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Oil and Gas Issues Technical Work Group

Draft Policy Option Document

Summary List of Pending Priority Policy Options for Analysis

	Policy Option	Aggregate GHG Reductions ($MMtCO_2e$)	GHG Reductions ($MMtCO_2e$)			Net Present Value (million 2009$) 5% Discount Rate	Cost Effectiveness (2009$ / tCO_2e) 5% discount Rate
			2015	2020	2025	2010 to 2025	
OG-1	Best Conservation Practices	*Not Quantified*					
OG-2	Reductions in Fugitive Methane Emissions	3.2	0.2	0.2	0.2	181.4	57
OG-3	Electrification of Oil and Gas Operations, with Centralized Power Production and Distribution	26.6	-	3.0	4.4	7,791.0	293
OG-4	Improved Efficiency Upgrades for Oil and Gas Fuel Burning Equipment	19.7	0.5	2.1	2.1	1,600.1	81
OG-5	Renewable Energy Sources in Oil and Gas Operations	8.0	0.7	0.7	0.7	2,603.4	327
OG-6	Carbon Capture (from North Slope High CO_2 fuel gas) and Geologic Sequestration with Enhanced Oil Recovery	7.8	-	0.9	0.9	1,368.8	176
OG-7	Carbon Capture (from exhaust gas at a centralized facility) and Geologic Sequestration with Enhanced Oil Recovery	19.7	1.8	1.8	1.8	3,094.1	157
OG-8	Carbon Capture (from exhaust gas) and Geologic Sequestration away from Known Geologic Traps	8.0	0.7	0.7	0.7	7,937.7	994

NOTES:

Results are gross economics that do not include consideration of taxes or royalties.

Cost estimates are rough order of magnitude based on generic North Slope data and not specific engineering studies.

In the Oil and Gas Industry the 'Net Present Value' would be regarded as 'Net Present Cost' (i.e.. Positive numbers indicate sub-economic)

Due to the analysis methodology, 'Cost Effectiveness' is probably lower than the break even cost of carbon needed to make a project economic.Cost Effectiveness Values do not apply in Cook Inlet due to vastly different production life, geographic distribution and physical constraints.

None of the analyses considered the impacts on short term production loss to implement the option (Options 2-7)

All Options are potential technical opportunities for reducing Green House Gas Emissions that require further evaluation.

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.

OG-1 Best Conservation Practices

Policy Description

This option recommends the state via communication efforts enhance companies' ongoing efforts to reduce 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):

- Consumption of liquid fuel at/in support of North Slope Oil Fields;
- Minimize fuel required for operation of flares;
- Optimize existing process to minimize energy consumption;
- Reduce miles driven and flown by employees and contractors;
- Cut electricity use in offices and camps

Policy Design

The option reduces carbon emissions by managing down the amount of fuel used to support oil & gas operations in Alaska. The option 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 option does not require large capital projects to accomplish.

Goals:

Encourage oil & gas workforce in continued energy conservation efforts;

Ensure that companies' ongoing efforts are creditable under any future GHG regulatory programs.

Timing:

The SOA should immediately begin efforts to enhance communication on best practices.

The SOA should 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, ADEC, GreenStar or some other third party to encourage communication of best practices between producers.

Implementation Mechanisms

The option 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 SOA website, 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;
    - Fleet turnover 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;
    - Encourage employees to reduce number of trips taken by vehicle or aircraft
    - Implementation of an energy management team.
    - Right sizing of equipment to smaller sources.
    - Electrical equipment replace gas fired sources.
    - Reduce fuel gas utilization through process optimization
    - Office move to energy efficient LEED certified building.
- GreenStar program participation to coordinate similar efforts;
- ADEC 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 (carbon dioxide) reduced.

Estimated GHG Reductions and Net Costs or Cost Savings

Not quantified but efforts expected to be at least cost-neutral

Key Uncertainties

None known

Additional Benefits and Costs

Benefits:

This option 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

TBD – [until CCMAG moves to final agreement]

Level of Group Support

TBD – [until CCMAG moves to final agreement]

Barriers to Consensus

TBD – [undetermined until final vote by the CCMAG]

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 additional emissions (ie the emissions related to compressor wet seals.) This option recommends studies on both these types of emissions, and the gross order of magnitude quantification estimates cover both fugitives and emissions related to wet seals.

This option relates to the technical and economic feasibility of reducing fugitive and wet seal emissions through first determining where leaks occur, and then planning the optimal corrections. Steps for this determination are:

1) Official refinements to fugitive methane inventories developed by ADEC and CCS 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 tonnes CO_2e per year1

2) Assessment of potential reductions and associated costs to reduce fugitive methane emissions;

Policy Design

Goals:

Start studies immediately on technical and economic aspects of implementation. Economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments as identified by gross quantification results. Review current leak detection procedures and update as needed.

The State of Alaska should participate in the federal legislative and rule making process by commenting and providing input to the Congress/EPA proposed reporting rules.

Timing: Studies could begin immediately.

Parties Involved: Unit Operators, State of Alaska

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any GHG reduction project.

- Evaluate how possible Federal GHG regulation program (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska.
- The State must work with the Federal government to ensure the economic vitality of Alaska (including new capital investments) by engaging in the national debate on GHGs and rule making to support the Cook Inlet and North Slope oil and gas industry;
- Any emissions reductions in the Alaska oil and gas sector must be creditable toward a federal program because there are but a discrete number of such reduction opportunities. A state or regional level program does not provide certainty this can occur;

- 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 (e.g., two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc). Alaska should not preempt the federal legislation and rule making;
- Fugitive emission reporting will be required pursuant to new rules proposed by EPA. These regulations are a first step in a federal GHG regulatory program. Oil and gas companies will comply with those regulations as they come into effect.
- Assure up front planning for budget, staffing, etc…
- Evaluate any regulation changes that may be required to allow criteria pollutant offsets for GHG reductions;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions are expedited;
- Use this information to inform policy makers

Implementation Mechanisms

Industry and/or State should work together to evaluate emission reductions start studies to recommend best way forward in economically reducing GHG emissions related to fugitive emissions and leakage due to wet seals.

Related Policies/Programs

Potential Federal cap and trade legislation and eventual EPA air quality regulations

Types(s) of GHG Reductions

Reduction of methane leakage into the atmosphere through finding and fixing leaks, and by replacing wet seals with dry seals.

Estimated GHG Reductions and Net Costs or Cost Savings

Potential emissions savings are through reduced leakage and reduction of methane emissions from compressor wet seals. Quantification was run assuming replacement of wet seals with dry seals over 4 years, though alternative methods of reducing emissions (ie capturing and flaring the methane) are also viable.

A rough order of magnitude, gross estimated cost is estimated to be $57 tonne for reduction of traditional fugitive emissions and wet seal upgrades. The estimate for expected yearly reduction in CO_2 emissions is 0.235 million tonnes CO_2e, and the estimate for the total reduced emissions through 2025 is 3.2 million tonnes CO_2e

In order to be consistent with the other OG options, **capital and operating costs were amortized out to 2035** when calculating $$/tonne CO_2 of mitigated emissions.

- **Data Sources: EPA, API,** Tools available to ICF and best professional judgment of TWG members
- **Quantification Methods:** ***[e.g.*** *Full life-cycle analysis with supply/demand equilibrium adjustments with TWG & MAG approval]*

Key Assumptions:

- Cost of natural gas until a gas pipeline is built is $0/mscf.
- Well head 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/tonne.
- Capital and operating costs were amortized out to 2035 to get an accurate cost/tonne.

Discount rate 5%. - The cost-effectiveness estimates reported here are consistent with the methodology adopted by the mitigation technical working groups 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 working groups for policy purposes. However, an estimate of the break-even price, i.e., the carbon price at which abatement would just become profitable to industry, could be higher than the cost-effectiveness reported 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 emissions reductions. Consequently, they may represent a lower bound on the industry breakeven-price (however, taking into account other factors, such as capital depreciation, would also alter the calculation). See, for example, EPA's methodology for calculating breakeven prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Some uncertainty exists around emission estimates provided above but need not be addressed at this time. The EPA GHG reporting rule will ensure the certainty of emission estimates as well as improve estimates of costs associated with reductions.

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 costs.

Feasibility Issues

Capital requirements

No regulatory mechanisms are suggested beyond pending federal rules. To encourage capital investment into larger emission reduction opportunities such as replacement of compressor wet seals, state could explore tax or other incentives.

Status of Group Approval

TBD – [until CCMAG moves to final agreement]

Level of Group Support

TBD – [until CCMAG moves to final agreement]

Barriers to Consensus

TBD – [undetermined until final vote by the CCMAG]

OG-3: Electrification of North Slope Oil and Gas Operations, with Centralized Power Production and Distribution

Policy Description

This option is a recommendation that the State of Alaska and the Oil and Gas Stake Holders commission a detailed study of the economics and technical feasibility of electrification of North Slope oil and gas operations with centralized power production and distribution. The system could be configured to serve Alaska's major oil and gas 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 into GHG reduction projects.

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, there is the potential to reduce these GHG emissions by a significant portion, which is dependent on the scale of the electrification. Our analysis, looking at this as a standalone option, grossly estimates a 50% reduction in GHG emissions, through the electrification of hydrocarbon activities.

Additionally the study should review the possibility of additional overall GHG savings through a combination of options. 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 options with different scenarios with various implementation percentages for the options. There may be a best option hybrid scheme that could provide a more cost effective overall thermal efficiency improvement package.

Policy Design

Goal: The goal of the study is to understand the economic and technical feasibility of a centralized power production and distribution system for the oil and gas production areas on the North Slope of Alaska. One element of the study must be to determine any barriers to the implementation of a centralized electricity production and distribution system and to provide recommendations on how to overcome these barriers. The State of Alaska should simultaneously review the business climate in the state and ensure that the climate encourages capital investment by the Oil and Gas stake holders 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 ADEC to provide the required permits in a timely manner. The State of Alaska should ensure that it has on staff 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.

Timing: Since this policy option, as currently configured, does not appear to be economically feasible given our rough order of magnitude quantification assumptions, the timing of Policy Option OG-3 is based on when or if the project financial feasibility ever meets or exceeds the required hurdle rate set for this project by the companies involved.

Geographic Focus: On both the North Slope and in the Cook Inlet, where feasible technically and economically on a project by project basis. 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.

- North Slope – The TWG's evaluation of the OG-3 option has shown, at a gross and rough order of magnitude level that the localized grid for North Slope Oil and Gas operations is technically feasible but is not likely to be economically feasible without a significant incentive program.
- Cook Inlet – Was not directly part of the quantification of this option, as the largest prize was on the North Slope. If the Cook Inlet were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations. This is because the Cook Inlet as a whole is nearing end of usable production life for the known fields. The Cook Inlet's current production life cycle, it's geographic distribution, and physical constraints result in a very different economic analysis for reducing GHG emissions than on the North Slope. The shorter remaining field life should result in a shorter amortization period and thus possibly result in a higher cost on a dollar per ton of CO_2e removed.
- Additional exploration and hydrocarbon recovery projects may change the economic and technical feasibility for this region, and or for the individual project.

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 oil and gas producers on the slope and their associated oil drilling support service companies.

Additional Research Needs: The technical and economic feasibility and any incentives should be fully investigated. Projects should be 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. The study should take into account any effects on the economy and jobs within the sector and its supporting businesses. The TWG ran all our rough economic viability screening assessments without a cost of carbon or potential tax incentives factored in. Additional research into the affect of the value of carbon for both near and long term may adjust the project value based on the avoided GHG emissions and the costs associated with that under some future program. The TWG ran the cases based on three potential well head values of natural gas, these were 2, 4, and 6 dollars per 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.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any GHG reduction project.

- Evaluate how possible Federal GHG regulation program (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics and technology.
- The State must work with the federal government to ensure the economic vitality of Alaska (including new capital investments) by engaging in the national debate on GHGs and rule making to support the Cook Inlet and North Slope oil and gas industry;
- Any emissions reductions in the Alaska oil and gas sector must be creditable toward a federal program because there are but a discrete number of such reduction opportunities. A state or regional level program does not provide certainty this can occur;
- 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 (e.g., two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc). Alaska should not preempt the federal legislation and rule making;
- Assure up front planning for budget, staffing, etc…
- Evaluate any regulation changes that may be required to allow criteria pollutant offsets for GHG reductions;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;
- Use this information to inform policy makers

Implementation Mechanisms

The study should focus on the financial feasibility of this option, and focus on ways of encouraging the oil and gas stake holders to invest the large capital required to implement this option. The TWG does not see any unsurpassable technical feasibility issues with the implementation of this option. The TWG has identified some regulatory hurdles that should be addressed immediately by both the State and the stake holders. The critical path is for State to design appropriate incentives to 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. Large factors in the economics of this option are the expected future prices of natural gas and the level of carbon taxes and the factors associated with implementing large projects (or any projects) on the North Slope of Alaska, these areas should be reviewed as part of an encompassing study.

Related Policies/Programs in Place

Currently the TWG knows of no known policies or programs that have a direct impact on this Policy Option; however there are the following areas that need to be explored:

- Legislative and Regulatory changes (both federal and state) are needed for existing air quality regulations so that greenhouse gas reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surround existing New Source Review requirements and greenhouse gas reduction projects.

- The State GHG Washington DC Contact should work directly with Climate Change staff in Washington DC and Congress to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska needs to be routine and is an essential part of the process.
- Streamlining and coordination between federal and state regulations
- Avoid duplicating or potentially conflicting regulations with existing or expected federal regulations
- Thorough analysis of utility statutes and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
- Changes to tax credit legislation and regulations to provide incentives for greenhouse gas reduction improvement projects may be required to facilitate project economics.
- Trained qualified regulatory staffing, and retention (ADEC, ADNR, RCA, AOGCC other) will improve timing and efficiency.
- Streamlining of permitting of new/revised facilities that are going to reduce GHGs
- Royalties and lease term impacts of operating a centralized power grid across lease boundaries. i.e. royalties are payable on fuel gas used to generate power that crosses a lease boundary

Types(s) of GHG Reductions

The primary type of GHG focused on by this project is Carbon Dioxide (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 option, with a very rough estimated in the 100's 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 Option 2 (Fugitive Methane Reduction), Option 5 (Renewable Energy Sources in Oil and Gas Fuel Burning equipment), Option 6 (Carbon Capture and Storage from high CO2 Fuel Gas) and Option 7 (Carbon Capture (from exhaust gas) and Sequestration as Enhanced Oil Recovery). These options together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

In the Oil and Gas production, transport, and refining sector on the North Slope there are approximately 11.9 Million Metric Tons of CO_2e produced each year.[1] Depending on the scope and costs of the project, various amounts could be mitigated. Assuming that we can improve the overall thermal efficiency of oil and gas operations by two and two thirds of the current efficiency, this would translate into a significant GHG reduction of CO_2.

This option should be evaluated in concert with options OG 1, 2, 4, 5, 6, 7 and 8, as the potential overall GHG savings and efficiencies could be maximized using a hybrid approach, as the costs of full implementation of the options are prohibitive both individually and/or collectively. These prohibitive costs were developed in a gross level review. It is the TWG's position that the order

1 Based on reported fuel burn data in ADEC's systems, as compiled by the state of Alaska for 2002

of magnitude of these estimates should be appropriate and reflective of the costs associated with these options.

Costs and GHG Savings:

The estimated GHG Aggregate savings through 2025 is 27 Million Metric Tonnes of CO2e, assuming a phased approach.

The estimated annual GHG reductions are based on the number of phases implemented:

- 1 Phase 1.48 MMT CO_2e per year
- 2 Phases 2.96 MMT CO_2e per year
- 3 Phases 4.44 MMT CO_2e per year (Maximum Available Phases through 2025)
- 4 Phases (Full Implementation) will result in 5.91 MMTCO2e per year
- If all four phase could be implemented it could result in an approximate annual reduction, in North Slope GHG emissions, of 50% from the baseline established in 2002.

The costs associated with this project are as follows:

Total estimated Capital Investment (NPV): $7.79 Billion

Estimated cost per ton of GHG (CO_2e) reduced: $293/ton CO_2e

- **Data Sources:** BP Exploration Alaska, ConocoPhillips Alaska Inc., Union Oil Company of California / Chevron, ICF, Environmental Protection Agency, and ADEC
- **Quantification Methods:** The project is phased in 4 equal portions with one phase added every 5 years. The overall project life is estimated through 2035, with the cumulative project emissions reductions taken through 2025 (MAG agreed reduction dates). The 2035 "life of" project date allows the large capital investments to be amortized over a longer, more realistic period, as not to artificially skew the dollar per ton cost of the project.
- **Key Assumptions:**
- Cost of Gas until the major gas sales pipeline is built is $0/mscf
- Costs of the effect of improved hydrocarbon reserves from the reinjection of saved fuel gas and oil production lost due to project implementation was not included.
- Well head cost of fuel gas after the major sales gas pipeline is built (2019) is $6/mscf (with sensitivities at $4 and $2)
- Cost of carbon is $0/tonne
- Project is capital costs amortized to 2035, due to the large capital expenditures, 2025 did not paint an accurate picture
- Discount rate 5% - The cost-effectiveness estimates reported here are consistent with the methodology adopted by the mitigation technical working groups 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 working groups for policy purposes. However, an estimate of the break-even price, i.e., the carbon price at which abatement would just become profitable to industry, could be higher than the cost-effectiveness reported 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 emissions reductions. Consequently, they may represent a lower bound on the industry breakeven-price (however, taking into account other factors, such as capital depreciation, would also alter the calculation). See, for example, EPA's methodology for calculating breakeven prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf

Key Uncertainties

- Future values of Carbon – assumed as zero for our review
- Value of North Slope Natural Gas – The TWG ran the studies with $2, 4, and 6 dollars per 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 and for the retrofit)

Additional Benefits and Costs

- This has a direct financial benefit for the state through improved oil and gas reserves as well as a greenhouse gas emissions benefit. Because with a centralized power grid at major oil and gas operations (especially on the North Slope), with the major efficiencies gained would mean less fuel burned, and thus ultimately more gas available for sale, and result in a smaller amount of GHG emissions, lower NO_X, lower SO_2, and lower PM emissions.
- Additional short term jobs to implement projects
- Waste (Abandonment of scrap associated costs and other issues);
- Land use cost increases
- Possible benefits to nearby communities and to expanding oil and gas exploration through access to the electric grid

Feasibility Issues

- The scenario may have significant technical merit, but could fail due to current lease restrictions and complex regulatory hurdles. To help overcome some of these hurdles, the State of Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, complex permitting or authorizations for land use. Large cross agency and regulatory interactions between the companies and the multitude of regulatory agencies with coordination of activities required (EPA, ADEC, 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: emission credits, tax credits, bonds,

technology investment, favorable lease terms, royalty reduction, emission credits need to be explored.

- Logistics of transporting equipment, State may need to perform 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

TBD – The TWG is generally in good consensus on the option

Level of Group Support

TBD – The TWG is generally in good consensus on the option

Barriers to Consensus

TBD – The TWG is generally in good consensus on the option

OG-4: Improved Efficiency Upgrades for Oil and Gas Fuel Burning Equipment

Policy Description

This option is a recommendation that the State of Alaska and the Oil and Gas Stake Holders 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 into GHG reduction projects.

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, there is the potential to reduce these GHG emissions by a significant portion, which is dependent on the scale of the equipment replacement. Our analysis, looking at this as a standalone option, we grossly estimate a 17.5% reduction in GHG emissions slope wide, through the replacement older technology equipment with newer higher efficiency equipment.

Additionally the study should review the possibility of additional overall GHG savings through a combination of options. 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 options with different scenarios with various implementation percentages for the options. There may be a best option hybrid scheme that could provide a more cost effective overall thermal efficiency improvement package.

Policy Design

Goal: The goal of the study is to understand 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 oil and gas production areas on the North Slope of Alaska. One element of the study must be to determine any barriers to the implementation of newer more efficient equipment and to provide recommendations on how to overcome these barriers. The State of Alaska should simultaneously review the business climate in the state and ensure that the climate encourages capital investment by the Oil and Gas stake holders in newer more efficient equipment on the North Slope of Alaska. One known barrier to implementation is staffing levels and training of the staff at ADEC to provide the required permits for the task in a timely manner. The State of Alaska should ensure that it has on staff 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.

Timing: Studies could begin immediately, but since this policy option does not appear to economically feasible, as currently configured, given our gross rough order of magnitude quantification assumptions, the timing of Policy Option OG-4 is based on when or if the project financial feasibility ever meets or exceeds the required hurdle rate set for this project by the companies involved.

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 end of usable production life for the known fields. The Cook Inlet's current production life cycle, it's geographic distribution, and physical constraints result in a very different economic analysis for reducing GHG emissions than on the North Slope. The shorter remaining field life that results in a shorter amortization period possibly could result in a higher cost on a dollar per ton of CO2e removed.

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 oil and gas producers on the slope and their associated oil drilling support service companies.

Research Needs: The technical and economic feasibility and any and all incentives should be fully investigated. Projects should be 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. The study should take into account any effects on the economy and jobs within the sector and its supporting businesses. The TWG ran all our rough economic viability screening assessments without a cost of carbon or potential tax incentives factored in. Additional research into the affect of the value of carbon for both near and long term may adjust the project value based on the avoided GHG emissions and the costs associated with that under some future program. The TWG ran the cases based on three potential values of natural gas, these were $2, 4, and 6 dollars per 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 that may be doing research on efficiency upgrades.
- Study alternative low Carbon Dioxide (CO_2) producing fuels that have upfront 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[2]

Implementation Mechanisms

The study should focus on the financial feasibility of this option, and focus on ways of encouraging the oil and gas stake holders to invest the large capital required to implement this option. The TWG does not see any unsurpassable technical feasibility issues with the implementation of this option, but has identified some regulatory hurdles that should be addressed immediately by both the State and the stake holders. The critical path is for State to design appropriate incentives to 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. Large factors in the economics of this option are the expected future price of natural gas and the level of carbon taxes and the factors associated with implementing large projects (or any projects) on the North Slope of Alaska, these areas should be reviewed as part of an encompassing study.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any GHG reduction project.

- Evaluate how possible Federal GHG regulation program (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics and technology.
- The State must work with the federal government to ensure the economic vitality of Alaska (including new capital investments) by engaging in the national debate on GHGs and rule making to support the Cook Inlet and North Slope oil and gas industry;
- Any emissions reductions in the Alaska oil and gas sector must be creditable toward a federal program because there are but a discrete number of such reduction opportunities. A state or regional level program does not provide certainty this can occur;
- 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 (e.g., two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc). Alaska should not preempt the federal legislation and rule making;
- Assure up front planning for budget, staffing, etc…
- Evaluate any regulation changes that may be required to allow criteria pollutant offsets for GHG reductions;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;
- Use this information to inform policy makers

2 Could have a negative impact in NOx production forcing NSR review

Related Policies/Programs in Place

Currently the TWG knows of no known policies or programs that have a direct impact on this Policy Option; however there are the following areas that need to be explored:

- Legislative and Regulatory changes (both federal and state) are needed for existing air quality regulations so that greenhouse gas reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surround existing New Source Review requirements and greenhouse gas reduction projects.
- The State GHG Washington DC Contact should work directly with Climate Change staff in Washington DC and Congress to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska needs to be routine and is an essential part of the process.
- Streamlining and coordination between federal and state regulations
- Avoid duplicating or potentially conflicting regulations with existing or expected federal regulations
- Thorough analysis of statute and regulations for unintended consequences that restrict GHG reduction projects.
- Changes to tax credit legislation and regulations to provide incentives for greenhouse gas reduction improvement projects may be required to facilitate project economics
- Trained qualified regulatory staffing, and retention (ADEC, ADNR, RCA, AOGCC other) will improve timing and efficiency
- Streamlining of permitting of new/revised facilities that are going to reduce GHG's

Types(s) of GHG Reductions

The primary type of GHG focused on by this project is 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 option, with a very rough estimated in the 100's 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 Option 1 (Conservation), Option 2 (Fugitive Methane Reduction), Option 5 (Renewable Energy Sources), Option 6 (Carbon Capture from fuel gas pre combustion and Sequestration with EOR), and Option 7 (Carbon Capture and Sequestration from exhaust gases as Enhanced Oil Recovery),. These options together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities in the Oil and Gas production, transport, and refining sector on the North Slope there are approximately 11.9 Million Metric Tons of CO_2e produced each year.[3] Depending on the scope and costs of the project, various amounts could be mitigated. Assuming that we can improve the overall thermal efficiency of oil and gas operations by two and two thirds of the current efficiency, this would translate into a GHG reduction of CO_2e.

3 Based on reported fuel burn data in ADEC's systems, as compiled by the state of Alaska for 2002

This option should be evaluated in concert with Options 1, 2, 3, 5, 6, and 7, as the potential overall GHG savings and efficiencies will be maximized using a hybrid approach. These costs were developed in a gross rough order of magnitude level review. It is the TWG's position that the order of magnitude of these estimates should be appropriate and reflective of the costs associated with these options.

Costs and GHG Savings:

The estimated GHG Aggregate savings through 2025 is 20 Million Metric Tonnes of CO_2e (MMTCO2e) assuming a phased approach.

The estimated annual GHG reductions are based on the implementation

- 2010 0.00 MMTCO2e per year (savings does not start until after completion of year 5)
- 2015 0.52 MMTCO2e per year
- 2020 and beyond 2.069 MMTCO2e per year (fully implemented and fully realized annual savings)
- If fully implemented it would result in an approximate annual reduction, in North Slope GHG emissions, of 17.5%.

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/ton CO_2e

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska Inc., Union Oil Company of California / Chevron, ICF, Environmental Protection Agency, and ADEC

Quantification Methods: The project is phased in 25% increments each 5 years, with an overall project life is estimated through 2035, with the cumulative project emissions reductions taken through 2025 (MAG agreed reduction dates). The 2035 "life of" project date allows the large capital investments to be amortized over a longer, more realistic period, as not to artificially skew the dollar per ton cost of the project.

Key Assumptions:

- Cost of Gas until the major gas sales pipeline is built is $0/mscf
- Cost of the Effect of improved hydrocarbon reserves from the saved gas
- Well head cost of fuel gas after pipeline is built (2019) is $6/mscf (with sensitivities at $4 and $2/mmscf)
- Cost of carbon is $0/tonne
- Project is capital costs amortized to 2035, due to the large capital expenditures, 2025 did not paint an accurate picture
- Discount rate 5% - The cost-effectiveness estimates reported here are consistent with the methodology adopted by the mitigation technical working groups 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 working groups for policy purposes. However, an estimate of the break-even price, i.e., the carbon price at which abatement would just become profitable to industry, could be higher than the cost-effectiveness reported 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 emissions reductions. Consequently, they may represent a lower bound on the industry breakeven-price (however, taking into account other factors, such as capital depreciation, would also alter the calculation). See, for example, EPA's methodology for calculating breakeven prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf

Key Uncertainties

- Future values of Carbon – assumed as zero for our review
- Value of North Slope Natural Gas – The TWG ran the studies with $2, 4, and 6 per 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 brown field 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 oil and gas reserves as well as a greenhouse gas emissions benefit.
- Overall fuel savings (more hydrocarbons available for sale), lower NO_X, lower SO_2, and lower Particulate Matter emissions.
- Additional short term jobs to implement projects
- Waste (Abandonment of scrap associated costs and other issues)

Feasibility Issues

- The scenario may have significant technical merit, but could fail due to regulatory hurdles. To help overcome some of these hurdles, the State of Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, complex permitting or authorizations for land use. Large cross agency and regulatory interactions between the companies and the multitude of regulatory agencies with coordination of activities required (EPA, ADEC, 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: emission credits, tax credits, bonds, technology investment, favorable lease terms, royalty reduction, emission credits need to be explored.
- Logistics of transporting equipment, State may need to perform 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 disincentive for (gas) fuel use efficiency.

Status of Group Approval

TBD – The TWG is generally in good consensus on the option

Level of Group Support

TBD – The TWG is generally in good consensus on the option

Barriers to Consensus

TBD – The TWG is generally in good consensus on the option

OG-5: Renewable Energy Sources in Oil and Gas Operations

Policy Description

This option is a recommendation that the State of Alaska and the Oil and Gas stake holders 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 into GHG reduction projects.

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 standalone option, we grossly estimate a 6% reduction in GHG emissions, through the implementation of renewable energy sources at hydrocarbon recovery facilities

Additionally the study should review the possibility of additional overall GHG savings through a combination of options. This may include a hybrid of options OG-1 through OG-7. A sensitivity analysis should be run using all of the options with different scenarios with various implementation percentages for the options. There may be a best option hybrid scheme that could provide a more cost effective overall thermal efficiency improvement package.

Policy Design

Goals:

The goal of the study is to understand the economic and technical feasibility of using renewable energy to supplement energy required to run oil and gas production areas on the North Slope of Alaska. The focus would be to determine how to best encourage the investment by the stake holders in capital projects to install renewable energy. One element of the study must be to determine any barriers to the implementation of a centralized electricity production and distribution system (which is a pre-requisite to allowing large volumes of supplemental renewable energy into the power grid) and to provide recommendations on how to overcome these barriers. The State of Alaska should simultaneously review the business climate in the state and ensure that the climate encourages capital investment by the Oil and Gas stake holders 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 ADEC to provide the required permits in a timely manner. The State of Alaska should ensure that it has on staff 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.

Timing: Studies could begin immediately, but since this policy does not appear to be economically feasible given our gross rough order of magnitude quantification assumptions, the timing of policy option OG-5 is based on when or if the project financial feasibility ever meets or exceeds the required hurdle rate set for this project by the companies involved.

Geographic Focus: On both the North Slope and in the Cook Inlet, where feasible technically and economically on a project by project basis. North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. The 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.

- North Slope – The TWG's evaluation of the OG-5 option has shown, at a gross and rough order of magnitude level that the use of renewable energy for North Slope Oil and Gas 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 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 end of usable production life for the known fields. The Cook Inlet's current production life cycle, it's geographic distribution, and physical constraints result in a very different economic analysis for reducing GHG emissions than on the North Slope. The shorter remaining field life that results in a shorter amortization period possibly could result in a higher cost on a dollar per ton of CO_2e removed.

Parties Involved: The key parties involved with this project are the State of Alaska, BP Exploration Alaska, Inc., ConocoPhillips Alaska, Inc., and all other oil and gas producers on the slope and their associated oil drilling support service companies.

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. The study should take into account any effects on the economy and jobs within the sector and its supporting businesses. The TWG ran all our rough economic viability screening assessments without a cost of carbon or potential tax incentives factored in. Additional research into the affect of the value of carbon for both near and long term may adjust the project value based on the avoided GHG emissions and the costs associated with that under some future program. The TWG ran the cases based on three potential values of natural gas, these were $2, 4, and 6 dollars per 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 related to conditions found in Alaska.
- Study location and types of renewable options to enhance the thermal efficiency of hydrocarbon recovery activities.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any GHG reduction project.

- Evaluate how possible Federal GHG regulation program (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics' and technology;
- The State must work with the federal government to ensure the economic vitality of Alaska (including new capital investments) by engaging in the national debate on GHGs and rule making to support the Cook Inlet and North Slope oil and gas industry;
- Any emissions reductions in the Alaska oil and gas sector must be creditable toward a federal program because there are but a discrete number of such reduction opportunities. A state or regional level program does not provide certainty this can occur;
- 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 (e.g., two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc). Alaska should not preempt the federal legislation and rule making;
- Assure up front planning for budget, staffing, etc…
- Evaluate any regulation changes that may be required to allow criteria pollutant offsets for GHG reductions;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions are expedited;
- Use this information to inform policy makers

Implementation Mechanisms

The study should focus on the financial feasibility of this option, and focus on ways of encouraging the oil and gas stake holders to invest the large capital required to implement this option. The TWG does not see any unsurpassable technical feasibility issues with this option, but has identified some regulatory hurdles that should be addressed immediately by both the State and the stake holders. The critical path is for State to design appropriate incentives to 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. Large factors in the economics of this option are future gas and carbon prices and the factors associated with implementing large projects (or any projects) on the North Slope of Alaska, these areas should be reviewed as part of an encompassing study.

Related Policies/Programs in Place

Currently the TWG knows of no known policies or programs that have a direct impact on this Policy Option; however there are the following areas that need to be explored:

- Legislative and Regulatory changes (both federal and state) are needed for existing air quality regulations so that greenhouse gas reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surround existing New Source Review requirements and greenhouse gas reduction projects.

- The State GHG Washington DC Contact should work directly with Climate Change staff in Washington DC and Congress to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska needs to be routine and is an essential part of the process.
- Streamlining and coordination between federal and state regulations
- Avoid duplicating or potentially conflicting regulations with existing or expected federal regulations
- Thorough analysis of utility statute and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
- Changes to tax credit legislation and regulations to provide incentives for greenhouse gas reduction improvement projects may be required to facilitate project economics
- Trained qualified regulatory staffing, and retention (ADEC, ADNR, RCA, AOGCC other) will improve timing and efficiency
- Streamlining of permitting of new/revised facilities that are going to reduce GHGs
- Royalties and lease term impacts of centralized power grid

Types(s) of GHG Reductions

The primary type of GHG focused on by this project is Carbon Dioxide (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 option, with a very rough estimated in the 100's 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 back-up power is available when the wind is not blowing, hence all aspects of Option 3 (Electrification and Centralized Power) are required prerequisites for this option. Additionally, maximum GHG Savings would be gained through implementing this option in conjunction with Option 1 (Conservation), Option 2 (Fugitive Methane Reduction), Option 4 (Improvements in the Thermal Efficiency of Oil and Gas Equipment), Option 6 (Carbon Capture from fuel gas pre combustion and Sequestration with EOR), and Option 7 (Carbon Capture from exhaust gases and Sequestration as Enhanced Oil Recovery). These options implemented together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

In the Oil and Gas production, transport, and refining sector on the North Slope there are approximately 11.9 Million Metric Tons of CO_2e produced each year.[4] Depending on the scope and costs of the project, various amounts could be mitigated. Assuming that we can improve the overall thermal efficiency of oil and gas operations by two and two thirds of the current efficiency, this would translate into a significant GHG reduction of CO_2.

4 Based on reported fuel burn data in ADEC's systems, as compiled by the state of Alaska for 2002

This option should be evaluated in concert with Options 1, 2, 4, 6, and 7, as the potential overall GHG savings could end up being greater than the baseline values.[5] The costs of the options are prohibitive for both implementing them individually and/or collectively. These prohibitive costs were developed in a gross level review. It is the TWG's position that the order of magnitude of these estimates should be appropriate and reflective of the costs associated with these options.

Costs and GHG Savings:

The estimated GHG Aggregate savings through 2025 is 8 Million Metric Tonnes of CO_2e.

The estimated annual GHG reductions are based on North Slope wind data and immediate implementation with the annual savings estimated at 0.7 MMT CO_2e

- When the forth phase is implemented it would result in an approximate annual reduction, in North Slope GHG emissions, of 6% from the baseline established in 2002.

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/ton CO_2e

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska Inc., Union Oil Company of California / Chevron, ICF, Environmental Protection Agency, and ADEC

Quantification Methods: The project is implemented immediately, with an overall project life estimated through 2035, and cumulative project emissions reductions estimated through 2025 (MAG established reduction dates). The 2035 "life of" project date allows the large capital investments to be amortized over a longer, more realistic period, as not to artificially skew the dollar per ton cost of the project.

Key Assumptions:

- Augmenting the current Central Power Station in Prudhoe Bay
- Well head cost of gas until the gas pipeline is built is $0/mscf
- Cost of the effect of improved hydrocarbon reserves from the saved gas
- Well head cost of fuel gas after pipeline is built (2019) is $6 mscf (sensitivities at $4 and $2/mmscf)
- Cost of carbon is $0/te
- Project is capital costs amortized to 2035, due to the large capital expenditures, 2025 did not paint an accurate picture
- Discount rate 5% - The cost-effectiveness estimates reported here are consistent with the methodology adopted by the mitigation technical working groups 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

5 See footnote 1

across the sector working groups for policy purposes. However, an estimate of the break-even price, i.e., the carbon price at which abatement would just become profitable to industry, could be higher than the cost-effectiveness reported 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 emissions reductions. Consequently, they may represent a lower bound on the industry breakeven-price (however, taking into account other factors, such as capital depreciation, would also alter the calculation). See, for example, EPA's methodology for calculating breakeven prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf

Key Uncertainties

- Future values of Carbon – assumed as zero for our review
- Value of North Slope Natural Gas – The TWG ran the studies with $2, 4, and 6 dollars per 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 can be utilized.

Additional Benefits and Costs

- The state would benefit from a centralized power grid at major oil and gas 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 smaller the amount of GHG emissions.
- Overall fuel savings (more hydrocarbons available for sale), lower NO_X, lower SO_2, and lower Particulate Matter emissions.
- Additional short term jobs to implement projects
- Land use cost increases
- Possible benefits to nearby communities and to expanding oil and gas exploration through access to the electric grid

Feasibility Issues

- The scenario may have significant technical merit, but could fail due to current lease restrictions and complex regulatory hurdles. To help overcome some of these hurdles, the State of Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, complex permitting or authorizations for land use. Large cross agency and regulatory interactions between the companies and the multitude of regulatory agencies with coordination of activities required (EPA, ADEC, 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: emission credits, tax credits, bonds,

technology investment, favorable lease terms, royalty reduction, emission credits need to be explored.

- Logistics of transporting equipment, State may need to perform 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 disincentive for (gas) fuel use efficiency.

Status of Group Approval

TBD – [until CCMAG moves to final agreement]

Level of Group Support

TBD – [until CCMAG moves to final agreement]

Barriers to Consensus

TBD – [undetermined until final vote by the CCMAG]

OG-6: Carbon Capture (from North Slope High CO_2 Fuel Gas) and Geologic Sequestration with Enhanced Oil Recovery

Policy Description

This option relates to the technical feasibility and economics of pre-combustion CO_2 capture, transport and geologic sequestration (CCS) 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 million metric tonnes of CO_2/yr. The geologic sequestration should utilize a reservoir where enhanced oil recovery (EOR) can improve the economics.

This option 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, a significantly more complicated procedure. With regards to sequestration, this option is identical to OG-7.

Policy Design

Goals:

- Start studies immediately on technical and economic aspects of implementation. Economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. Technical analysis to choose appropriate 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 in conjunction with energy efficiency options OG-3, 4, and 5, to both minimize the amount of CO_2 that needs to be processed as well as to reduce resource waste.
- Encourage investment through incentives:
    - Financial:
        - Carbon credits: Federal and State
        - Tax Incentives for capital investments
    - Regulatory:
        - Simplify/streamline the regulatory environment
        - Avoid overlapping regulations, ie State and Federal both regulating GHG emissions and underground injections. Recommend coordinating/participating with development of Federal regulations to insure the regulations fit Alaska.
        - 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 option 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 CCS (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, 4, and 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 for study on technical and economic feasibility
- North Slope Operator Technical Representatives.
- Operators of neighboring oil fields who might benefit from CO_2 EOR, ie the Endicott field.
- State of Alaska (ADNR, AOGCC, ADEC, ADOR, etc)

Research Needs:

Economic research

- Answer que**stion of appropr**iate incentives. Model effects on economy and jobs with various scenarios.
- Research long term value of carbon – huge impact on economics of these projects.
- Research long term value of natural gas.

Technical research

- Engage with/observe DOE Phase III pilot project testing of various capture and sequestration technologies.
- Technical feasibility study of the different entrained CO_2 capture technologies.

Incentives: Financial, Permitting, etc

- Appropriate tax credits for investment, CCS and EOR. Note that current larger tax credits for CCS over EOR ($20/tonne vs $10/tonne) could lead to a financial incentive to inject into an aquifer rather than into a reservoir for EOR, thereby potentially shortening field life. Streamlined permitting critical for project turnaround.
- Consider joint agency similar to the JPO to facilitate 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.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any Carbon Capture and Geologic Sequestration Project.

- Evaluate how possible federal GHG regulation programs (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics and technology;
- The State must work with the federal government to ensure the economic vitality of Alaska (including new capital investments) by engaging in the national debate on GHGs and rule making to support the oil and gas industry;
- Any emissions reductions in the Alaska oil and gas sector must be creditable toward a federal program because there are but a discrete number of such reduction opportunities. A state or regional level program does not provide certainty this can occur;
- 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 (e.g., two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc). Alaska should not preempt the federal legislation and rule making;
- Assure up-front planning for budget, staffing, etc.;
- Prepare for tradeoffs between carbon and other regulated pollutants, ie $NO_{x.}$ Evaluate any regulation changes that may be required to allow criteria pollutant offsets for GHG reductions;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;
- Use this information to inform policy makers.

The TWG recommends these overarching considerations be addressed in the next phase of analysis.

Implementation Mechanisms

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately. Critical path is for State to design incentives encouraging the major capital investments that will be required, operators to begin 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 that State and operators start working the complicated regulatory/permitting issues. Final economics will depend on the value for carbon and fuel gas. Financing CCS 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 CCS and EOR exist in current Federal Energy Plan (part of Bailout Bill.)

Policies under development or needed

- EPA regulations regarding CO_2 Underground Sequestration.[6] 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 vs mineral rights vs 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 option is strongly related to OG-7, CCS from exhaust gas post combustion in and near oil and gas fields with potential EOR.

There are many synergies with eventual sales of North Slope gas.

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 emissions 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 million metric tonnes CO_2 per year.

A rough order of magnitude, gross estimate, given best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $176 /tonne. The estimate for expected yearly

6 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. State may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

reduction in CO_2 emissions is 0.9 MMT CO_2 e, and the estimate for the total reduced emissions through 2025 is 7.8 MMT CO_2 e. Due to the size and complexity of this type 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 towards the end of the measurement period (2025.) In order to avoid presenting a misleading number, **capital and operating costs were amortized out to 2035** when calculating $$/tonne 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

Significant commitment from regulators will be needed to overcome existing hurdles in permitting/royalty/and regulatory environment.

- **Data Sources:** ***IPCC, ADEC, AOGCC, O&G TWG members, API, Oil and Gas Journal, 2nd Annual Conference on Carbon Sequestration,]***
- **Quantification Methods:** ***[e.g.*** *Full life-cycle analysis with supply/demand equilibrium adjustments with TWG & MAG approval]*

Key Assumptions:

- Cost of natural gas until a gas pipeline is built is $0/mscf.
- Well head 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/tonne.
- Capital and operating costs were amortized out to 2035 to get an accurate cost/tonne.
- Discount rate 5%.*
- Endicott Field 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.)
- Discount rate 5%. - The cost-effectiveness estimates reported here are consistent with the methodology adopted by the mitigation technical working groups 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 working groups for policy purposes. However, an estimate of the break-even price, i.e., the carbon price at which abatement would just become profitable to industry, could be higher than the cost-effectiveness reported 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 emissions reductions. Consequently, they may represent a lower bound on the

industry breakeven-price (however, taking into account other factors, such as capital depreciation, would also alter the calculation). See, for example, EPA's methodology for calculating breakeven 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 CCS projects still being developed, for long term monitoring requirements, conflicting state and federal regulations…)
- Availability of resources – building materials, space in existing facilities, water …
- Public acceptance of long term CO_2 storage

Long Term (after project can no longer be classified as EOR)

- What amount of leakage is authorized (any? a percentage?)
- Long term CCS (How long is long term?)
- Liability, how long, who?
- Logistical, legal, and royalty issues of cross unit operations (if reservoir for EOR is not in same unit as Prudhoe.)
- Time Frame, how long to permit? Build?

Recommended evaluation: a) Determine relative benefits of various pre combustion capture techniques (such as membrane versus solvent treatment) and b) Study CO_2 sequestration and EOR benefits within selected reservoirs. The choice of 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 enhanced oil recovery, EOR should be considered wherever feasible in the planning of CCS projects on the North Slope.

Specific Recommendations:

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 for new or upgraded facilities, power, space, and water requirements
- Costs for geological and geophysical studies for site selection/site monitoring
- Costs for drilling a well or 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 (includes 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 (ie impact on EOR recovery of maximizing CO_2 storage)
- Regulatory requirements (ie EPA UIC program, other state and federal requirements)
- Monitoring requirements (pre-, during, and post-injection)

Additional Benefits and Costs

In 2005, about 1.25 MMT (million metric tonnes) of CO_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 has long term benefit to 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 to 4 Bscfd, 5 to 10 MMT CO_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

- **Enhanced Oil Recovery (EOR)**: 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,[7] 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 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 richer gas could release more NOx by volume, triggering regulations requiring additional capital intensive control technologies.
- Capital costs for capture, transport, and injection of CO_2.
- Parasitic energy ie 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.
- Impact on global competitive standing if cost structure in US significantly higher than places without emissions limits.
- Increased cost of energy impacts 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 CCS projects – not yet established. Legal requirements and liability issues are unknown for long term CO_2 storage. These 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.

(See Uncertainties.)

7 DOE, 2005, Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska

Status of Group Approval

TBD – [until CCMAG moves to final agreement]

Level of Group Support

TBD – [until CCMAG moves to final agreement]

Barriers to Consensus

TBD – [undetermined until final vote by the CCMAG]

OG-7: Carbon Capture (from Exhaust Gas at a Centralized Facility) and Geologic Sequestration with Enhanced Oil Recovery

Policy Description

This option relates to the technical feasibility and economics of post combustion CO_2 capture, transport and geologic sequestration in or near existing Alaska oil and gas fields, including the upside of initial enhanced oil recovery (EOR.)

30% of the reported CO_2 emissions from Alaska are generated in the North Slope oil fields, primarily from combustion for power generation[8]. Fortuitously, the co-located or nearby oil and gas 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 option is focused on the central gas facility (CGF) at Prudhoe Bay, as preliminary studies have shown that CCS 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 option 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 regards to sequestration, this option is identical to OG-6.

Most concepts and issues related to carbon capture and geologic sequestration in oil and gas fields discussed in this option would apply to many facilities in the Cook Inlet as well, but the cost structures and logistics there are very different and would require an independent analysis.

Policy Design

Goals:

- Start studies immediately on technical and economic aspects of implementation. Economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. Technical analysis to include 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, 4, and 5 to minimize the amount of CO_2 that needs to be processed.

[8] DRAFT - Summary Report of Improvements to the Alaska Greenhouse Gas Emission Inventory (includes Final Alaska GHG Inventory and Reference Case Projection, Center for Climate Strategies, July 2007) http://www.climatechange.alaska.gov/docs/ghg_ei_rpt.pdf

- Encourage investment through incentives
    - Financial:
        - Carbon credits: Federal and State
        - Tax Incentives for capital investment requirements
    - Regulatory:
        - Simplify/streamline the regulatory environment
        - Avoid overlapping regulations, ie State and Federal both regulating GHG emissions and underground injections. Recommend coordinating/participating with development of Federal regulations to both insure the regulations fit Alaska, 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.

It is expected that EOR will be able to fully utilize all the CO2 that could be captured by the application of this option at the Prudhoe Bay CGF, even if option OG-6 is operating concurrently. However, since energy is needed to power CCS (burning gas and creating more CO_2), improving energy efficiency to minimize the gas that needs to be treated is desired. Energy efficiency options (OG-3, 4, and 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.

Geographic Focus:

While this option's focus is on Prudhoe Bay, lessons learned here on capture may be applied to the Cook Inlet's major emissions sources (Beluga Power Plant, the LNG plant, and the Tesoro refinery.) Future fully depleted onshore oil and gas fields may be a sequestration opportunity. Cook Inlet was not part of the quantification of this option. If the Cook Inlet were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations.

The Cook Inlet oil and gas 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 which will be targets for sequestration.

Parties Involved:

- Consultants for study on technical and economic feasibility.
- North Slope Operator Technical Representatives.
- Operators of neighboring oil fields who might benefit from CO_2 EOR, ie the Endicott field.
- State of Alaska (ADNR, AOGCC, ADEC, ADOR, etc)

Research Needs:

Economic research

- Answer question of appropriate incentives. Model effects on economy and jobs with various scenarios.
- Research long term value of carbon – huge impact on economics of these projects.
- Research long term value of natural gas.

Technical research

- Engage with/observe DOE Phase III pilot project testing of various capture and sequestration technologies.
- Technical feasibility study of the different post combustion CO_2 capture technologies.
- Update 2003 study of the Prudhoe Bay Central Gas Facility, determine 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 the Endicott field.

Incentives : Financial, Permitting, etc

- Appropriate tax credits for investment, CCS and EOR. Note that current larger tax credits for CCS over EOR ($20/tonne vs $10/tonne) 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 joint agency similar to the JPO to facilitate 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.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any Carbon Capture and Geologic Sequestration Project.

- Evaluate how possible federal GHG regulation programs (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics and technology;
- The State must work with the federal government to ensure the economic vitality of Alaska (including new capital investments) by engaging in the national debate on GHGs and rule making to support the Cook Inlet and North Slope oil and gas industry;
- Any emissions reductions in the Alaska oil and gas sector must be creditable toward a federal program because there are but a discrete number of such reduction opportunities. A state or regional level program does not provide certainty this can occur;
- 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 (e.g., two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc). Alaska should not preempt the federal legislation and rule making;
- Assure Up-Front Planning for budget, staffing, etc.;
- Prepare for tradeoffs between carbon and other regulated pollutants, ie NO_x. Evaluate any regulation changes that may be required to allow criteria pollutant offsets for GHG reductions;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;
- Use this information to inform policy makers.

The TWG recommends these overarching considerations be addressed in the next phase of analysis.

Implementation Mechanisms

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately. Critical path is for State to design incentives encouraging the major capital investments that will be required, operators to begin 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. Studies should include space, power requirements, and water requirements for each facility. Finally, the State and operators should immediately start working the complicated regulatory/permitting issues. Final economics will depend on the value for carbon. Financing CCS 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 CCS exist in current Federal Energy Plan (part of Bailout Bill)Policies under development or needed

- EPA regulations regarding CO_2 Underground Sequestration.[9] 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 vs mineral rights vs 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 option is strongly related to OG-6, CCS from entrained gas pre combustion, in and near oil and gas 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 emissions 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 million metric tonnes CO_2 per year.

A rough order of magnitude, gross estimate, given best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $157/tonne. The estimate for expected yearly reduction in CO_2 emissions is 1.8 MMT CO_2e. and the estimate for total reduced emissions through 2025 is 19.7 MMT CO_2e. Due to the size and complexity of this type 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 towards the end of the measurement period (2025.) In order to avoid presenting a misleading number, **capital and operating costs were amortized out to 2035** when calculating $$/tonne CO_2 of mitigated emissions. Huge capital expenditures

[9] 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. State may apply for primacy when final rules are adopted. See www.**epa.gov**/ogwdw/uic/wells_**sequestration**.html for further information.

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 to 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 permitting/royalty/and regulatory environment.

- **Data Sources:** ***IPCC, ADEC, AOGCC, O&G TWG members, API, Oil and Gas Journal, 2nd Annual Conference on Carbon Sequestration, DOE***
- **Quantification Methods:** ***[e.g.*** *Full life-cycle analysis with supply/demand equilibrium adjustments with TWG & MAG approval]*

Key Assumptions:

- Cost of natural gas until a gas pipeline is built is $0/mscf.
- Well head cost of natural gas after a pipeline is built (assumed 2019) is $6. (Sensitivities were run at $2,$4, and $6/mscf.) Cost of carbon =$0/tonne.
- Capital and operating costs were amortized out to 2035to get an accurate cost/tonne.
- Endicott Field 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.)
- Discount rate 5%. - The cost-effectiveness estimates reported here are consistent with the methodology adopted by the mitigation technical working groups 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 working groups for policy purposes. However, an estimate of the break-even price, i.e., the carbon price at which abatement would just become profitable to industry, could be higher than the cost-effectiveness reported 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 emissions reductions. Consequently, they may represent a lower bound on the industry breakeven-price (however, taking into account other factors, such as capital depreciation, would also alter the calculation). See, for example, EPA's methodology for calculating breakeven 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 CCS projects still being developed, for long term monitoring requirements, conflicting state and federal regulations…)
- Availability of resources – building materials, space in existing facilities, water …
- Public acceptance of long term CO_2 storage

Long Term (after project can no longer be classified as EOR)

- What amount of leakage is authorized (any? a percentage?)
- Long term CCS (How long is long term?)
- Liability, how long, who?
- Logistical, Legal, and Royalty issues of cross unit operations (if reservoir for EOR is not in same unit as Prudhoe.)
- Time Frame, how long to permit? Build?

Recommended evaluation: a) Determine relative benefits of various post combustion capture techniques, and b) Study CO_2 sequestration and EOR benefits within selected reservoirs. The choice of 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 enhanced oil recovery, EOR should be considered wherever feasible in the planning of CCS 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 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 Estimated Ultimate Recovery (EUR) and conservation/production of resources (ie impact on EOR recovery of maximizing CO_2 storage)
- Regulatory requirements (ie 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 oil and gas production at Prudhoe Bay is 9 MMT, almost ½ of all stationary GHG emissions in Alaska. ~ 2 MMT is related to the Central Gas Facility, CGF, which provides the best logistical and economic environment for CCS 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

- **Enhanced Oil Recovery (EOR)**: 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[10], 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 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.

10 DOE, 2005, Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska

- Parasitic energy, additional fuel is burned (and additional GHG's created) to provide ie 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 cost structure in US significantly higher than places without emissions limits.
- Increased cost of energy impacts overall cost of living for all.
- Higher cost structure may to 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 environment for CCS projects – 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 the DOE.

(See Uncertainties.)

Status of Group Approval

TBD – [until CCMAG moves to final agreement]

Level of Group Support

TBD – [until CCMAG moves to final agreement]

Barriers to Consensus

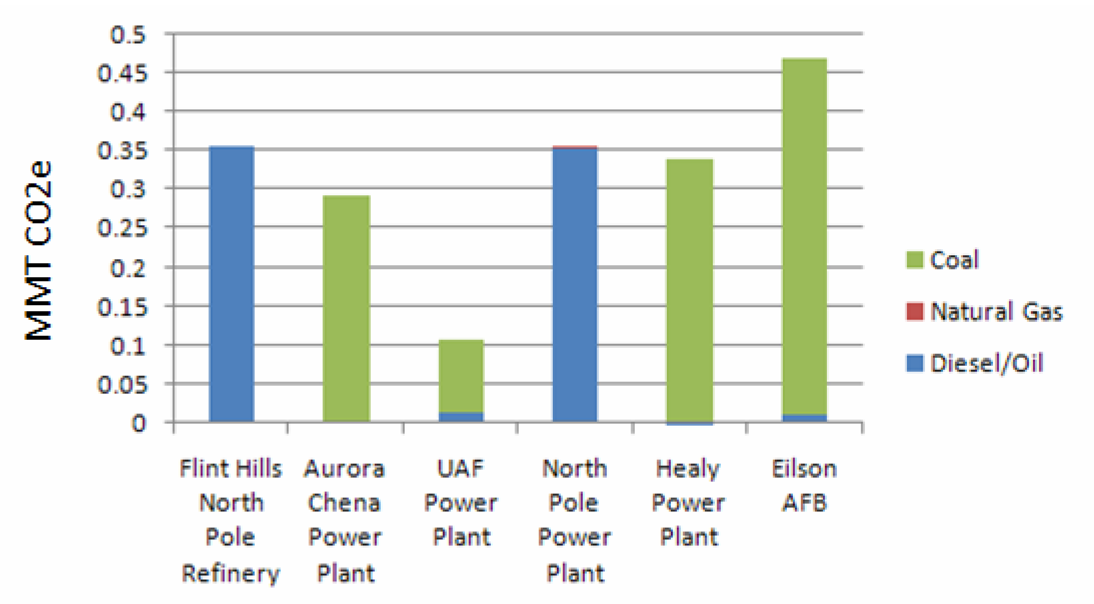
TBD – [undetermined until final vote by the CCMAG]

OG-8: Carbon Capture (From Exhaust Gas) and Geologic Sequestration away from Known Geologic Traps

Policy Description

This option relates to the technical and economic feasibility of CO_2 capture, transport and geologic sequestration far from oil and gas 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 oil or gas fields, differ in that there are no known reservoirs nearby. That means either a long pipeline needs to be built to either the North Slope or the Cook Inlet, or 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 (~2MMT CO_2e) with approximately 60% due to the burning of coal, and the rest related to the combustion of diesel fuel.[11]



Note: This option also deals with emissions outside the oil and gas sector.

Policy Design

Goals:

- Start studies immediately on technical and economic aspects of implementation. Economic analysis should include design of appropriate financial incentives to

11 *DRAFT - Summary Report of Improvements to the Alaska Greenhouse Gas Emission Inventory (includes Final Alaska GHG Inventory and Reference Case Projection, Center for Climate Strategies, July 2007)* http://www.climatechange.alaska.gov/docs/ghg_ei_rpt.pdf

responsibly encourage capital investments. Technical analysis to include size and type of facilities modifications, choice of appropriate combustion CO_2 capture technology and either search for nearby sequestration opportunities, or the planning 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 option in conjunction with, or after, all possible energy efficiencies that can be obtained. The less fuel burned overall, the less GHG to deal with.
- Encourage investment through incentives
    - Financial:
        - Carbon credits: Federal and State
        - Tax Incentives for capital investment requirements
    - Regulatory:
        - Simplify/streamline the regulatory environment
        - Avoid overlapping regulations, ie State and Federal both regulating GHG emissions and underground injections. Recommend coordinating/participating with development of Federal regulations to both insure the regulations fit Alaska, 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 CCS in interior Alaska will require significantly more time and money than in and around established oil and gas fields, as either a) an exploration program to establish the presence of a suitable geologic sequestration site in interior Alaska (most likely the Nenana basin) needs to be performed, or b) a long (to either the Cook Inlet or to the North Slope) pipeline 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.

Geographic Focus:

Fairbanks area in Interior Alaska

Approximately 2 MMT CO_2e is 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.

Parties Involved:

- Consultants for study on technical and economic feasibility.
- Power generating companies.
- Local land owners
- State of Alaska (ADNR, AOGCC, ADEC, ADOR, etc) and other regulatory agencies (EPA, FERC, RCA, etc)

Research Needs:

Economic research:

- Model and recommend most effective incentives. Model effects on economy and jobs with various scenarios.
- Research long term value of carbon – huge impact on economics of these projects.

Technical research:

- Engage with/observe DOE Phase III pilot project testing of various capture and sequestration technologies.
- Technical feasibility study of the different post combustion CO_2 capture technologies.

Incentives : Financial, Permitting, etc

- Appropriate tax credits for investment in CCS
- Streamlined permitting critical for project turnaround.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any Carbon Capture and Geologic Sequestration Project.

- Evaluate how possible Federal GHG regulation programs (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics and technology;
- The State must work with the federal government to ensure the economic vitality of Alaska (including new capital investments) by engaging in the national debate on GHGs and rule;
- Any emissions reductions in the Alaska must be creditable toward a federal program because there are but a discrete number of such reduction opportunities. A state or regional level program does not provide certainty this can occur;
- 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 (e.g., two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc). Alaska should not preempt the federal legislation and rule making;
- Assure Up-Front Planning for budget, staffing, etc.;

- Prepare for tradeoffs between carbon and other regulated pollutants, ie NO_x; Evaluate any regulation changes that may be required to allow criteria pollutant offsets for GHG reductions
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;
- Use this information to inform policy makers.

The TWG recommends these overarching considerations be addressed in the next phase of analysis.

Implementation Mechanisms

This option 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 time required for implementation, regulatory and capital investment hurdles should be addressed immediately. Critical path is for State to design incentives appropriate for capital investments, 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, State and operators should immediately start working the complicated regulatory/permitting issues. Final economics will depend on the value for carbon. Financing CCS projects will be sensitive to that value, and will be dependent on future cap and trade or carbon tax legislation.

Related Policies/Programs in Place

Existing Policies

- Some tax incentives for CCS exist in current Federal Energy Plan (part of Bailout Bill.)

Policies under development or needed

- EPA regulations regarding CO_2 Underground Sequestration.[12] 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
- State/local government permitting as necessary addressing issues beyond EPA UIC CO_2 sequestration rules
    - Ownership issues, surface rights vs mineral rights vs 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

12 New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment (comments due 12/24/08). AOGCC participating through Interstate Oil and Gas Compact Commission and Ground Water Protection Council. 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 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 to established oil and gas fields in the Cook Inlet or North Slope.

Estimated GHG Reductions and Net Costs or Cost Savings

Potential emissions savings through CO_2 capture from exhaust gases from coal and diesel burning sources in interior Alaska could be on the order of 2 million metric tonnes CO_2 per year.

A rough order of magnitude, gross estimate, given best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $994/tonne. The estimate for expected yearly reduction in CO2 emissions is 0.7 MMT CO_2 e. and the estimate for total reduced emissions through 2025 is 8.0 MMT CO_2 e. 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 towards the end of the measurement period (2025.) In order to avoid presenting a misleading number, **capital and operating costs were amortized out to 2035** when calculating $$/tonne CO_2 of mitigated emissions. Huge capital expenditures will be required by facility owners as significant retrofitting of existing power generating facilities will be needed. Dependant 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 to be burned to power carbon capture, compression, transport, injection and long term monitoring.

Significant commitment from regulators will be needed to overcome existing hurdles in permitting and in the regulatory environment.

Data Sources: ***IPCC, ADEC, AOGCC, O&G TWG members, API, Oil and Gas Journal, DOE, CCS***

Quantification Methods: ***[e.g.*** *Full life-cycle analysis with supply/demand equilibrium adjustments with TWG & MAG approval]*

Key Assumptions:

350 mile pipeline needed to transport CO_2 to known reservoir capable of long term CO_2 sequestration.

Discount rate 5%. - The cost-effectiveness estimates reported here are consistent with the methodology adopted by the mitigation technical working groups 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 working groups for policy purposes. However, an estimate of the break-even price, i.e., the carbon price at which abatement would just become profitable to industry, could be higher than the cost-effectiveness reported 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 emissions reductions. Consequently, they may represent a lower bound on the industry breakeven-price (however, taking into account other factors, such as capital depreciation, would also alter the calculation). See, for example, EPA's methodology for calculating breakeven prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Key hurdles 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 potential basins with geologic sequestration potential
- Identification and costs of geological and geophysical analysis required to provide confidence that chosen formation will provide long term geologic sequestration of injected CO_2 (ie 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 nearby sink can be found
- Logistics and Costs for CO_2 pipelines assuming long transport 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 (ie EPA UIC program, other state and federal requirements)
- Long term monitoring needs (pre , during, and post injection)
- Analysis of costs/benefits for different mechanisms of carbon capture, from produced gas, and removed pre and post combustion. Options should be compared on a tonnes CO_2 avoided basis (tons CO_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 H_2O) 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 MMT CO2e, about 1/10th 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 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 GHG), possible additional water requirements.
- Increase cost of energy impacts 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 south west 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 oil and gas 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 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 unmineable coal seams known to exist in interior Alaska, but this technology has significant hurdles 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.

- 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? Build?
- Logistics, space for new facilities? Availability of new required equipment?
- Public acceptance of long term storage
- Availability of resources (water, power)
- Public acceptance NIMBY

Status of Group Approval

TBD – [until CCMAG moves to final agreement]

Level of Group Support

TBD – [until CCMAG moves to final agreement]

Barriers to Consensus

TBD – [undetermined until final vote by the CCMAG]