SB

203

3309

SENATE COMMITTEE REPORT
First Committee of Referral

DATE: 1/19/10 FURTHER: Finance

Date of 5-Day Notice: ________________
(in accordance with Uniform Rule 23)

DATE TURNED
IN TO OFFICE: ____________

Resources Committee considered SENATE BILL NO. 203

SB 203 COOK INLET GAS STORAGE FACILITIES

"An Act relating to a tax credit for a facility to store Cook Inlet gas for sale and delivery in the state; relating to an exemption from the oil and gas exploration, production, and pipeline transportation property tax for a facility that stores Cook Inlet gas for sale and delivery in the state; and providing for an effective date."

and recommends:

[X] be **replaced** with [ ] **SCS** or [X] **CS** SB 203 / P (RES)

[ ] adopt **previous** [ ] **SCS** or [ ] **CS** ____________ (______)

[ ] attached amendment(s)

[ ] adopt ____________ Letter of Intent

[ ] further referral to ____________ Committee

SENATE BILL:
[ ] Same Title
[ ] New Title

HOUSE BILL:
[ ] Same Title
[ ] Technical Title Change
[ ] New Title w/ SCR #_____

NEW FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#
DNR	2-11-10			0	439

PREVIOUS FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#

[ ] **APPROPRIATION - no fiscal note**

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
[signature]	Stevens			✓	
[signature]	McGuire	✓			
[signature]	French	✓			
CO-CHAIR: [signature]	Wielechowski	✓			
CO-CHAIR:					

3310

26-LS1114\P
Bullock
2/4/10

CS FOR SENATE BILL NO. 203( )

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SIXTH LEGISLATURE - SECOND SESSION

BY

Offered:
Referred:

Sponsor(s): SENATORS FRENCH AND WIELECHOWSKI, Ellis

A BILL

FOR AN ACT ENTITLED

"An Act relating to the regulation of a gas storage facility by the Regulatory Commission of Alaska; relating to a tax credit for a facility to store Cook Inlet gas for sale and delivery in the state; relating to an exemption from the oil and gas exploration, production, and pipeline transportation property tax for a facility that stores Cook Inlet gas for sale and delivery in the state; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 42.05.990(4) is amended to read:

(4) "public utility" or "utility" includes every corporation whether public, cooperative, or otherwise, company, individual, or association of individuals, their lessees, trustees, or receivers appointed by a court, that owns, operates, manages, or controls any plant, pipeline, or system for

(A) furnishing, by generation, transmission, or distribution, electrical service to the public for compensation;

(B) furnishing telecommunications service to the public for compensation;

(C) furnishing water, steam, or sewer service to the public for compensation;

(D) furnishing by transmission or distribution of natural or manufactured gas to the public for compensation;

(E) furnishing for distribution or by distribution petroleum or petroleum products to the public for compensation when the consumer has no alternative in the choice of supplier of a comparable product and service at an equal or lesser price;

(F) furnishing collection and disposal service of garbage, refuse, trash, or other waste material to the public for compensation;

(G) furnishing a tank, depleted reservoir, injection well for gas storage permitted under AS 31.05, or other structure in the state for the storage of gas that is designated to be sold and delivered in the state by a public utility providing the service described in (D) of this paragraph;

* **Sec. 2.** AS 43.20 is amended by adding a new section to article 1 to read:

Sec. 43.20.046. Cook Inlet gas storage facility tax credit. (a) A taxpayer that is an owner of a Cook Inlet gas storage facility may apply as a credit against the state tax liability that may be imposed on the taxpayer under this chapter, for a tax year beginning after December 31, 2009, 20 percent of the taxpayer's qualified capital investment in a Cook Inlet gas storage facility. The credit is subject to the terms and conditions of this section and is in addition to any other credit authorized to the taxpayer by this chapter.

(b) A qualified capital investment for the investment credit under (a) of this section is

(1) a cash expenditure or a payment due under a binding payment agreement entered into after December 31, 2009, and before January 1, 2013, made for the direct cost of purchasing, constructing, or otherwise acquiring an ownership interest in the real property or tangible personal property used in this state for a Cook Inlet gas storage facility; in this paragraph, "property" includes

L

3312

(A) property that is placed in use under a capitalized lease or an operating lease; and

(B) machinery, appliances, supplies, and equipment directly related to the storage of gas produced from the Cook Inlet sedimentary basin and designated for sale and delivery in the state; and

(2) the cost of cushion gas acquired after December 31, 2009, and before January 1, 2013, that is required for a Cook Inlet gas storage facility to function.

(c) The credit for each tax year allowed under (a) of this section may not exceed 50 percent of the taxpayer's total tax liability under this chapter. An unused portion of the credit for the tax year

(1) may be carried forward into one or more of the following tax years, except that the unused credit from one tax year may not be carried forward for more than five following tax years;

(2) shall be applied to the taxpayer's tax liability under this chapter during the following tax year before allowance of a credit allowed under (a) of this section for that following tax year.

(d) To obtain the credit allowed by this section, the taxpayer has the burden of demonstrating compliance with the requirements of this section to entitle the taxpayer to the claim of and the amount of the credit. A credit may not be claimed before the gas storage facility is ready to receive gas for storage. To claim the credit, a person shall submit, on a form prescribed by the department, information that demonstrates that the taxpayer is eligible for the credit and evidence of the expenses that are the basis of the claim of the credit. A person

(1) required to file a return under this chapter shall submit the form claiming the credit with the taxpayer's return;

(2) not required to file a return under this chapter shall submit the form claiming the credit before May 1 of the year following the year in which the expenditure qualifying for the credit under this section is made.

(e) A taxpayer entitled to a credit under this section

(1) with prior written approval by the department, may convey, assign,

or transfer the credit to another taxpayer or business entity;

(2) forfeits the credit to which the taxpayer is entitled during the tax year and any carryover of it under (c) of this section, but does not forfeit the portion of the credit that accrued in a previous taxable year that may be carried over under (c) of this section, if the taxpayer

(A) disposes of the qualified capital investment;

(B) takes the qualified investment out of service; or

(C) fails to use the Cook Inlet gas storage facility primarily for the storage of gas for sale and delivery in the state.

(f) In this section,

(1) "Cook Inlet gas storage facility" means a tank, depleted reservoir, injection well for gas storage permitted under AS 31.05, or other structure in the state for the storage of gas that is produced from the Cook Inlet sedimentary basin and designated for sale and delivery in the state, and includes machinery, supplies, and equipment directly related to and necessary for filling and withdrawing gas from the structures holding the gas for storage in the facility;

(2) "Cook Inlet sedimentary basin" has the meaning given in AS 43.55.900;

(3) "cushion gas" means gas that is needed to pressurize the storage facility and that allows the storage facility to function.

* **Sec. 3.** AS 43.56.210(5) is amended to read:

(5) "taxable property"

(A) means real and tangible personal property used or committed by contract or other agreement for use within this state primarily in the exploration for, production of, or pipeline transportation of gas or unrefined oil (except for property used solely for the retail distribution or liquefaction of natural gas), or in the operation or maintenance of facilities used in the exploration for, production of, or pipeline transportation of gas or unrefined oil; "taxable property" includes

(i) machinery, appliances, supplies, and equipment;

(ii) drilling rigs, wells (whether producing or not),

3314

gathering lines and transmission lines, pumping stations, compressor stations, power plants, topping plants, and processing units;

(iii) roads, tank farms, tanker terminals, docks and other port facilities, and air strips;

(iv) aircraft and motor vehicles owned by a person whose principal business in the state is the exploration for, production of, or pipeline transportation of gas or unrefined oil and whose operation of the aircraft or motor vehicle directly relates to the conduct of that business;

(v) maintenance equipment and facilities, and maintenance camps and other related facilities; and

(vi) communications facilities owned by a person whose principal business in the state is the exploration for, production of, or pipeline transportation of gas or unrefined oil and whose operation of the communications facilities directly relates to the conduct of that business;

(B) does not include

(i) permanent residences;

(ii) office buildings requiring substantial local government services;

(iii) oil and gas pipeline systems owned and operated by a public utility that is certificated under AS 42.05.221 and is regulated by the Regulatory Commission of Alaska;

(iv) aircraft and motor vehicles, except aircraft and motor vehicles taxable under (A)(iv) of this paragraph; [AND]

(v) communications facilities, except communications facilities taxable under (A)(vi) of this paragraph; **and**

(vi) notwithstanding (A) of this paragraph, a Cook Inlet gas storage facility, as that term is defined in AS 43.20.046;

* **Sec. 4.** This Act takes effect immediately under AS 01.10.070(c).

3315

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: **SB 203**
() Publish Date:

Identifier (file name): SB 203-DNR-O&G-02-05-10
Title: Cook Inlet Gas Storage Facility Tax Credit
Sponsor: Senators Wielechowski, French, Ellis
Requester: Senate Resources Committee

Dept. Affected: Natural Resources
RDU: Resource Development
Component: Oil and Gas Development
Component Number: 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2011**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )							

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Estimate of any current year (FY2010) cost: ________

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

SB 203 amends AS 43.20 and adds a new section called the Cook Inlet gas storage facility tax credit. The bill would provide 20% of qualified capital investment of a Cook Inlet gas storage facility to receive a tax credit that does not exceed 50% within a tax credit year. This tax credit would: (1) be in addiiton to any other available credits authorized by this Chapter (2) may be conveyed, assigned or transferred to another taxpayer or business entity (3) appears to provide tax credit for any fees associated with the acquisition and maintenance of a gas storage lease or agreement (4) and includes the cost and royalties associated with "cushion gas".

There is no anticipated fiscal impact to the Division of Oil and Gas. The application of tax credits will have an indeterminant impact on the revenues acquired by the Division.

Prepared by: Kevin Banks, Director — Phone 269-8800
Division: Oil and Gas — Date/Time 2/5/10 5:00 PM
Approved by: Tom Irwin, Commissioner — Date 2/6/2010
Natural Resources

(Revised 11/6/2009 OMB)

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: SB 203
() Publish Date:

Identifier (file name): SB203-REV-TAX-02-05-10

Title	Cook Inlet Gas Storage Facilities	Dept. Affected:	Revenue
		RDU	Treasury and Taxation
		Component	Tax Division
Sponsor	Senator French		
Requester	(S) Resources	Component Number	2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2011**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )	***	***	***	***	***	***	***

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: ________

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

See Attached.

Prepared by: Johanna Bales, Deputy Director/Tim Harper, Economist III
Phone (907) 269-6628
Division: Tax Division
Date/Time 2/5/2010 5:50 p.m.
Approved by: Ginger Blaisdell, Director
Administrative Services Division
Date 2-5-10; 8:55pm

(Revised 11/6/2009 OMB)

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

BILL NO. SB 203

ANALYSIS CONTINUATION

Bill Language:

This bill provides a tax credit for the purchase, construction, or other acquisition of an ownership interest in a Cook Inlet (CI) gas storage facility. Capital expenditures qualifying for the credit include the acquisition of real and tangible personal property as well as cushion gas required for the facility to properly function. Only expenses incurred after December 31, 2009 and before January 1, 2013 would qualify for the credit. A taxpayer would be able to take a credit of 20% of its qualified capital investment against its Alaska corporate income tax (CIT). The taxpayer could offset no more than 50% of its total CIT liability in any given tax year. Any unused portion of the credit could be carried forward for five years. A taxpayer entitled to the credit could transfer the credit to another taxpayer.

This bill also would exempt a Cook Inlet gas storage facility from the oil and gas property tax.

Revenues:

Although it is difficult to determine the number of taxpayers who would take advantage of this tax credit, we do expect corporate income tax and oil and gas property tax revenues to decline. There are three existing gas storage facilities in the Cook Inlet region that would potentially qualify for the corporate income tax credit and oil and gas property tax exemption provided by this bill. Since this bill does not require the construction of new facilities, the sale of an existing facility would qualify for the credit. Taxpayers would most likely take steps to qualify these facilities for the associated tax credits.

Due to the complexity of the oil and gas property tax, it is difficult to determine what portion of existing property taxes would be exempt under this bill. However, we expect some portion of these existing facilities will qualify for the exemption and, therefore, state property taxes would decline. Because 43.56 allows a local municipality to receive property tax revenue on oil and gas property assessed by the state, the Kenai Peninsula Borough would also see a decline in their property tax as it relates to existing facilities and foregone revenues in the future for potential new facilities.

Reduction in corporate income tax and oil and gas property tax revenues are indeterminate at this time.

Expenditures:

The provisions of this bill would most likely require the hiring of additional state staff. It is not known at this time the number of position(s) that would be needed. Additional administrative work required of the Department would be dictated by the number of taxpayers who take advantage of the credit and the associated work required to validate those credits.

Alaska State Legislature

Senator Hollis French

SB 203 – Cook Inlet Gas Storage Facilities

Sponsor Statement

Senate Bill 203 creates economic incentives for companies in Cook Inlet to develop storage facilities for natural gas.

While natural gas supply in Cook Inlet is sufficient to supply southcentral Alaska with the energy it needs for the near future, the need to produce gas at a constant rate results in more gas than the system needs in the summer months and near-shortages when demand is far higher in the winter.

Recently, the Regulatory Commission of Alaska (RCA), the Municipality of Anchorage and local utility companies have all discussed the possibility of natural gas shortages for homes and businesses during peak winter use. Both Enstar and Chugach Electric Association indicated in a recent RCA hearing that gas shortages could occur as early as winter 2011-2012.

While incentives exist to encourage producers to explore for new supplies, there are no similar incentives for storage. According to studies and industry sources, development of an adequate storage system could cost companies $100 -- $200 million dollars.

Under SB 203 development costs for the creation of gas storage facilities or reservoirs will be eligible for a tax credit like those offered for development of new wells. Cushion gas, which would remain in storage wells to maintain pressure for efficient removal, would not be subject to taxation. The legislation would also exempt storage facilities and equipment from state property taxes.

Senator Hollis French

SB 203 SECTIONAL ANALYSIS

Section 1

Section 1 provides for a 20% tax credit on qualified gas storage facilities. Qualifying expenditures include; a payment for a lease, machinery, supplies, equipment, or the cost of cushion gas which pressurizes the well for efficient extraction. The gas must be designated for sale and delivery in Alaska. A qualifying purchase must be made between December 31, 2009 and January 1, 2013, and cannot exceed 50% of the total tax liability.

The section also outlines the process for applying for the tax credit, and defines "Cook Inlet gas storage facility," and "cushion gas."

Section 2

Section 2 exempts Cook Inlet gas storage facilities from state property taxes.

Senator Hollis French

CSSB 203\P Explanation of Changes

P. 2, line 13: Adds gas storage facilities to the definition of a "public utility" under the Alaska Public Utilities Regulatory Act.

P. 2, line 21: Inserted "direct cost" to definition of "a qualified capital investment." This narrows the costs to which a company would be allowed to apply the credit.

P. 3, line 9-10: Deleted "but shall be calculated before the application of any other credits allowed under this chapter." This was in conflict with other language in statute.

P. 3, line 20-21: Inserted "A credit may not be claimed before the gas storage facility is ready to receive gas for storage."

Petroleum news

Home | Advertising | Subscriptions | Publications

Providing coverage of Alaska and northern Canada's oil and gas industry
September 2009

Vol. 14, No. 38 Week of September 20, 2009

What price CI gas?

RCA gleans views on breaking utility supply contract approval logjam

Alan Bailey

Petroleum News

While concerns rise about whether natural gas supplies from Alaska's Cook Inlet basin will be able to keep up with local utility demand, especially during the depths of the winter, a debate continues regarding whether Cook Inlet gas prices are too low to entice sufficient new gas exploration and development, or whether the Cook Inlet gas producers are crying wolf over the gas supply situation, to increase their profits by pushing gas prices up.

Since 2004 the Regulatory Commission of Alaska, in its role of regulating the utilities and protecting energy consumers from unnecessarily high energy prices, has rejected as too expensive every gas supply contract that Enstar Natural Gas Co., the main Southcentral Alaska gas utility, has negotiated with Cook Inlet gas producers. A recent supply agreement between power utility Chugach Electric Association and gas producer ConocoPhillips is the only utility gas supply contract that the commission has approved in that time.

But what is a reasonable price for Cook Inlet natural gas?

On Sept. 16 RCA convened a technical conference to seek views on how to provide regulatory oversight of gas pricing, to help change the regulatory process for gas supply contract approval from what has all too often become an expensive and time consuming minefield, possibly delaying new gas development, into more of a well-marked pathway.

Producer view

The major Cook Inlet gas producers declined to participate in the conference, citing anti-trust issues that might be raised by their involvement in discussions about how gas prices might be set. But a written statement by Marathon, one of those producers, reiterated an often expressed oil company view that supply contracts, including gas pricing arrangements, should be "freely and fairly" negotiated between the producers and the utilities, rather than be specified in some way by regulators.

"The regulators should regulate the regulated, not the gas market," Marathon said. And negotiations between the producers and the utilities need to recognize that producers are driven by the balance between risk and reward, in a situation where gas projects in Alaska compete for finite funding with other projects on a global basis, the company said.

But the isolated nature of the tiny Cook Inlet utility gas market and the lack of a spot market for Cook Inlet gas have made it impossible to determine a market-driven local gas price and have led gas contract negotiations into some creative ways of establishing contract prices.

A few decades ago, prior to the formation of dynamic national and global natural gas markets, negotiations between Southcentral utilities and the Cook Inlet gas producers led to long-term contract gas prices indexed to the price of oil. And, with a large glut of Cook Inlet gas, those prices were low relative to other part of the United States.

Changing market

Then in the early 2000s, as tightening Cook Inlet gas supplies started to draw people's attention to the need for more Cook Inlet gas exploration, and as a burgeoning North American and global trade in natural gas drove the establishment of many gas trading hubs, Cook

Inlet gas contract negotiations moved toward the indexing of Cook Inlet gas prices to gas markets elsewhere, in particular to the Henry Hub market in the Lower 48.

Indexing Cook Inlet gas prices to Lower 48 prices would enable Cook Inlet gas exploration to compete for capital with gas exploration projects elsewhere, the gas producers argued.

In 2001 RCA approved a Unocal gas supply contract with Enstar that used a Henry Hub index, and in 2004 the commission approved a similar contract between Enstar and the NorthStar Energy Group. However, the commission subsequently dropped its support for Henry Hub indexing, and for other proposed indices involving North American trading points at the demand or downstream end of gas transmission networks, saying that these markets did not model the market situation in the Cook Inlet and resulted in over-priced Cook Inlet gas.

The commission proposed instead a price index based on a basket of producer basin markets, an approach that the producers rejected for contracts with Enstar but which forms the basis of the pricing in the recently approved Chugach contract.

Market index?

Is the use of this form of market index appropriate as a benchmark for gas prices in Cook Inlet, the commissioners asked at the Sept. 16 conference? And should the commission specify a "safe harbor" range of prices that would be acceptable to the commission and guarantee contract approval?

Some conference participants cautioned about the difficulty of restraining prices within a narrow range, an approach that seems akin to price controls. And Dan Dieckgraeff, Enstar's manager of rates and regulatory affairs, argued the case for price mechanism flexibility, given the inevitable differences between different contract situations and the evolving nature of gas markets.

Trying to pick a pricing mechanism that works perfectly today is not useful for determining gas prices in the future, given that gas markets around the world are changing continuously, he said.

And Commissioner Janis Wilson commented that experience of linking Cook Inlet gas prices to Lower 48 market indices has in practice demonstrated how little connection there is between the market dynamics in the Lower 48 and the gas supply and demand situation in the Cook Inlet.

"Here we are with a (gas) surplus in the Lower 48, prices going way down, and we're facing gas shortages (in the Inlet)," Wilson said.

Another possible Cook Inlet gas price model discussed at the conference is a price cap indexed to the estimated price of imported LNG, imports that would form an obvious alternative to the Cook Inlet basin as a gas source.

And Aurora Gas, the one producer to participate in the conference, would like to see some percentage of the total gas demand set aside for bidding in an open spot market that would give small producers like Aurora market access, while also establishing a market gas price. However, utilities have expressed concern about this concept, because of utility needs for assured supplies from medium- to long-term contracts.

No cost data

One problem that the commission faces when it comes to assessing a reasonable gas-price level is the absence of information regarding the cost of Cook Inlet gas production, information that the gas producers are unwilling to divulge, said Commissioner Anthony Price.

"One emphasis in prior gas contracts is that there's more cost in the Cook Inlet, and yet there's no evidence put on the record of the cost in the Cook Inlet," Price said. "... There's nothing we can land on."

Dieckgraeff said that, although costs factor into gas producer decision making, in his experience it is gas prices that determine gas producer investment commitments. On the other hand, the cost of servicing the extreme swings in Alaska utility gas demand between summer and winter must be taken into account when comparing Alaska gas prices with those in the Lower 48, he said.

In fact, the commission is seeking views on whether it should allow seasonal price variation, or possibly gas producer cost add-ons for the storage of gas for winter use, in approved gas supply contracts. The conference participants seemed to share a view that new gas storage in the Cook Inlet basin will prove to be a key factor in managing gas supplies for winter use, and that the necessary storage facilities will come at a cost. Storage facilities could also provide a gas market for small producers such as Aurora Gas, said Alan Dennis, royalty manager in Alaska's Division of Oil and Gas.

Price flexibility

However, as in models for the base pricing of gas, there needs to be flexibility from one contract to another in the way in which storage costs can be recovered, whether cost recovery comes from tiering the gas prices to different levels of delivery, or from a single, year-round "bundled" price. Dieckgraeff argued.

"One size fits all isn't the way we want to go here," he said.

RCA is also considering whether there may be value in legislative changes to state statutes, to specify how the commission should review utility gas supply contracts, perhaps with a specified pricing mechanism for the gas. These possibilities did not provoke any response from the conference participants, other than one comment that a statutory standard of the review for the contracts might be helpful in improving the review process.

Other topics discussed during the conference included the fact that the utilities in general support RCA pre-approval of their gas supply contracts, prior to tariff approval, as an essential means of eliminating the significant financial risk that would otherwise result from the possibility of the commission rejecting a contract after a tariff has gone into effect. Some conference participants also expressed concern that a too broad participation in utility tariff hearings, including the involvement of entities with unclear or inappropriate agendas, had in some cases unduly increased the length and cost of the hearings.

Petroleum news

Home | Advertising | Subscriptions | Publications

Providing coverage of Alaska and northern Canada's oil and gas industry
November 2009

Vol. 14, No. 45 Week of November 08, 2009

Tax incentives proposed for gas storage

Alaska Sen. French unveils bill offering tax credits, property tax relief to encourage Cook Inlet facilities for holding natural gas

Wesley Loy

For Petroleum News

Alaska state Sen. Hollis French plans to introduce legislation to provide tax incentives for development of Cook Inlet natural gas storage capacity.

French, an Anchorage Democrat who sits on the Senate Resources Committee, said he's concerned about potential winter gas supply shortages for homes and businesses in Southcentral Alaska.

"Storage makes sense. It's like cutting an extra cord of wood in the summer to burn in the winter," French said in a Nov. 2 press release.

A problem with storage, however, is the considerable expense.

"According to studies and industry sources, development of an adequate storage system could cost companies $100-$200 million," the press release said.

French's five-page draft bill defines a Cook Inlet gas storage facility as a tank, a depleted reservoir, an injection well for gas storage, "or other structure in the state for the storage of gas that is produced from the Cook Inlet sedimentary basin and designated for sale and delivery in the state."

The bill has two major elements.

First, it offers a state corporate income tax credit. A company may apply as a credit against its tax liability "20 percent of the taxpayer's qualified capital investment in a Cook Inlet gas storage facility," the bill says.

It defines a qualified capital investment as a cash expenditure or contract struck between Dec. 31 of this year and Jan. 1, 2013, for development of a storage facility.

Another qualified capital investment is the cost of "cushion gas" necessary to pressurize the storage facility. This permanent inventory of cushion gas is a major initial cost factor for storage developers.

The credit could not exceed 50 percent of a company's total tax liability each year, the bill says.

The bill's second major element would exempt gas storage facilities and equipment from the state oil and gas property tax.

Storage already happening

While Cook Inlet gas fields are approaching depletion, the most pressing issue right now is deliverability — getting enough gas into the distribution grid during the coldest winter days to meet peak demand. Regulators, energy companies and elected officials have talked increasingly of the possible need for consumer conservation measures or even rolling power blackouts as early as this winter.

French, a former oil industry worker and Senate bipartisan majority member who's running against Republican Gov. Sean Parnell, has touted storage as a way to squirrel away summer gas production for use during winter.

The storage incentives are akin to state perks now in place to encourage exploratory drilling, French said.

But some storage efforts already are progressing without the benefit of the tax incentives he is proposing.

Chevron and Marathon have established three storage facilities in depleted reservoirs at the Swanson River, Pretty Creek and Kenai fields.

Enstar Natural Gas Co., the major gas utility for Southcentral Alaska, is working with Houston-based ANR Pipeline Co., a TransCanada Corp. subsidiary, on development of a new storage facility.

Aurora Gas also wants to develop a gas storage facility at its Nicolai Creek gas field.

French's bill will be considered once the Legislature opens its new session on Jan. 19.

Two types of tax incentives

The bill has two major elements.

First, it offers a state corporate income tax credit. A company may apply as a credit against its tax liability "20 percent of the taxpayer's qualified capital investment in a Cook Inlet gas storage facility," the bill says.

It defines a qualified capital investment as a cash expenditure or contract struck between Dec. 31 of this year and Jan. 1, 2013, for development of a storage facility.

Another qualified capital investment is the cost of "cushion gas" necessary to pressurize the storage facility. This permanent inventory of cushion gas is a major initial cost factor for storage developers.

The credit could not exceed 50 percent of a company's total tax liability each year, the bill says.

The bill's second major element would exempt gas storage facilities and equipment from the state oil and gas property tax.

Storage already happening

While Cook Inlet gas fields are approaching depletion, the most pressing issue right now is deliverability — getting enough gas into the distribution grid during the coldest winter days to meet peak demand. Regulators, energy companies and elected officials have talked increasingly of the possible need for consumer conservation measures or even rolling power blackouts as early as this winter.

French, a former oil industry worker and Senate bipartisan majority member who's running against Republican Gov. Sean Parnell, has touted storage as a way to squirrel away summer gas production for use during winter.

The storage incentives are akin to state perks now in place to encourage exploratory drilling, French said.

But some storage efforts already are progressing without the benefit of the tax incentives he is proposing.

Chevron and Marathon have established three storage facilities in depleted reservoirs at the Swanson River, Pretty Creek and Kenai fields.

Enstar Natural Gas Co., the major gas utility for Southcentral Alaska, is working with Houston-based ANR Pipeline Co., a TransCanada Corp. subsidiary, on development of a new storage facility.

Aurora Gas also wants to develop a gas storage facility at its Nicolai Creek gas field.

French's bill will be considered once the Legislature opens its new session on Jan. 19.

Petroleum news

Home Advertising Subscriptions Publications

vol. 14, No. 34 Week of August 23, 2009

Providing coverage of Alaska and northern Canada's oil and gas industry

Seeking CI gas storage

Enstar working with TransCanada subsidiary on Cook Inlet gas storage facility

By Alan Bailey

Petroleum News

Faced with a slowly increasing natural gas demand accompanied by steadily declining Cook Inlet gas deliverability, Enstar Natural Gas Co, the main gas utility in Southcentral Alaska, is working with Houston-based ANR Pipeline Co, a subsidiary of TransCanada, to establish a new Cook Inlet underground gas storage facility with an eventual capacity of up to 15 billion cubic feet, to alleviate a pending gas deliverability shortfall, John Lau, Enstar's director of transmission operations, told Petroleum News Aug. 17. The two companies plan to make a final decision by the end of this year on whether to proceed with construction of the facility, he said.

ANR would fund, build and operate the facility as a third-party operator, with Enstar and other utilities paying for storage space.

With Southcentral Alaska utility gas predominantly used for heating homes and business, gas demand in the cold of winter typically peaks at levels 10 times greater than the troughs in demand during the summer. And in the past this huge seasonal demand swing has been accommodated by full-service supply contracts, in which Cook Inlet gas producers take responsibility for upping the supply rates during the winter.

Years ago increasing gas delivery was simply a matter of opening up valves on gas wells, but now there isn't that excess deliverability, Lau said. Instead, the producers now need expensive infrastructure to accommodate the demand swings, he said.

No new contracts

In addition, with 25 percent of its required gas supplies in 2011 not under contract, and no significant new gas supply contracts in the offing, Enstar is facing a supply crunch in about 16 months. And, since the Regulatory Commission of Alaska has rejected as too expensive all new gas supply contracts that Enstar has negotiated since 2001, Enstar anticipates that any new contracts that might fill the pending gas supply gap would involve constant rates of delivery year-round at constant pricing, an arrangement known in gas utility parlance as "flat gas."

"There's noone coming to us with contracts for us to take before the RCA anymore," Lau said. "So what we're looking at for contracts that we ... most likely will get in the future is that we're going to have to buy flat gas, or near flat gas."

The expected future introduction of these near constant delivery rate contracts will require Enstar to have access to a storage facility, to warehouse gas purchased in the summer for bolstering winter delivery. That storage need is the more pressing because of the possibility of the LNG export terminal on the Kenai Peninsula closing in 2011, when the current U.S. Department of Energy LNG export license expires — the LNG plant currently provides an invaluable service during severe cold weather by curtailing LNG production, to divert gas for utility use.

And even if gas from the North Slope starts flowing into Southcentral Alaska through a direct "bullet" pipeline from the slope, or through a spur line off a main North Slope gas line, Cook Inlet gas storage will be needed to enable a relatively constant flow of gas through the line year-round, to ensure viable pipeline operations, and to provide backup capacity for periods when the pipeline is shut-in.

Investigating options

Enstar has been investigating gas storage options for about three years and had proposed establishing its own storage facilities as part of the terms of two gas supply contracts that RCA rejected in 2008, Lau said. Subsequently, the utility has been considering options for storage that it now believes will be vital to the future of Southcentral utility gas supplies.

"Now we're looking at what we need in four years, six years, eight years," Lau said. "... The storage that's implemented here in the next couple of years, it'll be used in the Cook Inlet for decades to come."

And the gas producers will likely need to continue to operate their own storage facilities, to enable them to accommodate utility demand swings under the terms of some gas supply contracts, he said.

Although it would typically take about 36 months to permit, construct and fill a new underground storage facility, Enstar has asked ANR to work out how to make a new facility available to Enstar for the winter of 2011-2012, Lau said.

In fact, the coming winter of 2009-2010 could see a gas deliverability shortfall, if the weather becomes especially cold. But by 2011, under current supply arrangements, a shortfall will become certain, regardless of the weather, Lau said.

"We've identified dire consequences that will happen if we do not have gas available out of storage in the winter of 2011-2012," he said.

Four issues

ANR has extensive experience of operating gas storage in the Lower 48 and believes that the 2011 deadline for bringing the new Cook Inlet storage into operation is feasible, Lau said. But the aggressive project timeline will involve spending the next six months resolving four crucially important issues.

First of all, the companies need certainty about whether the Regulatory Commission of Alaska would approve Enstar's tariff changes for factoring in the fees that Enstar will need to pay to ANR for storage usage — Enstar must be sure that it will be able to recover the storage costs from the gas supply rates that it charges its customers, Lau said.

"No private entity will spend any capital on putting together any process or storage, unless they're sure they can recover their costs," he said.

Secondly the companies need to make sure that it will be possible to obtain the use of a suitable storage reservoir, given that all Cook Inlet field reservoirs are currently controlled by gas producers. Four possible reservoirs are under consideration and discussions are in progress with the relevant producers about gas storage possibilities, Lau said.

All of the reservoirs being considered are currently producing gas, a situation preferable to converting a completely depleted reservoir for storage, given that the remaining field gas, occupying perhaps 20 to 30 percent of the field reservoir, can be purchased as "pad gas," gas that simply supports the underground gas pressure and which would otherwise have to be injected into the reservoir, Lau explained.

The purchase of this in-place pad gas from the field owners would form a significant part of the capital cost of the gas storage project, he said.

A third issue is ensuring that all of the permits required to build and operate the storage facility can be obtained, including environmental permits and state approval of a gas storage lease in the chosen field reservoir.

The fourth challenge being addressed in the coming six months is the development of a viable business plan that would work effectively for all of the companies involved in some way with the gas storage project, Lau said.

Supply uncertainty

In addition to these primary challenges, significant uncertainty about the sources of future Southcentral Alaska add complications to Enstar and ANR's gas storage plans — future gas supplies could come from new gas discoveries in the Cook Inlet basin, through some form of gas line connecting to the North Slope or from the import of LNG. In particular the import of LNG though the existing LNG export facility on the Kenai Peninsula — a scenario that, based on current trends, Enstar thinks could come into play around 2014, 2015 — would impact the optimum way in which to design the new storage facility.

In fact, Enstar has started evaluating what additions will be made to Cook Inlet gas reserves in the coming years, to try to pin down the time when will begin to be necessary to boost Cook Inlet gas supplies by importing gas from elsewhere.

In particular, the company wants to know how much of the reserve additions that the state has projected are certain rather than just being possible.

"When it comes to keeping customers warm we need 100 percent (certainty)," Lau said.

Enstar is also discussing with ConocoPhillips and Marathon, the owners of the LNG facility, the possibility of re-gasifying LNG, to support peak utility gas deliverability during severe winter cold. However, uncertainty regarding the renewal of the LNG export license in 2011 complicates that option — Enstar is seeking an opinion from the federal regulators on what the renewal decision is likely to be.

But the core question of establishing a new underground storage facility comes back to ensuring that utility gas continues to flow to consumers during the cold Alaska winter.

"It's not going to be cheap, but it's certain supply," Lau said.

Did you find this article interesting?

Tweet it Digg it

twitter digg

Submit it to another favorite Social Site or Article Directory.

Email it to an associate.

Print this story

Click here to read the PDF version of this story. | Print this story | Email it to an associate.

Petroleum news

Home Advertising Subscriptions Publications

Vol. 14, No. 33 **Week of August 16, 2009**

Providing coverage of Alaska and northern Canada's oil and gas industry

More gas storage needed

Zager says a variety of storage options required; scope for conservation

Alan Bailey

Petroleum News

With winter cold in Southcentral Alaska perhaps three months away, the season is fast approaching when a severe cold snap could push the required delivery rate of utility natural gas for heating and power generation up to and perhaps beyond the limits of feasible production from gas wells in the Cook Inlet basin. One possible solution to this gas deliverability crunch is the use of gas storage facilities, to store excess gas produced during the summer and then release that gas into the utility system during the winter when demand is high.

Three facilities

There are already three storage facilities successfully operating in depleted gas fields around Cook Inlet. Marathon operates one of these facilities in its Kenai gas field; Chevron operates two facilities, one in the Swanson River field on the Kenai Peninsula and one in the Pretty Creek field on the west side of the Cook Inlet. And Aurora Gas is proposing to establish an additional storage facility in its Nicolai Creek field south of Tyonek.

"At peak, when our storage is full, we can do in excess of 60 million cubic feet per day out of the combined (Chevron) systems," John Zager, Chevron's Alaska manager, told Petroleum News Aug. 4.

Both facilities can help support either the on-going high gas load of a typical winter or the peak load during particularly severe cold. However, Chevron tends to use Pretty Creek primarily to bolster the on-going winter load.

"We tend to turn that on and leave it on throughout the winter, whereas we tend to use Swanson more as a peaking field," Zager said.

Zager said that gas storage is critical to addressing the short to intermediate issues relating to the deliverability of utility gas. And a variety of different types of storage could address different delivery needs, such as continuous or needle peaking supply. In addition to the type of below-ground storage that has been implemented already, the above-ground storage of LNG would be especially suitable for needle peaking delivery of gas.

Not cheap

But none of the gas storage options is cheap.

"People want to talk about affordable gas, which is a great desire, but you need to look at security of supply too," Zager said.

Both Chevron and Marathon operate their storage facilities in support of their own operations, to ensure that they can meet their contracted gas supply obligations during the winter. But the storage supports long-term, full-service supply contracts, with constant gas pricing regardless of season variations in demand. This type of contract is disappearing, in part because it does not recognize the full cost of meeting winter demand, Zager said.

Instead, pricing will likely become more flexible, perhaps tiered to the gas demand level, thus opening possible gas storage roles for gas utilities, power utilities or perhaps third-partY gas storage operators.

"The market will find an answer, given the opportunity," Zager said. "Tiered pricing may work. There may also be a mechanism whereby a utility and the customers would pay a capacity charge, whether they use the gas or not."

The concept of a capacity charge arises from the need to protect a gas storage operator from the risk of establishing and filling a storage facility, and then encountering a mild winter in which the storage is not needed — essentially the capacity charge would operate like an insurance premium, to ensure the availability of sufficient gas during exceptionally cold weather.

And then there is the risk associated with uncertainty in the future of the Cook Inlet gas market — in June Ethan Schutt, vice president for land and legal affairs for Cook Inlet Region Inc., a Native regional corporation with major land holdings around the Cook Inlet, told the Senate Resources Committee that CIRI had determined that the development of gas storage for third-party use in the Cook Inlet basin is very unattractive for private industry because of high development costs and high market uncertainty.

"Although the concept seems attractive and to serve a public purpose, the economics aren't worth the risk right now," Schutt said.

Technical challenges

However, aside from the commercial challenges of establishing a viable gas storage facility, anyone setting up an underground storage facility in the Cook Inlet basin faces some significant technical challenges. Whereas in the Lower 48 a company might construct an underground storage facility by using fossilized reef structures with large cavities, or by leaching salt from an underground salt dome to create a cavern that can be filled with gas, operators in the Cook Inlet basin have to use relatively poor reservoirs in muddy sandstones, Zager said.

"We in the Cook Inlet do not have what are considered good storage reservoirs," he said.

Producing gas too fast from a Cook Inlet sandstone reservoir runs the risk of sand production through the gas wells, while issues such as water encroachment in the reservoir need to be considered. There's also the risk of losing gas that's pumped into a less-than-optimum reservoir for storage.

"The first time you're filling that reservoir with gas, you're just hoping it comes back out again," Zager said.

And the need to use a depleted gas field for storage limits the number of underground storage facilities that can be brought into use, as well as determining the locations of gas storage sites and possibly introducing issues relating to joint ownership of field leases. The need to locate a storage facility at a place on the Cook Inlet pipeline system where stored gas can be delivered at sufficient rate through the pipelines further limits the availability of gas storage locations — many Chevron properties are offshore, where storage operation does not seem to make much sense, Zager said.

And no one is going to take the risk of trying to establish an underground facility in a location other than a depleted field.

"My theory would be if nature hasn't been able hold gas for a long period of time, I'm not going to bet on it," Zager said.

New gas

Zager also cautioned that, although gas storage can help with short-term gas deliverability issues, the storage does not actually create any new gas to bolster supplies. In the longer term gas from new Cook Inlet discoveries, from the North Slope or from LNG imports will have to come on line, he said.

And, in the short term, gas conservation, through measures such as turning down thermostats, using wood stoves and deferring activities with high power or gas consumption, could go a long way to overcoming the peak gas deliverability hurdle.

"If on a cold day you could shave demand by 10 percent, that would equate to a nice-sized gas field or an entire storage facility," Zager said.

And building a new storage facility, including permitting, and perhaps drilling a new well and installing compression, would likely take a couple of years.

"It's not like if we decided now, we can have anything ready for this winter, or probably even next winter," Zager said.

Did you find this article interesting?

Tweet it Digg it

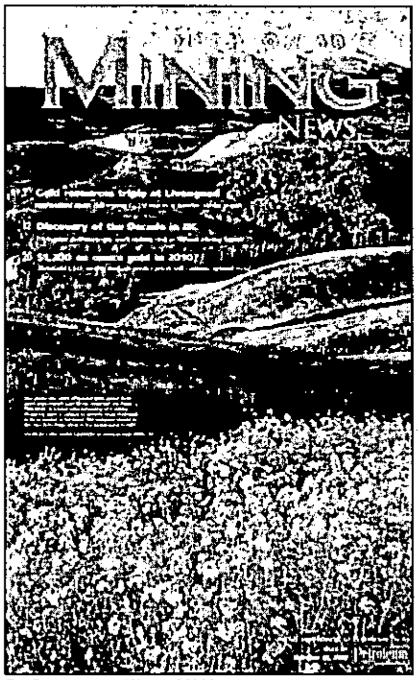
Submit it to another favorite Social Site or Article Directory.

Petroleum news

Vol. 14, No. 43 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of October 25, 2009 • $2

page 12 F&W proposes 200,541-square miles of critical habitat for polar bears

October Mining News inside



The October issue of North of 60 Mining News is enclosed

Alberta's leader in a deep hole

Oil Patch Insider

Alberta Premier Ed Stelmach is in a struggle for his political life.

Consider this:

• His Progressive Conservative party got relegated to third place in a recent election to fill a vacancy in the provincial legislature.

• Support for his governing party has tumbled to 30 percent from 54 percent three years ago, when he was chosen to succeed Ralph Klein, and his own performance as leader has close to a 60 percent disapproval rating.

• Klein, in what was widely seen as a poison dart, suggested Stelmach would need 70 percent support at the party's mandatory leadership review on Nov. 7 if Stelmach was to remain at the helm.

• Alberta's Auditor-General Fred Dunn warned the province could lose C$100 million in royalties this year because it allowed oil sands giants Suncor Energy and Syncrude Canada

see INSIDER page 24

BREAKING NEWS

EXPLORATION & PRODUCTION

OK for Shell plan

MMS approves Beaufort Sea 2010 drilling if permitting requirements met

By ALAN BAILEY
Petroleum News

On Oct. 19 Shell passed another major milestone in its multiyear quest to start exploration drilling on Alaska's Arctic outer continental shelf, when the U.S. Minerals Management Service approved the company's new Beaufort Sea exploration plan, a plan involving the drilling of two exploration wells during the 2010 open water season using a single drillship, the Frontier Discoverer.

"The Minerals Management Service is committed to developing offshore energy resources responsibly," said MMS Director Liz Birnbaum. "Now that we have approved Shell's plan and reached this important milestone, we will continue to work with Shell to ensure that all activities are conducted in a safe and environmentally responsible manner."

And time is of the essence for completion of the permitting for both the Beaufort and Chukchi Seas: The company has said that it needs it to be in a position to make a go-or-no-go decision on the 2010 drilling at the start of that year, given the expense and effort involved in ramping up for any Arctic outer continental shelf drilling activity.

Plan approval is subject to Shell obtaining all required permits and authorizations, including

see SHELL page 23

EXPLORATION & PRODUCTION

Cosmo back on track

Pioneer plans more appraisal work at offshore Cook Inlet prospect this year

By KAY CASHMAN
Petroleum News

Work on the Cosmopolitan oil prospect in Southcentral Alaska's Cook Inlet basin has ramped back up, operator Pioneer Natural Resources told Petroleum News Oct. 20.

In January, Pioneer put plans to drill an appraisal well on hold until 2010 because of low oil prices, although Tadd Owens said the company would continue to investigate the feasibility of commercial oil production from Cosmopolitan, which was discovered in 1967 by Pennzoil.

Owens, Pioneer's director of government and public affairs, also said Pioneer was "well positioned to ramp back up when prices recover."

"Pioneer will conduct additional appraisal work at Cosmopolitan during the fourth quarter of this year and first quarter of 2010. The company plans to work over and flow test the Hansen 1A L1 well — originally drilled in 2007 — in order to gain additional reservoir information."
—Tadd Owens, Pioneer Natural Resources Alaska spokesman

In August, Pioneer said it would continue with just one drilling rig in Alaska in 2009 and 2010 — at its offshore North Slope Oooguruk oil field —

see COSMO page 22

LAND & LEASING

Massive OCS feedback

NOAA, Natives oppose much of 2010-15 leasing plan; drillers, lawmakers endorse

By WESLEY LOY
For Petroleum News

ALAN BAILEY

KEN SALAZAR

A key scientific agency is advising the Obama administration against oil and gas leasing in large portions of the nation's Outer Continental Shelf.

The National Oceanic and Atmospheric Administration recommends that Alaska's North Aleutian basin, which takes in rich Bristol Bay commercial fishing and subsistence gathering grounds, be crossed off the government's proposed 2010-15 leasing schedule.

And NOAA also says no leasing should occur in Alaska's remote Chukchi Sea pending further research into oil spill risk and Arctic cleanup capabilities.

NOAA's position was amid an extraordinary outpouring of public feedback the U.S. Minerals Management Service received by the Sept. 21 extended deadline to comment on the new offshore leasing plan, which would revise the current 2007-12 plan.

MMS, an Interior Department agency that regulates offshore oil and gas activity, said it received more than 450,000 comments on the plan, which the Bush administration released in its final days in office.

see OCS FEEDBACK page 20

3338

contents

Petroleum News A weekly oil & gas newspaper based in Anchorage, Alaska

● NATURAL GAS

Mackenzie Gas Project mood on upswing on all sides

By GARY PARK
For Petroleum News

The key Canadian government and Imperial Oil leaders in the Mackenzie Gas Project are not even close to giving up on the scheme.

Environment Minister Jim Prentice said Oct. 14 the chances of a natural gas pipeline from Canada's Arctic have "never been closer" to success — a view strongly endorsed the next day by Imperial Chief Executive Officer Bruce March.


JIM PRENTICE

Prentice told the Calgary Herald's editorial board he is counting on the regulatory groundwork for the MGP to wrap up next spring.

March shares that view, saying the process is closer than ever to completion, although there is much work still to be done.

Despite an uncertain outlook for gas "those are the risks that all the developers and producers in the energy business know how to manage much easier than the risks" of the Joint Review Panel and other regulatory aspects of the MGP, he said.

"When we get to the point it is in our hands we will be thrilled," he said.

Prentice said he is confident the JRP, which is examining the socioeconomic and environmental aspects of the pipeline, will deliver its final report close to the December target date.

Assuming that happens, the National Energy Board should hear its final arguments in April, allowing the regulators to deliver their conclusions and recommendations to the federal cabinet.

Several years late

"As you know, (the JRP is) several years late," Prentice conceded. "But my understanding is that they should be able to get this done by the end of December.

"It's easy to be dismissive, but the truth is this has been a lot of work for many years and we've never been closer (in 40 years) to having the regulatory and environmental part finished."

Meanwhile, Imperial and its co-venturers (Shell Canada, ConocoPhillips Canada, ExxonMobil Canada and the Aboriginal Pipeline Group) have been working on a fiscal framework with the Canadian government.

Prentice said those talks are upbeat, despite the slump in gas prices.

"I get the sense the proponents continue to be committed to the project," he said.

Inuvik Mayor Derek Lindsay told the Calgary Herald that he was living in Inuvik when the first serious attempt to develop Arctic gas fell through in 1977.

"I don't want to see that happen again," he said. "It crippled this town for 10 years."

If and when a pipeline gets a green light, there will be more activity in Inuvik and in the Beaufort Sea. ●

● SAFETY & ENVIRONMENT

Uncertainty over Copenhagen talks

Prentice suggests financial crisis trumping environmental concerns; Obama administration looking at bilateral pacts with India, China a to break developed-developing country deadlock

By GARY PARK
For Petroleum News

Hopes for a global climate-change agreement are wilting in the buildup to December's United Nations-sponsored talks in Copenhagen, with the Canadian government suggesting that the financial crisis is trumping environmental concerns.

Environment Minister Jim Prentice said Oct. 14 he is far from sure an agreement will be reached in Denmark, not least because of the differences emerging between the United States and the European Union.

The Obama administration is also turning its energies to alternative bilateral pacts with India and China, with the intention of breathing fresh life into the deadlock between developing and economically advanced countries.

In a candid assessment, Prentice said "increasingly people are being realistic" about the chances for a full and complete agreement.

"There's probably too much work to be done in that time that is left," he said.

Prentice said it is likely that Copenhagen will achieve nothing more than "some agreed principles."

Whatever happens on the global stage, Prentice said Canada intends to roll out its own plans for reducing greenhouse gas emissions by 20 percent from 2006 levels by 2020.

If that happens, each Canadian province will have to carry its share of the load, which could involve more ambitious federal targets than Alberta is currently willing to introduce on its own, he suggested.

But Prentice said the road to Copenhagen has encountered the compelling argument that reducing poverty is a greater priority for less-wealthy countries than reducing GHGs.

Some expect greater certainty

Despite Prentice's less than optimistic forecast for Copenhagen, there are petroleum industry leaders who expect greater certainty on issues such as cap-and-trade systems and carbon capture and storage.

Peter Voser, the chief executive officer of Royal Dutch Shell, told a Calgary conference that society "needs real progress on climate policy frameworks that put a price on emissions and promote CCS and other clean energy technologies."

A spokesman for Environment Canada said the Canadian government remains committed to tabling a "full suite of specific policies (prior to the Denmark summit) covering all major sources of Canadian greenhouse gas emissions."

He conceded that federal plan will involve major revisions to the Canadian strategy released 18 months ago to cut GHGs by 20 percent by 2020 and 60 percent by 2050.

"The economic downturn and the renewed engagement by the new U.S. administration has required that we fine tune our approach to tackling climate change," he said.

The spokesman said there has been progress in talks between U.S. and Canadian officials seeking to harmonize climate

see UNCERTAINTY page 7

3340

Petroleum news

www.PetroleumNews.com

Kay Cashman	PUBLISHER & EXECUTIVE EDITOR
Mary Mack	CHIEF FINANCIAL OFFICER
Kristen Nelson	EDITOR-IN-CHIEF
Clint Lasley	GM & CIRCULATION DIRECTOR
Susan Crane	ADVERTISING DIRECTOR
Bonnie Yonker	AK / NAT'L ADVERTISING SPECIALIST
Heather Yates	BOOKKEEPER
Shane Lasley	IT CHIEF
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR
Steven Merritt	PRODUCTION DIRECTOR
Tim Kikta	COPY EDITOR
Alan Bailey	SENIOR STAFF WRITER
Wesley Loy	CONTRIBUTING WRITER
Gary Park	CONTRIBUTING WRITER (CANADA)
Rose Ragsdale	CONTRIBUTING WRITER
Ray Tyson	CONTRIBUTING WRITER
John Lasley	STAFF WRITER
Allen Baker	CONTRIBUTING WRITER
Sarah Hurst	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Mapmakers Alaska	CARTOGRAPHY
Forrest Crane	CONTRACT PHOTOGRAPHER
Tom Kearney	ADVERTISING DESIGN MANAGER
Amy Spittler	MARKETING CONSULTANT
Dee Cashman	CIRCULATION REPRESENTATIVE

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

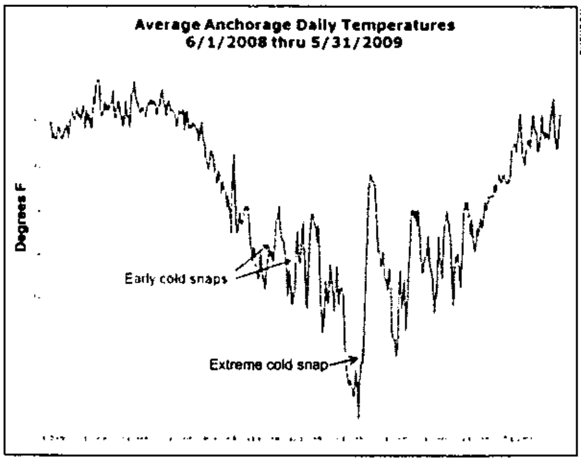
ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 14, No. 43 • Week of October 25, 2009
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years, $249.00 3 years
Canada — $185.95 1 year, $334.95 2 years, $473.95 3 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years, $561.00 3 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.



A graph of daily temperatures in Anchorage between June 2008 and May 2009 demonstrates the extreme fluctuations in temperature that typify a Southcentral Alaska winter. In this particular winter two cold snaps in October and November followed by an extreme cold spell in January nearly brought the Cook Inlet natural gas delivery system to its knees, especially when coupled with two gas compressor failures.

● NATURAL GAS

Are Cook Inlet gas supplies in crisis?

As winter approaches, Chevron manager presents facts, figures about natural gas supply and demand in Southcentral Alaska

By ALAN BAILEY
Petroleum News

Natural gas has flowed out of the Cook Inlet basin with apparent ease for around 40 years, in some ways the life blood of Southcentral Alaska, firing heater furnaces, fueling power stations and supporting significant industrial activity. But does recent talk about gas shortages in the basin signal the beginning of the end for Cook Inlet gas? Or is the region merely transitioning through a period when gas supplies come more into balance with demand, following years of excess gas resources?

At the Oct. 15 meeting of the Alaska Geological Society, Steve Wright, Chevron's Alaska development manager, presented his perspectives on the Cook Inlet gas situation. Wright, an experienced oil industry geologist, now oversees Chevron's Cook Inlet oil and gas development program.

Most of the Cook Inlet gas comes from oil and gas fields discovered during the heyday of oil exploration in the 1960s and 1970s. And, after many years of production, gas reserves — the volumes of gas confidently thought to exist in proven gas reservoirs — have declined by about 80 percent, from about 8 trillion cubic feet to about 1.5 tcf, Wright said.

"The Cook Inlet gas reserve base is now believed to be at its lowest point for 40 years," he said.

At the same time the gas deliverability — the rate at which gas can be produced and delivered to market — is also dropping.

"Total Cook Inlet gas deliverability has declined about 40 percent in the last three to four years," Wright said.

High investment

The declines in reserves and deliverability have come despite a high level of expenditure in Cook Inlet gas development in recent years, with something in excess of $500 million being invested in just the last two years, Wright said.

"Over the past two years alone there have been 29 gas development wells drilled in 11 different gas fields around the basin," he said.

Development activities have included six wells in the Grayling Gas Sands; three wells in the Beluga River field; two winter-drilled wells on the west side of Cook Inlet; two development wells and a compression project in the Ninilchik field; three development wells in the North Cook Inlet field; eight development and storage wells in the Kenai field; and two development wells in the Happy Valley field.

That development activity probably slowed the annual rate of the gas deliverability decline to between 10 and 15 percent; the natural decline rate would likely be 15 to 20 percent, were there to be no development intervention, Wright said.

Production data from the Alaska Oil and Gas Conservation Commission indi-

see GAS SUPPLIES page 5

continued from page 4

GAS SUPPLIES

cates that the deliverability decline has become especially pronounced in the last three years, mainly as a consequence of production declines from the four big legacy gas fields: Beluga River, North Cook Inlet, Grayling Gas Sands and Kenai. In fact, the Ninilchik field, a good-sized field that came on line in 2003 as a result of modern exploration, has actually been increasing its production, Wright said.

Faced with declining deliverability, Cook Inlet gas producers have developed three underground gas storage facilities, to warehouse summer-produced gas to help meet peak demand levels in the winter.

Grim picture

A chart of historic and forecast annual gas production, published by the Alaska Department of Natural Resources in December 2006 and sometimes referred to as the "gas cliff," paints a grim picture of future gas production expectations. According to this chart, after a huge ramp-up in Cook Inlet gas production in 1965 to 1970, production continued to climb for another 10 years before leveling off and remaining fairly constant until around 2006-07. Using future production estimates based on known gas reserves, DNR predicted that production would plunge precipitously in subsequent years.

But current estimates of gas production for 2009 indicate an overall production level considerably lower than the projected value on the 2006 DNR graph, Wright said.

"You might conclude that the DNR forecast was somewhat optimistic overall," he said.

And an Alaska Natural Gas Development Authority projection of gas supplies versus gas demand shows annual supply volumes dropping below total gas demand around 2012-13, Wright said.

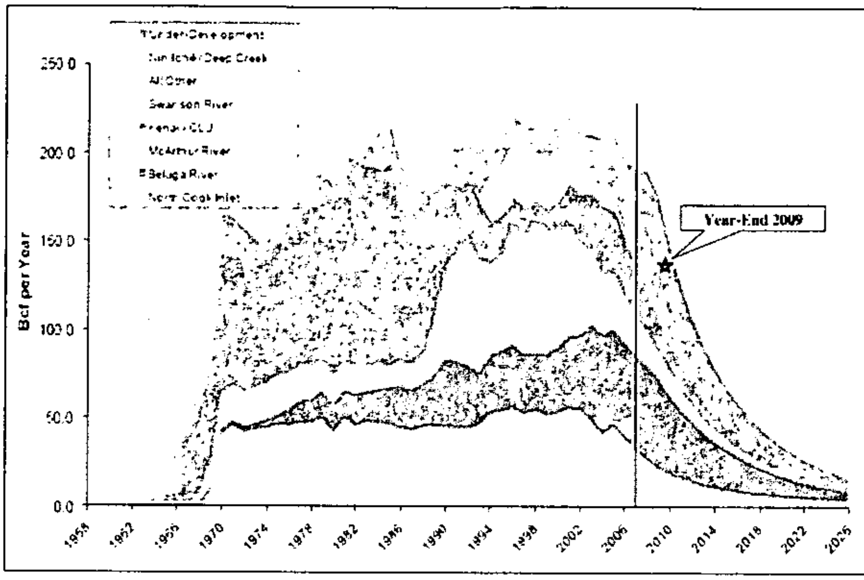
"After that point, total supply will not meet utility demand in the basin," he said.

Data presented to the Regulatory Commission of Alaska by Enstar Natural Gas Co., the main Southcentral Alaska gas utility, and by Chugach Electric Association, a major Southcentral electric utility, suggest shortfalls in utility gas supplies at around that same 2011-13 timeframe, Wright said.

Production figures from the LNG plant at Nikiski on the Kenai Peninsula also make sobering reading — the LNG plant was originally built to establish an export market for excess natural gas from the Cook Inlet basin.

According to data from ANGDA, in 2008 the LNG plant used on average about 180 million cubic feet per day of Cook Inlet gas, a gas volume that repre-

see **GAS SUPPLIES** *page 6*



ALASKA DEPARTMENT OF NATURAL RESOURCES/CHEVRON

A December 2006 Alaska Department of Natural Resources graph showing historic annual Cook Inlet natural gas production, and estimates of future production based on known gas reserves. A current estimate of total production for 2009 falls at a level below the 2006 DNR projection.

3342

continued from page 5

GAS SUPPLIES

sented about 42 percent of the total amount of gas produced from the basin.

"Exports from the LNG plant have ramped down significantly this year, and the 2009 numbers may actually show those LNG volumes to be half of what they were in 2008," Wright said.

Urgent

Plots of projected daily gas deliverability versus daily gas demand show an even more urgent problem: Daily gas deliverability will likely fall below peak demand requirements during the cold of the winter, well before total annual gas production drops below annual gas needs.

With much of the utility gas being burned to heat buildings, daily temperatures in Southcentral Alaska form the key drivers behind gas consumption, Wright explained. And there is an obvious annual cycle of temperature changes between warm summers and cold winters, he said. But superimposed onto that broad cycle are chaotic day-to-day temperature fluctuations, fluctuations that become much more extreme during the winter than during the summer.

"That's obvious to all of us who live here and know that winter temperatures can vary by 30 or even 50 degrees over a couple of days," Wright said.

Those extreme temperature fluctuations, on top of an already heightened winter demand, place a huge stress on the gas deliverability system. And at no time has that stress become more apparent than in January 2009, when a series of events brought utility gas delivery to the brink of failure.

The problem started with two early winter cold snaps in October and November of 2008.

"The gas storage project operators at the three gas storage projects around the inlet had to start depleting the volumes that they had in the reservoirs very early, to meet the demand during these cold snaps," Wright said.

Levels halved

As a consequence, gas levels in the storage facilities had dropped to half of their start-of-winter levels by the end of 2008.

Then came an exceptional, extreme cold period in January, with day temperatures averaging around minus 8 F to minus 10 F, and night temperature bumping 20 below zero for 10 days to two weeks: The semidepleted storage facilities struggled to keep up with the extreme gas demand.

> *"Exports from the LNG plant have ramped down significantly this year, and the 2009 numbers may actually show those LNG volumes to be half of what they were in 2008."*
>
> **—Steve Wright, Chevron's Alaska development manager**

"The reservoir pressures in the storage reservoirs were about half of what they had been," Wright said. "They could only deliver, because of the dynamics of gas flow, about a quarter of what their total deliverability would have been at the start of the winter."

The failure of two gas compressors, the machines used to drive gas through the gas pipeline system, then completed what Wright characterized as a perfect storm for gas supplies.

Then, as gas pressures in the gas transportation system started to fall rapidly, oil company and utility personnel swung into action.

"The producers and utilities went into emergency response mode and worked together very effectively and we were able to head off a potential catastrophic situation by supporting one another, moving gas around the system ... and working together to deal with this problem," Wright said.

The various stakeholders in the gas supply system have since been reviewing what happened in this emergency, refining contingency plans to deal with any similar situations in the future.

"What we do know is that these types of temperature scenarios can't be avoided," Wright said. "This is reality. What we've got to do is put plans in place to deal with those kinds of scenario when they develop."

Solutions?

But what's to be done about the bigger picture of dwindling Cook Inlet gas supplies?

Natural gas exploration in the Cook Inlet basin is especially challenging, thanks to a high-cost environment, a dwindling support industry, long development lead times and difficult operational logistics.

And the results of exploration over the past 10 years don't look too encouraging.

According to AOGCC data, eight different operators drilled 15 exploration wells and eight coalbed methane appraisal wells during that time period, Wright said.

"So we obviously had a lot of companies looking for gas," Wright said. "A lot of different ideas, concepts being generated, plays developed and wells drilled to test those concepts."

Five of the 15 exploration wells were classified as discoveries, with just two of the discoveries — the Ninilchik and Happy Valley fields — being deemed commercial.

"That translates to a commercial success rate of somewhere between 10 and 15 percent," Wright said. "Success rates for exploration in the Lower 48 are typically 50 percent or higher these days."

Moreover, in addition to land access being limited by the closure to oil and gas development of regions such as the Kenai National Wildlife Refuge, all of the moderate- to large-sized geologic structures that typify the reservoir settings of the established gas fields have now been drilled and tested, Wright said. Seasonal access restrictions on the western Cook Inlet coast result in a need to stage equipment over the winter. And, offshore, the listing of the Cook Inlet beluga whale and the increasing difficulty in renewing water discharge permits are raising new challenges for oil and gas development.

Wright also cautioned that, although there are explorers who want to drill offshore using a jack-up rig, a realistic time frame to bring a new offshore gas field on line, taking into account exploration, field appraisal, engineering, platform construction and development drilling, would likely be 10 years.

And, although there may well be potential to find new Cook Inlet natural gas resources in stratigraphic traps, subtle traps formed by the juxtaposition of rock strata, rather than the big structural traps of the established gas fields, discovering those subtle traps would be a major challenge, given the limitations of Cook Inlet seismic data. Essentially, the ancient river channels that would have generated these traps are quite narrow and cannot be resolved in the existing seismic, Wright said.

Other options

Other options being considered to bring new natural gas resources into Southcentral Alaska include a direct "bullet line" from the North Slope, or a spur line from a future main North Slope gas line. But first gas from a bullet line would be unlikely to appear before 2018, and first gas from a spur line might not flow until 2023.

Another possibility would be to import foreign LNG through the LNG plant on the Kenai Peninsula, although negotiating an acceptable LNG supply contract for the small quantities of utility gas required in Alaska could prove challenging, Wright said. And then there are possible alternative energy sources such as hydropower, geothermal power and CIRI's recently announced underground coal gasification plant.

But with so much uncertainty about the future, finding solutions will take a concerted effort by everyone, Wright said.

"We firmly believe that the best way to solve problems is through public and industry awareness, and working jointly," Wright said. "... There's no single entity, not a single producer, not a utility, not the regulatory agencies, not the State of Alaska, that can solve this problem on its own." ●

3343

● NATURAL GAS

Village corporations seek pipeline help

Coalition controls 100 miles of gas line route along Alaska Highway, wants partner to help pursue jobs, training for megaproject

By WESLEY LOY
For Petroleum News

A coalition of Alaska Native village corporations is seeking help in pursuing employment and other opportunities should a natural gas pipeline be constructed through their region.

The four corporations are arrayed along the Alaska Highway between Delta Junction and the border with Canada.

The coalition includes the Dot Lake, Northway, Tetlin and Tanacross village corporations. They are united as Din e'h LLC. State records show the limited liability company was organized on June 16 of this year.

Din e'h translates to "the people" in the Athabascan language of the Upper Tanana River valley.

Din e'h published an advertisement in the Oct. 11 edition of the Anchorage Daily News saying the group was "seeking a partner experienced in large project construction to provide capability, capacity, and proven performance for a joint venture in gas pipeline bidding processes.

"The goal is to create jobs, train workers, and encourage long-term economic opportunities for the Alaska Native people of the Upper Tanana."

The group planned to talk with qualified firms at an Oct. 24 meeting in Anchorage.

Belinda Thomas, general manager for Din e'h, told Petroleum News in an Oct. 20 e-mail the group had attracted several midsized and large contenders for the work.

Din e'h is looking for "teaming partners" who have "a strong commitment to local capacity building," Thomas said.

According to the group's newspaper ad, the four villages together own the surface estate of about 100 miles of the gas pipeline route between Delta Junction and the Canadian border.

Competing gas line projects

The four Native village corporations are among many localities likely to seek jobs or other benefits should major energy companies succeed in building a multibillion-dollar pipeline to carry the North Slope's prodigious natural gas reserves to market.

The project has been a dream of Alaska economic development boosters for decades, but the extreme cost and complexity of the project coupled with weak gas prices have kept the project from happening.

Currently, two competing projects are in the planning stages, with both aiming to hold open seasons next year to test interest among producers for signing long-term contracts to ship gas through a pipeline.

Both projects would follow the Alaska Highway into Canada, passing through the Din e'h region.

One project, called Denali, involves partners ConocoPhillips and BP. Pipeline operator TransCanada and ExxonMobil are teaming on the other project. ●

continued from page 3

UNCERTAINTY

change policies to advance "our respective environmental and energy objectives."

Voser said Shell endorses a cap and trade system that is at the core of the American Clean Energy and Security Act passed narrowly in June by the U.S. House of Representatives, viewing that as the lowest-cost means of reducing carbon dioxide emissions.

If that bill is adopted by the Senate, now seen as unlikely before 2010, the U.S. would be committed to lowering GHG emissions by 17 percent from the 2005 level by 2020 and 83 percent by 2050.

Alberta government hasn't wavered

The Alberta government has never wavered from its position that it will not support any national approach that erodes investment in the province's energy projects, notably the oil sands — something Prime Minister Stephen Harper put high on his list when he agreed to work with President Barack Obama on a joint climate change pact.

Harper reinforced that line after a meeting with Obama in mid-September when he reminded "all our American friends that Canada is by far the largest supplier of energy to the United States."

"And we are determined to be a continental partner in dealing with the very linked problems of climate change and energy security."

However, the two leaders made no specific reference to the oil sands.

In a symbolic gesture, David Jacobson, the new U.S. ambassador to Canada, visited the oil sands on Oct. 14 in what was billed as an effort to help the Obama administration draft a policy on major sources of energy supply for the U.S.

He said officials in both countries recognize there must be a balance between the need for energy security and protecting the environment.

"I've learned a lot about the tremendous strides that have been taken over the last several years with respect to improving the environmental record in treating the oil sands," Jacobson told reporters in Calgary.

He echoed the suggestion by Prentice that a deal in Copenhagen is a long shot, noting that the U.S. health care debate has eclipsed work on energy legislation in Congress, meaning the chances of major energy policy decisions before the international conference are slim. ●

3344

● FINANCE & ECONOMY

Canadian trusts face 'brave new world'

NAL sets standard with 4 deals in recent months as it bulks up prior to joining corporate world once trusts lose tax-free shelters

By GARY PARK
For Petroleum News

NAL Oil & Gas Trust is rapidly becoming a leader among Canada's trusts as it settles on a future strategy with barely one year left before losing its tax-free status.

It struck an agreement Oct. 13 to take over Breaker Energy for C$403 million (including the assumption of C$93 million in net debt) — its fourth deal in recent months.

Launched six years ago by former executives of Alberta Energy Co. (a founding company of EnCana), NAL is moving into the midrange of Canadian oil and gas producers.

Assuming the Breaker transaction is concluded in early December, NAL expects to enter 2010 with production of 31,000 barrels of oil equivalent per day from properties in Alberta, British Columbia and Saskatchewan.

NAL's objective is to add "quality assets with upside opportunity through internal investment and acquisitions."
—NAL Oil & Gas Trust CEO Andrew Wiswell

It will have a proved-plus-probable reserve life index of 8.7 years from reserves of 96 million boe, undeveloped land of 550 acres and tax pools (or credits) of C$1.2 billion (including Breaker's contribution of C$270 million).

Breaker will contribute production of 6,700 boe per day (45 percent oil and gas liquids and the rest natural gas), 23 million boe of proved-plus-probable reserves and 140,000 net undeveloped acres.

Deal follows earlier buys

The deal follows NAL's acquisitions of Alberta Clipper for C$115 million and Spearpoint Energy for C$16 million, plus a joint venture to exploit central Alberta's Cardium oil play.

The trust will issue about 25 million trust units at C$12.54 each to finance the acquisition, which works out to C$5.96 a Breaker share, a 12 percent premium to the junior company's preceding 20-day average trading price.

On a production basis, NAL is paying about C$58,000 per flowing barrel and C$16.91 per barrel for reserves, compared with ATB Financial's estimated average of C$46,195 and C$12.93.

Kim Page, an analyst with Wellington West Capital Markets, said that given the valuation metrics there is unlikely to be a counterbid.

Breaker President Dan O'Neil said blending his company's assets with NAL's strong financial position "will allow the combined entity to high-grade its opportunities and fully develop and expand Breaker's potential."

Breaker has pinpointed about 400 (350 net) low-risk development prospects, including 190 horizontal resource-style locations on its land, with the prospect of adding 2,900 boe per day in central Alberta and long-term gas opportunities in northeastern British Columbia of 50-100 billion cubic feet of recoverable gas.

NAL Chief Executive Officer Andrew Wiswell said the inclusion of Breaker will be another significant step in repositioning to convert NAL from a trust to a corporation in 2011, when the Canadian government will put both sectors on the same tax footing.

He said NAL's objective is to add "quality assets with upside opportunity through internal investment and acquisitions."

Action on the M&A front has been quietly gathering speed this year as trusts have decided what route they will take in the post-2010 world.

No single solution

The decision making comes three years after Canada's Finance Minister Jim Flaherty dropped a bombshell on the sector to avert a stampede by corporations in all sectors to join trust ranks and take advantage of a tax loophole.

Now that the initial anger has faded, the bulk oil and gas trusts seem resigned to joining the corporate world, though some will delay their transition while they use tax pools to reduce their taxable income beyond Jan. 1, 2011.

Some apparently believe that it will make no difference if they continue as trusts and some have trimmed their monthly cash payouts in favor of increasing capital spending to strengthen their reserves and production.

The conclusion is that there is no single solution for trusts plotting their future direction. Sayer Energy Advisors has reported that trusts completed C$1.4 billion in unit issues in the first half of 2009, compared with a paltry C$218 million in the same period of 2008, raising the total from unit issues and debentures to C$2.1 billion.

Sayer said these moves could underscore M&A activity by trusts that want to expand their core operations before joining the corporate world in 2011.

In addition to NAL, the busiest acquisitors have been Penn West Energy Trust and Zargon Energy Trust.

Blackmont Capital said that comparing the "real-world valuation parameters" of the NAL-Breaker deal with current market valuations of some intermediate producers, "a couple of them appear to be overvalued."

More capital appreciation

One thought taking hold is that the next generation of trusts will lean more toward capital appreciation from their transition income-generating priority, which could benefit the struggling service sector if it results in increased exploration and development, with an emphasis on horizontal wells and multifracturing work.

Meanwhile, Calgary-based investment dealer Peters & Co. has listed Pengrowth, Paramount Energy Trust and Peyto Energy Trust as relatively cheap takeover targets based on their expected 2010 cash flows per barrel of oil equivalent against their boe enterprise values.

"From an acquirer's viewpoint, desirable entities possess above average cash-flow generating capabilities and below average current valuation levels," the firm said.

Blackmont Capital said that comparing the "real-world valuation parameters" of the NAL-Breaker deal with current market valuations of some intermediate producers, "a couple of them appear to be overvalued."

In particular, the firm identified Birchcliff Energy and Progress Energy Resources as "expensive on a flowing barrel basis," while Celtic Exploration and Progress "look expensive on a reserve basis."

However, Blackmont said it was "dangerous to draw conclusions based only on this one transaction" adding it would "not expect market valuations to vary too widely from what real-world purchasers are prepared to pay for assets." ●

3345

● ALTERNATIVE ENERGY

RCA to adopt net metering regulations

New regulations provide incentive for investment in renewable electric generation, allowing consumers to put power into utilities

By KRISTEN NELSON
Petroleum News

Renewable power generation may be coming to your neighborhood. And it may be built by your neighbor, thanks to proposed regulations that would require Alaska's largest utilities to allow hookups by such privately built generation to their power grids.

The Regulatory Commission of Alaska voted 4 to 1 on Oct. 14 to adopt regulations establishing net metering requirements for the state's largest electric utilities.

The vote ends a tussle between Alaska's electric utilities and proponents of net metering, who believe net metering will increase renewable energy development in the state, while utilities believe net metering will be a burden on other consumers.

Net metering allows a customer of an economically regulated utility to interconnect eligible onsite generation facilities with the electric utility's distribution system, the commission said in an Oct. 16 press release.

In 2008 RCA rejected net metering standards proposed by the Bush administration and began work on regulations targeted to Alaska, including workshops with participation by utilities and proponents of net metering.

The regulations commissioners approved are the result of work done since the Environmental Policy Act of 2005 created guidelines for net metering which state regulators were required to consider, but not to accept.

Alaska regulations

The new Alaska regulations apply to economically regulated electric utilities with total retail sales of 5 million kilowatt hours or more, which limits the RCA regulations to the state's largest electric utilities: Bethel Utilities Corp., TDX North Slope Generating, Alaska Power Co., Alaska Electric Light & Power, Homer Electric Association, Matanuska Electric Association, Municipal Light & Power, Chugach Electric Association and Golden Valley Electric Association, which sell from 39.1 million kilowatt hours (Bethel), to 1.349 billion kilowatt hours (Golden Valley Electric).

The affected utilities would be required to interconnect with eligible customer generation systems up to a systemwide total capacity of 1.5 percent of average retail demand. Eligible customer generation systems are limited to a total onsite capacity of 25 kilowatts.

Net metering customers would be billed for net consumption and receive bill credits when the customer's generation exceeds usage.

Technologies eligible for net metering generation are limited to solar photovoltaic, solar thermal, wind, biomass, hydroelectric, geothermal, hydrokinetic, ocean thermal, landfill gas and biogas energy. The commission may approve other sources that generally have similar environmental impact.

For and against

Summaries of comments on the proposed regulations by RCA staff highlighted some of the disputed issues between net metering proponents and the state's electric utilities.

Municipal Light & Power — one of two electric utilities serving the Anchorage area — told the commission it believed net metering would cause more harm than good while the Alaska Power Association, which represents major consumer-owned power utilities in the state, including ML&P, said that although the proposed regulations did not reflect its preferred position, they were a reasonable compromise between two extremes.

The Alaska Center for the Environment said net metering would reduce utility bills for participating consumers, while the APA said public benefits of net metering would be privately subsidized by non-net metering consumers rather than through typical public means such as grants, tax incentives or similar methods.

ML&P said net metering would cause generation to be built that is not cost effective, burdening ratepayers as a group with higher costs, and requiring ratepayers who do not own net metered generation to subsidize the small minority of ratepayers who will install net metered generation.

Golden Valley Electric Association concurred, telling the commission that net metering is in conflict with the cost-causer cost-payer principle, requiring nongenerating members to subsidize members installing small renewable generation and forcing the utility electrical system to act as a battery for renewable generating facilities.

What about smaller utilities?

In response to comments that the 5 million-kilowatt-hour limit would prevent smaller utilities from utilizing net metering, RCA staff said if a utility is too small to be covered by the RCA regulations it can enact its own net metering regulations.

"The regulations require certain larger utilities to enact net metering rules. Smaller utilities, or utilities that are outside of our authority to economically regulate, are exempted from the requirement and instead allowed to choose independently whether net metering makes sense for their system."

RCA staff said the limitations on net metering were imposed to protect the integrity of the systems:

"The Railbelt electric system, the largest interconnected 'grid' in Alaska is very small in comparison to the nationwide grid in the Lower 48 states and lacks a robust transmission and distribution network."

TDX Sand Point Generating is a case in point, the staff said, with retail sales for their last fiscal year 4.254 million kilowatt-hours, an average retail demand of 485 kilowatts per day.

With the proposed 1.5 percent of average retail demand limit, TDX Sand Point could have up to 7.3 kilowatts of installed on-site consumer renewable generation, less than half of the proposed 25 kilowatt per installation limit proposed in the regulations.

see NET METERING page 10

3346

GOVERNMENT

Senate passes bill with icebreaker funding

The full U.S. Senate has passed the 2010 Homeland Security Appropriations conference report that includes $32.5 million in funding for enhancements to U.S. icebreaker capability, Sen. Lisa Murkowski, R-Alaska, said Oct. 20. The bill, which also appropriates U.S. Coast Guard funding for fiscal year 2010, now goes to President Obama for his signature.

The United States currently has just two working icebreakers, the Healy and the Polar Sea, with a third icebreaker, the Polar Star, currently in caretaker status.

The United States currently has just two working icebreakers, the Healy and the Polar Sea, with a third ice breaker, the Polar Star, currently in caretaker status.

Funding from the conference report that the Senate has just passed would pay to finish refurbishment of the Polar Star, to reactivate this icebreaker and extend its service life. The conference report would also require the Coast Guard to investigate whether a new heavy polar icebreaker class vessel should be built, or whether money should be spent on extending the service lives of the existing icebreakers — the Polar Sea has a remaining service life of five years, Murkowski said.

"While reactivation of our second heavy icebreaker helps, the U.S. must begin to plan for the long term replacement or extension of our ice breaker fleet," Murkowski said. "These vessels are becoming increasingly important as access to the Arctic, and its resources, increases due to climate change and a reduction in summer sea ice. Activities such as energy development, tourism, marine transportation and shipping will increase and the Coast Guard must have the resources to respond. This funding is a good start."

—ALAN BAILEY

continued from page 9

NET METERING

Smaller utilities also have different operating parameters, staff said, and interconnecting small non-firm generation may create operational problems, with scenarios varying from utility to utility.

But, RCA staff said, nothing in the regulations prevents a rural community from implementing net metering.

Limit at 1.5 percent

There were a number of objections to a limitation in the regulations of 1.5 percent — that is, a utility may refuse to interconnect for new net metering if that connection would cause net metering to exceed 1.5 percent of the utility's average demand.

APA, Chugach Electric Association and ML&P all pointed out that 1.5 percent was the agreement reached at the commission's technical conference.

RCA staff said the proposed regulations allow a utility to approach the commission regarding increasing the cap to allow additional net metering beyond the 1.5 percent of average retail demand.

"Staff believes it is the intent of the commission to allow a controlled trial of net metering that will limit the potential rate increase for consumers who do not choose to net meter. This cap is an essential part of limiting that financial risk."

Utilities are required to publish annually the result of the 1.5 percent of average retail demand calculation and the total nameplate capacity of interconnected net metering consumers, which will allow the commission to monitor how quickly interconnection is occurring and revisit net metering regulations as required, RCA staff said.

Commercial generation not included

There were objections to the limit of 25 kilowatts on consumer generation and the staff said that limit was chosen so that smaller consumer generators would have the opportunity to participate.

"With a larger generator capacity and a limited system capacity for net metering, the smaller systems could be squeezed out," RCA staff said.

Larger corporate consumers did not participate in the process, staff said, indicating a lack of serious interest at this time.

There were a large number of comments arguing that excess generation should be valued at the full retail rate rather than the discounted avoided-cost rate.

RCA staff said the language was based on "the compromise reached by the net metering advocates and the utilities at the technical conference. To alter this section at this juncture would undermine the fragile agreement that was reached by the participants. The net metering rules contained herein are designed to limit the potential negative financial effects of net metering" on those consumers who do not participate in net metering.

"Staff concurs that this mutes the benefits of net metering for those who participate in the program. Both sides on this issue have strongly argued their positions but neither side has any real experience with net metering in Alaska. Staff believes that going forward with the substance of the proposed regulation is the best way to build experience in net metering. The rules can be revisited in the future as needed and with actual data."

There were a number of objections to language in the proposed regulations allowing utilities to petition the commission for special rates for net-metered consumers "if the utility can demonstrate an adverse material rate impact on utility consumers that do not participate in the net metering program."

RCA staff said utilities always have the right to petition the commission for changes in the rates they charge, and it "believes the proposed language offers a protection to net metering consumers by requiring the utility to demonstrate that the effect of net metering is both 'adverse' and 'material' to consumers that do not participate in net metering."

The commission will release an order adopting net metering regulations, which become official once reviewed by the attorney general and the lieutenant governor. ●

On the Web

See previous Petroleum News coverage:

"RCA rejects federal net metering rules," in Sept. 14, 2008, issue at www.petroleumnews.com/pnads/853433629.shtml

"RCA starts net metering discussions," in Oct. 26, 2008, issue at www.petroleumnews.com/pnads/419740526.shtml

3347

• SAFETY & ENVIRONMENT

Canada backs carbon capture

Governments commit C$1.65B to 2 projects, claim they lead world in developing technology; others say industry should do cleanup

By GARY PARK
For Petroleum News

Canadian and Alberta taxpayers are starting to feel a rather large hand in their pockets as the two governments roll out plans for carbon capture and storage projects — their key technological initiative to remove greenhouse gas emissions from the atmosphere.

In early October, C$865 million in public money was pumped into Royal Dutch Shell's planned C$1.35 billion Quest project, with Chevron Canada and Marathon Canada as partners, to inject 1.1 million metric tons a year of carbon dioxide from the company's Edmonton-area heavy oil upgrader into underground storage, some of it for possible use in enhanced oil recovery.


STEPHEN HARPER

Less than a week later, the governments announced they would contribute C$781 million for a $1.4 billion CCS project TransAlta plans to capture about 1 million metric tons a year from its coal-fired electricity plant in central Alberta.

These handouts are taking place amid mounting questions about whether largely untested CCS technology will achieve its hoped-for goals without causing a financial boondoggle.

Of the public share, Alberta will account for almost C$1.2 billion, drawn over 15 years from the C$2 billion it has earmarked to develop and test CCS technology.

'Clean energy superpower'

Prime Minister Stephen Harper said the TransAlta venture, with Capital Power and Paris-based Alstom as partners, meets the federal government's objectives of helping economic recovery and improving the environment.

"To keep Canada on the cutting edge, we are investing massively in scientific research and development. A major focus of these investments is our energy sector."

Harper said that in order for Canada to meet its goal of becoming an "energy superpower" it must be a "clean energy superpower."

Alberta Premier Ed Stelmach said the benefits of Project Pioneer will extend far beyond the TransAlta plant by offering "lessons on how other plants might be retrofitted here in Alberta and around the world."

The project was not on the original short list of three projects that Alberta tagged for its CCS money.

A spokesman for Greenpeace said governments should play no role in subsidizing CCS efforts by giant companies.

"Industry created this toxic mess and they should be fully and financially responsible for cleaning it up," said Mike Hudema.

He also described CCS as a "risky, expensive smokescreen," urging governments to invest more in renewable energy technology, such as wind and solar power, which he said will create more jobs over time.

Alberta Energy Minister Mel Knight defended the approach, arguing government must be a partner in developing CCS technology.

Federal Natural Resources Minister Lisa Raitt, who joined Knight at the Quest announcement, said: "We have to start somewhere. We start today. There are some hurdles to CCS, but the good news is the technology has already been technologically proven."

Reduction in emissions pledged

The Canadian government has pledged to reduce greenhouse gas emissions by 20 percent below 2006 levels by 2020.

Graham Boje, vice president of health safety and sustainable development with Shell's Canadian division, cautioned that, despite the financial backing, Quest has yet to receive corporate sanctioning.

He said the project has a "long way to go before it becomes a fully operational CCS project. We're still in the project development phase and the final investment decision depends on a range of factors."

Boje said it will take about two years to complete engineering, undergo public consultation and obtain regulatory approvals.

The Alberta government is still working on the two other projects that made its initial short list: the Alberta Carbon Trunk Line, a joint proposal by Enhance Energy and North West Upgrading to incorporate gasification, carbon dioxide capture transportation, enhanced oil recovery and storage, drawing on carbon dioxide from the Agrium fertilizer plant and the planned North West heavy oil upgrader; and an integrated gasification combined-cycle power generation plant proposed by Epcor Utilities and Enbridge at the Genesee site in central Alberta.

Coalbed methane recovery honored

The Alberta government derived some hope when an enhanced coalbed methane recovery project, led by the Alberta Research Council, landed an international award in London, England, earlier in October.

The recognition from the Carbon Sequestration Leadership Forum was for work completed last year involving the injection of carbon dioxide into deep, unmineable coal bed, displacing the underground methane with CO2, reducing greenhouse gas emissions and improving the recovery of coalbed methane in the process.

Knight said the award established that the government-funded research council is a "global leader when it comes to contributing real solutions to address climate change."

The forum also endorsed a second Alberta project, co-led by ARC Resources and the research council, aiming to store carbon emissions from Alberta's industrial heartland region, north of Edmonton, in an underground reef formation, which is estimated to have the potential to handle 1 million metric tons a year of CO2 by 2015 for more than 20 years. ●

3348

● SAFETY & ENVIRONMENT

F&W proposes polar bear critical habitat

200,541 square-mile area includes much of the outer continental shelf, the barrier islands and land along the Beaufort Sea coast

By **ALAN BAILEY**
Petroleum News

On Oct. 22 the U.S. Fish and Wildlife Service announced its proposed designation of critical habitat for the polar bear, following the May 2008 listing of the bears as threatened under the Endangered Species Act. The proposed habitat region encompasses a total area of 200,541 square miles of U.S. territory covering those areas of the Arctic Alaska offshore continental shelf where water depths are 300 meters (980 feet) or less in depth; barrier islands and spits along Alaska's northern coast; and polar bear, on-land denning habitat along the Beaufort Sea coast.

The onshore denning habitat consists of lands within about 20 miles of the northern coast of Alaska between the Canadian border and the Kavik River, and within about eight miles of the coast between the Kavik River and the city of Barrow.

The announcement of the proposed critical habitat designation triggers a 60-day public comment period.

But Strickland emphasized that federal agencies had already been conducting Endangered Species Act section 7 consultations for the polar bear, prior to the critical habitat designation, and that the recent U.S. Minerals Management Service approval of Shell's Beaufort Sea exploration plan had successfully gone through this consultation process.

"This administration is fully committed to the protection and recovery of the polar bear," said Interior Assistant Secretary for Fish, Wildlife and Parks, Tom Strickland. "Proposing critical habitat for this iconic species is one step in the right direction to help this species stave off extinction, recognizing that the greatest threat to the polar bear is the melting of Arctic sea ice caused by climate change. As we move forward with a comprehensive energy and climate strategy, we will continue to work to protect the polar bear and its fragile environment."

Fish and Wildlife has also proposed the prohibition of international trade in polar bears and their parts, Strickland said.

Thorough evaluation

Although the Endangered Species Act requires the Department of the Interior to, if possible, designate critical habitat at the time a species is listed under the act, Fish and Wildlife has not proposed the critical habitat designation until now because of the time that it has taken to conduct a thorough evaluation and peer review of its proposal, Fish and Wildlife said.

Under the terms of the Endangered Species Act, geographic areas designated as critical habitat contain features that the Department of the Interior considers essential for the conservation of a listed species and that may require special management or protection. And under section 7 of the act, federal agencies must ensure that any federally authorized activities are unlikely to jeopardize the continued existence of the species or to destroy or adversely modify the critical habitat.

Oil industry

The designated critical habitat area for the polar bear includes places where the oil industry is active: Fish and Wildlife will evaluate the economic impacts of the habitat designation, Strickland said.

But Strickland emphasized that federal agencies had already been conducting Endangered Species Act section 7 consultations for the polar bear, prior to the critical habitat designation, and that the recent U.S. Minerals Management Service approval of Shell's Beaufort Sea exploration plan had successfully gone through this consultation process. Onshore and offshore oil and gas activities have also already been subject to significant review and regulation under the Marine Mammals Protection Act.

"We believe that it will not be a significant additional burden on the industry ... but it does further heighten the importance of trying to minimize any kinds of activity in these critical areas that might adversely affect the bear," Strickland said of the proposed critical habitat designation.

Critical habitat receives an additional level of legal protection under section 7 of the Endangered Species Act, he said.

Fish and Wildlife has stepped up its funding efforts and is expanding its consultation capabilities, including the deployment of staff to the North Slope to support the development and implementation of community-based, polar bear-human interaction plans for the North Slope villages, said Sam Hamilton, director of the U.S. Fish and Wildlife Service.

Sea ice

About 93 percent of the designated habitat area is occupied by winter sea ice, Strickland said.

"Through eons of time polar bears have evolved and adapted to life on the sea ice, and they depend on this area for resting, breeding, hunting and feeding," Hamilton said. "Polar bears require sea ice as a platform for hunting and feeding on seals; seasonal long-distance movements; travel to terrestrial maternal denning areas; resting and mating."

The majority of the U.S. polar bears remain on sea ice year round and prefer the shallow areas of the continental shelf, he said. And, according to Fish and Wildlife, most polar bear populations use onshore

see **HABITAT** page 19

3349

● LAND & LEASING

B.C. lifts lid on new gas play

Government discloses 'sleeping dog' in Liard basin, west of Horn River, Montney plays; operators tight-lipped about plans, results

By GARY PARK
For Petroleum News

It's in a hush-hush mode right now, but E&P companies in British Columbia could be quietly extending the province's gas hot spot beyond the Montney and Horn River formations.

One of the first public hints came at a Northeast British Columbia Natural Gas Symposium in Calgary at the end of September, when a senior government official said the little-explored Liard basin — west of the Horn River shale gas basin and 65 miles northwest of Fort Nelson — is generating strong interest at monthly land auctions.

Vic Levson, executive director of the Resource Development and Geoscience Branch of the B.C. Energy Ministry, said the region is a "sleeping dog that has been lying quiet."

But bidders committed C$48.3 million in the first seven months of 2009 to secure exploration rights in the basin, compared with C$18.5 million for all of 2008, doubling the average price to C$1,500 per hectare.

However, he said the companies are "keeping a pretty low profile," although some of the operators are shifting their exploration efforts to unconventional from conventional prospects.

The players include two majors — Apache and EOG Resources — while three juniors (a partnership of Questerre Energy and Transeuro Energy and Stone Mountain Resources) have embarked on evaluation programs.

Levson said the government is hopeful that the early exploration is the start of a new trend.

He said the province believes the basin is a "good target … we'd like to see more companies" take an interest in the area.

The lightly explored Beaver River area (incorporating the Liard basin and Fold Belt region) 100 miles northwest of Fort Nelson, has stirred interest among producers interested in evaluating and testing the potential of Mississippian-aged shales.

B.C. tops land sales

Otherwise, British Columbia, having topped Canada's provincial land sales for the first time in 2008, remains the frontrunner.

For the first nine months of the year, it generated C$330 million in successful bids, compared with C$247 million in Alberta and C$51 million in Saskatchewan.

That total was a starting C$3.5 billion behind the total for the same period last year, with British Columbia down about C$2 billion, Alberta off by C$715 million and Saskatchewan taking a C$797 million tumble, all paying the price for the industry-wide downturn.

British Columbia's per-hectare average price plunged to C$1,281 from C$3,820 in the first nine months of 2008; Alberta has edged up each quarter from C$119 to C$166 and C$257, but lags far behind the 2008 average of C$377; and Saskatchewan nosedived to C$297 from C$1,781.

There was no more hope for Alberta at its first October auction, which drew a mere C$21.9 million in successful bids and an average C$204 per hectare, compared with the C$38.7 million and C$329 per hectare at the comparable 2008 sale.

B.C. sees move to drilling

Otherwise, British Columbia is seeing the first signs that blockbuster land sales in 2007 and 2008 are being translated into drilling plans, although what is in store for the upcoming peak winter season has yet to be disclosed.

For the first nine months of 2009, the regulator has approved 532 new well licenses. Although that is down more than 30 percent from the same period of 2008, the September permits totaled 68, the most in any month since March and only 11 behind September 2008.

Alex Ferguson, commissioner of the B.C. Oil and Gas Commission, said the mood among operators is more positive than it was a few months ago, but until companies complete their budget plans the government is in a "blind spot."

Over the past seven years, the commission has approved 32 experimental schemes for shale gas formations, allowing ongoing research in drilling, completion and/or production technology.

For Horn River those in the experimental phase include majors such as Imperial Oil, EOG Resources Canada and Hunt Oil Company of Canada and smaller players such as Stone Mountain, Kodiak Bear Energy, Quicksilver Resources Canada and Storm Gas Resource.

EnCana has led the way in Horn River since 2001, listed as operator of 90 wells, 79 categorized as nonexperimental and five wells licensed as experimental, but not yet drilled, a commission report said.

It said that after completing its 2008 drilling program, EnCana reported average per well production rates of 5 million cubic feet per day, while the first wells of 2009 have posted flow rates of 9.5 million to 11 million cubic feet per day after 15 days.

The lightly explored Beaver River area (incorporating the Liard basin and Fold Belt region) 100 miles northwest of Fort Nelson, has stirred interest among producers interested in evaluating and testing the potential of Mississippian-aged shales. The commission said some promising results have already emerged from tests. ●

3350

Rosneft wants tax breaks for Arctic development

Russia needs to realistically assess the risks and costs of Arctic oil and gas development, Sergey Bogdanchikov, the president of state-owned oil company Rosneft, told the Murmansk International Economic Forum Oct. 15. Exploration drilling in the offshore Arctic can be done with far less certainty than drilling in traditional exploration areas in western Siberia, Bogdanchikov said. The cost of working in Arctic regions is also extremely high, he noted.

"Here we can already talk in quite concrete, specific terms, based on our development of the shelf off Sakhalin, and if you compare the figures from western Siberia, $30 to $50 to produce a ton of hydrocarbons, on the Far Eastern shelf we have about $300 and it will be at least $600 to $700 to produce a ton of hydrocarbons here on the Arctic shelf," Bogdanchikov said. "Companies have to be prepared for this and our government, of course, also has to be prepared for it. When it determines a tax policy for the offshore regions it can't be identical for the Caspian, the Sea of Azov, the Black Sea and the Arctic Shelf. We hope for mutual understanding with the government here.

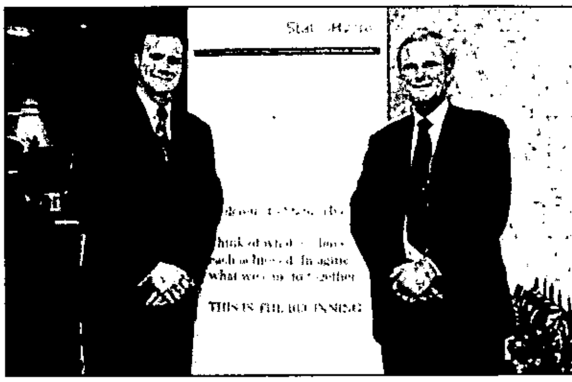
"We have to be honest above all with ourselves going into such a complex task as developing the Arctic shelf," Bogdanchikov said. "We are technologically backward here in the Russian Federation in virtually all the technology that is necessary."

At this point in Bogdanchikov's speech Alexei Miller, the CEO of Gazprom, Russia's other state-owned energy giant, interrupted to indicate that he agreed with the sentiment.

"We have to synchronize the following processes, the process of licensing on the shelf, the process of conducting geological exploration work and the process of preparing Russian industry, companies that are on both the regional and the national scale, in order to support these projects and to achieve the required production on time," Bogdanchikov said.

"When we're talking about investment of $250 to $300 billion, the question is whether this investment will go into Russian companies located in Russia or

see ROSNEFT page 16



VERONIKA SMOLENSKAYA/STATOILHYDRO

StatoilHydro CEO Helge Lund and Bengt Lie Hansen, president of StatoilHydro in Russia, at the signing of the Shtokman phase 1 agreement.

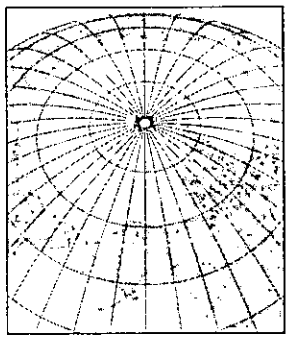
● OUR ARCTIC NEIGHBORS

StatoilHydro ready for Shtokman collaboration

Norwegian company will use experience from Ormen Lange, Snohvit to develop subsea installations for Russian Barents Sea project

By SARAH HURST

For Petroleum News



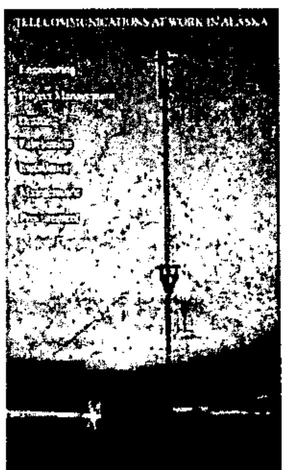
Norway's StatoilHydro is gearing up for the "mother of all projects" — developing the Shtokman gas field in the Russian part of the Barents Sea — Bengt Lie Hansen, the company's president in Russia, said in a speech at the Murmansk International Economic Forum Oct. 15. StatoilHydro is a partner in phase one of Shtokman, with a 24 percent interest in the Shtokman Development company. Russia's Gazprom has a 51 percent interest and France's Total has the remaining 25 percent.

StatoilHydro was trying for 20 years to get involved in Shtokman before signing the phase-one agreement in February 2008, Hansen said.

"(Shtokman) I think will be the locomotive for developments in the Arctic," he said. "And I think that will not only have implications for the investing companies, it will have lots of implications for the Murmansk region, as we have seen in other areas where there are offshore developments, you see a lot of spinoff effects that you hardly are able to assess before you start out."

Shtokman will provide gas to Europe via the planned Nord Stream pipeline under the Baltic Sea, and to Atlantic mar-

see SHTOKMAN page 16



3351

● SAFETY & ENVIRONMENT

No quick carbon fixes

Oil sands leader argues 'absolute' limits on oil sands' GHG would burden sector; Imperial boss says answers could take 100 years

By GARY PARK
For Petroleum News

Two leading players in the Alberta oil sands — the flashpoint of Canada's climate-change wrangling — have answered criticism that the sector is not doing enough to explain itself.

In the process, they got to grips with the range of challenges facing those seeking answers to greenhouse gas emissions.

Marcel Coutu, chief executive officer of Canadian Oil Sands Trust, which owns 36.7 percent of the giant Syncrude Canada operation, said oil sands producers should be allowed to raise GHGs, even if that means forcing other industrial sectors to shoulder a heavier share of meeting national climate change goals. Bruce March, chief executive officer of Imperial Oil, said it has taken 100 years to create the GHG problem and it will probably take another 100 years to meet growing global energy demand while dealing with climate change concerns.

Their comments came a month after Peter Voser, the new chief executive officer of Royal Dutch Shell, told a Calgary business summit that industry and governments have failed to promote the oil sands as a key answer to the energy needs of Asia and the wider world.

Arguing that oil sands opponents have done an effective job of trashing the resource, he called on industry and governments to play a more active role in promoting the oil sands and making a case for the future importance of unconventional oil.

New Alberta publicity campaign

The Alberta government has recently launched a three-year, C$25 million publicity campaign to counter some of the negative publicity from environmental groups who have labeled the oil sands as "dirty oil."

The Canadian Association of Petroleum Producers, whose member companies account for more than 90 percent of Canada's oil and natural gas production, has also admitted it is lagging in the battle for hearts and minds and has pledged to answer public concerns about the industry's environmental impact.

But Voser insists the oil sands could be taking a larger international role in energy markets by building pipelines to the British Columbia coast, opening up tanker routes to Asia-Pacific markets.

Speaking at the same Calgary conference, federal Environment Minister Jim Prentice agreed Canada needs to be more active in promoting its technological gains in energy production.

"Canada's role must be perceived as the most environmentally cautious producer of energy of all kinds, from green energy to hydrocarbons, in the world," he said.

Intensity-based limits proposed

But Coutu warned that if the oil sands face an absolute limit on their GHGs, regardless of increasing output, that would "put a very, very heavy burden on a business that is in a growth mode" and a key driver of the Canadian economy.

Rather that stifle oil sands output, the Canadian government should impose intensity-based limits, reducing per-barrel GHGs, leaving other industries to pick up the slack, he said.

> *Marcel Coutu, chief executive officer of Canadian Oil Sands Trust, which owns 36.7 percent of the giant Syncrude Canada operation, said oil sands producers should be allowed to raise GHGs, even if that means forcing other industrial sectors to shoulder a heavier share of meeting national climate change goals.*

"What we have to do is prioritize what is most important to the economy and our quality of life," Coutu said. "At the end of the day I don't think there is a single element of our economy that is more important than energy."

He told the editorial board of The Globe and Mail that the vast majority of GHGs result from the consumption of energy by motor vehicles, airplanes and heating homes and commercial buildings — rather than the production phase.

He said the oil sands account for only 5 percent of Canada's total emissions, suggesting that figure should be measured from a global perspective.

Coutu said Canada's net export energy role should also be taken into account, because Canada could end up being saddled with the environmental costs of products that are used in other countries.

March, speaking to the Calgary Chamber of Commerce on Oct. 15, said the industry and governments must work on policies that allow energy to be developed from all available sources — such as wind, solar, nuclear, hydroelectric and geothermal power — not just oil and gas.

"We also require new transformative technologies such as second generation biofuels, which require long-term research investments, but will have the potential to effect change on a global scale," he said.

Exxon investing in algae

ExxonMobil, which owns 69.6 percent of Imperial, is planning to invest more than C$600 million in a venture to develop biofuels from algae in a research and development venture with Synthetic Genomics, a privately held company that is concentrating on gene-based research.

March said this effort, which could bolster the world's transportation fuel supply and eventually reduce GHGs, needs long-term planning horizons to deal with climate change.

GHGs have been "created for 100 years and I believe it will take at least

see CARBON FIXES page 16

3352

kets in the form of LNG, according to Hansen. StatoilHydro's experience developing the Ormen Lange gas field in the Norwegian Sea just south of the Arctic Circle and the Snohvit gas field in the Barents Sea will enable it to develop the subsea installations for Shtokman, he said.

"Tie these installations after they've been pre-drilled by floating units to the large floating unit, which will be the floating production ship, which will be disconnectable due to the harsh environment and the ice," Hansen said. "Bring the gas and the condensate onshore to Teriberka, a journey of about 600 kilometers (373 miles), for processing and ready for transportation as pipeline gas as well as LNG.

"StatoilHydro feels prepared for venturing north together and we think that we can bring three main elements to that table, called TPC," Hansen said. TPC stands for "technology enabler," "performing challenging development tasks" and "cooperation across borders." The company has been an architect in developing technology on the Norwegian continental shelf and its skills in that regard are highly relevant in Russia, Hansen explained.

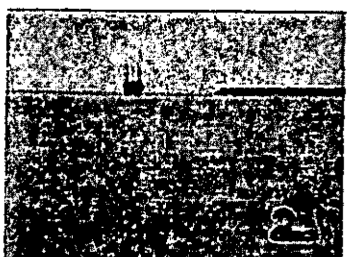
"We have been able to carry out megaprojects within cost and schedule — complex projects," Hansen said. "We know that these … have a tendency to experience cost overruns and schedule slippages, which of course has a detrimental effect on the viability of the project. So no one can guarantee, but I think we have to use the best experience and the best expertise we can get hold of.

"And my last comment is cooperation," Hansen said. "I think that is very important: We have been able to drive the cooperation between the authorities, the suppliers, the research facilities and the oil companies to obtain maximum value for everyone involved, and I think that is also some luggage that we would like to bring to Russia, which I think can create even better results in the future. So we are looking forward to be one of the partners in developing these fantastic possibilities that we can see in the Arctic." ●

3353

Enstar: Cook Inlet natural gas is rapidly diminishing

Enstar's gas supply manager Mark Slaughter (Mike Nederbrock/KTUU-DT)



According to Enstar, no one is sure exactly what is causing the depletion of reserves. (Mike Nederbrock/KTUU-DT)

by Lori Tipton
Wednesday, September 16, 2009

ANCHORAGE, Alaska -- The utility that uses Cook Inlet gas to help heat Southcentral Alaska says there is a steady depletion of gas reserves.

That was the topic of discussion Wednesday at the fifth annual Oil and Gas Congress meeting in Anchorage.

Enstar's gas supply manager, Mark Slaughter, says despite five new wells being drilled in the last year, research shows a considerable drop in the amount of gas in Cook Inlet.

In 2006, producers reported a rate of close to 150 million barrels per day, but as of last year they only reported about 50 million barrels per day.

According to Enstar, no one is sure exactly what is causing the depletion of reserves.

"There's a potential problem that's coming and we need to prepare for it, there's investments that need to be made, decisions that need to be made, and that date is coming," Slaughter said.

The U.S. Department of Energy has predicted local demand will outpace supply as early as 2014 -- producers are predicting it could happen by 2013.

Contact Lori Tipton at ltipton@ktuu.com

Comments

Cook Inlet Natural Gas Reservoir & Storage

RFP Number 2008-0400-7351

Prepared for the

Alaska Department of Revenue

Alaska Natural Gas Development Authority

December 31, 2007

Authors:
Charles P. Thomas
David M. Hite
Tom C. Doughty
Kevin K. Bloomfield

Prepared by

From Science to Solutions™

Science Applications International Corporation
1049 W. Fifth Avenue, 2nd Floor
Anchorage, Alaska 99501
Contact: Charles P. Thomas
Phone: (907) 301-8054
charles.thomas@saic.com
www.saic.com

3355

Disclaimer

This report did not involve the collection or generation of any new or original data. All conclusions and judgments presented in this report are based on information obtained at the time of the assessment. This report is intended to be used in its entirety. Taking or using in any way excerpts from this report are not permitted because, when taken out of context, such excerpts run the risk of being misinterpreted and are not representative of its findings; therefore, any party doing so does so at its own risk.

In preparing this report, SAIC has relied on verbal and written information provided by secondary sources and interviews, including information provided by customer. Because the assessment consisted of evaluating a limited supply of information, SAIC may not have identified all potential items of concern and/or discrepancies and, therefore, SAIC warrants only that project activities under this contract have been performed within the parameters and scope communicated by the Alaska Department of Revenue and the Alaska Natural Gas Development Authority reflected in the contract. SAIC has made no independent investigations concerning the accuracy or completeness of the information relied upon.

Executive Summary

The seasonal variation in South-central Alaska natural gas demand is large, about 1.75 times the yearly average demand on the peak demand day in the winter for total gas demand (utility natural gas for residential and commercial heating and electric utility use for power generation) and about 2.5 for utility gas only. Historically the swing in gas demand has been met by spare production capacity from the Cook Inlet gas fields. As Cook Inlet production capacity has declined, the capability of the existing gas fields has decreased to the point that gas storage has been developed by the operators to provide contracted quantities and to provide the peak capacity needed on the coldest days. On January 9, 2007 a record was set by ENSTAR that required that natural gas be diverted from the liquefied natural gas (LNG) plant to meet the peak requirement (ENSTAR 2007). In the future, unless additional natural gas resources are developed in the Cook Inlet basin, natural gas from other sources will have to be developed to meet the demand for natural gas. Options include a spur pipeline to bring North Slope natural gas to South-central Alaska or gas from interior basins (e.g., the Nenana Basin) or imported LNG. Other options to reduce the demand such as coal plants, wind farms, hydropower, geothermal, and tidal power opportunities in the Railbelt region may reduce the demand for natural gas for power generation but will not offset the need for natural gas for home and business heating unless customers convert home heating to electric heating.

The objective of this study is to identify potential locations for underground natural gas storage in the Cook Inlet region. Storage is anticipated to be essential to achieve the capacity and deliverability required to meet the regional need for load balancing, operational balancing, and efficient management of the spur line system supply.

The reservoir characteristics and the production infrastructure for the existing and potential gas storage reservoirs in the Cook Inlet provide the basis for the evaluation and determination of the most likely candidates for possible future underground storage. It is assumed that a spur pipeline connecting an Alaska Gas Pipeline transporting North Slope natural gas to markets outside Alaska with offtake points in Alaska will be operational in 2020. The storage volume and deliverability rate required to meet the anticipated natural gas demand for utility gas and electric power generation are estimated from historical production and demand data. The characteristics of an ideal underground natural gas storage facility (base-load and peaking-load gas storage facilities) are described as are the three existing underground Cook Inlet storage facilities and the characteristics of potential underground storage facilities in the Cook Inlet. Finally, the potential Cook Inlet storage fields and pools are compared to the ideal storage characteristics to arrive at a ranking of the potential gas storage reservoirs. A general description and estimate of the costs related to conversion of a gas production reservoir to a gas storage facility are presented.

Overview of Cook Inlet Reservoirs

The Cook Inlet area has been the subject of oil and gas exploration since the early 20th Century, and the initial commercial discovery was made in 1957 at the Swanson River oil field on the Kenai Peninsula. Over the next decade additional oil accumulations were discovered and developed. During the oil exploration and subsequently, 30 gas fields were discovered ranging in size from less than 1.0 billion cubic feet (Bcf) of gas to more than 2.3 trillion cubic feet (Tcf) of gas. There are currently 30 gas fields and 57 individual pools recognized by the Alaska Oil and Gas Conservation Commission.

Storage Volume, Rate of Delivery Requirements and Estimates

A Railbelt natural gas demand forecast developed by ANGDA based on historical and projected demands for the use sectors is used for this assessment (ANGDA 2006). This demand forecast is for the entire Railbelt and includes regions of the state that will be served by an Alaska Natural Gas Pipeline from the North Slope and a spur pipeline to South-central Alaska. However, some of these regions will not be directly served by the spur pipeline; i.e., Fairbanks, North Pole, Delta Junction, Healy, Tok, Valdez).

The future of industrial use of natural gas in the Cook Inlet area will be determined by availability and price of natural gas for industrial purposes in the South-central Alaska. Agrium closed its nitrogen fertilizer operations due to a shortage of natural gas supply in Alaska's Cook Inlet basin. The balance of the historical industrial natural gas usage is for the ConocoPhillips/ Marathon LNG plant at Nikiski. The export license expires March 31, 2009. The plant owners have applied to the U.S. Department of Energy for a 2-year extension of this export license but the outcome of that assessment is not known at this time.

Continued industrial use of natural gas to provide an industrial base in South-central Alaska such as continued LNG operations and petrochemical industry will be determined by the availability and price of gas in the Cook Inlet from gas produced in the Cook Inlet or delivered through a spur pipeline from the North Slope (Thomas et al. 2004, Thomas et al. 2006, ANGDA 2006).

The minimum gas storage based on future estimated demand ranges from 11.1 Bcf in 2020 to 15.7 Bcf in 2040. Depending on the minimum gas storage required to meet demand in South-central Alaska is considered **too risky** because of the serious consequences of any shortfall that would cause a disruption in service in winter. There are currently **no alternative sources** of natural gas for heating and other essential services so a shortage causing a disruption of service to large portions of service area would be very costly and highly disruptive. Therefore, a safety factor of 1.5 was applied to arrive at the amount of gas storage required to meet seasonal swings in demand and possible longer-term disruptions that could result from equipment failures or pipeline breaks requiring several days to weeks to repair. Use of the 1.5 safety factor results in estimated gas storage capacity requirements of 16.7 Bcf in 2020 increasing to 23.5 Bcf in 2040. The selected gas storage reservoirs must be capable of providing the daily delivery rates during peak-demand season or multiple gas storage reservoirs or peaking reservoirs must be developed. Gas storage must also be able to deliver the incremental rates needed on the coldest highest demand days.

Although it is not possible to accurately predict the supply and demand situation that will exist in 2020, the estimated demand implies that a 300 MMcf/d spur pipeline will be needed in 2020. This assumes no new additional sources of gas from the Cook Inlet and no offsetting reduction in demand that could result from power generation from sources other than natural gas. This spur pipeline capacity will need to be expanded to 350 MMcf/d in 2030, 400 MMcf/d in 2035 and 450 MMcf/d in 2040 to meet the anticipated demand growth. Future industrial demand is not included in these capacity volumes.

The design withdrawal rates for base storage requirements range from 120 MMcf/d in 2020 to 169 MMcf/d in 2040. Unless the base storage reservoirs are capable of providing adequate deliverability through additional wells to meet the anticipated peak-day demands, peaking storage facilities may need to come on line between 2020 and 2025 and increase to a minimum deliverability rate of about 80 MMcf/d.

Ranked Candidates for Base Load Storage

The ranking of potential future base load storage sites will be determined by the following considerations.

- Reservoir size near the ideal volume–excessive capacity may require large volumes of cushion gas in order to achieve optimum operating rates. Capacity significantly below the ideal would require high existing reservoir pressures to minimize cushion gas and maximize working gas. Excessive storage concerns may be offset by using a greater number of wells to keep withdrawal rates at required levels. Reservoir size less than the ideal volume will require multiple facilities, which may be an advantage, when taking disruptions into consideration.
- Deliverability of a reservoir is a function of the number of wells, reservoir pressure, and communication. In the scenario analyzed, the number of wells in each potential storage site is taken to be two times the number of wells utilized during that pools historically high production stage (Appendix A, Table A.2). It may be possible to achieve greater deliverability by drilling more infill wells and adding compression.
- Gas volume can be a very costly component of the storage economics. The amount of working gas is taken as a constant (20 Bcf) and the variable is the volume of cushion gas required, which is based largely on the reservoir pressure. Large low pressure reservoirs may require several 100 Bcf of gas to achieve the necessary pressure.
- Depletion prior to 2015 is preferred and prior to 2020 is a virtual necessity. This provides adequate time to plan and prepare the site for gas storage. Those that are depleted after 2020 would need to be deferred or some agreement with the lease holders/operators would need to be negotiated to use part or all the field/pool for storage.

The large Kenai Field pools and the Beluga River Undefined pool were excluded from the final list because they have very large reservoir size (capacity) and require excessive volumes of cushion gas, 146 to 179 Bcf (Appendix A, Table A.1) to achieve pressures equivalent to the ambient pipeline pressure.

The Beluga River Undefined pool is somewhat unique. It includes numerous pay sandstones (more than 40) in the Sterling and Beluga formations. These pays are cut by an unknown number of the wells, probably ranging from 2 or 3 per pay to perhaps as many as 10 per pay interval. Individual wells may penetrate and produce from as many as 50 pays. The volume of cushion gas required is nearly 650 Bcf (Appendix A, Table A.2). The issues regarding well integrity, communication between pay zones, and depletion status of individual sandstones indicate that using any of these horizons for storage is not feasible based on current knowledge. The operators continue to delineate and refine their understanding of the interrelations among pays, wells, and production. Hence, there may come a time when specific, depleted horizons are viable candidates for storage.

The rankings for the potential base load storage site candidates are shown in Table 1 and the locations are shown on Figure1. They are compared to the "Ideal Storage Pool" criteria.

The Swanson River Sterling pool is ranked as number one primarily because it has good-to-high deliverability, is expected to be depleted by 2020, and requires moderate amounts of cushion gas. The reservoir size is adequate but falls in the mid-range of the preferred size class, and expansion of storage capacity is limited to about 10 Bcf over the estimated requirement.

Table 1. Ranked Candidates for Cook Inlet Base Load Storage

Rank	Pool	Reservoir Size (Bcf)	Deliverability[1] (MMcf/d)	Cushion Gas Required (Bcf)	Depletion Date (Year)
	IDEAL POOL	**25-50**	**120-169**	**0.0**	**2010-2015**
1	Swanson River/Sterling	39	60 (160)	9.0	2019
2	Beaver Creek/Beluga	92	61 (106)	16.0	2028
3	Ivan River	97	34 (65)	8.0	2019
4	Kenai/Sterling # 5.2	66	30 (36)	0.0	1981
5	Swanson River/Tyonek	28	29 (89)	6.0	2006
6	Beaver Creek/Sterling	140	33 (51)	24.0	1994

1. The number in the column is the 'adjusted" low deliverability, which is the value used to rank the candidate sites; the number in parenthesis is the "adjusted" high deliverability and can be achieved but is not sustainable for the entire demand season (Appendix A, Table A.2).

The Beaver Creek Beluga site has excellent reservoir size, the highest deliverability, but requires more cushion gas and is not expected to be depleted until 2028. These latter two factors prevent it from being ranked No. 1 and could drop it below the Ivan River pool.

The Ivan River pool is rated as the third choice due to the capacity and moderate volume of cushion gas required. The expected depletion date of 2019 is an additional plus. The primary negative factor is the relatively low deliverability of only 34 MMcf/d under the assumed development scenario.

The Kenai Sterling # 5.2 has been depleted since 1981 and has good-to-excellent reservoir size. The capacity is in excess of the requirements and no cushion gas is required to achieve ambient pipeline pressures. The chief problem is deliverability of only 30 MMcf/d using the one-to-one producing well scenario. There are suggestions that water encroachment has been detected, which may have the potential to reduce deliverability.

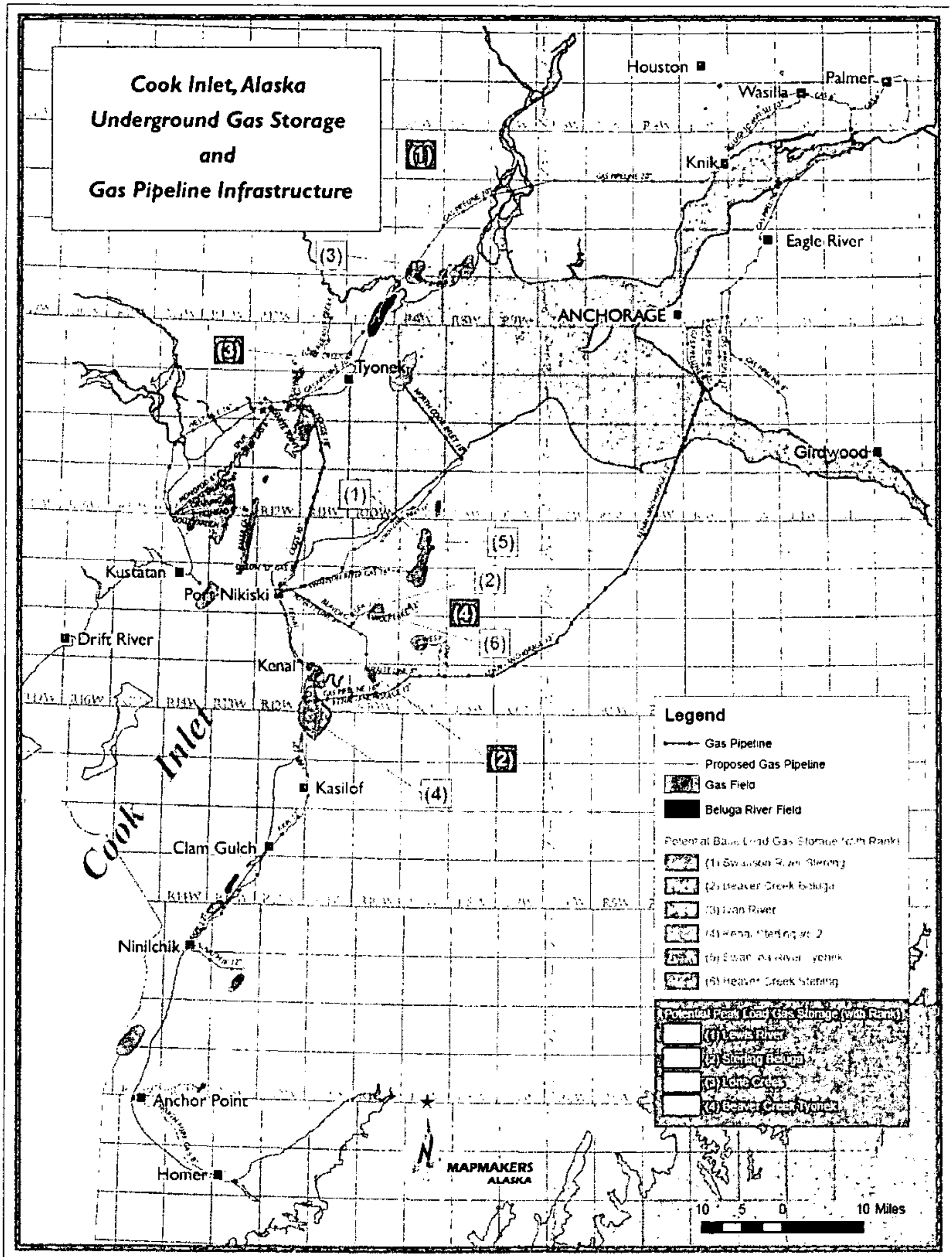
The Swanson River Tyonek pool is the smallest of the top six candidates at 28 Bcf, which is at the low end of the preferred size range. It requires a moderate amount of cushion gas, but has a projected deliverability in the one-to-one infill well case of only 29 MMcf/d.

The Beaver Creek Sterling pool is ranked No. 6 because of the problems with water encroachment, which requires a large volume of cushion gas and also reduces the deliverability. There is a large capacity for gas storage, and an early depletion date, but unfortunately that is due largely to the fact the pool watered out. The anticipated deliverability is about 33 MMcf/d.

The results of these evaluations indicate that there are viable potential future underground natural gas storage sites in the Cook Inlet gas fields that will meet the anticipated need for base load gas storage. However, among the leading candidates there are no true stand-alone reservoirs with regard to sustainable deliverability. Each of the candidate pools meets the capacity needs but under the proposed development none of them are capable of achieving the 120 to 169 MMcf/d design withdrawal rates (see Table 2.6 and Section 3.1).

Unless future detailed studies indicate otherwise, these pools in some combination should provide adequate storage for any reasonably forecast seasonal storage needs and achieve the deliverability needs for peak season demand. Under certain conditions, multiple base load storage facilities may negate the need for separate peak load storage, at least for the initial years of the pipelines existence.

Figure 1. Cook Inlet Potential Underground Gas Storage Locations and Gas Pipeline Infrastructure



3361

Ranked Candidates for Potential Peak Load Storage Sites

The need for a separate peak load facility or facilities depends on the ultimate nature of the base load storage facilities. At this time the working scenario requires peak load storage for the short, very high demand periods resulting from conditions of extreme cold weather. Five pools were identified that would be candidates for potential peak load storage as shown in Table 2. The total storage capacity of these pools ranges from 6.2 Bcf to 15.1 Bcf (Appendix A, Table A.3). These pools are all on the pipeline system and are within 50 to 100 miles of the major consumers. Three key factors were utilized to rank or eliminate the pools: reservoir size, deliverability, and cushion gas requirements.

Table 2. Cook Inlet Ranked Peaking Load Storage Candidates

Rank	Pool	Reservoir Size (Bcf)	Cushion Gas Required (Bcf)	Deliverability[1] (MMcf/d)
1	Lewis River Undefined	14.3	1.6	130
2	Sterling Beluga Undefined	15.1	2.0	125+
3	Lone Creek Undefined	6.2	0	62
4	Beaver Creek Tyonek Undefined	6.3	0.5	58

1. 1% of the working gas volume (reservoir size minus cushion gas).

The existing Cook Inlet gas storage facilities have gas volumes of this size or smaller and average deliverability rates are about one percent of the total working gas. Based on these averages, maximum deliverability rates may range from a low of 58 MMcf/d for the Beaver Creek Tyonek undefined pool to a high of 131 MMcf/d for the Sterling Beluga Undefined pool. This assumes the reservoirs are filled to capacity and the cushion gas has been discounted.

Using the one percent of working gas volume (reservoir size minus cushion gas) as average daily deliverability, only two of the remaining pools are capable of achieving the 80 MMcf/d maximum anticipated peak gas requirements in 2040. The Lone Creek Undefined and the Beaver Creek Undefined pools are fall below the margin of 70 MMcf/d in 2025 for the assumed spur pipeline rates. Both the Lewis River and Sterling Beluga undefined pools have capability to achieve the desired deliverability in 2040 with potentials of approximately 125 to 130 MMcf/d each.

The Lone Creek and Lewis River sites are located on the west side of the Cook Inlet and could easily supply the electrical generation plant, while the Beaver Creek and Sterling Beluga sites are located on the east side and could be dedicated to the gas utilities.

The location and ranking of the potential peak load gas storage reservoirs/pools are shown in Figure 1.

Summary of Potential Cook Inlet Storage Sites

Six potential base load storage and four peak load storage sites are identified in the study. All the base load storage candidates are of sufficient size that, even with the anticipated cushion gas requirements of the various pools, they retain the capacity for the requisite volume of about 20 Bcf of working gas. At the calculated low sustainable deliverability rates none of them are gauged to have rates that are sufficient to serve as the sole storage facility and multiple storage pools are required. At the calculated high deliverability rates the Beaver Creek Beluga (120 MMcf/d) and the Swanson River Sterling (160 MMcf/d) can meet the demand, but not for sustained periods or for the duration of the high demand winter season.

The four potential peak storage sites are equally distributed between the west and east sides of Cook Inlet and the Lewis River and Sterling Beluga undefined pools have the potential to meet any anticipated peak demand needs. The Lone Creek and Beaver Creek Tyonek, as a pair could also meet that demand.

Cost of Potential Storage Facilities

The total capital costs for a 20 Bcf working gas storage facility, requiring the purchase of 20 Bcf of cushion gas, drilling of four new wells at $7 million each, and capable of delivering a maximum rate of 100 MMcf/d are estimated to be $8.1 million/Bcf. This compares to values given in a study by the Federal Energy Regulatory Commission (FERC 2004) of $5 to $6 million/Bcf for a typical depleted natural gas reservoir storage field in the Lower 48. The costs will vary depending on the specific sites chosen. The average cost-of-service for 20 storage operator tariffs collected by FERC (2004) indicated a median cost-of-service of $0.64/Mcf. A determination of the regulatory framework that the spur pipeline and gas storage facilities in the Cook Inlet will need to be determined as well as site-specific requirements to provide an accurate estimate of the tariff. A cost-of service estimate is not included in this study.

Contents

Table .... Page

Figure .... Page

Acronyms and Abbreviations

ADNR	Alaska Department of Natural Resources
ADOG	Alaska Division of Oil and Gas
ANGDA	Alaska Natural Gas Development Authority
AOGCC	Alaska Oil and Gas Conservation Commission
Bcf	billion cubic feet of natural gas
DOE	U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
LNG	liquefied natural gas
md	millidarcies
MD	Measured depth
MMcf	million cubic feet natural gas
MMcf/d	million cubic feet per day
NETL	National Energy Technology Laboratory
RCA	Regulatory Commission of Alaska
Tcf	trillion cubic feet of natural gas
TVDss	True Vertical Depth sub-sea

Storage Measures

Total capacity is the maximum volume of gas that can be stored in an underground storage facility and is determined by the physical characteristics of the reservoir.

Base gas (or cushion gas) is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season.

Working gas capacity is, by definition, total capacity minus base gas.

Working gas is the volume of gas in the reservoir above the designed level of the base gas. Working gas is that which is available to the marketplace.

Deliverability is a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. Also referred to as the deliverability rate, withdrawal rate, or withdrawal capacity, deliverability is most often measured in terms of million cubic feet or dekatherms per day. The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular time, the pressure within the reservoir, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the amount of base and working gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn.

1 Introduction

The seasonal variation in South-central Alaska natural gas demand is large, about 1.75 times the yearly average demand on the peak demand day in the winter for total gas demand (utility natural gas for residential and commercial heating and electric utility use for power generation) and about 2.5 for utility gas only. Historically the swing in gas demand has been met by spare production capacity from the Cook Inlet gas fields. As Cook Inlet production capacity has declined, the capability of the existing gas fields and pools has decreased to the point that gas storage has been developed by the operators to provide contracted quantities and to provide the peak capacity needed on the coldest days. On January 9, 2007 a record was set by ENSTAR that required that natural gas be diverted from the liquefied natural gas (LNG) plant to meet the peak requirement (ENSTAR 2007). In the future, unless additional natural gas resources are developed in the Cook Inlet basin natural gas from other sources will have to be developed to meet the demand. Options include a spur pipeline to bring North Slope natural gas to South-central Alaska or gas from interior basins (e.g., the Nenana Basin) or imported LNG.

ANGDA is a major driving force to construct a pipeline to deliver North Slope gas into the Cook Inlet area to meet the energy needs of South-central Alaska. The need for a pipeline to bring natural gas to South-central Alaska is based on the declining natural gas reserves in the Cook Inlet from the currently developed fields. The critical nature of this need has been described in several recent reports and studies (Thomas et al. 2004, Thomas, et al. 2006, ANGDA 2006). The issues facing South-central Alaska future natural gas needs and sources were discussed in great detail by numerous presenters at the Alaska Oil and Gas Conservation Commission's (AOGCC) South Central Alaska Energy Forum held in Anchorage, Alaska, September 20-21, 2006.[1]

When a spur pipeline is used to deliver natural gas to South-central Alaska, it will be essential that the pipeline operate at a constant rate matching the nominated and contracted rate. This can be achieved by developing one or more of the depleted or nearly-depleted Cook Inlet gas reservoirs as gas storage facilities.

1.1 Objective

The objective of the project is to identify potential locations for underground natural gas storage in the Cook Inlet region. Storage is anticipated to be essential to meet storage capacity and deliverability required to meet the regional need for load balancing, operational balancing, and efficient management of the spur line system supply. The reservoir characteristics and the production infrastructure for the existing and potential gas storage reservoirs in the Cook Inlet provide the basis for the evaluation and determination of the most likely candidates for possible future underground storage.

1.2 Scope and approach

Section 2 of the report contains an analysis of the storage volume and deliverability rate required to meet the anticipated natural gas demand for utility gas for residential/commercial heating, and electric power generation. Section 3 contains a description of the characteristics of an ideal underground natural gas storage facility including base-load and peaking-load gas

[1] http://www.aogcc.alaska.gov/homeogc.shtml

storage facilities. Section 4 contains a description of the three existing underground Cook Inlet storage facilities. Section 5 describes the characteristics of potential underground storage facilities in the Cook Inlet. In Section 6 the potential storage facilities are compared to the ideal storage characteristics to arrive at a ranking of the potential gas storage reservoirs. Section 7 includes a general description and estimate of the costs related to conversion of a gas production reservoir to a gas storage facility to provide a general guideline for the costs on a unit volume basis.

The data used to analyze Cook Inlet oil and gas reservoirs were obtained from the publicly available sources including the AOGCC, Alaska Department of Natural Resources (ADNR), and the Regulatory Commission of Alaska (RCA). Chevron and Marathon currently operate gas storage facilities in the Cook Inlet at Swanson River, Pretty Creek and Kenai River Sterling Pool #6. These operators were contacted and they all provided general overviews of their operations and experiences in operating gas storage reservoirs in the Cook Inlet.

1.3 Overview of Cook Inlet Petroleum Geology and Reservoirs

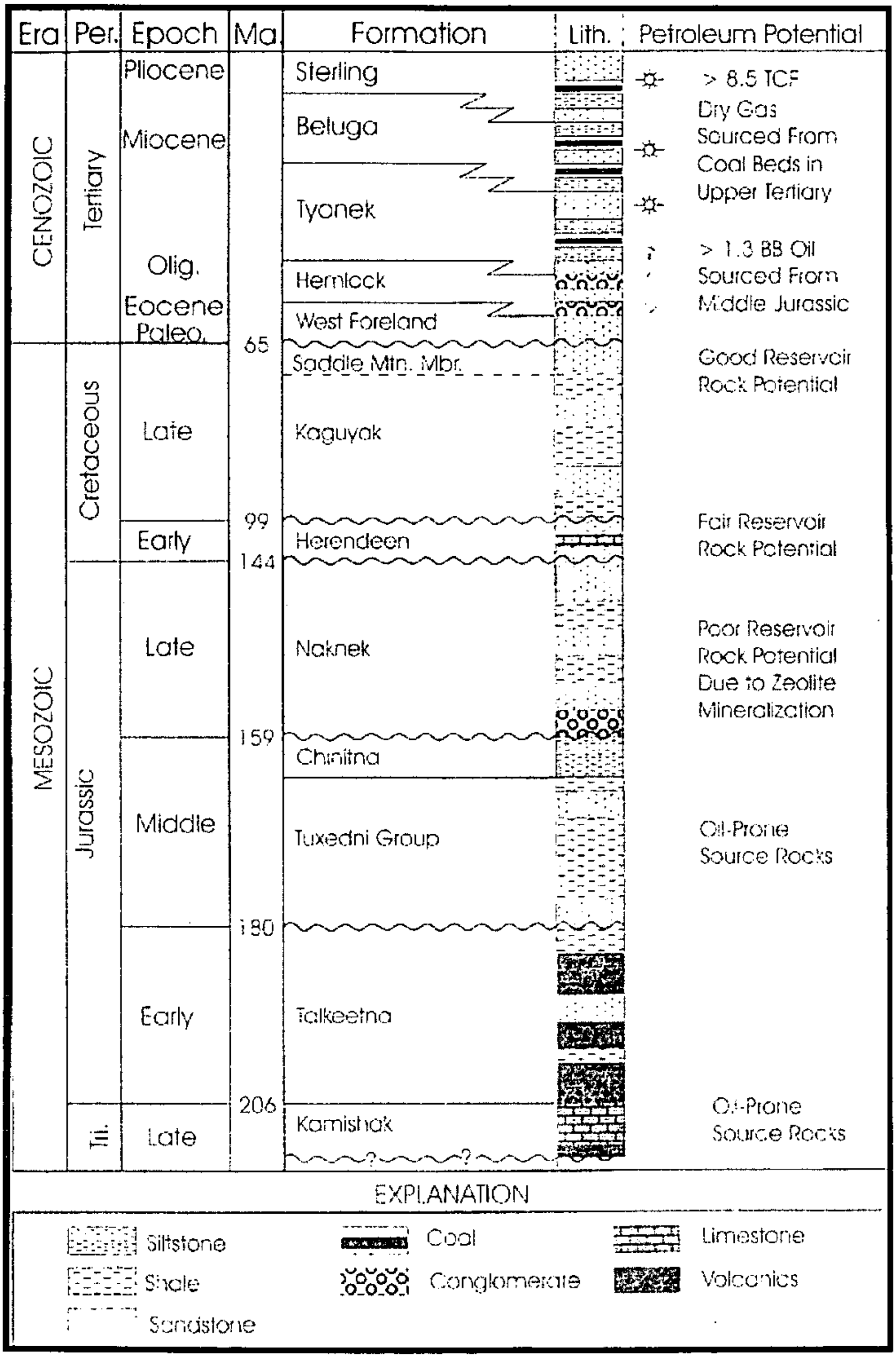
The effort to identify and evaluate potential Cook Inlet natural gas storage facilities is focused on the nearly depleted or depleted oil and gas reservoirs of the Cook Inlet Tertiary Basin. Prior to the discussion of the character and criteria required for Cook Inlet natural gas storage, it is informative to provide a very rudimentary over-view of the geological setting and petroleum geology of the Cook Inlet basin.

The Cook Inlet area has been the subject of oil and gas exploration since the early 20th Century, and the initial commercial discovery was made in 1957 at the Swanson River oil field on the Kenai Peninsula. Over the next decade additional oil accumulations were discovered and developed. During the oil exploration and subsequently, 30 gas fields were discovered ranging in size from less than 1.0 billion cubic feet (Bcf) of gas to more than 2.3 trillion cubic feet (Tcf) of gas (Thomas, et al. 2004, Table 2.5). The basin geological framework, character of the petroleum systems, the age, depositional framework, and distribution of hydrocarbons are discussed in considerable detail in Thomas, et al. (2004) and only a brief overview is provided here.

The entire Cook Inlet Tertiary section was deposited under non-marine conditions. The sub-aerial fans and a variety of fluvial channel systems constitute the reservoirs for the known, commercial oil and gas accumulations of the basin. The alluvial fan complexes provide thick, relatively continuous reservoirs and are best developed along the margins of the basin. The fluvial reservoirs have varying geometries and degrees of heterogeneity, depending upon the type of steam (braided, meandering, etc.) responsible for their formation. Consequently, these reservoirs have varying degrees of potential to serve as storage reservoirs depending on the nature of fluvial system and the degree to which they inter-finger with and migrate across the various overbank and flood plain facies (coals, mudstones, etc).

The Cook Inlet stratigraphic section (Figure 1.1) depicts both the Mesozoic and Cenozoic rocks of the Cook Inlet Basin and indicates the source intervals for oil and gas. The bulk of the gas is non-associated gas and is in no way related to the rocks or processes that generated the oil and associated gas. As can be seen from Figure 1.1 the oil is sourced thermogenically, from older Mesozoic rocks, and has accumulated in the lower portion of the Tertiary interval–in the West Foreland, Hemlock and lower Tyonek formations. Many of these oil-bearing reservoirs of the lower portion of the Tertiary section are of fan origin and hence thick and widespread in nature. This is especially true of the most important oil-bearing unit, the Hemlock Conglomerate.

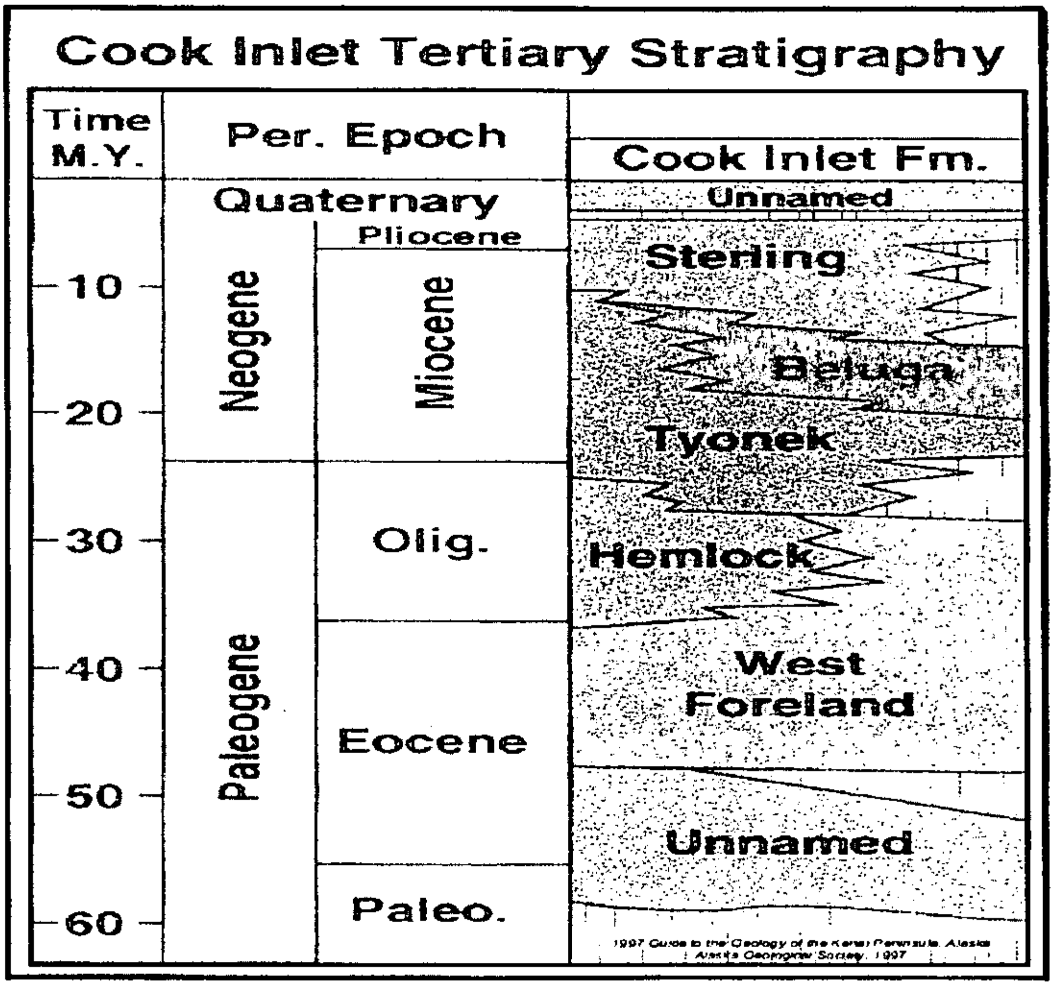
Figure 1.1. Cook Inlet Basin Alaska–Stratigraphic Column & Oil and Gas Reservoirs



3369

The non-associated gas was sourced biogenically, from the coals and coaly mudstones of the upper Tyonek, Beluga, and Sterling Formations. This gas has accumulated in reservoirs of the same age and system. These reservoirs are predominantly of fluvial origin, are more limited in distribution, and possess greater lateral heterogeneity. Figure 1.2 shows the stratigraphic and temporal relationships of the various formations of the Kenai Group (Swenson, R. F., 1997).

Figure 1.2 Cook Inlet Tertiary Section



There are currently 30 gas fields and 57 individual pools recognized by the Alaska Oil and Gas Conservation Commission (AOGCC 2006a). These Cook Inlet gas fields and pools, the cumulative production through 8/31/2007, and the remaining reserves estimates using a 10 MMcf/mon production cutoff for each pool are shown in Table 1.1. The reserves estimates were made using standard reservoir engineering material balance methodology (Slider 1983). The material balance data and the production rate versus pressure data for the field/pool are also used to estimate to estimate the amount of cushion gas required to return the pools to a pressure condition required to provide the required production rates. These estimated reserves total 1,102.4 Bcf in this analysis and do not include Probable/Under-development reserves. The ADNR Division of Oil and Gas (ADOG) 2007 Annual Report Table III.2 (ADNR 2007) lists gas reserves as 1,269.0 Bcf, without Probable/Under-development reserves, and 1,684.6 Bcf with

Probable/Under-development reserves. These reserves and production forecasts are close enough to the same that the ADOG production forecast (Table III.9. ADNR 2007) is used as a basis for estimating the gas storage capacity and deliverability rate required for gas storage in the Cook Inlet and the individual pool assessments performed in this study were used for individual pool estimates for the year when production is expected to stop and to determine the volumes of cushion gas required and associated pressures and deliverability rates.

The bulk of the Cook Inlet pools are in sandstone deposited by the fluvial channel systems of the upper Tyonek, Beluga, and Sterling formations. The sandstones of the lower part of the Sterling Formation constitute the best gas reservoirs in the basin and reflect the development of a thick succession of superposed fluvial channel systems. Consequently, it can be predicted, that all other factors being equal, the Sterling fields and pools should rank high in the ultimate listing of potential natural gas storage facilities.

The gas pools of the area are typically defined in one of two ways; 1) named after a specific sandstone within a formation as the Kenai #5.1 or #6 pools in the Kenai gas field, or 2) termed undefined, meaning there are multiple productive zones through the section and are named after the field or formation in which they occur, as Beluga River Undefined (produces from interval throughout the Beluga and Sterling formations) and Beaver Creek Tyonek Undefined (produces from intervals throughout the Tyonek).

Thomas et al. (2004) present a table derived from AOGCC data (2003) that provides porosity and permeability data for the three primary gas-bearing formations. While the number of samples is small, these data indicate the relative quality of the units as storage targets. In the most attractive unit, Sterling Formation, this sampling yields a porosity range of 10 to 33 percent with an average of 28 percent, and the permeability ranges from 125 to 2000 md with an average of 579 md. The upper Tyonek Formation has a porosity range of 12 to 29 percent with an average of 20.7 percent, and the permeability range is 0.25 to 1600 md with an average of 312 md. The Beluga Formation is the least prospective interval having a porosity range of 10 to 28 percent, with an average of 21.7 percent, but the permeabilities are much lower, ranging from 0.1 to 300 md, with an average of only 75 md. As stated earlier, the Sterling Formation gas pools should provide the most attractive options for future natural gas storage facilities.

Table 1.1. Cook Inlet Gas Fields and Pools (as of 08/31/2007)

Field	Pool	Cumulative (8/31/2007) (MMcf)	Remaining Reserves (10 MMcf/mon production cutoff)
Albert Kaloa	Undefined	2,933.1	1308.0
Beaver Creek	Beluga	60,379.6	22846.2
Beaver Creek	Sterling	125,952.9	0.0
Beaver Creek	Tyonek Undefined	5,498.4	0.0
Beluga River	Undefined	1,044,081.8	408665.2
Birch Hill	Undefined	65.3	0.0
Granite Pt	Undefined	872.8	0.0
Ivan River	Undefined	78,654.4	4666.0
Kasilof	Tyonek Undefined	1,868.2	398.4
Kenai	Beluga Undefined	0.1	0.0
Kenai	Sterling 3	332,329.2	5598.0
Kenai	Sterling 4	451,659.9	3892.8
Kenai	Sterling 5.1	484,638.7	0.0
Kenai	Sterling 5.2	44,031.6	0.0
Kenai	Sterling 6	530,063.8	12556.4
Kenai[1]	Sterling 6 Storage	488.5	N.A.
Kenai	Tyonek	187,060.5	8238.0
Kenai	Upper Tyonek Beluga	297,761.4	113899.6
Kenai C.L.U.	Beluga	64,121.5	37262.0
Kenai C.L.U.	Sterling Undefined	19,943.9	9538.4
Kenai C.L.U.	Tyonek D	1,399.4	0.0
Kenai C.L.U.	Upper Tyonek	71,898.7	8748.8
Kustatan	Undefined	311.4	0.0
Lewis River	Undefined	11,589.8	0.0
Lone Creek	Undefined	5,335.3	228.0
McArthur River[2]	Middle Kenai	1,066,396.2	111268.0
Middle Ground Shoal	Undefined	16,393.6	0.0
Moquawkie	Undefined	3,716.7	470.4
Nicolai Creek	Beluga Undefined	2,286.5	714.8
Nicolai Creek	North Undefined	1,123.2	0.0
Nicolai Creek	South Undefined	855.6	333.2
Ninilchik	Deep Undefined	8,767.0	15791.6
Ninilchik	Fc Tyonek Undefined	18,931.1	15714.8
Ninilchik	Go Tyonek Undefined	16,758.2	13870.8
Ninilchik	Pax Tyonek Undefined	1,319.8	2452.4
Ninilchik	Sd Tyonek Undefined	21,317.3	43967.6
North Cook Inlet[3]	Tertiary	1,763,222.1	231704.0
North Fork	Undefined	104.6	0.0
Pretty Creek	Undefined	9,402.2	0.0
Pretty Creek[1]	Beluga Storage	114.2	N.A.
Pretty Creek	Tyonek Undefined	3.0	0.0
Pioneer	Tyonek Undefined	3.0	0.0
Redoubt Shoal	Undefined	451.9	0.0
Redoubt Shoal	Tyonek Undefined	0.0	0.0
Sterling	Beluga Undefined	5,597.4	7911.2
Sterling	Sterling Undefined	3,699.9	0.0
Sterling	Tyonek Undefined	175.3	0.0
Stump Lake	Undefined	563.3	0.0
Swanson River	Beluga Undefined	1,018.4	1662.8
Swanson River	Sterling Undefined	30,248.2	4758.0
Swanson River[1]	Tyonek Undefined	18,347.1	N.A.
Three Mile Creek	Beluga Undefined	1,342.6	1586.0
Trading Bay	Undefined	5727.9	0.0
W Foreland	Tyonek Undefined 4.0	6,444.6	7289.6
W Foreland	Tyonek Undefined 4.2	2,839.1	3437.2
W Fork	Sterling A	1,230.8	0.0
W Fork	Sterling B	1,519.6	0.0
W Fork	Undefined	2,716.0	1649.6
Wolf Lake	Beluga-Tyonek Undefined	872.0	0.0

1. Current Gas Storage Fields/Pools
2. McArthur River Production Cutoff rate = 50 MMcf/mon
3. North Cook Inlet Production Cutoff rate = 100 MMcf/mon

3372

2 Storage Volume and Rate of Delivery Requirements

The seasonal variation in South-central Alaska natural gas demand is large, about 1.75 times the yearly average demand on the peak demand day in the winter for total gas demand (utility natural gas for residential/commercial heating and electric utility gas for power generation) and about 2.5 for residential/commercial utility gas only. Historically the swing in gas demand has been met by spare production capacity from the Cook Inlet gas fields. When a spur pipeline is used to deliver natural gas to South-central Alaska, it will be essential that the pipeline operate at a constant rate matching the nominated and contracted rate. This can be achieved in the Cook Inlet by developing one or more of the depleted or nearly-depleted gas reservoirs as gas storage facilities. The basis for estimating the natural gas volumes and delivery rates from gas storage reservoirs needed to meet the seasonal fluctuations in natural gas demand throughout the year are described in this section.

2.1 South-central Alaska Demand Forecast

A Railbelt natural gas demand forecast developed by ANGDA based on historical and projected demands for the use sectors is used for this assessment (ANGDA 2006). This demand forecast is for the entire Railbelt and includes regions of the state that will be served by an Alaska Natural Gas Pipeline from the North Slope and a spur pipeline to South-central Alaska. However, some of these regions will not be directly served by the spur pipeline; i.e., Fairbanks, North Pole, Delta Junction, Healy, Tok, Valdez). The utilities and service areas are defined as shown in Table 2.1.

Table 2.1. Railbelt Gas and Electric Utilities and Service Areas (ANGDA 2006)

Electric Utility	Service Area
Anchorage Municipal Light & Power (AML&P)	**Central Anchorage**
Chugach Electric Association (Chugach)	Anchorage, Kenai Peninsula, Whittier, Tyonek
Homer Electric Association (HEA)	Homer, Soldotna, Seldovia, Kenai
Matanuska Electric Association (MEA)	Chugiak, Eagle River, Palmer, Wasilla, Talkeetna
Golden Valley Electric Association (GVEA)	Fairbanks, North Pole, Delta Junction, Healy
Seward Electric System (SES)	Seward
Copper Valley Electric Association (CVEA)	Copper River Basin, Valdez
Alaska Power Company (APC)	Tok, Dot Lake
Gas Distribution Utility	**Service Area**
ENSTAR	South-central Alaska/Anchorage Area
Fairbanks natural Gas (FNG)	Portion of Fairbanks
Independents and Direct	Anchorage area in addition to ENSTAR

The forecast is described in the ANGDA (2006) report in Section 4.2 Gas Demand and is shown in Table 2.2 and Figure 2.1. The natural gas used for electrical power generation by Railbelt power utilities are shown in columns B through G and the gas utilities are shown in columns H thought J. The 5-year industrial average represents the historical use by the LNG plant and the Agrium fertilizer plant. The estimate for the gas used for operation of the natural gas production and delivery system is shown in column L. Column M shows the total natural gas demand in trillions of BTUs (tBtu). Some of these demand components, APC-Tok, CVEA, and FNG, will not be connected to the anticipated spur pipeline but their impact is minor relative to other uncertainties in long-term demand forecasting and these demand components are not removed from this assessment.

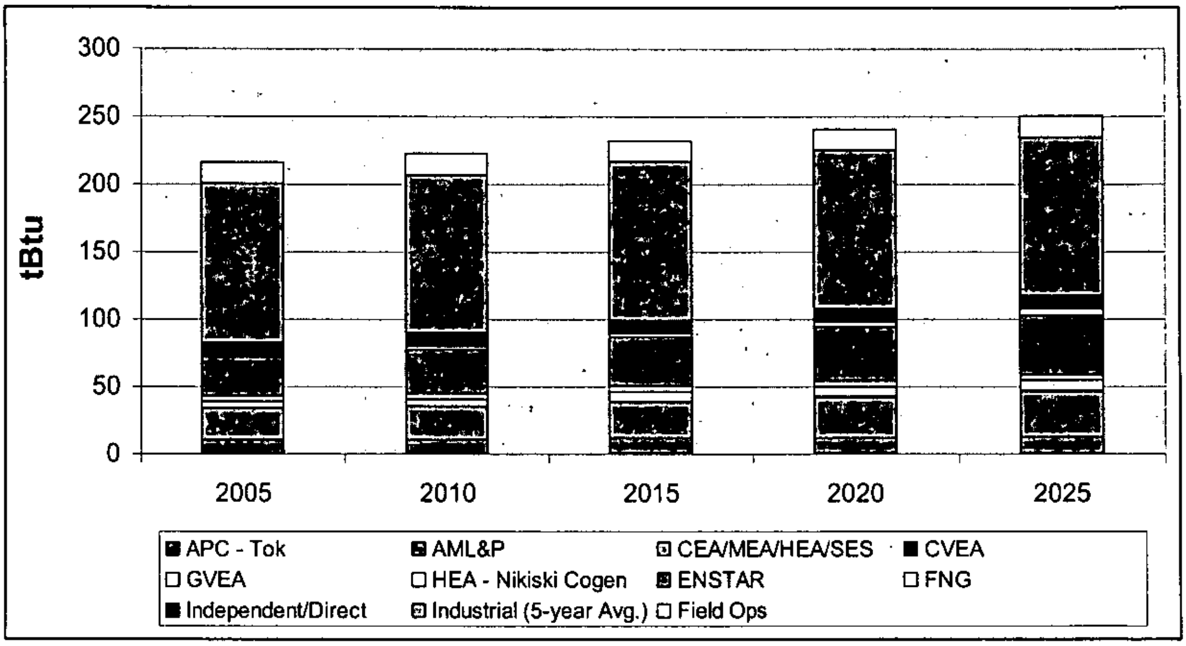
3373

Table 2.2. Railbelt Natural Gas Demand (trillion Btu–tBtu)

A	B	C	D	E	F	G	H	I	J	K	L	M
Year	APC Tok	Anch. ML&P	CEA/ MEA/ HEA/ SES	CVEA	GVEA	HEA - Nikiski Cogen	ENSTAR	FNG	Indep/ Direct	Industrial (5-year Avg.)	Field Ops	Total tBtu
2005	0	10.5	23.5	0	5	4.1	29.0	0.9	10	117.7	15.4	216.1
2010	0	10.9	25.1	0	5	4.1	33.1	1.6	10	117.7	15.4	222.9
2015	0.4	11.4	27.1	0.3	7.5	4.1	36.2	2.2	10	117.7	15.4	232.3
2020	0.4	12.1	29.9	0.3	7.6	4.1	40.2	3.2	10	117.7	15.4	240.9
2025	0.4	12.7	33.5	0.4	7.7	4.1	44.2	4.6	10	117.7	15.4	250.7

Source: ANGDA

Figure 2.1. Railbelt Natural Gas Demand (Source: ANGDA)



2.1.1 Industrial Demand

The future of industrial use of natural gas in the Cook Inlet will be determined by availability and price of natural gas for industrial purposes in the South-central Alaska. Agrium announced in a September 25, 2007 statement that it was closing its nitrogen fertilizer operations at the end of September due to a shortage of natural gas supply in Alaska's Cook Inlet basin (PN 2007). The balance of the historical industrial natural gas usage is for the ConocoPhillips/Marathon LNG plant at Nikiski. The export license to continue operation of this facility expires March 31, 2009. The plant owners have applied to the U.S. Department of Energy for a 2-year extension of this export license but the outcome of that assessment is not known at this time.

Continued industrial use of natural gas to provide an industrial base in South-central Alaska such as continued LNG operations and petrochemical industry will be determined by the availability and price of gas in the Cook Inlet from gas produced in the Cook Inlet or delivered through a spur pipeline from the North Slope (Thomas et al. 2004, Thomas et al. 2006, ANGDA 2006).

3374

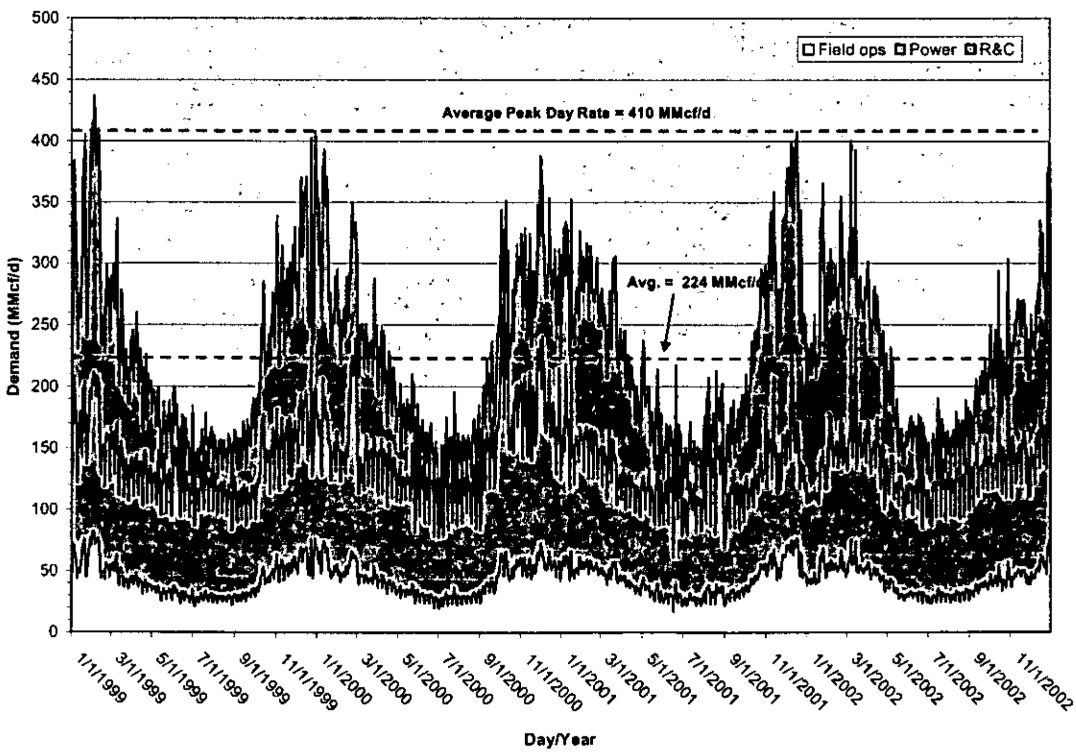
2.1.2 Seasonal Variations in Gas Demand

The seasonal fluctuation in gas demand is a function of ambient conditions and the balancing of available gas production, transmission, and end-user requirements of the South-central and Railbelt demand. Any industrial customers for natural gas from the spur pipeline will require a steady supply of natural gas and would be expected contract for constant delivery rates of gas and would not contribute to the seasonal fluctuations.

Historically, Cook Inlet gas fields have had adequate excess production capacity to meet seasonal demands. Ideally, the industrial users would not be called on to curtail industrial operations to meet peak-day demands from the gas utility and electric generation sectors. However, on January 6, 2007 natural gas was diverted from the LNG plant to meet a surge in demand due to cold weather (ENSTAR 2007). A properly designed spur pipeline and gas storage operation would alleviate the need for curtailing any future industrial operations.

The seasonal changes in demand that cause the need for gas storage are illustrated in Figure 2.2. Swings in utility gas demand (residential and commercial) are much larger than the power generation sector These data, which show daily demand for the 1999 to 2002 time period, are provided to illustrate the daily and seasonal demand swings and **should not be relied upon for decision purposes** because some of the data were generated by scaling to yearly average data from ADNR (2007). The natural gas from a spur pipeline that is not required to meet demand in the summer is available for injection into gas storage facilities for withdrawal to meet the shortfall in winter. This would allow a spur pipeline to be operated at a constant flow rate, which is highly desirable.

Figure 2.2. Illustrative South-central Alaska Daily Demand-1999-2002



Data sources: ENSTAR, AML&P and scaled to match yearly data by segment are reported by ADNR 2007, Table III.10, Division of Oil and Gas 2007 Report.

3375

2.1.3 Gas Demand Forecasts to 2040

Forecasts for the time period from 2020 to 2040 were developed by extending the forecast shown in Table 2.2 for electricity generation (Columns B to G), residential/commercial (columns H to J), and field operations Column L). Gas storage to make up for any short fall in spur pipeline delivery in these demand components is essential. Fro simplicity, utility gas is assumed to be 1000 Btu/Mcf, the results are shown in Table 2.3.

Table 2.3. Railbelt Natural Gas Demand to 2040 (1000 Btu/Mcf)

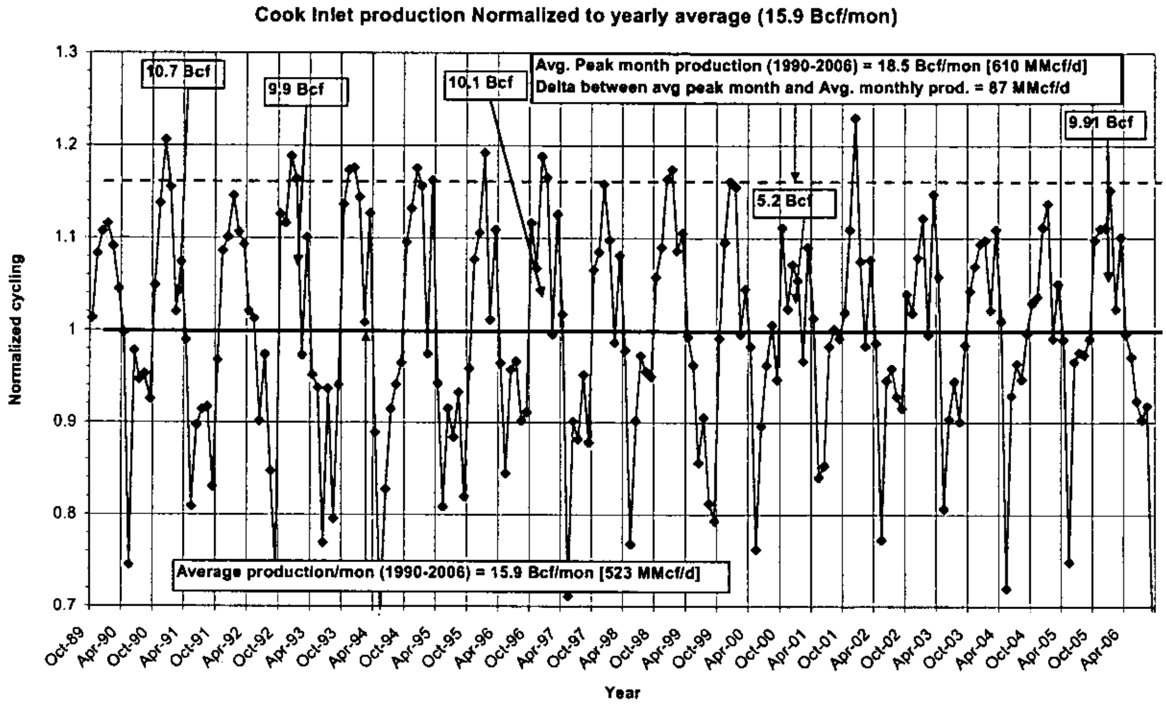
A	B	C	D	E	F	G	H
Year	Electric Utilities (Bcf/yr)	% increase Elec. Utilities	Gas Utilities (Res. and Commercial) (Bcf/yr)	% increase Gas Utilities	Field Ops (Bcf/yr)	Electric & Gas Utilities and Field Ops (Bcf/yr)	% increase Electric and gas Utilities and Field Ops
2005	43.1		39.9		15.4	98.4	
2010	45.1	4.64%	44.7	12.03%	15.4	105.2	6.91%
2015	50.8	12.64%	48.4	8.17%	15.4	114.6	8.89%
2020	54.4	7.09%	53.4	10.44%	15.4	123.2	7.55%
2025	58.8	8.09%	58.8	10.11%	15.4	133.0	7.95%
2030	63.5	8.00%	64.7	10.00%	15.4	143.6	7.96%
2035	68.6	8.00%	71.2	10.00%	15.4	155.1	8.04%
2040	74.1	8.00%	78.3	10.00%	15.4	167.7	8.12%

Source: SAIC based on ANGDA forecast (2006)

2.2 Storage Volumes and Rate of Delivery to Meet Seasonal Fluctuations

An analysis of Cook Inlet production history from 1990 to 2006 provides a long-term view of the year-to-year variation in production to meet total demand (industrial, residential/commercial, electricity production, and field operations and other) over a longer history. These data were normalized to the average monthly production rate of 15.9 Bcf/mon over this period and are shown in Figure 2.3. The volume of gas above the monthly average ranges from a high of 10.7 Bcf in the 1990-1991 winter season to a low of 5.2 Bcf in the 2000-2001 winter season. The average of the peak monthly production during this time period is 18.5 Bcf/mon. The difference between the average peak month and monthly average is 87 MMcf/d.

Figure 2.3. Normalized Cook Inlet Production (1990 to 2006)



2.2.1 Storage Volumes Based on Total Cook Inlet Production from 1990 to 2006

The average of gas for the peak-season months above the monthly average from 1990 to 2006 is 8.2 Bcf. In 2006 the volume was 9.6 Bcf. Using these volumes and the projected percentage increases in Table 2.2, Column H, the volume required for storage would range from 10.3 Bcf in 2020 to 14.0 Bcf in 2040 as shown in Table 2.4.

Table 2.4. Base Gas Storage Capacity Estimate from Historical Production

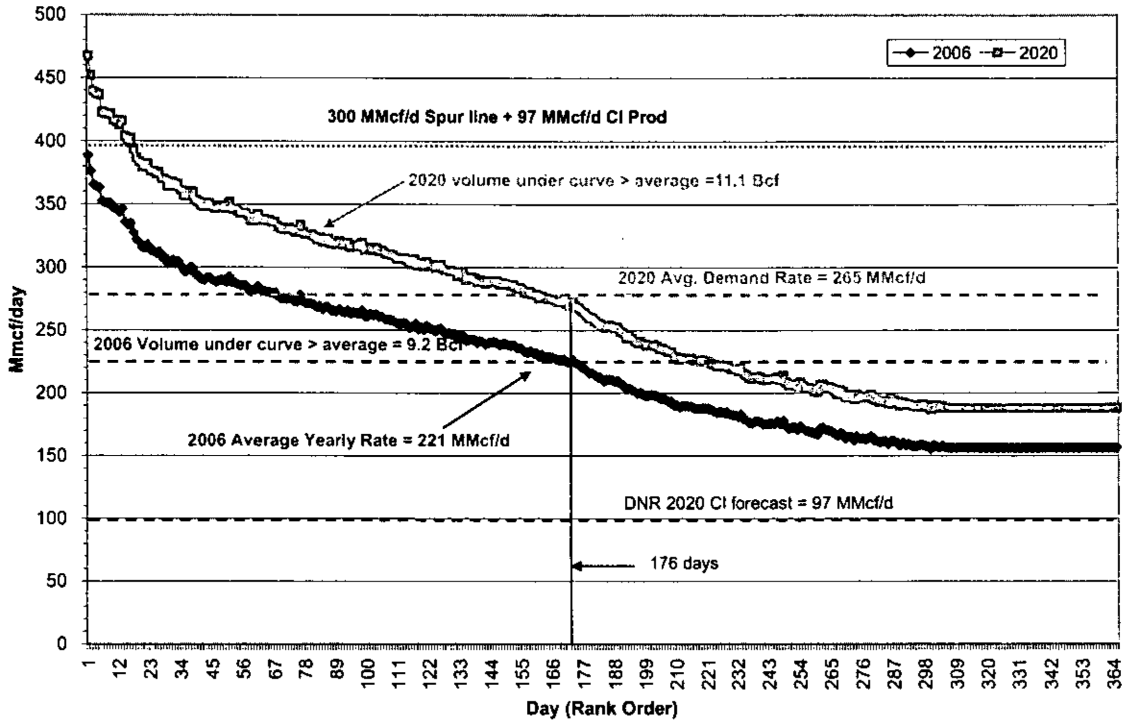
Year	Gas Storage Estimate (Bcf/yr)
2005	8.2
2010	8.8
2015	9.6
2020	10.3
2025	11.1
2030	12.0
2035	13.0
2040	14.0

2.2.2 Storage Volumes Based on Daily Gas Utility and Electric Utility Demand

Cook Inlet daily demand data are available from various sources for the Residential/Commercial and Electric Generation segments and have been complied for 2006 and forecasts developed through 2020 (Dunmire 2007). These data are shown in Figure 2.4. These demand volumes do not include the Fields Ops segment included in the Railbelt Demand included in Table 2.2.

The volume of gas above the average demand to meet Residential/Commercial and Electricity Generation demand for 2006 is 9.2 Bcf and 11.1 Bcf for 2020.

Figure 2.4. South-central Alaska Natural Gas Demand (Gas Utility and Power Generation)



The data used to develop Figure 2.4 also provide the peak-day demand for these demand segments (Dunmire 2007). The gas storage estimates, the average daily demand rate, and peak daily demand rate to 2040 are estimated based on the 2020 estimates using the percentage increases from Table 2.3 Column C for Electric Utilities (power generation) and Column E for Gas Utility (residential/commercial). These estimates are shown in Table 2.5. These estimates are about 10% larger than the volumes shown in Table 2.4 that were based on total Cook Inlet production. Gas storage reservoirs must be capable of supplying the volumes and deliverability rates to meet demand above the average daily rate throughout the high-demand season of the year. The daily demand analysis indicates this is about 176 days per year.

Table 2.5. Base Storage Estimate from Daily Demand

Year	Gas Storage Estimate (Bcf/yr)	Avg. Daily Demand (MMcf/d)	Peak daily Demand (MMcf/d)
2006	9.2	221	389
2020	11.1	265	467
2025	12.1	290	511
2030	13.2	316	559
2035	14.4	344	611
2040	15.7	376	668

The consequences to South-central Alaska utility gas customers of deliverability falling below demand for even one day in the winter makes it imperative that a safety factor be included in the planning for gas storage requirements. A longer disruption of several days or weeks resulting from events such as equipment failure or pipeline breaks is always a possibility. Hence, the base storage capacity is increased by 1.5 times the base gas storage estimate to provide a safety factor for evaluating potential gas storage reservoirs as shown in column C in Table 2.6. The gas storage volumes increase from 16.7 Bcf/yr in 2020 to 23.5 Bcf/yr in 2040. Table 2.6 also includes the average withdrawal rate for the base storage and the proposed design withdrawal rates of 1.9 times the average withdrawal rates, columns D and E, respectively.

Table 2.6. Base Gas Storage and Average Withdrawal Rates for Gas and Electric Utilities

A	B	C	D	E
Year	Gas Storage Estimate (Bcf/yr)	1.5 times Required Gas Storage (Bcf/yr)	Avg. Withdrawal Rate[1] (MMcf/d)	Design Withdrawal Rate[2] MMcf/d)
2006	9.2	--	--	–
2020	11.1	16.7	63.1	120
2025	12.1	18.2	68.9	131
2030	13.2	19.8	75.0	142
2035	14.4	21.6	81.8	155
2040	15.7	23.5	89.0	169

1. Average withdrawal rate = Required gas storage/176 days
2. The design withdrawal rates are 1.9 times the daily average withdrawal rates

It is essential that the spur pipeline and Cook Inlet production provide the **average daily demand** throughout the year and that gas storage or some other alternative source of gas be available to meet the daily demand above the average. The average daily demand must also include the volumes required for Field Ops to operate the natural gas supply system. Any Industrial demand would be in addition to the volumes presented in these tables. The minimum required throughput rate for a spur pipeline to meet this average requirement is shown in Table 2.7. However, a higher spur pipeline rate will be required in the first few years to provide gas to build cushion gas and working gas volumes required to meet the capacity and deliverability required.

Table 2.7. Minimum Spur Pipeline Rate to Meet Average Demand

Year	Average Daily Gas and Elec. Utility Demand (MMcf/d)	Average Daily Field Ops Demand (MMcf/d)[1]	Average Daily Demand (Gas and Elec. Utility & Field Ops) (MMcf/d)	Cook Inlet Production Forecast[2] (MMcf/d)	Spur Pipeline Rate Required for Average Daily Demand[3] (MMcf/d)
2006	221	42	263	--	--
2020	265	42	307	97	210
2025	290	42	332	52	280
2030	316	42	358	30	328
2035	344	42	386	17	369
2040	376	42	418	10	408

1. From Table 2.2.
2. ADNR 2007 Annual Report (Forecast extended to 2040 from 2036)
3. Spur pipeline rate = Average Daily Demand – Cook Inlet Production

Before a spur pipeline will be operational in 2020, South-central Alaska must have additional natural gas for power generation and residential/commercial use to meet the short fall from existing Cook Inlet reserves. This shortfall can be offset by successful Cook Inlet natural gas exploration; switching a portion of the power generation from natural gas to alternatives such as

3379

coal, wind, hydropower, or tidal power; import of LNG; or some combination of all of these options including energy efficiency and conservation measures. When a spur pipeline is available those options that have been put in place for the interim need will still be available. For example, if LNG import is part of the solution, it may need to be continued until gas storage has been built to a level to meet the winter season demand.

In addition, gas storage deliverability must be available to meet the peak-day demands. Gas storage reservoir characteristics, operational design, and costs will determine whether this can be accomplished by spare capacity from the base storage facility or if a peaking-load storage facility will be required to meet the demand.

Due to the necessity to nominate spur pipeline rates on a long-term basis and to build gas storage (cushion gas and working gas), it is assumed that the spur pipeline rate will initially be 300 MMcf/d. Because of the uncertainty of the alternatives, described above, that will have been put in place this assumption is only one possible scenario out of numerous possible scenarios. In addition, if there are industrial users for spur pipeline gas, the rate will need to be higher by that amount unless industrial users would be willing to be curtailed on high demand days.

The assumed initial rate of 300 MMcf/d would need to be increased in increments to meet growing demand and it is anticipated that the spur pipeline will be designed such that additional compression can be added to increase the throughput rate as needed. This also means that there must be opportunities to nominate higher off-take rates from the Alaska Gas Pipeline in the future as currently anticipated. The gas storage withdrawal rates needed for peak-day deliveries for the assumed spur pipeline rates of 300 MMcf/d in 2020 increasing to 450 MMcf/d by 2035 are shown in Table 2.8. These volumes would allow for a significant build up of gas storage of a full year's supply for Cook Inlet consumers or industrial use.

The peak-day demand shown in Table 2.6 has been increased by the average daily demand for the Field Ops demand segment (42 MMcf/d) for these calculations. The Field Ops demand will also vary on a daily basis throughout the year but volumes for that variation are not available.

Table 2.8. Gas Storage Deliverability Required for Peak-Day Rate

Year	Avg. Daily Demand (MMcf/d)	Estimated Peak day rate[1] (MMcf/d)	Cook Inlet Production Forecast[2] (MMcf/d)	Spur Pipeline Rates[3] (MMcf/d)	Gas Storage Withdrawal Rate Req'd for Peak Day[4] (MMcf/d)	Design Withdrawal Rate[5] (1.9 times Avg. Rate) (MMcf/d)	Max. rate req'd from peaking storage[6] (MMcf/d)	Yrly Volume Available for Cushion and Working Gas[7] (Bcf/yr)
2006	263	–	–	–	–	–	–	–
2020	307	509	97	300	112	120	-8	33
2025	329	553	52	300	201	131	70	8
2030	352	601	30	350	221	142	79	10
2035	377	653	17	400	236	155	81	15
2040	404	710	10	450	250	169	81	20

1. Peak day rates from Table 2.5 are increased by 42 MMcf/d to include the Field Ops volumes.
2. ADNR 2007 Annual Report (Forecast extended to 2040)
3. Assumed Nominated Spur Pipeline rates
4. Gas Storage Withdrawal Rate reqd. for Peak Day = Est. Peak Day rate – Cook Inlet Production – Spur Pipeline Rate
5. From Table 2.6.
6. Max. Rate for Peaking Storage = Gas Storage Withdrawal Rate Req'd on peak Day – Design Withdrawal Rate
7. Gas Volume available for Building Cushion & Working Gas Volumes = (Cook Inlet Prod. + Spur Pipeline Rate – Avg. Daily Demand)*365 days

2.3 Summary of Storage Volume and Rate of Delivery Estimates

Historical Cook Inlet production and seasonal demand data were both analyzed and indicate a similar gas storage requirement. The minimum gas storage based on future estimated demand ranges from 11.1 Bcf in 2020 to 15.7 Bcf in 2040. Depending on the minimum gas storage required to meet demand in South-central Alaska is considered too risky because of the serious consequences of any shortfall because there are **no alternative sources** of gas for heating and other essential services totally dependent on natural gas at this point in time. Therefore, a safety factor of 1.5 was applied resulting in an estimated gas storage capacity of 16.7 Bcf in 2020 increasing to 23.5 Bcf in 2040. The spur pipeline must have a delivery rate high enough to build up the cushion gas and working gas required for the selected reservoir to meet the base storage requirement plus the 50% safety factor in volume and provide the daily delivery rates during peak-demand season.

Gas storage must also be able to deliver the incremental rates needed on the coldest days. Based on an assumed 300 MMcf/d spur pipeline in 2020, with expansion to 350 MMcf/d in 2030, 400 MMcf/d in 2035 and 450 MMcf/d in 2040, the incremental delivery from gas storage required to meet the peak-day demand estimates ranges from 112 MMcf/d in 2020 to 250 MMcf/d in 2040. The design withdrawal rates for base storage requirements range from 120 MMcf/d in 2020 to 169 MMcf/d in 2040. Unless the base storage reservoirs are capable of providing adequate deliverability through additional wells to meet the anticipated peak demands, peaking storage facilities may need to come on line between 2020 and 2025 and increase to a minimum deliverability rate of about 80 MMcf/d.

The potential gas storage reservoirs are described in the Section 3.

3 Characteristics of Ideal Natural Gas Storage Facility

An ideal natural gas storage system is described that will meet the optimum base load and peaking load conditions for the Cook Inlet area. The characteristics of this storage system are based on gas volumes that are largely determined by an anticipated constant spur line capacity and seasonally variable usage volumes (residential, commercial, and industrial) in the Cook Inlet area. With these assumptions is place, both the ideal base load and peak load storage facilities are described within the constraints of the known geologic and engineering characteristics of the reservoir intervals of the Cook Inlet Tertiary section (Figure 1.1 and 1.2).

Ideal storage facilities are the products of a complementary interaction of geological, engineering, and logistical elements that are present within the Cook Inlet area. Essential parameters include proximity and connection to existing pipeline system(s), existing gas producing infrastructure, potential storage volume, reservoir geometry and heterogeneity, porosity, permeability, water saturation, water influx characteristics, access to potential storage site, and reservoir pressure/depth. The criteria necessary for the "ideal' storage facility or facilities are described below. The concept of a dual storage system requires that the base load and peak load storage sites/systems possess somewhat different characteristics.

3.1 Base Load Storage Facility Criteria

The base-load storage facility must be of sufficient size to accommodate the excess gas delivered during the low-demand summer months and have the characteristics that will facilitate the withdrawal of the gas during the winter season in quantities and at rates sufficient to meet the average expected demand. This storage facility is not intended or designed to meet the extreme volumes required for short periods during very high use days. The following criteria describe the ideal base-load storage reservoir for Cook Inlet.

- To meet the anticipated storage needs required to offset annual seasonal fluctuations in residential/commercial and power generation demand, at a proposed start-up date of 2020, the storage facility has a working gas capacity of 16.7 BCF (Table 2.8). The facility needs to be capable of expansion to 23.5 BCF or more by 2040, to satisfy the demands of a growing population. The storage system must be capable of delivering an average of 120 MMcf/d in 2020 and 169 MMcf/d in 2040.

  The storage volume discussed above represents only the working gas with a 150% safety factor and does not include the volume of cushion gas required. The cushion gas volume, depending on the reservoir conditions, may be zero to one, or more, times the working gas volume. Consequently, the target storage sites should be viewed as having a total storage capacity (cushion plus base load) of 25 to 50 Bcf gas-in-place.
- Trapped and capped with tank-like characteristics, distinct structure, and evidence of pressure depletion without support.
- Low to moderate water encroachment is preferred. Gas storage in a water-saturated sandstone may cause production problems if water is produced thereby decreasing gas flow rate and increasing water handling problems at the surface. Formation water may potentially trap gas when injection displaces it and then resaturates it during production operations (AOGCC 2005a).
- Gas field/pool near depletion but with enough residual gas to act as cushion gas and provide base-line pressure (≈ 1000 psi) at or near existing pipeline pressures, thus requiring little, if any, compression to get gas into distribution network.

- All wells in good condition, including injectors, producers, and any plugged wells within the area of storage; the production infrastructure is in place.
- Storage site located on and with access to an existing pipeline, with sufficient capacity to deliver required volumes on demand. The pipeline must not have bottlenecks that can compromise its ability to meet demand.
- Storage reservoir porosity of 15 percent or more and permeability in the range of 400 to 1,000 md. These parameters provide sufficient volumes for storage and guarantee high production rates
- Good lateral reservoir continuity, adequate net pay thickness (50 ft or more), and high net to gross ratios in the storage formation (0.75 to 1.0), to facilitate injection, communication, and withdrawal.
- Access to storage site must be unencumbered, no operator or environmental/refuge issues.
- Proximal to market(s) – generation plants, distribution systems, etc.

These criteria describe a storage reservoir that is capable of holding enough natural gas to satisfy long term seasonal demand requirements, provide a buffer should a disruption in delivery from the spur pipeline occur, and guarantee a prolonged steady supply of natural gas for months without the need to cycle additional gas into the storage facility.

3.2 Peak Load Storage Criteria

If a peak load storage facility is required, it may be met two ways. It may be provided by a separate storage site that is designed to produce high volumes of gas for short intervals, a few days at a time. After this short period of high production the facility may be exhausted and require recharging in preparation for the next interval of high demand. Many of the characteristics of an ideal peak load storage facility are similar to that of base load storage but some important differences exist and are highlighted in the following listing.

- Storage capacity of **6 to 8 Bcf** and capability of producing 60 **MMcf/d** in 2020 with ability to increase to **80 MMcf/d** by 2040 (Table 2.8).
- Trapped and capped with tank-like characteristics, distinct structure, and evidence of pressure depletion without support.
- No water encroachment.
- Gas field/pool at or near depletion, but with pressures equal to or above those of the pipeline system – preferably a deep reservoir to assist with high pressure requirement.
- All wells in good condition as with the base-load case and production infrastructure is in place.
- Storage site with **access to high volume pipeline.**
- Porosities and permeabilities of 15 percent and 400 to 1000 md respectively
- Good lateral continuity and reservoir homogeneity and high net-to-gross ratio and adequate pay thickness (50 ft) as in the base load case.
- Access to storage site must be unencumbered.
- Proximal to markets/customers.

These criteria describe a relatively small, well-defined reservoir, which has an existing infrastructure capable of both compressing and injecting significant volumes of gas at high pressure over a period of one to two weeks and producing similar volumes over the same period of time.

4 Characteristics of Existing Cook Inlet Underground Storage Facilities

There are currently three natural gas storage facilities in Cook Inlet. Two are operated by Chevron, Pretty Creek on the west side of Cook Inlet and Swanson River on the east side of the inlet as show in Figure 4.1. The third is operated by Marathon at the Kenai gas field on the east side of Cook Inlet. The operators of these facilities produce the gas and store it for times of high demand. This is unlike the situation that would exist if these facilities or other fields/pools operated by the Cook Inlet gas producers were to be utilized by the owners of North Slope natural gas delivered to the Cook Inlet area by a spur line. These third-party issues are beyond the scope of this study and will need to be evaluated by others at a later date.

4.1 Swanson River Natural Gas Storage Facility

The oldest natural gas storage facility in Cook Inlet is operated by Chevron at the Swanson River field (Figure 4.1). This storage facility was approved and the Storage Injection Order No. 2 was issued in 2001 (AOGCC 2001). The facility was later expanded to include a second reservoir (AOGCC 2005b). The facility stores dry gas from the Swanson River field and other Cook Inlet fields. The storage intervals are the 64-5 and 77-3 sandstones of the Tyonek Formation (AOGCC 2001, AOGCC 2005b, and Havelock 2006). The facility is situated on a major gas pipeline network, near the intended market. The facility has met all state requirements regarding integrity of wells, infrastructure, and stratigraphic isolation of the storage horizons and is located on a 16-inch gas pipeline (Figure 4.1)

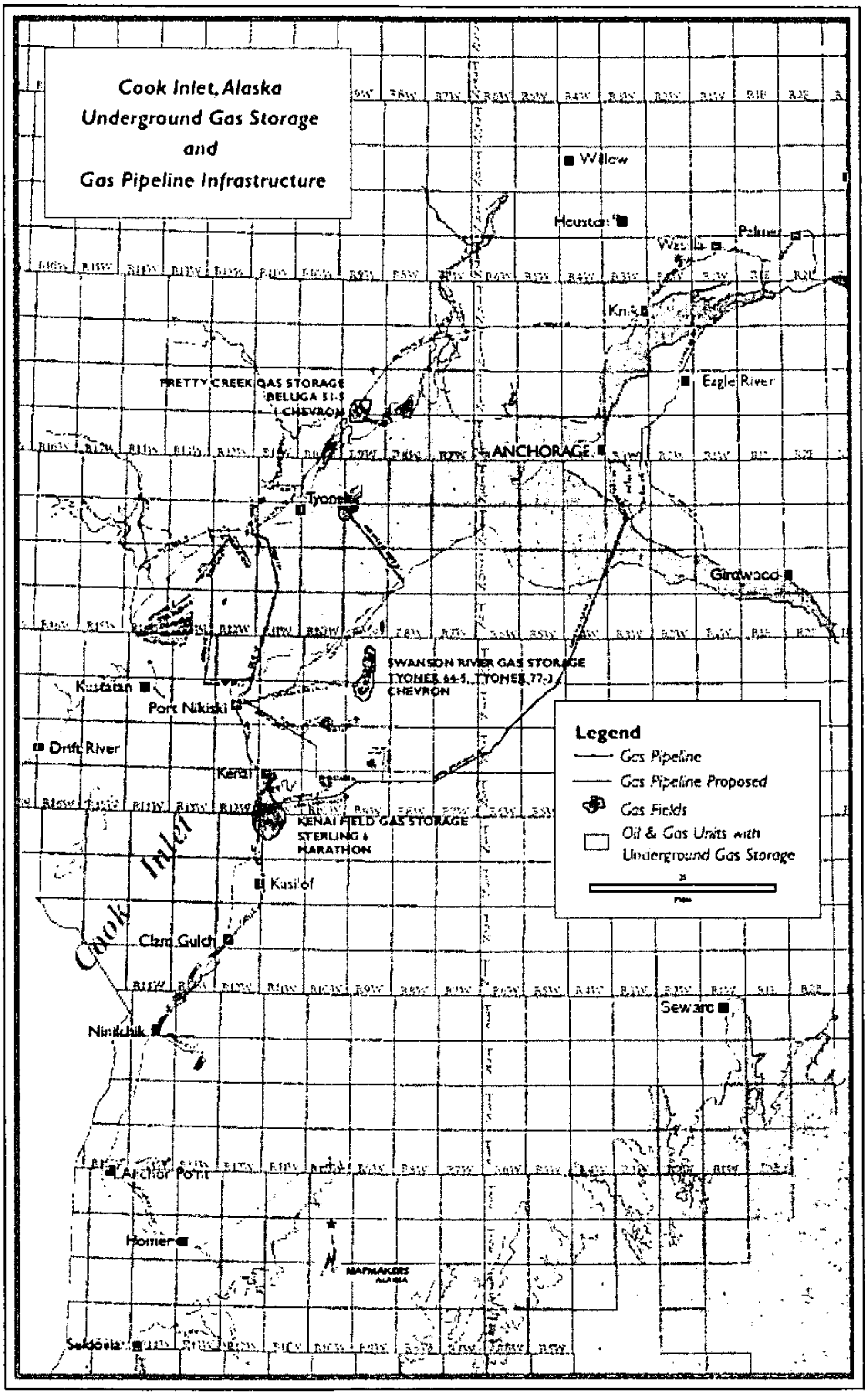
The original storage interval was the Tyonek 64-5 sandstone, defined as the sandstone between measured depths of 6,375 ft and 6,443 ft in the SRU #43-28 well. The SRU #43-28 well has a gas/water contact at a measured depth of 6,390 ft, providing for a net pay of approximately 12 ft (AOGCC 2006). The calculated porosity ranges from 10 to 36 percent, water saturation from 51 to 55 percent, and the permeability ranges to several hundred millidarcies. The reported average values for porosity and permeability in the AOGCC 2004 Annual Report on pool statistics are 29 percent and 200 md respectively (AOGCC 2006a). While the injection orders do not provide a depositional environment for the Tyonek 64-5 sandstone, the description of the encasing sediments strongly suggest that the unit is the product of deposition by meandering streams.

The reservoir pressure as of December 4, 2004 was 2,850 psi. The estimated maximum daily injection volume is 10 MMcf/d and peak production is also 10 MMcf/d.

The second storage reservoir at Swanson River is the Tyonek 77-3 sandstone, which is defined as the sandstone found in the SCU #42A-05 well between 7,972 and 8,001 ft measured depth (MD). The Tyonek 77-3 interval was approved in 2005 (AOGCC 2005b). Based on core data this sandstone has an average net reservoir porosity of 28 percent (AOGCC 2005b), permeability ranges to several hundred millidarcies, and average water saturation is 50 percent. Gross sandstone thicknesses range from 25 to 40 ft based on well control. The reservoir sandstone is interpreted as a meandering stream deposit, which is laterally equivalent to flood plain mudstones and coals.

The original reservoir pressure within the 77-3 sandstone was 4,774 psi and the average injection pressure is 3,500 psi (AOGCC 2005b). The estimated maximum injection rate is expected to be 42 MMcf/d (AOGCC 2005b) and peak production rate is about 10 MMcf/d (Havelock 2006).

Figure 4.1. Cook Inlet Map of Existing Storage Locations



3385

The working gas capacity and deliverability of the two Tyonek storage reservoirs at Swanson River are provided by Havelock (2006) in his presentation to the South Central Alaska Energy Forum. The working gas capacity is 2.2 Bcf/yr. The total daily average deliverability is 7.4 MMcf/d, and total daily peak deliverability is 20.8 MMcf/d, from two wells, one producing from the 64-5 and the other from the 77-3 sandstone.

The operator, Chevron,[2] has provided an update on the Swanson River storage facility, which revises the deliverability of the facility. There are now four production wells in the storage facility, two in the Tyonek 64-5 reservoir and two in the Tyonek 77-3 reservoir. These wells are expected to be capable of peak deliverability rates of 60 to 70 MMcf/d from a total storage volume of ~ 30 Bcf.

4.2 Pretty Creek Natural Gas Storage Facility

Chevron has developed a second gas storage facility at Pretty Creek (Figure 4.1), designed as a periodic peak demand producer (AOGCC 2005a). The storage gas is predominantly from the Middle Kenai Gas Pool in the McArthur River field, but may also include some gas from other fields on the west side of the inlet. The Pretty Creek storage facility is connected to a major 20-inch gas pipeline (Figure 4.1) and is in close proximity to the electrical generation facility at Beluga. The facility has met all the state requirements regarding well integrity, infrastructure, and isolated nature of storage reservoir. The isolated nature of the reservoir was established by material balance analysis.

The storage interval is the Beluga 51-5 sandstone, which is defined as lying between 5,144 ft MD (-3,585 ft TVDss) and 5,173 ft MD (-3,605 TVDss) in the PCU #4 well. Data regarding the nature of the 51-5 sandstone is not included in Injection Order No. 4 (AOGCC 2005a) but Chevron (2007) supplied the following information. The net pay is 16 ft and the net-to-gross ratio is 0.80. Porosity ranges from 18 to 30 percent with an average of 28 percent and permeability is 132 md based on a pressure buildup in the storage sandstone. The water saturation is poorly known but estimated to be about 45 percent. The general depositional environment is described as stream sediments deposited in a low energy environment (AOGCC 2005a). The injection order further states that these Beluga sandstones "are commonly lenticular and often discontinuous over interwell distances."

The estimated original pressure was 1,674 psi at a true vertical depth (TVD) of 3,686 ft. The average wellhead injection pressure is 1,550 psi. The estimated maximum injection rate is 20 MMcf/d (AOGCC 2005a).

The facility is small with limited storage capacity and deliverability. Havelock (2006) places the working gas volume at only 0.70 Bcf/yr and the total daily peak delivery at 7.3 MMcf/d. Chevron[2] has provided revised numbers for the Pretty Creek Beluga 31-5 storage facility. The storage volume is given as ~ 2.0 Bcf and a peak delivery rate of 10 MMcf/d when the reservoir is full.

4.3 Kenai Natural Gas Storage Facility

The third natural gas storage facility in the Cook Inlet area is the most recently developed and the largest established to date. It is operated by Marathon at the Kenai gas field. The storage interval is the Sterling #6 pool (Figure 4.1). This facility has a much greater storage potential than the Pretty Creek and Swanson River facilities combined. Gas from the Kenai and Cannery

[2] Chevron – personally communication, December 2007.

3386

Loop fields are stored during the summer for withdrawal during the high demand months of the winter.

The facility is connected to a 12-inch gas pipeline that supplies Anchorage (Figure 4.1). It has met all state requirements regarding infrastructure, reservoir isolation, and performance. However, there is a necessary qualifier; the storage facility meets the requirements for well integrity at the limited operating pressures and volumes, mandated by the Alaska Oil and Gas Conservation Commission. Caution was dictated by the lack of cement bond logs, for some wells, that are typically used to determine isolation of the injection zone in all wells penetrating the confining layer (AOGCC 2006).

The gas is stored in two thick fluvial sandstones, the C-1 and C-2 sandstones of the Sterling #6 gas pool. The sandstones are comprised of friable to unconsolidated sandstone to clayey sandstone, with minor inter-bedded siltstone and coal (AOGCC 1969). These sandstones are defined in the KU 31-07X well. The C-1 sandstone occurs between 4,366 ft and 4,500 ft TVDss and the C-2 interval is between 4,530 ft and 4,569 ft TVDss. The two sandstones have a total of 110 ft of net pay (AOGCC 2006a) and a net-to-gross ratio of 0.64. The two sandstones are in pressure communication, have porosities that range from 4 to 16 percent, permeabilities that range from 400 to 1000 md, and original water saturations of about 32 percent.

The original reservoir pressure was 2,138 psi at a datum of 4,565 ft TVDss (AOGCC 1969) and the maximum pressure at which the Sterling #6 gas storage will operate is 300 psi (AOGCC 2006b). The storage unit is currently operating at less than 200 psi. A typical injection cycle will consist of 6 Bcf stored during the summer and produced during the winter.

Peak delivery rates vary widely at the Sterling Pool #6. Pool #6 working gas capacity is currently 6 Bcf/yr, but may be expanded to 11 Bcf/yr or more. The total gas-in-place is limited to 50 Bcf under the current lease (Havelock 2006). Prior to being designated a storage interval, the Sterling #6 pool had produced more than 523 Bcf and OGIP is modeled to have been at least 563 Bcf (AOGCC 2006b). Thus, the true potential of this pool as a storage facility has not been realized and at some time in the future it could potentially be expanded to provide storage for 100 Bcf or more.

4.4 Summary of Existing Natural Gas Storage

The three existing natural gas storage facilities in the Cook Inlet area provide seasonal storage for their operators, who store surplus production during the low-demand summer season to meet their obligations and the increased demand of the utilities during the winter. The gas stored is exclusively from the fields that they (Chevron and Marathon) own and operate. This will not be the situation, when and if, storage from a spur line is initiated. However, the characteristics of these facilities are probably very like those that will be developed for storage of spur line natural gas. Havelock (2006) provided a table that summarized the existing facilities and it is reproduced (*with modifications*) here to provide an overview of the current situation and to serve as an example of what the future gas storage pools may resemble.

Table 4.1. Cook Inlet Gas Storage Deliverability (MMcf/d) (Havelock 2006) *(modified to include revisions for Swanson River and Pretty Creek as provided by Chevron;[3] numbers in parenthesis are from Chevron)*

Facility	Number of Wells	Peak Delivery/Well (Average) (MMcf/d)	February 2006 Rate (MMcf/d)	Historical Average Produced Volume (MMcf)	Total Daily Peak Delivery (MMcf)	Total Daily Average Delivery (MMcf)	Working Gas (Bcf/yr)
Swanson River (Tyonek 54-5 and 77-3)	2 *(4)*	10.4 *(~15 to 16)*	9.2	3.7	20.8 *(60 to 70)*	7.4	2.2
Kenai (Sterling Pool #6)	9	6.7	3.7	–	60.3	33.3	6.0
Pretty Creek (Beluga 31-5)	1	7.3 *(10)*	–	2.4	7.3 *(10)*	2.4	0.7
TOTAL	**12 (14)**				**88.4 (~135)**	**43.1**	**8.9**

[3] Chevron – personal communication, December 2007

3388

5 Characteristics of Potential Underground Storage Facilities in Cook Inlet

The objective is to identify and describe in detail the characteristics of depleted or soon to be depleted reservoirs that may be suitable for conversion to and use as future potential underground gas storage facilities in Cook Inlet

This task involves the identification, review, and evaluation of all gas fields or participating areas that may be depleted or otherwise abandoned by the time the spur line is built (10 years ±), to determine their suitability as base-load and/or peak-load gas storage facilities. Oil fields have been **excluded** and the effort is focused on the more conventional gas fields as potential storage facilities. The use of any of these gas fields/participating areas by a third party will likely depend on them no longer being economically viable as commercial gas fields.

In addition to the evaluation and characterization of the parameters listed under Tasks 2.1 and 2.2, the issue of ownership of the abandoned pore space and the ultimate responsibility for remediation and restoration of these fields may be factors that have to be considered in determining the viability of any site as a storage facility. These latter two components may have some bearing on the costs of operating some potential storage facilities.

5.1 Geological and Reservoir Engineering Characteristics of Potential Storage Facilities

The first step in evaluating Cook Inlet reservoirs as potential gas storage facilities was to eliminate the oil fields to avoid the issues related to duplication of facilities and the added costs of oil and water handling in these fields. As shown in Table 1.1, 30 gas fields and 57 gas pools have been discovered in the Cook Inlet Basin. The objective is to reduce this number to those that best meet the requirements and characteristics to function as a potential gas storage facility.

The elimination process began with the offshore gas fields (6 fields/6 pools), including the two large gas fields, McArthur River and North Cook Inlet fields. These were excluded because of the remoteness of the fields, difficult access, and limited space available to develop the gas handling and associated facilities. Next, those gas fields south of the Kenai gas field (4 fields and 8 pools) are considered to be too far removed from the major market/users and therefore are not included in the listing of fields that would be considered as potential future natural gas storage facilities. As a consequence of these two steps, the number of candidates was reduced to 20 fields and 43 pools. The bulk of the effort from this point onward was devoted to identification of primary candidates for base load storage.

The question of underground peak-load storage has two possible answers; either simply create larger base load facilities and add extra wells and increase the operating pressure or identify and develop smaller, high pressure high volume storage sites.

5.1.1 Potential Base Load Storage Facilities

After eliminating the oil fields, offshore gas fields and southern Kenai Peninsula gas fields, a high percentage of the remaining fields/pools are simply too small to provide adequate base load storage capacity for the winter heating and electrical generation needs of the area. Included in this category are fields like Albert Kaloa, Birch Hill, Lone Creek, and Lewis River, which have estimated ultimate recoveries (EUR) in the range of less than 1.0 Bcf to about 12.0 Bcf. To this point most of the culling of potential storage sites has not been based on geological and reservoir engineering criteria, but rather on location, type of native hydrocarbon, and size. There are a number of fields or pools that may have the requisite geological, engineering, and infrastructure characteristics to serve as future base load storage facilities for natural gas. These fields and pools will be the focus of this section of the report.

A total of six fields with 16 pools meet the initial set of requirements and are summarized in Table 5.1. This table provides information regarding the capacity to store cushion and working gas, reservoir parameters, and estimates of remaining reserves in 2020, the year reserves are expected to be depleted to the point of non-commerciality, and probability of reserves growth.

Table 5.1. Cook Inlet Gas Fields/Pools Geological and Engineering Characteristics

Field/pool (6/30 & 16/57)	Reservoir Volume[1] (Bcf)	Porosity[2] (%)	Perm.[3] (md)	Pay(n/g)[4] (Feet)	Pressure[5] (Psi)	Estimated reserves at 2020 (Bcf)[6]	Reserves[7] (Est. Yr. Depleted)	Reserves Growth[8] (high/mod/low/none)
Beaver Creek/ Sterling	140	30	2000	110 ft (0.88)	1100-2100	0	1994[9]	none
Beaver Creek/ Beluga	92	10	(25 ?) estimated	50 ft (1.00)	1943	2.0	2028	low
Beluga River/ Undefined	1,614	(S)31 (B)24	(S)50-199 (B)20-49	(S)107 ft (?) (B)106 ft (?)	(S)755 (B)942	73.6	2030[+]	high
Ivan River Undefined	97	20	1600	37 ft (0.39)	922	0	2019	low
Kenai/ Sterling #3	375	15	300-1000	88 ft (?)	175	0	2020	none
Kenai/ Sterling #4	506	15	300-1000	60 ft (?)	106	0	2016	none
Kenai/ Sterling #5.1	538	15	300-1000	113 ft (?)	310	0	1999[9]	none
Kenai/ Sterling #5.2	66	15	300-1000	53 ft (?)	1200	0	1981[9]	none
Kenai/ Sterling #6	603	4-16	400-1000	110 ft (0.64)	190	0	2019	none
Kenai/Upper Tyonek/Beluga	457	(25-29 ?) estimated	(25-250?) estimated	213 ft (?)	2311	19.9	2030[+]	mod
Kenai/ Tyonek	218	(25-29 ?) estimated	(5-500?) estimated	100' (?)	740	1.2	2027	mod
Cannery Loop/ Sterling	32	(15-20 ?) estimated	(300-1000) estimated	76' (?)	1012	0.4	2023	low
Cannery Loop/ Beluga	113	(10 ?) estimated	25	33' (0.6)	1627	3.6	2031	low
Cannery Loop/ Upper Tyonek	90	(25-29 ?) estimated	250	17' ().77)	651	0.3	2022	low
Swanson River/Sterling	39	28	200-250	10' (?)	1213	0	2019	low
Swanson River/Tyonek	28	25-29	5-500	13-40 (?)	2462	0	2006[9]	low

1. Reservoir Volume – Estimated Original Gas in Place Volume (OGIP).
2. Porosity – value either calculated or from cores; (?) indicates values estimated from equivalent producing intervals.
3. Permeability – value either calculated or from cores: (?) indicates values estimated from equivalent producing intervals.
4. Pay (n/g) – net pay in feet and (portion of sandstone-bearing interval that is net pay).
5. Pressure – current reservoir pressure.
6. Estimated reserves 2020 – reserves remaining to be recovered at assumed pipeline startup date.
7. Reserves (Estimated Year. Depleted) – year of last production from pool, now available for storage use.
8. Reserves Growth – probability that additional reserves will be attributed to the pool before 2020 and not included in estimated reserves 2020 column.
9. 10 MMcf/mon Production cutoff.

The criteria (1) through (8) in Table 5.1 will be applied to the candidate pools to determine their suitability for conversion to storage facilities. Each pool was examined in respect to the criteria listed above and will ultimately be ranked in terms of how closely it approaches the ideal characteristics described in Section 3. These comparisons are summarized below.

Reservoir Storage Volume: Adequate reservoir volume is the first and foremost criterion in choosing a storage facility. Based on the demand assumptions of Section 2.0, fields with adequate pressures to minimize the quantity of cushion gas may qualify if their capacity exceeds the 16.7 Bcf required for working gas volume, including a 50 percent safety margin. Under those standards all 16 pools would have adequate capacity to meet the base load storage needs of the region in 2020, but two, the Swanson River Tyonek and the Cannery Loop Sterling (Table 5.1), may be marginal to store the 23.5 Bcf needed in 2040.

Given that cushion gas will be required and perhaps in volumes equal to or greater than the working gas volume, then any pool with less than 25 Bcf of total gas storage capacity would probably be inadequate to meet the demand level expected in 2040. If the maximum expected volume of cushion gas required were equal to or slightly greater than the working gas, a total gas capacity of at least 50 Bcf would be needed. Two pools fail to satisfy this demand, Swanson River Tyonek and Cannery Loop Sterling and would not be adequate as stand-alone storage facilities. Thus under the foreseen demand scenario, 14 of the pools of Table 5.1 would have the necessary total gas storage capacity, if large volumes of cushion gas are required. Several of these have very large capacity and may be very costly to adequately charge if selected.

Porosity: Five of the pools lack data regarding porosity of the producing interval. Ten of the other eleven pools (Table 5.1) have porosities that are 15 percent or greater. The sole exception is the Beaver Creek Beluga pool, which averages 10 percent. There are no reliable porosity data for the reservoirs in the other five pools; which include the Cannery Loop pools and the Kenai upper Tyonek/Beluga and Beluga pools Table 5.1. By comparison with pools developed within the same interval and in relative proximity the Cannery Loop Sterling pool can be assumed to have porosity of 15 percent or more, and the Cannery Loop Beluga pool probably has porosities in the 10 percent range. Using Tyonek porosities from the Swanson River Tyonek pool it is reasonable to anticipate that the Kenai upper Tyonek/Beluga, Kenai Tyonek, and Cannery Loop upper Tyonek pools have porosities that exceed 15 percent and may range as high as 25 percent. Therefore, at least 14 of the pools have porosity of 15 percent or greater.

Permeability: The ability to produce at high rates requires the reservoir/pool have high permeability. Twelve of the pools have permeability data (Table 5.1) and four lack this information. For these four pools, the probable permeability range can be approximated by comparison with pools developed in similar units in nearby pools. Of the twelve pools with permeability data, at least ten equal or exceed 250 md (Table 5.1) and should be capable of high production rates. An additional three pools, the Kenai Tyonek Kenai upper Tyonek/Beluga, and Cannery Loop Sterling should also have permeabilities in this range. Based on the reported permeabilities or by analog with reported permeability ranges in the Beaver Creek Beluga and Kenai Beluga can be expected to have permeabilities of less than 100 md.

Pay: Net pay thickness is available for all the pools and ranges from a low of 10 ft in the Swanson River Sterling pool to more than 200 ft in the Beluga River Undefined. The net-to-gross ratio ranges from1.0 (Beaver Creek Beluga pool) to 0.39 (Ivan River Undefined), but the gross intervals are unknown for ten of the pools (Table 5.1). A high net-to-gross ratio combined with a pay thickness of 40 ft more provides for an excellent injection/withdrawal scenario. Ten of the pools have net pay in excess of 40 ft and three of those (Beaver Creek Sterling, Beaver Creek Beluga, and Kenai Sterling #6) have net-to-gross ratios in excess of 0.5. However, since

3391

there is little direct data on the nature of the interbedding of non-reservoir facies and the general lack of gross interval thicknesses, this parameter was not directly considered in the ranking of sites.

Pressure: Current pressure in the sixteen pools ranges from a high of 2,462 psi in the Swanson River Tyonek pool to a low of 100 to psi in four of the five Kenai Sterling pools (Table 5.1). Reservoir pressures near or above pipeline pressures are preferred to avoid the need for compression to get the gas into the pipeline system during periods of rapid withdrawal. Ten to twelve of the pools have pressures approaching or exceeding that goal. Pressures of this magnitude also reduce or eliminate the need for large volumes of cushion gas.

Estimated Reserves at 2020 and Estimated Year Depleted: The volume of recoverable native gas expected to remain in the reservoir at start up of the spur line potentially has a direct bearing on the availability or suitability of that pool as a potential storage facility. The estimated deletion rates suggest that only two pools, the Beluga River Undefined and the Kenai upper Tyonek/Beluga will still have significant remaining reserves in 2020; thus, essentially all of the remaining fourteen pools are storage candidates on this basis. The estimated year depleted refers to the date at which the field or pool would be no longer capable of economic production and a major impediment to development as a storage site would have been removed.

Reserves Growth: The life of these fields or pools depends not only on the existing known recoverable reserves but also on the as-yet-undiscovered or undeveloped/delineated resources within the known limits of the producing "structure." Single or two sandstone pools, such as the Kenai Sterling #6 pool are defined so that it is very difficult to "discover" additional reserves, unless a local fault block is indicated. On the other hand, fields like the Beluga River do not have defined single sandstone pools and in the fluvially dominated environment under which the sandstones were deposited, a multitude of additional channel sandstones are without question awaiting the properly placed extension or "exploration" well. The same is true of the Kenai field as a whole. While the probability of finding additional reserves in the Kenai Sterling #5.1 or #5.2 pools is essentially zero, the probability of finding gas within as yet untapped sandstones, present within the mapped outlines of the Kenai gas field is moderate to high. As an example of this Table 5.1 shows no anticipated reserves growth for the Kenai Sterling pools but indicates a moderate probability of reserve additions in the upper Tyonek/Beluga and Tyonek pools.

The effect of reserve additions would be to delay or make more difficult the transformation of a producing gas field into a storage facility. Table 5.1 indicates that six pools are considered to have no future reserve additions and should still be strong candidates for conversion to storage, six have a low probability of reserves growth and thus are good candidates for future natural gas storage; two pools have a moderate probability for reserves growth and combined with their anticipated depletion dates (Table 5.1) would be more risky choices, and one field, the Beluga River field has a high probability of significant reserves growth and on this basis presents one of the greatest challenges for conversion to storage.

These factors plus the infrastructure characteristics, location, pipeline access and other non-reservoir factors are examined and compared to the ideal facility for the purposes of ranking storage candidates in Section 6.

5.1.2 Potential Peak Storage Facilities

The need for a peaking storage facility is uncertain at this time. It is possible that a base load storage facility could be developed with the required working gas capacity, pressure regime, and spare wells for increased production during periods of high demand and thus eliminate the requirement for a smaller high rate, short term storage facility (see Table 2.7). However, it is necessary and prudent to identify possible peak load storage sites, even if they are not required at the start up of the spur pipeline. The evaluation of peak storage sites is focused on smaller pools with high pressures and the reservoir parameters necessary for high production rates.

Table 1.1 identifies five pools with storage volumes of 6.2 to 15.1 Bcf, which is sufficient to meet the anticipated peak load requirements if large volumes of cushion gas are not required. These pools are presented in Table 5.2.

Table 5.2. Cook Inlet, Potential Peak Load Gas Storage Sites

Field/Pool	Reservoir Volume (Bcf)	Porosity (%)	Permeability (md)	Pay (n/g)	Current Pressure (psi)
Beaver Crk/Tyonek undefined	6.3	(25 ?) estimated	(5-500 ?) estimated	45 ft (??)	1,124
Lewis River/Undefined	14.3	22	45	85 (0.45)	1,687
Lone Creek/Undefined	6.2	19	100	??	475
Pretty Creek/Undefined	11.0	22	~120 estimated	60 (.67)	910
Sterling/Beluga Undefined	15.1	10	0.1	100 ft (??)	3,154

Table 5.2 includes most of the same data as Table 5.1 with the exception of the various reserve categories. The criteria for a peak load facility are presented in Section 3.0 and differ from those for the base load facility in three significant ways: 1) require smaller volumes, a capacity of 5 to 10 Bcf or so; 2) require high reservoir pressures (2.0 to 2.5 times ambient pipeline pressures) to assure high production rates, and 3) access to high volume pipeline.

Reservoir Storage Volume: The reservoir storage volume presented in Table 5.2 is the total gas capacity, which must be adequate to include any required cushion gas as well as working gas. As a consequence, the Beaver Creek Tyonek Undefined and the Lone Creek Undefined pools, at 6.3 and 6.2 Bcf, may have inadequate storage, if a significant volume of cushion gas is required to achieve the necessary pressure to assure high production rates. This is especially true of the Lone Creek Undefined pool, which has a current pressure of only 475 psi. On the sole basis of capacity, the Pretty Creek Undefined, Lewis River Undefined, and the Sterling Beluga Undefined pools appear to be capable of providing the storage volumes necessary for a stand-alone peak load facility.

Porosity and Permeability: Porosity values for three of the pools (Table 5.2) is approximately 20 percent, which is good to excellent. There are no published data for the Beaver Creek Tyonek Undefined pool, but by analogy with the Swanson River Tyonek Pool an average porosity of 25-29 percent can be expected. The porosity of the Sterling Beluga Undefined is low at 10 percent and further downgrades this candidate.

Permeability is low by most Cook Inlet standards in all five pools, but exceptionally low (0.1 md) in the Sterling Beluga Undefined pool. The Lone Creek and Pretty Creek pools (Table 5.2) have permeability in the 100 to 120 md range, which suggests that high reservoir pressures may be required to boost production rates for peak load conditions. The Lewis River Undefined pool has a permeability of 45 md, which would require even higher pressures than the Lone Creek and pretty Creek pools.

Pay: Good to excellent pay thickness is known to be present in four of the pools (Table 5.2). There is no reported pay thickness for the Lone Creek Undefined pool. The pay parameter does not eliminate any of the pools from consideration.

Pressure: Since the peak load storage facilities need to be able to produce large volumes for short periods, it is advantageous for the facilities to operate at relatively high pressures, definitely above the ambient pipeline pressure. The current reservoir pressure in these five pools spans a low of 475 psi in the Lone Creek Undefined pool to a maximum of 3,154 psi in the Sterling Beluga Undefined pool. Most of these pools will probably require a volume of cushion gas to attain an operating pressure sufficient to meet peak demand flow rates. The sole exception is the Sterling Beluga Undefined pool, which has high pressure at 3,154 psi; however, the reservoir has a permeability of only 0.1 md and on this basis is suspect as a viable storage candidate.

5.1.3 Summary of Future Natural Gas Storage Options

The options for potential future natural gas storage facilities have been addressed from both the base load and peak load perspectives and the preliminary listing consists of 16 base load candidates and five peak load possibilities. Based on geological and reservoir engineering criteria these choices have been evaluated in terms of suitability and are ranked in Section 6 with respect to their approximation to the ideal facility as described in Section 3. While several of these sites may not have the capacity, as stand alone facilities, to fulfill the storage requirements, it might be advantageous to have two smaller storage sites as opposed to one large facility.

5.2 Gas Storage Reservoir Conversion Design Criteria

The potential gas storage fields in the Cook Inlet as described above are partially depleted gas production reservoirs. The conversion of the gas production reservoirs to gas storage reservoirs should are expected to consist of the following steps:

- Gathering of geological and engineering information.
- Assessing the mechanical condition of wells.
- Determining additional surveys needed.
- Determining the working storage content of the reservoir.
- Determining the number of wells needed.

In order to find the working storage content of a reservoir, the range of pressures used must be selected. The upper pressure is set based upon the information available, particularly the mechanical condition of the wells. The pressure range also has much to do with the flow capacity of the wells.

5.2.1 Mechanical Condition

The mechanical condition of the wells and facilities will impact the technical and economic viability. First, it is necessary to gather information on the field, such as:

- Initial reservoir pressure
- Gas production versus reservoir pressure
- Reservoir temperature
- Gas composition, gravity
- Wells drilled, locations, depths
- Reservoir structure
- Degree of water drive
- Well flow capacity
- Mechanical condition of wells.

All wells drilled to the producing horizon must be located, checked by cement bond log, caliper logs, casing inspection logs, and made mechanically sound. Where poor bond exists, squeeze cementing is required. When the casing is corroded, a liner may be cemented in place or other recompletion techniques with a non-corrosive completion fluid in the annulus. Even wells classed as dry holes should be reopened, re-cemented, or cased as observation wells.

5.2.2 Storage Capacity

Gas production and bottomhole pressure data were examined for each pool in the Cook Inlet area. Plots of P/Z versus cumulative production volumes were constructed for each pool resulting in estimates of original-gas-in-place (OGIP). Example data are shown in Appendix A, Figure A. and A.2. It was assumed that most pools would recover about 90% of OGIP at shut-in conditions. The two OGIP values were compared to insure a reasonable volume was estimated. The only pool for which the two values were not close was the Beaver Creek Sterling; the depletion performance indicates significant water influx occurred. The Kenai Sterling 5.2 also shows this characteristic behavior to a lesser degree but no water production was reported.

5.2.3 Field Deliverability

For most of the gas producing history of the Cook Inlet, supply exceeded demand; therefore, few, if any, wells were produced at capacity. Production history does not reflect the true deliverability of a pool. State of Alaska production records were used to determine the average production performance of each pool on a volume per day per well during the life of the pool. These data were combined on a plot of the P/Z versus cumulative recovery discussed in Section 5.2.2 (Appendix A). A best fit line was drawn to smooth the data over time and reservoir pressure. As noted above, these resulting flow rates are believed to be restricted volumetric rates. The flow rates used in this evaluation were increased by 50% to account for restricted flow rates, possible rate increases resulting from stimulation treatments, and current drilling and completion technology that will be used for any new wells. Marathon reports in a recent report (PN 2007a) that the use of their new Excape completion technology allows completion and fracture stimulation of several zones simultaneously, which will decrease costs and increase well productivity. A more complete well by well examination would be required to determine the amount of rate increase possible.

5.2.4 Design of Well Capacity

When the storage capacity has been set and the character of the market is known, a maximum flow rate for the field at a given content of gas can be estimated. From the estimated production schedule for the reservoir and peak day requirements, the amount of gas in the reservoir and hence the reservoir pressure can be determined. From the field performance curve and the reservoir pressure, the flowing well pressure can be determined for the stated flow rate. These calculations will give the suction pressure to the compressor required to send the gas to market.

5.2.5 Number and location of wells

The addition of the deliverabilities of the wells in the depleted field is likely to give a field deliverability curve that falls short of maximum flow rate. The remedy is to drill more wells or increase the deliverability of the old wells. A structure map of the field with the deliverability of the wells marked on it will provide a good tool to find locations in the reservoir that will give the higher deliverability needed. When drilling takes place, flow tests should be performed to determine the cumulative deliverability so that enough wells can be completed to match the predicted deliverability curve. When there is a high deliverability in part of the field and low in another the tendency may be to drill all new wells in the high permeability area. Care should be taken of creating a pressure sink if a common header gathering system is used. Wells from the high pressure, low permeability area will transfer the gas to low pressure area. Also to limit the surface piping gathering system, directional and horizontal wells should be considered.

5.2.6 Dehydration, Compression and Metering

Wellhead gas may pass directly to the gathering system without treatment, be heated, have alcohol injected into it or processed by a wellhead dehydration unit. Where central treating is performed, either solid absorbent or glycol absorption processes may be used. The solid adsorbents are more expensive to install, but easier to operate under overloaded, intermittent or short cycling conditions.

The compression requirement depends on the field operating pressure levels and market delivery pressure. Compression horsepower should be selected by an economic study of the number of wells, the field operating pressure level and the schedule of gas withdrawal in winter and need for injection in the summer.

Gas will be metered into and out of storage in American Gas Association standard meters to keep and accurate account of gas in the reservoir. Plant usage, gas losses while blowing of wells and even unaccounted for losses should be recorded.

5.2.7 Planned Observations

When converting a gas field to storage a long-term life is contemplated with a life cycle of over 30 years. The possibility that gas might find a way to leave the reservoir especially through mechanical imperfections should considered.

Gas analyses should be made of all natural gases in the vicinity of the depleted gas field to be converted to a storage field. These analyses may identify any gas found in water wells. A good guide or principle is that the water-filled confining zone above the caprock and in the gas zone on the edges of the field should be observed for both the absence of gas and the degree of pressure change.

6 Comparison of Ideal Storage Facility to Available Options

The criteria and characteristics identified in Section 3.0 are used to compare the variously identified potential storage facilities to the ideal Cook Inlet underground gas storage facility and rank them based on the results of this comparison. The ranking reflects how these options meet the optimum conditions required to satisfy base load and peak load needs associated with gas supply and usage in the Cook Inlet region. Table 6.1 was developed to facilitate the ranking process for the base load storage options but not all the criteria presented in Table 5.1 were used to construct Table 6.1. Some criteria will require additional study at the time of final selection, such as well integrity, water encroachment issues, and legal obstacles to use of the site for gas storage. Issues like access to a pipeline, relative proximity to customers, and tank-like characteristics are generally equivalent in all the remaining candidates and are excluded from the ranking criteria. The parameters of porosity, permeability, net pay, and net-to-gross have been replaced by a deliverability factor (Appendix A), which is the average well production rate derived from P/Z calculations times the anticipated number of producing wells. Finally, the total gas volume required to bring the reservoir to ambient pipeline pressure was added to the ranking process. Appendices A and B provide the basis for this table. Appendix A summarizes the process and values used to establish per well rates and volume of gas required to achieve ambient pipeline pressures. Appendix B shows the scaling used for the ranking criteria, where a ranking of 1 is best.

The limited number of peak load options did not require that a comparable table be constructed for that ranking.

6.1 Ranking Potential Base Load Storage Candidate Sites

The ranking of the base load storage candidate sites is shown in Table 6.1. It is an intermediate step in the final recommendation and reflects the comparison of the quantifiable criteria of the candidate sites to the ideal storage site, which is presented as standard for comparison. Pools with less than the ideal volume of 25 to 50 Bcf are included for consideration, as there may be justification for two or more storage facilities, as insurance against a disruption at the storage site or to reduce the potential need for large volumes of cushion gas at one of the larger sites.

The component values considered to constitute the Ideal Storage Facility are shown in Table 6.1. Pools 11 through 16 of Table 6.1 have very large reservoir size (capacity) and, with the sole exception of the Kenai Tyonek pool, require excessive volumes of cushion gas, 146 to 179 Bcf (Appendix A, Table A.1) to achieve pressures equivalent to the ambient pipeline pressure. As a consequence, these large Kenai Field pools and the Beluga River Undefined pool have been excluded from further consideration.

The Beluga River Undefined pool is somewhat unique. It includes numerous pay sandstones (more than 40) in the Sterling and Beluga formations. These pays are cut by an unknown number of the wells, probably ranging from 2 or 3 per pay to perhaps as many as 10 per pay interval. Individual wells may penetrate and produce from as many as 50 pays. The volume of cushion gas required is nearly 650 Bcf (Appendix A, Table A.2). The issues regarding well integrity, communication between pay zones, and depletion status of individual sandstones indicate that using any of these horizons for storage is not feasible based on current knowledge. Given that the operators continue to delineate and refine their understanding of the interrelations among pays, wells, and production, there may come a time when specific, depleted horizons are viable candidates for storage.

Table 6.1. Preliminary Comparison of Base Load Storage Options to the Ideal Storage Facility

Pool	Reservoir Size (Bcf)	Deliverability (MMcf/d)	Cushion Gas Volume (Bcf)	Depletion Date (Year)	Rank
IDEAL	**25-50**	**120-169**	**0.0**	**<2015**	
Swanson River/Sterling	1	2	1	2	**1**
Beaver Creek/Beluga	2	1	1	4	**2**
Swanson River/Tyonek	1	5	1	1	**3**
Beaver Creek/Sterling	3	4	1	1	**4**
Kenai/Sterling #5.2	2	5	1	1	**5**
Ivan River	2	4	2	2	**6**
Cannery Loop/Sterling	1	5	1	3	**7**
Cannery Loop/Upper Tyonek	2	5	1	3	**8**
Kenai/Sterling #5.1	5	1	5	1	**9**
Cannery Loop/Beluga	3	2	3	5	**10**
Kenai/Sterling #6	5	1	5	2	**11**
Kenai/Sterling #4	5	1	5	2	**12**
Kenai/Sterling #3	5	1	5	3	**13**
Kenai/Tyonek	5	3	3	4	**14**
Kenai/Upper Tyonek-Beluga	5	1	5	5	**15**
Beluga River/Undefined	5	1	5	5	**16**

Reservoir Size: All of the top ten pools have reservoir size that is equal to or greater than the ideal storage facility and meet the anticipated storage needs well into the middle of the 21st century. These are presented in Table 6.1. The two pools, the Cannery Loop Sterling and Swanson River Tyonek pools (Table 5.1 and Appendix B, Table B.1) have reservoir sizes that are at the lower end of the acceptable range and under some conditions may be too small to be stand-alone storage facilities but may provide secondary sites; however, they have the additional constraint in that they have limited deliverability (Appendix A, Table A.2). The other eight pools have sufficient reservoir size to qualify as stand-alone storage sites. Of these, the Kenai Sterling #5.1 pool has a reservoir size of nearly 500 Bcf (Table 5.1) and would require 178 Bcf of cushion gas to reach adequate reservoir pressure; thus, it is eliminated from further consideration on this basis. The results are that seven pools clearly meet the requirements for reservoir size and two additional pools may, but are definitely adequate as secondary pools.

Deliverability: The seven stand-alone and two smaller pools were examined from the aspect of deliverability. Deliverability is defined here as the calculated "adjusted" low average well rate times the number of wells expected to be producing from the storage facility (Appendix A, Table A.1). Table A.1 also shows the "adjusted" average high rate. The low rate was chosen, since it is the rate that must be sustainable as the storage facility is drawn down by production. For example, the Kenai Tyonek pool has been assigned a deliverability of 48 MMcf/d, but at high rates may deliver as much as 72 MMcf/d.

The Beaver Creek Beluga and Swanson River Sterling pools are expected to have deliverability rates of about 60 MMcf/d, and the Cannery Loop Beluga pool has the potential for over 50 MMcf/d. The Ivan River and Beaver Creek Sterling pools are expected to be capable of 30 to 40 MMcf/d, and the Kenai Sterling #5.2, and the Cannery Loop upper Tyonek are rated at 20 to

30 MMcf/d. This reflects the order in which they would be ranked on deliverability. From the deliverability perspective, none of these pools appears to have adequate rates to be stand-alone facilities.

The smaller Cannery Loop Sterling and Swanson River Tyonek pools are rated at 20 to 30 MMcf/d; further diminishing their attractiveness as prospective storage sites.

Cushion Gas Volume Required: The volume of cushion gas required to achieve ambient pipeline pressures is an important consideration. In this evaluation the remaining seven stand-alone and two secondary candidates have cushion gas requirements ranging from zero, in the case of the Kenai Sterling #5.2 pool, to 43 Bcf in the Cannery Loop Beluga pool (Appendix A, Table A.1). This provides an additional measure of the relative value of the potential site, in terms of monetary savings related to gas purchases.

Depletion Date: The remaining candidate pools were next evaluated based on the anticipated depletion date, which is an important factor in this analysis. It is necessary that the potential site be available for storage by the time the spur pipeline is operational. In this scenario, that date has been assumed to be 2020. Many advocates hope to have the pipeline in operation at an earlier date – such as 2017. The assumption was made that a pool would need to be at or near the end of its commercial life before it was converted to storage. Based on this assumption, pools like the Cannery Loop Beluga and the Beaver Creek Beluga, which are not expected to be depleted until 2031 and 2028, respectively, would drop considerably in the ranking. Four of the seven larger pools (Table 6.1) are expected to be depleted by 2020 and would be potentially available for conversion to storage. The Cannery Loop Upper Tyonek pool depletion date is estimated to be about 2022.

Among the smaller pools the Swanson River Tyonek pool is also expected to be depleted by 2020 and would be a possible storage site, while the Cannery Loop Sterling is expected to be depleted about 2023.

The summation and discussion above constitutes the basis for the final list of recommended sites to be considered as potential future base load storage facilities. This listing will deviate in some details from that of Table 6.1 due to a more objective integration of timing, deliverability, and total gas volumes required to attain pipeline pressures. The foregoing discussions of Section 6.1 establish the rational for this approach.

6.1.1 Final Ranking

The ranking of potential future base load storage sites is strongly determined by the following considerations. The other criteria of Tables 5.1 and 6.1 do not vary significantly among the principal potential storage sites and were largely discounted in this final selection process.

- Reservoir size near the ideal volume–excessive capacity may require large volumes of cushion gas in order to achieve optimum operating rates, and capacity significantly below the ideal would require high existing reservoir pressures to minimize cushion gas and maximize working gas. Excessive storage concerns may be offset by using a greater number of wells to keep withdrawal rates at required levels. Reservoir size less than the ideal volume will require multiple facilities, which may be an advantage, when taking disruptions into consideration.
- The deliverability of a reservoir is a function of the number of wells and reservoir pressure and communication. In the scenario presented in the following discussions, the number of wells in each potential storage site is taken to be two times the number of wells utilized during that pools historically high production (Appendix A, Table A.2). It may be possible to achieve greater deliverability by drilling more infill wells.

- Gas volume can be a very costly component of the storage issue. The amount of working gas is taken as a constant (20 Bcf) and the variable is the volume of cushion gas required, which is based largely on the reservoir pressure. Large low pressure reservoirs may require ten's to hundred's of Bcf's of gas to achieve the necessary pressure.
- Depletion prior to 2015 is preferred and prior to 2020 is a virtual necessity. This provides adequate time to plan and prepare the site for gas storage. Those that are depleted after 2020 would need to be deferred or some agreement with the lease holders/operators would need to be negotiated to use part of all the field/pool for storage.

Table 6.2 summarizes the rankings for the potential base load storage site candidates and compares them to the "Ideal Pool". The four criteria are listed with values extracted from Table 5.1 and Appendix A (Tables A.1 and A.2). Despite all efforts to base the decision on quantifiable, objective data, there remains an element of subjectivity in the selection process. Until detailed studies of the candidate pools are completed, the true strengths and weaknesses of these sites will be largely unknown. These ranked potential future base load storage sites are located on Figure 6.1.

Table 6.2. Ranked Candidates for Base Load Storage

Rank	Pool	Reservoir Size (Bcf)	Deliverability[1] (MMcf/d)	Cushion Gas Required (Bcf)	Depletion Date (Year)
	IDEAL POOL	**25-50**	**120-169**	**0.0**	**2010-2015**
1	Swanson River/Sterling	39	60 (160)	9.0	2019
2	Beaver Creek/Beluga	92	61 (106)	16.0	2028
3	Ivan River	97	34 (65)	8.0	2019
4	Kenai/Sterling # 5.2	66	30 (36)	0.0	1981
5	Swanson River/Tyonek	28	29 (89)	6.0	2006
6	Beaver Creek/Sterling	140	33 (51)	24.0	1994

1. The number in the column is the 'adjusted" low deliverability, which is the value used to rank the candidate sites, the number in parenthesis is the "adjusted" high deliverability and can be achieved but is not sustainable for the entire demand season (Table A.2).

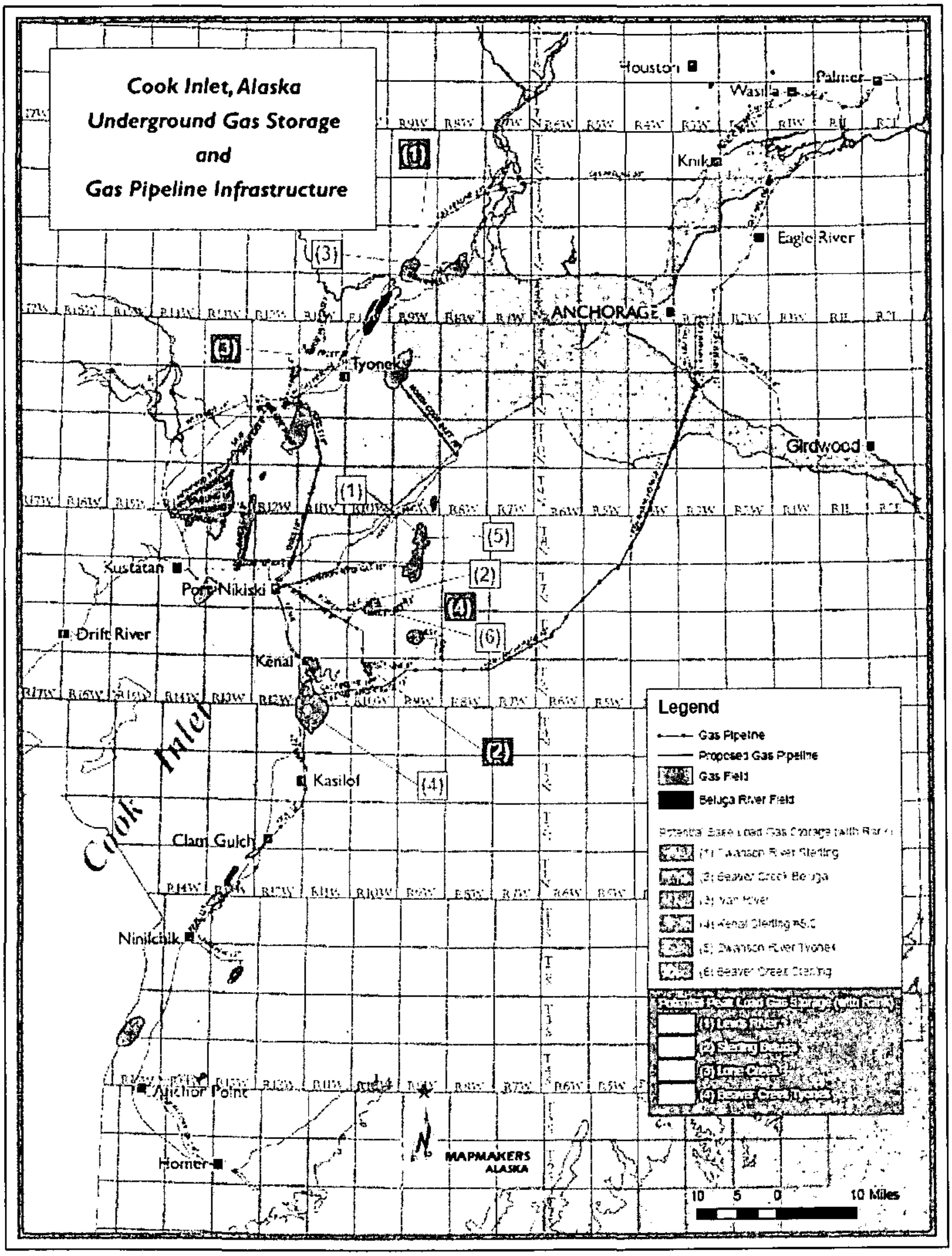
The Swanson River Sterling pool is ranked as number one primarily because it has good-to-high deliverability, is expected to be depleted by 2020 and requires moderate amounts of cushion gas. The reservoir size is adequate but falls in the mid-range of the preferred size class, and expansion of storage capacity is limited to about 10 Bcf.

The Beaver Creek Beluga site has excellent reservoir size, the highest deliverability, but requires more cushion gas and is not expected to be depleted until 2028. These latter two factors prevent it from being ranked No. 1 and could drop it below the Ivan River pool.

The Ivan River pool is rated as the third choice due to the capacity and moderate volume of cushion gas required. The expected depletion date of 2019 is an additional plus. The primary negative factor is the relatively low deliverability of only 34 MMcf/d.

The Kenai Sterling # 5.2 has been depleted since 1981 and has good-to-excellent reservoir size. The capacity is in excess of the requirements and no cushion gas is required to achieve ambient pipeline pressures. The chief problem is deliverability of only 30 MMcf/d using the one-to-one producing well scenario. There are suggestions that water encroachment has been detected, which may have the potential to reduce deliverability.

Figure 6.1. Cook Inlet Map of Storage Locations



3401

The Swanson River Tyonek pool is the smallest of the top six candidates at 28 Bcf, which is at the low end of the preferred size range. It requires a moderate amount of cushion gas, but has a projected deliverability in the one-to-one infill well case of only 29 MMcf/d.

The Beaver Creek Sterling pool is ranked No. 6 because of the problems with water encroachment, which requires a large volume of cushion gas and also reduces the deliverability. There is a large capacity for gas storage, and an early depletion date, but unfortunately that is due largely to the fact the pool watered out. The anticipated deliverability is about 33 MMcf/d.

The results of these evaluations indicate that there are viable potential future underground natural gas storage sites in the Cook Inlet gas fields. However, among the leading candidates there are no true stand-alone reservoirs with regard to sustainable deliverability. Each of the candidate pools meets the capacity needs but under the proposed development none of them are capable of achieving the 120 to 169 MMcf/d design withdrawal rates of Table 2.6 and Section 3.1.

The large pools, Kenai field pools and the Beluga River field, that were eliminated early in the evaluation process would have the deliverability required, if cushion gas volumes well in excess of 100 Bcf were injected (Appendix A, Table A.1). In fact, to establish ambient pipeline pressure, 648 Bcf of cushion gas would need to be injected into the Beluga River field (Appendix A, Table A.2) unless a zone or zones could be successfully isolated while maintaining active production operations. But, why shelve expensive cushion gas when the same volumes could be used as working gas in two or three smaller facilities, such as the Swanson River Sterling and others of Table 6.2? The use of two or more storage facilities also provides a safety measure in the case of a disruption at the storage facility. It would also be advantageous to have a facility located in both sides of the Cook Inlet for similar reasons.

Unless future detailed studies indicate otherwise, these pools in some combination should provide adequate storage for any reasonably forecast seasonal storage needs and achieve the deliverability needs for peak season demand. Under certain conditions, multiple base load storage facilities may negate the need for separate peak load storage, at least for the initial years of the pipelines existence.

6.2 Final Ranking Potential Peak Load Storage Candidate Sites

The need for a separate peak load facility or facilities depends on the ultimate nature of the base load storage facilities. At this time the working scenario requires peak load storage for the short, very high demand periods resulting from conditions of extreme cold weather. As identified in Section 5, there are five pools that would be candidates for potential peak load storage (Table 5.2) and the total storage capacity of these pools ranges from 6.2 Bcf to 15.1 Bcf (Appendix A, Table A.3). These pools are all on the pipeline system and are within 50 to 100 miles of the major consumers. Three key factors were utilized to rank or eliminate the pools. These are same factors used to develop the final rankings for the base load storage: reservoir size, deliverability, and cushion gas requirements.

The five identified pools/fields are of such a size that they meet the requirements of the peak load demand anticipated in 2020. In increasing order of total storage capacity they are (Appendix A, Table A.3):

- Lone Creek Undefined – 6.2 Bcf (requires zero cushion gas),
- Beaver Creek Tyonek Undefined – 6.3 Bcf (0.5 Bcf cushion gas),
- Pretty Creek Undefined – 11.0 Bcf (6.0 Bcf cushion gas),
- Lewis River Undefined – 14.3 Bcf (1.6 Bcf cushion gas),

- and Sterling Beluga Undefined – 15.1 Bcf (2.0 Bcf cushion gas).

The existing Cook Inlet gas storage facilities have gas volumes of this size or smaller and average deliverability rates are about one percent of the total working gas. Based on these averages, maximum deliverability rates may range from a low of 58 MMcf/d for the Beaver Creek Tyonek undefined pool to a high of 131 MMcf/d for the Sterling Beluga Undefined pool (Appendix A, Table A.3). This assumes the reservoirs are filled to capacity and the cushion gas has been discounted.

Based on minimization of cushion gas volume (Appendix A, Table A.3) the Pretty Creek Undefined pool would be eliminated, since nearly half the volume of gas in the pool would be unavailable for withdrawal.

Using the one percent of working gas volume (original gas in place minus cushion gas equals working gas) as average daily deliverability, the only two of the remaining pools are capable of achieving the 80 MMcf/d maximum anticipated peak gas requirements in 2040. The Lone Creek Undefined and the Beaver Creek Undefined pools are fall below the margin of 70 MMcf/d in 2025 for the assumed spur pipeline rates. Both the Lewis River and Sterling Beluga undefined pools have capability to achieve the desired deliverability in 2040 with potentials of approximately 125 to 130 MMcf/d each.

The ranking for peak load storage and reasons are given below, and their location and ranking are given in Figure 6.1.

1.) Lewis River Undefined: low cushion gas requirements, near power generation facility, and maximum potential deliverability of approximately 130 MMcf/d.

2.) Sterling Beluga Undefined: low cushion gas requirements, ready access to Anchorage area gas users, and maximum potential deliverability of 125+ MMcf/d.

3.) Lone Creek Undefined: falls short of the deliverability rate with a maximum rate of about 62 MMcf/d but requires no cushion gas and could provide a secondary peak storage facility.

4.) Beaver Creek Tyonek Undefined: falls short on deliverability rate at 58 MMcf/d but requires only 0.5 Bcf cushion gas and could provide a secondary peak storage facility.

The Lone Creek and Lewis River sites are located on the west side of the Cook Inlet and could easily supply the electrical generation plant, while the Beaver Creek and Sterling Beluga sites are located on the east side and could be dedicated to the gas utilities (Figure 6.1).

6.3 Summary of Potential Underground Natural Gas Storage Candidates

The evaluation has established the existence of six potential base load storage and four peak load storage sites. All the base load storage candidates are of sufficient size, that even with the anticipated cushion gas requirements of the various pools, they retain the capacity for the requisite volume of working gas. At the calculated low, sustainable deliverabilities none of them are gauged to have rates that are sufficient to serve as the sole storage facility and multiple storage units are required. At the calculated high deliverability rates the Beaver Creek Beluga (120 MMcf/d) and the Swanson River Sterling (160 MMcf/d) can meet the demand, but not for sustained periods or for the duration of the high demand winter season.

The four peak storage sites are equally distributed between the west and east sides of Cook Inlet and the Lewis River and Sterling Beluga undefined pools have the potential to meet any anticipated peak demand needs. The Lone Creek and Beaver Creek Tyonek, as a pair could also meet that demand.

7 Costs of Potential Storage Facilities

The Federal Energy Regulatory Commission (FERC) published a report in 2004 describing the "Current State of and Issues Concerning Underground Natural Gas Storage" (FERC 2004) that describes the status and economics of underground storage in the U.S. Storage economics, storage development costs, and the value of storage as described. Storage development costs for a typical 2-cycle/yr depleted reservoir field can cost between $5 million and $6 million/Bcf of working gas capacity (FERC 2004). The costs are site-specific based on:

- the quality and variability of the geologic structure of the proposed site;
- the amount of compressive horsepower required;
- the type of surface facilities needed;
- the proximity to pipeline infrastructure; and
- permitting and environmental issues.

The FERC report (2004) reports that cost-of-service is frequently used to value services offered by regulated storage providers such as interstate pipeline companies. It allows for recovery of costs and a return on capital. The FERC review (2004) of 20 storage operator tariffs indicated a median cost-of-service of $0.64/Mcf. The economic evaluation of Cook Inlet gas storage is expected to be different, most likely higher cost, than Lower 48 gas storage because of the inability to purchase gas at low prices in the summer for storage and sell it at higher prices in the winter season and the more remote and higher cost environment in the Cook Inlet. A cost-of-service estimate is not included in the report.

Estimates for capital and operating costs associated with developing and operating potential Cook Inlet storage facilities are described below. These costs are generic and general at this stage of gas storage design and are intended as a basic guideline to identify the components and provide a reasonable estimate of the magnitude. The regulatory framework and the allowable rates of return have not been established for any regulated storage facilities in Alaska.

The factors influencing the cost of operating the storage facility includes such items as:

- Conditioning the reservoir to serve as a storage facility.
- Designing and developing the gas injection and withdrawal infrastructure including reconditioning of old wells and drilling and completing any new wells required to meet deliverability requirements.
- Construction or upgrades of a pipeline to connect the gas storage facility to the gas distribution system.
- Rentals or other fees to owner of pre-existing infrastructure.
- Costs (price/unit volume) associated with acquiring a gas storage lease and any fees associated with the injection of stored gas, docking (length of time stored), and withdrawal.
- Purchase cost of cushion gas and working gas.
- Operating and maintenance costs.

It is noted in the FERC report (2004) that the cost of purchasing cushion gas is one of the most expensive elements of a storage project. In addition, if there are remaining reserves in the field at the time of conversion, the value of those stranded reserves may need to be added to the costs or accounted for in the yearly production cycle.

The estimated cost data in Table 7.1 are for a 20 Bcf working gas storage facility requiring 20 Bcf of cushion gas, four new infill wells, and 100 MMcf/d of maximum deliverability to provide a general guideline for expected costs to construct a storage facility in the Cook Inlet. The total capital costs include the purchase of cushion gas. The costs will vary depending on the specific sites chosen. The operating costs needed for a cost-of-service calculation can be estimated as shown based on percentages of the capital cost on an annualized basis. These calculations are not included in this study.

Table 7.1. Estimated Cost of Construction of a 20 Bcf Gas Storage Facility

Expenditure item includes installation	Cost
Compressor 4000 hp	$8,000,000
Dehydration	$2,200,000
Piping and valves	$50,000
Instrumentation and controls including metering	$1,000,000
Civil, concrete etc	$1,750,000
Insulation and paint	$25,000
Electrical bulk material	$500,000
Engineering	$750,000
Make up wells @ $7MM	$28,000,000
20 Bcf cushion gas @ $6.00 Mcf	$120,000,000
Total Capital Costs	**$162,275,000**
Total Capital Costs ($millions/Bcf)	**$8.1 million/Bcf**
Operating cost	
Fixed costs: Depreciation, interest taxes, insurance, etc. –41% of annualized capital costs	
Direct costs: 3% of annualized capital costs	

8 References

Alaska Department of Natural Resources, 2007, Alaska Oil and Gas Report 2007 Annual Report: Alaska Division of Oil and Gas, 95 p.

Alaska Geological Society, 1975, Oil and Gas Fields in the Cook Inlet Basin Alaska: Alaska Geological Society, 84 p.

Alaska Natural Gas Development Authority, 2006, Alaska natural Gas Development Authority Business Plan, prepared by Northern Economics, Inc., November 2006.

Alaska Oil and Gas Conservation Commission, 1969, Establishment of Pool Rules to Govern the Operation of the Kenai Gas Field: Conservation Order No. 82, 4 p. plus attachments.

Alaska Oil and Gas Conservation Commission, 2001, The Application of Union Oil Company of California, Swanson River Field: Storage Injection Order No. 2, 4 p.

Alaska Oil and Gas Conservation Commission, 2003, Commission Well-File Search for Cook Inlet Wells: Excel Spread Sheet, 248 entries.

Alaska Oil and Gas Conservation Commission, 2005a, The Application of Union Oil Company of California, Pretty Creek Field Gas Storage Facility: Storage Injection Order No. 4, 7 p.

Alaska Oil and Gas Conservation Commission, 2005b, The Application of Union Oil Company of California, Swanson River Field Gas Storage Facility: Storage Injection Order No. 6, 7 p.

Alaska Oil and Gas Conservation Commission, 2006a, State of Alaska, Alaska Oil and Gas Conservation Commission 2004 Annual Report of Annual Pool Statistics, (updated 17 February 2006): AOGCC_Web@admin.state.ak.us.

Alaska Oil and Gas Conservation Commission, 2006b, The Application of Marathon Oil Company, Kenai Gas Field Gas Storage Facility: Storage Injection Order #7, 7 p.

Chevron, 2007, Reservoir Parameters for Beluga 51-5 Storage Sandstone, Pretty Creek Field, Cook Inlet, Alaska, personal communication.

Dunmire, C. 2007, ANGDA Scenarios Study, November 2007.

ENSTAR Natural Gas Company, 2007, 2006-2007 Winter Update to RCA, Daniel Dieckgraeff,

Federal Energy Regulatory Commission (2004), Current State of and issues Concerning Underground natural Gas Storage, Staff Report, September 30, 2004. https://www.ferc.gov/EventCalendar/Files/20041020081349-final-gs-report.pdf

Havelock, B. 2006, Natural Gas Storage in Alaska: South Central Alaska Energy Forum, Alaska Department of Natural Resources, Division of Oil and Gas, 24 p.

Petroleum News, 2007, Agrium Shutting Down, Volume. 12, NO. 39., September 30, 2007.

Petroleum News, 2007a, Marathon Continues to chase Cook Inlet Gas, Vol. 12, NO. 44, November 4, 2007.

Slider, H.C., 1983, Worldwide Practical Petroleum Reservoir Engineering Methods, Penwell Books, Tulsa, Oklahoma, 1983.

Swenson, R. F., 1997, Introduction to the Tertiary Tectonics and Sedimentation in the Cook Inlet Basin: *in* Karl, S. M., Ryherd, T. J., and Vaughn, N. P., eds., Guide to the Geology of the Kenai Peninsula, Alaska, Alaska Geological Society, p. 18-27.

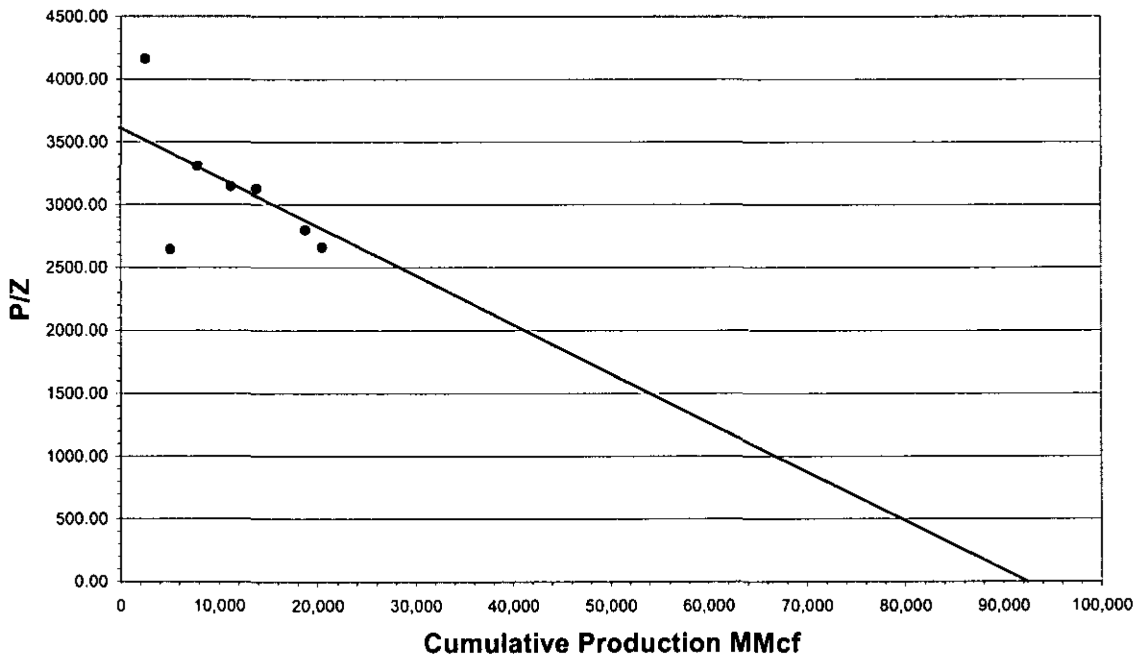
Thomas, C. P., Doughty, T. C., Faulder, D. D., and Hite, D. M., 2004, South-Central Alaska Natural Gas Study: U. S. Department of Energy, National Energy Technology Laboratory Arctic Energy Office.

Thomas, C.P., Ellsworth, C., Davies-Waldron, C, Friedman, D., Zarumba, R., Farber-Deanda, M., Bratvold, D., Messner, S., Kreczko, A., Faulder, D.D., Bloomfield, K., 2006, Alaska Natural Gas Needs and Market Assessment, prepared by SAIC for the U.S. Department of Energy, National Energy Technology Laboratory.

9 Attachments

Appendix A: Gas production and bottomhole pressure data were examined for each pool in the Cook Inlet area. Plots of P/Z versus cumulative production volumes were constructed for each pool resulting in estimates of original-gas-in-place (OGIP) as shown in Figure A.1 for the Beaver Creek Beluga Pool. It was assumed that most pools would recover about 90% of OGIP at shut-in conditions. The two OGIP values were compared to insure a reasonable volume was estimated. The only pool for which the two values were not close was the Beaver Creek Sterling and the depletion performance indicates significant water influx occurred. The Kenai Sterling 5.2 also shows this characteristic behavior to a lesser degree but no water production was reported.

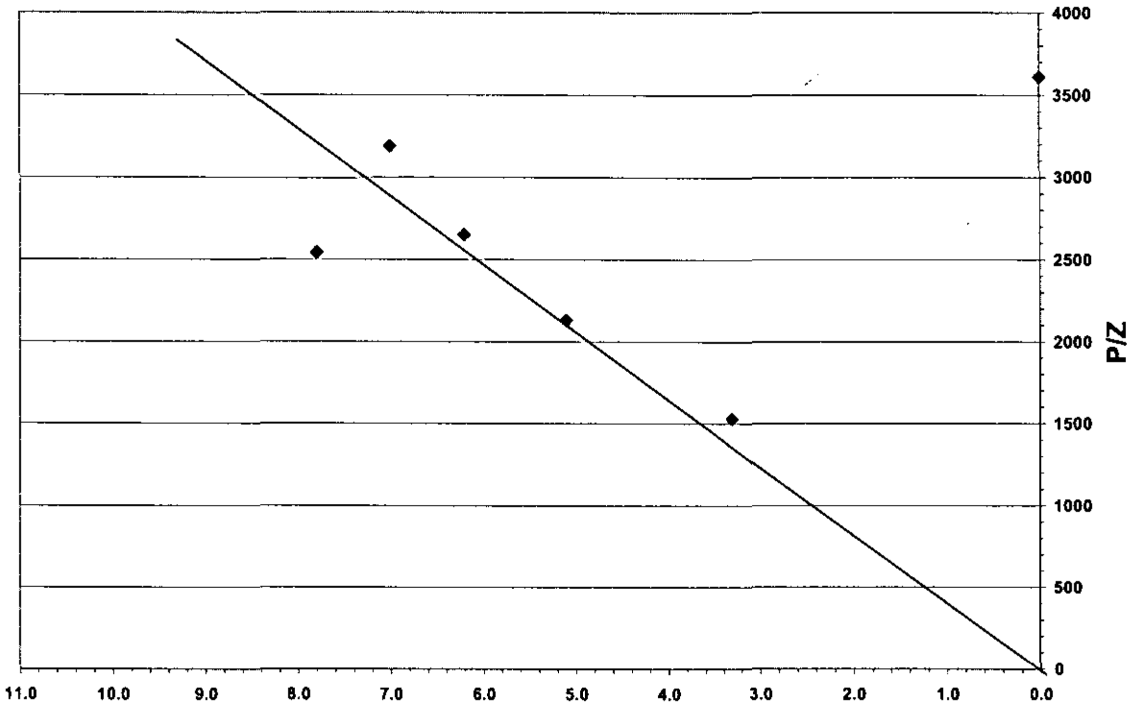
Figure A.1. Beaver Creek Beluga Pool, P/Z versus Cumulative Production



For most of the gas producing history of the Cook Inlet, supply exceeded demand; therefore, few if any wells were produced at capacity. Therefore, production history does not reflect the true deliverability of a pool in the Cook Inlet. State of Alaska production records were used to determine the average production performance of each pool on a volume per day per well during the life of the pool. These data were combined on a plot of the P/Z versus production rate as shown in Figure A.2. A best fit line was drawn to smooth the data over time and reservoir pressure. The flow rates on a per well basis were estimated from these curves for the as a function of pressure. The low rate is determined at a P/Z of 1000 and the high rate at the P/Z with 20 Bcf of Working Gas added to the remaining reserves at 2020. The pressures and rates are shown for each pool in Table A.1.

3408

Figure A.2. Beaver Creek Beluga Pool P/Z versus Production Rate



The historical Cook Inlet flow rates are thought to be restricted in many cases; therefore the flow rates used in this evaluation were increased by 50% to account for restricted flow rates. Possible rate increases resulting from stimulation treatments and current drilling and completion technology used on any new wells as shown in Table A.1 (adjusted average well rates in the last two columns in the table). Marathon recently reported on the use of their Excape completion technology that allows completion and fracture stimulation of several zones simultaneously, which decrease costs and increases well productivity. A more complete well by well examination would be required to determine the amount of rate increase possible in any pool.

Table A.2 shows the Cook Inlet Pools as ranked in Section 6. The table includes the Total Gas Required to have 20 Bcf of working gas above a P/Z of 1000, the number of existing wells, and the number of wells and deliverability with 1-to-1 infill, ½-to-1 infill, and no infill.

Table A.3 contains evaluation data developed by the same methodology used for data in Table A.1 and A.2 for the potential peaking storage pools. None of these reservoirs are expected to have any remaining reserves in 2020. The maximum deliverability is taken to be 1% of the working gas volume.

3409

Table A.1. Cook Inlet Potential Base Storage Pools: Evaluation data

Field/ Pool/ Formation	OGIP (Bcf)	2020 Status		Cushion Gas Volume[1]	P/Z with 20 Bcf Working Gas Added	Total Gas Required (Bcf)	Estimated Well Rate		Adjusted Avg. per well rate (MMcf/d)	
		P/Z	Remaining Reserves				Avg. at High P/Z (MMcf/d)	Avg. at P/Z of 1000 (MMcf/d)	High	Low
Beaver Creek										
Beluga	92.4	325	2.5	16	1800	36	4.4	2.5	6.6	3.8
Sterling	140.0	1,250	0	24[2]	1700	44	8.5	5.5	12.7	8.2
Ivan River										
Undefined	97.0	650	0	8	1,950	28	5.4	2.8	8.1	4.2
Cannery Loop										
Beluga	113.1	270	4.4	43	1,350	63	6.2	5.4	9.3	6.8
Sterling	32.0	300	0.6	9	2,520	29	15.0	6.0	22.5	9.0
Upper Tyonek	89.6	275	0.5	8	2,200	28	7.3	3.0	16.0	4.5
Kenai										
Sterling 3	375.5	225	0	146	1,120	166	5.7	5.2	8.6	7.8
Sterling 4	506.2	200	0	160	1,100	180	5.0	4.6	7.5	6.9
Sterling 5.1	538.4	250	0	178	1,080	198	4.7	4.4	7.1	6.5
Sterling 5.2	65.7	1,300	0	0	1,570	20	6.0	5.0	9.0	7.5
Sterling6	603.0	250	0	179	1,080	199	4.8	4.5	7.2	6.8
Tyonek	218.0	225	1.4	27	1,220	47	6.0	4.0	9.0	6.0
Upper Tyonek	457.4	610	22.7	60	1,210	80	1.3	1.0	2.0	1.5
Swanson River										
Sterling	39.2	330	0	9	2,580	29	13.4	5.0	20.1	7.5
Tyonek	28.0	340	0	6	3,090	25	7.4	2.4	11.1	3.6
Beluga River										
Undefined	1,614	295	83.8	628	1,020	648	12.2	12.0	18.3	18.0

1. Volume of gas required to increase P/Z to 1000 psi. Includes estimated reserves remaining at 2020.
2. This increases pressure to about 1,500 psi, which results in water-free reservoir conditions.

3410

Table A.2. Cook Inlet Potential Base Storage Pools: Number of Wells and Estimated Deliverability Rates

Rank	Pool (Preliminary Ranking – Table 6.1)	Total Gas Required (Bcf)	Wells		Estimated Delivery Rates (MMcf/d)					
			Existing wells	Number wells with 1 to 1 infill	1 to 1 infill		½ to 1 infill		No infill	
					Max[2]	Min[2]	Max	Min	Max	Min
1	Swanson River/Sterling (1)	29	4	8	160	60	121	45	80	30
2	Beaver Creek/ Beluga (2)	36	8	16	106	61	79	46	53	30
3	Ivan River (6)	28	4	8	65	34	49	25	33	17
4	Kenai/Sterling # 5.2 (5)	20	2	4	36	30	27	23	18	15
5	Swanson River/Tyonek (3)	25	4	8	89	29	67	22	45	15
6	Beaver Creek/ Sterling (4)	44	4[1]	4	51	33	38	25	25	16
	Kenai/ Sterling # 5.1 (9)	198	14	28	199	182	149	137	100	91
	Kenai/ Sterling # 4 (12)	180	14	28	210	193	158	145	105	97
	Kenai/Tyonek (14)	47	4	8	72	48	54	36	36	24
	Cannery Loop/ Beluga (10)	63	4	8	74	54	56	41	37	27
	Cannery Loop/ Sterling (7)	29	1	2	46	18	--	--	23	9
	Cannery Loop/Upper Tyonek (8)	28	2	4	44	18	33	14	22	9
	Kenai Sterling 6 (11)	199	12	24	173	163	130	122	86	82
	Kenai Sterling 3 (13)	47	9	18	155	140	112	101	77	70
	Kenai Upper Tyonek (15)	80	23	26	92	69	69	52	46	35
	Beluga River Undefined (16)	648	17	34	622	612	467	459	311	306

1. Two wells that watered out early in field life cannot be used.
2. From Table A.1, Adjusted average per well rate.

Table A.3. Cook Inlet Potential Peaking Storage Pools: Evaluation Data

Field/Pool	OGIP (Bcf)	2020 P/Z	Cushion Gas (Bcf)	Working Gas (Bcf)	Max. Rate = 1% Working Gas ((MMcf/d)
Lewis River Undefined	14.3	650	1.6	12.7	127
Sterling Beluga Undefined	15.1	400	2	13.1	131
Lone Creek Undefined	6.2	60	0	6.2	62
Beaver Creek Tyonek Undefined	6.3	600	0.5	5.8	58
Pretty Creek Undefined	11	240	5	6.0	60

APPENDIX B: Scaling criteria utilized to rank candidate gas pools as potential future base load gas storage facilities. These factors are used in constructing the various ranking tables of Sections 5 and 6. The specific criterion is shown with a range of values and the rank of 1 to 5, **with 1 being the best.**

Table B.1. Scaling Criteria to Rank Candidate Pools

CRITERION:	RANGE	RANKING	CRITERION:	RANGE	RANKING
Reservoir size	25-50 Bcf	1	Pay	>50'	1
	50-100 Bcf	2		40-50'	2
	100-150 Bcf	3		30-40'	3
	<25 Bcf	4		20-30'	4
	>150 Bcf	5		<20'	5
Depletion	<2015	1	Net-to-gross	0.8-1.0	1
	2015-2020	2		0.6-0.8	2
	2020-2025	3		0.4-0.6	3
	2025-2030	4		0.2-0.4	4
	>2030	5		<0.2	5
Proximity	<50 miles	1	Pressure	>2,000 psi	1
	50-75 miles	2		1,000-2,000 psi	2
	75-100 miles	3		500-1,000 psi	3
	100-125 miles	4		250-500 psi	4
	>125 miles	5		<250 psi	5
Porosity	>25 %	1	Cushion Gas Required	0-25 Bcf	1
	20-25 %	2		25-30 Bcf	2
	15-20 %	3		30-40 Bcf	3
	10-15 %	4		40-50 Bcf	4
	<10 %	5		>50 Bcf	5
Permeability	>1,000 md	1	Deliverability	>60 mmcf/d	1
	500-1,000 md	2		50-60 mmcf/d	2
	250-500 md	3		40-50 mmcf/d	3
	125-250 md	4		30-40 mmcf/d	4
	<125 md	5		< 30 mmcf/d	5