($2005)	Total Costs ($/ton delivered)
2010	4,000	6,492	100,000	56,492	$1,571,196	$5,038,842	$117
2011	4,000	6,492	100,000	56,492	$1,590,230	$5,038,842	$117
2012	5,000	8,114	125,000	70,614	$2,011,579	$6,298,553	$118
2013	6,000	9,737	150,000	84,737	$2,442,444	$7,558,263	$118
2014	7,000	11,360	175,000	98,860	$2,882,827	$8,817,974	$118
2015	8,000	12,983	200,000	112,983	$3,332,726	$10,077,685	$119
2016	8,000	12,983	200,000	112,983	$3,370,792	$10,077,685	$119
2017	8,000	12,983	200,000	112,983	$3,408,859	$10,077,685	$119
2018	9,000	14,606	225,000	127,106	$3,877,791	$11,337,395	$120
2019	9,000	14,606	225,000	127,106	$3,920,616	$11,337,395	$120
2020	10,000	16,229	250,000	141,229	$4,403,823	$12,597,106	$120
2021	10,000	16,229	250,000	141,229	$4,451,406	$12,597,106	$121
2022	9,000	14,606	225,000	127,106	$4,049,090	$11,337,395	$121
2023	8,000	12,983	200,000	112,983	$3,637,258	$10,077,685	$121
2024	7,000	11,360	175,000	98,860	$3,215,909	$8,817,974	$122
2025	6,000	9,737	150,000	84,737	$2,785,043	$7,558,263	$122
Total	**118,000**	**191,500**	**2,950,000**	**1,666,500**	**$50,951,588**	**$148,645,849**	**$120**

[a] TSS Consultants, *Southeast Alaska Biomass-to-Ethanol Project Feedstock Supply Plan Final Report*, June 20, 2000. Estimate of 25 BDT/acre for second-growth forest thinning.

[b] AK DNR, State of Alaska Capital Project Summary, Governor's FY04 Capital Budget, Improve Forest Productivity in Southern Alaska, March 4, 2003.

[c] TSS Consultants, *Southeast Alaska Biomass-to-Ethanol Project Feedstock Supply Plan Final Report,* June 20, 2000. Estimate of $80–$100 BDT logging residue collected and delivered to a proposed ethanol plant in southeast Alaska.

BDT = bone dry ton; PCT = pre-commercial thinning.

Incremental Timber Production. PCT offers the potential for GHG benefits by sequestering more carbon over a shorter period of time into more merchantable timber capable of producing carbon durable forest products. When that timber is turned into durable wood products (e.g., lumber, furniture), the carbon is sequestered for periods of decades or longer. Sealaska provided

results from a modeling study of timber production on second-growth lands,[17] which showed that a managed site using PCT following a 70-year rotation would yield 39,000 board-feet/acre of harvestable timber, while an unmanaged stand after a 90-year rotation would yield 27,000 board-ft/acre. Therefore, the incremental timber production for managed stands would be 257 board-ft/acre/yr. Using this incremental production estimate and an assumed density of 7 dry tons/thousand board-ft, the estimates shown in Table H-5 were derived. As shown in this table, about 0.37 million metric tons (MMt) of CO_2 would be sequestered in merchantable timber that would likely have been sequestered in non-merchantable timber in an unmanaged stand (and presumably lost to decomposition following future harvest).

Commercial Thinning. The practice of commercial thinning will produce carbon durable forest products and biomass capable of producing a wood waste alternate fuel product or energy. Revenue from the sale of commercial products is used to offset, or help offset, treatment costs, and there will be more merchantable timber capable of producing carbon durable forest products at rotation harvest. This treatment has the potential of lengthening rotation age as well.

Table H-5. Incremental timber production following pre-commercial thinning

Year	Acres Thinned	Incremental Timber for DWP Accumulated (tons)	Incremental Carbon Accumulated (tCO_2)	Thinning Costs ($)	Discounted Thinning Costs ($2005)
2010	4,000	—	—	$1,571,196	$1,571,196
2011	4,000	7,200	13,200	$1,590,230	$1,514,504
2012	5,000	14,400	26,400	$2,011,579	$1,824,561
2013	6,000	23,400	42,900	$2,442,444	$2,109,875
2014	7,000	34,200	62,700	$2,882,827	$2,371,709
2015	8,000	46,800	85,800	$3,332,726	$2,611,278
2016	8,000	61,200	112,200	$3,370,792	$2,515,337
2017	8,000	75,600	138,600	$3,408,859	$ 2,422,612
2018	9,000	90,000	165,000	$3,877,791	$2,624,641
2019	9,000	106,200	194,700	$3,920,616	$2,527,264
2020	10,000	122,400	224,400	$4,403,823	$2,703,565
2021	10,000	140,400	257,400	$4,451,406	$2,602,645
2022	9,000	158,400	290,400	$4,049,090	$ 2,254,685
2023	8,000	174,600	320,100	$3,637,258	$1,928,916
2024	7,000	189,000	346,500	$ 3,215,909	$1,624,253
2025	6,000	201,600	369,600	$ 2,785,043	$ 1,339,653
Total	**118,000**	**1,445,400**	**2,649,900**	**$50,951,588**	**$34,546,695**

DWP = durable wood product; tCO_2e = metric tons of carbon dioxide equivalent.

[17] Southeast Alaska Wood Energy, presentation by R. Harris, Sealaska, provided to S. Roe, Center for Climate Strategies (CCS), November 2008.

Using the same assumed costs for PCT described above ($417/acre) escalated with historic PPI data for 2002–2007, the estimated annual thinning costs are shown in Table H-5. Using the total accumulated carbon (2.65 $MMtCO_2$) and the total discounted costs ($34 million [$2005]) yields a cost-effectiveness estimate of $13/ton. Note that these cost estimates do not include the additional future value of the incremental timber yield. The cost of PCT does not address the cost of recovery of PCT material for biomass production, which is addressed in FAW-2.

It is possible that pre-commercial thinning can result in increased carbon sequestration over a long enough time period. Modeling has shown that managed forests produce higher levels of usable wood than unmanaged forests.[18] However, because this wood is measured in board-feet rather than overall biomass/carbon content, it is uncertain if carbon sequestration has increased in managed versus unmanaged forests. Given this uncertainty, PCT is not assumed to increase overall carbon sequestration.

Element B. Boreal Forest Mechanical Fuels Treatment Projects

The quantifiable GHG benefits associated with this element are tied to the use of biomass removed during fuel treatments as an energy source, thereby reducing fossil fuel use and associated GHG emissions. Fuel treatments also lower the potential for catastrophic wildfires ("stand-replacement fires") and potentially structure fires, thereby lowering the potential for large losses in carbon stocks and future sequestration potential. This latter benefit is potentially much larger than the biomass energy benefit; however, information is not available to conduct a defensible quantification of the benefit.

Table H-6 provides the estimated dry tons of biomass removed from boreal forest treatments per the policy goals. Estimates of biomass density were taken from a recent DOF analysis of mechanical fuel treatments in the Fairbanks area.[19] A 75% biomass recovery factor is assumed. The estimated biomass removed in 2025 (~11,500 dry tons) was included in the Biomass Supply and Demand Assessment at the front of this appendix (see Table H-1).

The delivered costs of biomass were also taken from the same DOF study of the Fairbanks area. That study estimated a delivered cost of chipped green biomass of ~$52/ton. This value assumes a transportation distance of 40 miles to the end user. Assuming a 50% moisture content and using the historic PPI data for the logging industry, a cost of $105/dry ton delivered (2005$) was estimated. This value was included in Table H-1 of the Biomass Supply and Demand Assessment.

[18] The two diagrams come from personal communication with Rick Rogers by Steve Roe, November 2008.

[19] Douglas Hanson, *Analysis of Wood Volume Available From Hazard Fuel Reduction Projects and Development of Wood Residue Markets in the Fairbanks Area*, State of Alaska, Department of Natural Resources, Division of Forestry, 2007. Available at http://www.forestry.alaska.gov/pdfs/07Biomass_Report.pdf.

Table H-6. Boreal forest treatments and biomass recovered

Year	Acres Treated	Biomass Density[a] (dry tons/acre)	Biomass Recovery Factor	Biomass Recovered (dry tons/yr)
2010	1,000	6.15	0.75	4,613
2011	1,100	6.15	0.75	5,074
2012	1,200	6.15	0.75	5,535
2013	1,300	6.15	0.75	5,996
2014	1,400	6.15	0.75	6,458
2015	1,500	6.15	0.75	6,919
2016	1,600	6.15	0.75	7,380
2017	1,700	6.15	0.75	7,841
2018	1,800	6.15	0.75	8,303
2019	1,900	6.15	0.75	8,764
2020	2,000	6.15	0.75	9,225
2021	2,100	6.15	0.75	9,686
2022	2,200	6.15	0.75	10,148
2023	2,300	6.15	0.75	10,609
2024	2,400	6.15	0.75	11,070
2025	2,500	6.15	0.75	11,531
Total	**28,000**			**129,150**

[a] Douglas Hanson, *Analysis of Wood Volume Available From Hazard Fuel Reduction Projects and Development of Wood Residue Markets in the Fairbanks Area*, State of Alaska, Department of Natural Resources, Division of Forestry, 2007. Assumes 50% moisture content to convert from green to dry tons.

Element C. Community Wildfire Risk Reduction Plans

The quantifiable GHG benefits associated with this element are similar to those of Element B: use of biomass removed during fuel treatments as an energy source, and lower potential for catastrophic wildfires ("stand-replacement fires") and structure fires. As with Element B, the latter benefit is potentially much larger than the biomass energy benefit; however, information is not available to conduct a defensible quantification of the benefit in terms of avoided CO_2 emissions and avoided loss of carbon sequestration potential. Therefore, a similar approach was taken to develop an estimate of the amount of biomass that would be available as a result of fuel treatments from implementation of these plans. The primary assumption was that the fuel treatments would be mechanical treatments, not prescribed fire.

Table H-7 provides a summary of biomass removed annually and available for energy use based on implementation of the policy goals. The number of acres to be treated annually was based on the levels of treatment conducted for the Fairbanks area from the report cited above and discussions with DOF.[20] In the Fairbanks area, wildfire risk reduction calls for about 1,500 acres/yr to be treated. To estimate the treatment area needed for the average size community addressed by this policy, the Center for Climate Strategies (CCS) assumed that the average

[20] D. Hanson, AK DOF, personal communication with S. Roe, CCS, January 2009.

community was one-third of the size of Fairbanks. This would mean that 500 acres should be treated annually in each of the plan areas. It was further assumed that treatments would be needed for 15 years before all of the areas requiring fuel reduction were treated.

As shown in Table H-7, similar assumptions were made for biomass density and recovery as for the analysis under Element B above. The estimated removals for 2017–2025 (~58,000 dry tons/yr) were used as input to the Biomass Supply and Demand Assessment at the front of this appendix (see Table H-1). The same delivered cost as described under Element B is assumed for this option ($105/dry ton in 2005$).

Table H-7. Boreal forest treatments and biomass recovered

Year	Acres Treated	Biomass Density[a] (dry tons/acre)	Biomass Recovery Factor	Biomass Available (dry tons/year)
2010	0	6.15	0.75	0
2011	7,500	6.15	0.75	34,594
2012	7,500	6.15	0.75	34,594
2013	7,500	6.15	0.75	34,594
2014	7,500	6.15	0.75	34,594
2015	7,500	6.15	0.75	34,594
2016	7,500	6.15	0.75	34,594
2017	12,500	6.15	0.75	57,656
2018	12,500	6.15	0.75	57,656
2019	12,500	6.15	0.75	57,656
2020	12,500	6.15	0.75	57,656
2021	12,500	6.15	0.75	57,656
2022	12,500	6.15	0.75	57,656
2023	12,500	6.15	0.75	57,656
2024	12,500	6.15	0.75	57,656
2025	12,500	6.15	0.75	57,656
Total	**157,500**			**726,469**

[a] Douglas Hanson, *Analysis of Wood Volume Available From Hazard Fuel Reduction Projects and Development of Wood Residue Markets in the Fairbanks Area*, State of Alaska, Department of Natural Resources, Division of Forestry, 2007. Assumes 50% moisture content to convert from green to dry tons.

Element D. Boreal Forest Reforestation After Fire or Insect Damage and Disease

The GHG benefits for this element are the difference in carbon sequestration levels under BAU (no reforestation of lands damaged by fire/pests/disease) and sequestration levels following reforestation. The policy goals call for reforestation of 5% of high-site-class lands by 2010, 15% by 2015, and 25% by 2025. No information is currently available on the number of boreal forest acres that would be considered high-site-class. As a surrogate, CCS obtained 2004–2006 data on Alaska wildfire acres and the number of acres considered to be high-burn-severity.[21] The available data cover only 2004–2006 and show that, on average, high-burn-severity areas comprise 19% of the total burn area. From the Alaska GHG Inventory and Forecast (I&F) (Appendix D of this report), the average wildfire activity in the state during 1994–2004 was about 1.4 million acres/yr. Hence, on average, about 260,000 acres of high-severity-burn areas are created in the state annually.

Discussions between CCS and state foresters[22] have revealed a range of opinion regarding how reforestation projects should be carried out. This range of opinion is driven by several factors. First, historically, reforestation projects have been carried out to promote future timber harvests, using the species thought to have the most future value as a timber resource (e.g., white spruce). Given the rise in the occurrence, affected area, and severity of wildfires, state foresters appear to be rethinking the desirability of reforestation projects using species susceptible to fire (including white spruce). Second, from a carbon sequestration perspective, mixed hardwood forests may offer superior performance, especially during the early decades following replanting.

Based on discussions with state foresters, following a wildfire, through natural succession, some areas will come back into mixed hardwood stands fairly quickly. In other cases, grasses will take over and may dominate the area for years or potentially decades. These areas could benefit the most from replanting efforts and could yield significant GHG reductions. Hence, the analysis below assumes that the reforestation projects will involve replanting areas taken over by grasses with hardwood species.

Information on biomass accumulation in boreal hardwood stands is limited. CCS received an estimate of 30 cords/acre over 35 years from a DOF staff person for balsam poplar stands.[23] Using an assumed density of 26 pounds [lbs]/ft^3 (0% moisture) and a 50% carbon content for biomass, an annual carbon accumulation rate for balsam poplar stands would be 0.648 metric tons of carbon (tC)/acre-yr.

For the BAU scenario (grassland succession), an estimate of the AG carbon accumulation was taken from the 2006 inventory guidelines from the Intergovernmental Panel on Climate Change (IPCC) Volume IV, Chapter 6.[24] The default peak AG biomass for grasslands in boreal

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[21] Monitoring Trends in Burn Severity Program, U.S. Geological Survey and USFS, available at http://mtbs.gov/index.html.

[22] J. Hermanns, AK DOF, Tok Area Forest, and A. Egren, DNR AK DOF Delta Area Forest, personal communications with S. Roe, CCS, March 2009.

[23] J. Graham, AK DOF, personal communication with J. Hermanns, AK DOF, 3/03/2009.

[24] IPCC 2006, section 6.3.1.2, Available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_06_Ch6_Grassland.pdf.

ecosystems is 1.7 metric tons of biomass per hectare (dry mass basis). So over the same 35-year period, the new grassland would have accumulated 0.010 tC/acre-yr (assuming 50% carbon content of the biomass). The incremental carbon accumulation for a replanted boreal hardwood stand over a grassland would be 0.638 tC/acre-yr (0.648–0.010 tC/acre-yr).

The schedule for reforestation projects is based on the average number of high-severity-burn areas created every year described above and in the policy goals. For example, the schedule assumes that 5% of high-severity-burn areas created in 2009 would be replanted in 2010, and that 25% of the areas created in 2024 are replanted in 2025. Replanting cost estimates for hardwood species were not available, so estimates for replanting costs of white spruce are used as a surrogate ($321/acre).[25] Table H-8 below provides a summary of the acres to be replanted, the incremental accumulated carbon, and the costs. The total discounted costs are divided by the total GHG reductions (CO_2) through 2025 to yield a cost-effectiveness of $92/t$CO_2$.

Table H-9. Boreal reforestation GHG benefits and costs

Year	Acres Replanted	Incremental Carbon Accumulated (tCO_2)	Replanting Costs ($)	Discounted Planting Costs ($2005)
2010	13,152	30,757	$4,320,745	$4,320,745
2011	18,413	43,060	$6,049,042	$5,760,993
2012	23,674	55,363	$7,777,340	$7,054,277
2013	28,935	67,666	$9,505,638	$8,211,327
2014	34,196	79,969	$11,233,936	$9,242,187
2015	39,457	92,272	$12,962,234	$10,156,249
2016	42,087	98,424	$13,826,382	$10,317,459
2017	44,718	104,575	$14,690,531	$10,440,286
2018	47,348	110,727	1$5,554,680	$10,528,020
2019	49,979	116,878	$16,418,829	$10,583,724
2020	52,609	123,030	$17,282,978	$10,610,249
2021	55,240	129,181	$18,147,127	$10,610,249
2022	57,870	135,333	$19,011,276	$10,586,190
2023	60,501	141,484	$19,875,425	$10,540,362
2024	63,131	147,636	$20,739,574	$10,474,894
2025	65,761	153,787	$21,603,723	$10,391,760
Total	**697,072**	**1,630,147**	**$228,999,460**	**$149,828,971**

GHG = greenhouse gas; tCO_2 = tons of carbon dioxide.

Key Assumptions:

Element A—For the incremental reductions associated with PCT and subsequent higher levels of merchantable timber, it is assumed that the carbon lost due to PCT is replaced during a 70-year rotation by growth release of crop trees. It is also assumed that biomass densities are otherwise

[25] D. Hanson, AK DOF, personal communication with S. Roe, CCS, March 2009.

similar between managed and unmanaged stands, and that there has only been a shift of biomass from non-merchantable to merchantable stock as a result of PCT. The higher future value of timber on managed stands has not been factored into the costs. Carbon benefits due to removal of biomass as a result of PCT for conversion into wood waste alternate fuel or energy production are questionable by the TWG.

Element B-—A continuous supply of biomass for energy from this element will depend on maintaining annual treatment levels at the 2025 level (2,500 acres/yr) in the post-2025 period. The cost assumption is based on end use within a 40-mile radius. Future improvements in mechanical treatment and biomass collection and processing technologies have the potential to significantly reduce the estimated costs.

Element C—Similar assumptions as cited above for Element B are used for continuous supplies of biomass and delivered costs. To maintain biomass supply in the post-2025 time frame, new community plans would need to be developed and implemented with mechanical treatment prescriptions.

Element D-—Reforestation projects carried out as a result of this policy are designed to displace burn areas likely to be taken over by grasses with hardwood species. Costs for hardwood replantings are similar to those for white spruce. The future value for the additional biomass sequestered is not included.

Key Uncertainties

Quantification of the cost per $MMtCO_2$ does not consider the other benefits of the stand treatments. It is uncertain what the incremental cost-effectiveness per ton is for these practices if incentives are provided (e.g., federal incentives would not be counted toward the societal costs for Alaska using the CCS costing methods). We do know most of these practices are being implemented irrespective of the sequestration or offset benefits. Private landowners, however, rely heavily on federal cost share or grant programs that face a questionable future in terms of congressional appropriations. For example, even though landowners are thinning without receiving any benefit from $MMtCO_2$ capture, they may not be able to continue without outside revenue or federal funds. While state and federal land managers may not be in a position to sell carbon credits, the existence of such a market will help demonstrate the benefits and justify funding requests.

Quantifying the reduced carbon emissions from catastrophic wildfires as a result of boreal forest mechanical fuel treatments is difficult.

Additional Benefits and Costs

Element A

- Through silviculture treatments, increases wood product output per acre and provides associated economic benefits (or conversely maintains forest product output on a smaller timberland footprint).
- Improves wildlife habitat (improves deer browse in silviculture-treated stands).
- Provides employment opportunities in rural communities in southeast Alaska.

- Maintains and enhances overall forest health to promote stand and ecosystem resilience to changing climate and resulting insect, disease, and other environmental stressors.

Element B

- Reduces catastrophic wildfire (difficult to quantify).
- Reduces loss of life and property due to catastrophic wildfire near settlements.
- Reduces carbon emissions from loss of property and from reconstruction of lost properties.
- Provides indirect wildlife benefits through management of stand structure and browse.

Element C

- Reduces catastrophic wildfire (difficult to quantify).
- Reduces loss of life and property due to catastrophic wildfire near settlements.
- Reduces carbon emissions from loss of property and from reconstruction of lost properties.
- Provides indirect wildlife benefits through management of stand structure and various habitat benefits.
- Engages communities in a proactive manner to empower residents to actively participate in and take responsibility for risk awareness and mitigation activities for wildland fire.

Element D

Results in social, economic, and biological benefits of reforestation, too numerous to list. State law recognizes these benefits by requiring reforestation after logging, with fires and salvage being exceptions to reforestation requirements.

Feasibility Issues

- Location, location, location. The lack of infrastructure and distance to end users limit the feasibility of any of the elements on the location, which affects costs of the treatments, transportation of the fuel if applicable, and additional benefits to justify the treatments.
- See prior comments regarding feasibility issues with respect the PCT residue from coastal forests. The same issues apply to other residue types if there is no infrastructure or if the location is distant to end users.

Status of Group Approval

Approved.

Level of Group Support

Unanimous

Barriers to Consensus

Not applicable.

FAW-2. Expanded Use of Biomass Feedstocks for Energy Production

Policy Description

This policy recommendation would increase the amount of biomass available from forestry and municipal solid waste (MSW) for generating heat/electricity and liquid/gaseous biofuels to displace the use of fossil energy sources. It would also foster the development of biomass-to-energy projects where they are compliant with environmental requirements (see Implementation Mechanisms, below, for examples of projects and actions needed).

Policy Design

Goals:

- *Element A:* By 2025, utilize biomass feedstocks to offset 10% of the state's heating oil use in the commercial and residential sectors.
- *Element B:* By 2025, utilize biomass feedstocks to produce 5% of the state's electricity.
- *Element C:* By 2025, utilize biomass feedstocks to offset 5% of the state's fossil transportation fuels.

Timing:

- By 2010, establish a demonstration pilot facility to produce biomass electricity, heat generation, synthetic fuels, or biomass alternate fuel products.
- By 2015, utilize 50% of policy the goals.
- By 2025, achieve the full policy goals.

Parties Involved: Executive and legislative branches of state government, DNR, Alaska Department of Environmental Conservation (DEC), Alaska Energy Authority (AEA), ANCs, UA, Southeast Conference, Alaska Industrial Development Authority, CES and agencies, NRCS, Alaska State Chamber of Commerce, RDC, Alaska Forest Association, Alaska Public Service Commission, Alaska Department of Revenue, Alaska electric utilities and cooperatives, crop producers, and timberland owners.

Other: None.

Implementation Mechanisms

Alaska should foster the following, where they are compliant with environmental requirements:

- Wood biomass alternative fuel products for heat and electric generation from sawmill by-products;
- Methods to economically utilize that portion of harvested trees not being used to make conventional forest products to produce wood biomass alternative fuel products or generate heat and electricity;

- Methods to economically utilize biomass generated from silvicultural treatments and wildland fire fuel reduction treatments in the production of biomass alternative fuel products or heat and electric generation;
- Methods to economically utilize feedstocks from MSW (e.g., urban wood waste, waste vegetable oil);
- Large- and small-scale technologies that generate heat and electricity (combined heat and power [CHP] as well as cogeneration) and the production of synthetic fuels from biomass;
- Both conventional and emerging technologies (e.g., cellulosic ethanol/other liquid fuel, pyrolysis, gasification) for biomass utilization; and
- Opportunities for industry, communities, and individuals to use biomass alternative fuel products to substitute for fossil fuels for heat or transportation. This should be done either using 100% biomass or co-firing with other fuels.

A strong timber industry in Alaska will serve to both stabilize and reduce the overall cost of delivered biomass in the state. If increased demand for biomass as a result of GHG policies can strengthen the market for timber, then there could be cost benefits in the future.

Related Policies/Programs in Place

The TWG and state agencies can work with CCS to identify existing or planned programs that address issues raised in this recommendation. In Governor Palin's 2009 State of the State address, she enumerated the following goal: "[generate] 50 percent of our electric power with renewable sources. That's an unprecedented policy across the U.S, but we're the state that can do it with our abundant renewables, and with Alaskan ingenuity."[26]

Types(s) of GHG Reductions

CO_2, Nitrous Oxide (N_2O), Methane (CH_4): Displaces emissions from fossil fuel combustion in electricity and heat production, as well as transportation.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2020, 2025 ($MMtCO_2e$):

Element A: 0.01, 0.03, 0.04, respectively.

Element B: 0.07, 0.12, 0.18, respectively.

Element C: 0.03, 0.06, 0.09, respectively.

[26] Governor Palin, State of Alaska, State of the State address, 2009. Available at: http://www.gov.state.ak.us/news.php?id=1610.

Net Cost per tCO_2e:

Element A: $90.

Element B: $38.

Element C: $52.

Element A. Biomass Feedstocks to Offset Heating Oil Use

Small-scale biomass heat generators are already being installed in public facilities in Alaska, such as schools. There is also the opportunity to see wide-scale use of pellet fuels in remote residential applications and other wood combustion appliances. This technology generates heat with very low associated GHG emissions. Through CHP, small-scale generators can provide both electricity and heat, although using this technology on a small scale is more difficult and very location-specific. Therefore, installation of more cost-effective CHP technology only occurs after 2015 and on a more limited scale than the biomass heating units. The electricity generated through CHP goes toward the 5% state electricity goal, discussed further in Element B. The heating requirements for FAW-2 can be seen in Table H-10.

Table H-10. Heating needs to meet 10% biomass for heating goal

Year	Goal	Billion Btu (From Petroleum) Replaced With Biomass
2009	0.0%	0
2010	0.6%	28
2011	1.3%	56
2012	1.9%	85
2013	2.5%	113
2014	3.1%	141
2015	3.8%	171
2016	4.4%	201
2017	5.0%	232
2018	5.6%	264
2019	6.3%	296
2020	6.9%	321
2021	7.5%	346
2022	8.1%	371
2023	8.8%	394
2024	9.4%	417
2025	10.0%	442

Btu = British thermal unit.

To meet the needs for FAW-2, small-scale generators similar to the ones produced by Community Power Corporation (CPC) will be required. The CPC generators are used as an example, and this is in no way an endorsement of this technology over similar generators. These are 66-kilowatt (kW) generators, which if used as directed, would consume 442 dry tons of

biomass feedstock annually, providing a little over 3,900 million British thermal units (MMBtus) of usable heat. Heat-only generators would be used for 2010–-2015, after which 50% of generators will be assumed to be heat-only and 50% will be assumed to be combined heat and power (CHP) units. These units will produce 443 megawatt-hours (MWh) of electricity (all figures annual), as well as the previously stated 3,900 MMBtus of usable heat.[27] The number of heating units was determined based on the number that would be required to meet Alaska's 10% goal. Ideally, these units will be located in more remote settings, where fossil fuel generators are used to produce both electricity and heat. The 442 billion Btus of heat required were divided by the number of Btus provided by a single generator. The capital costs for these generators were estimated to be $4,000/kW of capacity, or about $264,000 per unit. In the case of the CHP generators, additional costs for heat distribution will vary according to the circumstances of each project, but they are estimated to add 27% to the capital costs on average.[28] Thus, the capital costs of installation include the cost of the infrastructure to deliver any heat generated. The estimate of biomass feedstocks required comes from the amount of biomass needed to keep the generators in operation. Table H-11 outlines the costs of the small-scale CHP units required in this policy, assuming a cost of woody biomass to be $65/delivered dry ton. The costs are also displayed for a cost of $120/delivered dry ton, to provide a comparison of the cost-effectiveness of this policy, given the potentially large range of biomass costs that can occur in Alaska.

Table H-11. Number and costs of small-scale heating and CHP units required

Year	Total Units Installed	Total Heating Units Installed	Total CHP Units Installed	Capital Cost of Installation	Annual Fuel Requirements (dry tons biomass)	Cost of Biomass Feedstocks @ $65/Dry Ton ($MM)	Cost of Biomass Feedstocks @ $120/Dry Ton ($MM)
2009	0	0	0	$0	0	$0.0	$0.0
2010	7	7	0	$2.4	3,165	$0.2	$0.4
2011	14	14	0	$2.4	6,334	$0.4	$0.8
2012	22	22	0	$2.4	9,509	$0.6	$1.1
2013	29	29	0	$2.4	12,689	$0.8	$1.5
2014	36	36	0	$2.4	15,874	$1.0	$1.9
2015	43	43	0	$2.5	19,222	$1.2	$2.3
2016	51	47	4	$2.6	22,630	$1.5	$2.7
2017	59	51	8	$2.6	26,101	$1.7	$3.1
2018	67	55	12	$2.7	29,634	$1.9	$3.6
2019	75	59	16	$2.7	33,231	$2.2	$4.0
2020	82	63	19	$2.2	36,104	$2.3	$4.3
2021	88	66	22	$2.1	38,904	$2.5	$4.7
2022	94	69	25	$2.1	41,635	$2.7	$5.0
2023	100	72	28	$2.0	44,297	$2.9	$5.3

[27] Based on Community Power Corporation information provided by Art Lilley, 2/14/09.

[28] Based on the estimate that the heat distribution cost is typically $4,000 and the system costs are $10,000–$20,000. See http://www.toolbase.org/Technology-Inventory/Electrical-Electronics/combined-heat-power.

Year	Total Units Installed	Total Heating Units Installed	Total CHP Units Installed	Capital Cost of Installation	Annual Fuel Requirements (dry tons biomass)	Cost of Biomass Feedstocks @ $65/Dry Ton ($MM)	Cost of Biomass Feedstocks @ $120/Dry Ton ($MM)
2024	106	75	31	$2.0	46,894	$3.0	$5.6
2025	112	78	34	$2.1	49,688	$3.2	$6.0

CHP = combined heat and power; $MM = million dollars.

The electricity emissions factor used comes from the Alaska I&F. The amount of electricity generated was calculated based on the number of generators in operation. The GHG emissions from biomass come from multiplying the Btus of biomass going into the generator by the emissions factor for biomass (0.002 tCO_2e/MMBtu). The electricity cost ($/kilowatt-hour [kWh]) comes from the ESD TWG,[29] who gave an estimate for the avoided cost of electricity produced in rural Alaska to be 21.4 cents/kWh, which is significantly higher than the estimate for the state as a whole. See Table H-12 for more details.

Table H-12. Electricity produced and GHG savings from small-scale heating and CHP

Year	Electricity Generated (MWh)	GHG Emissions From Biomass (tCO_2e)	GHG Emissions Savings Electricity (tCO_2e)	Electricity Emissions Factor (tCO_2e/MWh)	Rural Electricity Cost ($/kWh)	Electricity Savings ($MM)
2009	0	0	0	0.53	$0.214	$0
2010	0	97	0	0.54	$0.214	$0
2011	0	195	0	0.53	$0.214	$0
2012	0	292	0	0.53	$0.214	$0
2013	0	390	0	0.52	$0.214	$0
2014	0	488	0	0.51	$0.214	$0
2015	0	591	0	0.51	$0.214	$0
2016	1,672	696	834	0.50	$0.214	$0
2017	3,374	803	1,662	0.49	$0.214	$1
2018	5,107	912	2,482	0.49	$0.214	$1
2019	6,872	1,022	3,295	0.48	$0.214	$1
2020	8,281	1,111	3,919	0.47	$0.214	$2
2021	9,655	1,197	4,509	0.47	$0.214	$2
2022	10,994	1,281	5,068	0.46	$0.214	$2
2023	12,300	1,363	5,596	0.45	$0.214	$3
2024	13,574	1,442	6,096	0.45	$0.214	$3
2025	14,944	1,528	6,625	0.44	$0.214	$3

CHP = combined heat and power; GHG = greenhouse gas; kWh = kilowatt-hour; $MM = million dollars; MWh = megawatt-hour; tCO_2e = tons of carbon dioxide equivalent.

[29] The avoided cost of rural electricity includes arctic northwest and southwest Alaska estimates. The primary source for the ESD figures is from AEA (http://www.iser.uaa.alaska.edu/Publications/akelectricpowerfinal.pdf).

The heat produced from CHP is shown in Table H-13 below. The GHG savings were calculated based on the assumption that diesel generators would be replaced with biomass CHP plants. The diesel fuel costs and emissions factor come from the Alaska Quantifications and Assumptions memo (Appendix E of this report). A transportation efficiency of 92% was assumed to move the heat from the generator to the place where heating is required (be it residential or commercial).[30] This accounts for the difference seen between heat generated and heat delivered.

Table H-13. Heat produced and GHG savings from small-scale heating and CHP

Year	Heat Generated (billion Btu)	Heat Delivered (billion Btu)	Diesel Fuel Costs ($/MMBtu)	Diesel Fuel Savings—Heat ($MM)	GHG Emissions Saved—Heat (tCO_2e)	Additional O&M Costs ($MM)
2009	0	0	$13.25	$0.00	0	$0.0
2010	28	26	$12.65	$0.33	2,021	$0.3
2011	56	52	$12.11	$0.63	4,046	$0.5
2012	85	78	$11.33	$0.88	6,073	$0.8
2013	113	104	$10.68	$1.11	8,104	$1.1
2014	141	130	$10.41	$1.35	10,139	$1.3
2015	171	157	$9.83	$1.55	12,277	$1.6
2016	201	185	$9.42	$1.75	14,454	$1.9
2017	232	214	$9.43	$2.02	16,671	$2.2
2018	264	243	$9.57	$2.32	18,927	$2.5
2019	296	272	$9.71	$2.64	21,225	$2.8
2020	321	296	$9.81	$2.90	23,060	$3.0
2021	346	319	$9.81	$3.13	24,848	$3.2
2022	371	341	$9.81	$3.34	26,592	$3.5
2023	394	363	$9.81	$3.56	28,293	$3.7
2024	417	384	$9.81	$3.77	29,951	$3.9
2025	442	407	$9.81	$3.99	31,736	$4.1

Btu = British thermal unit; CHP = combined heat and power; GHG = greenhouse gas; $MM = million dollars; MMBtu = million British thermal units; O&M = operation and maintenance; tCO_2e = tons of carbon dioxide equivalent.

The total costs and GHG benefits of small-scale CHP are outlined in Table H-14. The cost-effectiveness estimated at a delivered biomass cost of $65/ton is $90/$tCO_2e$, while at $120/ton, the cost-effectiveness would be $128/$tCO_2e$.

[30] Hannes Schwaiger and Gerfried Jungmeier. "Overview of CHP Plants in Europe and Life Cycle Assessment (LCA) of GHG Emissions for Biomass and Fossil Fuel CHP Systems." Institute of Energy Research. September 2007. Available at: http://www.atee.fr/cp/37/6-%2018-09%20SCHWAIGER%20JOANNEUM%20R.pdf.

Table H-14. Net costs of and GHG savings from small-scale heating and CHP

Year	Discounted Net Costs (assuming $65/ton biomass) ($MM)	Discounted Net Costs (assuming $120/ton biomass) ($MM)	Net GHG Emissions Avoided ($MMtCO_2e$)
2009	$0.0	$0.0	0.00
2010	$2.0	$2.1	0.00
2011	$2.0	$2.3	0.00
2012	$2.1	$2.5	0.01
2013	$2.2	$2.6	0.01
2014	$2.2	$2.8	0.01
2015	$2.4	$3.0	0.01
2016	$2.2	$3.0	0.01
2017	$2.1	$2.9	0.02
2018	$1.9	$2.8	0.02
2019	$1.8	$2.7	0.02
2020	$1.4	$2.3	0.03
2021	$1.2	$2.2	0.03
2022	$1.1	$2.1	0.03
2023	$1.0	$2.0	0.03
2024	$0.9	$1.9	0.03
2025	$0.9	$1.9	0.04
Total	**$27**	**$39**	**0.3**

CHP = combined heat and power; GHG = greenhouse gas; $MM = million dollars; $MMtCO_2e$ = million tons of carbon dioxide equivalent.

Element B. Biomass Feedstocks for Electricity Use

The goal was determined using baseline data from the Alaska I&F.[31] BAU electricity generation grows over the policy period from about 6.5 terawatt-hours (TWh) in 2009 to approximately 8.6 TWh in 2025. Biomass usage over the period is based on the existing biomass generation capacity, although the current estimate is for no significant biomass contribution to electricity production between 2009 and 2025. This baseline information, along with the projected target, is illustrated in Table H-15. The additional biomass needed reflects the net amount of electricity needed after consideration of the power that would be produced by the CHP units quantified under Element A, above.

[31] The CCS Alaska Energy Supply I&F (Appendix D).

Table H-15. Expanded use of biomass goal determination

Year	Total BAU Projected Generation (GWh)	Policy Goal Proportion of Total In-State Electricity Generation (%)	Additional Biomass Generation to Meet Policy Goals (after CHP) (GWh)	Estimated Biomass Required (MMBtu)*
2009	6,504	0.0%	—	
2010	6,617	0.3%	21	206,795
2011	6,733	0.6%	42	420,816
2012	6,851	0.9%	64	642,252
2013	6,970	1.3%	87	871,296
2014	7,092	1.6%	111	1,108,148
2015	7,216	1.9%	135	1,353,010
2016	7,342	2.2%	159	1,589,369
2017	7,470	2.5%	183	1,833,855
2018	7,601	2.8%	209	2,086,681
2019	7,734	3.1%	235	2,348,061
2020	7,869	3.4%	262	2,622,093
2021	8,006	3.8%	291	2,905,809
2022	8,146	4.1%	320	3,199,435
2023	8,288	4.4%	350	3,503,206
2024	8,433	4.7%	382	3,817,360
2025	8,581	5.0%	414	4,140,860

* The assumed heat rate for biomass plant is 10,000 Btu per kilowatt-hour.

BAU = business as usual; CHP = combined heat and power; GWh = gigawatt-hour; MMBtu = millions of British thermal units.

This analysis focuses on the incremental GHG benefits associated with the utilization of additional biomass to offset the consumption of fossil fuels. The analysis assumes biomass will be used to replace electricity.

The GHG benefits from electricity were calculated by assuming that using biomass reduces CO_2e emissions by the Alaska-specific emissions factor for electricity generation. The CO_2e associated with this amount of electricity in each year is estimated by multiplying the MWh produced by the Alaska-specific emission factor for electricity production from the Alaska GHG I&F (these values in tCO_2e/MWh vary in each year of the forecast).[32] See Table H-16 for more details.

[32] Total electricity emissions per MWh were provided by the ESD TWG, and range from 0.53 tCO_2e/MWh in 2009 to 0.44 tCO_2e/MWh in 2025. It is recognized that biomass combustion is not truly zero CO_2e/MWh; however, the methane and nitrous oxide emissions from biomass combustion are relatively small.

Table H-16. Expanded use of biomass GHG benefits and approximate biomass demand

Year	Policy Goal Proportion of Total In-State Electricity Generation (%)	Additional Biomass Generation to Meet Policy Goals (after CHP) (GWh)	Electricity Emissions Factor (tCO_2e/MWh)	Avoided Emissions From Electricity Production ($MMtCO_2e$)	Approximate Amount of Biomass Required to Meet Goal (assuming 12 MMBtu/ton) (dry tons)
2009	0.0%	—	0.532		—
2010	0.3%	21	0.541	0.01	17,233
2011	0.6%	42	0.534	0.02	35,068
2012	0.9%	64	0.527	0.03	53,521
2013	1.3%	87	0.520	0.05	72,608
2014	1.6%	111	0.513	0.06	92,346
2015	1.9%	135	0.506	0.07	112,751
2016	2.2%	159	0.499	0.08	132,447
2017	2.5%	183	0.492	0.09	152,821
2018	2.8%	209	0.486	0.10	173,890
2019	3.1%	235	0.480	0.11	195,672
2020	3.4%	262	0.473	0.12	218,508
2021	3.8%	291	0.467	0.14	242,151
2022	4.1%	320	0.461	0.15	266,620
2023	4.4%	350	0.455	0.16	291,934
2024	4.7%	382	0.449	0.17	318,113
2025	5.0%	414	0.443	0.18	345,072
			Cumulative	**1.5**	

CHP = combined heat and power; GHG = greenhouse gas; GWh = gigawatt-hour; MMBtu = millions of British thermal units; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; MWh = megawatt-hour; tCO_2e = metric tons of carbon dioxide equivalent.

Biomass to Electricity Costs

The cost calculation has two main components: fuel costs and capital/operational/maintenance costs. The fuel component is based on the difference in costs between supply of biomass fuel and the assumed fossil fuel that it is replacing. The assumed biomass fuel cost used in this analysis is indicated in Table H-17, and the assumed fossil fuel costs are indicated in Table H-18. While MSW has been identified as a potential feedstock, it has not been included in the cost analysis. It is possible that MSW energy feedstocks have a very low or negative cost. This is because in the current market, waste haulers pay a tipping fee to the landfill or transfer station that receives the waste, and haulers could forego this payment through delivery as an energy feedstock.

The cost of implementing the policy is estimated by assuming the replacement of fossil fuel-generated electricity with biomass-generated electricity. In this case, it is the relative proportion of fuel mixes required under the BAU scenario (i.e., coal, natural gas, or oil in MMBtu), as defined by the U.S. Environmental Protection Agency's (EPA's) Emissions & Generation

Resource Integrated Database (eGRID)—i.e., 72% coal, 13% natural gas, and 15% oil (it is assumed that biomass would not replace hydropower), as indicated in Table H-7.[33]

The difference in costs of feedstock supply between biomass and coal, natural gas, and heating oil is calculated using the costs outlined in Tables H-17 and H-18. The difference in costs ($/MMBtu) is multiplied by the amount of energy (MMBtu) being replaced by biomass. Operation and maintenance (O&M) costs were taken from Table 38 of the U.S. Department of Energy (DOE) Energy Information Administration's (EIA) *Annual Energy Outlook 2008.*[34] While use of biomass may be pursued through other technology types (e.g., gasification) or end uses (e.g., heat or steam), this methodology was used to provide an estimate of the costs of co-firing with biomass feedstocks replacing traditional electricity consumption. The costs for both $65/delivered ton and $120/delivered ton are included.

Table H-17. Assumed costs of biomass feedstocks

Biomass Fuel Type	Cost ($/dry ton delivered)	Heat Content (MMBtu/ton)	Cost ($/MMBtu delivered)	Source
Forest Feedstocks	$65.00	15.4	$4.23	As shown in the Biomass Supply and Demand section of this appendix (Table H-1), these costs are near the mid-point of the range of likely low-cost biomass feedstocks in Alaska (~$35/dry ton) and moderately high-cost feedstocks (~$100/dry ton). It is also within the range of estimated delivered biomass cost within the boreal forest (Tok Forest area).[35] The above cost information is also consistent with the information produced for the Wolverine Clean Energy Venture study in Michigan[36] and summaries on Michigan pulpwood costs in a document titled: *Michigan Timber Market Analysis. Final Report.*

$/MMBtu = dollars per million British thermal units.

[33] Based on eGRID data for Alaska: coal, 56%; nuclear, 0%; oil, 12%; natural gas, 10%; hydro, 23%; wind, 0%; and biomass, 0.1% (http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html).

[34] See http://www.eia.doe.gov/oiaf/aeo/.

[35] Hermanns, J., AK DOF, personal communication with S. Roe, CCS, March 2009.

[36] Froese, R., and Miller, C., *Biomass Co-Firing for the Wolverine Clean Energy Venture: An Assessment of Potential Supply, Environmental Limitations, and Co-Benefits Through Carbon Sequestration*, School of Forest Resources and Environmental Science, Michigan Technological University, January 30, 2008.

Table H-18. Assumed costs of fossil fuel feedstocks[37]

Year	Coal	Natural Gas	Residual Fuel Oil ($/MMBtu)
2009	$1.20	$6.82	$13.25
2010	$1.24	$6.36	$12.65
2011	$1.24	$6.07	$12.11
2012	$1.23	$5.86	$11.33
2013	$1.22	$5.60	$10.68
2014	$1.23	$5.43	$10.41
2015	$1.22	$5.32	$9.83
2016	$1.21	$5.29	$9.42
2017	$1.22	$5.34	$9.43
2018	$1.25	$5.39	$9.57
2019	$1.25	$5.42	$9.71
2020	$1.26	$5.24	$9.81
2021	$1.26	$5.24	$9.81
2022	$1.26	$5.24	$9.81
2023	$1.26	$5.24	$9.81
2024	$1.26	$5.24	$9.81
2025	$1.26	$5.24	$9.81

$/MMBtu = dollars per million British thermal units.

Table H-19 shows the costs of biomass co-firing. Note that the fuel costs shown to in the far right columns of Table H-19 indicate net costs of fuel, as compared with existing electricity generation. Therefore, this is the cost to use biomass minus the costs of coal/natural gas/oil, according to Alaska's fuel mix. There are positive costs of both the $65/ton and the $120/ton scenarios, when compared with the default fuel mix assumed for Alaska (72% coal, 13% natural gas, and 15% oil). The break-even cost of replacing these fuels is somewhere in the range of $50/ton for this policy, although this changes from year to year based on fossil fuel costs. This explains why the fuel costs in the high-cost scenario outlined in Table H-19 are more than double the costs of the mid-range fuel costs scenario. The total costs of biomass co-firing are outlined in Table H-20.

[37] Fossil fuel costs ($/MMBtu) for 2009–2020 come from the Methods of Quantification memo (Appendix E). Costs for 2021–2025 were held constant at 2020 levels.

Table H-19. Costs of generating electricity from biomass

Year	Estimated Electrical Output (MWh)	Estimated Cumulative Capacity (MW)	Variable O&M Costs (2005 $MM)	Fixed O&M Costs (2005 $MM)	Fuel Costs—Mid-Range[a] (2005 $MM)	Fuel Costs—High[b] (2005 $MM)
2009	—	—	$0.0	$0	$0.0	$0.0
2010	20,680	3	0.0	$0.1	$0.1	$0.9
2011	42,082	6	$0.1	$0.2	$0.3	$1.8
2012	64,225	9	$0.1	$0.3	$0.5	$2.8
2013	87,130	2	$0.2	$0.4	$0.9	$4.0
2014	110,815	15	$0.2	$0.5	$1.2	$5.1
2015	135,301	18	$0.3	$0.6	$1.6	$6.4
2016	158,937	21	$0.4	$0.7	$2.0	$7.6
2017	183,386	25	$0.4	$0.8	$2.2	$8.8
2018	208,668	28	$0.5	$0.9	$2.4	$9.9
2019	234,806	32	$0.5	$1.1	$2.7	$11.1
2020	262,209	35	$0.6	$1.2	$3.0	$12.4
2021	290,581	39	$0.6	$1.3	$3.3	$13.7
2022	319,944	43	$0.7	$1.4	$3.6	$15.1
2023	350,321	47	$0.8	$1.6	$4.0	$16.5
2024	381,736	51	$0.9	$1.7	$4.4	$18.0
2025	414,086	56	$0.9	$1.9	$4.7	$19.5

[a] Delivered price of $65/dry ton in $2005.

[b] Delivered price of $120/dry ton in $2005.

$MM = million dollars; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; MW = megawatt; MWh = megawatt-hour; O&M = operation and maintenance.

Table H-20. Net costs of biomass-to-electricity production

Year	Total Costs @ $65/Dry Ton (2005 $MM)	Total Costs @ $120/Dry Ton (2005 $MM)
2009	$0.0	$0.0
2010	$0.3	$1.0
2011	$0.6	$2.1
2012	$1.0	$3.3
2013	$1.5	$4.6
2014	$1.9	$5.9
2015	$2.5	$7.3
2016	$3.0	$8.7
2017	$3.5	$10.0
2018	$3.8	$11.3
2019	$4.3	$12.7
2020	$4.8	$14.1

Year	Total Costs @ $65/Dry Ton (2005 $MM)	Total Costs @ $120/Dry Ton (2005 $MM)
2021	$5.3	$15.7
2022	$5.8	$17.3
2023	$6.4	$18.9
2024	$6.9	$20.6
2025	$7.5	$22.3
Total	**$59**	**$176**

$MM = million dollars.

Element C. Biomass Feedstocks to Offset Fossil Transportation Fuels

Biofuel GHG Reductions

The benefits for this policy are dependent on developing in-state production capacity that achieves GHG benefits beyond petroleum fuels. This policy quantifies the benefits and costs of producing sufficient renewable liquid cellulosic ethanol to meet the policy goal. Other biofuels exist, from currently available fuels, such as biodiesel and corn ethanol, to more advanced fuels, such as ethanol derived from algae and other (non-cellulosic) feedstocks. This analysis focuses on cellulosic ethanol as an example of the potential for GHG reduction through biofuel use. While large-scale cellulosic ethanol plants are under construction throughout the United States, the technology remains in its early stages, and the costs of cellulosic ethanol are not yet certain. Table H-2.12 lists the quantity of biofuels required in each year to meet the goals of FAW-2.

Table H-21. Quantity of biofuel required in FAW-2

Year	Implementation Path (% biofuels displaced)	BAU AK Gasoline Consumption (MM gallons)	Displacement Goal (MM gallons)
2009	0%	231	0
2010	0%	231	1
2011	1%	232	1
2012	1%	234	2
2013	1%	235	3
2014	2%	236	4
2015	2%	237	4
2016	2%	239	5
2017	3%	240	6
2018	3%	241	7
2019	3%	243	8
2020	3%	244	8
2021	4%	245	9
2022	4%	246	10
2023	4%	247	11
2024	5%	248	12
2025	5%	249	12

AK = Alaska; BAU = business as usual; MM = million.

The incremental benefit of cellulosic production over gasoline from all other feedstocks targeted by this policy is 9.74 tCO_2e reduced/1,000 gallons (gal), based on the difference between the life-cycle CO_2e emission factor of gasoline and the life-cycle CO_2e emission factor of cellulosic ethanol (1.51 t/1,000 gal).[38] The incremental benefit values will be used, along with the production in each year, to estimate GHG reductions. Annual cellulose production is multiplied by the estimated ethanol yield per ton of biomass, based on the projection that ethanol yield will increase from 70 gal/ton biomass to 90 gal/ton biomass by 2012 and to 100 gal/ton biomass by 2020.[39] This increase was assumed based on the maturation of cellulosic ethanol technology, allowing increased yield per ton of biomass feedstock.

Table H-22 shows the number of 3 million (MM) gal/year cellulosic plants that will need to go on line in Alaska to convert the available biomass feedstock to ethanol, and summarizes the quantity of other biofuels that can be produced with the Alaska feedstock supply, assuming that food crops will not be utilized for fuel. Some of the emission reductions from cellulosic ethanol

[38] Argonne National Laboratory GREET (Greenhouse gases, Regulated Emissions and Energy use in Transportation) model 1.8b emission factor for mixed feedstock cellulosic E100 (100% ethanol) for flex-fuel vehicle in grams per mile (g/mi) x GREET model average fuel economy (100 mi/4.3 gal).

[39] J. Ashworth, U.S. DOE, National Renewable Energy Laboratory, personal communication with S. Roe, CCS, April 2007.

will not occur in Alaska, and thus must be counted separately. Otherwise, comparing the forecast reductions against the Alaska I&F would no longer be possible.

Table H-22. Projected biofuel production and emission reductions

Year	Cellulosic Ethanol Plants Required	Cellulosic Feedstock Used (MM dry tons/yr)	Cellulosic Ethanol Production (MM gallons/yr)	Total Life-Cycle Emission Reductions ($MMtCO_2e$)	Total In-State Emission Reductions ($MMtCO_2e$)
2009	0	0.00	0	0.00	0.00
2010	1	0.01	1	0.01	0.01
2011	1	0.02	1	0.01	0.01
2012	1	0.02	2	0.02	0.02
2013	1	0.03	3	0.03	0.02
2014	2	0.04	4	0.04	0.03
2015	2	0.05	4	0.04	0.03
2016	2	0.06	5	0.05	0.04
2017	3	0.07	6	0.06	0.05
2018	3	0.08	7	0.07	0.05
2019	3	0.08	8	0.07	0.06
2020	3	0.08	8	0.08	0.06
2021	4	0.09	9	0.09	0.07
2022	4	0.10	10	0.10	0.08
2023	4	0.11	11	0.11	0.08
2024	4	0.12	12	0.11	0.09
2025	5	0.12	12	0.12	0.09
Total				**1.0**	**0.8**

MM = million; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; yr = year.

Note: Cellulosic plants required are not necessarily whole numbers in each year. The analysis assumes that these plants will be going on line mid-year or are operating at less than full capacity.

In-state emission reductions consider only GHG benefits that will happen in Alaska. Life-cycle emission reductions consider the energy inputs and outputs that come with production and distribution of the various fuels. The life-cycle emissions figure is used in the summary table on page M-H-1 of this appendix.

Cellulosic Ethanol Costs

The cellulosic ethanol costs of this option are estimated based on the capital and operating costs of cellulosic ethanol production plants. A study by the DOE National Renewable Energy Laboratory (NREL) was used to estimate the O&M costs of a 70-MMgal/yr cellulosic ethanol plant.[40] These costs were scaled down to accommodate the smaller cellulosic plants in Alaska, although O&M costs could not be scaled down in a linear fashion, because there are some efficiency losses from lost economies of scale. Cellulosic plants in this analysis are assumed to

[40] National Renewable Energy Laboratory, *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover*, NREL/TP-510-32438 (Golden, CO, June 2002). Accessed June 2008 at www.nrel.gov/docs/fy02osti/32438.pdf.

produce 3 MMgal ethanol/yr. The average capital cost of a new cellulosic ethanol plant is estimated to be $21.5 million, which is based on the average capital cost/MMgal of production for six different cellulosic ethanol plants. The costs estimated for these plants were quite variable, so rather than taking the estimated cost of a single plant, an average of $7.17/gal/yr was used. For a 3-MMgal/yr plant, this average results in a cost of $21.5 million. A new plant will need to be built for every 3 MMgal of annual ethanol production needed. It was assumed that the capital costs will be paid according to a cost recovery factor over the 20-year lifetime of the plant. The cost of biomass feedstocks made up a significant portion (~60%) of variable costs. Therefore, the NREL estimate of feedstock costs ($30/ton) were replaced with more current estimates of the cost of delivered biomass: $65/ton for woody feedstocks.[41] The plant proposed by the NREL study produces some excess electricity, although the costs and benefits of generating this electricity are not considered in this analysis. The revenue source for the ethanol plant is the value of the ethanol being produced (from EIA *Annual Energy Outlook 2009*).[42] The costs of cellulosic ethanol production are shown in Table H-23. The value of the cellulosic ethanol produced and net costs of the program are outlined in Table H-24.

[41] The basis for this is related to summaries on Michigan pulpwood costs in a document titled *Michigan Timber Market Analysis*: *Final Report*, prepared for the Michigan Department of Natural Resources by Prentiss and Carlisle, March 10, 2008 (http://michigansaf.org/Forestinfo/1-Maininfo.htm). Alaska biomass costs will be substituted once they are available.

[42] See http://www.eia.doe.gov/oiaf/aeo/.

Table H-23. Cost summary for cellulosic ethanol plants

Year	Cellulosic Ethanol Production (MM gal)	Cost of Feedstock @ $65/Ton Biomass (2005 $MM)	Cost of Feedstock @ $120/Ton Biomass (2005 $MM)	Other Annual Costs ($MM)	Total Annual Costs @ $65/Ton Biomass ($MM)	Total Annual Costs @ $120/Ton Biomass ($MM)	Annualized Capital Costs ($MM)
2009	0	$0	$0	$0	$0	$0	$0
2010	1	$1	$1	$4	$4	$5	$2
2011	1	$1	$2	$4	$5	$6	$2
2012	2	$2	$3	$4	$5	$7	$2
2013	3	$2	$4	$4	$6	$8	$2
2014	4	$3	$5	$7	$10	$12	$3
2015	4	$3	$6	$7	$11	$13	$3
2016	5	$4	$7	$7	$11	$14	$3
2017	6	$4	$8	$11	$15	$19	$5
2018	7	$5	$9	$11	$16	$20	$5
2019	8	$5	$10	$11	$17	$21	$5
2020	8	$5	$10	$11	$16	$21	$5
2021	9	$6	$11	$15	$21	$26	$7
2022	10	$7	$12	$15	$21	$27	$7
2023	11	$7	$13	$15	$22	$28	$7
2024	12	$8	$14	$15	$22	$29	$7
2025	12	$8	$15	$18	$26	$33	$9

gal = gallon; MM = million; $MM = million dollars.

Table H-24. Cellulosic ethanol revenue and net costs

Year	Sale Price/Gallon Ethanol ($2005)	Value of Cellulosic Ethanol Produced ($MM)	Discounted Net Cellulosic Ethanol Costs @ $65/Ton Biomass ($MM)	Total Cellulosic Ethanol Costs @ $120/Ton Biomass ($MM)
2009	$2.91	$0	$0	$0
2010	$1.92	$1	$4	$4
2011	$2.07	$3	$3	$4
2012	$2.19	$5	$2	$3
2013	$2.28	$7	$1	$2
2014	$2.00	$7	$4	$5
2015	$1.86	$8	$4	$5
2016	$1.94	$10	$3	$4
2017	$2.16	$13	$4	$6
2018	$2.20	$15	$3	$5
2019	$2.23	$17	$2	$5
2020	$2.23	$19	$1	$4
2021	$2.24	$21	$3	$6
2022	$2.25	$22	$2	$5
2023	$2.27	$25	$2	$4
2024	$2.28	$27	$1	$4
2025	$2.27	$28	$3	$5
Total			**$41**	**$70**

$MM = million dollars.

To provide an overview of the entire policy, Table H-25 summarizes the GHG savings and net costs of all three elements of FAW-2. The assumed delivered cost of biomass for these cost estimates is $65/dry ton.

Table H-25. Costs and GHG savings of FAW-2

Year	$MMtCO_2e$ Saved: Heating	$MMtCO_2e$ Saved: Electricity	$MMtCO_2e$ Saved: Biofuels	$MMtCO_2e$ Saved: Total	Net Costs: Heating ($MM)	Net Costs: Electricity ($MM)	Net Costs: Biofuel ($MM)	Net Costs ($MM)
2009	0.00	0.00	0.00	0.00	$0.0	$0.0	$0.0	$0.0
2010	0.00	0.01	0.01	0.02	$2.0	$0.3	$3.7	$5.9
2011	0.00	0.02	0.01	0.04	$2.0	$0.6	$2.8	$5.4
2012	0.01	0.03	0.02	0.06	$2.1	$1.0	$1.6	$4.6
2013	0.01	0.05	0.02	0.08	$2.2	$1.5	$0.6	$4.2
2014	0.01	0.06	0.03	0.09	$2.2	$1.9	$3.9	$8.0
2015	0.01	0.07	0.03	0.11	$2.4	$2.5	$3.5	$8.3
2016	0.01	0.08	0.04	0.13	$2.0	$3.0	$2.6	$7.6

Year	$MMtCO_2e$ Saved: Heating	$MMtCO_2e$ Saved: Electricity	$MMtCO_2e$ Saved: Biofuels	$MMtCO_2e$ Saved: Total	Net Costs: Heating ($MM)	Net Costs: Electricity ($MM)	Net Costs: Biofuel ($MM)	Net Costs ($MM)
2017	0.02	0.09	0.05	0.15	$1.6	$3.5	$4.2	$9.3
2018	0.02	0.10	0.05	0.17	$1.2	$3.8	$3.3	$8.3
2019	0.02	0.11	0.06	0.19	$0.8	$4.3	$2.4	$7.5
2020	0.03	0.12	0.06	0.21	$0.3	$4.8	$1.4	$6.4
2021	0.03	0.14	0.07	0.23	$0.0	$5.3	$3.2	$8.5
2022	0.03	0.15	0.08	0.25	–$0.2	$5.8	$2.5	$8.1
2023	0.03	0.16	0.08	0.27	–$0.4	$6.4	$1.7	$7.6
2024	0.03	0.17	0.09	0.29	–$0.6	$6.9	$1.1	$7.4
2025	0.04	0.18	0.09	0.32	–$0.7	$7.5	$2.6	$9.4
Total				**$2.6**				**$117**

$MM = million dollars; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Key Assumptions: The discount rate used in this analysis is 5%, as stated in the Methods of Quantification memo in Appendix E. The discount rate used can have a significant impact on cost-effectiveness. For example, if a 3% discount rate is used for the biofuels option, the cumulative cost would be $52 million for Element C, or $66/t (as opposed to the current estimate of $41 million and $52/t).

Key Uncertainties

- *General*—Delivered fuel costs are highly dependent on project specifics, location, and infrastructure. A detailed biomass feedstock analysis that identifies the volume of biomass available and at what cost from mill waste, improved timber harvest utilization, pre-commercial thinning, and commercial thinning is essential to provide accurate estimates of the cost-effectiveness of biomass technologies.
    - Even in cases where biomass is currently available at a reasonable price, it can be difficult to find capital investment in biomass-intensive projects. Because the timber industry has declined significantly in the past two decades, uncertainty in long-term biomass supply factors into decision making regarding capital investments. Additional biomass sources that can be demonstrated to be reliable in the long term (such as MSW) would be helpful in securing additional investment in biomass technologies.
    - To do these analyses, a single cost for delivered biomass must be used. However, this is heavily dependent on biomass feedstocks being available nearby in order to sell at this price. If biomass cannot be delivered to a given location at the estimated price, then the economic analysis is going to be dramatically affected. This limitation pushes the limits of a state-level analysis, and additional investigation of biomass availability is recommended. A geographic information system-based, localized approach to feedstock availability would significantly improve these analyses.
- *Economies of scale*—The rural Alaska setting presents challenges due to remoteness, size of communities, O&M capabilities, etc. Urban areas may have lower costs for coal, natural gas, and hydroelectric power, which makes renewable technologies less cost-competitive.

- *Net GHG reductions for biomass energy displacement of fossil fuels*—The total fuel-cycle emissions for collection, processing, delivery, and combustion of biomass have not been captured in the current analysis. However, the full fuel-cycle GHG emissions associated with fossil fuel extraction, processing, and transport have also not been factored into the estimates of net GHG reductions. Based on previous similar analyses, CCS does not believe that factoring the full fuel-cycle emissions would have a significant impact on the results.
- *Biomass supply*—The feasibility of any wood waste to be used in an alternate fuel project will be based in part on the cost of the biomass or "supply." The capital costs of adding a biomass wood waste facility to produce heat and/or heat and power at an existing mill are significant and should consider at a minimum the following points:
  - *Wood waste from the mill operation.* Logging and hauling costs have already been expended in getting the logs to the mill to manufacture lumber. This is the lowest-cost material for supply.
  - *Improved utilization from existing logging operations.* This wood is currently left in the woods or at the sort yard and is not recovered for any product. Fixed costs for roads, sort yards, equipment mobilization, etc., have been expended for the logs being sought for export or manufacture. Additional costs are the increased marginal costs to handle this material and to deliver it to the mill site. Material from conventional harvest systems will cost less than material that could be harvested from helicopter operations.
  - *Silviculture: commercial thin.* Costs for this biomass material are partly or wholly offset by revenue from the commercial log from which a product will be manufactured.
  - *Silviculture: pre-commercial thin.* This biomass is the most expensive material, as the trees being cut by definition are not commercial, so no revenue is being generated. Also, the size and nature of the material are the most costly to handle and transport to processing centers. No yarding equipment is mobilized for PCT and transportation infrastructure (such as roads, bridges, and sort yards), and log transfer facilities are often not in service when PCT takes place. The ratio of removed stems to crop trees can exceed ten to one, and damage to crop trees by removal of PCT residue is certain.
- *Element A*—The costs of constructing heat distribution systems associated with CHP plants are not known and have not been included, but will add to the overall cost of these systems.
- *Element B*—There could be potential location issues with population centers. Unless biomass feedstocks are located near both population centers and large-scale power plants, implementing this option will not be possible.
- *Element C*—Cellulosic ethanol plants are more cost-effective with larger plant sizes. It is unlikely that Alaska has sufficient biomass supplies to support a large-scale (50-MMgal/yr) ethanol plant. The analysis for Element C assumes four 3-MMgal/yr plants, although some of the costs are scaled down from cost estimates of larger plants. While the analysis attempts to avoid any unrealistic assumptions, it is possible that these smaller plants will be significantly more expensive in terms of annual O&M costs.

Additional Benefits and Costs

Additional Benefits

- Biomass fuels can have a big economic benefit in communities, particularly rural areas where energy costs are a significant part of the economy. Dollars stay in the community versus being exported to import fuels from far away.
- Developing biomass fuel harvest and transport infrastructure can open the door to other forest management enterprises.
- It may be possible to sell fuel offset credits to a carbon exchange, such as the Chicago Climate Exchange (CCX), to produce an additional revenue stream.
- Having markets for lower-grade forest products discourages "high grading," and usually results in better forest management practices.

Additional Costs

- Fuel switching results in winners and losers. For example, if biomass offsets coal, it might negatively affect important long-standing business in Alaska.
- Risks are associated with technologies that are unfamiliar, risks of system failure, or increases in life-cycle costs.
- Risks of fuel supply disruptions often require redundant multi-fuel systems for backup in addition to capital costs.

Feasibility Issues

Location, economies of scale, and limitations in infrastructure all make careful selection of biomass projects important. Early failures could frustrate the goals to broaden biomass use, so it will be important to vet projects thoroughly and to provide technical assistance and other support to the early demonstration projects to ensure successful startups.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

FAW-3. Advanced Waste Reduction and Recycling

Policy Description

This policy recommendation will reduce overall waste generation and GHG emissions through increased recycling and active management of organic wastes. Recycling decreases upstream GHG emissions from material production and transportation, and management of organic wastes decreases downstream GHG emissions associated with the production of methane in landfills. This policy will also increase economically sustainable recycling and organic management efforts, including new and existing programs, by encouraging participation of both residential and commercial consumers, by identifying existing markets and technologies, and by supporting the development of necessary in-state infrastructure. Overall accomplishment of the policy's goals will be documented via a reduction in the volume of waste deposited into landfills.

Policy Design

Goals:

- Quantify current waste generation rates (pounds per capita per day) for rural and urban areas.
- Reduce the waste stream, via source reduction/re-use and waste diversion, by 10% by 2012, 15% by 2015, and 25% by 2025.

Timing: Start in 2010, and ramp up to higher levels in 2012 and 2015, consistent with the above goals,

Parties Involved: Consumers, manufacturers, relevant trade associations, consumer associations, all state and local agencies, retail outlets, nonprofit organizations, shippers, waste management industry.

Other: Urban areas are considered to be Anchorage, Mat-Su Valley, Fairbanks, and Juneau. Rural areas are all other communities in the state.

Implementation Mechanisms

Implementing the policy will require some combination of the following possible actions:

- Funding will need to be allocated to allow the state, via the DEC, to act upon its statutory authority to establish a "Solid Waste Reduction and Recycling Program" (AS 46.06.031) and to provide grants for building material recovery and waste-to-energy facilities.[43] This would likely require additional staff capacity.
- Tracking progress toward the stated goals will require legislation mandating the reporting of recycling and landfilling data (tons/year) to the DEC and adoption of a data-gathering and reporting mechanism, such as Re-TRAC.[44]

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[43] See http://touchngo.com/lglcntr/akstats/STATUTES/Title46/Chapter06/Section031.htm.

[44] See http://www.emergeknowledge.com/retrac.html.

- Achieving the stated goals may require the establishment of statewide or regional target per-capita waste disposal rates.
- Minimizing the cost of recycling will require creating needed infrastructure and coordinating material shipments to achieve an economy of scale. This could require subsidizing shipping from rural communities without road access. Authorizing the transport of recyclables via the Alaska Marine Highway System would benefit communities served by that system.
- Taxes or fees on products brought into the state and/or on wastes disposed of in landfills may be options to pay necessary subsidies, programs, grants, and staffing.
- Promoting waste reduction and recycling incorporates elements from individuals to industry. Consistent outreach will be a vital component for individuals, and the support of local recycling industries will be a keystone to sustainable recycling efforts.

Related Policies/Programs in Place

- Three of the largest communities in Alaska are embarking on new recycling programs. In Anchorage, the Municipality has dedicated a fund for recycling and is planning to build on private efforts by expansion of drop-off sites, school district recycling, and public outreach. The municipal collection utility, which serves approximately 20% of Anchorage residences, began implementing a Pay As You Throw (PAYT) and curbside recycling program in October 2008. The residential waste hauler, Alaska Waste, is offering curbside recycling service to one-third of Anchorage and Eagle River residences, and has an optional PAYT service.
- The City and Borough of Juneau has just completed an evaluation by a consultant for a long-range solid waste management strategy and analysis. Alaska's capital city is targeting the implementation of a curbside recycling program in 2009.
- In the Matanuska-Susitna Valley, Valley Community for Recycling Solutions is securing funds and moving forward for the construction and operation of a Community Recycling Center. The site is located adjacent to the Matanuska-Susitna Borough's Central Landfill.
- Alaskans for Litter Prevention and Recycling has statewide programs, including "Flying Cans," which provides backhaul of aluminum cans in communities, as well as an in-store plastic bag recycling, reuse, and conservation toolkit available on its Web site www.alparalaska.com.
- There are also many recycling programs throughout the state that are not mentioned here.

Types(s) of GHG Reductions

CO_2: *Upstream energy use reductions*—The energy and GHG intensity of manufacturing a product is generally less when using recycled feedstocks than when using virgin feedstocks.

CH_4: Diverting biodegradable wastes from landfills will decrease in methane gas releases from landfills.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2020, 2025 ($MMtCO_2e$): 0.27, 0.45, and 0.65, respectively.

Net Cost per tCO_2e: –$8.

Data Sources: Data on current waste disposal and recycling were provided by DEC, along with input informing the cost parameters.[45] Where Alaska-specific data were not available, CCS utilized national defaults derived from the EPA 2007 waste characterization report.[46] GHG emission reductions were modeled using EPA's WAste Reduction Model (WARM).[47]

Quantification Methods:

Business-as-Usual Waste Management Forecast

The BAU waste management profile in Alaska was developed using input from DEC.[48] However, because Alaska does not require the reporting of recycling data, the BAU profile represents an incomplete picture of current recycling efforts and rates. MSW landfills are classified according to the average daily tonnage received. Class I landfills accept more than 20 tons/day, Class II accept 5–20 tons/day, and Class III landfills accept less than 5 tons/day. Population projections are from an Alaska Department of Labor report, and were used to develop the waste generation projections for the state, as well as the four key Alaska population centers (Anchorage, Fairbanks, Matanuska-Susitna Valley, and Juneau).[49] (See Table H-26 for the total Alaska waste management projection.) The remainder of this section will describe the methods for developing the BAU waste management forecasts for distinct communities and community groups in Alaska.

[45] D. Buteyn (AK DEC), personal communication with H. Lindquist (CCS) December 11, 2008. D. Buteyn personal communication with B. Strode (CCS) December 2008 and January 2009.

[46] U.S. EPA. 2008. "Municipal Solid Waste in the United States: 2007 Facts and Figures." Available at: http://www.epa.gov/osw/nonhaz/municipal/pubs/msw07-rpt.pdf.

[47] U.S. EPA. "WAste Reduction Model (WARM)." Version 8, May 2006. Available at: http://www.epa.gov/climatechange//wycd/waste/calculators/WARM_home.html. EPA created WARM to help solid waste planners and organizations track and voluntarily report GHG emission reductions from several different waste management practices. WARM is available as a Web-based calculator and as a Microsoft Excel spreadsheet. WARM calculates and totals GHG emissions of baseline and alternative waste management practices—source reduction, recycling, combustion, composting, and landfilling. The model calculates emissions in tons of carbon equivalent (tCe), tCO_2e, and energy units (MMBtu) across a wide range of material types commonly found in MSW. For an explanation of the methodology, see the EPA report *Solid Waste Management and Greenhouse Gases: A Life-Cycle Assessment of Emissions and Sinks*, EPA530-R-02-006, May 2002. Available at: http://epa.gov/climatechange/wycd/waste/SWMGHGreport.html.

[48] D. Buteyn (AK DEC), personal communication with H. Lindquist (CCS), December 11, 2008. D. Buteyn personal communication with B. Strode (CCS), December 2008 and January 2009.

[49] Alaska Department of Labor and Workforce Development. 2007. "Alaska Population Projections: 2007–2030." Available at: http://www.labor.state.ak.us/research/pop/projections/AlaskaPopProj.pdf.

Table H-26. Alaska BAU waste management projection, 2005–2025

Total Alaska MSW	2005	2010	2012	2015	2020	2025
MSW Generated (tons)	825,883	868,914	886,110	911,919	955,432	997,360
MSW Landfilled (tons)	729,402	767,035	782,326	805,250	843,640	880,301
MSW Incinerated (tons)	29,604	30,658	31,118	31,821	32,987	34,169
MSW Diverted (tons)[a]	66,877	71,222	72,666	74,848	78,805	82,890
Total Alaska Diversion (%)	8.1%	8.2%	8.2%	8.2%	8.2%	8.3%

[a] "MSW Diverted" includes waste recycled and waste composted.

BAU = business as usual; MSW = municipal solid waste.

According to data provided by DEC, 310 communities in Alaska deposit waste in 222 Class III landfills. The waste generation from these communities is assumed to be 5.9 lb/person/day. The population depositing waste in Class III landfills was assumed to be the remainder of the state's population after the populations of Class I and Class II communities were considered. DEC reported that about 10 tons/yr of aluminum cans are shipped from Class III communities to be recycled. The quantity and growth rate of waste incinerated in Class III landfill communities are consistent with inputs used for the Alaska I&F. The amount of waste landfilled is the difference between the waste generated and the waste incinerated and diverted. Table H-27 presents the BAU waste management projections for the Class III landfill communities.

Table H-27. BAU waste management projections for Class III landfill communities, 2005–2025

Class III Landfill Communities	2005	2010	2012	2015	2020	2025
MSW Generated (tons)	71,553	71,562	71,736	71,997	72,068	71,809
MSW Landfilled (tons)	45,548	44,648	44,449	44,141	43,239	41,971
MSW Incinerated (tons)	25,995	26,904	27,277	27,845	28,819	29,827
MSW Diverted (tons)[a]	10	10	10	10	10	10

[a] "MSW Diverted" includes waste recycled and waste composted.

BAU = business as usual; MSW = municipal solid waste.

Similar to Class III landfill communities, Class II landfill communities are assumed to generate 5.9lb/person/day of waste. DEC estimates that Class II communities account for 7.3% of the total population of Alaska, and reported a small amount of waste recycled at these facilities (less than 300 tons/yr). The waste incinerated is based on the estimated amount incinerated by the North Slope Borough in Barrow. Therefore, the total waste landfilled is the difference between the waste generated and the waste incinerated. Table H-28 presents the BAU waste management projections for Class II landfill communities.

Table H-28. BAU waste management projections for Class II landfill communities, 2005–2025

Class II Landfill Communities	2005	2010	2012	2015	2020	2025
MSW Generated (tons)	42,579	44,897	45,876	47,344	49,803	52,150
MSW Landfilled (tons)	38,748	40,882	41,756	43,064	45,284	47,400
MSW Incinerated (tons)	3,609	3,753	3,841	3,975	4,167	4,341
MSW Diverted (tons)[a]	222	262	278	304	352	409

[a] "MSW Diverted" includes waste recycled and waste composted.
BAU = business as usual; MSW = municipal solid waste.

The Class I landfills were divided into the "Metro Class I Landfills" (Anchorage, Fairbanks, Mat-Su Valley, and Juneau) and the "Non-Metro Class I Landfills" (Kenai Peninsula, Kodiak, and Unalaska). The average per-capita waste generation rate for each landfill was based on input from DEC. The generation rate for the Non-Metro group was estimated by taking the weighted average of the generation rates from the landfills in that group. Based on data compiled by DEC, the baseline recycling rate for Anchorage is 19%, the baseline recycling rate for the Mat-su Borough is 1.2%, and the recycling rate for Juneau and Fairbanks is 5.7%.[50] It was assumed that Fairbanks had a recycling rate equal to that of Juneau. Recycling attributed to the Non-Metro Class I landfill communities is based on reported recycling from the Kenai Peninsula Borough.[51] It was also assumed that no MSW combustion took place in Class I landfill communities. Table H-29 outlines the waste management projections for Class I landfill communities.

Table H-29. BAU waste management projection for Class I landfill communities, 2005–2025

Class I Landfills	2005	2010	2012	2015	2020	2025
Non-Metro Class I Landfill Communities						
MSW Generated (tons)	100,213	103,820	105,084	106,995	109,528	111,309
MSW Landfilled (tons)	98,895	101,744	102,882	104,589	106,739	108,076
MSW Incinerated (tons)	0	0	0	0	0	0
MSW Diverted (tons)[a]	1,318	2,075	2,201	2,406	2,789	3,233
Anchorage						
MSW Generated (tons)	408,555	430,619	438,593	450,554	472,846	495,776
MSW Landfilled (tons)	352,203	371,223	378,097	388,408	407,626	427,393
MSW Incinerated (tons)	0	0	0	0	0	0
MSW Diverted (tons)[a]	56,352	59,396	60,496	62,145	65,220	68,383
Fairbanks						
MSW Generated (tons)	115,591	122,397	124,947	128,773	134,397	139,844

[50] D. Buteyn (AK DEC), personal communication with H. Lindquist (CCS), December 11, 2008. D. Buteyn personal communication with B. Strode (CCS), December 2008 and January 2009. Anchorage recycling information from a data sheet compiled by Alaskans for Litter Prevention and Recycling, provided by D. Buteyn of AK DEC. Additional input provided by D. Mears of Anchorage Solid Waste Services via e-mail on March 2, 2009.

[51] Kenai Peninsula Borough Solid Waste Office. 2008. "Recycling and Solid Waste Programs." Data collected for the Homer Bailing Facility and Central Peninsula Landfill. Available at: http://www.borough.kenai.ak.us/SolidWaste/Informational%20Pages/recyclewaste.htm.

Class I Landfills	2005	2010	2012	2015	2020	2025
MSW Landfilled (tons)	109,048	115,469	117,875	121,484	126,789	131,928
MSW Incinerated (tons)	0	0	0	0	0	0
MSW Diverted (tons) [a]	6,543	6,928	7,072	7,289	7,607	7,916
Mat-Su Borough						
MSW Generated (tons)	56,199	63,960	68,060	74,211	84,570	94,277
MSW Landfilled (tons)	55,532	63,202	67,253	73,331	83,567	93,159
MSW Incinerated (tons)	0	0	0	0	0	0
MSW Diverted (tons) [a]	666	758	807	880	1,003	1,118
Juneau						
MSW Generated (tons)	31,194	31,659	31,814	32,046	32,220	32,195
MSW Landfilled (tons)	29,428	29,867	30,013	30,232	30,396	30,372
MSW Incinerated (tons)	0	0	0	0	0	0
MSW Diverted (tons) [a]	1,766	1,792	1,801	1,814	1,824	1,822

[a]"MSW Diverted" includes waste recycled and waste composted.

BAU = business as usual; MSW = municipal solid waste.

GHG Benefit Analysis

CCS applied the goals set forth by the MAG in the Policy Design section of this policy to the Alaska BAU waste management scenario in Table H-26. As the TWG did not prescribe a specific ratio of diversion that will be met through recycling/composting to what will be met through source reduction, CCS assumed the ratio of the two diversion strategies needed to meet the goal. Tables H-30, H-31, and H-32 display the assumed annual diversion targets, the policy waste management scenario, and the incremental waste diversion, respectively. As the annual target for waste diversion does not exceed the BAU diversion level until 2013, it is assumed that there is zero incremental diversion in these years.

Table H-30. Yearly waste management targets, 2010–2025

Types of Diversion	2010	2012	2015	2020	2025
Recycling/Composting	5.0%	10.0%	13.0%	16.5%	20.0%
Source Reduction	0.0%	0.0%	2.0%	3.5%	5.0%
Total Waste Diversion	**5.0%**	**10.0%**	**15.0%**	**20.0%**	**25.0%**

Table H-31. Alaska policy waste management scenario, 2010–2025

Total Alaska	2010	2012	2015	2020	2025
MSW Generated (including source reduction, tons)	868,914	886,110	911,919	955,432	997,360
MSW Incinerated (tons)	30,658	31,118	31,821	32,987	34,169
MSW Recycled/Composted (tons)	71,222	88,611	118,549	157,646	199,472
MSW Source Reduced (tons)	—	—	18,238	33,440	49,868
Total MSW Diverted (tons)	71,222	88,611	136,788	191,086	249,340
MSW Landfilled (tons)	767,035	766,381	743,310	731,359	713,851

MSW = municipal solid waste.

Table H-32. Alaska incremental waste diversion, 2010–2025

Total Alaska	2010	2012	2013	2015	2020	2025
MSW Recycled/Composted (tons)	—	15,945	25,027	43,702	78,841	116,582
MSW Source Reduced (tons)	—	—	5,965	18,238	33,440	49,868
Total MSW Diverted (tons)	**—**	**15,945**	**30,992**	**61,940**	**112,281**	**166,450**

MSW = municipal solid waste.

The incremental waste diversion was allocated among the Metro Class I landfills based on the proportion of waste diverted—and in the case of source reduction, the proportion of waste generated—in each metro area under the BAU scenario. Any remaining incremental diversion needed to meet the goal was allocated to Anchorage. Table H-33 portrays the assumed incremental waste diversion for each of the major population centers in Alaska.

Table H-33. Metro Class I landfill incremental waste diversion, 2010–2025

Metro Class I Landfills	2010	2012	2013	2015	2020	2025
Anchorage						
MSW Recycled/Composted (tons)	—	14,459	22,698	39,651	71,619	106,037
MSW Source Reduced (tons)	—	—	4,443	13,538	24,649	36,552
MSW Diverted (tons)	—	14,459	27,142	53,188	96,267	142,589
Fairbanks						
MSW Recycled/Composted (tons)	—	903	1,417	2,474	4,463	6,599
MSW Source Reduced (tons)	—	—	841	2,575	4,704	6,992
MSW Diverted (tons)	—	903	2,258	5,049	9,167	13,591
Mat-su Valley						
MSW Recycled/Composted (tons)	—	189	297	518	935	1,382
MSW Source Reduced (tons)	—	—	467	1,484	2,960	4,714
MSW Diverted (tons)	—	189	764	2,002	3,895	6,096
Juneau						
MSW Recycled/Composted (tons)	—	395	616	1,059	1,825	2,563
MSW Source Reduced (tons)	—	—	213	641	1,128	1,610
MSW Diverted (tons)	—	395	828	1,700	2,952	4,173

MSW = municipal solid waste.

GHG benefits were determined by using WARM,[52] which uses information for specific material inputs and disposal/diversion methods to estimate GHG emission reductions based on BAU and policy scenarios. Avoided emission of CO_2 and associated GHGs derives from the reduction of the total mass of products and packaging produced from virgin materials, including the energy consumption necessary for the production of the products and packaging. WARM accounts for the origin of carbon sequestered in raw materials. Therefore, CO_2 emissions from the combustion or decomposition of organic waste are not counted toward the total emissions. CH_4 and N_2O emissions due to landfilling or combustion of organic waste, as well as avoided future CO_2 sequestration are counted toward the net life-cycle emissions of each waste management practice.

The key requirement for inputting data into WARM is that the amount of waste generated for each waste type must be the same under the policy and BAU scenarios. Therefore, although waste that is source-reduced is not actually generated, it is considered as a part of the total generated under the policy scenario, as that waste has the potential to be generated without incremental diversion efforts. A second requirement for an accurate result from WARM is that the MSW managed should be broken up by waste type. There are six categories and 34 distinct waste types accepted by WARM. Based on available Alaska data, 18 of those waste types were utilized. Tables H-34 and H-35 show the baseline waste generation, disposal, and diversion characterization. Table H-35 shows all potential waste types that may be entered into WARM, although data were not sufficient to develop a characterization that included estimates for all waste types. In cases where, due to data selection from multiple sources, there was more waste projected to be diverted than generated for a given waste type, it was assumed that the maximum diversion percentage for any waste type is 90%.

Table H-34. Assumed baseline Alaska waste characteristics—waste categories

Waste Categories	Baseline Generation Composition (BAU)	Baseline Anchorage, Juneau, Fairbanks Recycling Composition (BAU)	Baseline Mat-Su Valley Recycling Composition (BAU)	Baseline Non-Metro Recycling Composition (BAU)
Paper	32.7%	45.9%	87.9%	96.1%
Organics	25.3%	1.6%	0.0%	0.0%
Mixed Plastic	12.1%	0.7%	7.3%	0.5%
Metals	8.2%	46.4%	4.8%	3.4%
Glass	5.3%	1.5%	0.0%	0.0%
Other	16.4%	3.8%	0.0%	0.0%

[52] U.S. EPA. WAste Reduction Model (WARM)." Version 8, May 2006. Available at: http://www.epa.gov/climatechange//wycd/waste/calculators/WARM_home.html. EPA created WARM to help solid waste planners and organizations track and voluntarily report GHG emission reductions from several different waste management practices. WARM is available as a Web-based calculator and as a Microsoft Excel spreadsheet. WARM calculates and totals GHG emissions of baseline and alternative waste management practices—source reduction, recycling, combustion, composting, and landfilling. The model calculates emissions in tCe, tCO_2e, and energy units (MMBtu) across a wide range of material types commonly found in MSW. For an explanation of the methodology, see the U.S. EPA, *Solid Waste Management and Greenhouse Gases: A Life-Cycle Assessment of Emissions and Sinks*, EPA530-R-02-006, May 2002. Available at: http://epa.gov/climatechange/wycd/waste/SWMGHGreport.html.

BAU = business as usual.

Table H-35. Assumed baseline Alaska waste characteristics—waste types

Waste Types	Baseline Generation Composition (% of waste generated)[53]	Baseline Anchorage, Juneau, Fairbanks Recycling Composition (% of waste recycled)[54]	Baseline Mat-Su Valley Recycling Composition (% of waste recycled)[55]	Baseline Non-Metro Recycling Composition (% of waste recycled)[56]	Total Baseline Recycling Composition (% of waste recycled)
Paper	**32.7%**	**45.9%**	**87.9%**	**96.1%**	**47.0%**
Corrugated Cardboard	12.3%	25.8%	27.7%	47.1%	26.1%
Magazines/Third-Class Mail	3.3%	2.5%			2.4%
Newspaper	4.3%	8.5%		39.4%	8.8%
Office Paper	2.4%	0.2%			0.2%
Phonebooks	0.3%	0.4%			0.4%
Textbooks	0.5%	0.0%			0.0%
Mixed—Residential	7.1%	8.5%	60.2%	9.7%	9.1%
Mixed—Office	2.5%	0.0%			0.0%
Glass	**5.3%**	**1.5%**		**0.0%**	**1.5%**
Metals	**8.2%**	**46.4%**	**4.8%**	**3.4%**	**45.4%**
Aluminum Cans	0.6%	0.2%	2.2%	3.4%	0.3%
Steel Cans	1.0%	0.0%			0.0%
Mixed Metals	6.6%	46.2%	2.6%		45.1%
Plastics	**12.1%**	**0.7%**	**7.3%**	**0.5%**	**0.8%**
HDPE	2.2%	0.0%			0.0%
LDPE	2.5%	0.0%			0.0%
PET	1.5%	0.0%			0.0%
Mixed Plastics	5.9%	0.7%	7.3%	0.5%	0.8%
Organics	**25.3%**	**1.6%**	**0.0%**	**0.0%**	**1.5%**
Food Scraps	12.5%	0.0%			0.0%
Yard Trimmings	12.8%	1.6%			1.5%
Other	**16.4%**	**3.8%**	**0.0%**	**0.0%**	**3.8%**

HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate.

[53] U.S. EPA. 2008. "Municipal Solid Waste in the United States: 2007 Facts and Figures." Available at: http://www.epa.gov/osw/nonhaz/municipal/pubs/msw07-rpt.pdf.

[54] D. Buteyn (AK DEC), personal communication with H. Lindquist (CCS), December 11, 2008. D. Buteyn personal communication with B. Strode (CCS), December 2008 and January 2009.

[55] Ibid.

[56] Ibid.

The BAU and policy waste management projections (Tables H-26 and Table H-31, respectively) were multiplied by the percentages in Table H-35 to provide WARM inputs for 2015 and 2025. Again, it was assumed that the maximum diversion rate for any given waste type is 90%. It was also assumed that only biogenic waste (i.e., paper and organics) could be combusted. The amount of each biogenic waste type combusted is in proportion to that waste type's generation quantity. The amount of source reduction for each waste type for which this diversion method is an accepted WARM input was also proportional to each waste type's generation quantity. The amount of waste landfilled was estimated by subtracting the amount of waste diverted and combusted from the total waste generated. Tables H-36 and H-37 display the BAU and policy WARM modeling for 2025.

Table H-36. 2025 BAU WARM inputs

Material	Tons Generated	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Aluminum Cans	5,730	281	5,449	—	N/A
Steel Cans	9,576	—	9,576	—	N/A
Copper Wire				—	N/A
Glass	53,294	1,194	52,100	—	N/A
HDPE	22,173	—	22,173	—	N/A
LDPE	25,116	—	25,116	—	N/A
PET	14,756	—	14,756	—	N/A
Corrugated Cardboard	122,561	21,867	93,449	7,245	N/A
Magazines/Third-Class Mail	33,201	1,988	29,250	1,963	N/A
Newspaper	43,090	7,625	32,918	2,547	N/A
Office Paper	23,547	161	21,994	1,392	N/A
Phonebooks	2,747	303	2,282	162	N/A
Textbooks	5,259	—	4,948	311	N/A
Dimensional Lumber					N/A
Medium-Density Fiberboard					N/A
Food Scraps	124,209	N/A	116,867	7,342	—
Yard Trimmings	128,055	N/A	119,217	7,570	1,268
Grass		N/A			
Leaves		N/A			

Material	Tons Generated	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Branches		N/A			
Mixed Paper (general)					N/A
Mixed Paper (primarily residential)	70,797	7,497	59,115	4,185	N/A
Mixed Paper (primarily from offices)	24,567	—	23,115	1,452	N/A
Mixed Metals	66,127	36,997	29,130	—	N/A
Mixed Plastics	58,553	629	57,923	—	N/A
Mixed Recyclables	164,003	3,080	160,923	—	N/A
Mixed Organics		N/A			
Mixed MSW		N/A			N/A
Carpet					N/A
Personal Computers					N/A
Clay Bricks		N/A		N/A	N/A
Concrete				N/A	N/A
Fly Ash				N/A	N/A
Tires					N/A
Total	**997,360**	**82,890**	**880,301**	**34,169**	

BAU = business as usual; HDPE = high-density polyethylene; LDPE = low-density polyethylene; MSW = municipal solid waste; N/A = not applicable; PET = polyethylene terephthalate; WARM = WAste Reduction Model.

Table H-37. 2025 policy WARM inputs

Material	Baseline Generation	Tons Source Reduced	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Aluminum Cans	5,730	791	676	4,262	—	N/A
Steel Cans	9,576	1,323	—	8,253	—	N/A
Copper Wire						N/A
Glass	53,294	7,361	2,873	43,060	—	N/A
HDPE	22,173	3,063	—	19,111	—	N/A
LDPE	25,116	3,469	—	21,647	—	N/A
PET	14,756	2,038	—	12,718	—	N/A
Corrugated Cardboard	122,561	16,928	52,621	45,766	7,245	N/A
Magazines/Third-Class Mail	33,201	4,586	4,784	21,869	1,963	N/A
Newspaper	43,090	5,952	18,350	16,242	2,547	N/A
Office Paper	23,547	3,252	388	18,515	1,392	N/A
Phonebooks	2,747	379	729	1,477	162	N/A
Textbooks	5,259	726	—	4,222	311	N/A
Dimensional Lumber						N/A
Medium-Density Fiberboard						N/A
Food Scraps	124,209	N/A	N/A	116,867	7,342	—
Yard Trimmings	128,055	N/A	N/A	117,434	7,570	3,052
Grass		NA	NA			
Leaves		N/A	N/A			
Branches		N/A	N/A			
Mixed Paper, Broad		N/A				N/A
Mixed Paper, Residential	70,797	N/A	18,041	48,571	4,185	N/A
Mixed Paper, Office	24,567	N/A	—	23,115	1,452	N/A
Mixed Metals	66,127	N/A	59,514	6,613	—	N/A
Mixed Plastics	58,553	N/A	1,515	57,038	—	N/A
Mixed Recyclables	164,003	N/A	36,930	127,073	—	N/A

Material	Baseline Generation	Tons Source Reduced	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Mixed Organics		N/A	N/A			
Mixed MSW		N/A	N/A			N/A
Carpet						N/A
Personal Computers						N/A
Clay Bricks			N/A		N/A	N/A
Concrete		N/A			N/A	N/A
Fly Ash		N/A			N/A	N/A
Tires						N/A
Total	**997,360**	**49,868**	**199,472**	**713,851**	**34,169**	

HDPE = high-density polyethylene; LDPE = low-density polyethylene; MSW = municipal solid waste; N/A = not applicable; PET = polyethylene terephthalate; WARM = WAste Reduction Model.

The resulting output for the 2015, 2020, and 2025 WARM runs predict the GHG reductions for these years to be 0.27, 0.45, and 0.65 $MMtCO_2e$, respectively. The cumulative GHG reductions are calculated to be 5.3 $MMtCO_2e$. Table H-38 displays a summary of the waste diversion, reduction, and GHG benefits of this policy recommendation.

Table H-38. Overall policy results—GHG benefits

Year	Avoided Emissions ($MMtCO_2e$)	Incremental Waste Diversion (tons)	Source Reduction (tons)	Incremental Recycling (tons)	Incremental Composting (tons)
2010	—	—	—	—	—
2011	—	—	—	—	—
2012	—	15,945	—	15,945	—
2013	0.09	30,992	5,965	24,805	223
2014	0.18	46,324	12,044	33,834	446
2015	0.27	61,940	18,238	43,033	669
2016	0.30	71,664	21,174	49,710	780
2017	0.34	81,561	24,162	56,507	892
2018	0.38	91,629	27,203	63,423	1,003

Year	Avoided Emissions ($MMtCO_2e$)	Incremental Waste Diversion (tons)	Source Reduction (tons)	Incremental Recycling (tons)	Incremental Composting (tons)
2019	0.42	101,869	30,295	70,459	1,115
2020	0.46	112,281	33,440	77,615	1,226
2021	0.49	122,784	36,625	84,822	1,338
2022	0.53	133,452	39,860	92,143	1,449
2023	0.57	144,286	43,146	99,580	1,561
2024	0.61	155,285	46,482	107,132	1,672
2025	0.65	166,450	49,868	114,798	1,784
Total	**5.3**	**1,336,463**	**388,502**	**933,806**	**14,155**

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Cost-Effectiveness

Source reduction—The amount of source-reduced waste shown in Table H-31 is based on CCS's best judgment that source reduction will feasibly account for one-fifth of the 25% diversion goal by 2025. The cost-effectiveness estimate for source reduction in Alaska comprises three elements: the cost of program implementation, the avoided costs of waste collection, and the cost of disposal.

The cost of program implementation is assumed to be $1 per capita per year.[57] This cost applies only to the regions served by the Metro Class I landfills. The cost figure uses a population projection from Alaska Department of Labor.[58] These funds are assumed to cover any outreach and marketing programs necessary to implement the source reduction goal.

Source reduction is expected to save money by reducing the amount of waste that has to be collected and disposed of in landfills. The avoided collection cost is assumed to be $2.50 per household per month (calculations based on total households in these areas yield a

[57] The source reduction program cost is a preliminary estimate consistent with costs assumed in similar options considered by CCS projects in Washington and Colorado.

[58] Alaska Department of Labor and Workforce Development. 2007. "Alaska Population Projections: 2007–2030." Available at: http://www.labor.state.ak.us/research/pop/projections/AlaskaPopProj.pdf.

per-ton collection cost of $9.72).[59] The landfill tipping fees that are offset vary by municipality. The landfill tipping fees used for this analysis are $60 for Anchorage, $61 for Fairbanks, $50 for Mat-su Borough, and $140 for Juneau.[60]

The analysis assumes that costs begin to be incurred in 2012. The estimated cost savings result in a net present value (NPV) of –$5.3 million. Cumulative GHG reductions attributed to source reduction are 1.8 MMtCO_2e, and the estimated cost-effectiveness is –$3/t$CO_2$e, as shown in Table H-39.

Table H-39. Cost analysis for source reduction

Year	Anchorage Tons Reduced	Fairbanks Tons Reduced	Mat-Su Tons Reduced	Juneau Tons Reduced	Alaska Metro Population	Avoided Landfill Tipping Fee (2006 $MM)	Avoided MSW Collection Costs (2006 $MM)	Program Costs (2006 $MM)	Net Source Reduction Costs (2006 $MM)	Discounted Costs (2006 $MM)
2010	—	—	—	—	502,210	$0.0	$0.0	$0.0	$0.0	$0.0
2011	—	—	—	—	508,674	$0.0	$0.0	$0.0	$0.0	$0.0
2012	—	—	—	—	515,138	$0.0	$0.0	$0.5	$0.5	$0.5
2013	4,443	841	467	213	521,601	$0.4	$0.1	$0.5	$0.1	$0.1
2014	8,956	1,700	962	426	528,065	$0.7	$0.1	$0.5	–$0.4	–$0.3
2015	13,538	2,575	1,484	641	534,529	$1.1	$0.2	$0.5	–$0.8	–$0.6
2016	15,694	2,988	1,755	738	541,186	$1.3	$0.2	$0.5	–$1.0	–$0.8
2017	17,883	3,407	2,037	835	547,843	$1.5	$0.3	$0.5	–$1.2	–$0.9
2018	20,106	3,832	2,332	932	554,499	$1.7	$0.3	$0.6	–$1.5	–$1.0
2019	22,361	4,265	2,640	1,030	561,156	$1.9	$0.4	$0.6	–$1.7	–$1.1
2020	24,649	4,704	2,960	1,128	567,813	$2.1	$0.4	$0.6	–$1.9	–$1.2
2021	26,965	5,148	3,287	1,224	574,318	$2.3	$0.4	$0.6	–$2.1	–$1.2

[59] U.S. Census Bureau. "State & County QuickFacts. Accessed on January 9, 2009, at: http://quickfacts.census.gov/qfd/states/02/0203000.html, http://quickfacts.census.gov/qfd/states/02/0224230.html, http://quickfacts.census.gov/qfd/states/02/02170.html, and http://quickfacts.census.gov/qfd/states/02/0236400.html.

[60] D. Buteyn (AK DEC), personal communication with H. Lindquist (CCS), December 11, 2008. D. Buteyn personal communication with B. Strode (CCS), December 2008 and January 2009.

Year	Anchorage Tons Reduced	Fairbanks Tons Reduced	Mat-Su Tons Reduced	Juneau Tons Reduced	Alaska Metro Population	Avoided Landfill Tipping Fee (2006 $MM)	Avoided MSW Collection Costs (2006 $MM)	Program Costs (2006 $MM)	Net Source Reduction Costs (2006 $MM)	Discounted Costs (2006 $MM)
2022	29,313	5,600	3,627	1,321	580,823	$2.5	$0.5	$0.6	–$2.4	–$1.3
2023	31,694	6,057	3,977	1,417	587,328	$2.7	$0.5	$0.6	–$2.6	–$1.4
2024	34,107	6,521	4,340	1,513	593,833	$2.9	$0.5	$0.6	–$2.8	–$1.4
2025	36,552	6,992	4,714	1,610	600,338	$3.1	$0.6	$0.6	–$3.1	–$1.5
Total	**286,260**	**54,631**	**34,583**	**13,028**					**–$7.9**	**–$5.3**

$MM = million dollars; MSW = municipal solid waste.

Recycling—The net cost of increased recycling rates in Alaska was estimated by adding the increased costs of collection for single-stream recycling, revenue obtained for the value of recycled materials, and avoided landfill tipping fees. There is also a significant amount of material collected as source-separated material at drop-off sites. The additional cost for separate curbside collection of recyclables is $9.72 per ton. The capital cost of additional recycling facilities in Alaska is estimated to be $5.6 million.[61] Annualized over the 10-year policy period at 5% interest, the capital cost is $0.4 million/yr. The avoided cost for landfill tipping is the same as in the source reduction calculations. CCS assumed the value of recycled materials to be zero, based on recent volatility in recycling markets. Table H-40 provides the results of the cost analysis, which assumes that costs begin to be incurred in 2012. The estimated cost savings result in an NPV of –$51.0 million. Cumulative GHG reductions attributed to recycling are 1.6 $MMtCO_2e$, and the estimated cost-effectiveness is –$10/$tCO_2e$.

[61] Based upon the ratio of capital cost per household used in the Vermont analysis. Vermont capital cost a result of personal communication
between P. Calabrese (Cassella Waste Management) and S. Roe (CCS).

Table H-40. Cost analysis for recycling

Year	Anchorage Tons Recycled	Fairbanks Tons Recycled	Mat-Su Tons Recycled	Juneau Tons Recycled	Annual Collection Cost (2006 $MM)	Annual Capital Cost (2006 $MM)	Annual Recycled Material Revenue (2006 $MM)	Landfill Tip Fees Avoided (2006 $MM)	Net Policy Cost (Recycling) (2006 $MM)	Discounted Costs ($MM)
2010	—	—	—	—	$0.0	$0	$0.0	$0.0	$0.0	$0.0
2011	—	—	—	—	$0.0	$0	$0.0	$0.0	$0.0	$0.0
2012	14,459	903	189	395	$0.2	$0.4	$0.0	$1.1	–$0.6	–$0.5
2013	22,504	1,394	297	610	$0.3	$0.4	$0.0	$1.8	–$1.1	–$1.0
2014	30,706	1,896	406	825	$0.4	$0.4	$0.0	$2.4	–$1.7	–$1.4
2015	39,067	2,407	518	1,041	$0.5	$0.4	$0.0	$3.1	–$2.2	–$1.7
2016	45,140	2,780	599	1,192	$0.6	$0.4	$0.0	$3.6	–$2.6	–$2.0
2017	51,325	3,160	681	1,342	$0.7	$0.4	$0.0	$4.1	–$3.0	–$2.2
2018	57,621	3,546	764	1,492	$0.7	$0.4	$0.0	$4.6	–$3.5	–$2.3
2019	64,029	3,940	849	1,642	$0.8	$0.4	$0.0	$5.1	–$3.9	–$2.5
2020	70,548	4,340	935	1,792	$0.9	$0.4	$0.0	$5.6	–$4.3	–$2.6
2021	77,119	4,743	1,022	1,938	$1.0	$0.4	$0.0	$6.1	–$4.7	–$2.8
2022	83,798	5,153	1,110	2,083	$1.1	$0.4	$0.0	$6.6	–$5.2	–$2.9
2023	90,584	5,569	1,199	2,228	$1.2	$0.4	$0.0	$7.1	–$5.6	–$3.0
2024	97,478	5,992	1,290	2,372	$1.3	$0.4	$0.0	$7.7	–$6.1	–$3.1
2025	104,479	6,421	1,382	2,516	$1.3	$0.4	$0.0	$8.2	–$6.5	–$3.1
Total	**848,854**	**52,243**	**11,241**	**21,468**					**–$51.0**	**–$16.2**

$MM = million dollars.

Composting—As WARM considers the sole form of diversion for yard trimmings and food waste to be composting, the tons of these items that are "recycled" are assumed to be composted. The net costs for increased composting in Alaska were estimated by adding the additional costs for collection (same calculation as recycling) and the net cost for composting operations. The net cost for composting operations is the sum of the annualized capital and operating costs of composting, increased collection fees, revenue generated through the sale of compost, and the avoided tipping fees for landfilling. Information on the capital and operating costs of composting facilities was received from Cassella Waste Management during the analysis of a similar option in Vermont.[62] These data are summarized in Table H-41.

Table H-41. Capital and operating costs of composting facilities

Annual Volume (tons)	Capital Cost ($1,000)	O&M Cost ($/ton)
<1,500	$75	$25
1,500–10,000	$200	$50
10,000–30,000	$2,000	$40
30,000–60,000+	$8,000	$30

O&M = operation and maintenance.

CCS assumed that the composting facilities to be built within the policy period would tend to be from the first category (a capital cost of $75,000 and an O&M cost of $25/ton) shown in Table H-41. It is assumed that three of these facilities are needed to meet the goal. To annualize the capital costs of these facilities, CCS assumed a 15-year operating life and a 5% interest rate. Other cost assumptions include the landfill tipping fees from the source reduction and recycling sections, an additional source-separated organics collection fee of $9.72/ton (as used above in the recycling element), a compost facility tipping fee of $16.50/ton,[63] and a compost value of $16.50/ton.[64]

Table H-42 presents the results of the cost analysis for composting. GHG reductions were assumed not to begin until 2012, and the cumulative reductions estimated were 0.0020 $MMtCO_2e$. An NPV of $0.03 million was estimated, along with a cost-effectiveness of $13/$tCO_2e$.

[62] P. Calabrese (Cassella Waste Management), personal communication with S. Roe (CCS), June 5, 2007. Because the cost was not originally specified in terms of 2007$, assume the cost to be valid for 2005.

[63] Emerson, Dan. *Latest Trends in Yard Trimmings* Composting. 2005. Accessed on May 23, 2008, from: http://hs.environmental-expert.com/resultEachArticle.aspx?cid=6042&codi=5723&idproducttype=6.

[64] D. Buteyn (AK DEC), personal communication with H. Lindquist (CCS), December 11, 2008. D. Buteyn personal communication with B. Strode (CCS), December 2008 and January 2009.

Table H-42. Cost analysis for composting

Year	Anchorage Tons of Waste Composted	Fairbanks Tons of Waste Composted	Mat-Su Tons of Waste Composted	Juneau Tons of Waste Composted	Annual Cost O&M ($MM)	Capital Cost ($MM)	Annualized Capital Cost ($MM)	Annual Collection Cost ($MM)	Avoided Landfill Tipping Fees ($MM)	Value of Composted Material ($MM)	Total Annual Composting Cost ($MM)	Discounted Costs ($MM)
2010	—	—	—	—	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$ 0.00	$0.00
2011	—	—	—	—	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012	—	—	—	—	$0.00	$0.23	$0.02	$0.00	$0.00	$0.00	$0.02	$0.02
2013	195	22	—	6	$0.01	$0.00	$0.02	$0.00	$0.01	$0.00	$0.02	$0.01
2014	389	45	—	12	$0.01	$0.00	$0.02	$0.01	$0.02	$0.01	$0.01	$0.01
2015	584	67	—	18	$0.02	$0.00	$0.02	$0.01	$0.03	$0.01	$0.00	$0.00
2016	681	78	—	21	$0.02	$0.00	$0.02	$0.01	$0.04	$0.01	$0.00	$0.00
2017	779	89	—	24	$0.02	$0.00	$0.02	$0.01	$0.04	$0.01	$0.00	$0.00
2018	876	100	—	27	$0.03	$0.00	$0.02	$0.01	$0.05	$0.02	–$0.01	$0.00
2019	974	111	—	29	$0.03	$0.00	$0.02	$0.01	$0.05	$0.02	–$0.01	–$0.01
2020	1,071	123	—	32	$0.03	$0.00	$0.02	$0.01	$0.06	$0.02	–$0.01	–$0.01
2021	1,168	134	—	35	$0.03	$0.00	$0.02	$0.02	$0.06	$0.02	–$0.01	–$0.01
2022	1,266	145	—	38	$0.04	$0.00	$0.02	$0.02	$0.07	$0.02	–$0.02	–$0.01
2023	1,363	156	—	41	$0.04	$0.00	$0.02	$0.02	$0.07	$0.03	–$0.02	–$0.01
2024	1,461	167	—	44	$0.04	$0.00	$0.02	$0.02	$0.08	$0.03	–$0.02	–$0.01
2025	1,558	178	—	47	$0.04	$0.00	$0.02	$0.02	$0.08	$0.03	–$0.03	–$0.01
Total	**12,366**	**1,415**	**—**	**374**							**–$0.1**	**$0.03**

$MM = million dollars; O&M = operation and maintenance.

The overall cost analysis, as seen in Table H-43, yields an NPV of –$43.2 million and a cost-effectiveness of –$8, based on the cumulative emission reductions of 5.3 $MMtCO_2e$.

Table H-43. Overall policy results—cost-effectiveness

Year	Net Program Cost: Source Reduction ($MM)	Net Program Cost: Recycling ($MM)	Net Program Cost: Composting ($MM)	Total Net Program Cost ($MM)	Discounted Cost (2006 $MM)	Cost-Effectiveness ($/$tCO_2e$)
2010	$0.0	$0.0	$0.00	$0.0	$0.0	
2011	$0.0	$0.0	$0.00	$0.0	$0.0	
2012	$0.5	–$0.6	$0.02	–$0.1	–$0.1	
2013	$0.1	–$1.1	$0.02	–$1.0	–$0.9	
2014	–$0.4	–$1.7	$0.01	–$2.0	–$1.7	
2015	–$0.8	–$2.2	$0.00	–$3.0	–$2.4	
2016	–$1.0	–$2.6	$0.00	–$3.7	–$2.7	
2017	–$1.2	–$3.0	$0.00	–$4.3	–$3.0	
2018	–$1.5	–$3.5	–$0.01	–$4.9	–$3.3	
2019	–$1.7	–$3.9	–$0.01	–$5.6	–$3.6	
2020	–$1.9	–$4.3	–$0.01	–$6.2	–$3.8	
2021	–$2.1	–$4.7	–$0.01	–$6.9	–$4.0	
2022	–$2.4	–$5.2	–$0.02	–$7.5	–$4.2	
2023	–$2.6	–$5.6	–$0.02	–$8.2	–$4.4	
2024	–$2.8	–$6.1	–$0.02	–$8.9	–$4.5	
2025	–$3.1	–$6.5	–$0.03	–$9.6	–$4.6	
Total	**–$20.8**	**–$51.0**	**–$0.08**	**–$71.9**	**–$43.2**	**–$8**

$MM = million dollars; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Key Assumptions:

In entering MSW management data into WARM, a key assumption is that no portion of the policy goals will be achieved via existing programs. Accordingly, the BAU projections extend current practices into the future and do not include any additional gains in the recycling or composting rates of existing programs. Therefore, to the extent that growth in existing programs does contribute toward achieving the policy goals, there will be a corresponding decrease (from the WARM estimates) in the GHG reductions that new programs must achieve. To that same extent, the benefits and costs calculated by WARM are overstated.

Other key assumptions include those that are built into WARM and used to calculate life-cycle GHG benefits, and the assumptions stated above regarding the costs associated with meeting the policy goals for increased source reduction, recycling, and composting.

Finally, the BAU projections assume that all landfills recover and utilize methane at a 75% recovery rate. This is based on a built-in assumption in WARM that all waste disposed of is placed in landfills that actively recover methane at this assumed rate.

Key Uncertainties

According to DEC, 23,700 tons of MSW were shipped out of Alaska in 2006. Most of this waste originates in southeast Alaska and is managed in Washington and Oregon. Since the ultimate management techniques used to treat this waste (e.g., recycling, landfilling) are not known, CCS did not consider the waste exported as a part of Alaska's waste stream.

Due to insufficient data on the characterization of waste landfilled in Alaska, CCS was required to project the BAU and policy scenarios using a default national waste characterization from EPA. The adjustments and aggregation of material types required to fit the data to WARM reduce the certainty of the GHG benefit estimates.

The economic sustainability of recycling programs in Alaska depends on the market value of the recycled materials being greater than the cost to transport those materials to recyclers. Until and unless Alaska develops an in-state recycling industry, the viability of recycling programs will fluctuate with changes in the price of fuel and the market value of recyclables. There will be some buffering of commodity prices as a whole, as higher-value materials (e.g., aluminum) subsidize lower-value materials (e.g., plastics). There are some existing and developing in-state recycling industries; however, there may not be sufficient feedstock to support in-state recycling industries for all materials. Due to geographic constraints, Alaskan recycling industries are likely to be local or regional efforts, further reducing potential economies of scale. It is important to note that currently, local recycling efforts do not remanufacture the recycled products. For instance, newspaper is made into insulation and other cellulose replacements, rather than being remade into newsprint. Similarly, recycled glass is not remanufactured into bottles.

The MAG feels that the economic uncertainty present at the time of this analysis may justify a decrease in the discount rate. The cost-effectiveness analysis described above was repeated with a 3% discount rate, rather than a 5% discount rate. The lower discount rate increases the NPV of the savings from FAW-3 to –$53 million, for a cost-effectiveness of –$10/t$CO_2$e.

Additional Benefits and Costs

- Increased recycling will increase the anticipated life span of existing landfills due to the decreased amount of waste disposed of in those landfills.
- Increased recycling will decrease the revenue generated by landfills, but may not yield an equivalent decrease in operating costs.
- Small-scale composting of MSW could reduce costs for some rural communities by generating soil material that could be used as cover material for the local landfill.

Feasibility Issues

None identified.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

NS-6. Develop Capacity in New Forestry and Wood Biomass Opportunities

Following is a policy that was considered by the Alaska Natural Systems Adaptation Group. This policy has been moved to this appendix because of the overlap between it and FAW-1 and FAW-2B. This policy is mostly concerned with fostering the growth and management of healthy forests in Alaska, and getting the most possible benefits from Alaska's forestland. While the GHG benefits of adaptation policies are not quantified, this policy nonetheless can provide additional insight into issues of forest health. There is overlap with biomass supply in all of FAW-1 and FAW-2B.

Policy Description

Alaska should invest in economic development and infrastructure to attract and facilitate development of industrial capacity, at appropriate scales, to use insect- or fire-damaged timber and underutilized or new sources of wood biomass.

As the changing climate stresses the forests of Alaska, mortality of trees will increase due to insects, fire, and tree-decline agents. Finding economic and innovative uses for dead, small, and underutilized species will help managers confront this forest health crisis and provide for resilient forests more able to withstand rapid change.

This policy would invest in developing and deploying new harvesting technology and silvicultural techniques and demonstrating a variety of wood biomass systems to produce heat and power for rural and urban communities.

This policy would build on work initiated by the Alaska Wood Energy Development Task Group in 2002 and continue efforts to complete feasibility studies, engineering, financing, and construction of biomass space-heating facilities for public buildings. This can occur at several different scales—from individual wood-pellet stoves, solid-wood boilers, and wood-chip boiler systems. The policy would also explore the use of wood chips in co-firing applications with coal to produce electricity in large-scale utility settings.

Without investment in and demonstration of these types of projects and facilities, the technology will be slow to develop in Alaska. While there has been significant movement toward a variety of alternative energy options, wood biomass consistently ranks near the top in economics and ability to be implemented quickly. By demonstrating different technologies at a variety of scales, communities will be able to choose the best options for their situation. This would include fuel type, quantities available on a sustainable and economic basis, heat-load need, and a variety of other factors. In turn, this will permit forest managers to aggressively address forest health issues and utilize wood that would otherwise increase fire hazard and cause further declines in forest stand and community resilience.

Policy Design

This policy has several different facets that work together to achieve the overall result of using dead, small, or underutilized tree species to improve overall forest health and to form the basis of

a wood bioenergy industry. This industry can function at several scales and can be as simple as an energy-efficient wood stove in a single-family dwelling, to a large, complex wood-energy plant in an urban community. The important aspect of this proposal is that it can be implemented at both the small and the large ends of the wood-energy spectrum, with numerous options in between. Communities can scale their options to the level they are comfortable with.

Currently in the state, there are several installations of Garn boilers, which use solid wood, much like a wood stove, but on a larger scale. The Garns are used to heat public buildings and other small-to-medium-sized buildings. There is a need to demonstrate a wood chip system that is more automated than the Garns and can handle large heat loads, such as an entire high school, hospital, or prison. Two communities, Delta and Tok, are considering a project like this, and both have applied to the AEA grant program to secure funds to move ahead with this work.

The next step up would be to look at a co-firing opportunity with an electric utility, where coal and wood chips would be burned together to produce the steam required to run turbines and generators to make electricity. UA is interested in this off-the-shelf technology for a proposed new generating unit at its Fairbanks campus.

All of these options are viable short-term solutions that have been in use in other parts of the nation and the world for many years. Alaska's cheap supplies of energy have prevented their evaluation and use in the state, and there is a need to demonstrate their reliability and economic feasibility.

In addition, air quality and related health issues have been raised by EPA concerning fine particulate matter (PM), called $PM_{2.5}$. Recently, the community of Fairbanks joined the City and Borough of Juneau in being a nonattainment area for the $PM_{2.5}$ standard. Wood-burning appliances, especially older wood stoves and some outdoor wood furnaces, will not meet this standard. Wood pellet stoves and boilers can meet this standard, and homeowners may need to switch to this type of fuel if they wish to continue using wood fuels. There is a need to manufacture wood pellets in Alaska, and at least one company has taken steps to do so, but there is much work to do on the harvesting and transportation sides to ensure that pellets can be produced economically.

This is important for mitigating the effects of climate change, because wood burning offsets fossil fuels, like oil, coal, or natural gas. Wood also produces CO_2 when combusted, but new trees are taking the place of harvested trees in the forest. These young trees sequester carbon and thus are considered carbon-neutral from a GHG perspective. Additionally, if the nation or Alaska adopts a cap-and-trade program for GHGs, the fuel offsets mentioned above can be sold as carbon credits in carbon exchange markets, such as CCX.

Goals:

There are several overarching goals for this policy:

- Replace fossil fuels with a renewable, locally produced fuel that is considered carbon-neutral with regard to GHG emissions.
- Create local employment in harvesting, silvicultural work, and operation of energy facilities, especially in rural communities.

- Actively manage forestlands for a variety of social, economic, and biological benefits.
- Demonstrate the feasibility and economics of different bioenergy technologies, from small- to large-scale technologies for space heating and electrical needs.

Specific goals include:

- Construct a wood chip boiler installation at a public school or similar facility, and have it operational by 2010.
- Complete feasibility studies for five communities interested in wood energy projects annually for each of the next 10 years.
- Develop and demonstrate harvesting and transportation systems using currently available equipment for wood energy facilities. Demonstrate one road-based system and one rural harvesting system.
- Establish a wood energy coordinator position in DOF to provide technical assistance to communities and AEA to determine the sustainability of wood supplies for wood energy projects.

Timing:

- Build on projects already initiated to enable rapid deployment of wood energy systems beginning in 2009. Additional projects can be brought on line as soon as feasibility studies, engineering, financing, and construction can be accomplished.
- Over the next 10 years, numerous projects can move forward in both urban and rural communities.
- Results will be both short and long term, and can be expected to continue through the design life of the facility.

Parties Involved: A number of entities can participate in this effort, ranging from public and private organizations with expertise in the areas discussed. A partial list would include AEA, Alaska Wood Energy Task Group, DOF, USFS, state and private forestry, DOE, USFS Forest Products Lab, Tanana Chiefs Conference, UA, Cold Climate Housing Research Center (CCHRC), and others.

Evaluation: The main type of monitoring would take place on the forest management side of this proposal. Managers would ensure that forest health and productivity were being maintained on sites and that best management practices (BMPs) were being applied. The state's Forest Resources and Practices Act could provide both effectiveness and implementation monitoring of BMPs.

Forest certification via a third-party organization, such as the Sustainable Forestry Initiative or the Forest Stewardship Council, could also ensure appropriate management standards are in place.

Research and Data Needs: The concept that wood fuels are carbon neutral should be thoroughly examined. This is a complex topic that involves carbon budgets and cycles in a

dynamic environment. Protocols for certifying carbon storage and sequestration rates are needed for boreal and coastal forests.

Research in new harvesting equipment or application and adaptation of current equipment should be supported.

Air quality monitoring and testing of various wood-burning appliances should be completed in an arctic environment. CCHRC would be an ideal organization to conduct this needed work.

Implementation Mechanisms

This policy can best be implemented by building on efforts underway in a number of other organizations.[65] Coordination of these efforts is a key element for success and the efficient use of funding and talent. Currently, several projects are moving ahead as the result of funding via the AEA Alaska Renewable Energy Fund grant process. Fifteen wood biomass projects were funded under the Round 1 request for proposals, and the emphasis for this option should focus on providing support and technical assistance to ensure all these projects are successfully implemented.

Hiring a wood energy coordinator in DOF to provide technical assistance would facilitate accomplishing these projects. A key aspect will be developing harvest and biomass sourcing plans to ensure an economic and stable supply of biomass for these projects. This position would also assist with initial feasibility analysis for proposed projects and would focus on quantifying available fuel supplies and the cost per delivered ton of biomass feedstock to an energy facility. This will help ensure projects are viable from both economic and biological perspectives.

With regard to air quality concerns, work is also underway at CCHRC to test different types of wood-combustion appliances and fuel types to quantify emission profiles. This effort is instrumental in identifying the appropriate technologies for use in residential and light commercial applications, especially in urban and suburban locations. Support for this work should continue and should be expanded with additional funding as needed.

UA should be encouraged to continue its evaluation of the feasibility of including a co-firing bioenergy option for the proposed new power facility on campus. A facility that would co-fire wood chips or industrial pellets with coal should receive due consideration. A publication and resources from the USFS Sitka Forest Products Lab should be consulted in the process.[66]

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[65] Alaska Wood Energy Development Task Group Briefing Paper, Division of Forestry, May 2008. Available at: http://forestry.alaska.gov/pdfs/08DOF_AWEDTGBriefing.pdf.

[66] Nicholls, D.L., Patterson, S.E. and Uloth, Erin, *Wood and Coal Cofiring in Interior Alaska: Utilizing Woody Biomass From Wildland Defensible-Space Fire Treatments and Other Sources,* USFS Sitka Forest Products Lab, 2006. Available at: http://www.treeresearch.fs.fed.us/pubs/22566.

Related Policies/Programs in Place

Governor Palin's energy goal of 50% renewable by 2025 is directly related to the elements of this policy. Woody biomass for both heat and power production can play a role in achieving this goal, along with other types of renewable energy.

The Fuels for Schools program in the intermountain western states is a good example and source of information for woody biomass energy projects and should be emulated in Alaska.[67] Many other examples of successful wood energy projects around the country and overseas should be consulted as Alaska furthers the development of a state program.

Feasibility Issues

The suite of wood energy options for space heating is a well-understood technology that is very feasible to implement at the scales discussed. There is some need to ensure that air quality issues are addressed and the appropriate combustion appliances are recommended for situations unique to each application and community. Power generation options are also well understood, at least for larger-scale operations, such as in co-firing or in stand-alone biomass generation facilities. Problems could result if the scale of a facility is too large and is mismatched to the biomass resource. A thorough fuel analysis should be completed for proposed projects to ensure they are well matched to the sustainability, quantity, and type of biomass fuels in the area.

Projects that are considering a CHP approach (co-generation) are also fairly straightforward, but at smaller scales the technology is still developing. The same can be said for some of the harvesting equipment currently under development or just recently developed for small-stem biomass applications. While there are promising advancements in this field, caution and due diligence should be completed before investing capital in some of these prototype or first-generation harvesting or wood power systems.

Additional Benefits and Costs

In addition to the benefits of reducing CO_2 emissions via the offset of fossil fuels, this policy produces a number of direct and indirect benefits to the communities and individuals who adopt these principles.

Direct Benefits

- A huge asset to a community is a sustainable fuel supply that is locally produced and not subject to the wild fluctuations of fuel oil and natural gas.
- Forestlands surrounding the community will be actively managed, and a number of forest health benefits will accrue as a result. The treatment of hazard fuels will reduce future costs of suppressing fire in areas where the state cannot allow fire to burn, and will reduce overall emissions when treated areas do burn.

Indirect Benefits

[67] See http://www.fuelsforschools.info/.

- The importance of creating jobs and economic development, especially in rural areas of the state, cannot be overstated. Jobs will result from opportunities in both harvesting and other forest management activities, and in the operation of energy facilities.
- Habitat improvements will benefit a variety of species that depend on a mosaic of vegetation types and early-succession stages of forest development.
- Biomass facilities that replace previously used fossil fuels will be able to sell carbon credits for the fuel offsets generated.
- Providing a use for the low-quality, small-diameter trees in the forest will create opportunities for expansion of the forest product industry. Higher-quality trees can be sawn or processed into other products, because the whole stand will be managed, not just the best-quality trees.

Costs: The only specific cost generated by this policy is the creation of a wood energy forester position in DOF. Salary and operating costs would be approximately $100,000/yr. Key duties are discussed in the Implementation Mechanisms section, above.

Other direct costs would be the various projects, but other funding sources are currently available, such as AEA, USFS, DOE, and under some of the provisions of the American Recovery and Reinvestment Act (ARRA) of 2009. The Alaska Wood Energy Task Group via DOF and USFS has submitted a proposal for funding under the ARRA that would fund a number of wood energy projects around the state.

Appendix I
Oil and Gas
Policy Recommendations

Summary List of Alaska Climate Change Mitigation Policy Recommendations

Policy No.	Policy Recommendations	GHG Reductions ($MMtCO_2e$)				Net Present Value (million 2009$)	Cost-Effective-ness (2009$ /tCO_2e)	Level of Support
		2015	2020	2025	Total 2010-2025	2010–2025		
OG-1	Best Conservation Practices	*Not Quantified*						Unanimous
OG-2	Reductions in Fugitive Methane Emissions	0.2	0.2	0.2	3.2	$181.4	$57	Unanimous
OG-3	Electrification of North Slope Oil and Gas Operations, With Centralized Power Production and Distribution	—	3.0	4.4	26.6	$7,791.0	$293	Unanimous
OG-4	Improved Efficiency Upgrades for Oil and Gas Fuel-Burning Equipment	0.5	2.1	2.1	19.7	$1,600.1	$81	Unanimous
OG-5	Renewable Energy Sources in Oil and Gas Operations	0.7	0.7	0.7	8.0	$2,603.4	$327	Unanimous
OG-6	Carbon Capture (From North Slope High-CO_2 Fuel Gas) and Geologic Sequestration With Enhanced Oil Recovery	—	0.9	0.9	7.8	$1,368.8	$176	Unanimous
OG-7	Carbon Capture (From Exhaust Gas at a Centralized Facility) and Geologic Sequestration With Enhanced Oil Recovery	—	1.8	1.8	16.1	$3,094.1	$192	Unanimous
OG-8	Carbon Capture (From Exhaust Gas) and Geologic Sequestration Away From Known Geologic Traps	0.7	0.7	0.7	8.0	$7,937.7	$994	Unanimous
	Sector Total Before Adjusting for Overlaps	**9.4**	**10.8**	**89.4**	**2.1**	**$24,576.5**		
	Sector Total After Adjusting for Overlaps	TBA	TBA	TBA	TBA	TBA		
	Reductions From Recent Actions (CAFE Standards)	**0**	**0**	**0**	**0**	**0**		
	Sector Total Plus Recent Actions							

NOTES:

These represent the best set of options available for reducing GHG emissions in the Oil and Gas Sector. They are recommended to the Climate Change Sub-Cabinet for further study.

Policies were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, the results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies.

"'Net Present Value" used in the summary table above would be regarded in the oil and gas industry as "Net Present Cost." Positive numbers in the two right-hand columns indicate that an investment in the policy would generate a financial loss.

"Net Present Value" and "Cost-Effectiveness" values do not apply in Cook Inlet or any other oil and gas basin, due to vastly different production life, geographic distribution, and physical constraints.

Due to the analytical methodology, "Cost Effectiveness" is likely lower than the break-even cost of carbon needed to make a project economically feasible.

None of the modeling included the impact of short-term production loss to implement the policies OG-2 though OG-7.

These policies are technology-based opportunities for reducing greenhouse gas emissions (GHG), not policies to be directly implemented by Alaska.

The GHG savings estimates presented here are not additive. Policies have significant, sometimes complete, overlap in targeted GHG emissions.

CAFE = corporate average fuel economy; CO_2 = carbon dioxide; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $\$/tCO_2e$ = dollars per metric ton of carbon dioxide equivalent; OG = oil and gas.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing the implementation efficiency of any GHG reduction project:

- Evaluate how possible federal GHG reduction programs, such as cap and trade, a carbon tax, and/or command and control, could impact the oil and gas (O&G) industry in Alaska.
- Engage in the national debate on GHG reduction to craft a program that ensures the economic vitality of Alaska's O&G sector, and allows for increased production from the state's untapped O&G resources.
- Ensure any emission reductions in the Alaska O&G sector are creditable toward a federal program, because there are limited reduction opportunities.
- Do not preempt the federal legislation and rulemaking. The federal government will impose GHG regulations and requirements independent of Alaska, so state actions in this regard will be redundant and will serve only to impose regulatory confusion and to increase compliance costs (two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc).
- Fugitive emission reporting will be required pursuant to new rules proposed by the U.S. Environmental Protection Agency (EPA). These regulations are a first step in a federal GHG regulatory program. O&G companies will comply with these regulations as they come into effect.
- Ensure up-front planning for budget, staffing, etc.

- Consider net environmental benefits for GHG reduction projects, where there are potential trade-offs between currently regulated pollutants and GHGs (e.g., between nitrogen oxides [NO_X] and carbon dioxide [CO_2]).
- Consider streamlined permitting that allows expediting permits for projects that offer GHG emission reductions.
- Use this information to inform policymakers.

OG-1. Best Conservation Practices

Policy Description

This policy recommends the state via communication efforts enhance companies' ongoing efforts to reduce greenhouse gas (GHG) emissions using common-sense measures that minimize fuel consumption. Specific initiatives are already being developed to suit the needs of specific conservation opportunities. Such initiatives/opportunities include (but are not limited to):

- Reduce consumption of liquid fuel at/in support of North Slope oil fields;
- Minimize the fuel required for operation of flares;
- Optimize the existing process to minimize energy consumption;
- Reduce miles driven and flown by employees and contractors; and
- Cut electricity use in offices and camps.

Policy Design

The policy reduces carbon emissions by decreasing the amount of fuel used to support O&G operations in Alaska. It is largely behavior-based and is achieved by ongoing encouragement to individuals in making good conservation choices and, through repetition, for those choices to become habits. The policy does not require large capital projects to accomplish its goals.

Goals:

- Encourage the O&G workforce in continued energy conservation efforts;
- Ensure that companies' ongoing efforts are creditable under any future GHG regulatory programs.

Timing:

- Alaska should immediately begin efforts to enhance communication on best practices.
- Alaska should currently be trying to influence any programs on the federal level to ensure the companies' ongoing efforts are creditable under proposed GHG regulations.

Parties Involved: North Slope & Cook Inlet producers, Alaska Department of Environmental Conservation (DEC), GreenStar, or some other third party to encourage communication of best practices between producers.

Other: None.

Implementation Mechanisms

The policy would be implemented through companies' internal workforce outreach programs to share best practices for reducing fuel consumption. Sharing best practices and individual and

organizational recognition programs could be developed through the GreenStar program, the State of Alaska Web site, and/or North Slope producer Intranet sites.

Related Policies/Programs in Place

Conservation efforts already under way:

- Increased the number of bull rails available for plugging in vehicles during cold weather.
- Powered well pads sufficient to run drill rigs on field electrical grids, reducing diesel fuel use.
- Converted diesel-fired equipment to gas-fired equipment.
- Converted the Prudhoe Bay fleet to more fuel-efficient vehicles.
- Implemented education programs to turn off lights when not in use and to encourage the use of fluorescent bulbs where feasible.
- Encouraged employees to reduce the number of trips taken by vehicle or aircraft.
- Implemented an energy management team.
- Right-sized equipment to smaller sources.
- Reduced fuel gas utilization through process optimization.
- Moved Chevron's Anchorage office to an energy-efficient Leadership in Energy and Environmental Design (LEED)-certified building.
- Participate in the GreenStar program to coordinate similar efforts.
- DEC and the Municipality of Anchorage have successfully performed similar outreach to encourage use of block heaters.

Types(s) of GHG Reductions

Fuel combustion-related emissions (CO_2) reduced.

Estimated GHG Reductions and Net Costs or Cost Savings

Not quantified, but efforts are expected to be at least cost-neutral.

Key Uncertainties

None known.

Additional Benefits and Costs

Benefits: This policy will result in near-term reductions of carbon emissions, as well as emissions of conventional pollutants.

Costs: It is believed no additional State of Alaska budget is necessary to implement. Costs to O&G producers in Alaska will be modest and will vary by initiative.

Feasibility Issues

No regulatory mechanisms are proposed. There are no significant feasibility issues with implementation of this option. Conservation efforts will need to be tempered by operational integrity and life safety issues, particularly on the North Slope.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-2. Reductions in Fugitive Methane Emissions

Policy Description

Fugitive methane emissions are defined as unintentional releases of methane to the atmosphere, such as leaks from valves, flanges, unions, tube fittings, or buried pipe. In addition, common practice includes emissions related to compressor wet seals. This policy recommends studies on both types of emissions. The quantification modeling covers both fugitives and emissions related to wet seals on the North Slope.

This policy relates to the technical and economic feasibility of reducing fugitive and wet seal emissions by first determining where leaks occur, and then planning the optimal corrections. Steps for this determination are:

- Begin official refinements to fugitive methane inventories developed by DEC and the Center for Climate Strategies in 2006–2007 (current inventories dramatically overestimate the fugitive emissions). A more recent study by ICF International provides a more realistic estimate of +/–0.16–0.32 million metric tons of carbon dioxide equivalent per year ($MMtCO_2e/yr$).[1]
- Assess potential reductions and associated costs to reduce fugitive methane emissions.

Policy Design

Goals:

- Initiate studies immediately on the technical and economic aspects of implementation. Include in the economic analysis the design of appropriate financial incentives to encourage capital investments as identified by gross quantification model results.
- Review current leak detection procedures and update as needed. Alaska should participate in the federal legislative and rulemaking process by commenting on and providing input to the reporting rules proposed by Congress and EPA.

Timing: Studies could begin immediately.

Parties Involved: Unit operators, State of Alaska.

Other:

Geographic Focus: On the North Slope and in Cook Inlet, where feasible technically and economically on a project-by-project basis. The North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. As most O&G emissions are associated with facilities located on the North Slope, the biggest potential savings in GHG emissions are there.

The quantification modeling of this policy focused on the North Slope only. If Cook Inlet were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations. Cook Inlet O&G production is nearing the end

of usable production life for the known fields. That and its geographic distribution and physical constraints result in an economic analysis for reducing GHG emissions very different from the economic analysis for reducing GHG emissions on the North Slope.

Implementation Mechanisms

Industry and the state should work together to evaluate emission reductions and initiate studies to recommend the best way forward to economically reduce fugitive emissions due to wet seals.

Related Policies/Programs

Potential federal cap-and-trade legislation and EPA air quality regulations.

Types(s) of GHG Reductions

Reduce methane leakage by finding and fixing leaks, and by reducing the emissions related to wet seals.

Estimated GHG Reductions and Net Costs or Cost Savings

The model predicts a $57/metric ton (t) cost for reduction of fugitive emissions and wet seal upgrades. The estimate for expected yearly reduction in CO_2 emissions is 0.235 $MMtCO_2e$, and the estimate for the total reduced emissions through 2025 is 3.2 $MMtCO_2e$.

Data Sources: EPA, American Petroleum Institute (API), tools available to ICF International, and the best professional judgment of the O&G Technical Work Group (TWG) members.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Quantification facilitated by ICF International. Current emissions estimated using ICF International study. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., Intergovernmental Panel on Climate Change, etc.

Quantification assumes replacement of wet seals with dry seals over 4 years. Alternative methods of reducing emissions, such as capturing and flaring the methane, are viable, but are not modeled.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of natural gas until a gas pipeline is built is $0 per thousand standard cubic feet (Mscf).
- The wellhead cost of natural gas after a pipeline is built (assumed 2019) is $6/Mscf, and sensitivities were run at $2, $4, and $6/Mscf.
- Cost of carbon = $0/t.

- Capital and operating costs were amortized to 2035.
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG for all TWGs involved in this process. The estimates can be interpreted as a rough indication of the ”social” cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Fugitive methane emission estimates are preliminary and based on limited data. The EPA GHG reporting rule will ensure better accuracy in emission estimates, as well as improve estimates of the costs associated with GHG reductions.[1]

Additional Benefits and Costs

Implementation of the EPA GHG reporting rule in 2010 will allow Alaska to benefit from the improved inventory information without incurring additional government costs.

Feasibility Issues

- Capital requirements.
- No regulatory mechanisms are suggested beyond pending federal rules. The state could explore tax or other incentives to encourage capital investment in emission reduction opportunities, such as replacement of compressor wet seals.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

[1] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. The Alaska Oil and Gas Conservation Commission (AOGCC) is participating through the Interstate Oil and Gas Compact Commission and Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

SAMPLE

OG-3. Electrification of North Slope Oil and Gas Operations, With Centralized Power Production and Distribution

Policy Description

This policy recommends that the State of Alaska and the O&G stakeholders commission a detailed study of the economics and technical feasibility of electrification of North Slope O&G operations with centralized power production and distribution. The system could be configured to serve Alaska's major O&G operations throughout the North Slope, and possibly to known expected expansion areas. The focus of the study should be to develop, through various means, incentive programs to promote capital investment in GHG reduction projects.

Currently, 30% of Alaska's reported GHG emissions are generated in the North Slope oil fields, primarily from combustion of natural gas in gas turbines. Centralizing the turbines and taking advantage of improved efficiencies offers the potential to reduce these GHG emissions by a significant portion, which is dependent on the scale of the electrification. The study should also review the possibility of additional overall GHG savings through a combination of policies. This may include a hybrid of OG-3 with OG-4, OG-5, OG-6, and OG-7. A sensitivity analysis should be run using all of the O&G policies with different scenarios with various implementation percentages for the options. There may be a best policy hybrid scheme that could provide a more cost-effective overall thermal efficiency improvement package.

Policy Design

Goals:

- Study the economic and technical feasibility of a centralized power production and distribution system for the O&G production areas on the North Slope of Alaska.
- Determine barriers to the implementation of a centralized electricity production and distribution system.
- Provide recommendations on how to overcome barriers.

Timing: Parties Involved: State of Alaska, BP Exploration Alaska, Inc., ConocoPhillips Alaska, Inc., Chevron, Exxon-Mobil, and the various other smaller O&G producers on the slope and their associated oil drilling support service companies.

Geographic Focus: On the North Slope and in Cook Inlet, where feasible technically and economically on a project-by-project basis. The North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. As most power is utilized on the North Slope, with the largest amount generated at the Prudhoe Bay field, the biggest potential savings in GHG emissions are there.

- The TWG's evaluation of this policy has shown, based on gross economics, that the localized grid for North Slope O&G operations is technically feasible, but is not likely to be economically feasible without significant incentives.

- Cook Inlet was not included in the quantification of this policy, as the largest GHG reduction prize was on the North Slope. If Cook Inlet were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations. Cook Inlet as a whole is nearing end of usable production life for the known fields. Its current production life cycle, geographic distribution, and physical constraints result in an economic analysis for reducing GHG emissions that is very different from the North Slope analysis. The shorter remaining field life should result in a shorter amortization period, and thus possibly a higher $/t$CO_2$e removed cost.

Research Needs: Fully investigate the technical and economic feasibility and any incentives. Review projects individually and as a collective of projects to ensure both short-term and long-term visions are maintained.

Economic Research Areas—Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. Take into account any effects on the economy and jobs within the sector and its supporting businesses. Involve the Alaska Department of Revenue (DOR) in this study.

Rough economic viability screening assessments were run without a cost of carbon or potential tax incentives factored in. Additional research into the effect of the value of carbon for both near and long terms may adjust the project value based on the avoided GHG emissions and the value associated with carbon under some future program. Cases were run based on three potential wellhead values of natural gas: $2, $4, and $6/Mscf. The future value of natural gas over the required performance period for the study is very difficult to predict; hence, additional research may be needed.

Technical Research Areas—Engage with any federal, state, or private entities doing research on efficiency upgrades.

Implementation Mechanisms

The study should focus on the financial feasibility of this option, and on ways of encouraging O&G stakeholders to invest the large capital required to implement this policy. There are no insurmountable technical feasibility issues with the implementation of this option. Some regulatory hurdles exists that should be addressed immediately by both the state and the stakeholders. The critical path is for the state to design appropriate incentives to facilitate a significant level of capital investments, and for operators to begin design of facilities needed to maximize the GHG reductions within an acceptable economic framework.

Alaska should simultaneously review the business climate in the state, and ensure that the climate encourages capital investment by the OG stakeholders in a centralized electrical power generation plant and distribution system on the North Slope.

One known barrier to implementation is staffing levels and training of the staff at DEC to provide the required permits in a timely manner. Alaska should ensure that it has a trained and experienced workforce to implement the large permitting and regulatory changes for the North Slope operations within its agencies to help facilitate the implementation of the GHG reduction options.

Specific issues are:

- Legislative and regulatory changes (both federal and state) are needed for existing air quality regulations so that GHG reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surrounding existing New Source Review (NSR) requirements and GHG reduction projects.
- The state's GHG liaison in Washington, D.C., should work directly with appropriate congressional staffers to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska need to be routine and are an essential part of the process.
- Work to streamline and coordinate between federal and state regulations.
- Avoid developing regulations that duplicate or potentially conflict with existing or expected federal regulations.
- Conduct a thorough analysis of utility statutes and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
- Consider changing tax credit legislation and regulations to provide incentives for GHG reduction improvement projects and facilitate project economics.
- Train and retain qualified regulatory staff (DEC, Alaska Department of Natural Resources [DNR], Regulatory Commission of Alaska [RCA], Alaska Oil and Gas Conservation Commission [AOGCC], others) to improve timing and efficiency.
- Streamline the permitting of new/revised facilities designed to reduce GHGs.
- Examine royalties and the lease-term impacts of operating a centralized power grid across lease boundaries (royalties are payable on fuel gas used to generate power that crosses a lease boundary).

Related Policies/Programs in Place

Currently, no policies or programs appear to have a direct impact on this policy.

Types(s) of GHG Reductions

Primarily CO_2 from significant reduction in the amount of fuel gas burned.

Estimated GHG Reductions and Net Costs or Cost Savings

There is a very large potential cost of this policy, with a very rough estimate in the hundreds of millions of dollars to billions of dollars, depending on the scope and complexity. Maximum GHG savings would be gained through implementing this option in conjunction with OG-2: Reductions in Fugitive Methane Emissions, OG-5: Renewable Energy Sources in Oil and Gas Operations, OG-6: Carbon Capture From North Slope High-CO_2 Fuel Gas and Geologic Sequestration With Enhanced Oil Recovery, and OG-7: Carbon Capture [From Exhaust Gas at a Centralized Facility] and Geologic Sequestration With Enhanced Oil Recovery. These policies together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

Approximately 11.9 $MMtCO_2e$ of GHGs are produced each year in the OG production, transport, and refining sector on the North Slope.[2] Depending on the scope and costs of the project, various amounts could be mitigated. Assuming that massive investment could be generated to fully fund centralization and electrification and improve the overall thermal efficiency of O&G operations for the entire North Slope, approximately half of the current emissions could be mitigated.

This policy should be evaluated in concert with policies OG-1, OG-2, OG-4, OG-5, OG-6, OG-7, and OG-8. The potential overall GHG savings and efficiencies could be maximized using a hybrid approach, as the costs of full implementation of the policies are prohibitive both individually and collectively. These prohibitive costs were developed in a gross-level, rough order-of-magnitude review. The order of magnitude of these estimates should be appropriate and reflective of the costs associated with these policies.

Modeled Costs and GHG Savings:

The estimated GHG aggregate savings through 2025 is 27 $MMtCO_2e$, assuming a phased approach. The estimated annual GHG reductions are based on the number of phases implemented:

- 1 phase - 1.48 $MMtCO_2e$/year.
- 2 phases - 2.96 $MMtCO_2e$/year.
- 3 phases - 4.44 $MMtCO_2e$/year (maximum available phases through 2025).
- 4 phases - 5.91 $MMtCO_2e$/year (full implementation). Implementing all four phases could reduce North Slope GHG emissions by approximately 50% from the baseline established in 2002.

The costs associated with this project are as follows:

- Total estimated capital investment (net present value [NPV]): $7.79 billion.
- Estimated cost per tCO_2e reduced: $293.

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska, Inc., Union Oil Company of California/Chevron, ICF International, EPA, and DEC.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. The project is phased in four equal portions, with one phase added every five years. The overall project life is estimated through 2035, with the cumulative project emission reductions taken through 2025 (reduction date for all sectors set by the MAG). The 2035 ”life of project" date allows the large

[2] Based on reported fuel burn data in DEC’s systems, as compiled by the State of Alaska for 2002.

capital investments to be amortized over a longer, more realistic period, so as not to artificially skew the dollar-per-ton cost of the project. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of gas until the major gas sales pipeline is built is $0/Mscf.
- The long-term value of improved hydrocarbon reserves due to burning less fuel gas was not included.
- Costs related to lost production during project construction were not included.
- The wellhead cost of fuel gas after the major sales gas pipeline is built (2019) is $6/Mscf (with sensitivities at $4 and $2/Mscf).
- The cost of carbon is $0/t.
- The project's capital costs are amortized to 2035, due to the large capital expenditures (2025 did not paint an accurate picture).
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

- Future values of carbon were assumed as zero for the TWG's review.
- Value of North Slope natural gas—The TWG ran the studies with $2, $4, and $6/Mscf, to understand the sensitivities associated with the cost of gas.
- The size and scope of the electrification project (facility costs, both for the new facility and for the retrofit).

These uncertainties should be reviewed as part of an encompassing study.

Additional Benefits and Costs

This policy has a direct financial benefit for the state through improved O&G reserves, as well as a GHG emission reduction benefit. The major efficiencies gained with a centralized power grid at major OG operations (especially on the North Slope) would result both in less fuel burned and

thus ultimately more gas available for sale, and in lower volumes of GHG, NO_X, sulfur dioxide (SO_2), and particulate matter (PM) emissions. Other costs and benefits include:

- Additional short-term jobs to implement projects.
- Costs of disposing of waste—e.g., abandonment of scrap.
- Land-use cost increase.
- Possible benefits to nearby communities and to expanding OG exploration through access to the electric grid.

Feasibility Issues

- The policy may have significant technical merit, but could fail due to current lease restrictions and complex regulatory hurdles. To help overcome some of these hurdles, Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, and complex permitting or authorizations for land use. Extensive cross-agency and regulatory interactions are needed between the companies and the multitude of regulatory agencies with responsibility for coordination of the activities required (EPA, DEC, Alaska Minerals Management Service [MMS], DNR, DOR, U.S. Army Corps of Engineers Alaska District [COE], AOGCC, Alaska North Slope Borough [NSB], RCA, etc.). These agencies should form a commission to help simplify the implementation of GHG projects.
- Currently, the projects are both individually and collectively challenged from an economics standpoint. Therefore, substantial financial incentives need to be explored, including emission credits, tax credits, bonds, technology investment, favorable lease terms, and royalty reduction. The Alaska DOR should be involved in this study.
- The logistics of transporting equipment may necessitate additional significant haul road maintenance and even a possible upgrade.
- A review of the fiscal terms and lease agreements is needed to determine if there are any clauses in the current agreements that create a disincentive for energy efficiency improvements. For example, on the North Slope (unit-by-unit) lease terms may create disincentives for (gas) fuel use efficiency.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-4. Improved Efficiency Upgrades for Oil and Gas Fuel-Burning Equipment

Policy Description

This policy recommends that Alaska and the O&G stakeholders commission a detailed study of the economics and technical feasibility of replacing older-technology equipment with newer high-efficiency equipment to improve overall thermal efficiency, thus reducing GHG emissions per unit of generated power. The focus of the study should be to develop, through various means, incentive programs to promote capital investment in GHG reduction projects.

Currently, 30% of Alaska's reported GHG emissions are generated in the North Slope oil fields, primarily from combustion of natural gas in gas turbines. Centralizing the turbines and taking advantage of improved efficiencies offer the potential to reduce these GHG emissions by a significant portion, which is dependent on the scale of the equipment replacement. Looking at this as a stand-alone option, we grossly estimate that replacing older-technology equipment with newer high-efficiency equipment will result in a 17.5% reduction in GHG emissions slope-wide.

The study should also review the possibility of additional overall GHG savings through a combination of policies. This may include a hybrid of OG-4 with OG-3, OG-5, OG-6, and OG-7. A sensitivity analysis should be run using all of the O&G policies with different scenarios that have various implementation percentages for the options. There may be a best policy hybrid scheme that could provide a more cost-effective overall thermal efficiency improvement package.

Policy Design

Goals:

- Study the economic and technical feasibility of replacing the older equipment in service on the North Slope with newer, more efficient equipment. The primary focus of this option is in the O&G production areas on the North Slope of Alaska.
- Determine barriers to the implementation of newer, more efficient equipment.
- Provide recommendations on how to overcome barriers.

Timing: Early studies will facilitate the earliest possible implementation.

Parties Involved: The key parties involved with this project are the State of Alaska, BP Exploration Alaska, Inc., ConocoPhillips Alaska, Inc., Chevron, Exxon-Mobil, and the various other smaller O&G producers on the slope and their associated oil drilling support service companies.

Other:

Geographic Focus: Facilities on the North Slope have the highest potential savings, followed by facilities in the Cook Inlet area. But efficiencies can be gained anywhere if technically feasible, and should be addressed on a project-by-project basis. Projects will be prioritized, and then

more promising options will be evaluated separately, as the economics depend on multiple factors, including location, type and age of the machinery to be analyzed, etc.

Quantification was exclusively run on North Slope facilities. Cook Inlet was not directly part of this study, as the limited resources were focused on the North Slope and the largest opportunity was on the North Slope. Cook Inlet onshore facilities could be included in a future evaluation, and economics and technical feasibility would need to be reviewed independently from the North Slope operations. It must be noted that the Cook Inlet as a whole is nearing the end of its usable production life for the known fields. Its current production life cycle, geographic distribution, and physical constraints result in an analysis for reducing GHG emissions that is very different from the North Slope analysis. The shorter remaining field life that results in a shorter amortization period could result in a higher $/t$CO_2$e removed cost.

Research Needs: Fully investigate the technical and economic feasibility and any incentives. Review projects reviewed individually and as a collective of projects to ensure both short-term and long-term visions are maintained.

Economic Research Areas—Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. Take into account any effects on the economy and jobs within the sector and its supporting businesses. Involve the Alaska DOR in this study.

All rough economic viability screening assessments were run without a cost of carbon or potential tax incentives factored in. Additional research into the effect of the value of carbon for both near and long terms may adjust the project value based on the avoided GHG emissions and the value associated with carbon under some future program. The cases were run based on three potential values of natural gas: $2, $4, and $6/Mscf. The future value of natural gas over the required performance period for the study is very difficult to predict; hence, additional research may be needed.

Technical Research Areas

- Engage with federal, state, or private entities doing research on efficiency upgrades.
- Study alternative low-CO_2-producing fuels that have up-front CO_2 capture, such as hydrogen produced from field gas methane.
- Review suggestions to current technologies for simple adjustments that could improve thermal efficiency, such as firing temperature changes or thermal efficiency improvement packages from the manufacturers.[3]

Implementation Mechanisms

The study should focus on the financial feasibility of this policy, and focus on ways of encouraging the O&G stakeholders to invest the large capital required to implement this option. There appears to be no insurmountable technical feasibility issues with the implementation of this option, however some regulatory hurdles should be addressed immediately by both the state and the stakeholders. The critical path is for the state to design appropriate incentives to

[3] Could have a negative impact on NO_x production, forcing NSR.

facilitate a significant level of capital investments, and operators to begin design of facilities needed to maximize the GHG reductions within an acceptable economic framework. Significant factors in the economics of this option are the expected future price of natural gas, the level of carbon taxes, and the factors associated with implementing projects on the North Slope. These areas should be reviewed as part of an encompassing study.

Alaska should simultaneously review the business climate in the state and ensure that it encourages capital investment by the O&G stakeholders in newer, more efficient equipment on the North Slope. One known barrier to implementation is staffing levels and training of the staff at DEC to provide the required permits for the task in a timely manner. Alaska should ensure that it has a trained and experienced workforce to implement the large permitting and regulatory changes for the North Slope operations within its agencies, to help facilitate the implementation of the GHG reduction options.

Specific issues are:

- Legislative and regulatory changes (both federal and state) are needed for existing air quality regulations so that GHG reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surrounding existing NSR requirements and GHG reduction projects.
- The state's GHG liaison in Washington, D.C., should work directly with congressional staffers to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska need to be routine and are an essential part of the process.
- Work to streamline and coordinate between federal and state regulations.
- Avoid developing regulations that duplicate or potentially conflict with existing or expected federal regulations.
- Conduct a thorough analysis of statutes and regulations for unintended consequences that restrict GHG reduction projects.
- Consider changing tax credit legislation and regulations to provide incentives for GHG reduction improvement projects and facilitate project economics.
- Train and retain qualified regulatory staff (DEC, DNR, RCA, AOGCC, others) to improve timing and efficiency.
- Streamline permitting of new/revised facilities designed to reduce GHGs.

Related Policies/Programs in Place

Currently, no policies or programs appear to have a direct impact on this policy.

Types(s) of GHG Reductions

Primarily CO_2 from significant reduction in the amount of fuel gas burned.

Estimated GHG Reductions and Net Costs or Cost Savings

There potential cost of implementation is very roughly estimated to be in the hundreds of millions of dollars to billions of dollars, depending on the scope and complexity. Maximum

GHG savings would be gained through implementing this policy in conjunction with OG-1: Best Conservation Practices, OG-2: Reductions in Fugitive Methane Emissions, OG-5: Renewable Energy Sources in Oil and Gas Operations, OG-6: Carbon Capture From North Slope High-CO_2 Fuel Gas and Geologic Sequestration With Enhanced Oil Recovery, and OG-7: Carbon Capture From Exhaust Gas at a Centralized Facility and Geologic Sequestration With Enhanced Oil Recovery. These policies together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

Approximately 11.9 $MMtCO_2e$ of GHGs are produced each year in the O&G production, transport, and refining sector on the North Slope.[4] Depending on the scope and costs of the project, various amounts up to 2 $MMtCO_2e$ could be mitigated through improvements in energy efficiencies. This policy should be evaluated in concert with the policies listed in the preceding paragraph, as the potential overall GHG savings and efficiencies will be maximized using a hybrid approach. These costs were developed in a gross-level, rough order-of-magnitude review. The order of magnitude of these estimates should be appropriate and reflective of the costs associated with these policies.

Modeled Costs and GHG Savings:

The estimated GHG aggregate savings through 2025 is 20 $MMtCO_2e$, assuming a phased approach. The estimated annual GHG reductions are based on the implementation:

- 2010—0.00 $MMtCO_2e$/year (savings do not start until after completion of year 5).
- 2015—0.52 $MMtCO_2e$/year.
- 2020 and beyond—2.069 $MMtCO_2e$/year (fully implemented and fully realized annual savings). If fully implemented, it would result in an approximate 17.5% annual reduction in North Slope GHG emissions.

The costs associated with this project are as follows:

- Total estimated capital investment (NPV): $1.60 billion.
- Estimated cost per ton of GHG (CO_2e) reduced: $81.

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska, Inc., Union Oil Company of California/Chevron, ICF, EPA, and DEC.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. The project has four phases in five-year increments. The overall project life is estimated through 2035, with the cumulative project emission reductions taken through 2025 (reduction date for all sectors,

[4] Based on reported fuel burn data in DEC's systems, as compiled by the State of Alaska for 2002.

established by MAG). The 2035 life-of-project date allows the large capital investments to be amortized over a longer, more realistic period, so as not to artificially skew the dollar-per-ton cost of the project. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of gas until the major gas sales pipeline is built is $0/Mscf.
- The long-term value of improved hydrocarbon reserves from the saved gas.
- The wellhead cost of fuel gas after the pipeline is built (2019) is $6/Mscf (with sensitivities at $4 and $2/Mscf).
- The cost of carbon is $0/t.
- The project's capital costs are amortized to 2035, due to the large capital expenditures (2025 did not paint an accurate picture).
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

- Future values of carbon were assumed as zero.
- Value of North Slope natural gas: Studies were run with $2, $4, and $6/Mscf, to understand the sensitivities associated with the cost of gas.
- The size and scope of the overall project. (Facility costs for this type of retrofit in a brownfield environment are very difficult to quantify due to the site-specific nature of each upgrade.)

Additional Benefits and Costs

- This has a direct financial benefit for the state through improved O&G reserves as well as a GHG emission reduction benefit.
- Overall fuel savings (more hydrocarbons available for sale) and lower NO_X, SO_2, and PM emissions.
- Additional short-term jobs to implement projects.

- Cost to dispose of waste, e.g., abandonment of scrap.

Feasibility Issues

- The policy may have significant technical merit, but could fail due to regulatory hurdles. To help overcome some of these hurdles, Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, and complex permitting or authorizations for land use. Extensive cross-agency and regulatory interactions are needed between the companies and the multitude of regulatory agencies with responsibility for coordination of the activities required (EPA, DEC, MMS, DNR, DOR, COE, AOGCC, NSB, RCA, etc.). These agencies should form a commission to help simplify the implementation of GHG projects.
- Currently, the projects are both individually and collectively challenged from an economics standpoint. Therefore, substantial financial incentives need to be explored, including emission credits, tax credits, bonds, technology investment, favorable lease terms, and royalty reduction. The Alaska DOR should be involved in this study.
- The logistics of transporting equipment may necessitate additional significant haul road maintenance and even a possible upgrade.
- A review of the fiscal terms and of lease agreements is needed to determine if there are any clauses in the current agreements that create a disincentive for energy efficiency improvements. For example, on the North Slope (unit-by-unit) lease terms may create disincentives for (gas) fuel use efficiency.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-5. Renewable Energy Sources in Oil and Gas Operations

Policy Description

This policy is a recommendation that Alaska and OG stakeholders commission a detailed study of the economics and technical feasibility of developing renewable energy sources to improve overall thermal efficiency, thus reducing GHG emissions per unit of generated power. The focus of the study should be to develop, through various means, incentive programs to promote capital investment in GHG reduction projects.

Currently, 30% of Alaska's reported GHG emissions are generated in the North Slope oil fields, primarily from combustion of natural gas in gas turbines. Looking at this as a stand-alone option, a gross estimate of a 6% reduction in GHG emissions is viable through the implementation of renewable energy sources at hydrocarbon recovery facilities.

The study should also review the possibility of additional overall GHG savings through a combination of policies. This may include a hybrid of policies OG-1 through OG-7. A sensitivity analysis should be run using all of the policies with different scenarios with various implementation percentages for the policies. There may be a best policy hybrid scheme that could provide a more cost-effective overall thermal efficiency improvement package.

Policy Design

Goals:

- Study the economic and technical feasibility of using renewable energy to supplement energy required to run O&G production areas on the North Slope of Alaska.
- Determine how to best encourage investment in capital projects to install renewable energy.
- Identify barriers to the implementation of a centralized electricity production and distribution system (which is a prerequisite to allowing large volumes of supplemental renewable energy into the power grid).
- Provide recommendations on how to overcome these barriers.

Timing: Early studies will facilitate the earliest possible implementation.

Parties Involved: The key parties involved with this project are the State of Alaska, BP Exploration Alaska, Inc., ConocoPhillips Alaska, Inc., and all other O&G producers on the slope and their associated oil drilling support service companies.

Other:

Geographic Focus: On the North Slope and in Cook Inlet, where feasible technically and economically on a project-by-project basis. The North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. As most power is utilized on the North Slope, with the largest amount generated at the Prudhoe Bay field, the biggest potential savings in GHG emissions are there.

- Evaluation of this policy has shown, using gross economics, that the use of renewable energy for North Slope O&G operations is technically feasible, but is not economically feasible without a significant level of currently unknown incentive programs.
- Cook Inlet was not directly part of this study, as the limited resources were focused on the North Slope and the largest GHG reduction opportunity was on the North Slope. Cook Inlet onshore facilities could be included in a future evaluation, and economics and technical feasibility would need to be reviewed independently from the North Slope operations. Cook Inlet as a whole is nearing the end of its usable production life for the known fields. Its current production life cycle, geographic distribution, and physical constraints result in an economic analysis for reducing GHG emissions that is very different from the North Slope analysis. The shorter remaining field life that results in a shorter amortization period could result in a higher $/tCO_2e$ removed cost.

Research Needs:

Economic Research Areas—Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. Take into account any effects on the economy and jobs within the sector and its supporting businesses. Involve the Alaska DOR in this study**.**

All rough economic viability screening assessments were run without a cost of carbon or potential tax incentives factored in. Additional research into the effect of the value of carbon for both near and long terms may adjust the project value based on the avoided GHG emissions and the value associated with carbon under some future program. The cases were run based on three potential values of natural gas: $2, $4, and $6 /Mscf. The future value of natural gas over the required performance period for the study is very difficult to predict; hence, additional research may be needed.

Technical Research Areas

- Engage with federal, state, or private entities doing research on alternative energy.
- Engage with federal, state, or private entities that may be doing research in renewable energy sources, such as wind, hydro, and geothermal, especially as they are related to conditions found in Alaska.
- Study the location and types of renewable options to enhance the thermal efficiency of hydrocarbon recovery activities.

Implementation Mechanisms

The study should focus on the financial feasibility of this policy, and focus on ways of encouraging the O&G stakeholders to invest the large capital required to implement this policy. There are no insurmountable technical feasibility issues with this policy, but there are some regulatory hurdles that should be addressed immediately by both the state and the stakeholders. The critical path is for (1) the state to design appropriate incentives to facilitate a significant level of capital investments, and (2) operators to begin design of facilities needed to maximize the GHG reductions within an acceptable economic framework. Significant factors in the economics of this policy are future gas and carbon prices and the factors associated with implementing projects on the North Slope. These areas should be reviewed as part of an encompassing study.

Specific issues are:

- Legislative and regulatory changes (both federal and state) are needed for existing air quality regulations, so that GHG reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surrounding existing NSR requirements and GHG reduction projects.
- The state's GHG liaison in Washington, D.C., should work directly with congressional staffers to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska need to be routine and are an essential part of the process.
- Work to streamline and coordinate between federal and state regulations.
- Avoid developing regulations that duplicate or potentially conflict with existing or expected federal regulations.
- Conduct a thorough analysis of utility statute and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
- Consider changing tax credit legislation and regulations to provide incentives for GHG reduction improvement projects and facilitate project economics.
- Train and retain qualified regulatory staff (DEC, ADNR, RCA, AOGCC, others) to improve timing and efficiency.
- Streamline permitting of new/revised facilities designed to reduce GHGs.
- Examine royalties and the lease-term impacts of operating a centralized power grid across lease boundaries (royalties are payable on fuel gas used to generate power that crosses a lease boundary).

Related Policies/Programs in Place

No existing policies or programs appear to have a direct impact on this policy.

Types(s) of GHG Reductions

Primarily (CO_2) from significant reduction in the amount of fuel gas burned.

Estimated GHG Reductions and Net Costs or Cost Savings

Costs of the project are very roughly estimated to be in the hundreds of millions of dollars to billions of dollars, depending on the scope and complexity. Large-scale energy from renewable sources can only be used if there is an electrical grid to feed into, electrification has taken place, and sufficient backup power is available when the wind is not blowing. Hence, all aspects of OG-3: Electrification of North Slope Oil and Gas Operations with Centralized Power Production and Distribution are required prerequisites for this option. Additionally, maximum GHG savings would be gained through implementing this option in conjunction with OG-1: Best Conservation Practices, OG-2: Reductions in Fugitive Methane Emissions, OG-4: Improved Efficiency Upgrades for Oil and Gas Fuel-Burning Equipment, OG-6: Carbon Capture From North Slope High-CO_2 Fuel Gas and Geologic Sequestration With Enhanced Oil Recovery, and OG-7: Carbon Capture From Exhaust Gas at a Centralized Facility and Geologic Sequestration with

Enhanced Oil Recovery. These policies implemented together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

Approximately 11.9 $MMtCO_2e$ of GHGs are produced each year in the O&G production, transport, and refining sector on the North Slope.[5] Depending on the scope and costs of the project, various amounts could be mitigated by the addition of renewable wind energy. Adding wind power to a centralized gas facility could mitigate 0.75 $MMtCO_2e$.

This policy should be evaluated in concert with policies identified above, as the potential overall GHG savings could end up being greater than the baseline values.[6] The costs of the policies are prohibitive for implementing them both individually and collectively. These costs were developed in a gross-level, rough order-of-magnitude review. The order of magnitude of these estimates should be appropriate and reflective of the costs associated with these options.

Modeled Costs and GHG Savings: The estimated GHG aggregate savings through 2025 is 8 $MMtCO_2e$. The estimated annual GHG reductions are based on North Slope wind data and immediate implementation of wind power at a centralized gas facility, with the annual savings estimated at 0.7 $MMtCO_2e$.

The costs associated with this project are as follows:

- Total estimated capital investment (NPV): $2.60 billion.
- Estimated cost per ton of GHG (CO_2e) reduced: $327.

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska, Inc., Union Oil Company of California/Chevron, ICF, EPA, and DEC.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. The project is implemented immediately, with an overall project life estimated through 2035, and cumulative project emission reductions estimated through 2025 (reduction dates established for all sectors by the MAG). The 2035 life of project date allows the large capital investments to be amortized over a longer, more realistic period, so as not to artificially skew the dollar-per-ton cost of the project. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The current Central Power Station in Prudhoe Bay is augmented.
- The wellhead cost of gas until the gas pipeline is built is $0/Mscf.

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[5] Based on reported fuel burn data in DEC's systems, as compiled by the State of Alaska for 2002.

[6] Ibid.

- No value was given for the long-term increase in hydrocarbon reserves related to the saved gas.
- The wellhead cost of fuel gas after the pipeline is built (2019) is $6/Mscf (sensitivities at $4 and $2/Mscf).
- The cost of carbon is $0/t.
- The project's capital costs are amortized to 2035, due to the large capital expenditures (2025 did not paint an accurate picture).
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

- Future values of carbon were assumed as zero.
- Value of North Slope natural gas—The TWG ran the studies with $2, $4, and $6/Mscf, to understand the sensitivities associated with the cost of gas.
- The size and scope of the renewable energy project.
- The size and scope of the requisite electrification project (OG-3) needed, so that the electrical power generated by renewable sources can be utilized.

Additional Benefits and Costs

- The state would benefit from a centralized power grid at major O&G operations (especially the North Slope), in that the major efficiencies gained mean less fuel burned, and more fuel ultimately available for sale. In addition, the citizens of the state would benefit, as the less fuel burned, the lower the GHG emissions.
- Overall fuel savings (more hydrocarbons available for sale) and lower NO_X, SO_2, and PM emissions.
- Additional short-term jobs to implement projects.
- Land-use cost increases.
- Possible benefits to nearby communities and to expanding O&G exploration through access to the electric grid.

Feasibility Issues

- The policy may have significant technical merit, but could fail due to current lease restrictions and complex regulatory hurdles. To help overcome some of these hurdles, Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, and complex permitting or authorizations for land use. Extensive cross-agency and regulatory interactions are needed between the companies and the multitude of regulatory agencies with responsibility for coordination of the activities required (EPA, DEC, MMS, DNR, DOR, COE, AOGCC, NSB, RCA, etc.). These agencies should form a commission to help simplify the implementation of GHG projects.
- Currently, the projects are both individually and collectively challenged from an economics standpoint. Therefore, substantial financial incentives need to be explored, including emission credits, tax credits, bonds, technology investment, favorable lease terms, and royalty reduction. The Alaska DOR should be involved in this study.
- The logistics of transporting equipment may necessitate additional significant haul road maintenance and even a possible upgrade.
- A review of the fiscal terms of lease agreements is needed to determine if there are any clauses in the current agreements that create a disincentive for energy efficiency improvements. For example on the North Slope (unit-by-unit) lease terms may create disincentives for (gas) fuel use efficiency.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-6. Carbon Capture (From North Slope High-CO_2 Fuel Gas) and Geologic Sequestration With Enhanced Oil Recovery

Policy Description

This policy relates to the technical feasibility and economics of CO_2 separation from produced gas, transport, and geologic sequestration (carbon capture and storage [CCSR]) from gas used for fuel in and around Prudhoe Bay. The technical goal is to remove and sequester the 10%–12% CO_2 from the natural gas produced at Prudhoe before that gas is burned in power generators, thereby lowering North Slope emissions by approximately 8%, or ~1 $MMtCO_2$/yr. The geologic sequestration should utilize a reservoir where enhanced oil recovery (EOR) can improve the economics.

This policy is very similar to OG-7, but differs in that it calls for removing CO_2 from entrained gas pre-combustion, rather than from post-combustion, exhaust gases. Capturing the emissions post-combustion is a significantly more complicated procedure. With regard to sequestration, this policy is identical to OG-7.

Policy Design

Goals:

- Initiate studies on the technical and economic aspects of implementation. The economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. The technical analysis should be conducted to choose an appropriate CO_2 capture technology and the best reservoir for CO_2 injection to maximize economics, especially relating to EOR benefits.
- Study the implementation of this policy in conjunction with energy efficiency policies OG-3, OG-4, and OG-5, to both minimize the amount of CO_2 that needs to be processed as well as reduce resource waste.
- Encourage investment through incentives:
  - Financial:
    - Provide federal and state carbon credits.
    - Provide tax incentives for capital investments.
  - Regulatory:
    - Simplify/streamline the regulatory environment.
    - Avoid overlapping state and federal regulations of GHG emissions and underground injections. Recommend coordinating with and participating in the development of federal regulations to ensure the regulations fit Alaska's conditions.
    - Study state permitting/regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to cover additional workloads.

Timing: Early studies will facilitate the earliest possible implementation.

This policy could logically be implemented before OG-7, and all the CO_2 captured would likely be able to be utilized in EOR, thereby maximizing the economic benefits. However, since energy is needed to power CCSR (burning gas and creating more CO_2), improving energy efficiency to minimize the volume of gas that needs to be treated is desired. Energy efficiency options (OG-3, OG-4, and OG-5) should be considered in order to minimize waste.

A "pure" sequestration project could not be permitted at this time, as the regulations are currently being developed. The permitting process is in place for EOR applications.

Parties Involved:

- Consultants to conduct the study on technical and economic feasibility.
- North Slope operator technical representatives.
- Operators of neighboring oil fields who might benefit from CO_2 EOR—e.g., Endicott Field.
- State of Alaska (DNR, AOGCC, DEC, DOR, etc.).

Research Needs:

Economic Research

- Model the effects on the economy and jobs with various scenarios. Involve Alaska DOR in this analysis.
- Research the long-term value of carbon, which could have a huge impact on the economics of these projects.
- Research the long-term value of natural gas.

Technical Research

- Engage with and observe the U.S. Department of Energy (DOE) Phase III pilot project testing of various CCSR technologies.
- Conduct a technical feasibility study of the different entrained CO_2 capture technologies.

Incentives: Financial, Permitting, Etc.

- Provide appropriate tax credits for investment in CCSR and EOR. Note that current larger tax credits for CCSR over EOR ($20/t versus $10/t) could lead to a financial incentive to inject into an aquifer rather than into a reservoir for EOR, thereby potentially shortening field life.
- Streamline the permitting process, which is critical for project turnaround.
- Consider a joint agency similar to the Joint Pipeline Office (JPO) to facilitate efficiencies in permitting between agencies (only needed in cases of cross-unit applications.) Currently, the AOGCC is the main regulatory agency for permitting for underground injection of CO_2 for EOR. An additional facilitating agency might be beneficial in the case of cross-unit or special requirements mandated by eventual federal regulations for underground injection of CO_2 for sequestration.

Implementation Mechanisms

To minimize the time required for implementation, regulatory and capital investment hurdles should be addressed immediately. A critical path is for the state to design incentives encouraging the major capital investments that will be required; operators to begin the design of facilities needed to strip the CO_2 from the fuel stream, transport it to a reservoir, and inject it for EOR; and finally the state and operators to start working on the complicated regulatory and permitting issues. The final economics will depend on the value for carbon and fuel gas. Financing CCSR projects will be sensitive to that value, and will be dependent on future cap-and-trade or carbon tax legislation.

Broad Recommended Evaluation

- Determine the relative benefits of various pre-combustion capture techniques (such as membrane versus solvent treatment).
- Study CO_2 sequestration and EOR benefits within selected reservoirs. The choice of a final sequestration site should be based on safety, long term-storage capability, and economics. The more robust the economics, the faster this technology can be put into place. Since studies show that many oil fields in and around Prudhoe Bay would benefit from EOR, it should be considered wherever feasible in the planning of CCSR projects on the North Slope.

Specific Recommended Evaluation

Risks and uncertainties in the following categories should be addressed:

- Maturity of and applicability of various capture technologies.
- Costs for capture, transport, and sequestration.
- Potential for CO_2 leakage.
- Potential EOR benefits.

Detailed analysis should cover:

- Applicable capture technologies, pros and cons, recommendation for pilot.
- Pros and cons of surrounding reservoirs for sequestration.
- Availability and costs of new or upgraded facilities, power, space, and water requirements.
- Costs for geological and geophysical studies for site selection and monitoring.
- Costs for drilling wells that are not suitable for storage.
- Costs for down-hole well testing, maintenance, and repairs.
- Value from possible tax or carbon credits.
- Value from added reserves due to EOR.

- Estimates of CO_2 emissions avoided (including additional emissions from capture, transport, and injection operations).
- Risk assessment for short- and long-term storage.
- Impacts on estimated ultimate recovery (EUR) and conservation/production of resources, e.g., impact on EOR recovery of maximizing CO_2 storage).
- Regulatory requirements (e.g., EPA UIC program, other state and federal requirements).
- Monitoring requirements (pre-, during, and post-injection).

Related Policies/Programs

Existing Policies

- EPA regulations for underground injection for EOR.
- Some tax incentives for CCSR and EOR exist in current federal legislation (carbon mitigation incentives included in the Emergency Economic Stabilization Act of 2008).

Policies Under Development or Needed

- EPA regulations regarding CO_2 underground sequestration.[7] The state may seek primacy for this activity upon final EPA rulemaking.
- EPA regulations, if any, and other federal laws regarding air quality, water quality, carbon tax or cap and trade, etc.
- State/local government permitting, as necessary, addressing issues beyond EPA underground injection control (UIC) CO_2 sequestration rules.
  - Ownership issues—surface rights versus mineral rights versus pore space rights.
  - Long-term liability at sequestration sites.
  - Royalties and lease-term impacts of CO_2 sequestration and use for EOR.
  - Land-use regulations and requirements.
- Potential federal cap-and-trade legislation and ultimate EPA air quality regulations.
  - Potential conflict between increased fuel use (decreased hydrocarbon reserves) due to capture and injection, and benefits for reduction of CO_2 through sequestration.

Related Policies/Programs

- This policy is closely related to OG-7, CCSR from exhaust gas post-combustion in and near O&G fields with potential EOR.
- There are many synergies with eventual sales of North Slope gas.

[7] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. AOGCC, participating through Interstate Oil and Gas Compact Commission and Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

Types(s) of GHG Reductions

CO_2 removed from fuel gas used at Prudhoe Bay before combustion, and injected into an underground reservoir for EOR and long-term sequestration.

Estimated GHG Reductions and Net Costs or Cost Savings

Potential emission savings through CO_2 capture from entrained gas used for fuel at Prudhoe Bay to EOR injection at Endicott Field could be on the order of 1 $MMtCO_2$/yr.

A gross economic estimate, modeled using best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $176/t. The estimate for expected yearly reduction in CO_2 emissions is 0.9 $MMtCO_2e$, and the estimate for the total reduced emissions through 2025 is 7.8 $MMtCO_2e$. Due to the size and complexity of this type of project, there is significant uncertainty in this estimate of $/t.

Due to the very large investments required, as well as timing and logistical constraints, large amounts of capital expenditures occur toward the end of the measurement period (2025). To avoid presenting a misleading number, capital and operating costs were amortized to 2035 when calculating $/t$CO_2$ of mitigated emissions. Capital expenditures will be required by facility owners, as significant retrofitting of existing power-generating facilities will be needed. In addition, significant amounts of fuel will be burned to power the capture, compression, and injection process. Currently, that fuel has zero value, but in the advent of gas sales, that gas has value. Additional expenditures will be required for CO_2 transport pipelines and injection wells, as well as for a long-term monitoring program.

Data Sources: IPCC, DEC, AOGCC, O&G TWG members, API, *Oil and Gas Journal*, 2nd Annual Conference on Carbon Sequestration.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies, e.g., IPCC, etc. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of natural gas until a gas pipeline is built is $0/Mscf.
- The wellhead cost of natural gas after a pipeline is built (assumed 2019) is $6/Mscf, and sensitivities were run at $2, $4, and $6/Mscf.
- The cost of carbon is $0/t.
- Capital and operating costs were amortized to 2035 to get an accurate cost/metric ton.

- Endicott Field is used for EOR cost estimates. (It has appropriate metallurgy in the production facilities.)
- Sufficient EOR opportunities will be available for all captured CO_2. (This has yet to be demonstrated, in addition to the CO_2 expected from major gas sales.)
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Key hurdles are investment, capital cost, and regulatory environment.

Economic

- Value of natural gas, current and future.
- Future values of carbon.
- Hydrocarbon reserves impact, value and amount of EOR reserves.
- Facilities upgrade costs.

Logistical

- Regulatory environment (for permitting, for CCSR projects still being developed, for long-term monitoring requirements, conflicting state and federal regulations, etc.). A significant commitment from regulators will be needed to overcome existing hurdles in the permitting, royalty, and regulatory environments.
- Availability of resources—building materials, space in existing facilities, water, etc.
- Public acceptance of long-term CO_2 storage.

Long Term (after project can no longer be classified as EOR)

- Leakage—Is leakage authorized? If so, what amount/percentage?)
- Long-term CCSR—How long is long term?
- Liability—Who is liable, and for how long?
- Logistical, legal, and royalty issues of cross-unit operations (if the reservoir for EOR is not in the same unit as Prudhoe).

- Time frame—How long to permit? How long to build?

Additional Benefits and Costs

In 2005, about 1.25 $MMtCO_2$ emissions on the North Slope were due to naturally occurring CO_2 entrained within the gas. In addition to the immediate benefit of capturing CO_2 prior to combustion, studying and potentially implementing a pilot for the capture and sequestration of CO_2 from fuel gas can provide long-term benefits for eventual gas sales. Sale gas specifications will require removal of most of the CO_2 from much larger gas volumes than are currently handled. (At projected gas sales production rates of 2–4 billion standard cubic feet per day, 5–10 $MMtCO_2$/yr will ultimately need to be captured and sequestered.)

Longer term, this technology will need to be implemented for eventual gas sales, and at that point the economics could improve for treating fuel gas.

In addition to the benefit of reduced CO_2 emissions, sequestering the CO_2 in a reservoir where it can be used to enhance the oil recovered has great potential value.

Benefits

- Significant economic advantages can be obtained if the initial CO_2 sequestration is partnered with EOR. Where EOR is effective, and reports indicate that many fields on the North Slope would benefit,[8] injection of CO_2 "washes out" residual oil left after initial production. While much of this CO_2 is cycled back to the surface with residual oil, a significant percentage remains trapped in the reservoir, even while active cycling is taking place. The rest of the CO_2 cycles up mixed with residual oil, is separated at the surface, and is re-injected into the reservoir. This cycling continues until EOR is no longer productive, at which point all the CO_2 in the reservoir remains sequestered. At that time, CO_2 could theoretically continue to be injected until injection pressure or some other operational limit is reached.
- Longer term, this technology will need to be implemented for eventual gas sales, if only due to pipeline specifications requiring no more than 1.5% CO_2. Implementing this technology now would act as a large-scale pilot for eventual gas sales.

Costs

- Burning leaner gas could release more NO_x by volume, triggering regulations requiring additional capital-intensive control technologies.
- Capital costs for capture, transport, and injection of CO_2.
- Parasitic energy—i.e., extra power used to capture the CO_2. Additional fuel gas is burned to provide power needed for compression, dehydration, transport, and injection.
- Possible additional water requirements.
- Increased operating costs.

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[8] Advanced Resources International. April 2005. *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska.* Prepared for the U.S. Department of Energy, Office of Fossil Energy–Office of Oil and Natural Gas. Available at: http://www.adv-res.com/unconventional-gas-literature.asp.

- Impact on global competitive standing if the U.S. cost structure is significantly higher than in countries without emission limits.
- Increased cost of energy affects the overall cost of living for all.
- Higher cost structure may shorten ultimate field life and EUR of hydrocarbons.

Feasibility Issues

Capital Requirements

- State and federal (especially EPA) regulatory environment for CCSR projects—not yet established. Legal requirements and liability issues are unknown for long-term CO_2 storage, which have a major impact on cost and timing.
- Pre-combustion CO_2 removal is commonly used in industry, but has never been implemented on the North Slope.
- Other—See Key Uncertainties, above.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-7. Carbon Capture (From Exhaust Gas at a Centralized Facility) and Geologic Sequestration With Enhanced Oil Recovery

Policy Description

This policy relates to the technical feasibility and economics of post-combustion CO_2 capture, transport, and geologic sequestration in or near existing Alaska O&G fields, including the upside of initial EOR.

Currently, 30% of the reported CO_2 emissions from Alaska are generated in the North Slope oil fields, primarily from combustion for power generation.[9] Fortuitously, the co-located or nearby O&G reservoirs provide large volumes of potential storage space. In addition, many of the oil reservoirs are likely candidates for CO_2 EOR. Quantification for this policy is focused on the central gas facility (CGF) at Prudhoe Bay, as preliminary studies have shown that CCSR would have the highest possible efficiencies at this facility, due to the concentration and sizes of the turbines. CGF accounts for ~16% of all North Slope emissions.

This policy is very similar to OG-6, but differs in that it calls for removing CO_2 from exhaust or flue gases post-combustion, as opposed to removing it from entrained gas pre-combustion. Capturing the CO_2 post-combustion is a more complicated and expensive process, as each individual piece of machinery needs to be adapted for the capture process. Additionally, the transport is more complicated and expensive due to the many point sources of capture. With regard to sequestration, this policy is identical to OG-6.

Most concepts and issues related to carbon capture and geologic sequestration in O&G fields discussed in this policy would apply to many facilities in Cook Inlet as well, but the cost structures and logistics there are very different and would require an independent analysis.

Policy Design

Goals:

- Initiate studies on the technical and economic aspects of implementation. The economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. The technical analysis should include the size and type of facilities modifications, choice of appropriate combustion CO_2 capture technology, and choice of best reservoir for CO_2 injection to maximize economics, especially relating to EOR benefits.
- Study the implementation of this option after, or in some cases in conjunction with, energy efficiency options OG-3, OG-4, and OG-5 to minimize the amount of CO_2 that needs to be processed.
- Encourage investment through incentives:

[9] Alaska Department of Environmental Conservation. January 2008. "DRAFT—Summary Report of Improvements to the Alaska Greenhouse Gas Emission Inventory." (Includes Final Alaska GHG Inventory and Reference Case Projection.) Available at: http://www.climatechange.alaska.gov/docs/ghg_ei_rpt.pdf.

- Financial:
  - Provide federal and state carbon credits.
  - Provide tax incentives for capital investment requirements.
- Regulatory:
  - Simplify/streamline the regulatory environment.
  - Avoid overlapping state and federal regulations of GHG emissions and underground injections. Recommend coordinating with and participating in development of federal regulations to ensure the regulations both fit Alaska's conditions and allow for early implementation.
  - Study the state permitting and regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to cover additional workloads.

Timing:

- Early studies will facilitate the earliest possible implementation.
- It is expected that EOR will be able to fully utilize all the CO_2 that could be captured by the application of this policy at the Prudhoe Bay CGF, even if OG-6 is operating concurrently. However, since energy is needed to power CCSR (burning gas and creating more CO_2), improving energy efficiency to minimize the gas that needs to be treated is desired. Energy efficiency policies (OG-3, OG-4, and OG-5) should be considered in order to minimize waste.
- A "pure" sequestration project could not be permitted at this time, as regulations are currently being developed. The permitting process is in place for EOR applications.

Parties Involved:

- Consultants for conducting the study on technical and economic feasibility.
- North Slope operator technical representatives.
- Operators of neighboring oil fields who might benefit from CO_2 EOR—e.g., Endicott Field.
- State of Alaska (DNR, AOGCC, DEC, DOR, etc.).

Other:

Geographic Focus

- While this policy's focus is on Prudhoe Bay, lessons learned here on capture may be applied to Cook Inlet's major emission sources (Beluga Power Plant, the liquefied natural gas plant, and the Tesoro refinery), where future fully depleted onshore O&G fields may be a sequestration opportunity. Cook Inlet was not part of the quantification of this option. If it were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations.
- The Cook Inlet O&G field production life cycle, geographic distribution, and physical constraints result in potentially higher costs for reducing GHG emissions than on the North Slope.

- There is potential for future coal-to-gas/liquids production in Cook Inlet, which may present additional sources of GHG emissions that in turn will be targets for sequestration.

Research Needs:

Economic Research

- Answer the question of appropriate incentives.
- Model the effects on the economy and jobs with various scenarios.
- Involve Alaska DOR in this analysis.
- Research the long-term value of carbon, which can have a huge impact on the economics of these projects.
- Research the long-term value of natural gas.

Technical Research

- Engage with and observe the DOE Phase III pilot project testing of various capture and sequestration technologies.
- Conduct a technical feasibility study of the different post-combustion CO_2 capture technologies.
- Update the 2003 study of the Prudhoe Bay CGF, and determine the costs and requirements to retrofit existing facilities to add CO_2 capture technology, pipelines, compressors, and dehydrators, as well as wells needed to inject/cycle CO_2 in Endicott Field.

Incentives: Financial, Permitting, Etc.

- Provide appropriate tax credits for investment in CCSR and EOR. Note that current larger tax credits for CCSR over EOR ($20/t versus $10/t) could lead to a financial incentive to inject into an aquifer rather than into a reservoir for EOR, thereby potentially shortening field life.
- Streamline permitting critical for project turnaround.
- Consider creating a joint agency similar to the JPO to facilitate efficiencies in permitting between agencies (only needed in case of cross-unit applications.) Currently, the AOGCC is the main regulatory agency for permitting for underground injection of CO_2 for EOR. An additional facilitating agency might be beneficial in the case of cross-unit or special requirements mandated by eventual federal regulations for underground injection of CO_2 for sequestration.

Implementation Mechanisms

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately. A critical path is for the state to design incentives encouraging the major capital investments that will be required; operators to begin the design of facilities needed to strip the CO_2 from the individual fuel exhaust streams, transport it to appropriate reservoirs, and inject it for EOR; and the state and operators to immediately start working on the complicated regulatory/permitting issues. Studies should include space, power, and water requirements for

each facility. Final economics will depend on the value for carbon. Financing CCSR projects will be sensitive to that value, and will be dependent on future cap-and-trade or carbon tax legislation.

Related Policies/Programs

Existing Policies

- EPA regulations for underground injection for EOR.
- Some tax incentives for CCSR exist in current federal legislation (carbon mitigation incentives included in the Emergency Economic Stabilization Act of 2008).

Policies Under Development or Needed

- EPA regulations regarding CO_2 underground sequestration.[10] The state may seek primacy for this activity upon final EPA rulemaking.
- EPA regulations, if any, and other federal laws regarding air quality, water quality, carbon tax or cap and trade, etc.
- State/local government permitting, as necessary, addressing issues beyond EPA UIC CO_2 sequestration rules.
  - Ownership issues—surface rights versus mineral rights versus pore space rights.
  - Long-term liability at sequestration sites.
  - Royalties and lease-term impacts of CO_2 sequestration and use for EOR.
  - Land-use regulations and requirements.
- Potential federal cap-and-trade legislation and ultimate EPA air quality regulations.
  - Potential conflict between increased fuel use (decreased hydrocarbon reserves) due to capture and injection, and benefits for reduction of CO_2 through sequestration.

Related Options

This policy is closely related to OG-6, CCSR from entrained gas pre-combustion, in and near O&G fields with potential EOR.

Types(s) of GHG Reductions

CO_2 removed from fuel gas post-combustion exhaust streams at Prudhoe Bay, and injected into an underground reservoir for EOR and long-term sequestration.

Estimated GHG Reductions and Net Costs or Cost Savings

- Potential emission savings through CO_2 capture from exhaust gases at the Prudhoe Bay CGF facility and EOR injection at Endicott Field could be on the order of 2 $MMtCO_2$/yr.

[10] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. AOGCC is participating through the Interstate Oil and Gas Compact Commission and the Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

- A gross economics estimate, modeled using best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $157/t. The estimate for expected yearly reduction in CO_2 emissions is 1.8 $MMtCO_2e$, and the estimate for total reduced emissions through 2025 is 19.7 $MMtCO_2e$. Due to the size and complexity of this type of project, there is significant uncertainty in the $/t.
- Due to the very large investments required, as well as timing and logistical constraints, large amounts of capital expenditures occur toward the end of the measurement period (2025.) To avoid presenting a misleading number, capital and operating costs were amortized to 2035 when calculating $/t$CO_2$ of mitigated emissions. Large capital expenditures will be required by facility owners, as significant retrofitting of existing power-generating facilities will be needed. In addition, significant amounts of fuel will be burned to power the capture, compression, and injection process. Currently, that fuel has zero value, but in the advent of gas sales, that gas has value. Additional expenditures will be required for CO_2 transport pipelines and injection wells, as well as for a long-term monitoring program.
- Significant commitment from regulators will be needed to overcome existing hurdles in the permitting, royalty, and regulatory environments.

Data Sources: IPCC, DEC, AOGCC, O&G TWG members, API, *Oil and Gas Journal*, 2nd Annual Conference on Carbon Sequestration, DOE.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Quantification facilitated by ICF International. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies, e.g., IPCC, etc.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of natural gas until a gas pipeline is built is $0/Mscf.
- The wellhead cost of natural gas after a pipeline is built (assumed 2019) is $6/Mscf. (Sensitivities were run at $2, $4, and $6/Mscf.)
- The cost of carbon is $0/t.
- Capital and operating costs were amortized to 2035 to get an accurate cost per metric ton.
- Endicott Field was used for EOR cost estimates. (It already has appropriate metallurgy.)
- Sufficient EOR opportunities will be available for all captured CO_2. (This has yet to be demonstrated, in addition to the CO_2 expected from major gas sales.)
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the ”social” cost per ton of emissions reduced, and so can be used to

rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Key concerns are the investment, capital cost, and regulatory environments.

Economic

- Value of natural gas, current and future.
- Future values of carbon.
- Value of hydrocarbon reserves, including EOR.
- Facilities' upgrade costs.

Logistical

- Regulatory environment (for permitting, for CCSR projects still being developed, for long-term monitoring requirements, conflicting state and federal regulations, etc.).
- Availability of resources—building materials, space in existing facilities, water, etc.
- Public acceptance of long-term CO_2 storage.

Long Term (after the project can no longer be classified as EOR)

- Is any leakage authorized? If so, how what amount/percentage?
- Long-term CCSR—How long is long term?
- Liability—Who is liable, and for how long?
- Logistical, legal, and royalty issues of cross-unit operations (if the reservoir for EOR is not in the same unit as Prudhoe).
- Time frame—How long to permit? How long to build?

Recommended Evaluation:

- Determine the relative benefits of various post-combustion capture techniques.
- Study CO_2 sequestration and EOR benefits within selected reservoirs. The choice of a final sequestration site should be based on safety, long-term storage capability, and economics. The more robust the economics, the faster this technology can be put into place. Since studies show that many oil fields in and around Prudhoe Bay would benefit from EOR, it should be considered wherever feasible in the planning of CCSR projects on the North Slope.

Specific Recommendations:

Risks and uncertainties in the following categories should be addressed:

- Maturity of technology.
- Costs for capture, transport, and sequestration.
- Potential for CO_2 leakage.
- Acidification of the reservoir and impact of corrosion on facilities.

Detailed analysis should cover:

- Pros and cons of capture facilities types and locations.
- Availability and costs for new or upgraded facilities, "parasitic" power requirements, space, and water requirements.
- Pros and cons of surrounding reservoirs for sequestration/EOR.
- Costs for drilling a well or wells that are not suitable for storage.
- Costs for down-hole well testing, maintenance, and repairs.
- Reservoir analysis and simulation studies.
- Value from a possible tax or carbon credits.
- Value from added reserves due to EOR.
- Estimates of CO_2 emissions avoided (includes additional emissions from capture, transport, and injection operations).
- Logistical issues related to construction and operations in an isolated arctic environment.
- Risk assessment for short-term and long-term storage.
- Costs for geological and geophysical studies for site monitoring.
- Impacts on EUR and conservation/production of resources (i.e., impact on EOR recovery of maximizing CO_2 storage).
- Regulatory requirements (e.g., EPA UIC program, other state and federal requirements).
- Monitoring requirements (pre-, during, and post-injection).

Additional Benefits and Costs

The 2002 estimate of CO_2 emissions related to O&G production at Prudhoe Bay is 9 MMt, almost half of all stationary GHG emissions in Alaska. About 2 MMt is related to the CGF, which provides the best logistical and economic environment for CCSR due to the size and density of the turbines.

In addition to the benefit of reducing CO_2 emissions, sequestering the CO_2 in a reservoir where it can be used to enhance the oil recovered has significant impact on the economics.

Benefits

- Significant economic advantages can be obtained if the initial CO_2 sequestration is partnered with EOR. Where EOR is effective, and reports indicate that many fields on the North Slope would benefit,[11] injection of CO_2 "washes out" residual oil left after initial production. While much of this CO_2 is cycled back to the surface with residual oil, a significant percentage remains trapped in the reservoir, even while active cycling is taking place. The rest of the CO_2 cycles up mixed with residual oil, is separated at the surface, and is re-injected into the reservoir. This cycling continues until EOR is no longer productive, at which point all the CO_2 in the reservoir remains sequestered. At that time, CO_2 could theoretically continue to be injected until injection pressure or some other operational limit is reached.
- Potential synergies in construction of CGF capture facilities with upgrades for energy efficiencies.

Costs

- Capital costs for capture, transport, and injection of CO_2.
- Parasitic energy—Additional fuel is burned (and additional GHGs created) to provide the power for capture, compression, dehydration, transport, and injection of the CO_2.
- Possible additional water requirements.
- Increased operating costs.
- Impact on global competitive standing if the U.S. cost structure is significantly higher than in countries without emission limits.
- The increased cost of energy impacts the overall cost of living for all.
- The higher cost structure may shorten ultimate field life, and EUR of hydrocarbons.

Feasibility Issues

- Capital requirements.
- Logistics, space, water availability for new facilities.
- State and federal (especially EPA) regulatory environments for CCSR projects are not yet established. Legal requirements and liability issues are unknown for long-term CO_2 storage. These have major impacts on cost and timing.
- Post-combustion CO_2 removal is not an established commercial process. Large-scale tests are currently ongoing through DOE.
- Other—See the Key Uncertainties section, above.

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[11] Advanced Resources International. April 2005. *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska.* Prepared for the U.S. Department of Energy, Office of Fossil Energy–Office of Oil and Natural Gas. Available at: http://www.adv-res.com/unconventional-gas-literature.asp.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

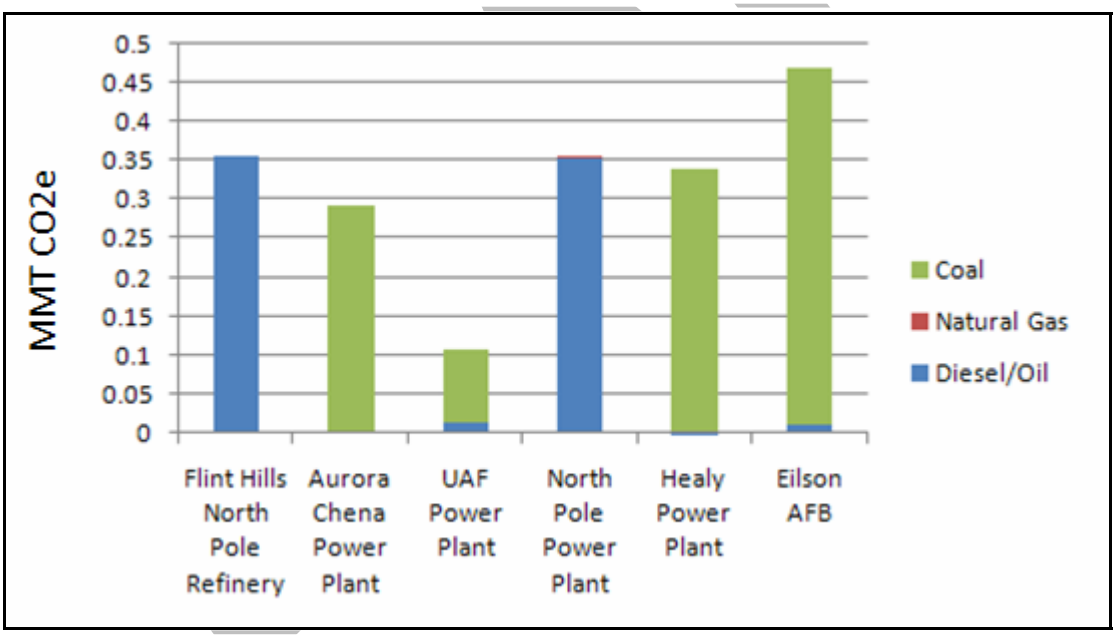
OG-8. Carbon Capture (From Exhaust Gas) and Geologic Sequestration Away From Known Geologic Traps

Policy Description

This policy relates to the technical and economic feasibility of CO_2 capture, transport, and geologic sequestration far from O&G infrastructure, in areas where a nearby storage reservoir is not proven. The capture and storage aspects, while similar in many aspects to those described in OG-7 for exhaust gas sources near existing Alaska O&G fields, differ in that there are no known reservoirs nearby. That means either that a long pipeline needs to be built to either the North Slope or Cook Inlet, or that an exploration program to prove up an appropriate storage reservoir needs to be executed.

Outside of the North Slope and Cook Inlet, the largest CO_2 sources are in interior Alaska, in and around the Fairbanks area. These sources encompass about 10% of Alaska's stationary sources of CO_2 (~2MMtCO_2e), with approximately 60% due to the burning of coal, and the rest related to the combustion of diesel fuel (Figure I-1).[12]

Figure I-1. 2002 CO_2e emissions from interior Alaska



CO_2e = of carbon dioxide equivalent; MMt = million metric tons.

Note: This option also deals with emissions outside the O&G sector.

[12] Alaska Department of Environmental Conservation. January 2008. "DRAFT—Summary Report of Improvements to the Alaska Greenhouse Gas Emission Inventory." (Includes Final Alaska GHG Inventory and Reference Case Projection.) Available at: http://www.climatechange.alaska.gov/docs/ghg_ei_rpt.pdf.

Policy Design

Goals:

- Initiate studies on the technical and economic aspects of implementation. The economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. The technical analysis should include the size and type of facilities modifications and the choice of appropriate combustion CO_2 capture technology, and should either search for nearby sequestration opportunities or plan for a pipeline to known reservoirs with proven seals.
- Because of the additional use of fuel required for capture, transport, and injection of CO_2, and the resultant GHG emissions related to its combustion, study the implementation of the policy in conjunction with, or after, all possible energy efficiencies that can be obtained. The less fuel burned overall, the less GHGs emitted.
- Encourage investment through incentives:
  - Financial:
    - Provide federal and state carbon credits.
    - Provide tax incentives for capital investment requirements.
  - Regulatory:
    - Simplify/streamline the regulatory environment.
    - Avoid overlapping state and federal regulations of GHG emissions and underground injections. Recommend coordinating with and participating in the development of federal regulations to ensure the regulations fit Alaska's conditions and to allow early implementation.
    - Study state permitting/regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to cover additional workloads.

Timing: Early studies will facilitate the earliest possible implementation.

Implementation of CCSR in interior Alaska will require significantly more time and money than in and around established O&G fields, as either (1) an exploration program to establish the presence of a suitable geologic sequestration site in interior Alaska (most likely the Nenana Basin) would need to be performed, or (2) a long pipeline (to either Cook Inlet or the North Slope) would need to be built.

A commercial geologic sequestration project could not be permitted at this time, as the regulatory environment is still being developed.

Parties Involved:

- Consultants for conducting the study on technical and economic feasibility.
- Power-generating companies.
- Local landowners.
- State of Alaska (DNR, AOGCC, DEC, DOR, etc.) and other regulatory agencies (EPA, Federal Energy Regulatory Commission, RCA, etc.)

Other:

Geographic Focus: Fairbanks area in interior Alaska. Approximately 2 $MMtCO_2e$ are generated within approximately 100 miles of Fairbanks, but no proven geologic sinks are in that area. There is potential for a future coal gasification plant in Fairbanks, which would generate additional GHG emissions.

Research Needs:

Economic Research

- Model and recommend the most effective incentives. Model the effects on the economy and jobs with various scenarios. Involve Alaska DOR in this analysis.
- Research the long-term value of carbon, which could have a huge impact on the economics of these projects.

Technical Research

- Engage with and observe the DOE Phase III pilot project testing of various capture and sequestration technologies.
- Conduct a technical feasibility study of the different post-combustion CO_2 capture technologies.

Incentives: Financial, Permitting, Etc.

- Provide appropriate tax credits for investment in CCSR.
- Streamline the permitting process, which is critical for project turnaround.

Implementation Mechanisms

This policy using nearby sequestration cannot currently be implemented commercially under the current regulatory environment, though building a long pipeline is at least an understood, if time consuming, procedure. To minimize the time required for implementation, regulatory and capital investment concerns should be addressed immediately. A critical path is for the state to design incentives appropriate for capital investments, for operators to begin design of facilities and permitting needed to strip the CO_2 from the individual fuel exhaust streams, and to start either an exploration program to find a reservoir suitable for sequestration nearby, or the planning for a long pipeline. Capture technology studies should include space, power, and water requirements for each retrofitted facility. Finally, the state and operators should immediately start working on the complicated regulatory and permitting issues. Final economics will depend on the value of carbon. Financing CCSR projects will be sensitive to that value, and will be dependent on future cap-and-trade or carbon tax legislation.

Policies Needed

- State/local government permitting, as necessary, addressing issues beyond EPA UIC CO_2 sequestration rules.
    - Ownership issues—surface rights versus mineral rights versus pore space rights.
    - Long-term liability at sequestration sites.

- Land-use regulations and requirements.
- Potential federal cap-and-trade legislation and ultimate EPA air quality regulations.

Related Policies/Programs in Place

Existing Policies

- Some tax incentives for CCSR exist in current federal legislation (carbon mitigation incentives included in the Emergency Economic Stabilization Act of 2008).

Policies Under Development

- EPA regulations regarding CO_2 underground sequestration.[13] The state may seek primacy for this activity upon final EPA rulemaking.
- EPA regulations, if any, and other federal laws regarding air quality, carbon tax or cap and trade, etc.

Types(s) of GHG Reductions

CO_2 removed from fuel gas post-combustion exhaust streams in interior Alaska, related to the burning of coal and diesel fuels, and injected into a nearby underground reservoir (yet to be discovered) or into established O&G fields in Cook Inlet or the North Slope.

Estimated GHG Reductions and Net Costs or Cost Savings

Potential emission savings through CO_2 capture from exhaust gases from coal and diesel burning sources in interior Alaska could be on the order of 2 $MMtCO_2$/yr.

A gross economics estimate, modeled using best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $994/t. The estimate for expected yearly reduction in CO_2 emissions is 0.7 $MMtCO_2e$, and the estimate for total reduced emissions through 2025 is 8.0 $MMtCO_2e$. Due to the size and complexity of this kind of project, there is significant uncertainty in this number.

Due to the very large investments required, as well as timing and logistical constraints, large amounts of capital expenditures occur toward the end of the measurement period (2025). To avoid presenting a misleading number, capital and operating costs were amortized to 2035 when calculating $/$tCO_2$ of mitigated emissions. Large capital expenditures will be required by facility owners, as significant retrofitting of existing power-generating facilities will be needed. Depending on the type of capture technology chosen, additional water resources may also be required. For purposes of quantification, a 350-mile pipeline was assumed. No value was given to EOR at this time, as it is presumed that local sources would provide sufficient supply. In addition, significant amounts of fuel will be burned to power carbon capture, compression, transport, injection, and long-term monitoring.

[13] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. AOGCC is participating through the Interstate Oil and Gas Compact Commission and the Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

Data Sources: IPCC, DEC, AOGCC, O&G TWG members, API, *Oil and Gas Journal*, DOE, Center for Climate Strategies.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The capital and operating costs were amortized to 2035.
- A 350-mile pipeline is needed to transport CO_2 to a known reservoir capable of long-term CO_2 sequestration.
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector working groups for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Key uncertainties are investment, capital cost, identification of a suitable reservoir for sequestration, and regulatory environment.

- Maturity of capture technology for coal and diesel combustion sources.
- Costs for capture, transport, and sequestration.
- Costs for geological and geophysical studies for site selection.
- Potential for CO_2 leakage.

Specific studies should address:

- Pros and cons of various capture technologies for coal or diesel power sites.
- Identification of basins with geologic sequestration potential.

- Identification and costs of geological and geophysical analysis required to provide confidence that the chosen formation will provide long-term geologic sequestration of injected CO_2 (e.g., test wells, down-hole well testing, maintenance and repairs, reservoir analysis, and simulation studies).
- Facilities requirements and costs (including additional power, space, and water).
- Logistics and costs for CO_2 pipelines, assuming a nearby sink can be found.
- Logistics and costs for CO_2 pipelines, assuming a long transport is required.
- Value from possible tax or carbon credits.
- Estimates of CO_2 emissions that could be avoided (including additional emissions from capture, transport, and injection operations).
- Logistical issues related to construction and operations in an extreme temperature environment.
- Risk assessment for long-term storage.
- Regulatory requirements (e.g., EPA UIC program, other state and federal requirements). A significant commitment from regulators will be needed to overcome existing hurdles in permitting and in the regulatory environment.
- Long-term monitoring needs (pre-, during, and post-injection).
- Analysis of costs and benefits of different mechanisms of carbon capture, from produced gas, and of removing carbon pre- and post-combustion. Options should be compared on a tCO_2-avoided basis (tCO_2 captured – tons CO_2 generated by capture, transport, and storage processes).
- Identification and cost estimate of additional infrastructure that would be required for transport and injection of CO_2 to injection sites.
- Identification and cost estimate of new or upgraded well construction if required for injection of potentially corrosive (if mixed with water) CO_2. Studies are needed to determine how well materials hold up to long-term exposure to various concentrations of CO_2.

Additional Benefits and Costs

The 2002 estimate of CO_2 emissions related to power generation in the Fairbanks area is 2 $MMtCO_2e$, about 10% of all the stationary GHG emissions in Alaska. Technically, a significant portion could be captured and injected if the appropriate capture technology could be built and a suitable storage site is found.

Benefits

- Incentive-driven potential to replace aging facilities if synergistic with capture and sequestration.
- Employment opportunities.

Costs

- Parasitic energy demand 20%–50% extra power requirements (burning more fuel, creating more GHGs), possible additional water requirements.
- The increased cost of energy impacts the overall cost of living for all.
- Increased operating costs.

Feasibility Issues

Reservoir selection will be a challenge in interior Alaska, as currently there are no identified sequestration sites. Geologically, Fairbanks is underlain by metamorphic rocks that are highly sheared and faulted and would have very limited, if any, CO_2 trapping capacity. The nearest coal-bearing sedimentary rock is in the Nenana Basin to the southwest, which is likewise highly deformed. Still unknown is the potential in the Nenana Basin for saline reservoir storage, though an Exploration License is currently active in that area. An O&G exploration well (currently being planned) could add much-needed information to answer whether there is prospective CO_2 geologic sequestration potential in a saline reservoir. To confirm sequestration potential, additional wells, seismic data acquisition, and computer modeling would likely be required before proof of ability to sequester CO_2 long term would be established. With current information, however, the ability of a rock to sequester CO_2 for any length of time is completely unknown.

Possible long-term sequestration potential exists in unminable coal seams known to exist in interior Alaska, but this technology has significant obstacles, and long-term injection into coal seams has not yet proven feasible, especially in areas where permafrost can be expected.

Finally, risk assessment and a long-term monitoring program will be required for all sequestration projects. EPA is currently working on regulations that will be applied to sequestration projects, but long-term (time frame still to be defined) post-injection monitoring will certainly be an expectation for any sequestration site.

Other feasibility issues include:

- Costs—Can capital be raised?
- Available technology, technology maturity.
- Legal issues—Will long-term injection be approved?
- Liability—Who is responsible long term?
- Ownership of pore space.
- Conflicting regulatory requirements.
- Time frame—How long to permit? How long to build?
- Logistics—space for new facilities and availability of new required equipment.
- Public acceptance of long-term storage
- Availability of resources (water, power).
- Public acceptance—"Not in my back yard" (NIMBY) concerns.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

Appendix J
Transportation and Land Use
Policy Recommendations

Summary List of Alaska Climate Change Mitigation Policy Recommendations

Policy No.	Policy Recommendation		GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million 2005$)	Cost-Effective-ness ($/$tCO_2e$)	Level of Support
			2015	2020	2025	Total 2010–2025			
TLU-1	Transit, Ridesharing, and Commuter Choice Programs		0.002	0.003	0.005	0.046	$29.9	$651	Unanimous
TLU-2	Heavy-Duty Vehicle Idling Regulations and/or Alternatives		0.004	0.009	0.009	0.095	$24.3	$255	Unanimous
TLU-3	Transportation System Management		0.006	0.006	0.006	0.092	–$9.7	–$105	Unanimous
TLU-4	Promote Efficient Development Patterns (Smart Growth)		0.019	0.043	0.066	0.501	Net Savings	NQ	Unanimous
TLU-5	Promotion of Alternative-Fuel Vehicles		0.026–0.084	0.054–0.173	0.09–0.288	0.669–2.139	$207.3–$494.8	$135–$740	Unanimous
TLU-6	VMT and GHG Reduction Goals in Planning		0.019	0.043	0.066	0.501	NQ	NQ	Unanimous
TLU-7	On-Road Heavy-Duty Vehicle Efficiency Improvements	a. SmartWay®	0.050	0.075	0.084	0.930	–$52.3	–$56	Unanimous
		b. Phase Out	0.025	0.012	0.000	0.198	$20.9	$106	
		c. Public Fleets	0.016	0.033	0.037	0.364	NQ	NQ	
TLU-8	Marine Vessel Efficiency Improvements		0.012	0.022	0.032	0.269	$20.4	$76	Unanimous
TLU-9	Aviation Emission Reductions		NQ	NQ	NQ	NQ	NQ	NQ	Unanimous
TLU-10	Alternative Fuels Research and Development		NQ	NQ	NQ	NQ	NQ	NQ	Unanimous
	Sector Total Before Adjusting for Overlaps		**0.210**	**0.363**	**0.500**	**4.444**	**$364.3**	**$82**	
	Sector Total After Adjusting for Overlaps		**0.187**	**0.313**	**0.423**	**3.850**	**$364.3***	**$95***	
	Reductions From Recent Actions		**0.397**	**0.531**	**0.732**	**5.995**	**NQ**	**NQ**	
	Sector Total Plus Recent Actions		**0.412**	**0.844**	**1.155**	**9.845**	**NQ**	**NQ**	

*Does not include any cost for policies TLU-4, TLU-6, or TLU-7c, but does include emission reductions for those policies.

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent; NQ = not quantified; VMT = vehicle miles traveled.

Note: Negative numbers indicate cost savings.

TLU-1. Transit, Ridesharing, and Commuter Choice Programs

Policy Description

Under this policy, the state would provide the leadership and resources necessary to help expand Alaska's public transit and ridesharing system. To alter Alaskan driving habits to reduce greenhouse gas (GHG) emissions, issues of convenience, choice, and finance must be major elements in expanded transit and ridesharing operations. Public education will also be paramount to success.

To reduce GHG emissions though expanding transit opportunities, commuters need to be provided with progressive incentives to change their behavior. Intense, long-term education must be undertaken to demonstrate the financial savings for transit users. Current successful van routes from Wasilla into Anchorage appear to offer cost savings to the users. The overall system connections, from parking lots to rail to bus routes, must meet citizen demands to get from home to workplace and lead to a public awareness of system functionality. Piecemeal programs will fade away with the lack of public buy-in.

The majority of GHG reduction with increased transit and ridesharing services is expected to be achieved in the state's larger population areas.

If funding is not allocated to initiate the larger programs, then beginning with individual large employers incorporating financial incentives may be the best method to achieve success.

Policy Design

This policy would:

- Develop park-and-ride systems that are coupled to increased urban transit schedules. Estimates of new infrastructure will be needed in cold areas to keep car engines heated.
- Develop outlying collector routes with buses or vans to high-employment destinations—e.g., university campuses, oil industry offices, and state offices. A daytime shuttle or van offer to provide for personal lunchtime trips has been demonstrated in the private workplace.
- Provide funding support to expand the current transit systems' operations to increase the frequency of in-town schedules.
- Develop rail tie-in along existing track. Diesel multiple-unit cars from Wasilla to Anchorage and North Pole–University of Alaska (UA) Fairbanks campus through Fairbanks would be leased on an initial winter basis. Funding would be provided to invest in these cars and a program operator, a possible statewide or regional transit authority.
- The Alaska Department of Transportation and Public Facilities (ADOT&PF) will help achieve an expansion of transit services in Alaskan communities, including coordinated transit solutions, and will seek additional funds to support this expansion.

Goals:

- Double transit ridership in Alaska by 2025, compared to 2007 levels.
- Double vanpooling in Alaska by 2025, compared to 2007 levels.
- Increase the carpool mode share in Alaska by 2025.
- Support the development of a Regional Transportation Authority in Anchorage and Fairbanks to integrate all alternatives into one coordinated regional system. This system would eventually include rail, bus transit, paratransit, and ferries, where appropriate.

Timing: See above.

Parties Involved: Local transit authorities, Alaska Railroad, local and state governments, ADOT&PF.

Other: None.

Implementation Mechanisms

Alaska should develop legislation that provides transit funding that augments current Future Teachers of Alaska grants and/or should pass through funds in combination with local government operational funding. A state funding source could be an incentive for small local governments to consider implementing limited transit operations in central core areas.

To the extent that commuter van ridesharing is operated primarily by rider subscription, this approach may offer a fractional reduction in GHG emissions in less densely populated locales associated with urban work environments.

Related Policies/Programs in Place

Transit in Anchorage

Since 2002, People Mover[1] ridership in Anchorage has exceeded estimations. Service enhancements through route restructuring and increases in operations, combined with high fuel prices, have attracted more commuters, resulting in 2008 ridership being the highest in People Mover's history. Future plans include improving service frequency to a bus every half hour from 6 a.m. to 6 p.m., as well as increased peak-hour frequency on seven routes in corridors that have the highest ridership.

While the trend in Anchorage is matching the success of transit systems in the lower 48 states, Anchorage riders are more responsive to service increases. The industry standard for new service is that a 10% increase in service will result in a 7% increase in riders. Changes made since 2002 have increased service 18%, with a corresponding 28% increase in riders, indicating a strong latent demand for public transportation.

[1] See: http://www.muni.org/transit1/index.cfm.

Anchorage's Long Range Transportation Plan[2] addresses high-frequency, high-performance express bus service on the Glenn Highway corridor to pick up 5%–7% of the peak-period commuters.

Currently, the transit fixed-route fleet has 55 buses. People Mover's long-range goals double the size of the fleet. In the short term, approximately $7 million is needed to replace the aging fleet, and another 20–25 buses are needed to meet the goals of the increased frequency on key corridors. The increased transit availability and ridership provide a direct benefit to reducing GHG and managing congestion by reducing the number of overall vehicles on the road.

Transit and Intelligent Transportation Systems in Anchorage

Anchorage's People Mover system has implemented a number of intelligent transportation systems (ITS) in the past 5 years. Scheduling and dispatching systems, bus schedule information via a 24-hour telephone system, and most significantly, TransitRealTime provide the actual time a bus will arrive at a stop via the Internet and signs at major bus stops. This technology is being implemented to enhance the reliability, predictability, and attractiveness of transit services for existing and potential bus riders.

Ridesharing in Anchorage

Anchorage's Ridesharing program provides carpool- and vanpool-matching services for residents in Anchorage and metropolitan areas. Ridesharing's primary objective is to encourage and support alternatives to single-occupant-vehicle (SOV) commuters by coordinating with employers, disseminating information, sponsoring vanpool services, and providing rideshare-matching services.

The current most significant need in addressing ridesharing is the commuting traffic between Mat-Su and Anchorage. Currently, 700 residents travel in 49 vanpools between Mat-Su and Anchorage and in 3 vanpools between Anchorage and Girdwood. Park-and-ride lots are full, and more than 700 residents are on the waiting list to enroll in the vanpool program. The lack of vans used in the rideshare program is the largest obstacle. Anchorage and Mat-Su are working to solve this need, including seeking financial support from the state legislature.

Statewide Actions

The September 2008 Governor's Coordinated Transportation Task Force approval of Administrative Order #243 is an important step in advocacy for transit improvements.[3]

Types(s) of GHG Reductions

Primarily carbon dioxide (CO_2). Small reductions in nitrous oxide (N_2O) and methane (CH_4).

[2] See: http://www.muni.org/transplan/.

[3] See: http://gov.state.ak.us/admin-orders/243.html.

Estimated GHG Reductions and Net Costs or Cost Savings

Table J-1. Estimated GHG reductions and costs of or cost savings from TLU-1

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
TLU-1	Transit, Ridesharing, and Commuter Choice Programs	0.002	0.003	0.005	0.046	$29.9	$651

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources:

- *Transit and Vanpool Ridership and Passenger Miles Traveled in Anchorage and Fairbanks:* National Transit Database, 2007. Available at: http://www.ntdprogram.gov/ntdprogram/data.htm.
- *Transit and Vanpool Fuel Use:* National Transit Database, 2007. Available at: http://www.ntdprogram.gov/ntdprogram/data.htm.
- *Transit Operating Costs:* National Transit Database, 2007. Available at: http://www.ntdprogram.gov/ntdprogram/data.htm.
- *Mode Shift Factor for Transit Systems in Small Urban Areas:* American Public Transportation Association (APTA), "Recommended Practice for Quantifying Greenhouse Gas Emissions from Transit (Draft)," August 2008.
- *Fuel Prices*: U.S. Department of Energy (DOE) Information Administration (EIA), *Annual Energy Outlook 2009* (AEO2009). Available at: http://www.eia.doe.gov/oiaf/aeo/.

Quantification Methods:

- Passenger miles traveled (PMT) in transit and vanpool vehicles was assumed to double, along with ridership, by 2025.
- PMT was multiplied by the mode shift factor from APTA guidance to determine the number of vehicle miles traveled (VMT) displaced by bus, rail, and demand-response ridership. For vanpool ridership, we consider PMT to replace VMT on a 1:1 basis. This assumption is consistent with the methodology that the City of Anchorage uses to calculate the VMT displacement of its vanpool program. Vanpools target the commuter population, whose main alternative mode tends to be SOV driving—i.e., driving alone.
- The increase in VMT displaced in each year was multiplied by standard emission factors to arrive at GHG reductions.
- An increase in buses and vans in service was calculated assuming that average passenger-load factors would increase by 50% by 2025. This is equivalent to a 2.7% annual improvement in load factors. We assume that the average route miles traveled per vehicle will not change. Therefore, 33% more vehicles will be required to double transit ridership.

- We calculated transit vehicle emissions using data on diesel and gasoline consumption reported by transit agencies to the National Transit Database. We assume that by 2025, 25% of the bus fleet will be diesel-electric hybrid vehicles, with 30% better fuel economy than conventional diesel buses (based on the experience of King County, Washington [WA] Metro Transit). We assume that other new vehicles purchased will use the same fuel types and achieve the same mileage as current vehicles.
- For policy cost, we calculated the following components:
  - *Capital Cost Increase:* We calculated the cost of new vehicles based on current vehicle prices. An average 35-foot bus costs about $350,000 (Luke Hopkins, Fairbanks North Star Borough). An average van costs about $40,000 (Paula Kangis, City of Anchorage). We assume that other capital costs, including facilities, stations, systems, guideways, and replacement costs for existing vehicles, are unaffected by this policy.
  - *Operating Cost Increase:* We assume that operating costs for each mode will increase by 33% to 2020, proportional to the increase in transit service.
  - *User Cost Savings:* Users of transit save money on vehicle expenses for every mile they do not drive their cars. Users save on gas, depreciation of vehicle value, and maintenance expenses. Fuel costs are calculated from the *Annual Energy Outlook 2009*.[4] Depreciation and maintenance costs are drawn from http://www.commutesolutions.org.

Key Assumptions: Ridership increase begins in 2010 and rises steadily to 2025. Vehicle passenger loads increase by 50% to 2025.

Key Uncertainties

The appropriate mode shift factor for the proposed transit and vanpool expansions may be higher than estimated in APTA guidance. The guidance estimates that only one-third of transit trips would have been made in a unique vehicle trip if no transit were available. Commute trips on transit are more likely to replace an SOV trip than non-commute trips.

Additional Benefits and Costs

Transit expansion in urban areas can facilitate more compact development patterns and help reduce roadway congestion. Both of these benefits produce additional reductions in GHG emissions.

Feasibility Issues

None identified.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

[4] See: http://www.eia.doe.gov/oiaf/aeo/.

Barriers to Consensus

None.

TLU-2. Heavy-Duty Vehicle Idling Regulations and/or Alternatives

Policy Description

Alaska will focus on reducing idling times for diesel and gasoline heavy-duty vehicles, buses, and other vehicles through a combination of statewide anti-idling regulations and by promoting and expanding the use of technologies that reduce heavy-duty vehicle idling. These technologies include vehicle equipment modifications, such as auxiliary power units (APUs), direct-fired heaters, and automatic engine shutdown/startup system controls. Other effective means of idle reduction come through the use of ITS technology, such as electronic weigh station bypass systems. These systems allow safe and legal vehicles to pass a weigh station, at highway speed, without stopping for inspection. This bypass eliminates the need for a heavy-duty vehicle to idle its engine for a period from as few as 10 minutes to as many as 60–90 minutes.

Recognizing Alaska's severe arctic and subarctic winter conditions, accommodations must be made for below-zero winter temperatures. APUs, for example, can ameliorate the effects of idling, but idling cannot be entirely prohibited, such as when extreme weather conditions warrant.

Alaska will encourage the adoption of statewide statutes or regulations and local ordinances to promote idle reduction for all vehicles. All vehicle owners, public and private, will be subject to these regulations and to the penalties prescribed in the statute or regulations.

Policy Design

Alaska will develop and implement a statewide regulation banning extended idling by heavy-duty vehicles given accommodations for below-zero arctic and subarctic winter conditions. As with all regulations, they must be enforceable, with a reasonable expectation of penalty for noncompliance. Alaska will also provide local governmental units with model language for adoption as local anti-idling ordinances.

Alaska will encourage and promote reduced idling through programs aimed at increasing voluntary adoption of idle-reduction technologies. Components of such an effort should include collaborative outreach and education timed with the implementation and enforcement of a statewide anti-idling regulation, and seeking funding for pilot projects and demonstrations as well as funds available though any federal or other programs to evaluate the effectiveness of various idle-reduction technologies.

Alaska may also provide additional incentives to fleet or individual heavy truck owners to purchase and install idle-reduction technologies on their vehicles. These incentives may come in the form of full grants, matching grants, tax credits, and low- or no-interest loans.

Alaska may also provide incentives to assist the private fleets to convert some of their vehicles to hybrid operation. Such engine technology is or soon will become available in the marketplace.

Goals: Accomplishment of the following goals should result in significant reductions in GHG emissions and should also show significant fuel savings.

- ADOT&PF will lead by example with the installation of idle-reduction technology and/or idle-reduction policies/procedures for its fleet of heavy-duty vehicles. This goal will be phased to accomplish installation of these technologies or adoption of policies; 20% will be so equipped by 2012, with the remaining 80% equipped by 2020, with exception for vehicles used only seasonally.
- Local governments and school districts will install idle reduction for their fleets at a rate similar to or slightly lagging that of ADOT&PF.
- Commercial and private fleets will be encouraged through regulation and through incentives to meet the same timetables.

Timing:

- The target date for the development and implementation of anti-idling regulations for state and local governments is the end of 2011. Legislation can be introduced in the 2010 session of the Alaska Legislature to establish the statutory authority to require that regulations and local ordinances be adopted to implement these requirements.
- The target date for partial and full implementation of idle-reduction technologies by all parties is 20% by 2012 and the remaining 80% by 2020, with exception for vehicles used only seasonally.

Parties Involved: The Alaska Department Environmental Conservation (DEC) will be the lead agency to adopt and enforce the statute or regulations on both public and private vehicle owners. Other parties include ADOT&PF, the Alaska Departments of Commerce and Community Development and Revenue, local governments, school districts, commercial and private truck fleets, tour bus operators, trucking associations, unions, shippers, and metropolitan planning organizations (MPOs), including the Fairbanks Metropolitan Area Transportation Study (FMATS) and the Anchorage Metropolitan Area Transportation Solutions (AMATS).

Other: None.

Implementation Mechanisms

- Alaska DEC will adopt idling regulations for private and public agency vehicles by the end of 2011. Legislation can be introduced in the 2010 session of the Alaska Legislature to establish the statutory authority for these regulations. The regulation will include concise language so that the agency with enforcement responsibilities is clearly delineated and has full authority to enforce the ordinance. The language should also include any exemptions to the idling policy that can be easily observed. In developing the idling regulation, the U.S. Environmental Protection Agency's (EPA's) recent Model State Idling Law should be reviewed for potential language.
- Alaska DEC will develop a program to provide incentives for idle-reduction technologies by the end of 2010. Funding can come from both state and federal sources.

- For vehicles it owns, ADOT&PF will install idle-reduction technologies and/or promote idle reduction through internal policies and training.
- The state will also provide information and education to targeted audiences. Trucking companies should be encouraged to do their own supervision. Outreach materials should emphasize the fuel-saving benefits, reductions in toxic emissions, and reduced engine wear associated with reducing idling. The state should provide information to fleet carriers, shippers, retailers, bus companies, school districts, and others involved in the diesel fleet industry, indicating the economic and environmental benefits of applying idle-reduction technologies. The state should identify best practices within the industry and recognize companies with these best practices in place within Alaska, to encourage companies to select these carriers for their shipments.

Related Policies/Programs in Place

U.S. EPA-approved idle-reduction devices are excluded from the 12% federal excise tax under Section 206 of the Energy Improvement and Extension Act of 2008 (Public Law 110-343). EPA has published a complete list of idle-reduction devices that are eligible for the retail excise tax exemption. The types of devices include fuel-operated heaters, battery air conditioning systems, APUs/generator sets, thermal storage systems, and shore connection systems. The complete list of EPA-approved idle-reduction devices can be found at: www.epa.gov/smartway/transport/what-smartway/idling-reduction-fet.htm.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Table J-2. Estimated GHG reductions and costs of or cost savings from TLU-2

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/tCO_2e$)
		2015	2020	2025	Total 2010–2025		
TLU-2	Heavy-duty Vehicle Idling Regulations and/or Alternatives	0.004	0.009	0.009	0.095	$24.3	$255

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources:

- *Vehicle Populations for State and Local Government and Private and Commercial Vehicles:* Federal Highway Administration (FHWA), *Highway Statistics 2006* (Tables MV-7 and MV-9). Available at: http://www.fhwa.dot.gov/policy/ohim/hs06/index.htm.
- *Alaska Population Forecasts:* Alaska Department of Labor, *Alaska Economic Trends: Population Projections 2007 to 2030*, October 2007. Available at: http://labor.state.ak.us/trends/oct07.pdf.

- *Fuel Prices:* EIA, *Annual Energy Outlook 2009,* Early Release, Table 12. Available at: http://www.eia.doe.gov/oiaf/aeo/index.html.

Quantification Methods:

- *Highway Statistics 2006* provides limited data on heavy-duty truck populations in Alaska. Based on these data, we estimate the population of private- and state and local government-owned combination trucks (truck tractors) and buses in Alaska (2,584 buses and 4,323 truck tractors in 2007). Data from the state Department of Motor Vehicles (DMV) suggest there are private 9,994 trucks over 12,000 pounds (lbs) gross vehicle weight registered in the state (a portion of which is combination trucks). Thus, we assume 5,671 heavy-duty single-unit trucks (9,994 minus 4,323).
- The population of heavy-duty trucks in future years was estimated to increase proportionally to the population of the state until 2025.
- The number of hours of idling reduced was calculated from assumed total hours of idling, target penetration rates, and assumed policy effectiveness. Fuel savings and emission reductions were calculated based on hours of idling reduced.
- Cost was calculated based on the installation costs of anti-idling technologies and the fuel cost savings incurred by anti-idling measures. To estimate costs, we assumed the following:
  - Installation of PonyPack APUs on new combination trucks, at a cost of $10,000 each.
  - Fuel use in PonyPack is 0.2 gallons per hour (gal/hr), compared to the average rate of 0.75 gal/hr for the truck engine.
  - For other heavy-duty vehicle types (buses and single-unit trucks), no equipment installation is required. Idle reduction is achieved through training, education, and regulation.

Key Assumptions:

- Buses and heavy-duty trucks idle an average of 312 hours per year (hr/yr) each. (Assumption from the Puget Sound Clean Air Agency and the Washington State Department of Ecology. Consistent with estimates from the California Air Resources Board.)
- There is no substantial overnight idling of long-haul vehicles in Alaska.
- 25% of idling is discretionary idling that can be reduced by vehicles installing anti-idling technologies or complying with new regulations. Discretionary idling includes idling during vehicle loading and unloading, idling at rest stops, and extended idling at station stops (for transit vehicles). The remaining 75% of idling is non-discretionary, which includes vehicles stopped in traffic, operating power equipment, emergency situations, and when the engine is needed to keep the vehicle warm.
- 20% of vehicles will be compliant by 2012; 100% of vehicles will be compliant by 2020. Reductions begin in 2011.

Key Uncertainties

None identified.

Additional Benefits and Costs

Reducing idling by heavy-duty vehicles and locomotives would reduce particulate matter (PM) emissions. Many scientific studies have linked breathing PM to a series of significant health problems, including aggravated asthma, difficult breathing, chronic bronchitis, heart attacks, and premature death. Diesel PM is of specific concern, because it is likely to be carcinogenic to humans when inhaled.

Feasibility Issues

None identified.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

TLU-3. Transportation System Management

Policy Description

Alaska would seek to reduce GHG emissions from the transportation sector through improvements to transportation system management. These efforts would focus on the improvement, management, and operation of the transportation infrastructure, with a focus on the roads and highway systems.

Policy Design

- Roundabouts can reduce traffic queuing and delay, thus saving fuel and reducing GHG emissions; they also have safety benefits. ADOT&PF will encourage the installation of roundabouts.
- To improve fuel economy and reduce GHG emissions per mile traveled, the state will reduce maximum speed limits on state highways to 60 miles per hour (MPH), or lower where appropriate. Additional benefits are reduced traffic injuries and fatalities.
- ADOT&PF will continue its commitment to providing a multimodal transportation system by continuing to invest in transit, bike, and pedestrian facilities. ADOT&PF spends an average of roughly $5 million annually on these facilities and expects this level of commitment to continue or increase.
- All urban areas (i.e., >5,000 population) will continue to include consideration of bike and pedestrian facilities in their urban transportation plans.
- ADOT&PF, in partnership with urban communities, will work to improve traffic signal synchronization on all state-managed routes (mostly arterials) in urban areas (i.e., >5,000 population) by 2012. Signal synchronization reduces start/stop traffic on arterial routes, as the lights are timed to continuously move traffic forward at the target pace. This strategy also helps reduce traffic queuing, thus saving fuel and reducing GHG emissions.
- ADOT&PF will complete conversion of all traffic lights to light-emitting diode (LED) bulbs by 2010 and will work with cities to convert roadway luminary lighting under city jurisdiction. LED bulbs significantly conserve energy, and thereby indirectly reduce GHG emissions.
- All urban transportation plans will be updated by 2012, with an emphasis on operations and safety. The operations elements in urban transportation plans will improve traffic flow and reduce conflict points, and can result in turn lanes, reconfiguration of intersections, or access control. In metropolitan areas, the transportation plans will meet air quality conformity requirements for criteria pollutants.
- Congestion management plans for all high-traffic-volume construction projects will be considered by ADOT&PF. These plans implement strategies to keep traffic flowing through construction zones, thus reducing fuel use and GHG emissions.
- Access management will continue to be pursued consistent with Alaska statutes and ADOT&PF policies. Access management is intended to reduce the number of street and

- The state will install traffic management technologies and provide public information of travel conditions on high-volume commuter routes, especially those lacking practical bypasses. ADOT&PF, along with partner communities, will complete by 2010 a comprehensive ITS Plan for the Glenn Highway corridor between Anchorage and the Mat-Su valley.
- The state will improve the manner in which incidents and accidents on high-volume routes are processed, and will require drivers involved in crashes to pull away from travel lanes. Implementation will require educational signs, and possibly a statutory change requiring moving vehicles to the side of a road in non-injury accidents. The state will also accelerate accident-scene processing, following the Washington state model (faster accident scene cleanup, faster documentation of scene evidence, while not compromising investigation of facts); this may require some trial deployment and testing of the new approach in the courts.

Goals: See above.

Timing: See above.

Parties Involved: ADOT&PF, FMATS and AMATS, local governments.

Other: None.

Implementation Mechanisms

Roundabouts

ADOT&PF, FMATS, and AMATS should evaluate potential intersection locations for roundabout installation.

ADOT&PF will:

- Report on its roundabout evaluation criteria and list all locations evaluated annually for potential roundabout installation, to be no less than 5 intersections/locations annually.
- Encourage the installation of roundabouts when the installation is based on sound engineering principles.
- Work cooperatively with local governments seeking information on the principles of roundabout installation.
- Assist the cities and boroughs in their analysis of roundabout suitability for intersections under their jurisdiction.
- Consider roundabout treatment at planned right-angle intersections for new construction and upgrades and when completing routine safety reviews.

ADOT&PF has previously adopted roundabouts in the 2007 *Alaska Strategic Highway Safety Plan* as a preferred solution, where practicable, for safety reasons (see: http://dot.alaska.gov/stwdplng/shsp/index.shtml).

ITS Plan

Routes, such as the Glenn Highway between Anchorage and the Mat-Su Valley, experience considerable traffic during peak conditions. Due to a lack of alternative routes, such incidents as accidents and spilled loads can tie up traffic for hours. ADOT&PF, along with partner communities, will strive to complete by 2010 a comprehensive ITS Plan for the corridor that would:

- Evaluate and prioritize installation of speed and congestion sensors and Internet-accessible cameras.
- Use these technologies to monitor conditions, respond to incidents, and inform the public of incidents and congestion.
- Use all available means of communication, including radio, e-mail/text message, Variable Message Signs, Highway Advisory Radio, and Internet media.
- Deploy (perhaps on a trial basis) courtesy patrols that can respond to breakdowns, vehicles out of fuel, flat tires, and accident scenes.
- Capture better data on incidents so that progress can be evaluated (e.g., benefit-cost analyses).

Related Policies/Programs in Place

LED Lights

To improve the energy efficiency of traffic signal and roadway lighting, several efforts are underway in Anchorage. The Municipality has already installed LED lights in all of its traffic signals to reduce energy costs. It is estimated that the energy cost for traffic signals alone is reduced by about 30%. In addition, the Municipality is reviewing all outdoor lighting, which includes over 16,000 streetlights, as well as pedestrian lighting, parking garage lighting, and trail lighting. Streetlights currently utilize a 150 watt (W) - 400W high-pressure sodium (HPS) fixture, which operates approximately 4,400 hr/yr at an annual energy cost of $2.2 million. It is also possible to reduce the load or wattage of the streetlights and/or provide dimming devices for greater energy and cost savings.

As of December 2008, Anchorage has finalized design criteria for low-speed, residential street lighting, and is installing over 4,000 LED fixtures in neighborhoods throughout the city. The Municipality is undergoing testing of LED fixtures for higher-speed roadways and hopes to finalize criteria for this application in 2009.

The quality, amount, brightness, glare, and uniformity of lighting are all key elements in the effort for better and lower-cost lighting. In addition to cost and energy savings, lighting can provide a better color of light (white instead of orange or blue), enhanced safety through improved visibility, less light trespass into homes, and less light pollution into the night sky. The effort to minimize the operational maintenance cost is a significant benefit. The LED fixtures

being installed in Anchorage use 50% of the energy of HPS fixtures, and the lamps last roughly five to seven times as long.

Transit Improvements

The recently approved (September 2008) Governor's Coordinated Transportation Task Force (Administrative Order #243) is an important step in advocacy for transit improvements.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Table J-3. Partial quantification only based on reduced speed limits

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
TLU-3	Transportation System Management	0.006	0.006	0.006	0.092	–$9.7	–$105

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources:

- *Speed Limits, Average Vehicle Speeds, and Daily Traffic Counts on Alaska State Highways*: ADOT&PF.
- *VMT*: Alaska GHG Inventory and Projections (Appendix D of this report).
- *Annual VMT by Vehicle and Facility Type:* FHWA, *Highway Statistics 2006* (Table VM-1). Available at: http://www.fhwa.dot.gov/policy/ohim/hs06/.
- U.S. EPA, Office of Transportation and Air Quality, SmartWay Transport Partnership, *A Glance at Clean Freight Strategies: Reducing Highway Speed,* EPA420-F-04-007, February 2004. Available at: www.epa.gov/smartway/smartway_fleets_strategies.htm.
- Dierkers, Greg, et al., *CCAP Transportation Emissions Guidebook*, Guidebook Emissions Calculator, Center for Clean Air Policy. Available at: www.ccap.org/guidebook.
- *Fuel Prices*: EIA, *Annual Energy Outlook 2009,* Early Release, Table 12. Available at: http://www.eia.doe.gov/oiaf/aeo/index.html.

Quantification Methods:

- VMT for each future year for affected highways was calculated using data on VMT by vehicle and facility type from FHWA and projections of VMT for Alaska. VMT on routes currently posted at 65 MPH is assumed to increase proportionally with total statewide VMT.
- Improvements in fuel economy for affected vehicles were calculated based on the assumptions below.

- The cumulative reduction in CO_2 emissions from the improved fuel economy of targeted vehicles was calculated beginning in 2010.
- Cost savings were calculated based on forecast fuel prices and estimated fuel savings. Education and enforcement costs are calculated based on the assumptions below.

Key Assumptions:

- Reducing the speed limit from 65 to 60 MPH will cause 25% of vehicles to reduce their speed by 5 MPH.
- Each 1-MPH reduction of speed from 70 MPH to 55 MPH yields a fuel economy increase of 0.1 mile per gallon for heavy-duty diesel trucks (EPA).
- Each 1-MPH reduction of speed down to 55 MPH yields a 1% reduction in CO_2 emissions per mile (Dierkers et al.).
- Education and enforcement for reduced speed limits will require four new full-time employees at a cost of $100,000/yr each.
- Public education campaign (media ads and other communication techniques) will cost $100,000/yr. (Alaska currently spends about $30,000/yr on media ads discouraging speeding and aggressive driving.)

Key Uncertainties

Compliance with lower speed limits is uncertain, as noted below under Feasibility Issues.

Additional Benefits and Costs

- Strategies that reduce congestion can provide significant economic benefits to the state.
- Some strategies that improve highway system efficiency have safety benefits (reduce vehicle crashes).
- Strategies that reduce vehicle idling or stop-and-go traffic patterns will reduce emissions of criteria air pollutants (such as PM), resulting in public health benefits.

Feasibility Issues

Optimal traffic speeds from a safety standpoint are a function of the roadway and driver's perception of what is a safe speed. If the legal speed limit is lowered below what the majority of drivers perceive as a safe speed, the ability to enforce the new speed becomes difficult. This is because people respect laws they feel are reasonable, and tend to ignore laws that they believe are unreasonable.

Lowering speed limits can create a pattern of law breakers and law abiders on the same highway. As the difference in speeds of these two groups expands, the likelihood of accidents and aggressive driving is likely to increase. If this were to occur, the hidden cost of this strategy is much more than just signs, enforcement, and education. It may also be a higher accident rate as a direct result of the lower speed limit.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

TLU-4. Promote Efficient Development Patterns (Smart Growth)

Policy Description

GHG emission reduction through efficient, sustainable (i.e., smart growth) land development patterns will need to be incorporated with reduced VMT, transit improvements, and sustained implementation of multimodal links to facilitate biking, walking, and winter trail use in residential and urban areas.

Issues and items to be developed would include:

- State policy issues detailing funding parameters and funders' policies distributing state and federal dollars.
- Changes to state laws and regulations.
- Local development plans—e.g., *Anchorage 2020*,[5] Fairbanks North Star Borough Regional Comprehensive Plan.
- Local zoning code changes.
- Increased urban/residential density factors.
- Land "disposal" sales and auctions, including UA and the Alaska Mental Health Land Trust.
- Subdivision codes and standards to set aside people-friendly open spaces and greenbelt reserves.
- Tax credits/incentives to developers.
- Must be combined with infrastructure planning—roads and utilities.
- Public buy-in is necessary. There must be strong incentives to have people accept programs.

Policy Design

This policy will focus on promoting land-use changes that result in higher densities in developed, urban areas. It will also focus on incorporating retail zones and small limited commercial nodes in residential developments, with a goal of reducing driving needs by facilitating walking or bicycling, and also reducing the length of driving trips. Changes to residential development patterns, including new subdivisions around population centers, will require a full gambit of incentives to produce the desired change. Efforts to promote land-use changes should be coordinated with the Alaska Municipal League.

The Department of Education will require school boards in selecting new school sites to favor sites that can be reached by walking and biking for the majority of the population the school will serve. Travel of school children by parent-driven vehicles is widely practiced, and is considered a major component in traffic volumes due peak periods. The benefits of walking and biking to

[5] See: http://www.muni.org/Planning/prj_Anch2020.cfm.

schools include not only reduced vehicular fuel consumption and GHG emissions, but also a more physically fit youth population.

Goals: By 2020, increase the share of Alaska's annual new residential and commercial construction that occurs within the denser parts of urban areas (compared to a business-as-usual baseline) through redevelopment, infill, and mixed uses that take advantage of the existing public investment in infrastructure, public services, and facilities. Simulation studies performed in other metropolitan areas have shown that efficient development patterns can reduce VMT in the range of 3%–20% over a 20–30-year time horizon. Using the lower end of this range, the goal for Alaska should be to reduce urban area VMT by 3% by 2025.

Note that implementation of this strategy may be affected by new federal regulations on metropolitan transportation planning and GHG reduction.

Timing: See above.

Parties Involved: State and local governments, developers, transit agencies, Alaska Municipal League, ADOT&PF, MPOs.

Other: None.

Implementation Mechanisms

The state should:

- Require all new elementary schools to be located on sites with good pedestrian and bicycle access.
- Require that all state government work centers to be located in the central business district or other established core business areas of municipalities or, if this is not possible, in a suburban location with good pedestrian and bicycle access.
- Enable and encourage local governments to adopt financial incentives for infill or location-efficient development, such as fast-track permitting and reduction of building permit fees and system development or impact fees.
- Enable and encourage local governments to modify zoning codes to allow land-use mixing, which can reduce the length of driving trips and encourage walk trips. Also, encourage amendments to zoning codes to allow mother-in-law apartments in single-family residential zones.
- Establish financial incentives (density bonuses, property tax credits) for developers to construct more multifamily dwellings, including senior/retirement units for denser development in urban areas.
- Designate green spaces in urban areas, including street trees and landscaping, to create pedestrian-friendly streetscapes and improve the pedestrian environment.
- Establish incentives for alternative non-motorized travel to workplaces, such as tax-free transit passes.

- Enable and encourage local governments to develop building design guidelines or standards that incorporate energy efficiency, a smaller CO_2 footprint, and lower dwelling utility costs. Higher design standards offer higher quality to draw existing populations into denser urban centers.
- Modify state law to allow differential tax rates for energy efficiency and reduced GHG footprint.

Where regional or comprehensive land-use plans are in place, municipalities should develop maps that show land suitable for residential and light commercial development, focusing on infill and transit-oriented parcels that can reduce VMT.

Related Policies/Programs in Place

FMATS and AMATS are working with UA Fairbanks to improve its travel models to include GHG emissions. The enhanced models may improve the quantification of this policy in the future.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Table. J-4. Estimated GHG reductions and costs of or cost savings from TLU-4

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
TLU-4	Promote Efficient Development Patterns (Smart Growth)	0.019	0.043	0.066	0.501	Net Savings	NQ

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; NQ = not quantified; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

The GHG impacts of this policy are identical to policy TLU-6, which has a goal of reducing per-capita light-duty vehicle GHG emissions in urban areas 3% by 2025.

Data Sources:

An extensive body of research has demonstrated the ability of smart growth development policies to reduce VMT in urban areas. By creating denser, mixed-use developments served by transit, bicycle, and pedestrian infrastructure, smart growth policies reduce the distances that people need to travel to reach their destinations, and reduce the need to travel by car. A number of regional studies throughout the United States have estimated the specific benefits of smart growth to various urban regions. Ewing et al. estimate that compact development can reduce VMT per capita by 30% over the sprawling development patterns typical of the last few decades in the United States. (For more information, see Ewing et al., *Growing Cooler: The Evidence on*

Urban Development and Climate Change, Urban Land Institute, 2008. Available at: http://www.smartgrowthamerica.org/gcindex.html.)

For a summary of other relevant literature, see:

- U.S. EPA, *Our Built and Natural Environments: A Technical Review of the Interactions Between Land Use, Transportation, and Environmental Quality,* EPA 231-R-01-002, January 2001. Available at: http://www.epa.gov/dced/built.htm.
- FHWA, Toolbox for Regional Policy Analysis. Available at: http://www.fhwa.dot.gov/planning/toolbox/index.htm.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Achieving the target reduction in VMT depends on implementation of the policy initiatives at all levels of government. It is possible that required planning could be done in a way that does not change development patterns, and thus does not reduce VMT and emissions. That is, the policy language does not require these outcomes.

External forces can have a significant effect on VMT and land development patterns, which creates additional uncertainty regarding the impacts of this policy. For example, fuel prices affect vehicle use. A major increase in fuel prices would help to encourage use of alternative travel modes, and might increase the benefits of this policy. Conversely, a reduction in fuel prices would make it more difficult to reduce VMT through smart growth and multimodal transportation planning efforts. Land development patterns are strongly influenced by regional and state macroeconomic forces. The ability of governments to influence land-use patterns depends to some extent on developer demand.

Additional Benefits and Costs

Land-use policies, such as the densification of developed land, mixing of compatible land uses, and other urban design measures, have beneficial spin-offs for other strategies. Land-use-based policies further mode-switching policies because these policies help create an environment that is easier served by transit, biking, and walking.

Compact development patterns also reduce public expenditure on infrastructure and services. A variety of literature finds that integrated transportation and land-use planning produces net savings on the total costs of buildings + land + infrastructure + transportation. While some components may be higher, the preponderance of literature suggests net savings overall (see U.S. EPA, 2001, above). A National Academy of Sciences/Transportation Research Board review found substantial regional and state-level infrastructure cost savings from more compact development.[6] An analysis of the New Jersey State Plan found that municipalities, counties, and

[6] Robert Burchell et al., *The Costs of Sprawl—Revisited* (TCRP Report 39), Transportation Research Board, Washington, D.C., 1998. Available at: http://www.trb.org/news/blurb_detail.asp?ID=2578.

school districts would save an estimated $160 million from 2000 to 2020 by pursuing smart growth patterns.[7]

Feasibility Issues

Land-use changes will not have a large impact on transportation systems and GHG emissions over the short term. However, over longer time spans, land-use changes aimed at creating denser, mixed-use settlements may offer important opportunities to reduce vehicle use and GHG emissions.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

[7] Robert Burchell et al., *The Costs and Benefits of Alternative Growth Patterns: The Impact Assessment of the New Jersey State Plan*, Center for Urban Policy Research, Rutgers University, September 2000. Available at: http://www.state.nj.us/dca/divisions/osg/docs/iaexecsumm090100.pdf.

TLU-5. Promotion of Alternative-Fuel Vehicles

Policy Description

Alternative-fuel vehicles (AFVs) offer significant opportunities to reduce GHG emissions from the light-duty fleet. Alternative fuels include natural gas, propane, biodiesel, electricity, ethanol, hydrogen, and fuel cells. AFVs include hybrid vehicles that utilize more than one power source to move the vehicle. Because of Alaska's large deposits of natural gas, compressed natural gas (CNG) vehicles may be a particularly viable option for the state. However, questions remain about the feasibility and benefits of CNG vehicles in Alaska.

This mitigation policy consists of two parts. The first part is working toward the replacement of existing light-duty vehicle fleets with AFVs. The second part consists of better informing the public of the benefits of purchasing AFVs and providing incentives as well.

Public-sector agencies[8] and some private-sector firms own large numbers of vehicles. Converting these fleets to AFVs can result in large reductions of pollutants and GHGs.

The second component of this policy consists of providing information to consumers about the benefits of AFVs, such as fuel efficiency, cleaner air, cost savings, and technological benefits.

The policy would be implemented through a series of federal- and state-supported low-cost loans, grants, attractive financing of trade-in vehicles, tax incentives, and other incentives and subsidies to promote the use of AFVs.

Implementation of this policy would be supported by TLU-10: Alternative Fuels Research and Development.

Policy Design

Goals:

- Increase the use of light-duty AFVs by public-sector agencies and private-sector firms to 25% of on-road fuel consumption by 2020 and 35% by 2030.
- Increase the use of AFVs by consumers to 10% of on-road fuel consumption by 2020 and 25% by 2030.
- The AFV technologies chosen should produce a minimum 15% life-cycle reduction in GHG emissions per mile, compared to conventional fuels.

Timing: See above.

Parties Involved: *Parties affected*—government at all levels, other fleets; *implementers*—government, military.

[8] Public-sector agencies include federal, state, and local governments, school districts, and utilities.

Other: None.

Implementation Mechanisms

- State legislation should authorize financing (2% loans) for AFV purchases by 2012.
- State legislation should create a rebate program to encourage consumer purchases of AFVs.
- State legislation should create incentives for local governments to purchase AFVs or convert existing fleet vehicles to alternative fuels. Because local governments cannot benefit from tax incentives, one option is to create a state program that converts tax incentives into a rebate, allowing local governments to purchase AFVs at a lower price.
- The state should also encourage conversion of gasoline vehicles to CNG in appropriate situations. The U.S. Congress has encouraged conversion of cars to CNG, with tax credits of up to 50% of the auto conversion cost and the CNG home filling station cost. However, while CNG is a much cleaner fuel, the conversion can only be performed by manufacturers certified to perform aftermarket conversions on vehicles to operate on alternative fuels. There do not appear to be any certified manufacturers for conversion in Alaska. One challenge preventing more widespread conversion of standard engines to operate on alternative fuels is the high cost associated with becoming certified to perform the conversion; meeting the requirements imposed by EPA can cost up to $50,000.

Related Policies/Programs in Place

- Under the 2005 federal Energy Policy Act (EPAct), approximately 5% of gasoline sales will be replaced by ethanol nationally by 2012.
- FMATS and AMATS are working with UA Fairbanks to improve their travel models to include GHG emissions. The enhanced models may improve the quantification of the costs and benefits of this policy in the future.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Table J-5. Estimated GHG reductions and costs of or cost savings from TLU-5

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
TLU-5	Promotion of Alternative Fuel Vehicles	0.026–0.084	0.054–0.173	0.09–0.288	0.669–2.139	$207.3–$494.8	$135–$740

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources:

- *GHG Reduction Factors from Alternative Fuels*: The GREET (Greenhouse gases, Regulated Emissions and Energy use in Transportation) model v1.8. Available at: http://www.transportation.anl.gov/modeling_simulation/GREET/.
- *Electricity Generation Mix in Alaska:* from EPA's eGRID (Emissions & Generation Resource Integrated Database) 2007. Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.
- *VMT Forecasts*: Alaska GHG Inventory and Forecast (Appendix D of this report).
- *Vehicle Fleet Data:* FHWA, *Highway Statistics 2006* (Table VM-1). Available at: http://www.fhwa.dot.gov/policy/ohim/hs06/index.htm.
- *Fuel Price Forecasts:* EIA, *Annual Energy Outlook 2009*, Early Release, Tables 12 and 13. Available at: http://www.eia.doe.gov/oiaf/aeo/index.html.
- *Current Year Fuel Prices by State:* EIA, State Energy Data System, 2008, Tables S5a and S2a. Available at: http://www.eia.doe.gov/emeu/states/_seds_updates.html.

Quantification Methods:

Three possible scenarios were evaluated for compliance with the AFV goals:

- 100% of AFV run on CNG for 100% of mileage.
- 100% of AFV are electric vehicles.
- 100% of AFV are plug-in hybrid electric vehicles (PHEVs).

Table J-6 shows life-cycle (well-to-wheels) GHG emissions per mile for automobiles, calculated using GREET v1.8. These figures take into account Alaska's electricity generation mix and proximity to reserves of petroleum and natural gas.

Table J-6. Life-cycle (well-to-wheels) GHG emissions per mile for automobiles

Energy Source	GHG per Mile (gCO_2e)	Reduction From Gasoline
Gasoline	482	
CNG	410	–15.1%
Electric	250	–48.2%
PHEV	315	–34.6%

CNG = compressed natural gas; GHG = greenhouse gas; gCO_2e = grams of carbon dioxide equivalent; PHEV = plug-in hybrid electric vehicle.

These figures assume average driving cycles for light-duty vehicles driven in the United States. Typical driving cycles in Alaska may be different from those in other parts of the country, given the limited urban development and longer distances between settlements in the state. These potential differences may affect the relative reductions in GHG emissions achievable using the various alternative-fuel propulsion technologies.

The following proportions were assumed for VMT in light-duty vehicles. These assumptions are based on available data on vehicle populations from *Highway Statistics 2006*:

- Public vehicles: 1%.
- Commercial vehicles: 20%.
- Private vehicles: 79%.

Penetration rates are assumed to increase smoothly starting in 2011 to reach the stated goals. For each year, we calculate VMT affected by the goal. Reduction percentages from GREET are applied to calculate total GHG reductions. Results for each scenario are presented in Table J-7.

Table J-7. Life-cycle (well-to-wheels) GHG emissions per mile for automobiles

AFV Scenario	Reductions ($MMtCO_2e$)		
	2012	2012	Cumulative Reductions (2008–2025)
CNG	0.009	0.009	0.611
Electric	0.029	0.029	1.954
PHEV	0.021	0.021	1.403

AFV = alternative-fuel vehicle; CNG = compressed natural gas; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; PHEV = plug-in hybrid electric vehicle.

We drew information on the cost of alternative vehicle technologies from studies comparing each of the three technologies to conventional vehicles:

- Electric Power Research Institute (EPRI), *Comparing the Benefits and Impacts of Hybrid Electric Vehicle Options for Compact Sedan and Sport Utility Vehicles*, Final Report, July 2002. Available at: http://mydocs.epri.com/docs/public/000000000001006892.pdf.
- EPRI, *Advanced Batteries for Electric-Drive Vehicles: A Technology and Cost-Effectiveness Assessment for Battery Electric Vehicles, Power Assist Hybrid Electric Vehicles, and Plug-in Hybrid Electric Vehicles*, Final Report, May 2004. Available at: http://mydocs.epri.com/docs/public/000000000001009299.pdf.
- Yocobucci, Brent, *Natural Gas Passenger Vehicles: Availability, Cost, and Performance*, 2008. Available at: http://opencrs.com/document/RS22971.

Each of the studies estimates the difference in cost between a conventional vehicle and the alternative vehicle type in three categories: vehicle purchase cost, cost of fuel, and vehicle maintenance cost. (The Yocobucci study did not provide any difference in maintenance costs for CNG vehicles; therefore, we assume that maintenance costs for CNG vehicles are comparable to those for conventional vehicles. Anecdotal evidence suggests that CNG vehicles are on average cheaper for owners to maintain than conventional vehicles; however, repair shops may need to be retrofitted in order to service CNG vehicles.) Using these findings, we calculate the costs to increase the share of each AFV to the target percentage by 2025. These costs would typically be borne by the owners of the AFVs, unless the state subsidizes any portion of the vehicle purchase or operating costs.

For CNG vehicles, an additional cost for refueling equipment was included. There is currently very little infrastructure for CNG refueling in Alaska. The Yocobucci study assumed that CNG vehicle owners would need to purchase and install home refueling equipment, at a cost of approximately $3,900 each. If CNG becomes widely used as a fuel for passenger vehicles in Alaska, we expect that centralized infrastructure will be provided, perhaps at a lower cost. Still, infrastructure costs for CNG will almost certainly be higher than those for PHEV or electric vehicles. These vehicle types require little to no new infrastructure, since they can be charged using existing home electrical outlets.

We updated information on fuel costs in each of the studies with the latest energy price forecasts from EIA. To account for generally higher costs of petroleum in Alaska versus the continental U.S., we scale national fuel price forecasts by the current differential between average national prices and prices in Alaska. Although CNG in Alaska is currently cheaper than CNG in the continental U.S., prices are expected to converge in the near future. Therefore, we use the U.S. average price forecast for CNG.

Information about the capital, fuel, and maintenance costs of each vehicle type is provided in Table J-8. Costs for each vehicle type were drawn from separate studies that use potentially different methodologies. The reader should take care in comparing costs across vehicle types using this information.

Table J-8. Additional cost compared to conventional gasoline vehicle

Vehicle Type	Capital Costs	Fuel Costs (cents per mile)	Maintenance Costs ($ per year)
CNG	$9,480	–6.5¢	ND
Electric	$4,258	–3.0¢	–$350
PHEV	$6,351	–6.4¢	–$94

CNG = compressed natural gas; carbon dioxide equivalent; ND = no data available, but anecdotal reports suggest likely cost savings; PHEV = plug-in electric hybrid.

Key Assumptions: See above.

Key Uncertainties

Transportation fuel providers would need to change their production and distribution methods to achieve the goals. Because the policy does not prescribe particular technology pathways, and because technology in this area is changing quickly, there is substantial uncertainty about which fuels and technologies fuel providers will use to meet the standard. The program assumes that providers will use the most cost-effective options to meet the standard, but compliance costs are unknown at this time.

Additional Benefits and Costs

Most alternative fuels produce lower emissions of PM and other localized pollutants, therefore, this strategy will produce air quality and public health benefits.

Feasibility Issues

AFVs use fairly new technologies, many of which have not been tested extensively in cold climates, such as Alaska's climate. Very cold operating conditions may present problems for electric motors and biofuels particularly. The feasibility of this option will depend upon the development of a viable mass-market AFV for Alaska.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

TLU-6. VMT and GHG Reduction Goals in Planning

Policy Description

Transportation planning has historically focused on meeting the user demands for transportation, reacting primarily to changes in population growth, land use, and other demands, such as freight or resource movements. In many respects, the profession has been reactive or passive to these other considerations. Transportation planning generally evaluates the tradeoffs of agency costs, travel time, and user costs. The idea of using planning as a means of reducing both the number of miles driven and the production of GHGs is the cornerstone of this policy. By empowering transportation planners to evaluate alternative proposals on the basis of VMT and/or GHG generation, decision makers can further improve the organization of communities so as to reduce the impacts of transportation on the environment.

It is important that personal mobility be retained as a paramount goal. Such mobility is a hallmark of modern society, for it empowers people to live, work, shop, play, and go to school at locations they choose, rather than those for which no other alternative exists due to lack of mobility. Historically in the United States, VMT has risen much faster than population, including a 3:1 ratio in Alaska since statehood. Thus, any policy that attempts to reduce the per-capita VMT and GHG production must be carefully tailored and include follow-up monitoring during implementation, to ensure it does not have a negative effect on the economy. Moreover, the real goal of this policy should focus on emission reductions, even if VMT is unfettered. The fact that VMT can occur without emissions, depending upon the means of propulsion, suggests the ultimate goal should be on the form of energy and not the use of vehicles.

Unlike other states, where highway travel is the predominant source of transportation emissions, in Alaska the predominant emissions source is aviation, with highways a distant second. Thus, many Alaska communities are limited in their mobility options, relying solely on aviation and seasonal barge deliveries of freight and fuel. Nearly 30% of the state's population is limited in mobility options, and any analysis must consider these circumstances. Currently, due to high energy costs, villages are experiencing out-migration to Alaska's cities, where employment is more readily found and the cost of living is lower. This will increase per-capita VMT within the state, as a cohort of the population is moving into the ranks of drivers.

Transportation planning is one tool to better inform decision makers. Many important decisions affecting VMT are made by various other entities. For example, the decision made in siting a new school may make busing and/or driving by parents the unavoidable option for pupil transport. Yet, seldom is this even considered by school boards when they make decisions for new school locations. When a new school is sited where walking and biking are not safe or practical, it results in millions of vehicle trips being necessary over the long life of the school. This is but one example of how TLU-6 can help inform transportation planners of the consequences of their decisions.

Policy Design

Greenhouse Gases

Calculating CO_2 emissions associated with an individual transportation project is not straightforward. The analysis can be quite complicated, as most projects form only one piece of a larger network. Transportation planners' models do not generally predict the land use, induced demand, changes in speed and fleet that will occur during the project life, or travel characteristics of the user population. For example, such phenomena as trip linking or what has happened in modern Alaska, when a large cohort of young people who arrived in the 1970s later age and thus have fewer children at home and follow a different life style, are generally not considered in even today's most sophisticated models. However, whether adopted by the state, or later mandated under federal law,[9] predicting the GHG emissions of any given project, including all considered alternatives, is likely to become a requirement soon.

Goals: Require all significant transportation system plans developed at the state and MPO level, and all actions that would change or provide a new mode of transportation or enlarge capacity, to evaluate their contribution to GHG emissions. Currently, traffic models to assist in such evaluations exist only at the metropolitan level in Alaska; thus, time may be needed to develop tools for non-metropolitan areas.

Timing: The two MPOs (FMATS and AMATS) would work with ADOT&PF to start developing consistent methods to evaluate GHG emissions from transportation system plans, and relevant projects by the end of 2010.

Parties Involved: ADOT&PF, FMATS, and AMATS.

Other: None.

Vehicle Miles Traveled

Goals:

- Support and promote public and private planning and development practices, including smart growth planning (see TLU-4) and infrastructure provisions, such as expanded opportunities for non-vehicular travel that reduce the number and/or length of trips made in Alaska.
- By 2015, reduce the per-capita light-duty VMT by 1% in communities that offer transit services and 3% by 2025.

Timing: See above.

Parties Involved: ADOT&PF, FMATS, and AMATS.

Other: None.

[9] The Ninth Circuit, which includes Alaska, recently held that federal agencies must assess climate change impacts in environmental documents prepared under the National Environmental Policy Act (9th Cir., November 15, 2007).

Implementation Mechanisms

- The two MPOs (FMATS and AMATS) would work with ADOT&PF to develop consistent methods to evaluate GHGs from transportation system plans and relevant projects by the end of 2010.
- The state legislature would enact a policy that requires per-capita reductions in VMT in communities that offer transit services.

Related Policies/Programs in Place

None identified.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Table J-9. Estimated GHG reductions and costs of or cost savings from TLU-6

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/tCO_2e$)
		2015	2020	2025	Total 2010–2025		
TLU-6	VMT and GHG Reduction Goals in Planning	0.019	0.043	0.066	0.501	NQ	NQ

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; NQ = not quantified; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent; VMT = vehicle miles traveled.

The GHG impacts of this policy are identical to option TLU-4, which has a goal of reducing per-capita light-duty-vehicle GHG emissions in urbanized areas by 3% by 2025.

Data Sources:

- *Statewide VMT Projections:* Alaska GHG Inventory and Forecast (Appendix D of this report).
- *Population Forecasts for Alaska and Alaska Urban Regions*: *Alaska Economic Outlook*, October 2007. Available at: http://www.labor.state.ak.us/research/trends/oct07pop.pdf.

Quantification Methods:

- Baseline VMT in the Anchorage/Mat-Su, Fairbanks, and Juneau regions was projected based on the assumptions below.
- VMT reduction in Anchorage/Mat-Su, Fairbanks, and Juneau was estimated based on the stated goals.

Key Assumptions:

VMT per capita in the Anchorage/Mat-Su, Fairbanks, and Juneau regions is assumed equal to statewide VMT per capita.

Key Uncertainties

The goal of limiting the per-capita use of light-duty vehicles by 1%, then 3% by 2015 and 2020, respectively, may be considered short of a "stretch goal" by some observers. Further, as written, the goal exempts heavy-vehicle VMT, and further exempts communities that lack transit systems. However, the Alaska circumstance is so significantly different; the following factors are put forward to justify this seemingly "soft" goal.

- *Gas Line Construction:* Alaska is facing the construction of one and possibly two major pipelines in the coming decade, which will substantially amplify the economy and the number of trips being made, since most of the line's construction lies beyond the reach of transit, walking, or biking. The larger gas line project will be the largest private-sector construction project in North American history, and will have a material impact on VMT.
- *Migration to Other Modes:* Alaskans rely extensively on aviation as a means of travel, and in some cases, where possible, their travel mode of choice may be changed to highway travel. Since highway travel is often less fuel intensive than aviation, this is a good outcome for GHG production, even if it results in increased VMT.
- *Not Including Heavy-Vehicle Trips in the Goal:* Much of Alaska's reliance on freight and construction vehicles (non-light-duty vehicles) is related to oil and gas industry or other resource production. Including these types of trips in any goal is not realistic, since there are very limited options for such freight and equipment movements.
- *Historic Pattern of VMT Growth:* Alaska has seen its VMT measure increase by about 300%, as compared to its population. This is higher than in the United States, where 250% growth has been observed. Yet nearly 30% of Alaskans cannot drive beyond the confines of their community due to an incomplete road network; thus, the actual ratio might have been higher if more roads were available. In a state larger than Texas, Montana, and California combined, long-distance travel is sometimes unavoidable. Thus, any VMT and GHG reduction goal must keep this in mind.
- *Land-Use Changes Are Slow Moving:* Once developed, land use in Alaska is relatively fixed. Thus, the pattern of vehicle use from developed locations is not easily addressed by transportation planners. Examples include the practice of large-lot subdivisions within the rapidly growing Mat-Su area, the hillside development in south Anchorage, and residential land development outside the Fairbanks bowl area that requires 20–50-mile round trips. Encouraging walking and biking to schools that are miles from their pupils is another example of prior decisions that lock in vehicle use for many more years into the future.
- *Alternatives May Not Exist:* If a community is too small or too spread out for transit and walking, what choices are there for residents, but to drive as they do today? Many of Alaska's communities are not likely to see transit systems in the foreseeable future. The van ridesharing options become the primary methods to reduce SOV driving. Thus, any VMT reduction goal in such communities is not founded in reality.

Additional Benefits and Costs

Reducing VMT creates a number of ancillary benefits, including reduced congestion, reduced pollutant emissions and negative public health effects, fewer roadway crashes, and economic benefits to vehicle owners.

Feasibility Issues

See Key Uncertainties above.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

TLU-7. On-Road Heavy-Duty Vehicle Efficiency Improvements

Policy Description

Alaska should create new services and provide additional support to existing voluntary and incentive-based programs that help public and private on-road heavy-duty diesel-powered fleets reduce GHG emissions.

Policy Design

This policy employs a combination of three primary strategies to achieve GHG emission reductions:

- Develop incentives to encourage public and private on-road diesel fleets to participate in the EPA SmartWay® Transport Partnership Program.
  - *Goal:* Achieve the following public and private fleet participation in Smart Way: 30% of total trucks in Alaska by 2012, and 50% by 2020.
- Provide incentives to phase out "old" (1988 and older) high-GHG-emitting on-road heavy-duty diesel engines, and replace them with modern lower-GHG-emitting diesel engines if appropriate. Vehicles replaced by the program must be permanently scrapped in order to achieve a net emission reduction. They may not be sold into the used truck market.
  - *Goal:* Phase out 50% of "old" (1988 and older) high-GHG-emitting on-road heavy-duty diesel engines by 2015.
- Develop incentives for state, borough, and municipal government-managed vehicle fleets to develop and implement plans to reduce GHG emissions from their public transit, school bus, and maintenance vehicles. Examples could include idling reduction strategies, alternatively powered engines—liquefied natural gas, natural gas, electric, hybrid, resource sharing, etc.
  - *Goal:* Achieve a minimum 20% GHG emission reduction from the 2008 benchmark by 2020.

Goals: See above.

Timing: Immediately—no need to wait.

Parties Involved: ADOT&PF, DEC, municipal and local governments, Alaska Railroad, Alaska Trucking Association, public and private partners, local and statewide businesses, several not-for-profit organizations.

Other: None.

Implementation Mechanisms

- The state will develop a program to offer subsidized low-interest loans as an incentive to replace pre-1988 on-road heavy-duty diesel engines and or tractors.

- The state will develop a program to offer significant vehicle registration fee discounts for vehicles participating in the EPA SmartWay® program.

Related Policies/Programs in Place

None identified.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Table J-10. Estimated GHG reductions and costs of or cost savings from TLU-7

Policy No.	Policy Recommendation		GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)
			2015	2020	2025	Total 2010–2025		
TLU-7	On-Road Heavy-Duty Vehicle Efficiency Improvements	a. SmartWay®	0.050	0.075	0.084	0.930	–$52.3	–$56
		b. Phase Out	0.025	0.012	0.000	0.198	$20.9	$106
		c. Public Fleets	0.016	0.033	0.037	0.364	NQ	NQ

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent; NQ = not quantified.

Data Sources:

- *Fuel Economy Impacts of Truck Efficiency Strategies:* Based on U.S. EPA FLEET (Freight Logistics Environmental and Energy Tracking Performance) model. http://www.epa.gov/smartway/transport/calculators/loancalcfreight.htm
- *Vehicle Registration Data:* Alaska DMV.
- *Heavy-Duty-Vehicle Fuel Efficiency:* Vehicle Inventory and Use Survey (VIUS): 1992, 1997, 2002. Available at: http://www.census.gov/svsd/www/vius/products.html.
- *Vehicle Populations:* FHWA, *Highway Statistics 2006* (Tables MV-7 and MV-9). Available at: http://www.fhwa.dot.gov/policy/ohim/hs06/index.htm.
- *Fuel Price Forecasts:* EIA, *Annual Energy Outlook 2009*, Early Release, Tables 12 and 13. Available at: http://www.eia.doe.gov/oiaf/aeo/index.html.
- ICF International, *Analysis of Goods Movement Emission Reduction Strategies*, Task 1 Draft Report, prepared for the Southern California Association of Governments (SCAG), May 14, 1007. Available at: http://www.scag.ca.gov/goodsmove/pdf/AnalysisGoodsMovement Emission_DraftReport.pdf.
- California Air Resources Board, *Evaluation of Port Trucks and Possible Mitigation Strategies*, April 2006. Available at: http://www.arb.ca.gov/msprog/onroad/porttruck/execsum.pdf.

Quantification Methods:

Part a—SmartWay®

Based on information from the EPA FLEET model, we estimated that the average vehicle can improve fuel efficiency by 6% by participating in SmartWay®. We applied this fuel efficiency improvement to the target population stated in the policy goal, as a share of the entire heavy-duty fleet population in Alaska.

To estimate costs, truck efficiency strategies were assumed to involve:

- Installation of single-wide tires and wheels on new combination trucks, in lieu of dual tires and wheels, at a cost savings of $1,040 per truck.
- Installation of trailer side skirts on a combination truck trailer at a cost of $2,400, and installation of NoseCone on single-unit trucks at a cost of $700.
- Use of low-friction engine and drive train lubricants at a cost of $118 per year for combination trucks and $18 per year for single-unit trucks.

Part b—Phase Out

Registration data from the Alaska DMV were used to determine the average turnover rate of heavy-duty vehicles. We estimated that under normal conditions, only 14% of the fleet in 2015 will date from 1988 or before; by 2025, only 2% of the fleet will date from 1988 or before. We estimated the impact of reducing the share of 1988 or older vehicles by half, to 7% in 2015 and to 1% in 2025. We assumed that average VMT is the same for older and newer heavy-duty vehicles. We also assumed that new vehicles introduced by the program will achieve an average fuel efficiency improvement of 16% (the average efficiency improvement reported by VIUS for short-haul trucks from 1992 to 2002).

We assumed that scrapped vehicles will be replaced with used vehicles, 5 years old on average. The $42,000 cost per replacement vehicle was drawn from an analysis of heavy-duty vehicle replacement measures by ICF International for SCAG, and from cost data compiled by the California Air Resources Board. This value represents the full cost of the vehicle, which may be partly or wholly subsidized by the State of Alaska.

Part c—Public Fleets

Based on data from *Highway Statistics 2006*, we estimated that 6.7% of heavy-duty vehicles in Alaska are owned by government agencies. We assumed that, on average, these vehicles travel the same number of miles annually as private vehicles and commercially owned heavy-duty vehicles. We calculated linear emission reductions to reach the goal of 20% reduction for publicly owned heavy-duty vehicles in 2020.

We did not estimate the cost of this measure, since no particular implementation measures are specified by the policy. Costs will vary, depending on the specific compliance mechanisms, and could be either positive or negative (cost savings).

Key Assumptions: Described above.

Key Uncertainties

None identified.

Additional Benefits and Costs

This policy will reduce diesel PM emissions. Many scientific studies have linked breathing PM to a series of significant health problems, including aggravated asthma, difficult breathing, chronic bronchitis, heart attacks, and premature death. Diesel PM is of specific concern because it is likely to be carcinogenic to humans when inhaled.

Feasibility Issues

None identified.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

TLU-8. Marine Vessel Efficiency Improvements

Policy Description

Actions by the state can promote efficiencies and conservation options for commercial and recreational fishing, marine tourism, and other forms of marine transportation.

Because Alaska's commercial fishing economy powers most coastal communities and provides employment levels higher than any other private industry in the state, it is critical to mitigate GHG emissions from the sector as a way to ensure continued commercial fishing activities. Registration information available from the state through the Commercial Fisheries Entry Commission for 2007 shows that there are 9,695 registered Alaska commercial fishing vessels, including 6,028 diesel and 3,510 gasoline vessels, with 1981 as the average year of construction and a mean horsepower rating of 311. While the vessel registrations range from two-cycle gasoline-powered outboard skiffs to sophisticated factory ships, the larger vessels are more likely to be newer and have operational plans that include engine and hull efficiency improvements. The medium and small vessels that typically operate seasonally are more likely to need government assistance to encourage installation of more fuel-efficient engines.

It may also be possible to improve the efficiency of commercial fishing operations through improved management of fisheries. Regulations that govern the opening and closing of fishing seasons, as well as the transportation of commercial catches, could be adjusted to reduce fuel consumption. GHG reductions may also be achieved through regulations that minimize travel requirements for all fisheries—commercial, commercial sport, recreational, personal use, and subsistence.

Charter vessels are generally less than 50 feet, and are likely to have issues similar to those faced by the small and medium vessels in the commercial fleet; information on the charter vessel fleet's makeup is not as readily available. Determining the nature of the recreational fleet and issues relating to fuel efficiency is more problematic. Larger vessels, such as cruise ships and ferries, would typically have sophisticated operational plans that consider fuel efficiency issues with government oversight well established.

Policy Design

The basic policy recommendation for promoting installation of more fuel-efficient engines or hull design is to provide financial incentives, such as low-cost loans, that would encourage vessel owners to implement changes without unduly compromising industry economics. For the Alaska resident commercial fleet, Alaska's Department of Commerce, Community, and Economic Develop (DCCED) already has a commercial fishery revolving loan fund that could be further altered to allow for targeting energy efficiency improvements. For the out-of-state residents, options include a DOE loan program or inclusion of fishermen in equipment upgrade programs established for farmers under the U.S. Department of Agriculture (USDA). Charter and recreational vessels are currently not eligible under the DCCED program and need an alternate avenue for financial assistance.

Efficiency improvements relating to conduct of a given commercial, commercial sport (charter), recreational, personal use, or subsistence fishery are regulatory in nature and would require action by the Alaska Board of Fisheries (BOF). Currently, there are no BOF criteria specifically relating to efficiency or GHG emissions, other than cost considerations. A policy requiring the BOF to consider energy efficiency when setting regulations would not require any funding or subsidy, but would allow the BOF to at least consider GHG emissions.

Goals:

- Provide financial incentives to accelerate replacement of marine vessel engines, such that by 2020, no more than 50% will be pre-2000 engines. (EPA's Tier 1 standards for marine engines took effect in 2000.)
- Encourage federal and state agencies that regulate commercial fishing to consider GHG emissions when making policy decisions.

Timing: See above.

Parties Involved: DCCED, Alaska Departments of Energy and Fish and Game, BOF, Alaska State Legislature, DOE, and USDA.

Other: None.

Implementation Mechanisms

- For the Alaska resident commercial fleet, expand the DCCED commercial fishery revolving loan fund to targeting energy efficiency improvements. This could involve lowering the interest rate for improving vessel fuel efficiency (which may be unnecessary if the current House Bill 20 is signed).
- For the out-of-state residents, encourage development of a DOE loan program that could target commercial marine vessels. Also encourage inclusion of fishermen in equipment upgrade programs set up for farmers under USDA.
- For charter and recreational vessels, which are currently not eligible under the DCCED program, develop a new state program to encourage energy efficiency improvements.
- Develop regulations that can reduce the GHG footprint of fisheries in Alaska that include a policy that requires the BOF to take energy efficiency into account for commercial, commercial sport (charter), recreational, personal use, and subsistence fisheries. The Alaska Department of Fish and Game also needs direction to manage fisheries in a way that can accommodate GHG reductions.

Related Policies/Programs in Place

DCCED has a commercial fishery revolving loan fund.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Table J-11. Estimated GHG reductions and costs of or cost savings from TLU-8

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)				Net Present Value 2010–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)
		2015	2020	2025	Total 2010–2025		
TLU-8	Marine Vessel Efficiency Improvements	0.012	0.022	0.032	0.269	$20.4	$76

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources:

- *Vessel Age Distributions*: Alaska Commercial Fisheries Entry Commission, Permit Holder Database (2008).
- California Air Resources Board, *The Carl Moyer Program 2006 Status Report*. January 2007. Available at: http://www.arb.ca.gov/msprog/moyer/status/status.htm.
- *Fuel Price Forecasts*: EIA, *Annual Energy Outlook 2009*, Early Release, Tables 12 and 13. Available at: http://www.eia.doe.gov/oiaf/aeo/.
- *Current Year Fuel Prices by State:* EIA, State Energy Data System (SEDS), 2008, Tables S5a and S2a. Available at: http://www.eia.doe.gov/emeu/states/_seds.html.

Quantification Methods:

- The quantification method uses vessel age as a proxy for engine age; we are not aware of any data on the actual age of operating marine engines. We calculated the percentage of vessels that are 20 years old or older using data from the Permit Holder Database. Approximately two-thirds of vessels in 2008 are more than 20 years old.
- We assumed that the age distribution of vessels will remain constant in future years. We calculated the percentage of vessel engines that should be replaced by the incentive each year in order to attain the goal of no more than 50% pre-2000 engines in 2020. We assumed that the program will continue funding engine replacements at a similar rate after 2020. We also assumed that vessels taking advantage of the incentives have average fuel use and GHG emissions. For engines affected by the turnover incentives, we applied an improvement in fuel economy of 12%, according to the key assumptions below.
- Emission reductions in each year were calculated as follows:
  - tCO_2e reduced = total vessels repowered in all previous years x 12,500 gallons diesel per vessel x 12% x carbon content of diesel fuel.
- Note that the use of vessel age as a proxy for engine age overstates the benefits of this policy, since many older vessels will already have replaced their original engines.
- The cost of the policy was calculated based on data from the Carl Moyer Program in California. The program provides grants for owners of vehicles, including fishing vessels, to replace equipment in order to reduce emissions of criteria pollutants. Fishing vessel engines

typically cost about $50,000 to replace. We calculated the capital cost of these replacements, in addition to the cost savings on diesel fuel. Fuel price forecasts were scaled up to reflect higher costs in Alaska using data from SEDS.

Key Assumptions:

- Engines replaced by the program will improve fuel economy an average of 12%, based on information provided by Alaska fleet operators.
- The average fishing vessel uses 12,500 gallons of diesel fuel per year. This assumption is based on fishing vessels in California. Alaskan fishing vessels may travel longer distances and therefore burn more fuel per year. Higher annual fuel use would increase the emissions impact and reduce the cost of the policy. For example, if fishing vessels burn 17,000 gallons of fuel annually, the policy would produce a net cost savings within the period of analysis.

Key Uncertainties

None identified.

Additional Benefits and Costs

This policy could promote economic development by supporting Alaska's commercial fishing industry.

Feasibility Issues

None identified.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

TLU-9. Aviation Emission Reductions

Policy Description

In addressing GHG emissions from the aviation sector, Alaska must take into account its unique interests in the sector, the policies and practices of other states and territories, and other national and international laws and policies affecting aviation and environmental goals.

Aviation plays a critical role in the Alaskan economy and society. Alaska's location on the great circle route connecting Asia, North America, and Europe affords the state a vital role and unique opportunities within the international aviation system. At the intrastate level, vast distances between population centers and relatively underdeveloped infrastructure supporting other transportation modes require Alaska to rely more on intrastate aviation than other jurisdictions. Alaskan policy must take in account and protect these unique interests.

At the same time, both commercial air transportation and the climate change challenge are manifestly global in character. These factors intensify the need to calibrate policies carefully to ensure they do not merely deter or deflect economically beneficial aircraft operations (and associated emissions) to other jurisdictions.

Climate change policy also must account for and operate within the long-standing and complex frameworks of environmental and aviation policies. In the environmental sphere, Alaska has the responsibility to meet National Ambient Air Quality Standards for criteria pollutants, such as PM and carbon monoxide. Recognizing that many measures aimed at reducing GHG emissions could have the co-benefit of reducing criteria pollutant emissions, policies should allocate limited resources accordingly. Similarly, aviation is subject to comprehensive federal regulation designed to ensure safety and maximize the availability of affordable air transportation services throughout the country. State and local authority to directly regulate air carrier operations is necessarily limited by that framework, and Alaska, like other states, must calibrate policies accordingly.

Policy Design

This mitigation option includes three components:

- Support modernization of the air traffic management system.
- Identify existing and new operational best practices.
- Promote alternative fuels for aviation.

Support Modernization of the Air Traffic Management System

Support the Federal Aviation Administration (FAA) in the redesign and improvement of the existing, outdated, air traffic management system through the implementation of the Next Generation Air Transportation System project (NextGen). Implementation of NextGen, which will include enhanced communications, navigation, and surveillance, will reduce air traffic delays and shorten routes, resulting in a more efficient National Airspace System with a

significant reduction in GHG emissions. According to the FAA, full implementation of NextGen has the potential to reduce GHG emissions by 10%–15%. Alaska will take measures to support the implementation of NextGen and document the associated emission reductions.

Goals:

- Identify opportunities to assist the FAA's implementation of NextGen.
  - Advocate for implementation of NextGen in the U.S. Congress.
  - Identify state-specific actions that will assist with the timely implementation of NextGen.
- Determine potential GHG emission reductions in Alaska resulting from implementation of NextGen.
  - Catalog emission reductions associated with the existing use of advanced navigation technology.
  - Project potential emission reductions associated with additional NextGen improvements.

Timing:

- *2010*—Identify opportunities to assist the FAA in achieving the goals in its Roadmap for Implementation, including carrying out the actions identified above on a timely basis.
- *2010*—Identify existing emission reductions resulting from advanced navigation technologies.
- *2011*—Identify potential emission reductions associated with full implementation of NextGen.
  - Revise the projections as NextGen is implemented to determine whether they are accurate and what level of emission reductions is being achieved.

Parties Involved: The State of Alaska will lead this effort, with input and assistance from airports and aircraft operators.

Other: None.

Identify Existing and New Operational Best Practices

Identify existing and new operational best practices for maximizing fuel efficiency in the aviation sector, facilitate (including through financial incentives) voluntary implementation of such practices where practical, and evaluate resulting emission benefits where possible. Potential operational strategies include:

- Using electric power supplied from airport gates in lieu of running aircraft APUs.
- Developing infrastructure to support the operation of electrified airport ground support equipment, which typically is provided by the airport but may be funded through federal programs.
- Applying strategies under pilot control that may result from a system-wide assessment of airline operations, such as increasing use of single-engine taxi, decreasing use of reverse thrust, and minimizing excess fuel loading (to reduce weight).

Many of these practices require the cooperation of multiple parties. Therefore, the state will facilitate cooperation among airports, aircraft owners and operators, and other parties where necessary, to implement operational best practices.

Goals:

- Identify measures currently used and evaluate the emission benefits they achieve.
- Identify new measures that will lead to additional benefits.
- Identify means to facilitate voluntary implementation of identified measures.

Timing:

- Identify existing measures and means to facilitate voluntary implementation (2010–2011).
- Identify new measures and means to facilitate voluntary implementation (ongoing—prepare initial report in 2011).

Parties Involved: Aircraft operators, airports, State of Alaska.

Other: None.

Promote Alternative Fuels for Aviation

Adopt a clear statement that it is the policy of the State of Alaska to facilitate the rapid introduction of alternative fuels for aviation that both are economically viable and have a reduced emissions profile on a life-cycle basis. Identify and implement measures to support the production, distribution, and use of alternative aviation fuels. Implementation of this policy would be supported by TLU-10: Alternative Fuels Research and Development.

Goals: Similar to the operational best practices measure, above.

Timing: Similar to the operational best practices measure, above.

Parties Involved: Aircraft operators, airports, State of Alaska, fuel providers.

Other: None.

Implementation Mechanisms

See Policy Design, above.

Related Policies/Programs in Place

None identified.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

None identified.

Additional Benefits and Costs

None identified.

Feasibility Issues

None identified.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

TLU-10. Alternative Fuels Research and Development

Policy Description

The state will support research and development of alternative transportation fuels that are feasible in the Alaska climate, result in significant life-cycle GHG reductions when used in Alaska, and can benefit Alaska's economy. Some alternative fuels being promoted in the lower 48 states do not work well in arctic climates. Furthermore, most of the existing research on life-cycle GHG impacts of alternative fuels does not consider the Alaska context, so there is uncertainty regarding which fuels and technologies will result in net GHG reductions in Alaska. This strategy would support research to answer these questions.

If viable low-carbon alternative fuels are identified for Alaska, the state should encourage in-state production and distribution of these fuels. This can help to ensure that Alaska receives economic benefits from the expanded use of alternative fuels.

Various incentives can encourage companies to continue or begin producing alternative fuels, such as granting state tax credits based on the amount of alternative fuel produced, reducing taxes for alternative-fuel production facilities, or providing loans or grants to companies that are producing or want to produce alternative fuels.

Alaska would need to promote alternative fuels that are most appropriate for Alaska's climate, and can encourage collaboration with other research entities across the Arctic region (e.g., Norway) to identify such alternatives. The state could organize a public/private fuel-buying consortium that enters a long-term contract with a supplier to help overcome the risk of producing alternative fuels. Application of these incentives should always consider the full cycle of energy and GHG impacts.

Policy Design

Research should focus on existing alternative propulsion technologies and methods to make existing technologies more viable in Alaska, rather than on development of new propulsion technologies. For example, biodiesel performs poorly in cold weather conditions, but vehicles with two fuel tanks can warm engines and biodiesel fuel using conventional fuel. Research might include pilot programs to evaluate the costs and benefits, including GHG emission reduction, of various alternative propulsion technologies.

Goals:

- Determine the market potential, cost, and GHG impacts of existing alternative fuel and vehicle types in Alaska.
- Determine methods to encourage the in-state production and use of alternative fuels.

Timing: Begin immediately.

Parties Involved: ADOT&PF, Alaska Energy Authority, UA, Alaska Department of Natural Resources, energy and electricity providers, vehicle manufacturers.

Other: None.

Implementation Mechanisms

- The Alaska Center for Energy Power, at UA Fairbanks, is a likely lead organization for the research program. The center should be consulted on the appropriate scope and design of the research program.
- Alaska should set aside dedicated funding for the proposed research. Federal funding may also be available through such programs as the Rural Energy for America Program, the State Energy Program, or the 2009 Recovery Act. Additional funding may be contributed by any private-sector research partners.

Related Policies/Programs in Place

- EPAct includes provisions requiring an increasing volume of renewable fuel to be included in the gasoline sold in the United States, starting in 2006 with 4 billion gallons, and increasing to 7.5 billion gallons by 2012. Under EPAct, renewable fuel includes motor vehicle fuel produced from grain, starch, vegetable, animal, or other biomass material; cellulosic biomass ethanol; waste-derived ethanol; and biodiesel.
- Alaska Waste is testing biodiesel as a fuel for refuse and recycling collection trucks in the Anchorage area. The company is constructing a facility capable of processing used cooking oil into biodiesel. The facility is expected to become operational in 2009.
- The Indiana Soybean Alliance has developed a new type of biodiesel that can be used in extremely cold conditions. The group is testing the fuel in Alaska.

Types(s) of GHG Reductions

Primarily CO_2. Small reductions in N_2O and CH_4.

Estimated GHG Reductions and Net Costs or Cost Savings

Not quantified. This is an enabling policy for TLU-5 and TLU-9.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

None identified.

Additional Benefits and Costs

This policy could support economic development by helping to catalyze production of alternative fuels in Alaska.

Feasibility Issues

None identified.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.