Title
Alaska geologic CO2 storage: Scoping evaluation of deep coal seam and saline aquifer storage potential

Authors
Stevens, Scott
Moodhe, Keith

Publication Date
2009-03-23

ALASKA GEOLOGIC CO2 STORAGE SCOPING STUDY

Scott Stevens
Advanced Resources International

DOE Contract No.: DE-FC26-05NT42593
Contract Period: October 1, 2005 - May 11, 2011

Table of Contents

Tables

Figures

Abstract

As part of the West Coast Regional Carbon Sequestration Partnership (WESTCARB), Advanced Resources International, Inc. evaluated at a preliminary basin level the CO_2 storage potential of deep coal seams and saline aquifer sandstones in Alaska. Based on scoping review of petroleum well logs, reservoir data, maps, and geologic reports originally compiled by the Alaska DNR, MMS, USGS, and industry for petroleum exploration purposes, we estimate Alaska has approximately 120 Gt of CO_2 storage potential in deep coal seams (Table A) and perhaps 16,700 Gt in saline aquifer sandstones (Table B).

Alaska has large coal resources concentrated mainly in the onshore North Slope and Cook Inlet regions. North Slope coals occur in the Lower Cretaceous Nanushuk and Upper Cretaceous Colville Groups as well as the Tertiary Sagavanirktok Group. Coal rank ranges from lignite A to high-volatile A bituminous. Based on thickness, rank, and aerial distribution, deep coals in the North Slope are estimated to have about 98 Gt of CO_2 storage capacity. However, because coalbed methane (CBM) testing has not yet occurred in the North Slope, critical reservoir properties (i.e., permeability) are unknown.

In southern Alaska, the Cook Inlet's Miocene Tyonek Formation contains approximately 30-50 m of sub-bituminous rank coal at favorable CO_2 storage depths of 800-1200 m. A 4-well vertical coalbed methane pilot conducted by Evergreen Resources flowed fairly high water rates, indicating at least modest coal seam permeability (1-10 mD). The Tyonek is estimated to have about 21 Gt of CO_2 storage capacity, as well as 136 Tcf of CBM potential. Using a 3:1 ratio of CH_4/CO_2 storage, we estimate Alaska's deeply buried coals may be capable of storing approximately 120 Gt of CO_2. Although smaller than the North Slope, the onshore Cook Inlet basin would be the better location from an operational viewpoint for a CO_2 injection test to confirm the actual storage capacity of Alaska's deep coal deposits.

Alaska's saline aquifer sandstone formations have far greater CO_2 storage capacity than its deep coals (albeit without the potential economic benefit of enhanced methane recovery). We mapped and analyzed the thickness, lateral and depth distribution, and reservoir quality of sandstone formations in eight of Alaska's largest sedimentary basins, both onshore and offshore (note : Cook Inlet was excluded from the study). The Chukchi Sea and North Slope regions stand out as having particularly large CO_2 capacity, estimated at about 5,000 Gt each. In particular, the Cretaceous Nanushuk Formation in the Colville basin (North Slope) and Chukchi Sea region is a widespread and attractive potential storage unit.

The next five basins (North Aleutian/Bristol Bay, St. George, Navarin, Beaufort Sea, and Gulf of Alaska) each have on the order of 1,000 Gt of CO_2 storage potential, though each basin has its unique geologic setting as well as challenges. The eighth basin (Norton) is rather small and has thinner, more limited sandstone targets. All of these basins, particularly the Beaufort, are located in operationally difficult areas challenged

by persistent and mobile ice flows. Next steps for evaluating Alaska's saline aquifer storage potential could include detailed basin studies of the more promising areas. In particular the North Slope and Chukchi Sea, where petroleum exploration activity recently has increased, may offer opportunities for joint industry testing.

Table A : Preliminary Estimate of Deep Coal Seam CO_2 Storage Potential in Alaska

Region	Identified & Undiscovered Coal Resources (Btons)	Mean Ash Content (%)	Mean Moisture Content (%)	Identified & Undiscovered Coal Resources (Btons, daf)	Mean Volatile Matter (%)	Gas Content (scf/ton daf)	CBM Resources (Tcf)	CO_2 Storage Capacity (scf/ton) (daf)	CO_2 Storage Capacity (Tcf)	CO_2 Storage Capacity (Gt)
North Slope	**4,020**	**10.3**	**12.5**	**3,103**	**30.1**	**200**	**621**	**400**	**1,241**	**65**
Nenana	**17**	**9.9**	**24.7**	**11**	**35.9**	**100**	**1**	**200**	**2**	**0**
Cook Inlet	**1,292**	**10**	**20**	**905**	**35.0**	**150**	**136**	**400**	**362**	**19**
Total	**5,329**			**4,019**			**758**		**1,605**	**84**

Table B : Preliminary Estimate of Sandstone Saline Aquifer CO_2 Storage Potential in Alaska

Saline Aquifer Basin	Prospective Area (km^2)	Avg Depth (m)	Reservoir Pressure (psi)	Sandstone Thickness (m)	Rock Volume (km^3)	Avg Porosity (%)	Pore Volume (km^3)	CO_2 Storage Saturation (%)	CO_2 Storage Density kg/m^3	CO_2 Storage Capacity Gt
Chukchi Sea	100,000	2,000	2,855	600	60,000	25%	15,000	50%	700	5,250
North Slope / Colville	75,000	2,000	2,855	750	56,250	25%	14,063	50%	700	4,920
North Aleutian / Bristol Bay	20,000	1,700	2,429	1,100	22,000	23%	5,060	50%	700	1,770
St. George	5,000	1,800	2,571	2,500	12,500	31%	3,875	50%	700	1,360
Navarin	80,000	1,800	2,571	325	26,000	15%	3,900	50%	600	1,170
Beaufort Sea	30,000	2,300	3,281	500	15,000	20%	3,000	50%	700	1,050
Gulf of Alaska	40,000	2,000	2,855	500	20,000	15%	3,000	50%	600	900
Norton	19,500	2,400	3,423	300	5,850	15%	878	50%	600	260
TOTAL	**369,500**									16,700

1.0 Introduction

Background

This study was performed for WESTCARB by Advanced Resources International, Inc. (ARI), a consulting firm based that focuses on geologic CO_2 storage technologies and unconventional oil and gas resource development.

The purpose of the study is to evaluate at a scoping level the geologic CO_2 storage potential of sedimentary strata in Alaska. One region was excluded from the study. The saline aquifer and enhanced oil recovery storage potential of the Cook Inlet region was evaluated separately by the Alaska Division of Natural Resources. However, ARI did evaluate the deep coal seam storage potential in the Cook Inlet region.

WESTCARB Project

The West Coast Regional Carbon Sequestration Partnership is one of seven research partnerships established in 2003 and co-funded by the U.S. Department of Energy (DOE) to characterize regional carbon sequestration opportunities and to develop action plans for pilot-scale validation tests. WESTCARB is evaluating opportunities in a six-state region (California, Oregon, Washington, Nevada, Arizona, and Alaska) for removing carbon dioxide (CO_2) from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted; both will help slow the atmospheric buildup of this greenhouse gas and its associated climatic effects.

A key part of the project is identifying subsurface locations to store the captured CO_2. These geologic sinks are expected to include deep formations (such as oil and gas reservoirs as well as saline aquifers) that are essentially leak-proof. These potential sinks will then be matched with major anthropogenic CO_2 sources, such as large utilities and industrial emitters.

DOE's intention is to combine WESTCARB's findings with those of the other six partnerships to create a national "carbon atlas" to better understand how sequestration technology can help the United States reduce the carbon intensity of its economy and mitigate climate changes. On the basis of the source and geologic characterization, WESTCARB will prioritize geologic sequestration opportunities within the region and will propose pilot-scale projects that combine industrial CO_2 capture, CO_2 transport via pipeline, and injection into geologic formations for storage or enhanced oil and gas recovery.

Methodology

No previous state-wide estimate of Alaska's CO_2 storage potential has been performed. To conduct this study, ARI reviewed published and unpublished geologic and reservoir information on Alaska's sedimentary basins. We constructed basin-level maps of coal and sandstone thickness, evaluated representative well logs to gather porosity and permeability data, and developed a first-order volumetric estimate of the CO_2 storage potential. Given the large size and apparent CO_2 storage capacity of Alaska's sedimentary basins, this relatively small effort should be viewed as the starting point for more rigorous future evaluations.

Data Control

ARI gathered geologic data gathering for most of the onshore and offshore sedimentary basins in Alaska and synthesized this data set into a GIS system (ArcView format). The data base comprises well logs, seismic reflection data, and basin studies which were originally conducted for the purposes of conventional oil and gas exploration. However, in many cases these data also are useful for CO_2 storage analysis. We also compiled surface geology, detailed topography and bathymetry data, cities, towns, and oil and gas pipeline infrastructure locations. Due to budget limitations, not all of this extensive data set could be fully analyzed, as ARI focused its analysis on the geologic storage potential of the higher-potential basins in Alaska. However, the files provide a good basis for future more detailed studies. **Figure 1** shows the data set in its entirety.

2.0 Deep Coal Seam CO_2 Storage Potential in Alaska

Alaska contains major coal deposits that range from shallow outcrop to over 2,000 m deep. Three major geologic provinces account for vast majority of Alaska's coal resources (**Figure 2**) : 1) Southern Alaska – Cook Inlet region; 2) Northern Alaska - North Slope Region; and 3) Central Alaska – Nenana Region. Most of Alaska's coal is sub-bituminous in rank, but extensive high-volatile bituminous rank deposits exist in the western North Slope and Central Alaska. Coal mining has been limited to date mainly due to the remoteness and climate.

To estimate CO_2 storage capacity, it is necessary first to estimate coal and CBM resources. ARI estimates Alaska's CBM resources to be approximately 776 Tcf of gas in place, larger than the estimated 600 Tcf resources in the Lower-48 States.

2.1 Coal and CBM Resources

In contrast to the Lower 48 States, where coalbed methane (CBM) development is advanced and several enhanced CO_2-CBM pilots have been tested, CBM testing in Alaska is still at the very earliest conceptual stage. Basic information on coal thickness, quality, depth, and rank are available. However, few reservoir data (such as gas content or permeability) exist for deep coals in Alaska.

Initial CBM well testing has occurred in the onshore Cook Inlet region in southern Alaska, but other areas of the state remain essentially untested. The Alaska Department of Natural Resources (DNR) and the U.S. Geological Survey (USGS) have conducted initial evaluations of coal and coalbed methane resources in certain regions of Alaska, providing a basis for our preliminary estimate of CO_2 storage capacity.

Coal Resources. Although coal mining activity has been limited, Alaska contains major coal deposits that range from shallow outcrop to over 2,000 m deep. Three major geologic provinces account for approximately 90% of Alaska's coal resources (**Map 1**) : 1) Southern Alaska – Cook Inlet Region; 2) Northern Alaska - North Slope Region; and 3) Central Alaska – Nenana Region. Most of the coal resource estimates date back to the early 1980's. They tend to be biased towards shallow mineable coal deposits and frequently do not consider coals encountered in deep oil & gas wells that are prime targets for CBM development and CO_2 storage.

- The **Southern Alaska – Cook Inlet** region has Tertiary (Miocene) coal resources in the Tyonek Formation. Demonstrated resources are estimated at 2.9 to 12 billion tons, with another 970 to 1,600 billion tons of undiscovered (but reasonably reliable) resources. The coal deposits total about 80-150 feet thick and in many onshore areas occur at favorable storage depths of 2,600 to 3,700 feet. Coal rank is sub-bituminous to high-volatile bituminous C. The coals are estimated to have sourced about 7.7 Tcf out the Cook Inlet's total 8.3 Tcf of conventional natural gas reserves. The Alaska DNR has estimated 245 Tcf of CBM resources in the Cook Inlet, while the USGS has placed resources at 140 Tcf of gas in place.

- The ***North Slope*** region has coals in the Lower Cretaceous Nanushuk and Upper Cretaceous Colville Groups as well as in the Tertiary Sagavanirktok Group. Coal underlies an area of approximately 83,000 km^2. Coal rank ranges from lignite A to high-volatile A bituminous, with a mean rank of high-volatile C bituminous. Identified resources are 120 billion short tons, with a further 3,870 billion tons of undiscovered but likely coal resources. Although the largest in Alaska, these deposits are not currently mined due to their depth and remoteness.
- The ***Central Alaska – Nenana*** region has Tertiary coals estimated at 6.4 to 7.7 billion tons of identified resources, with an additional 10 billion tons of undiscovered resources. Coal thickness is approximately 50 to 66 feet and occurs at depths ranging from surface to around 3,000 feet. Coal rank ranges from lignite to sub-bituminous, mainly sub-bituminous C. Although smaller than the North Slope and Cook Inlet, the Nenana basin is the only coal province in Alaska that is currently being mined. The region is not continuously underlain by coal, but instead comprises numerous small structural basins (synclines) that are separated by anticlinal highs. Coal occurs in the Tertiary Usibelli Group.

CBM Resources. The first published estimate of CBM resources in Alaska was the Alaska DNR's 1,000 Tcf of gas in place.[1,2] In 2004, the USGS national coal resource evaluation also examined CBM in Alaska, characterizing it as "exceedingly large," but did not actually quantify CBM resources.[3]

In 2006, the USGS assessed CBM resources in the North Slope region only, estimating a total 19 Tcf in place.[4] Although the USGS did not display their methodology in this report, standard volumetric calculation would imply an average gas content of only 6 scf/ton (dry, ash-free basis) was used in the estimate. That would seem to be much lower than reasonable gas content given the rank and depth of North Slope coal seams. (Typical gas contents in the Lower-48 States vary from 30 to 600 scf/ton, d.a.f.)

ARI developed an independent preliminary estimate of CBM resources (**Table 1**). We started with the USGS coal resource estimate, adjusting to ash- and moisture-free basis because these components do not adsorb gas. We further inferred an average methane content based on the average coal rank in each region, indicated by the mean volatile matter content (higher rank coals have higher gas storage capacity). Gas content was assumed to range from 100 scf/ton in the relatively low-rank and shallow Nenana region, to 200 scf/ton in the higher-rank and deeper North Slope region.

Using this methodology, we preliminarily estimate CBM resources in Alaska to be approximately 758 Tcf, somewhat less than the initial 1,000 Tcf Alaska DNR estimate. We further estimated that geologically high-graded CBM resources in the Cook Inlet, the only area in Alaska to have experienced CBM well testing to date, could be approximately 27.1 Tcf.

Table 1 : Estimated coalbed methane resources in Alaska.

Region	Identified & Undiscovered Coal Resources (Btons)	Mean Ash Content (%)	Mean Moisture Content (%)	Identified & Undiscovered Coal Resources (Btons, daf)	Mean Volatile Matter (%)	Methane Content (scf/ton, daf)	Total CBM Resources (Tcf)	High-Graded CBM Resources (Tcf)
North Slope	*4,020*	*10.3*	*12.5*	*3,103*	*30.1*	*USGS 6*	*18*	
North Slope	4,020	10.3	12.5	3,103	30.1	ARI 200	621	
Nenana	17	9.9	24.7	11	35.9	ARI 100	1	
Cook Inlet	1,292	10.0	20.0	905	35.0	ARI 150	136	27.1
ARI Total	5,329			4,019		ARI	758	

2.2 CO_2 Storage Potential

ARI performed a highly preliminary estimate of the CO_2 storage potential. As previously for the CBM resource assessment, ARI used the USGS estimates of coal resources as a starting point (**Table 1**). The CO_2 sorption capacity of Alaskan coals has not yet been measured in the laboratory. Therefore, we used sorption analyses for similar-rank coals to estimate CO_2 storage capacity in each of the three Alaskan coal regions.

The ratio of CO_2/CH_4 adsorption capacity ranges from about 2:1 to over 10:1, depending on coal rank, maceral composition, and other factors.[5] Based on the somewhat low coal rank in Alaska (lower than San Juan but higher than Powder River basin), we assumed that the CO_2 storage capacity was three times that for methane, ranging from about 300 to 600 scf/ton (d.a.f.). However, this number is highly approximate and needs to be updated with actual laboratory CO_2 adsorption measurements.

ARI estimates that Alaska has on the order of 120 Gt (2,273 Tcf) of CO_2 storage capacity in deep coal seams, mainly in the North Slope and Cook Inlet regions. However, it is likely that only a portion of this total storage target would be considered favorable for CO_2 sequestration, due to variations in permeability, seam geometry, surface access, faulting, and other site-specific but currently undetermined conditions.

Table 2 : Estimated CO_2 storage capacity in deep Alaska coal deposits

Region	Identified & Undiscovered Coal Resources (Btons)	Mean Ash Content (%)	Mean Moisture Content (%)	Identified & Undiscovered Coal Resources (Btons, daf)	Mean Volatile Matter (%)	Methane Content (scf/ton, daf)		Total CBM Resources (Tcf)	CO2 Storage Potential (Tcf)	CO2 Storage Potential (Gt)
North Slope	*4,020*	*10.3*	*12.5*	*3,103*	*30.1*	*USGS*	*6*	*18*		
North Slope	4,020	10.3	12.5	3,103	30.1	ARI	200	621	1,862	98
Nenana	17	9.9	24.7	11	35.9	ARI	100	1	3	0
Cook Inlet	1,292	10.0	20.0	905	35.0	ARI	150	136	407	21
ARI Total	5,329			4,019		ARI		758	2,273	120

The following sections discuss in greater detail the coal deposits, CBM resources, and CO_2 storage potential of the three main Alaska coal regions.

2.3 Cook Inlet

Geology. The Cook Inlet region of southern Alaska is a tectonically active, convergent plate margin (**Figure 3**). Subduction of the Pacific Ocean plate northward beneath Alaska since latest Triassic generated a classic island arc system with deep ocean trench, accretionary prism (Chugash Terrane), forearc basin (including the Cook Inlet area) with Mesozoic and Cenozoic marine and nonmarine strata, and an andesitic volcanic arc.[6]

The Cook Inlet basin covers an area of approximately 36,000 km^2 and contains up to 10 km of marine Mesozoic sedimentary rocks and 8 km of Tertiary nonmarine sedimentary rocks. Cook Inlet is a NE-SW trending forearc basin associated with the Aleutian Island Arc subduction system. The basin fill has been folded and faulted by continuing subduction, creating conventional structural traps. [7]

The Oligocene to Pliocene Kenai Group is the major coal-bearing sequence in the Cook Inlet region (**Figure 4**). The base of this unit is the Hemlock Conglomerate, comprising fine- to coarse-grained sandstones, siltstone (tuffaceous in part), sporadic coal seams, and conglomerate. Sandstones within this unit have good porosity and permeability (average 17% and 80 mD) and provide the dominant conventional hydrocarbon reservoir of the Cook Inlet Basin.

Overlying the Hemlock Conglomerate are the Tyonek, Beluga, and Sterling formations, thick sequences of alluvial sandstones, siltstones, mudstones, carbonaceous shales, and coals with a combined thickness of up to 7 km. Sandstones are commonly massive or lenticular channel deposits, consisting of quartz, feldspar, lithic fragments, and volcaniclastic debris. Similarities in lithology among the three formations, as well as rapid lateral facies changes and the lack of diagnostic fossils, have made it difficult to determine precise and consistent stratigraphic contacts.

The Miocene Tyonek and Beluga Formations host the major coal deposits in the Cook Inlet basin, although the Chickaloon Formation has locally thick coals in the Matanuska Valley.[8] The Kenai Group is interpreted to be an alluvial fan deposit comprising meandering stream systems, with coal seams developed in swamp or marsh settings on the floodplains.[9]

Gas Infrastructure. The Cook Inlet has a liquefied natural gas (LNG) facility (Kenai-Nikiski plant) for exporting natural gas produced in the basin to Asian markets (**Figure 5**). Operated by ConocoPhillips (70%) and Marathon (30%), the plant has annual production of about 1.2 million t. Most of Kenai's production is exported to Japan. Kenai is the oldest LNG plant in operation, having started production in 1969.

Current estimates of the conventional gas reserves remaining in the Cook Inlet Basin vary from 1 to 2 Tcf, which are not sufficient for long-term LNG exports. Thus, the CBM resources of the Cook Inlet have taken on renewed interest, especially following the recent Australian model of converting CBM to LNG for export.[10] Commercial CBM production from the Cook Inlet need not await the construction of a pipeline to the Lower-48 States, but could be handled out of the existing Kenai LNG facility.

Coal Resources. Demonstrated coal resources in the Miocene Tyonek Formation are estimated at 2.9 to 12 billion tons, with another 970 to 1,600 billion tons of undiscovered resources. The Cook Inlet coals can total up to 1,000 feet or more in places, making this one of the thickest known coal deposits (**Figure 6**).[11] The coal seams often occur at optimal CBM and CO_2 storage reservoir depths of 1000 to 4000 feet. Coal rank is sub-bituminous to high-volatile bituminous C. Vitrinite reflectance at the Pioneer lease reached R_o = 0.6%. The coals are estimated to have sourced about 7.7 Tcf out the Cook Inlet's total 8.3 Tcf of conventional natural gas reserves.

CBM Resources. The onshore Cook Inlet region near Anchorage appears particularly prospective for CBM development, with thick sub-bituminous rank coals onshore with gas contents of 100-200 scf/ton. Only one CBM production pilot has been tested to date, the 4-well Evergreen Resources pilot northwest of Anchorage. This pilot did not succeed commercially but provided useful geologic and reservoir information.

ARI estimates that the onshore Cook Inlet region has about 136 Tcf of accessible CBM resources in place (**Table 1**). This estimate does not include offshore potential, which has not been developed elsewhere due to high costs. ARI's estimate is similar to a recently published USGS estimate (using similar but independent methodology) of 140 Tcf.[12]

ARI further estimated that 20% or 27.1 Tcf of this total would located in high-quality areas with favorable permeability, hydrology, and other reservoir properties. Applying a standard 50% recovery factor, ARI estimates there could be 13.6 Tcf of technically recoverable CBM resources in the onshore Cook Inlet region.

CBM Testing. The onshore Cook Inlet is the only region in Alaska that has experienced CBM well testing to date. No CBM testing has occurred yet in the North Slope region. CBM projects have included one Alaska DNR gas content corehole, a number of confidential coreholes drilled by Unocal (now Chevron), and Evergreen Resources' (now Pioneer Resources) production pilots. There has also been an offshore coal seam well recompletion test conducted by XTO Energy.

Currently, only one company (Fowler Oil and Gas) is actively pursuing CBM exploration in the Cook Inlet area. Considering the size of the Cook Inlet basin coal deposit, available data on coalbed methane reservoir properties remain limited.

- **Alaska DNR.** In 1994 the state agency DNR drilled Alaska's first gas content corehole (AK-94-1), located in the Matanuska-Susitna Valley (**Figure 7**), about 50 km north of Anchorage. Approximately 40 feet of coal was cored and desorbed using standard US Bureau of Mines analytical procedures. Gas content was encouragingly high and increased regularly with depth, ranging from 63 scf/ton (d.a.f.) at a depth of 500 feet (R_o = 0.47%), to 245 scf/ton at a depth of 1,300 feet (R_o = 0.58%). Gas composition was mainly methane (98-99%), with minor CO_2 and N_2. Overall, reservoir properties tested in this corehole were favorable for CBM development and CO_2 storage (**Figure 8**).

- **Unocal.** During the late 1990's, Unocal drilled several coreholes to test gas content in the same portion of the upper Cook Inlet (Matanuska-Susitna Valley), but decided not to attempt production wells. Data from these coreholes remain confidential.

- **Evergreen.** During 2002-2004, Evergreen Resources (now Pioneer Resources) tested a 294,890-acre lease in this area (coincidentally called the Pioneer Unit; **Figure 7**). Evergreen had already developed a successful CBM project in the Raton basin, Colorado. The company's first Alaska land acquisition was in 2001, when they acquired a 100% WI in 64,000 gross acres, including $1 MM paid to Ocean Energy and Unocal for 48,000 acres.

  Coal seams in this area are in the Oligocene-Miocene Tyonek Formation, part of the Matanuska coal field. Coals total 80-150 ft thick, are high-volatile bituminous in rank (R_o=0.6%), and occur at depths of 2,600 to 3,700 feet. There are some structures, including the Pittman anticline, bounded by two active reverse faults.

  During 4Q-2002, Evergreen drilled two separate 4-well CBM pilot production patterns (total 8 vertical wells). The company mobilized crews and equipment from the Raton basin. This undoubtedly added costs to the project but was necessary given the lack of suitable local capability. An air-percussion rig was used to drill to total depth in only three days (**Figure 9**).

ARI reviewed unpublished well records for the Evergreen test in detail. **Figure 10** shows the coal thickness that was perforated. Individual coal seams are fairly thin (3 - 6 feet). A total 34 to 39 feet of coal was completed in the wells. Coal seam depths ranged from 1700-2300 feet, which is generally considered favorable for CO_2 storage in this reservoir type. During the second quarter of 2003, Evergreen hydraulically stimulated all four wells of first pilot and one well of the second pilot. Four zones were frac'd in each well (**Figure 11**).

Although drilling permits were granted for two water-disposal wells, Evergreen abandoned the project in 2004 following long-term production testing, saying it was "probably not capable of commercial production." It is worth noting that the $1.80/Mcf wellhead gas price was among the lowest in the USA at the time. There was also considerable environmental opposition to the project.

- **Stormcat Energy.** This small natural gas operator acquired leases near the Evergreen project in the onshore Cook Inlet. Stormcat entered the play in 2004 by acquiring two leases totaling 18,359 acres at auction from the Alaska Mental Health Trust. Stormcat paid approximately $200,000 for 100% working interest in the leases, which run for a period of 5 years. However, Stormcat – which also has operations in the Powder River basin and the Fayetteville Shale -- entered bankruptcy in 2008 and has not drilled any CBM wells in Alaska.

- **XTO Energy.** In late 2003 this large independent gas producer tested a shallow uphole CBM zone in one or two of the company's shut-in wells at C platform, offshore Cook Inlet, where they operated conventional oil production (**Figure 12**). This was one of only very few offshore CBM well tests ever conducted. Gas production was needed to replace 700 Mcfd of gas from Unocal's Baker platform, which had been shut down. Results have not been released and it is not clear whether the test was successful or not.

- **Fowler Oil and Gas.** This small local independent operator currently holds about 25,000 CBM-prospective acres in the Matanuska Valley, the same general area as the Alaska DNR and Evergreen CBM projects. Fowler hold a permit to drill one well in the environmentally sensitive Mat-Su Valley. As of February 2009, the well site had been constructed but drilling is waiting on further funding.

  The Fowler leases reportedly are underlain by about 18 coal seams, each 6-10 feet thick. ARI estimates gas content to be in the 100-250 scf/ton range as measured in the nearby Alaska DNR corehole, although Fowler has estimated higher gas contents up to 500 scf/ton.

  Fowler plans to minimize environmental controversy encountered by Evergreen by using horizontal rather than vertical frac wells and has engaged Scientific Drilling as a potential drilling contractor. Scientific is planning on a 5-seam completion. Fowler also plans to use a downhole water diverter to directly re-inject water into a disposal zone without lifting it to the surface. (This method is being tested by Marathon Oil and Continental in the Powder River basin.)

After a 7-month application period to the Alaska Oil & Gas Conservation Commission, Fowler finally was granted a permit in May 2008 to drill a single “mother” well, from which multiple lateral wells could be kicked off. The permit is valid (and confidential) for two years. As of report time, Fowler had not yet spud the well.

- **Marathon Oil.** Alaska’s tight gas resources are beginning to attract interest but still have not been thoroughly assessed. The first conference on Alaska tight gas resources was held during April 2008 in Anchorage.[13] And the Alaska DNR has just begun a major research effort to characterize tight gas sandstone formations in the Cook Inlet region. Potential TGS target include the Eocene West Foreland Formation, which underlies the Miocene Tyonek coals in the Cook Inlet basin, is a complex fluvial to alluvial fan clastic deposit that may have TGS potential.[14]

  Marathon already has been completing tight gas and nearby coal formations in Alaska for about 7 years.[15] Not surprisingly, Marathon finds the Alaskan operating environment more challenging for TGS development than the Lower-48 states. Marathon’s main concerns for Alaska include relatively low gas prices, higher costs, geographic challenges, and the immature state of the service industry infrastructure.

  Marathon’s Kenai gas field has a thick clastic Tertiary gas-bearing section (**Figure 13**). The primary TGS target is the Beluga Sandstone in the offshore Cook Inlet. They typically encounter 10-20 gas sands within a 1700-foot thick stratigraphic interval. Individual sandstones range from 5-30 feet thick, with 0.01 to 3.0 mD of permeability (<0.1 mD generally is the cutoff for tight sands). Numerous coal seams also are present in the section.[16] Prior to hydraulic stimulation, Marathon’s wells produced at 0.5 to 1.0 MMcfd initially (pure methane, no condensate); some sands did not contribute at all.

CO_2 Storage Potential. Using the USGS coal resource estimate and an average estimated CO_2 adsorption content of 450 scf/ton (d.a.f.), three times the average 150 scf/ton methane content, ARI estimated CO_2 storage potential in the onshore Cook Inlet region to be approximately 21 Gt (**Table 2**). This preliminary estimate could be improved with new laboratory and well test data on the sorption characteristics of Cook Inlet coal.

Conclusions. The onshore Cook Inlet appears to have Alaska’s best potential for coalbed methane development as well as near-term CO_2 storage. Coal seams are thick, laterally extensive, and present at target depths of about 1 km. Early, albeit quite limited CBM testing has taken place. The existing natural gas infrastructure of Kenai LNG facility and gas pipelines, as well as drilling and well services, could help support CO_2 storage testing and operations in this region.

A future more detailed study could evaluate the large data set that exists in the Cook Inlet (**Figure 14**). There are several dozen well penetrations that could help define coal seam thickness, geometry, rank, and gas kicks, but their interpretation was beyond the scope of this preliminary scoping study. This evaluation could be followed by a possible CO_2 injection test in a well of opportunity, such as the planned and already permitted Fowler Oil & Gas well in the Matanuska-Susitna Valley.

2.4 North Slope

Geology. Coal underlies an area of approximately 83,000 km^2 in the onshore North Slope region (**Figure 15**). Coal occurs mainly in the Lower Cretaceous Nanushuk and Upper Cretaceous Colville Groups as well as in the Tertiary Sagavanirktok Group, representing deltaic and fluvial depositional environments.[17]

The Nanushuk Group is about 3 km thick and comprises a regressive marine to non-marine sequence. The lower Nanushuk Group comprises the marine-deposited Tuktu, Kukpowruk, and Grandstand Formations (**Figure 16**). Overlying these are the nonmarine Chandler, Corwin, and Ninuluk Formations.

Roughly 150 individual coal seams individually ranging up to 6 m thick occur in the middle and upper parts of the Nanushuk Group. Total coal thickness exceeds 400 feet in the thickest areas, within the western part of the Alaska National Petroleum Reserve.

Overlying the Nanushuk Group is the 1.5-km thick Upper Cretaceous Colville Group, which also contains extensive coal deposits. The Colville Group comprises (from bottom to top) the marine Seabee and Schrader Bluff Formations, and the coal-bearing, nonmarine Prince Creek Formation. However, the Colville Group coals are thinner, higher in ash content, and lower in rank (lignite) than those of the Nanushuk Group and thus have been less well studied.

Nanushuk coal rank is significantly higher than for the younger Miocene-age sub-bituminous coal deposits of the Cook Inlet basin. Nanushuk coal ranges from lignite A to high-volatile A bituminous, with a mean rank of high-volatile C bituminous. Identified resources are 120 billion short tons plus a further 3,870 billion tons of undiscovered (but fairly high probability) coal resources. Although the largest in Alaska, North Slope deposits are not currently mined due to their depth and remoteness.

Unconformably overlying the Cretaceous Nanushuk Formation are the Cretaceous-Tertiary Jago River and Sagavanirktok Formations. The Jago River Formation dates to Late Cretaceous to Paleocene, while the Sagavanirktok Formation is Paleocene to Pliocene and may be as young as Pleistocene.

The 2.3-km thick Sagavanirktok Formation, which intertongues with the Canning Formation of the Colville Group, comprises a coarsening-upward sequence of mainly sandstones, with siltstones, mudstones, conglomerates, carbonaceous shales, and coals (**Figure 17**).[18] Within the Sagavanirktok Formation are two coal zones, a lower 260-m thick unit with 12 coal seams and an upper 110-m thick unit with 7 coal seams. Individual coal beds range up to 7 m thick. Coal beds are distributed over an area of 15,000 km^2. The lower coal zone was deposited in an alluvial-delta plain setting, while the upper coal zone reflects lower delta-plain and back-barrier mires.

CBM Resources. There are no desorbed gas content data for the Alaska North Slope region, nor have laboratory sorption isotherms been measured. Based on mostly bituminous coal rank and average burial depths of approximately 2000 feet, ARI assumed a preliminary gas content of 200 scf/ton (d.a.f.). This generates a volumetric estimate of 621 Tcf of CBM gas in place (**Table 1**), a very significant deposit roughly equivalent in size to total Lower-48 State CBM resources.

Based on this assumed gas content and the USGS coal resource estimate, ARI estimates volumetrically there are approximately 621 Tcf of coalbed methane resources in the North Slope (**Table 1**). These CBM resources have not yet been well tested, are located far from existing natural gas infrastructure, and thus represent a long-term target for natural gas supplies.

CO_2 Storage Potential. Using the USGS coal resource estimate and an average estimated CO_2 adsorption content of 600 scf/ton (d.a.f.), three times the average 200 scf/ton methane content, ARI estimated CO_2 storage potential in the onshore North Slope region to be approximately 98 Gt (**Table 2**). This highly preliminary estimate could be improved with new laboratory and well test data on the sorption characteristics of North Slope coal.

Conclusions. Although the onshore North Slope region has a massive coal resource with significant CO_2 storage capacity, data on CBM reservoir properties are practically non-existent. The Cook Inlet region, with somewhat smaller but still sizeable resources, still appears to be Alaska's best near-term area for CBM development and CO_2 storage. Future work to locate and interpret individual coal corehole and oil and gas well logs in the western North Slope region, as well as sorption isotherm lab testing would be a low-cost but high-return approach to refine our preliminary estimate of CO_2 storage potential.

2.5 Central Alaska (Nenana)

Geology. The Nenana coal field in central Alaska is the state's smallest coal province yet also its most thoroughly studied, because it has experienced the most extensive coal mining. The Nenana coal province is located in the northern foothills of the Alaska Range (**Figure 18**). The region is not continuously underlain by coal, but rather comprises numerous small structural basins (synclines) that are separated by anticlinal highs where coal is not present, stretching over an area 15 km from north-south and 160 km long east-to-west.

Coal occurs mainly in the Tertiary Usibelli Group, a nonmarine sedimentary sequence. The Usibelli Group comprises (from bottom to top) the coal-bearing Healy Creek, noncoaly Sanctuary, coal-bearing Suntrana and Lignite Creek Formations and the noncoaly Grubstake Formation (**Figure 19**).[19] It is overlain unconformably by the Nenana Gravel. Up to 30 coal beds occur in the Usibelli Group, typically 0.7 m thick and reaching a maximum 9 m thick.

Coal in the Central Alaska-Nenana coal province ranges from lignite to subbituminous, most commonly subbituminous C. Coal in the Healy Creek and Lignite Creek coalfields ranges from 3,410 to 5,120 kcal/kg (mean 4,320 kcal/kg). Ash content ranges from 5 to 34% (mean 9.9%) and moisture content 15-33% (mean 24.7%).[20]

Coal Resources. The Central Alaska – Nenana region (**Figure 19**) has Tertiary coals estimated at 6.4 to 7.7 billion tons of identified resources, with an additional 10 billion tons of undiscovered resources.[21] Coal thickness is approximately 50 to 66 feet and occurs at depths ranging from surface to around 3,000 feet. Coal rank ranges from lignite to sub-bituminous, mainly sub-bituminous C. Although smaller than the North Slope and Cook Inlet, the Nenana basin is the only coal province in Alaska that is currently being mined.

CBM Resources and CO_2 Storage Potential. Based on the relatively low rank and shallow coals in the Central Alaska Nenana coal field, ARI estimated methane content to be in the range of 100 scf/ton. This is less than estimated for the deeper and/or higher rank North Slope (200 scf/ton) and Cook Inlet (150 scf/ton) areas and results in a volumetric calculation of only 1 Tcf of CBM resource in place (**Table 1**). Assuming CO_2 storage capacity of 300 scf/ton (triple the CH_4 content), total CO_2 storage could be well under 1 Gt (**Table 2**). The small potential of the Central Alaska Nenana coal field would appear to warrant low priority for future analytical and testing work.

2.6 Development Potential

Alaska CBM deposits still are at a very early stage of testing and there is very little reservoir data for evaluating CO_2 storage potential and costs. There are many reservoir risks including low permeability, undersaturation, lack of isolation from aquifers, as well as other risks. It is useful to look for commercial analogs in similar geologic settings, two of which appear broadly similar to Cook Inlet and the North Slope, though neither is a perfect analog.

One possible analog is the Powder River basin in Wyoming, which currently produces more than 1 Bcfd from about 30,000 vertical wells. However, the Powder River is considered a unique setting, in that CBM wells are uniquely shallow (300-1000 feet), very thick (50-100 foot individual seams), very low rank sub-bituminous to lignite (R_o = 0.3%), have low gas content (<50 scf/ton), but also extremely high permeability (~1 darcy). Powder River CBM wells are completed open-hole and unstimulated, an unusual method for the industry. Water production rates are high initially (500-1000 bwpd). Although per-well reserves are modest (<0.5 Bcf), capital costs are low ($0.25 million currently) and the basin is economic to develop at wellhead prices above $5/Mcf.

A second analog for Alaska CBM resources is the Washakie sub-basin within the Greater Green River basin of Wyoming,[22] where Anadarko and other operators currently are developing a 2 Tcf field. The eastern “Atlantic Rim” portion of the Washakie basin has multiple-seams that are moderately thick, ranging from 12 to 30 m within a 200-m thick stratigraphic section. Typically, about half (15 m) of the coal is completed and stimulated. Individual coal seams show lateral variation in thickness. Coal rank is comparable to that of the Cook Inlet and portions of the North Slope (R_o = 0.5%). Permeability is in the range of 10-30 mD, which is rather high but conceivable for Alaska. The coals are over-pressured with pressure gradients of 0.48-0.67 psi/foot and commonly are drilled with mud weights ranging from 10.3-12.3 pounds per gallon.

Washakie basin vertical frac wells spaced 160 acres and drilled to 600-m depth cost approximately $1 million all-inclusive, including drilling, completion, frac, pumping equipment, gathering system, and amortized costs for a water disposal well. ARI’s analysis indicates these wells recover an average 1.3 Bcf/well in the better areas, while less favorable areas recover 0.5 Bcf/well. The produced gas has a heating value of 990-1,000 Btu/ft^3, with <0.5% CO_2.

Water production in the Washakie CBM development is fairly high (1,200 barrels/day) during initial dewatering, then declines to below 500 Bwpd after about four years. Produced water quality ranges from 1,000-1,450 ppm TDS, mainly sodium bicarbonate. Most of the produced water is injected into the underlying Deep Creek sandstone at depths of 3,000 to 4,000 ft or Nugget sandstone at a depth of 9,600 ft at rates of 5,000 to 10,000 Bwpd per well.

In summary, while by no means a perfect commercial analog, the eastern Washakie and the Powder River basins together appear reasonably similar to Cook Inlet and North Slope CBM resources in terms of coal thickness, geometry, structural geology, rank, and hydrology. It would appear that Alaska CBM resources, and by inference their CO_2 storage, have development potential.

Drilling and completion costs for CBM and CO_2 injection wells in Alaska are uncertain but likely to be 20-100% higher than in the Lower-48 USA. The Alaska DNR has estimated the costs of drilling CBM test wells in several remote parts of the state, including the North Slope, central Alaska, and the northeastern Aleutian Islands (but not Cook Inlet).[23] These were full-sized, cased wells including a complete program of gas content and permeability testing. However, the wells were not to be stimulated or produced, so no frac, equipment, or water-disposal costs were included. The number of wells per site ranged from 2 to 4, thus rig mobilization costs were steep. Overall well costs were estimated to range from $0.25 to $1.0 million per well.

For the typical 3000-foot deep, 5-frac well in southern Alaska, ARI estimates capital costs for drilling, completion, stimulation, and equipment to run approximately $1.0

million per well, with an additional $0.5 million/well for gathering pipelines ($1.5 million/well all-in costs). There may be another $0.1 million/well for road construction, seismic, and other non-drilling costs. We further assume that gas treating and compression would be leased and appear as an operating expense.

CBM production and CO_2 injection operating costs will depend primarily on well depth, water production and disposal, power costs, and remoteness. Alaska operating costs probably will remain higher than L-48 costs due to climate and relative remoteness. No data on produced-water quality is available. Based on Evergreen's plan to re-inject, we assume that this would be necessary.

2.7 Gas Shale Resources

Gas shale reservoirs are the fastest growing natural gas supply source in the USA, as the large resource base becomes geologically better understood and advancements in well drilling and stimulation result in improving recovery. Gas shale production in 2008 averaged over 6 Bcfd, about 10% of US gas production, while major producer EnCana projects close to 15 Bcfd of gas shale production in the US by 2015.[24]

Although some of the other regional partnerships are evaluating gas shales for CO_2 storage, this study did not consider the CO_2 storage potential of gas shales in Alaska. First, budget constraints limited the study scope to conventional and CBM reservoir types. Second, there essentially are no public data on gas shale reservoir properties in the state. ARI's research did not uncover any documented gas shale targets in Alaska that could be included in this preliminary CO_2 storage evaluation. However, future more detailed evaluations should consider gas shale potential.

The only known gas shale exploration taking place in Alaska is by the mining company Teck Cominco, supported by ARI on the evaluation and testing of gas shale deposits near its Red Dog zinc mine in remote western Alaska.[25] Apart from this commercially confidential test, Alaska's gas shale resources remain poorly characterized.

3.0 Saline Aquifer Storage Potential

As is commonly the case for most geologic provinces, saline aquifer formations account for the bulk of Alaska's geologic CO_2 storage potential. However, unlike storage in deep coal or depleted oil and gas fields, saline aquifer storage would not benefit from potential enhanced hydrocarbon recovery. Most of Alaska's saline aquifer storage potential is located far from anthropogenic CO_2 sources and should be viewed as some of the country's longest-term storage potential. Although unlikely to be utilized anytime soon, it is still useful to attempt to quantify the undoubtedly vast storage potential of Alaska's thick and laterally widespread saline aquifers.

There are four main storage mechanisms for CO_2 operate in saline aquifer rocks.[26] These are:

- **Structural and Stratigraphic Trapping.** Migration of CO_2 in response to its buoyancy and/or pressure gradients within the reservoir is prevented by low permeability barriers (caprocks) such as shale.

- **Residual saturation trapping.** Capillary forces and adsorption onto the surfaces of mineral grains within the rock matrix trap some of the injected CO_2 along its migration path.

- **Dissolution Trapping.** Injected CO_2 dissolves and becomes trapped within the reservoir brine.

- **Geochemical Trapping.** Dissolved CO_2 reacts with pore fluids and minerals in the rock matrix of the reservoir, slowly forming reaction products as solid carbonate minerals over hundreds to thousands of years.

For the purposes of a first-order capacity estimate, we calculated structural and stratigraphic trapping in the estimated pore space. Residual saturation and dissolution trapping were not considered, due to lack of reservoir data at this early stage. Geochemical trapping was considered to be too slow to be significant over the time frame of an injection project (20-40 years) but would be significant over a much longer period.

All of the CO_2 storage estimates computed in this report, particularly for the poorly understood saline aquifer formations, should be viewed as highly scoping in nature. Further more detailed basin evaluation should be performed to confirm and refine these estimates.

3.1 North Slope Region (Colville Basin and Adjacent Chukchi/Beaufort Seas)

Introduction. The North Slope region contains several large sedimentary basins and is one of Alaska's most important potential CO_2 storage areas. **Figure 20** shows the major sedimentary basins in the North Slope region with CO_2 storage potential. These include the onshore North Slope and Colville basins and the offshore Nuwuk and Kaktovik basins. (The Chukchi and Beaufort Sea areas are discussed in separate sections.)

Figure 21 shows well, seismic and other data that ARI gathered into an ArcView GIS project for the CO_2 storage evaluation. Due to budget constraints, only a small sampling of the data could be interpreted for the current study. However, future analysis could build on our data compilation.

The onshore North Slope is dominated by the Colville basin, which hosts the prolific Prudhoe Bay and nearby oil fields. The Colville basin is relatively well studied, with extensive petroleum industry drilling and research conducted by the Alaska DNR and USGS.

The Colville Basin is the major sedimentary depositional feature on the North Slope and one of the largest basins in the USA (**Figure 22**). It is bounded on the south by the Brooks Range Thrust and on the north by the Barrow Arch, which generally parallels the Arctic Sea coastline.[27] Sedimentary rocks in the Brooks Range have been uplifted and structurally deformed, thus are not considered to be primary targets for CO_2 storage (**Figure 23**). Also not considered was the CO_2 storage potential of the National Petroleum Reserve Alaska (NPRA), which is located on the northern, shallower flank of the Colville basin, nor the Arctic National Wildlife Reserve (ANWR), which is located to the east.

A great thickness of Tertiary and Cretaceous clastic sediments derived from the ancestral Brooks Range was deposited in the North Slope foreland basin of northern Alaska. Uplift and erosion in the foothills of the Brooks Range has exposed these deposits. The rock units are dominantly nonmarine to near-shore shallow-marine shelf sediments deposited in fluvial, delta-plain, delta-front, prodelta, and shallow-shelf environments. Slope and basinal sediments deposited as turbidites and other sediment gravity flows correlative with the non-marine sediments also occur.

Figure 24 shows a schematic stratigraphic correlation section of the Brookian Sequence across the North Slope, while **Figure 25** shows a regional seismic cross section.[28] The sedimentary sequence comprises the Cretaceous Torok, Nanuskuk, Seabea, Tuluvak, and Shrader Bluff Formations as well as the Late Cretaceous to Paleocene Prince Creek and Paleocene-Ecocene Sagavanirktok Formations. The best targets for CO_2 storage appear to be thick and deep sandstones within the Torok and particularly the Nanushuk Formations.

Potential CO_2 Storage Reservoirs. Potential CO_2 storage reservoirs in the Colville basin include the following formations, presented from oldest to youngest.

- **Torok** (Cretaceous) : The oldest clastic unit in the North Slope Colville basin is the Torok Formation, a thick sequence of mainly nonresistant, fine-grained sedimentary rocks. The Torok forms the base of the folded sedimentary sequence that creates most of the northern foothills belt. The formation thickens from a minimum 1 km in the Arctic Coastal Plain in the north to about 6 km in the southern fold belt region. Age ranges from Aptian to Cenomanian.

  The Torok comprises mainly dark-gray to black silty shale, mudstone, and clay shale with interbedded thin-bedded siltstone and lesser amounts of greenish-gray, thin-bedded siltstone and finegrained sandstone.[29] Fine- to medium-grained sandstone also is common in the lower part of the formation. Channelized, thin-bedded fine-grained sandstone and debris-flow deposits are locally present in the lower part of the formation. Oil-stained sandstones up to 100 m thick are present, indicating good porosity and permeability development in past history.

  The Torok is the lower portion of the Nanushuk-Torok clastic wedge, with mudstone facies deposited in marine slope and basin-floor settings and sandstone facies deposited as turbidites in lower slope and basin-floor settings. The Torok is often deformed by chevron folding and faulting, because as a relatively thick and competent layer, it acts as a detachment surface for décollement folding of the overlying Nanushuk Formation.

- **Nanushuk** (Cretaceous) : This unit contains thick sandstones of Albian to Cenomanian age in the south-central North Slope, mainly non-marine and shallow marine deposits (**Figure 26**).[30] The Nanushuk typically is an erosionally resistant sandstone that forms prominent landscapes on the North Slope (**Figure 27**). Deep well data are sparse but outcrop samples have good permeability and porosity. **Figure 28** shows a transect from the marine shelf to the alluvial plain, illustrating the southward-thickening wedge of Nanushuk clastic deposits.

  Formation thickness of the Nanushuk ranges from about 250 m in the northeast, to about 1.5 km in the outcrop belt of the central Colville basin, to over 6 km in the western Colville basin. Subsurface data show that the Nanushuk pinches out along a shelf margin trending southward from the Colville River delta. Nonmarine sediments decline in importance from south to north.

  A total of 24 lithofacies in 10 facies associations have been mapped in the Nanushuk Formation (**Figure 29**). In order from base to top, facies range from alluvial floodbasin succession above crevasse splay sandstones, to trough cross-bedded sandstone, to pebble conglomerate with lenticular sandstone. Shoreface association is the most abundant association in marine strata of the Nanushuk.

Distributary mouth bar, distributary channel, and tidal inlet associations are common over relatively narrow stratigraphic thickness in the lower part of the formation. Nonmarine strata along south side of the outcrop belt include abundant tabular fluvial bodies, channel-fills, and alluvial floodbasin successions. Nonmarine sand and conglomerate bodies in outcrop are typically separated by poorly exposed fine-grained floodbasin successions (overbank facies associations), which might act as inter-formation seals for CO_2 trapping. (For example, back-barrier mudstone has been mapped immediately above shoreface sands.)

Figure 30 shows a measured outcrop section of the Nanushuk Formation, in the Kanayut River area, North Slope basin. The section measures a total 620 m thick, of which sandstone accounts for approximately 80% or 500 m. More typically, total Nanushuk formation thickness is approximately 10,000 feet (3 km; **Figure 31**).

The deltaic complexes in the south-central North Slope portion of the Nanushuk Formation are interpreted as having resembled the modern Po, Rhone, and Danube River deltas.

- **Seabee** (Cretaceous) : Conformably overlying the Nanushuk Formation, the Seabee (previously termed the Shale Wall Member of the Shrader Bluff Formation) comprises mudstone, silty mudstone, and fissile, organic-matter-rich paper shale, with interbedded bentonite and thin, silicified tuff beds. Thin siltstone and fine-grained sandstone beds are locally present, as are large (1.2-m) concretions.

  The Seabee Formation thickens from about 100 m west of Chandler River to about 400 m along the Nanuskuk River to the east (**Figure 32**). Seismic data shows the unit thickens abruptly eastward across the shelf margin to about 600 m. Its age is Cenomanian to Coniacian.

  The Seabee does not appear to be a primary target for CO_2 storage, given the predominance of mudstone and shale relative to scarce sandstones. However, the Seabee may act as an effective seal to the underlying sandstone-rich Nanushuk and Torok Formations.

- **Tuluvak** (Cretaceous) : Age of this unit is Turonian to Coniacian with thickness of approximately 400 m. The Tuluvak Formation forms the main reservoir at Gubik gas field and is locally oil stained, indicating good porosity and permeability in these areas. The middle part of the Tuluvak Formation is the coarsest and best-exposed, to pebble and boulder conglomerate. Interbedded coals and carbonaceous shales are abundant north of the Colville River. Well-sorted, fine- to medium-grained quartz marine sandstone also occur.

Although it has good reservoir properties in places, the Tuluvak is not particularly thick compared to other formations in the North Slope and thus may be viewed as a secondary CO_2 storage target.

- **Shrader Bluff** (Cretaceous) : Santonian to Maastrichtian in age, the Shrader Bluff Formation consists mainly of marine sandstones and shale which are locally and variably tuffaceous.[31] The formation reaches up to 800 m thick in the Chandler River region, thinning to about 400 m in the Umiat area (**Figure 32**).[32]

  The formation has been divided into three members, in ascending order: the Rogers Creek, Barrow Trail, and Sentinel Hill Members. The members represent a transgressive-regressive-transgressive cycle within the overall regressive succession of the Schrader Bluff and Prince Creek Formations. Subsurface data indicate the Schrader Bluff intertongues basinward (to the northeast) with deeper marine strata of the Canning Formation.

  The Schrader Bluff is bentonite-rich, containing common bentonitic shale, tuffaceous mudstone, and bentonitic fine-grained, fossiliferous sandstone, as well as beds of relatively pure bentonite. The upper part consists mostly of shallow-marine sandstones, incised by nonmarine channel sandstones.

- **Prince Creek** (Late Cretaceous to Paleocene) : This unit consists mainly of light-colored, nonmarine sandstones interbedded with carbonaceous mudstone, coal, and bentonite. Sandstones are very fine- to fine-grained and variably tuffaceous. Sands grains are dominantly quartz and black to gray chert. Thick sections of interbedded bentonite, bentonitic mudstone, carbonaceous shale, and coal also occur. Deposits characteristic of fluvial, meandering-stream environments are interbedded with deposits from marginal marine and intermittent shallow-marine intervals. Formation thickness is poorly controlled but appears to be around 400 m.

- **Sagavanirktok** (Paleocene to Eocene) : This formation unit consists of poorly consolidated siltstone, sandstone, conglomerate, and lignite of Tertiary age roughly 2 km thick. It's shallow depth and relatively poor reservoir qualities would seem to rate it as low potential for large-scale CO_2 storage.

Oil and Gas Potential. The North Slope is the largest oil and gas producing area in Alaska as well as one of the most important in the country. The Ellesmerian sequence includes the reservoirs for the Prudhoe Bay, Lisburne and Endicott fields. The Beaufortian or rift sequence includes the Kuparuk River, Alpine, and Milne Point fields, among others. Finally, the Brookian sequence in the Colville basin includes the Meltwater, Tarn and West Sak oil fields.

The USGS recently conducted an updated study of undiscovered, technically recoverable oil and gas resources in the central North Slope region. The study comprised 24 individual conventional resource plays in the onshore and offshore region between NPRA and ANWR.[33] The mean estimate was determined to be approximately 4 BBO and 33 Tcf.

In addition, the Beaufort and Chukchi Sea areas in the Arctic Ocean north of the North Slope probably contain large undiscovered oil and gas resources. These continental shelf regions share a tectonic rift history with the North Slope region, but are considered to have even larger undiscovered resource potential. The MMS recently evaluated these areas and identified twelve large (>150,000-acre) prospective structures that individually exceed the size of Prudhoe Bay field. MMS estimates undiscovered potential oil and gas resources in the combined Beaufort and Chukchi seas in the Arctic Ocean to be about 24 BBO and 104 Tcf (mean estimate).[34]

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the North Slope Colville basin. Thickness was difficult to estimate, despite the relative abundance of data. The Nanushuk Formation was assumed to be the main target, averaging 2 km thick including a conservative average 1 km of sandstone thickness. The Nanushuk was estimated to cover an area of 75,000 km^2, approximately the entire area of the Colville basin. In addition, the Schrader Bluff Formation was estimated to add an additional 250 m of sandstone over an equivalent area, for a total 750 m net sandstone thickness. Other formations could add additional sandstone thickness but were not considered given their generally lower reservoir quality.

Based on average sandstone thickness (750 m) and porosity (25%) data and the estimated total basin area (75,000 km^2) and the average depth to the sandstone package (2,000 m), we estimate that the CO_2 storage potential of the Colville basin could be on the order of 4,920 Gt.

3.2 Chukchi Sea Area

Introduction. North and offshore of the Colville basin, the Chukchi and Beaufort Seas on Alaska's Arctic continental shelf contain extensive but still poorly defined sedimentary sequences. These areas are covered most of the year by moving ice sheets, making these particularly challenging areas for petroleum (or CO_2 storage) operations.

ARI compiled data location maps for these regions (**Figures 33** and **34**), showing mostly 1970 and 80's-vintage seismic data and the relatively few petroleum exploration wells that have been drilled in these remote and operationally hostile Arctic Ocean areas.

The Minerals Management Service (MMS) conducted early studies during the 1970 and 80's when initial leasing and industry exploratory drilling took place.[35,36] MMS recently (2006) updated its estimate of undiscovered oil and gas resources in the

Chukchi/Beaufort Sea region, but there still is little publicly available geologic information, apart from the older, low-quality seismic reflection data and the key Shell Klondike 1 exploration well log.

Thus, it was not possible to conduct a thorough investigation of the CO_2 storage potential of the Chukchi and Beaufort Sea areas. Fortunately, however, the geology of these regions is considered by researchers in Alaska to be broadly similar to that of the Colville basin. We treated the Chukchi and Beaufort Seas as extensions of the Colville basin for the purpose of estimating CO_2 storage capacity.

Initially explored during the early 1980's, when over 100,000 line miles of seismic data were collected, recent higher oil prices have sparked renewed interest in the petroleum potential of the Chukchi Sea. In its first petroleum license auction since 1991, the MMS recently garnered $3.5 billion in bonuses for new exploration and production leases.[37] However, the Chukchi Sea remains a remote and operationally highly challenging region for petroleum development as well as CO_2 storage.

The 127,000-km^2 Chukchi Sea region encompasses the outer continental shelf of northwestern Alaska (**Figure 35**). The Chukchi Sea actually is not defined as a geologic basin but rather is an MMS administrative area. About 90% of this area is in water shallower than about 200 feet, which until recently has been considered the practical limit for petroleum development in the Arctic.

The Chukchi and Beaufort Sea areas share similar general stratigraphy (**Figure 36**). Sedimentary units in the Chukchi comprise the metamorphosed Franklinian sequence of carbonates and clastics (Cambrian-Early Devonian); the Ellesmerian sequence of mildly deformed marine shelf deposits (Late Devonian-Early Cretaceous); and the Brookian clastic transgressive wedge of deep marine to nonmarine sediments (Early Cretaceous-Holocene). Some units, such as the Ellesmerian, are even thicker than their onshore equivalents in the central Chukchi Sea. Seismic interpretation shows that the regional geology of the Chukchi Sea is an extension of the onshore North Slope and Brooks Ranges (**Figure 37**).

Figure 38 shows a time-structure map of acoustic basement in the Hope basin, Chukchi Sea. Structural elements in the Chukchi are extensions of those present in the onshore North Slope. Faults trend mainly northwest-southeast. The Ellesmerian reflector can be traced from onshore to an estimated depth of 45,000 feet in the Tunalik basin. The basin's southern margin is defined by thrusting associated with the Herald Arch. The Wainwright fault zone defines the northern boundary.

Potential CO_2 Storage Reservoirs. The Chukchi Sea region contains numerous potential saline aquifer reservoirs that could be suitable for CO_2 storage. The most prospective may be the Ellesmerian sequence, including the Endicott, Lisburne, and Sadlerochit Groups and the Kuparuk River Formation, all of which are productive in the Prudhoe Bay oil fields. Major sandstones also occur in the Brookian sequence, including in the Nanushuk Group.

The Shell Klondike 1 well was a critical data point for our estimate of CO_2 storage capacity of the Chukchi Sea region. It was located about 75 miles northwest of Point Lay in the central Chukchi Sea and drilled vertically in 1989 to a total depth of about 12,000 feet (**Figure 33**). The well encountered a clastic sequence, including numerous reservoir-quality sandstones in the Kuparuk, Torok, and Nanushuk Formations as well as the Brookian unit.

Figure 39 shows the stratigraphic log from this key well. Sandstones become better developed and more frequent towards the top of the sequence, especially within the Nanushuk and Brookian sequences. Individual sandstone units range from 50 to 400 feet thick. The upper two sandstone units in the Cretaceous Torok and Nanushuk Formations that were cored and analyzed had good porosity (28%) and permeability (63-259 mD). However, at the Kavik-equivalent Formation level close to 11,300 feet deep, the sandstone had become extremely tight (k = 0.01 mD), although oil shows still were apparent.

Overall, the Klondike 1 well and seismic coverage in the basin suggests that the Chukchi Sea could have significant CO_2 storage potential within saline aquifers. **Figure 40** shows the detailed sandstone analysis for this well, including sandstone depth, thickness, and reservoir quality data.

The well penetrated a total gross sandstone thickness of about 3,405 feet. Three sidewall cores were analyzed, with good porosities (28%) in the two shallower samples and much lower porosity (6%) in the deepest sample. Permeability also was much higher in the shallow samples (63 to 259 mD vs 0 mD). Based on this small data set, the net CO_2-prospective storage depth in the Chukchi Sea would seem to be in the range of roughly 3000-10,000 feet. The Klondike well encountered a net total of 1,880 feet (573 m) of sandstone with good porosity, permeability, and depth characteristics.

Lacking additional well data, ARI assumed that the Klondike sandstone thickness, depth and reservoir quality would be uniform throughout the Chukchi Sea basin, a simplistic but necessary assumption.

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the Chukchi Sea basin based on rounded average sandstone thickness (600 m) and porosity (25%) data from the Klondike well. The density of CO_2 at this depth (2,000 m) and probable low temperature (20º C) likely would be high (700 kg/m^3).[38] Based on the estimated total basin area with at least 2 km of sediment (100,000 km^2) and the average depth to the sandstone package (2,000 m), we estimate that the CO_2 storage potential of the Chukchi Sea basin could be on the order of 5,250 Gt.

3.3 Beaufort Sea Area

The Beaufort Sea geology was introduced previously in the Chukchi Sea section. The Beaufort Sea is covered by a pervasive and mobile ice cover which complicates petroleum (or CO_2 storage) activities. From an operational perspective, the Beaufort Sea likely would be Alaska's most challenging area for CO_2 storage.

The Beaufort differs from the Chukchi in that oceanic rifting took place during early Cretaceous time, marked on its southern edge by the "Hinge Line." The northern portion of the Beaufort Sea (Canada basin) is characterized by thin sedimentary deposits overlying oceanic crust and likely would not be suitable for CO_2 storage. South of this line, however, much of the Beaufort contains a thick Ellesmerian sequence, correlative with productive units in the Prudhoe Bay region, such as the prolific Triassic Ivishak Sandstone.

Thus, the CO_2-prospective portion of the Beaufort Sea is restricted to a long, narrow belt that parallels the modern coastline of northern Alaska (**Figure 41**). Basins in this belt include the Nuwuk and Kaktovik basins as well as the Arctic Platform. The estimated area prospective for CO_2 storage is approximately 30,000 km^2. Based on onshore Arctic Coastal Plain trends, the MMS predicted that the geothermal gradient in the Beaufort Sea subsurface ranges from 27-36ºC/km.

The Ellesmerian is absent or buried deeper than 20,000 feet in the Nuwuk and Kaktovik basins, but fluvial-deltaic sandstones in the Brookian sequence are well developed and considered to have the potential for good reservoir characteristics (**Figure 42**). More deeply buried Brookian turbidites, formed in submarine canyon complexes, are considered lower potential for petroleum and CO_2 development. Brookian sandstone porosities are thought to range from 12-16% in the lower-quality deltaic sandstones to 25-35% in the pro-deltaic sandstones.

Exploration wells in the US Beaufort Sea remain confidential, but the Dome Petroleum Natsek E-56 well log, located about 30 miles east of the US-Canada border in the Canadian portion of the Beaufort Sea, is available (**Figure 43**). This well encountered a 3,200-foot thick gross section of good-quality, fluvial sandstones and conglomerates (porosity >10%) in the Late Cretaceous to Early Eocene section at depths of 6,500-8,700 feet. Siltstones, shales, and coal seams are intercalated with these sandstones. Net sandstone thickness in this section alone is more than 1,600 feet.

Additional marine sandstones were penetrated in the deeper Late Cretaceous section, but appear to have poor reservoir quality (porosity <10%). The sandstone sequences are overlain by thick (5,000 feet) and continuous Early Paleocene marine shales, which would seem to be an effective CO_2 seal. The US Beaufort Sea is likely to have similar sandstone and shale sequences suitable for CO_2 storage.

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the Beaufort Sea basin based largely on the Dome Natsek well log. Average sandstone thickness was estimated to be 500 m, with estimated 20% average porosity. The density of CO_2 at this average depth (2,300 m) and probable moderately low temperature (72º C) likely would be high (700 kg/m^3).[39] Based on the total basin area with at least 2 km of sediment (30,000 km^2, stretching an estimated 600 km east-west by 50 km north-south) and the average depth to the sandstone package (2,300 m), we estimate that the CO_2 storage potential of the Beaufort Sea basin could be on the order of 1,050 Gt.

3.4 Norton Basin

Introduction. The Norton basin is located off the west coast of Alaska, just south and southwest of the Seward Peninsula. It generally corresponds with the Norton Sound in the eastern Bering Sea (**Figure 44**). The Norton basin is elongated in the east-west direction, extending over a total area of about 34,000 km^2. Water depths are fairly shallow, ranging up to 50 m.

Norton Sound actually comprises two distinct sub-basins separated by the northwest-trending Yukon Horst, which has up to 3 km of uplift. The Stuart basin in the east part of Norton Sound has up to 6.5 km of sediments, while the St. Lawrence basin to the west contains up to 5 km of sedimentary deposits. These basins contain up to 24,000 feet of Tertiary marine and non-marine sedimentary rocks.[40] The geothermal gradient is fairly high, stabilized at about 45º C/km in the COST #1 well.[41]

Figure 46 shows a structure map on seismic horizon A in the Norton basin. The Norton basin is structurally fairly complex with numerous mainly northwest-southeast trending faults and folds. It is an extensional basin adjacent to the right-lateral strike-slip Kaltag Fault, which extends offshore southwestward from onshore Alaska and forms the southern margin of the Norton basin. Outcrop samples of sandstones from outcrops surrounding Norton Sound tend to have poor reservoir properties, generally less than 10% porosity and about 1 mD of permeability.[42]

Since 1984 a total of six petroleum exploration wells have been drilled in the Norton basin; all have been plugged and abandoned with no commercial discoveries announced. In 1980 two joint industry COST (Continental Offshore Stratigraphic Test) wells were drilled and logged in the shallow Norton Sound portion of the Norton basin.

The COST #1 well was drilled west of the Yukon Horst in the St. Lawrence sub-basin, which COST #2 penetrated the Stuart sub-basin east of the uplift. Both wells were drilled into the deeper portions of their respective sub-basins and so encountered relatively thick sedimentary sections.

The COST wells both were drilled to metamorphic basement at depths of 12,500 to 14,500 feet, and encountered generally similar clastic marine shelf sequences of Eocene to Pleistocene sediments (**Figure 47**). These Paleogene and Neogene deposits rest unconformably on Precambrian to Paleozoic metasedimentary basement, similar to outcrops in the Seward Peninsula.

The Arco Norton Sound COST No. 1 well was drilled to a total depth of 14,683 feet in 90 feet of water on OCS lease block 197, approximately 54 miles northwest of Nome, Alaska.[43] The well encountered a 900-m thick continental coal-bearing Eocene (?) section and 1600-m thick Oligocene mostly marine sequence. This was followed by 560-m thick Miocene, 400-m thick Pliocene and 350-m thick unconsolidated Pleistocene sediments.

Potential CO_2 Storage Reservoirs. Potential reservoir sandstones in the COST #1 well in the St. Lawrence sub-basin were outer shelf upper slope and turbidite deposits. COST #2 sandstones in the Stuart sub-basin were deposited mainly in alluvial, deltaic, and shallow shelf settings. This relationship probably reflects the Stuart basin's closer proximity to sediment sources.

The Neogene section in the COST wells comprises Miocene and Pliocene diatomites, diatomaceous mudstones, siltstones and sandstones, reflecting inner- to middle-shelf depositional environments (**Figure 48**). The diagenic conversion from Opal-A to Opal-CT appears to occur at a depth of about 3,500 feet in these wells. Thus, most of the diatomaceous section would be low-permeability Opal-A mudstone, probably with poor reservoir characteristics.

Underlying the Neogene are Oligocene turbidites which actually account for most of the sedimentary sequence in the Norton basin and have much better potential reservoir properties. Several regressive/transgressive sequences occurred during the Oligocene, depositing interbedded shallow shelf to deltaic sandstones, siltstones, mudstones, and coals. Nonmarine deltaic sediments are more prevalent in the Stuart sub-basin, again reflecting its closer proximity to sediment sources; COST #2 well penetrated a number of thick coal seams.

Figure 49 is a detailed sandstone thickness log for the COST #1 well showing turbiditic sandstone development between depths of 7,200 to 8,350 feet. Individual sandstones in the Oligocene generally are 5-20 feet thick and relatively clean based on their large SP and gamma log deflections as well as core and petrographic data. Analysis of whole core in sandstones from depths of 7030 to 7046 feet (admittedly a small sampling) in the COST #2 well showed porosities ranging from 8.5 to 20.3%, averaging 15%. Quartz content averaged 40% with significant lithic fragments, feldspar, and clay. Permeability averaged about 100 mD.

Thermal maturity is fairly low in the Norton basin, with the COST #2 well measuring vitrinite reflectance of only 0.54% at a depth of 10,000 feet. Maturity increased to 0.74% at 11,900 feet, with a sharp increase to 1.0% at 12,200 feet indicating a possible erosional unconformity.

The most recent (1995) resource assessment prepared by the MMS for the Norton basin places its potential undiscovered natural gas at about 2.7 Tcf. Of this total, perhaps 29 Bcf has not been developed but is located within 30 miles of Nome and may be producible over 30 years. Development costs for this part of Alaska are high, but one recent (2005) study determined that development could be economically feasible.[44]

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the Norton basin based on relatively thin average high-quality sandstone thickness (300 m) and low-moderate porosity (15%) data from the Norton COST well. The density of CO_2 at this depth (2,400 m) and probable high temperature (100º C) likely would be moderately high (600 kg/m^3).[45] Based on the total basin area with at least 2 km of sediment (19,500 km^2) and the average depth to the sandstone package (2,400 m), we estimate that the CO_2 storage potential of the Norton basin could be on the order of 260 Gt.

3.5 Navarin Basin

Introduction. The Navarin basin is located west of the Norton basin in far western offshore Alaska, close to the disputed US-Russian international boundary (**Figure 44**). Data for the Navarin basin that were gathered by ARI into a GIS project are shown on **Figure 50**.

The Navarin basin covers a total area of approximately 80,000 km^2, as defined by the 2-km basement depth, about equivalent to the state of Maine. The Navarin basin is considered a forearc tectonic setting that formed in the Late Cretaceous-early Tertiary as a response to oblique subduction or transform motion between the Kula and the North American plates.[46]

The Navarin basin contains in excess of 10 km of Tertiary sedimentary rocks and comprises three sub-basins (Navarinsky, Pervenets, and Pinnacle Island) that are separated by basement uplifts (**Figures 51** and **52**). The basin trends northwest-southeast and is fairly symmetrical. Several major northwest-trending faults cut the basin, with the deeper Horizon B reflector reaching depths below 11,000 feet in the basin center.

The Pinnacle Island sub-basin, southernmost of the three depocenters in the Navarin basin, is an asymmetric northwest-trending graben measuring 170 miles long by 45 miles wide and filled with over 10 km of Tertiary sediment. The Pervenets sub-basin is a symmetrical graben 75 miles long by 15 miles wide with up to 10 km of Tertiary sediment. The Navarinsky sub-basin, northernmost of the three, is more circular in shape, extending about 70 by 50 miles and containing at least 10 km of Tertiary deposits.

Seismic data interpretation performed by the MMS and the Arco Navarin COST #1 well, the first deep stratigraphic test in the region, provide the main data sources for the CO_2 storage evaluation. The Navarin COST 1 well was funded by a consortium of 18 oil companies and drilled in 1983 by joint industry operator Arco. Located in 432 feet of water, and centrally located within the Navarin basin, the COST well was drilled vertically to a total depth of 16,400 feet. A total 20 conventional whole cores, each 30-feet long, were cut between depths of 3,637 to 16,342 feet. The well was cased to a depth of 12,834 feet and a thin 20-foot interval from 6,278-6,298 feet was drill-stem tested.

The lower section penetrated by the COST well (13,000-16,400 feet) comprised Late Cretaceous Campanian and Maastrictian sections (**Figure 53**). Unconformably overlying the Mesozoic was a thin Eocene and much thicker Oligocene section from depths of about 5,700 to 13,000 feet. These are conformably overlain by Miocene and Pliocene deposits from about 1,500 to 5,700 foot depth.

The Late Cretaceous section includes an angular unconformity at a depth of about 12,780 feet, below which rocks dip 25-30 degrees and have been intruded by diabase and basalt sills. The Eocene section consists of dark-gray calcareous claystone and sandy mudstone.

The lower Oligocene section comprised poorly sorted gray claystone, mudstone, and sandy mudstone with abundant detrital clay matrix that was deposited in a bathyal environment. The middle to upper Oligocene interval is characterized by sandy mudstone, fine-grained muddy sandstone, and claystone with rare lenses of siltstone and sandy carbonate that reflects marine outer shelf and upper slope environments.

The Miocene interval consists of fine and very fine-grained, poorly to well sorted sandstone and siltstone interbedded with mudstone and claystone, probably deposited in a middle to outer neritic environment. Some of the sandstones are up to 100 feet thick, with 28-33% porosity but fairly low permeability (5 to 233 mD). Finally, the Pliocene interval consists of poorly sorted, silty to sandy mudstone and diatomaceous ooze deposited in a mid-shelf environment.

Potential CO_2 Storage Reservoirs. Apart from the Late Cretaceous coal-bearing section, the fine-grained clastic sediments encountered in the Navarin COST wells all were deposited in a marine environment. Reservoir characteristics are generally poor, with porosity and permeability reduced by compaction, cementation, diagenesis, and authigenesis.[47]

The only significant potential reservoir-quality sandstones occur in the early to middle Miocene to late Oligocene sequence, namely zones C-1 and C-2 at depths of about 5,000-7,000 feet in the COST well. These marine shelf sandstones occur in a regressive sequence with 1,425 feet of net sandstone out of a total 2,120-foot thick section. About 1,070 feet of this sandstone was characterized by SP deflections of at least 10 mV, considered good reservoir quality. These sandstones are described as feldspathic litharenites, dominated by feldspar and lithic fragments with quartz generally accounting for less than 40% of the grains.

Sandstone porosity was determined by core and log analysis to range from 25% to 35%. However, effective porosity determined petrographically, considered by MMS to be more indicative of actual conditions, was much lower at 5-20% with an average of about 15% (**Figure 54).** Permeability also generally was low, mostly under 10 mD although a few samples measured in the range of 20-120 mD.

Static bottomhole temperature analysis in the Navarin COST well indicate a stable temperature of about 100º C at a depth of 8,000 feet. The temperature gradient was about 1.8º F / 100 feet from TD to a depth of about 3,800 feet and higher (2.5º F / 100 feet) above the 3,800-foot depth level.

Thermal maturity is relatively low in the Navarin basin. The COST well encountered vitrinite reflectance of 0.6% at a depth of 10,000 feet. Anomalously high R_o's of up to 4% were encountered at depths below 13,000 feet in this well, probably reflecting local contact metamorphism with Miocene-age sills that intruded the Cretaceous section.

The only successful RFT test in the COST 1 well confirmed over-pressured reservoir conditions below depths of about 9,400 feet. The pressure gradient was calculated at 0.524 psi/foot pressure gradient, significantly higher than hydrostatic 0.45 psi/foot gradient at this location. These abnormal pressures may reflect hydrocarbon generation at depth overlain by effective sealing shales. Of note, sealing caprock was identified in the well at a depth of 8,500 to 9,550 feet, comprising "grey, sticky, plastic, bentonitic shales" that appear to be excellent seals.

A second over-pressured zone was identified between 2,500 and 3,840 foot depth, which may be caused by diagenetic changes in the Miocene siliceous diatomite-rich shales. Although considered potential drilling hazards, these overpressured zones indicate the presence of good sealing cap rocks for effective CO_2 storage in the Navarin basin.

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the Navarin basin based on relatively thin average high-quality sandstone thickness (325 m) and low-moderate porosity (15%) data from the Navarin COST well. The density of CO_2 at this depth (1,800 m) and probable high temperature (100º C) likely would be moderately high (600 kg/m^3). Based on the large total basin area with at least 2 km of sediment (80,000 km^2) and the average depth to the sandstone package (1,800 m), we estimate that the CO_2 storage potential of the Norton basin could be on the order of 1,170 Gt.

3.6 North Aleutian / Bristol Bay Basin

Introduction. Located in southwestern Alaska, the North Aleutian/Bristol Bay basin lies just north of the Aleutian Island Arc (**Figure 55**). The portion of the basin containing at least 2 km of sediment extends over an area of approximately 20,000 km^2 (400 km east-west by 50 km north-south), the vast majority of which is offshore. Data control is relatively sparse, consisting mainly of outcrop studies along the north Aleutian coast and several deep offshore petroleum exploration wells, including notably the NAS COST 1 joint industry stratigraphic test well.

The Bristol Bay basin is not productive for oil and gas and has experienced relatively little drilling activity during the past few decades. However, it is a frontier oil- and gas-prospective basin that tectonically is a back-arc basin in the Aleutian Island Arc subduction system. **Figure 56** shows the regional geology and tectonics of the Bristol Bay basin and Alaska Peninsula.

The Bruin Bay Fault separates unmetamorphosed, oil-prone Mesozoic sedimentary rocks to the southeast from highly metamorphosed and intruded Mesozoic rocks to the northwest. The David River Zone (DRZ) west of Port Moller is a combination dextral strike-slip and uplift that separates the subsiding Bristol Bay basin on the north from the transpressional Black Hills Uplift to the south.

Potential CO_2 Storage Reservoirs. Triassic to Tertiary sedimentary rocks are present in the North Aleutian / Bristol Bay basin (**Figure 57**). The main oil and gas prospective targets are the Eocene Tolstoi, Eocene-Oligocene Stepovak Fm, and Miocene Bear Lake Formations (**Figure 58**). Overall, the Bristol Bay hydrocarbon system is considered somewhat analogous to that of the well-studied productive Cook Inlet basin.[48] Seismic and well log data gathered into an ArcView GIS data base are shown in **Figure 59**.

The Bristol Bay COST 1 well, a joint industry research effort operated by Arco, was drilled in 1983 to a total depth of 17,155 feet (**Figure 60**). The well encountered thick sandstones with good reservoir characteristics, particularly between the depths of 3,000 to 8,000 feet. Individual sandstone units ranged from 10 to 200 feet thick and are separated by siltstones and shales (**Figure 61**).

Overall, sandstone porosity in the COST well averaged about 22.8% while permeability averaged 338 mD (**Figures 62, 63**; not thickness-weighted), both good values for CO_2 storage. The Cenozoic units penetrated in the well are coaly and dominantly gas-prone, possibly with minor liquid-prone coals.[49]

Vitrinite reflectance measured in the NAS COST 1 well in the western Bristol Bay basin showed R_o increasing fairly linearly from a very low 0.15% at a depth of 3,000 feet to a maximum 1.0% near total depth of just over 17,000 feet. This low trend suggests paleo heat flow in this basin has been fairly low.

Despite the lack of oil and gas activity, there are significant mainly sandstone saline aquifer formations in the Bristol Bay basin that could provide CO_2 storage capacity. The main units with reservoir data and CO_2 storage potential include the Tertiary Bear Lake, Stepovak, and Tolstoi Formations, of which the Miocene Bear Lake Formation appears to have the most attractive potential reservoir rocks. Few reservoir data are available for the older Mesozoic sedimentary rocks.

Figure 64 shows a regional stratigraphic cross-section of the Bristol Bay basin, illustrating the thickness and continuity of the Miocene Bear Lake, Stepovak, and Tolstoi Formations. The Bear Lake Formation is the most laterally persistent, while the Stepovak and Tolstoi Formations either were eroded or not deposited on paleo highs. However, all three units have thick sandstone packages with good porosity and permeabiolity, as well as interbedded shales with excellent hydrocarbon sealing capacities.

The Miocene Bear Lake Formation (BLF) is present offshore in most of the Bristol Bay basin and is exposed along the coast near Port Moller on the Alaska Peninsula. It is exposed along the coast of the Alaska Peninsula near Port Moller, where it is approximately 1.2 km thick. The BLF is considered to have the best reservoir potential in the Bristol Bay basin,[50] with Mesozoic rocks and Cretaceous-Tertiary coals and carbonaceous shales the most likely potential hydrocarbon source. Total organic carbon is approximately 5.3%, with hydrocarbon index of 756 and vitrinite reflectance ranging from 0.6% to 0.8%.

The BLF is a transgressive sequence resulting from rapid subsidence on the southeastern margin of the foreland basin, despite a eustatic drop in sea level that took place during its deposition. This subsidence may have been caused by a northward prograding thrust belt or emplacement of intrusive rocks in the arc to the south.

The lower BLF section is characterized by fossiliferous, cross-stratified sandstone and interbedded coal and mudstone deposited in a fluvial setting. The central portion of the BLF is mainly bioturbated sandstone and shale interbedded with wavy- and flaser-bedded sandstone and shale. The upper BLF consists of flaser- and wavy-bedded sandstone and conglomerate, bioturbated sandstone locally rich in marine trace and megafossils, and coarse-grained, bioturbated, channelized sandstone interbedded with discrete horizons rich in marine megafossils.

The Alaska DGSS measured porosity and permeability of sandstones on 11 samples taken at two onshore locations from the Bear Lake Formation. Porosity of samples within the same sandstone package varied from about 4% to 17%, generally averaging around 10%. Permeability was mostly quite low (<0.05 mD), qualifying as tight sandstone. However, two samples from the Sundean location measured significantly higher permeability of around 0.2 mD and one sample from the Left Head location measured about 0.5 mD.

Deep petroleum exploration wells in the offshore central Bristol Bay basin had considerably higher porosity and permeability (**Figure 65**). The Tertiary Bear Lake Formation has the best porosity (25 to 40%) and permeability (10 to 4,000 mD), followed by the Stepovak (5-35%; 0.01-3,000 mD) and Tolstoi (0-25%; 0.02-200 mD) Formations. No water chemical composition data were available, but formation water is assumed to be saline given the age of the units and the mainly offshore location. Overall, the Mesozoic and Tertiary sedimentary rocks in the Bristol Bay basin appear to be excellent potential CO_2 storage reservoirs.

Potential intra-reservoir seals exist in the Bristol Bay basin, considered by the AGGS to be similar to those in the Cook Inlet, mainly interbedded shales. The hydrocarbon seal capacity in the Bear Lake, Tolstoi, and Staniukovich Formation ranges from several hundred to nearly 4,000 feet, indicating excellent potential CO2 sealing capacity in the basin (**Figure 66**). Numerous structural and stratigraphic traps also are present. These seals would appear to be sufficiently thick and laterally widespread for effective CO_2 trapping.

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the North Aleutian / Bristol Bay basin based on average sandstone thickness (1,100 m) and porosity (23%) data from the centrally located North Aleutian COST well. The density of CO_2 at this depth (1,700 m) and probable low temperature (50º C) likely would be high (700 kg/m^3).[51] Based on the total basin area with at least 2 km of sediment (20,000 km^2) and the average depth to the sandstone package (1,700 m), we estimate that the CO_2 storage potential of the North Aleutian / Bristol Bay basin could be on the order of 1,770 Gt.

3.7 St. George Basin

Introduction. Located in southwestern Alaska, the St. George basin is located north of the Aleutian Islands and west of the North Aleutian/Bristol Bay basin (**Figure 67**). The St. George basin is a northwest-trending graben approximately 200 by 25 miles in size with over 40,000 feet of Tertiary sediments overlying Lower Cretaceous Hoodoo to Upper Jurassic Naknek acoustic basement rocks penetrated by the St. George COST #1 well. Tertiary deposition took place during graben formation, probably related to oblique subduction of the Kula plate underneath North America, and continues with active subsidence to the present time.[52]

Two COST wells were drilled in the St. George basin during the early 1980's. In 1976 Arco drilled the COST No. 1 well in 442 feet of water about 20 miles south of the graben to a total depth of 13,771 feet. The well penetrated about 10,000 feet of volcaniclastic Cenozoic sediment overlying basaltic basement rock. Strata encountered in the well were Pliocene (from 1600-3600 feet), Miocene (from 3600-5370 feet), Oligocene (from 5370 to 8410 feet), and Eocene (from 8410 to 10,380 feet).[53]

The sedimentary section in the COST 1 well consisted of interbedded sandstone, siltstone, mudstone, diatomaceous mudstone, and conglomerate reflecting mainly volcanic source terranes. The sediments consist of physically and chemically unstable materials that are easily deformed and altered. Permeabilities are lower than might be expected for the given porosities. Porosity and permeability have been reduced by ductile grain deformation, cementation, and authigenesis.

The COST No. 2 well was drilled within the first set of faults on the south flank of the graben, penetrating over 12,000 feet of volcaniclastic Cenozoic sediment and 2000 feet of the underlying Mesozoic sedimentary rocks.[54]

Potential CO_2 Storage Reservoirs. Thick Tertiary sedimentary rocks with good potential reservoir characteristics are present in the St. George basin. **Figure 68** shows sandstone sequences ranging from 200 to 1650 net feet thick at depths of 1,600 to 11,000 feet in the two St. George COST wells. Porosity ranges from 25-38% with permeability averaging close to 100 mD. On average for the two wells, total reservoir-quality sandstone thickness averages about 2,500 m, with average 31% porosity and fair permeability in the range of 50-100 mD (**Figure 69**).

Figure 70 shows the lithologic log for the COST #2 well, which penetrated over 12,000 feet of volcaniclastic Cenozoic sediment and 2000 feet of the underlying Mesozoic sedimentary rocks. The sandstones encountered in this well generally have good reservoir quality, totaled over 9,000 feet thick, and have 31% average porosity 50-100 mD of permeability.

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the St. George basin based on excellent average sandstone thickness (1,800 m) and porosity (31%) data from the centrally located North Aleutian COST well. The density of CO_2 at this depth (1,700 m) and probable low temperature (50º C) likely would be high (700 kg/m^3).[55] Based on the total basin area with at least 2 km of sediment (20,000 km^2) and the average depth to the sandstone package (1,800 m), we estimate that the CO_2 storage potential of the North Aleutian / Bristol Bay basin could be on the order of 1,770 Gt.

3.8 Gulf of Alaska Region

Introduction. Located along the southern edge of Alaska (**Figure 71**), the continental margin of the northern Gulf of Alaska is tectonically and stratigraphically much more complex and diverse than the other areas of the state discussed earlier in this study. The continental margin of Alaska is an amalgam of allochthonous terranes of various origin that accreted to their present positions during Mesozoic and Tertiary time.

The Gulf of Alaska's continental margin contains a fairly continuous Cenozoic stratigraphic section more than 10 km thick that consists of marine and non-marine clastic rocks. Seismic stratigraphy analysis performed by the MMS has defined several major sequences Y2, Y3, and Section III that average about 12,000, 19,000, and 10,000 feet thick, respectively (**Figures 72-74**). However, much of this section is of poor reservoir quality and likely not to be suitable for CO_2 storage.

Thirteen petroleum exploration wells have been drilled in the offshore Gulf of Alaska region, including six COST wells on the Kodiak Shelf in 1976-77, resulting in no commercial discoveries. Seven of the 13 wells bottomed in Miocene or older sediments. The other six wells did not penetrate deeper than the Plio-Pleistocene section of the Yakataga Formation, which likely is the best potential CO_2 storage unit in this region. ARI's GIS data location map is shown in **Figure 75**.

Potential CO_2 Storage Reservoirs. Tertiary sandstones are the main potential petroleum and CO_2 storage opportunities in the Gulf of Alaska stratigraphic section. Although sandstone or conglomerate occurs in nearly all of the onshore Tertiary units, offshore only the Yakataga and Kulthieth Formations appear likely to contain coarse-grained rocks of sufficient thickness and areal distribution to represent prospective reservoir targets.[56]

- **Yakataga Formation.** This mid-late Miocene, Pliocene, and Pleistocene age unit is the principal clastic target for petroleum exploration (and potentially CO_2 storage) in the Gulf of Alaska. It occurs over an arcuate area stretching approximately 200 miles parallel to the coastline by about 30 miles wide (**Figure 76**), for an area of about 6,000 mi^2 (15,000 km^2). Percentage sandstone declines to the south, from as much as 80% near the coast to less than 10% distally.

  Sandstones and conglomerates in the Yakataga Formation are predominantly glacio-marine in origin and were deposited in inner shelf to upper slope settings. Deposition took place mainly by sediment gravity flow in large submarine channel systems located downslope from tidewater glaciers. This resulted in lenticular sandstone deposits that are generally poorly sorted and mineralogically immature, with poor reservoir characteristics. Yakata sandstones are lithic arkose consisting of about 35% quartz, 40% feldspar (mainly plagioclase), and 25% lithic fragments.

  The total thickness of sandstone in the Yakataga Formation varies from about 250 to 3,800 feet in the Gulf of Alaska. Furthermore, the percentage of sand diminishes rapidly to the south away from the glacial sources. In the Arco OCS Y-0007 exploration well, individual sandstone beds vary widely in thickness, from about 10 feet to over 200 feet (**Figure 77**). Sandstone quality is relatively better in the lower part of the unit. Sandstone and conglomerate reached 15% of the formation in the Middleton Island well, with an average 13% porosity. Overall, porosity declines rapidly with depth, in general from about 30% at 1,500 foot depth to about 15% at 8,000 foot depth (**Figure 78**). Permeability is generally less than 10 mD at depths below 5,000 feet, and nearly absent below about 12,000 feet.

- **Kultheith Formation.** This unit was penetrated by only one of the offshore wells (Y-0211) but seismic mapping indicates it extends over an extensive area (perhaps 200 by 50 miles or approximately 25,000 km^2) in the southeast corner of the Gulf of Alaska, close to the US-Canadian border (**Figure 79**). Kulthieth sandstones were deposited in non-marine to relatively deep marine environments in an oceanic basin along a continental margin. This well encountered 29 individual sandstones ranging from 6 to 153 feet thick (total about 1,500 feet), distributed over a depth range of 8,574 to 11,530 feet (**Figure 80**). These sandstones typically consist of 60-85% quartz, 1.5 to 7% feldspar, 4-14% mica, and 1-30% shale. Porosity declined with depth from about 20% near the top of the section to 10% near the base.

Scoping CO_2 Storage Estimate. ARI volumetrically estimated the CO_2 storage potential of saline aquifers in the Yakagata and Kulthieth Formations of the Gulf of Alaska. We assumed an average sandstone thickness of 500 m and 15% porosity, based on the Y-0007 and Y-0211 wells. The density of CO_2 at this depth (2,000 m) and probable temperature (80º C) likely would be high (700 kg/m^3). Based on the total basin area with at least 2 km of sediment (15,000 km^2 for Yakagata plus 25,000 km^2 for the Kulthieth for a total 40,000 km^2) and the average depth to the sandstone package (2,000 m), we estimate that the CO_2 storage potential of the Gulf of Alaska basin could be on the order of 900 Gt.

5.0 Conclusions and Recommendations

1) Alaska’s sedimentary basins have large storage capacity both in deep coal seams and (particularly) in saline aquifer sandstone formations. This is clear from the extensive data base of well logs, core analyses, seismic, maps, and geologic studies that have been prepared for petroleum exploration. However, most of the inputs used in this assessment for calculating storage capacity are uncertain. Thus, the 120 Gt and 16,700 Gt storage estimates should be viewed as highly approximate, though probably better than order-of-magnitude.

2) The potential for CO_2 storage in deep coal seams in Alaska, though probably very large (120 Gt), remains poorly understood. Future work should include laboratory sorption isotherm measurements of Alaska coal seam candidates to determine methane and CO_2 storage capacity and behavior. In-situ well testing of coal seam permeability, hydrology, and stress also are needed, ideally with an industry partner in the CBM-prospective onshore Cook Inlet basin.

3) Alaska’s saline aquifer storage capacity demonstrably is large but poorly understood. Future work should include more detailed well log and basin evaluations, particularly of the high-potential North Slope and Chukchi Sea regions. There could be joint industry opportunities for well and core testing in these areas, where exploration interest has been rejuvenated.

References

[1] Smith, T.N., 1995. "Coalbed Methane Potential for Alaska and Drilling Results for the Upper Cook Inlet." Intergas Conference, May 15-19, Tuscaloosa, Alabama, p. 1-21.

[2] Tyler, R., Scott, A., and Clough, J., 1998. "Coalbed Methane Potential and Exploration Targets for Rural Alaskan Communities." Alaska Division of Geological and Geophysical Surveys Final Report, 169 p.

[3] Flores, R., Stricker, G., and Kinney, S., "Alaska Coal Geology, Resources, and Coalbed Methane Potential." US Geological Survey, DDS 77, 2004.

[4] Roberts, S. et al., 2006. "Assessment of Coalbed Gas Resources in Cretaceous and Tertiary Rocks on the North Slope, Alaska, 2006." Preliminary 2-page report.

[5] Kolak, J.J. and Burruss, R.C., 2005, "A Geochemical Investigation into the Effect of Coal Rank on the Potential Environmental Impacts of CO_2 Sequestration in Deep Coal Beds." U.S. Geological Survey Open-File Report 2004-1370.

[6] Helmhold, K.P., "Potential Tight Gas Sandstone Reservoirs in Cook Inlet Basin : A Petrologic Perspective." RPSEA Alaska Unconventional Gas Forum, Anchorage, Alaska, April 7, 2008.

[7] Montgomery, S.L. and Barker, C.E., "Coalbed Methane, Cook Inlet, South-Central Alaska: A Potential Giant Gas Resource." AAPG Bulletin, v. 87, p. 1-13, January 2003.

[8] Wahrhaftig, C., Bartsch-Winkler, S., and Stricker, G.D., "Coal in Alaska." in G. Plafker and H. C. Berg, eds., The Geology of North America: the Geology of Alaska. Geological Society of America, Boulder, Colorado, v. G-1, p. 937–978, 1994.

[9] Swenson, R. F., "Introduction to Tertiary Tectonics and Sedimentation in the Cook Inlet Basin." In N. R. Karl-Vaughn and T. J. Ryherd, eds., Guide to the Geology of the Kenai Peninsula, Alaska, Geological Society of Alaska, p. 18–27, 1997.

[10] Oil and Gas Journal, 2009. "Golar, LNG Ltd Agree on Gladstone LNG Project." Oil & Gas Journal, February 23.

[11] Merritt, R. D., and C. C. Hawley, "Map of Alaska's Coal Resources: Alaska Division of Geological and Geophysical Surveys Special Report 37, scale: 1:2,500,000, 1 sheet, 1986.

[12] Montgomery and Barker, 2003.

[13] RPSEA Alaska Unconventional Gas Forum, Anchorage, Alaska, April 7, 2008.

[14]LePain, D.L., "Depositional Systems and Predictability of Low Permeability Reservoirs in Tertiary NonmarineNonmarineDeposits, Cook Inlet, AlaskaDeposits, Alaska." RPSEA Alaska Unconventional Gas Forum, Anchorage, Alaska, April 7, 2008.

[15] Snider, P., "Seven Years of Completing Tight Gas Formations in Alaska Utilizing Conveyed Perforating: Success, Lessons Learned, and New System Improvements." RPSEA Alaska Unconventional Gas Forum, Anchorage, Alaska, April 7, 2008.

[16] Swenson, B., "The Role of Low Permeability Gas Reservoirs in Alaska." RPSEA Alaska Unconventional Gas Forum, Anchorage, Alaska, April 7, 2008.

[17] Flores et al., 2004.

[18] Roberts, S.B., Stricker, G.D., and Affolter, R.H., 1992, "Reevaluation of Coal Resources in the Late Cretaceous-Tertiary Sagavanirktok Formation, North Slope, Alaska." In Bradley, D.C., and Ford, A.B., eds., Geologic Studies in Alaska by the Geological Survey, 1990, U.S. Geological Survey Bulletin 1999, p. 196–203.

[19] Wahrhaftig, C., "The Cenozoic Section at Suntrana, Alaska." In Hill, M.L., ed., Cordilleran Section of the Geological Society of America, Boulder, Colorado, Geological Society of America, Centennial Field Guide, v. 1, p.445–450. 1987.

[20] Affolter, R.H., Stricker, G.D., Flores, R.M., and Stanley, R.G., "Geochemical Evaluation of Coal from the Tertiary Usibelli Group, Usibelli Coal Mine, Alaska." In Rao, P.D., and Walsh, D.E., eds., Focus on Alaska Coal 1993, Proceedings of the Conference, Fairbanks, University of Alaska Mineral Industry Research Laboratory Report 94, p. 167–182, 1994.

[21] Tyler, R., Scott, A., and Clough, J., 1998. "Coalbed Methane Potential and Exploration Targets for Rural Alaskan Communities." Alaska Division of Geological and Geophysical Surveys Final Report, 169 p.

[22] Lamarre, R. and Ruhl, S., "Atlantic Rim Coalbed Methane Play: The Newest Successful CBM Play in the Rockies." Rocky Mountain Section, AAPG Meeting, Denver, Colorado, August 9-11, 2004.

[23] Ogbe, D.O., Clough, J., Bott, J., and Hawley, M.A., "Planning Exploratory Drilling for Coalbed Methane Resource Development in Rural Alaska." SPE Western Regional Meeting, Anchorage, Alaska, 26-28 May, 1999.

[24] Sander, P., "CERI 2009 Natural Gas Conference." Calgary, Alberta, Canada, EnCana, February 24, 2009.

[25] Kelafant, J., Booth, J., and Glavinovich, P., "Gas Shale Exploration at the Red Dog Mine, Alaska." 102nd Annual Meeting of the Cordilleran Section, Geological Society of America, 81st Annual Meeting of the Pacific Section, AAPG, and the Western Regional Meeting of the Alaska Section, SPE, May 8-10, 2006.

[26] Chadwick, A., Arts, R., Bernstone, C., May, F. Thibeau, S., and Zweigel, P. „Best Practice for the Storage of CO_2 in Saline Aquifers." SACS and CO2Store Projects, 273 p., 2007.

[27] Wartes, M., "„DGGS / DOG 2006 North Slope Field Tour." Alaska Division of Geological & Geophysical Surveys, 2006.

[28] Wartes, M. and Decker, P., „DGGS / DOG 2007 North Slope Field Tour." Alaska Division of Geological & Geophysical Surveys, 2007.

[29] Mull, C.G., Houseknecht, D.W., and Bird, K.J., "Revised Cretaceous and Tertiary Stratigraphic Nomenclature in the Colville Basin, Northern Alaska." US Geological Survey, Professional Paper 1673, 2008.

[30] LePain, D.L., "Sedimentology and Sequence Stratigraphy of the Nanushuk Formation, South-Central North Slope, Alaska." Alaska Division of Geological & Geophysical Surveys, Monthly Luncheon Presentation, January 19, 2007.

[31] Flores, R.M., Myers, M.D., Houseknecht, D.W., Stricker, G.D., Brizzolara, D.W., Ryherd, T.J., and Takahashi, K.I., "Stratigraphy and facies of Cretaceous Schrader Bluff and Prince Creek Formations in Colville River Bluffs, North Slope, Alaska." U.S. Geological Survey Professional Paper 1748, 52 p., 2007.

[32] Decker, P.L. and Wartes, M.A., "Overview of Recent North Slope Energy Studies, Part 1: North-Central Foothills, Sagavanirktok River Area." DNR Spring Technical Review Meeting, March 26, 2008.

[33] Garrity, C.P., Houseknecht, D.W., Bird, K.J., Potter, C.J., Moore, T.E., Nelson, P.H., and Schenk, C.J., "U.S. Geological Survey 2005 Oil and Gas Resource Assessment of the Central North Slope, Alaska: Play Maps and Results." Open-File Report 2005-1182.

[34] Sherwood, K., "Petroleum Potential of the Arctic Offshore of Alaska." Minerals Management Service, April 6, 2006.

[35] Craig, J.D., Sherwood, K.W., and Johnson, P.P., "Geologic Report for the Beaufort Sea Planning Area, Alaska." Minerals Management Service, 1985, 192 p.

[36] Thurston, D.K. and Theiss, L.A., "Geologic Report for the Chukchi Sea Planning Area, Alaska." Minerals Management Service, 1985, 193 p.

[37] Minerals Management Service, "MMS Chukchi Sea Lease Sale 193 Breaks Energy Records With $2.6 Billion in High Bids." Press Release, February 6, 2008.

[38] Bachu, S., "Screening and Ranking of Sedimentary Basins for Sequestration of CO_2 in Geological Media." Environmental Geology, vol. 44, p. 277-289, 2003.

[39] Bachu, S., "Screening and Ranking of Sedimentary Basins for Sequestration of CO_2 in Geological Media." Environmental Geology, vol. 44, p. 277-289, 2003.

[40] Turner, R.F., Martin, G.C., Risley, D.E., Steffy, D.A., Flett, T.O., and Lynch, M.B., "Geologic Report for the Norton Basin Planning Area, Bering Sea, Alaska." Minerals Management Service, 1986.

[41] Wiley, T.J., "Sedimentary Basins of Offshore Alaska and Adjacent Regions." US Geological Survey, Open-File Report 86-35, 1986.

[42] Fisher, M.A., "Petroleum Geology of Norton Basin, Alaska." AAPG Bulletin, v. 66, p. 286-301, 1982.

[43] Turner, R.F. editor, "Geological and Operational Summary, Norton Sound COST 1 Well, Norton Sound, Alaska." Minerals Management Service, U.S. Geological Survey, Open-File Report 83-124, 1983.

[44] Reitmeier, C., "Engineering and Economic Analysis of Natural Gas Production in the Norton Basin." U.S. Dept. of the Interior, Minerals Management Service, 2005.

[45] Bachu, S., "Screening and Ranking of Sedimentary Basins for Sequestration of CO_2 in Geological Media." Environmental Geology, vol. 44, p. 277-289, 2003.

[46] Turner, R.F., Martin, G.C., Flett, T.O., and Steffy, D.A., "Geologic Report for the Navarin Basin Planning Area, Bering Sea, Alaska." Minerals Management Service, 1985.

[47] Turner, R.F., McCarthy, C.M., Steffy, D.A., Lynch, M.B., Martin, G.C., Sherwood, K.W., Flett, T.O., and Adams, A.J., "Geological and Operational Summary of the Navarin Basin COST No. 1 Well, Bering Sea, Alaska." Mineral Management Service, 1984.

[48] Reifenstuhl, R., Decker, P., Helmold, K., Gillis, B., Loveland, A., and Blodgett, R., „Hydrocarbon Systems, Basin Analyses, 2004-2007 Field & Subsurface Data: Bristol Bay - Alaska Peninsula Frontier Basin." Alaska Geological and Geophysical Surveys, October 16, 2007.

[49] Decker, P., "Comparison of Mesozoic and Cenozoic Source Rock Characteristics, Puale Bay Outcrops and NAS COST 1 Well, Alaska Peninsula –North Aleutian Basin." Alaska DNR Spring Technical Review Meeting, March 27, 2008.

[50] Finzel, E.S., Ridgway, K.D., Reifenstuhl, R.R., White, J., and Blodgett, R.B., "Chronostratigraphic Correlation and Interpreted Depositional Environments of the Miocene Bear Lake Formation, Bristol Bay Basin, Alaska Peninsula." AAPG Annual Convention, Houston, Texas, April 9-12, 2006.

[51] Bachu, S., "Screening and Ranking of Sedimentary Basins for Sequestration of CO_2 in Geological Media." Environmental Geology, vol. 44, p. 277-289, 2003.

[52] Comer, C.D., Herman, B.M., and Zerwick, S.A., "Geologic Report for the St. George Planning Area, Bering Sea, Alaska." Minerals Management Service, 1987.

[53] Turner, R.F., McCarthy, C.M., Comer, C.D., Larsen, J.A., Bolm, J.G., Banet, A.C. Jr., and Adams, A.J., "Geological and Operational Summary, St. George Basin COST No. 1 Well, Bering Sea, Alaska." Minerals Management Service, 1984.

[54] Turner, R.F., McCarthy, C.M., Comer, C.D., Larsen, J.A., Bolm, Flett, T.O., and Adams, A.J., "Geological and Operational Summary, St. George Basin COST No. 2 Well, Bering Sea, Alaska." Minerals Management Service, 1984.

[55] Bachu, S., "Screening and Ranking of Sedimentary Basins for Sequestration of CO_2 in Geological Media." Environmental Geology, vol. 44, p. 277-289, 2003.

[56] Risley, D.E., Martin, G.C., Lynch, M.B., Flett, T.O., Larson, J.A., and Horowitz, W.L., "Geologic Report for the Gulf of Alaska Planning Area." Minerals Management Service, 1992.