ALASKA LEGISLATURE COMMITTEE FILES 1995-1996 8672
8952 SENATE RESOURCES

How Governments Help Their LNG Projects

- **Modify fiscal terms to improve project competitiveness**
  - Arthur D. Little study for Government of Papua New Guinea concluded
    - + LNG projects typically not highly profitable; less profit than oil projects
    - + Government takes must be significantly less than for oil projects
    - + Gas projects given special fiscal terms
  - Countries that recently or are currently modifying fiscal terms include: Indonesia, Malaysia, Oman, Papua New Guinea, Qatar
- **Provide stability of fiscal terms**
  - Arthur D. Little study for government of Papua New Guinea concluded:
    - + Stability of fiscal terms is very important to encourage investors and financing
    - + PNG should commit to not changing fiscal terms without compensation
    - + Disputes on fiscal stability should be settled by international arbitration
  - Examples of fiscal certainty provided to LNG projects
    - + For Indonesia's Badak project, government contractually responsible for all taxes (and increases thereof) other than income tax
    - + Australia's Northwest Shelf project exempted from Resource Rent Tax
- **Participate in downstream facilities** (Abu Dhabi, Brunei, Indonesia, Malaysia, Qatar)
- **Provide necessary approvals**

Conclusions

- Producers have made good progress on project definition and costs.
- Project is not yet economic.
- A project of this size, cost and complexity will require the involvement and cooperation of many parties including both the State and Federal government.
- Significant uncertainty remains in the areas of fiscal and regulatory environment, market timing, product pricing and project costs.
- Improvements are needed to ensure the project becomes competitive.
  - Improved fiscal terms and contractual certainty needed from both State and Federal governments.
  - Timely permits consistent with project cost requirements.
  - Favorable market terms and conditions along with market assistance to rapidly place full LNG volumes.
- Costly engineering design can be justified only after progress is made on fiscal, permitting and marketing issues and when project structure begins to firm.

Next Steps

- **Role of State of Alaska in helping LNG project be competitive**
  - Identify potential roles for State (e.g., fiscal climate, permitting)
  - Develop strategy to engage the Federal government on fiscal and permitting issues
- **Fiscal terms**
  - Identify social and economic benefits of an LNG project to State of Alaska
  - Define features of contractual certainty for LNG project and all Alaskan oil and gas operations
  - Secure an agreement that defines progress toward fiscal relief, fiscal certainty and risk reduction
- **Permitting**
  - Seek an approach to permitting that recognizes goal of a cost competitive project and which minimizes project "dry hole" risks
  - Validate Producer LNG export development options
- **Seek conceptual response from market**

Memorandum
State of Alaska

To: Tony Knowles
Governor

From: Wilson L. Condon
Commissioner of Revenue

John T. Shively
Commissioner of Natural Resources

William L. Hensley
Commissioner of Commerce
& Economic Development

Bruce M. Botelho
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Date: January 22, 1996

Subject: Commercialization of North Slope Gas - What Should the State Be Doing?

I. INTRODUCTION.

What should the state government do to promote the project to pipe Alaska North Slope natural gas to tidewater, liquefy it, and tanker the liquefied natural gas (LNG) to customers in Japan, Taiwan and South Korea? The Departments of Revenue, Natural Resources, Commerce and Economic Development and Law have prepared this briefing paper to address this question. The three major North Slope oil producers (Arco, BP, and Exxon), and the Yukon Pacific Corporation (YPC), were consulted in the preparation of this paper.

Alaska North Slope proven natural gas reserves are very large, in the range of 35 trillion cubic feet (tcf). They include Prudhoe Bay at 26 tcf, Point Thomson at 3 to 5 tcf, and Kuparuk, Lisburne, and Endicott, together at 2 to 6 tcf. The amount of energy in these gas reserves is

equivalent to 6 billion barrels of oil - the amount of current remaining developed oil reserves on the North Slope.

Since 1970 various interested firms have continuously studied the possibility of commercializing these large North Slope gas reserves. First came the Gas Arctic Project of the early 1970's (a pipeline through the Arctic Refuge and up the McKenzie River to the mid-continent). Then followed the El Paso project of the mid-1970's (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to California). Next came the Alcan Project of the late 1970's and early 1980's (a pipeline to Fairbanks and then down the Alcan Highway to the mid-continent - some of the southern Canadian portions of this project were actually constructed). This was followed by the proposed Trans Alaska Gas System project (TAGS) in the early 1980's that has now evolved into the project proposed by YPC today (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to the Far East). During the 1980's and 1990's, while the TAGS sponsors were promoting their project to deliver Alaska LNG to the Far East, some of the Prudhoe Bay producers continued to study projects to deliver North Slope gas to the North American mid-continent. Recently, however, the major North Slope producers have clearly shifted the focus of their ANS gas commercialization efforts to the Far East.

Here's where things sit today. The producers recently released their findings on a proposed project that would market Alaska LNG in the Far East. Representatives of the major North Slope producers then visited potential customers in Far East markets. Representatives of YPC have just completed another of their many Far East marketing trips. Further, Phillips, a relatively minor

Prudhoe Bay producer with significant interests in a yet undeveloped North Slope gas and condensate field, Point Thomson, has recently proposed to commence the project by marketing gas from that field to expedite commencement of a North Slope to Far East LNG project.

At today's energy prices and projected construction costs, the economic feasibility of the proposed Alaska LNG project appears doubtful. Minimally, either increases in gas prices or decreases in projected construction costs must occur to make the project economically viable. If constructed, the potential revenues to the state over the life of the project under the current tax and royalty fiscal regime will be much smaller - by at least a factor of 10 - than the revenues the state will receive from North Slope oil developments over the life of those projects. However, as North Slope oil production continues its decline, proposals to commercialize the vast natural gas reserves on the North Slope inevitably draw increased attention. North Slope gas would make some contribution to state revenues, thereby somewhat offsetting the revenue loss of declining oil production. Further, many environmentalists contend that developing North Slope gas is much more environmentally responsible than further North Slope oil development.

We recommend the state address several issues now to enhance the chances that interested firms - including the North Slope lessees - will construct a North Slope gas project for three reasons. First, new marketing opportunities may soon open. Second, long lead times will be required to construct the project. Third, the competition from other countries to capture the gas marketing opportunities in the Far East are and will continue to be formidable.

We recommend you designate a working team from the pertinent executive departments to accomplish the following:

1. Determine if any modifications to the terms of the state's fiscal regime applicable to ANS gas production would significantly enhance the economic feasibility of the proposed project.

2. Carefully evaluate the costs and benefits of the potential modifications to the state's fiscal regime that would significantly enhance the economic feasibility of the proposed project;

3. Determine if there are any modifications to the federal tax structure pertaining to this proposed project the state could responsibly promote that would significantly enhance the economic feasibility of the proposed project.

4. Determine and pursue actions to facilitate federal action on permits and licenses needed for the proposed project.

5. Determine what actions the state could take with respect to its options to take its royalty share of North Slope gas production in-kind that would promote the construction of the project.

6. Determine what actions the state could take with respect to its royalty-in-kind options to maximize state benefits from the proposed project;

7. Determine and pursue actions to assist in marketing ANS gas to would-be customers in the Far East;

8. Assist in interesting would-be investors, particularly those from the Far East destination market countries, to commit to the project;

9. Evaluate whether the state should or should not invest in the proposed project;

10. Work with the Point Thomson working interest owners who have apparently expressed an interest in providing large volumes of gas for the proposed project well before 2010, the date the Prudhoe Bay producers have indicated as "most likely" for the commencement of gas deliveries from the Prudhoe Bay reservoir;

11 Work with the Prudhoe Bay producers to better understand the effect that large scale gas sales will have on future oil production from the Prudhoe Bay reservoir.

12. Evaluate the environmental considerations pertinent to the differing routes and terminal locations for the proposed pipeline project.

13. Work with the producers and YPC to ascertain what other steps the state might responsibly take to facilitate this project; and

14. Determine whether there are any other feasible commercialization options, including:

- Marketing the gas in the Lower 48;
- Converting gas on the North Slope to hydrocarbons that are liquid and can be transported in the TAPS pipeline, or
- Generating electricity on the North Slope and using high efficiency transmission lines to move the electricity to market

II. FACTORS INFLUENCING THE COMMERCIALIZATION OF NORTH SLOPE GAS.

Five major factors currently determine the feasibility of the large scale commercialization of North Slope gas. They are:

- The cost of developing the gas delivery system relative to expected gas prices
- The demand for the gas in the Far East markets and competition among potential supplies of LNG
- The pipeline economic disadvantage in competing for a place in the market
- How the sale of the gas would affect Prudhoe Bay liquid production
- The availability of an alternative North Slope gas supply prior to full scale Prudhoe Bay

gas availability

1. Cost Relative to Expected Gas Prices

Developing the transportation system to move North Slope gas to the Far East market will be very expensive. Here is what will be needed:

- Gas conditioning plant (approximately 10% of total cost)
- Pipeline to tidewater (approximately 40% of total cost for a Valdez route)
- LNG plant and marine terminal (approximately 25% of total cost)
- A fleet of LNG tankers (approximately 25% of total cost)

Both the producers and YPC currently estimate that the project would cost $15 billion. There may be opportunities to reduce the cost by $3 billion through infrastructure sharing, more efficient pipeline construction methods, larger LNG liquefaction trains, and a more economic ship design. The producers claim it would cost $100 million for a detailed engineering study to assess whether significant savings are now possible. The producers differ in their assessments of the likelihood that they will soon actually undertake such a study.

Infrastructure sharing includes:

- Use of the Prudhoe Bay compression facilities, camps and power generation for the gas conditioning plant

- Conversion of some of the TAPS pump stations to compressor stations, and using the oil pipeline workpads and state highways for the pipeline
- Use of the Valdez marine terminal facilities, civil work and loading berth for the LNG plant[1]

Pipeline construction advances include Arctic application of state-of-the-art ditching machines, use of high strength pipe, and pipe laying rates that are much faster than those used at the time TAPS was constructed.

Larger LNG liquefaction trains[2] (larger than currently available) can reduce per unit liquefaction costs.

In addition, the producers have been analyzing additional savings from pipeline routes to the northwestern Alaska coast at either Wainwright or Kivalina. These routes avoid mountains and are less than half the distance to Valdez. They would, however, require ice-breaking LNG tankers, which have never operated in pack ice before. By reducing the high fixed cost of the pipeline, the western route would afford the project the opportunity to commence operations in smaller stages and thus enhance the start-up economics of the proposed project. The staging advantage is discussed in more detail in Section II(3) below. The producers are still studying the

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[1] There is some question as to whether an LNG plant located very close to the oil facilities might violate exclusion zone requirements for LNG siting established by the U.S. Department of Transportation.

[2] A train is an individual liquefaction and shipping unit.

relative advantages and disadvantages of the western routes.

On an overall project basis, the minimum cost efficient size of the project appears to require a sale and delivery of 2 billion cubic feet (bcf) per day. This results in annual deliveries of 14 million metric tons of LNG - the unit of measure used in the Far East LNG markets.[3] The project requires a ten year lead time to achieve full operation; five years for construction, and five years to ramp-up to full production.

LNG is sold in the Far East markets on a per million British Thermal Unit (mmbtu) basis. Generally, pure natural gas - methane - has an energy content of about 1,000 btu per cubic foot; that is one million btus per thousand cubic feet (mcf). However, both the North Slope producers and YPC maintain that the North Slope gas would be "spiked" with ethane, propane, and butane to increase the energy value per unit of volume and thus to enhance its value.[4] The producers estimate the gas used for the proposed project would be spiked to 1,170 btu per cubic foot for the first ten years, and 1,100 thereafter. In the economic analysis we have done for this paper, we have assumed an average energy content of 1,150 btu per cubic foot of natural gas for the duration of the project. This "spiking" enhances the value of the gas by 15%.

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[3] To put the likely size of a gas line project in context with the current North Slope oil production operations, a two billion cubic feet per day gas line would carry the energy equivalent of about 350,000 barrels per day of oil.

[4] Ethane, propane and butane are more complex hydrocarbons often classified as "NGL's" at ordinary temperature and pressure. These substances are, however, gases. They have significantly higher energy content per cubic foot than methane.

If this project is constructed, how much will it cost to ship ANS gas to the Far East? If the project (1) costs $15 billion (both the producers' and YPC's current estimate), (2) operates for 25 years with daily throughput of 2 bcf, and (3) earns a 4% after-tax real rate of return (11.4% nominal), then it will cost $5/mmbtu to ship the ANS gas from the North Slope to the Far East.[5] This cost includes a 50 cent/mcf operating cost and a 30 cent/mcf cost pertinent to the state's 20 mill oil and gas property tax.[6] LNG today is selling for about $3.50/mmbtu in the Far East, 30% lower than the $5.00/mmbtu projected cost for transporting gas from the North Slope of Alaska to that market. At this price, these economic projections yield a negative wellhead value of $1.50/mmbtu for the project. Put otherwise, based on these projected costs, a threshold gas price of $5.00/mmbtu in the Far East markets is necessary to yield a zero wellhead value at the North Slope. It is obvious that if these costs are correct, then higher wellhead values would be required to induce investors to construct this project.

If the gas price remains at $3.50/mcf in the destination market, how would it be possible to raise the wellhead value? By reducing the capital costs for the project by one third either by significantly lowering the rate of return on the project or by greatly reducing construction costs or

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[5] This assumes 75% debt, 25% equity, with a nominal rate of return of 12.9% on the equity and a rate for the debt two percentage points below the return on equity. YPC has suggested that 75-25 is a likely debt/equity ratio for the project. We have assumed equity and debt rates of return that may not accurately reflect those that would be obtained for financing the project. We believe, however, that a real after-tax rate of return of about 4% for the project is the lowest return investors would accept. See Appendix A for a more detailed discussion of the economic analysis pertinent to this project.

[6] This 50 cent/mcf operating cost has been suggested as the likely operating cost by both the producers and YPC.

both.[7]

What about the LNG price in the Far East? For this proposed project to be economically feasible, that price would have to increase to at least $5.00/mmbtu if the project and capital costs cannot be significantly reduced.

LNG in Japan currently commands a 15% premium over crude oil on an energy equivalent basis.[8] This premium arises from several factors:

- Gas burns much more cleanly than fuels derived from crude oil.
- Gas powered units such as gas turbine electric generators are more efficient and require lower capital costs than their oil powered cousins.
- Recognizing the high costs of LNG projects, parties in the Far East markets have negotiated premiums for LNG with respect to crude oil at low oil prices, and corresponding discounts at high oil prices

It follows that a $5/mmbtu LNG price is equivalent to a price of $25 per barrel (bbl) for crude oil

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[7] Pursuant to the settlement agreement governing the TAPS tariff, the TAPS oil pipeline has been permitted to earn a 6.4% after-tax real rate of return (15% nominal). The gas pipeline should be less risky than TAPS. A strong argument can be made that a 4% after-tax real rate of return will be required for this project. See Appendix A for a more detailed discussion.

[8] Currently crude oil prices in Japan are between $17 and $18 per barrel. There are 5.8 times as many btus in a barrel of crude oil as an mcf of gas. Thu the following equation -- 5.8 X 3.5/17.5 = 1.16 -- tells you that a btu of energy derived from LNG selling for $3.50/mmbtu costs 16% more than a btu of energy derived from crude oil selling for $17.50/bbl.

In other words, given the current relationship between oil prices and gas prices, oil prices would have to be $25/bbl in order for North Slope gas to provide a 4.1% real rate of return on the proposed transportation investment and leave a zero North Slope wellhead value. Currently crude oil sells for about $17-18/bbl in Japan. If LNG did not command a premium over crude oil, the equivalent oil price in the Far East would have to be $29/bbl.

Appendix A sets forth a more detailed discussion of the economics of the proposed ANS LNG project.

2. Far East Demand for LNG and Competition Among Potential Suppliers.

Current LNG consumption in the Far East is about 55 million metric tons per year (mmty).[9] LNG consumption has been increasing at 6% per year since 1980, and is expected to grow between 5% and 10% annually through 2010. However, exponential growth cannot continue in this market indefinitely. Therefore, we have used a 6% annual growth rate for LNG demand in the Far East for planning with respect to this proposed project. Six percent annual growth would result in LNG consumption in the Far East markets of about 100 mmty in 2005 and 130 mmty in 2010.

There is no unsatisfied demand in the Far East LNG markets before the year 2000. Contracts sufficient to fill all the anticipated increases in the Far East demand through the end of this decade are already in place.

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[9] The proposed North Slope to Far East gas transportation project operating at 2 bcf per day would supply 14 mmty - about 25% of the current supply. The 55 million tons of LNG consumed each year in Far East markets is the daily energy use equivalent of about a million and a half barrels of oil per day - about the volume that currently flows through TAPS.

The LNG market opportunities are significantly different than the market opportunities for crude oil. There are few LNG buyers. Because of the large up-front investments required for an LNG project, and to reduce risk, long term contracts must be in place before the producers, the buyers or YPC would commence construction of the ANS gas transportation project.

The competition for selling LNG to the Far East is considerable. The following table shows, by country, existing supplies

CURRENT SUPPLY TO FAR EAST LNG MARKET	
Location	Gas Supply (mmty)
Alaska (Cook Inlet)	1
Abu Dhabi	5
Brunei	7
Indonesia	27
Australia	7
Malaysia	8
Total	55

Capacity to supply an additional 8 mmty from Malaysia and 6 mmty from Qatar is currently under construction. Relatively low cost expansion of existing LNG facilities in Australia, Indonesia, and Malaysia of 5 mmty each (a total of 15 mmty) are under serious consideration

The following table summarizes the existing supplies, supplies currently under construction, and available low cost expansion opportunities at existing LNG plants

CURRENT AND NEAR TERM LNG SUPPLIES TO FAR EAST MARKET	
Source	**Gas Supply (mmty)**
Existing Supplies	55
New Plants Under Construction	14
Low Cost Expansion Opportunities Available	15
Total	**84**

Including the North Slope, new grass roots projects could add the amounts reflected in the following table.

LARGE NEW LNG PROJECTS PROPOSED TO SUPPLY THE FAR EAST MARKETS	
Location	**Gas Supply (mmty)**
Alaska	14
Australia	13
Indonesia (Natuna)	15
Oman	6
Papua New Guinea	6
Qatar	15
Sakhalin	10
Yemen	5
Total	**84**

The Qatar, Oman and Yemen projects appear to be in the advanced planning stages. The Indonesian project is the giant Natuna field, for which Exxon is the proposed operator. Given the large size of both the proposed Natuna and Prudhoe Bay projects, there is - at most - room for

only one of these as a source of supply in the Far East LNG market in the near term. At full development it would appear that the proposed Natuna project is more expensive per mcf delivered than the proposed North Slope project. However, the Natuna project can be staged in increments, staging the North Slope project severely affects its economics, especially with a Prince William Sound terminal.

The gas reserves in most of the countries supplying the Far East LNG market are very large and are expanding. Much of this gas was found in the course of exploring for oil. These gas supplies are more than ample for current markets. If deliberate exploration for gas ensued, it is likely that these gas reserves would increase substantially. The following table shows 1993 year-end gas reserves for selected countries.

CURRENT RESERVES OF MAJOR FAR EAST MARKET LNG SUPPLIERS	
Country	**Reserves (tcf)**
Abu Dhabi	177
Australia	100
Indonesia	89
Malaysia	72
Qatar	236
Total	**674**

Alaska has about 35 tcf in discovered reserves on the North Slope.

If demand in the Far East LNG market continues to grow 6% annually, the demand in 2005 will

be 100 mmty. Given apparent lower cost supplies of 84 mmty from existing, under construction, and low cost expansion sources, this leaves 16 mmty for new grass roots suppliers. At a 14 mmty minimum, an Alaskan project would have to capture 88% of the projected unfilled demand in 2005 to be able to fit into the market. Using the same assumptions, the demand in 2010 would be 130 mmty. Of this, 46 mmty would be available for grass roots projects for which construction has not yet commenced, a new Alaska project coming on line in 2010 would have to capture 30% of this projected unfilled demand.

3. The Pipeline Economic Disadvantage in Competing for a Place in the Market.

Of all the grass roots projects, Alaska is the only one which requires a major pipeline to bring the gas to tidewater. Nearly half of the total anticipated construction cost for the proposed Alaska project is attributable to the pipeline. The pipeline is a burdensome one-time, up-front cost that places the proposed Alaska project at a competitive disadvantage.

The proposed Alaska gas project only achieves the economies of scale which make it feasible at its full 14 mmty proposed capacity. While many of the competing projects also have comparable per unit costs, they attain those costs at much lower production levels. This is particularly true for the projects proposed in Qatar, Oman and Yemen. The need to cover the costs for the one-time, up-front pipeline investment is what makes the proposed Alaska project different. It may only be economic if its sponsors can begin the project at full capacity. Placing 14 mmty at once in the Far East LNG market may be difficult, given that multiple buyers will need to simultaneously commit

to the project.

Increments to existing projects have a "nimbleness" advantage to big new baseload, grass roots projects. Suppose there is just enough room in the marketplace in 2005 for the proposed Alaska project - 14 mmty. If any small addition to an existing project captures *any* part of the 14 mmty demand in the marketplace, the Alaska project may not be able to make a go of it. Furthermore, proposed increments to already existing LNG projects in most cases have a per unit cost advantage over the per unit costs of new grass roots projects.

Projects without major pipelines do not necessarily require as high a proportion of their investment up front. Ships and liquefaction facilities can be added in increments. Pipeline capacity cannot easily be added in increments. Therefore, projects which require a high proportion of investments in pipelines must capture bigger increments in the developing markets to be economic. This necessarily provides any project without a substantial pipeline leg an advantage. For this reason the producers have looked - and will continue to look - carefully at the proposed western route. Even though the tanker costs, the offshore loading terminal costs, and the risk of supply disruptions pertinent to the proposed western route would be higher, reducing the proposed project's pipeline cost might make it possible to achieve competitive costs at reduced production levels. The western route project might well be economic with initial volumes well below 14 mmty. Obviously if the required initial amounts are smaller, it would be much easier to fit such a project into the market.

The problem created by the large minimum size of the North Slope project is further exacerbated by the number of buyers that would be required to consume the proposed project volume. Most likely the need to find buyers for this new large volume all at once will require sales to several customers in more than one country, and the sale to any one customer is likely to be dependent on sales to all other customers. This could make marketing the ANS gas a complicated endeavor.

4. The Role of Gas in Prudhoe Bay Liquid Production.

Currently the highest and best use of the gas in the Prudhoe Bay reservoir is to facilitate the production of liquids. Gas reinjected into the reservoir increases liquid recovery as a result of several different recovery mechanisms. When does it make sense to sacrifice liquid recovery for gas production? The answer is: when substituting gas production for liquid production results in a more valuable stream of total outputs from the reservoir. Today the highest value is achieved by maximizing liquid production from the North Slope because the liquid streams are so much more valuable than the likely flow of gas. As liquid production rates decline, however, a time may come when the potential gas stream will become more valuable than that of the liquids sacrificed by sending the gas to market. The volume of liquids sacrificed declines every year the project is delayed.

The liquid recovery mechanisms at Prudhoe Bay all depend directly or indirectly on reservoir pressure. Production is facilitated by higher pressure, which pushes the oil out of the rock. The pressure in the reservoir depends mainly on the amount of oil, gas and water in the reservoir. Because of its compressibility, reinjection of produced gas is the primary mechanism used to

maintain pressure in the Prudhoe Bay reservoir. Injection of sea water and produced water are also major elements in the Prudhoe Bay reservoir pressure maintenance program.

A Major Gas Sale (MGS) of Prudhoe Bay gas would permanently remove the gas from the Prudhoe Bay reservoir and consequently accelerate the decline in reservoir pressure. The pressure in the Prudhoe Bay reservoir is currently declining at 30 pounds per square inch (PSI) per year. When production began in 1977, the Prudhoe Bay reservoir pressure was 4,200 PSI, today it is 3,400 PSI. The producers estimate that an MGS would triple the rate of annual decline to 90 PSI unless new steps were taken to mitigate some of the loss. There is no disagreement that in the short run (next 8-10 years) accelerated reservoir pressure decline would result in less ultimate oil production. There is some disagreement as to the timing and total volume loss associated with the proposed gas pipeline project, and on the manner in which the loss might be mitigated. However, there appears to be no guaranteed, low cost way to mitigate these losses [10]

Thus the optimal date for an MGS depends on the expected performance of the Prudhoe Bay reservoir as well as predicted oil and gas prices. The longer the expected benefits from gas

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[10] Where maintaining high reservoir pressure is necessary to maximize liquid recovery, in some locations around the world the natural gas may be valuable enough to justify marketing it and replacing it in the reservoir with another gas - usually nitrogen cryogenically recovered from the atmosphere. The producers at Prudhoe Bay have considered this option, but the projected wellhead value of Prudhoe Bay gas has always been too low to justify it. Similarly, the Prudhoe Bay producers have considered attempting to mitigate pressure losses through expanded waterflood, they have concluded that would be destructive to gravity drainage in other parts of the reservoir and to oil well hydraulic performance. Finally, the Prudhoe Bay producers have considered injecting water into the apex of the gas cap (as opposed to the oil rim), this step, they believe, could eliminate much of the liquid recovery achieved by the vaporization of residual liquids in the gas cap that occurs with gas cycling.

pressure maintenance and gas cycling, the later the optimal date for commencing an MGS. However, very late in the life of the field, losses in liquid production as a result of an MGS become quite small relative to the value of a gas sale. In addition, the economies of scale realized by producing and selling both oil and gas from the same facilities are such that an MGS would probably extend the time during which oil production would continue to be economic. To the extent an MGS would extend field life, liquid losses would be negated. Likewise, there could be some accelerated oil recovery benefits realized due to increased gas handling capacity resulting from an MGS after 2015.[11]

The producers now believe that 2005 would be the earliest appropriate time to possibly begin deliveries pursuant to an MGS. They contend that 2010 is the "most likely" time they would commence deliveries under an MGS. The producers have selected the year 2005 as the earliest appropriate time for three reasons:

- The liquid loss after 2005 from diverting gas for commercialization may be de minimis
- The producers believe 2005 will be a good time to enter the markets (see section on demand above)

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[11] As the field matures more and more gas is produced with each barrel of oil. Currently approximately 7.5 billion cubic feet of gas are produced each day with the oil at Prudhoe Bay. Oil production capacity is constrained by the ability to process and reinject this large volume of associated gas. Depending on the North Slope equipment scheme ultimately installed, some gas handling capacity is freed up as some gas is diverted for sale. Increasing the gas handling capacity at Prudhoe Bay would certainly result in acceleration of oil recovery, but probably not in significant additional oil recovery. Gas handling capacity probably cannot increase, however, until the waterflood/EOR project ends (around 2015), because of the bottleneck caused by the limited gas dehydration capacity of the flow stations/gathering centers.

- The intra-field compensatory agreements between the oil rim and gas cap owners will mostly be completed then [12]

Regarding the liquid losses, the producers now estimate that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of the Prudhoe Bay field. They estimate a loss of 100 million barrels of oil for a 2010 sale. The significance of those losses will depend on the relative prices of oil and gas as well as actual operation and development decisions made over the next ten years. For instance, if we assume the wellhead values of Prudhoe Bay oil currently forecast by the Department of Revenue, then the gas must be worth at least 40 cents per mcf at

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[12] The Prudhoe Bay field is unitized with two participating areas: the oil rim and the gas cap. BP owns a relatively higher percentage of the oil rim (51%), and Arco and Exxon own relatively higher percentages of the gas cap (42% each). The gas cap currently has 70% of the gas resources and the oil rim 30%. Thus BP still owns 25% of the overall gas reserves, and has no apparent motive for being disinterested in commercializing the Prudhoe Bay gas absent negative impacts on oil production. Pursuant to an order from the Alaska Oil and Gas Conservation Commission, the working interest owners are currently attempting to unitize the two properties

In 2005 the fuel gas supply option, whereby the oil rim owners are obligated to secure a certain volume of gas from the gas cap owners to fuel field operations, lapses

Also, major gas sale delay credits cease in 1997. These are reimbursements of payments of the oil rim owners to the gas cap owners for early investments made by the gas cap owners in anticipation of an early gas sale. The oil rim receives some of their already-paid reimbursements back if there is an MGS before 2005

In addition, through another agreement, in 2005 the gas cap owners will beg to supply half the gas needed to make miscible injectant for enhanced oil recovery operations. Currently the oil rim owners supply all of the gas. This will release oil rim gas for sale

There are other incentives in the unit operating agreements for the oil rim owners to support an MGS. Upon an MGS, the gas cap owners will pick up significantly higher proportions of the operating costs of the field. Further, once an MGS occurs the oil rim owners get allocated proportionally more liquids

the wellhead to offset the value of the barrels lost as a consequence of a gas sale commencing in 2005. To offset the loss of barrels for a gas sale commencing in 2010, the gas wellhead value must only be 15 cents/mcf. The likely level of gas prices is discussed more fully above. These "loss" estimates assume a five year ramp-up to 2 bcf of gas per day sold from Prudhoe Bay. Appendix C describes the derivation of these loss projections.

5. Point Thomson - A Potential Supply Source Prior to Prudhoe Bay Gas Availability?

Phillips Petroleum has recently suggested the use of gas from the Point Thomson field to jump start the proposed ANS gas project. The Point Thomson reservoir, a large gas and gas condensate reservoir which overlies a very thin oil rim, is located 60 miles east of Prudhoe Bay. The Department of Natural Resources estimates the reservoir contains 3 tcf of recoverable gas reserves; some producers have estimated the reservoir contains 5 tcf. The reservoir is included in the Exxon-operated Point Thomson Unit.

Phillips, one of the Point Thomson working interest owners - which has interests with co-lessees Mobil and Chevron (together these companies are often referred to as MPC with respect to their jointly leased North Slope properties) - is willing to commit its gas now to the YPC project. Together MPC owns the leases which cover 47% of the surface acreage included in the unit and claim to have a higher percentage of the recoverable reserves in the unit. Phillips believes it may be able to supply up to 1 bcf per day of natural gas from this reservoir for up to five years. If

supplying this amount was indeed feasible, early Point Thomson production could assist in making it possible to commence a North Slope gas project before significant volumes of gas are required from the Prudhoe Bay reservoir. Early gas sales from Point Thomson could allow a gradual phase in of gas sales from Prudhoe Bay.

There are many technical questions that would have to be addressed with respect to this Point Thomson proposal. The Point Thomson reservoir is a very high pressure retrograde condensate reservoir; that means liquids drop out of the gas recovered from the reservoir when the pressure of the gas drops. Under the Phillips proposal would the gas be kept at high pressure and moved to Prudhoe Bay for liquid recovery? Can gas production at the volumes Phillips proposes occur without dropping reservoir pressure to the point where there are significant volumes of liquid lost in the reservoir? Since the Point Thomson reservoir pressure is so high (almost right at 10,000 PSI), doesn't it make sense to produce the reservoir until the pressure drops to the 4,000 - 5,000 PSI range before reinjection and cycling commence to avoid the very high reinjection costs that a 10,000 PSI reservoir would require? If the answer to that question is "Yes," doesn't that suggest that the Phillips proposal may have merit in promoting the development of the Point Thomson resource?

The cost of bringing Point Thomson reserves to the Prudhoe Bay area would, of course add to the cost of the pipeline portion of the project.

III. OTHER CONSIDERATIONS.

1. What's in it for the State.

On the revenue side, under the applicable fiscal regime the State will receive severance taxes, royalties and property taxes from the gas project. The property tax will be the most significant. With $11 billion of assessed property (which excludes the ships), the 20 mill Oil and Gas Property Tax will yield $220 million per year initially, the tax revenue from this tax will decline with the depreciation of the property. Half of the revenue from this tax will go to cities and boroughs. This tax will affect the economics of the project two ways. First, because it applies during the construction period, it is a large additional up-front cost imposed on the project; second, once the project is operating, the annual property tax bill will add 30 cents per mcf to the operating costs of the project on an equivalent amortized basis.[13]

If the netback from the Far East yielded a 50 cent/mcf wellhead value, taxes and royalties would total $60 million annually. Based on current cost projections, a 50 cent wellhead value would be achieved only if LNG prices were $5.50/mmbtu in the Far East (and oil prices were $27.50/bbl - see discussion in Section II(1) above). Under the current applicable state corporate income tax statute, the state would receive about $30 million per year in corporate income taxes from the project. Thus, if world energy prices increase by 60 percent, the state could expect about $190 million per year in taxes and royalties from the project during the early years of operation. That amount would, of course, decline as the value of the gas pipeline depreciated.

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[13] The $5/mmbtu LNG cost discussed on page 10 in Section II(1) includes the amount of this tax.

Construction of a pipeline to transport gas from the North Slope to Valdez would create 10,000 construction jobs and 600 permanent operational jobs. A pipeline following the TAPS corridor would also make natural gas available to Fairbanks, Valdez and other smaller communities along the route.

An MGS would enhance the economics of other gas deposits on the North Slope.

In addition, as discussed above, the commercialization of gas late in the life of the Prudhoe Bay reservoir would probably enhance oil production economics as well.

2. <u>The Role of Yukon Pacific.</u>

YPC has been active in promoting an ANS LNG project that would use the TAPS route to Valdez. YPC is a subsidiary of CSX Corporation, a conglomerate with holdings concentrated in transportation. CSX owns one of the nation's largest railroads, and it owns Sealand. As a consequence of other business involvements, CSX has had significant experience in marine transportation and in certain aspects of the gas business.

YPC has spent large amounts of time and money obtaining several of the major permits necessary to transport and market gas. These include:

- Presidential finding for the project.
- Project-wide environmental impact statement.

- Federal right-of-way.
- State right-of-way.
- Department of Energy authorization for export of gas.
- Final environmental impact statement for a liquefaction plant at Anderson Bay near Valdez.
- FERC order granting authorization for LNG facility siting.

Although the degree to which some of these permits may be exclusive is questionable, there is considerable time, expense, and expertise invested in their procurement.

The North Slope producers clearly have the right to utilize the Prudhoe Bay gas for oil production as long as they are not wasting the gas. They also have the right to market the gas. If Prudhoe Bay gas commercialization yielded a higher net present value than utilizing the gas in the field to maximize oil production, the state might be able to take action to compel the producers to market the gas. In the absence of some sort of successful state action to compel Prudhoe Bay gas sales, YPC must depend solely on the oil rim and gas cap owners to obtain Prudhoe Bay gas.

There are disagreements among YPC and the producers. YPC has argued that based on the public statements made by the producers, there is no reason the gas should not be currently available for sale. YPC has also argued that: (1) the Prudhoe Bay producers will not sell the gas because of intra-owner conflict in the field resulting from the disparate oil/gas ownership, (2) specific companies are improperly advancing their own interests either in the field or in other places in the

world with a decision not to sell even though, according to YPC, selling would maximize the overall benefits from the Prudhoe Bay Reservoir; and (3) the State should take action to force the Prudhoe Bay producers to enter into an MGS. We believe there are sound engineering and economic reasons behind the current plans for short term and mid term gas use at Prudhoe Bay.

IV. WHAT SPECIFIC ACTIONS HAVE THE VARIOUS PARTIES URGED THE STATE TO CONSIDER?

Following are some of the ideas interested parties, including YPC and the producers, have urged the state to study:

1. Taking action to force the Prudhoe Bay producers to sell their Prudhoe Bay gas;
2. Using the state's royalty-in-kind share of Prudhoe Bay gas to promote the proposed project;
3. Marketing the state's royalty-in-kind share of Prudhoe Bay gas along with the producers to promote the project;
4. Agreeing to commit the state's royalty-in-kind share of Prudhoe Bay gas to the project at a fixed (and possibly discounted) price.
5. Altering the 20 mill Oil and Gas Property Tax so it does not impose another large front-end cost on the project, and
6. Altering the state's basic fiscal arrangements so that the state takes an equity interest in the entire project up stream from the LNG tankers, and, in exchange, agrees to forego royalties, severance tax and the 20 mill Oil and Gas Property Tax

These questions should all be addressed in conjunction with the implementation of the 14 recommendations set forth on pages 4, 5 and 6 of this briefing paper.

APPENDIX A

Alaska North Slope Gas Transportation System Feasibility

The Relationship Between Required Rate of Return and Far East Market LNG Prices

At today's energy prices and projected construction costs, the proposed North Slope gas project is economically feasible if and only if the project's would-be investors are willing to accept a fairly low rate of return for the project. Consequently, it is unlikely these firms will be willing to provide the necessary financing to construct the project unless they are convinced of one or more of the following:

1. The project is, in fact, a very low risk project;
2. The price of LNG in the Far East is likely to increase significantly in the next few years thereby providing a much higher return for the proposed project than would be available at current prices, or
3. The project construction costs will be significantly lower than the current estimate of $15 billion.

An investor's willingness to invest depends on the balance of anticipated risk and reward from the investment. Citizens are willing to invest in passbook savings accounts with their relatively low returns (approximately 4.5% today) in part because the U.S. government insures that depositors will get their money back virtually any time they want it. On the other hand, high-risk investments command higher returns to compensate investors for the risk. For example some

computer venture start-ups are currently yielding returns near 25% to their investors. For large projects, a firm's willingness to invest will depend on the perceived risk and reward of the project compared to other opportunities for investing available funds. A firm will invest in projects with the highest anticipated return balanced against the anticipated risk. Projects compete for financing based on their perceived risk and rates of return.

For example, to assure a 7% nominal rate of return (1.5% after-tax real), the proposed North Slope LNG project would need a $3.65/mmbtu price floor in the Far East and a zero wellhead netback (the current Far East LNG price is $3.50/mmbtu). But, one can get this same return by making a riskless investment in the government bond market.

We do not know precisely the risk would-be investors will perceive in the proposed North Slope gas transportation project. Will the project face a significant marketing risk? It is highly likely that if the project is constructed there will be little risk that the project will not have guaranteed customers. The contracts for LNG sales in the Far East would almost certainly be in place prior to construction commencement. How about the risk of very low energy prices? Far East LNG contracts are almost universally pegged to the price of oil and other energy supplies, but if oil prices fall below a certain level, the gas prices may be subject to renegotiation. To insure a 2% after-tax real rate of return, this project needs a $3.90/mmbtu price floor in the Far East. What happens if the project costs $18 billion rather than $15 billion? Then the very low return realized at today's energy prices would become negative.

Will the perceived risk of this proposed project require a return equal to or greater than: (1) a thirty year treasury bond, (2) a AA corporate bond, (3) a BBB corporate bond, (4) the return equity investors currently receive for investing their funds in developed, stable utility companies, or (5) the return earned by investors in the Trans Alaska Pipeline System (TAPS) as a consequence of the tariff settlement agreement?

The charts that follow use "after-tax real" rates of return. It may be helpful to explain briefly the relationship between "after-tax real" and "nominal" rates of return. After-tax real rates of return are the returns realized after making an allowance for inflation and income taxes.

The after-tax real rate of return is the difference derived by subtracting the inflation rate from the product of the nominal rate of return multiplied by the difference obtained by subtracting the tax rate from one. It may be easier to understand this equation by expressing it algebraically as follows:

After-Tax Real Rate of Return = [Nominal Rate of Return * (1 - Tax Rate)] - Inflation Rate

To work through an example, take the applicable 30 year U.S. Government Bond rate, which currently provides a return of 6%. Further, assume an effective combined corporate income tax rate of 38.0% (35% federal and 4% composite state)[1] and an inflation rate of 3%.

[1] Since the state tax is deductible for federal taxes the combined rate is 38%.

After-Tax Real Rate of Return = [Nominal Rate of Return * (1 - Tax Rate)] - Inflation Rate

= [0.06 * (1-0.38)] - 0.03

= 0.0072, or 0.72%

The following table compares the nominal returns in today's marketplace with the corresponding after-tax real returns. Again the basic assumptions are a 38% effective combined corporate income tax rate and a 3% inflation rate.

NOMINAL AND REAL RATES OF RETURN		
	Nominal Rate of Return	**Real After Tax Rate of Return**
30 Year Treasury	6.0%	0.72%
AA Corporate Bond	6.8%	1.22%
BBB Corporate Bond	7.4%	1.59%
Rate of Return Received by Equity Investors in Developed, Stable Utility Projects	10.5%	3.51%
Rate of Return Selected for Illustrative Purposes for the Proposed ANS Gas Transportation Project	11.4%	4.07%
Rate of Return Permitted TAPS Owners under TAPS Tariff Settlement	15.0%	6.40%

On the basis of this information, is a 4% after-tax real rate of return required to attract investors to the proposed ANS gas transportation project? Is it too high? Is it too low? The following

analysis uses that rate of return for illustrative purposes. There are many good arguments that this 4% after-tax real rate of return is in the neighborhood of the return investors would require to invest in the proposed North Slope LNG project. One could certainly make the case that the proposed Alaska to Far East LNG project would be less risky than TAPS. There is virtually no risk that the gas cannot be produced from the reservoir. There would be a set contract in place guaranteeing a price. Construction of the TAPS project proved that such a large Arctic project can be done. The builders of the proposed LNG project can profit from the TAPS construction experience.

Figure 1 below shows the price LNG must receive in the Far East to yield various after-tax real rates of return on the proposed project.

Figure 1
The Relationship Between Far East LNG Prices & Return on the Proposed North Slope Gas Transportation Project

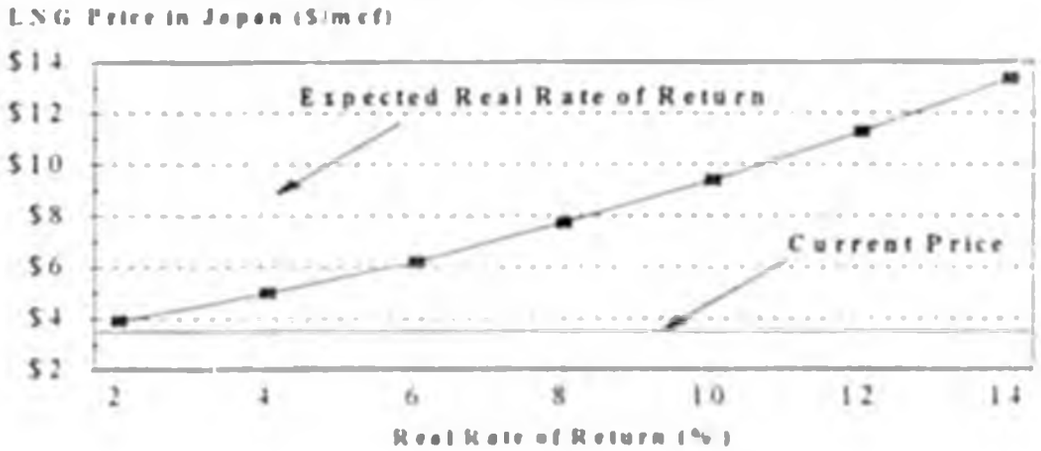

Figure 1[2] shows that to obtain a 2% after-tax real rate of return on the proposed $15 billion transportation project with a twenty-five year project life, the price of LNG in the Far East would have to be $3.90/mmbtu, at this price the project would yield a zero wellhead value. The current price in Japan is $3.50/mmbtu. This equates to an after-tax real rate of return on the project with a zero wellhead value slightly under 2%. Using the same assumptions, Figure 1 shows that a 4% after-tax real rate of return with a zero wellhead value requires a $5.00/mmbtu sales price in the Far East.

In addition to using equity to finance part of the project, the investors will probably make arrangements to issue debt to finance a portion as well. For many reasons, the interest rates on the debt issued to construct the proposed LNG project will probably be lower than the return required to attract equity capital.

For the analysis in this briefing paper, we have assumed the project would be financed by 75% debt and 25% equity. The debt/equity ratio could vary widely. We have assumed a nominal rate of return on the equity portion of the investment of 12.9%, for the debt we have assumed a nominal rate of return 2% below the equity rate. These assumed rates of return may not accurately reflect those that would be obtained for financing the project. We believe, however, that a combined real after-tax rate of return of about 4% for the project is the lowest return investors would accept.

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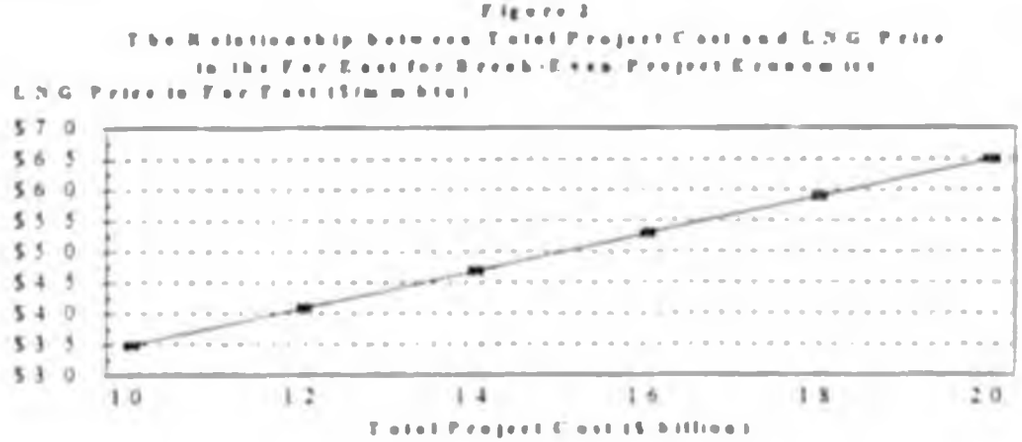
[2] These figures include a $0.50/mcf operating cost and a $0.30/mcf 20 mill oil and gas property tax payment.

At a 4% real after-tax rate of return on the project, a price of $5.00/mmbtu in the Far East would be required to yield a zero wellhead value. If the project were 100% debt financed, the required Far East price would be $4.50/mmbtu. If the project were 100% equity financed, the required Far East price would be $6.40/mmbtu.

Figure 2 depicts the break-even gas price required in the Far East at different project construction costs. For this comparison the assumed financing arrangements are: (1) 75% debt and 25% equity; (2) the equity portion requires a 5% real after-tax rate of return; (3) the debt portion of the project is financed at a rate 2% less than the nominal equity return; and (4) the inflation rate over the life of the project is 3%. At the current project cost estimate of $15 billion, the required destination price in the Far East is $5.00/mmbtu. Figure 2 shows that it would take a one-third reduction in project construction costs, to $10 billion, for the current price in the Far East, $3.50/mmbtu, to yield a zero wellhead value on the North Slope.



APPENDIX B

Technical Description of Gas Line Rate of Return Model

The gasline rate of return (ROR) model computes a levelized per mcf amount that computes break-even transportation costs for the entire system, including the tankers, at a specified rate of return. The model uses a cost of service methodology. The levelized cost is the total discounted cost divided by the total discounted volume. There are six cost components: depreciation, operating costs, property tax, income tax, interest, minimum cents per mcf severance tax[1], and after tax margin (profit or the return on base equity investment).

The after-tax margin is the product of the nominal rate of return and the undepreciated equity capital. The income tax allowance is the product of the tax gross-up factor and the after tax margin. The tax gross-up factor is that number which when multiplied by the after tax margin yields the state and federal corporate income tax amounts given the cost of service for the given year[2].

In this model we assumed no inflation for the system components and 3% for the economy as a whole. We have also assumed 75% debt and 25% equity, with the cost of debt at two percentage

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[1] The minimum cents per mcf severance tax is 6.4 cents. We have assumed an economic limit factor of 0.8.

[2] Given a state corporate income tax rate of 9.4% and a federal corporate income tax rate of 35%, the tax gross-up factor is

$$(.094 + (.35 \times (1 - .094))) / (1 - (.094 + (.35 \times (1 - .094)))) = 0.6981$$

points below the nominal rate of return.

Other key assumptions include:

- $15 billion in capital costs
- $11 billion in non-ship capital subject to the property tax
- 2 million mcf per day for 25 years
- 5 year ramp-up
- $0.50/mcf operating costs
- 1.1 mmbtu to mcf ratio

The model is shown on the following table.

[illegible] ROR Model

Operating cost	0.5
Capital Cost	15000
[illegible]	0.733333333
Years	25
Real Equity ROR	5
Nominal Equity ROR	12.90
Nominal Debt ROR	10.90
Tax Gross-up factor	0.6901
Percent Equity	0.25
Percent Debt	0.75
HHV Adj	1.15
Return on Capital discount	11.01

Year	Gas Volume (Bcf/d)	Gas Volume (Bcf/yr)	Operating Cost	Depreciation	Undepreciated Amount for Property Tax	Property Tax	Depreciation (for return)	Undepreciated Amount - for return	Return on Base (after tax margin)	Income Tax Allowance	Interest	Severance Tax	Cost of Service	Discount Factor	Discount Cost	Discount Volume
0	0.4	146	73	600	15000	220	194	4851	626	437	1432	7	3395	0.941	3195	137
1	0.8	292	146	600	14400	211	194	4657	601	419	1432	13	3421	0.834	2851	243
2	1.2	438	219	600	13800	202	194	4463	576	402	1432	20	3451	0.738	2548	323
3	1.6	584	292	600	13200	194	194	4269	551	385	1432	26	3480	0.654	2275	382
4	2	730	365	600	12600	185	194	4075	526	367	1432	33	3508	0.579	2032	423
5	2	730	365	600	12000	176	194	3881	501	350	1432	33	3456	0.513	1773	375
6	2	730	365	600	11400	167	194	3687	476	332	1432	33	3405	0.454	1547	332
7	2	730	365	600	10800	158	194	3493	451	315	1432	33	3354	0.402	1350	294
8	2	730	365	600	10200	150	194	3299	426	297	1432	33	3303	0.356	1177	260
9	2	730	365	600	9600	141	194	3105	401	280	1432	33	3251	0.316	1026	231
10	2	730	365	600	9000	132	194	2911	376	262	1432	33	3200	0.280	895	204
11	2	730	365	600	8400	123	194	2716	351	245	1432	33	3149	0.248	780	181
12	2	730	365	600	7800	114	194	2522	325	227	1432	33	3097	0.219	679	160
13	2	730	365	600	7200	106	194	2328	300	210	1432	33	3046	0.194	592	142
14	2	730	365	600	6600	97	194	2134	275	192	1432	33	2995	0.172	515	126
15	2	730	365	600	6000	88	194	1940	250	175	1432	33	2944	0.152	449	111
16	2	730	365	600	5400	79	194	1746	225	157	1432	33	2892	0.135	390	99
17	2	730	365	600	4800	70	194	1552	200	140	1432	33	2841	0.120	340	87
18	2	730	365	600	4200	62	194	1358	175	122	1432	33	2789	0.106	295	77
19	2	730	365	600	3600	53	194	1164	150	105	1432	33	2738	0.094	257	68
20	2	730	365	600	3000	44	194	970	125	87	1432	33	2687	0.083	223	61
21	2	730	365	600	2400	35	194	776	100	70	1432	33	2635	0.074	194	54
22	2	730	365	600	1800	26	194	582	75	52	1432	33	2584	0.065	168	48
23	2	730	365	600	1200	18	194	388	50	35	1432	33	2533	0.058	146	42
24	2	730	365	600	600	9	194	194	25	17	1432	33	2481	0.051	127	37
														Total	25828	4497

levelized cost and	5.74
btu adj	1.15
break-even price ($/mmbtu)	4.99

APPENDIX C

Technical Explanation for Estimating the Value of Lost Oil

Currently the highest and best use of gas at Prudhoe Bay is to facilitate oil production. The producers have estimated that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of Prudhoe Bay, and a 2010 sale would result in a 100 million barrel loss.

The significance of those losses depend on the relative values of oil and gas. Because of the time value of money these values are dependent on the time profile of the losses. The projected time profile of these losses is shown below.

The loss in oil reserves is a function of cumulative gas removed from the reservoir over time. A uniform series time rating function relates the loss of an mcf of gas to both an immediate loss of oil and a loss of oil through time.

We estimated time series of reserves losses for both 2005 and 2010 sales. These losses were multiplied by the respective predicted oil price for the subject year and discounted at 10%. The total discounted losses were divided by the total discounted volume of gas. This represents the wellhead price of gas that would make the producers indifferent to the reserve losses.

For a 2005 sale the gas price is $0.40/mcf, and for 2010 the price is $0.15/mcf. The derivation of these amounts is shown on the following tables.

Value of Lost Oil - 2005 Sale

Year	Gas (bcf/y)	Disc Factor	Disc Gas	Oil Price ($/bbl)	Oil (bbls)	Disc Oil Loss
2005	146	0.953	139	16.61	1	16
2006	292	0.867	253	17.03	2	30
2007	438	0.788	345	17.43	3	41
2008	584	0.716	418	17.91	4	51
2009	730	0.651	475	18.75	6	73
2010	730	0.592	432	19.34	7	80
2011	730	0.538	393	19.81	8	85
2012	730	0.489	357	20.59	9	91
2013	730	0.445	325	21.15	10	94
2014	730	0.404	295	21.83	12	106
2015	730	0.368	268	22.42	13	107
2016	730	0.334	244	23.03	14	108
2017	730	0.304	222	23.65	15	108
2018	730	0.276	202	24.29	17	114
2019	730	0.251	183	24.94	18	113
2020	730	0.228	167	25.62	19	111
2021	730	0.208	151	26.31	20	109
2022	730	0.189	138	27.02	21	107
2023	730	0.171	125	27.75	23	109
2024	730	0.156	114	28.50	24	107
2025	730	0.142	103	29.27	25	104
2026	730	0.129	94	30.06	26	101
2027	730	0.117	86	30.88	28	101
2028	730	0.106	78	31.71	29	98
2029	730	0.097	71	32.57	30	95
			5679		384	2258
					Value	0.40

Value of Lost Oil - 2010 Sale

Year	Gas (bcf/y)	Disc Factor	Disc Gas	Oil Price ($/bbl)	Oil (bbls)	Disc Oil Loss
2010	146	0.953	139	19.34	0	0
2011	292	0.867	253	19.81	1	17
2012	438	0.788	345	20.59	1	16
2013	584	0.716	418	21.15	2	30
2014	730	0.651	475	21.83	2	28
2015	730	0.592	432	22.42	3	40
2016	730	0.538	393	23.03	4	50
2017	730	0.489	357	23.65	4	46
2018	730	0.445	325	24.29	5	54
2019	730	0.404	295	24.94	5	50
2020	730	0.368	268	25.62	6	57
2021	730	0.334	244	26.31	6	53
2022	730	0.304	222	27.02	7	57
2023	730	0.276	202	27.75	7	54
2024	730	0.251	183	28.50	8	57
2025	730	0.228	167	29.27	8	53
2026	730	0.208	151	30.06	9	56
2027	730	0.189	138	30.88	9	52
2028	730	0.171	125	31.71	10	54
2029	730	0.156	114	32.57	11	56
2030	730	0.142	103	0.00	0	0
2031	730	0.129	94	0.00	0	0
2032	730	0.117	86	0.00	0	0
2033	730	0.106	78	0.00	0	0
2034	730	0.097	71	0.00	0	0
			5679		108	882
					value	0.16

Senate Resources Committee

QUESTIONS FOR YUKON PACIFIC TO ADDRESS IN SENATE RESOURCES COMMITTEE HEARING JANUARY 29, 1996

1) How current are the permits that you have? What portion of them are federal permits and what portion are state permits?

2) What is your proposed method for financing the liquefaction facilities, pipeline, and transportation system? What is your estimated timeline and cost for construction of these facilities?

3) Can Yukon Pacific and its partners finance and construct the full system without equity investment by the producers? What wellhead rate can you pay to make the investment viable? How does this compare to wellhead gas prices elsewhere in the world?

4) What does the market project for supply and demand of gas?

5) Recent talks by representatives of the producers suggest that a market urgency does not exist. However, others dispute this. Competition from other major projects in Australia, Indonesia, Malaysia and Qatar will be strong. What is your explanation of this discrepancy?

6) Can gas from Point Thompson start flowing as early as 2003-2004 in the gas pipeline, with commitment that Prudhoe Bay gas will follow within time certain (say 2006-2008)?

7) What if anything would help advance the date for this project by one year to 18 months?

Senate Resources Committee

QUESTIONS FOR PRODUCERS TO ADDRESS IN SENATE RESOURCES COMMITTEE HEARING JANUARY 29, 1996

1) How does the "Issues Resolution Agreement" among ARCO/EXXON/BP affect project timing and producers' perception of market window?

2) Recent talks by Ken Thompson suggest that a market urgency does not exist. However, others dispute this. Competition from other major projects in Australia, Indonesia, Malaysia and Qatar will be strong. Why aren't the producers expressing a stronger sense of urgency?

3) What is the time value of your projected loss of 400 million barrels of oil if gas is removed from the gas cap? How does this compare with the value of gas? What is the impact on revenue to the State?

4) Can gas from Point Thompson start flowing as early as 2003-2004 in the gas pipeline, with commitment that Prudhoe Bay gas will follow within time certain (say 2006-2008)?

5) What if anything would help advance the date for this project by one year to 18 months?

6) What is the likelihood that the timeline you are suggesting might slip?

7) When do contracts need to be in place to assure 2005 startup?

Senate Resources Committee

QUESTIONS FOR REVENUE TO ADDRESS IN SENATE RESOURCES COMMITTEE HEARING JANUARY 29, 1996

1) What are current gas prices and longterm forecast?

2) What are the projected revenues to the State of Alaska from a gas pipeline project and on what are these projections based?

3) What is the royalty on ANS gas? Does it vary from lease to lease and/or unit to unit?

4) Has the Administration reached consensus on the point at which it believes a gas pipeline must be developed to utilize the gas resource in the best interests of the state?

NAVIG-ABLE WATERS HEARING

2-28-96

SENATOR LOREN LEMAN

Northwest Anchorage

716 W 4th Ave, Suite 520, Anchorage, AK 99501 (907) 258-8189 Session: State Capitol, Juneau, AK 99801 (907) 465-2095

February 19, 1996

Attorney General Bruce Botelho
Department of Law
PO Box 110300
Juneau, AK 99801

Re: Tide and Submerged Lands and Navigable Water Oversight Hearing

Dear Attorney General Botelho:

Alaska was granted title to all tide and submerged lands at statehood and the right to manage its waters. Since statehood, however, we have seen numerous attacks on the state's ownership and management rights, including differing interpretations of state constitutional authorities. Because of the importance of these issues, the Senate Resources Committee will hold an oversight hearing to examine the State's policies and programs directed at protecting the State and public interests.

The hearing will be held on February 28, 1996 at 3:30 PM in the Butrovich Room. We request that your department be prepared to brief the legislature on:

1. Background information regarding the state's submerged land waters jurisdiction and ownership authorities and responsibilities that are founded in statute and the constitution.

2. Procedures involved in asserting state title and management of navigable waters and tide submerged lands.

3. Describe existing jurisdictional and ownership conflicts involving tide and submerged lands and navigable waters and your department's role in addressing these conflicts.

4. Navigable waters access concerns.

5. The status of existing related litigation.

6. Your department's policies, priorities and programs related to the management, jurisdiction and ownership of navigable waters and tide and submerged lands.

7. Problems your agency has experienced due to the shutdown of the navigability section.

8. How state actions relate to federal reserved water rights and potential implications.

9. Agency recommendations.

We would appreciate your participation so we can address administration, agency and legislative policy issues. The oversight hearing will undoubtedly require some in-depth discussions so we would appreciate your having experienced and technical staff available. We have scheduled primarily listen only teleconferencing which will allow for technical staff to be on-line to answer specific questions if travel to the hearing is not possible or feasible. Please advise which stations you want on teleconference.

The agencies participating in this hearing will be the Department of Law, Department of Natural Resources, Department of Fish and Game and the Department of Transportation and Public Facilities. The hearing will include 10 minute briefings by each agency followed by questions from the committee members. Members of the Resources Committee would be grateful for any advanced material which could be made available prior to the hearing.

Thank you for your assistance.

Sincerely,

Loren Leman

Senator Loren Leman
Senate Resources Committee Chairman

ak/ram
cc: Commissioner Shively, DNR
Commissioner Rue, DF & G
Commissioner Perkins, DOT & PF

MEMORANDUM

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING and WATER MANAGEMENT

TO: John Shively, Commissioner

DATE: January 12, 1996

TELEPHONE NO.: 269-8625

FROM: Jules Y. Tileston, Director

SUBJECT: Black-Kandik-Nation rivers FY 97 budget to support quite title litigation

All three rivers cross or are near the Canadian Border north of the Yukon River (see map). All three rivers are non-glacial, small to medium sized, and lack major lakes to augment low flows. All three have been determined in part to be navigable by the BLM as part of land transfers to Doyon Ltd. and to Chalkyitsik Native Corporation. Both the Kandik and Nation rivers are tributaries to the Yukon River and involve a part of the Yukon-Charlie National Rivers unit of the National Park System. The Black River is a tributary to the Porcupine River and involves a part of the Yukon Flats National Wildlife Refuge. Quiet title action was filed 1993 by the state (attached).

When we were preparing the FY 97 budget for the Division, we discussed with Joanne Grace (AG's Office) the likelihood of having to take supporting action of the state's request for quiet title on 42 miles of the Nation River, 80 miles of the Kandik River, and 250 miles of the Black River. At that time, we could not tell when the federal court would rule on a motion. We also explored the expected costs of DNR to provide support to the AG for these three rivers. We also considered potential funding arrangements wherein the department support would come from the AG in the form of an RSA. Preliminary estimated costs for the DNR are between $50K and $75K. This includes a combined AG DNR field trip to validate available hydrologic information and collect any supplemental information needed as well as technical review of government documents provided the state during the discovery process. Field work requires helicopter support. We did not have a good read on when, or what the federal court would rule on the federal government's motion to dismiss. Therefore, nothing was included in the FY 97 budget for this litigation.

Joanne Grace alerted me early this week that the Ninth Circuit, in late December 1995, denied the federal government's second motion for an appeal. The federal government has 60 days (about March 1996) to file its answer on the state's 1993 quiet title request on these three rivers. Accordingly, we should know the extent of any disagreement the federal government has on the entire 370 miles of river ownership. We do not expect the federal government to agree with the state's position, but we do expect that portions of one or more of the three river segments will be considered to be in state ownership because navigability. Joanne also advised me that the AG did not want to cloud his FY-97 budget request with a RSA for DNR support on this litigation. Therefore, we need to come up with $75K that simply is not in the Division's FY-97 budget. I have discussed this with Marty Rutherford and she suggested that a supplemental appropriation may be the best way given where we are in the budget process. Any prelimary work done this FY can be absorbed without impacting other high priority work.

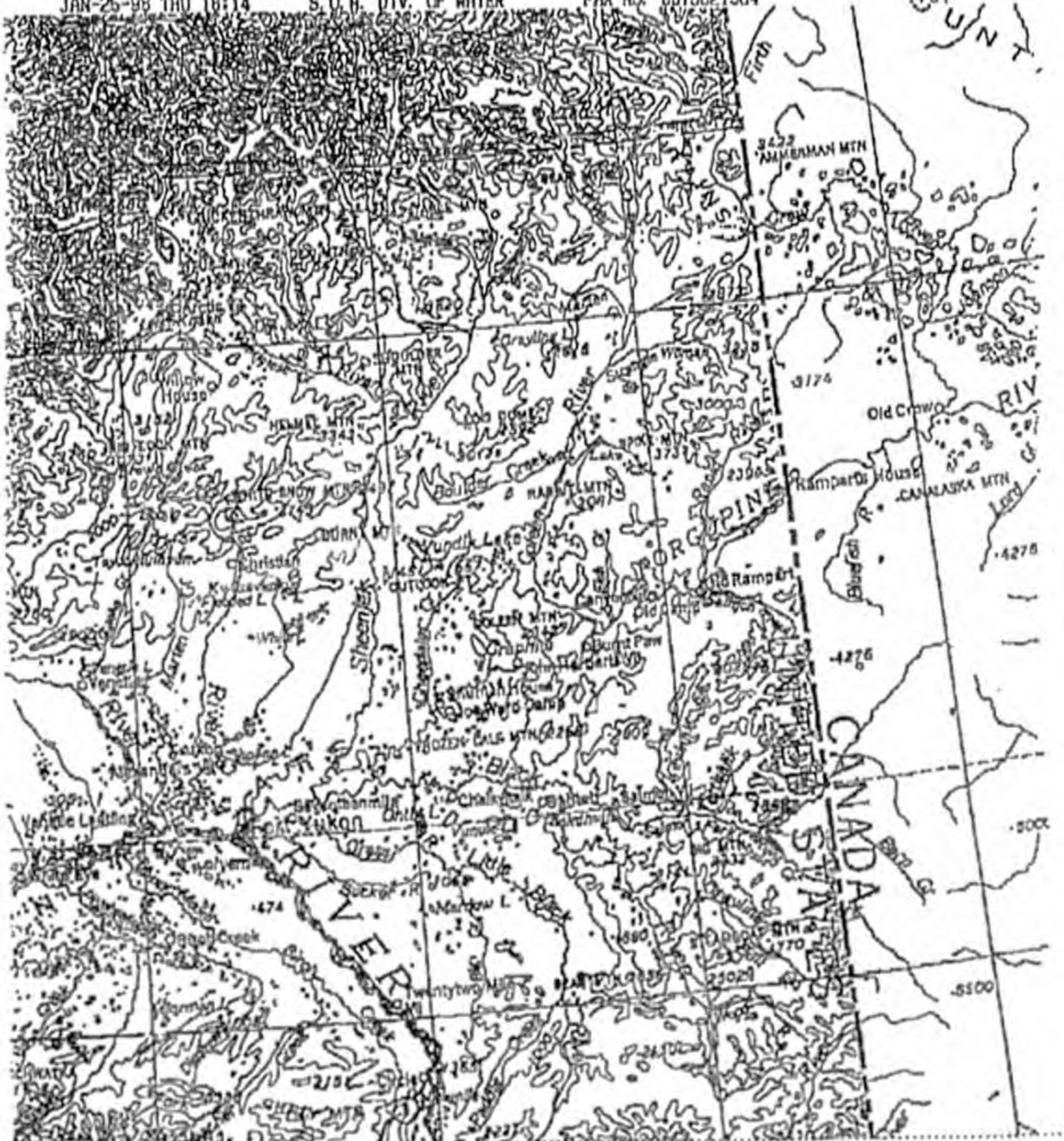
A final federal court determination on the upstream boundaries of these three river segments has a major and significant impact on the state ownership of a substantial portion of all small to medium sized rivers in Interior, Southcentral, Southwestern, and Northwestern Alaska. The BLM also determined that the interconnected sloughs on the Black River were navigable. A final court decision on the interconnected slough issue has significant statewide implications. As you may recall, I was one of the federal government expert witnesses on the BLM hearing on the Kandik River. Therefore, I intend to work closely on the field data collection and the interpretation of these data as it affects navigability. We have the potential to reduce the total field costs in two ways: use fire contract helicopter support (if available), and share costs with the federal government. I have asked Joanne to contact Bruce Landon in Justice to determine whether the state and the federal government can mutually collect data and set up a process that the state and federal government can then mutually agree on the factual data relating to stream profiles, hydrology, watershed characteristics, etc. I am making a similar contact with Debrah Williams.

Accordingly, I strongly recommend that we request $75K funding for the Division of Mining and Water Management for FY-97.

enclosures (2)

cc: M. Rutherford

JAN-25-96 THU 16:14 S.O.A. DIV. OF WATER FAX NO. 9075621384 P. 04



Tina 267-2476
Fax.

JAN-26-98 FRI 10:31 AK FISH & GAME FAX NO. 9072672472 P. 05
JAN-26-98 THU 18:21 S.O.A. DIV. OF WATER FAX NO. 9075821384 P. 17

DESCRIPTIVE TITLE:
Navigation Litigation Support

CONTACT:

Gary Prokosch, 269-8645

DESCRIBE WHAT THIS AMENDMENT CHANGES FROM THE GOVERNOR'S ORIGINAL BUDG SUBMISSION, WHY IT IS NECESSARY, AND THE CONSEQUENCES IF IT IS NOT APPROVED:

See Attached

CODE	EXPEND BY OBJECT	GOV ORIG	AMEND	GOV AMEND
100	Personal Services	0.0	52.2	52.2
200	Travel	0.0	2.0	2.0
300	Contractual Services	0.0	32.0	32.0
400	Supplies	0.0	0.5	0.5
500	Equipment	0.0	1.0	1.0
600	Lands/Buildings	0.0	0.0	0.0
700	Grants/Claims	0.0	0.0	0.0
800	Miscellaneous	0.0	0.0	0.0
	TOTAL	0.0	87.7	87.7
1002	Federal Receipts	0.0	0.0	0.0
1003	General Fund Match	0.0	0.0	0.0
1004	General Fund	0.0	87.7	87.7
1005	GF/Program Receipts	0.0	0.0	0.0
1007	I/A Receipts	0.0	0.0	0.0
1061	CIP Receipts	0.0	0.0	0.0
1055	I/A Oil & Hazardous	0.0	0.0	0.0
1021	ARLF Receipts	0.0	0.0	0.0
POSITION INFORMATION	PFT			
	PPT	0.0	0.5	0.5
	Non Permanent	0.0		0.0

FY 97

GBA Governor's Budget Amendment

AGENCY Natural Resources

BRU Resource Development

COMPONENT Water Development #816

Page 1 of 1

Revised Date

Black-Kandik-Nation Rivers Supplemental Budget Form Text, 01/19/96

The Black, Kandik, and Nation Rivers are non-glacial, small to medium sized, and lack major lakes to augment low flows. All three have been determined in part to be navigable by the BLM as part of land transfers to Doyon Ltd. and to Chalkyitsik Native Corporation. The State filed quiet title action in 1993.

When the DMWM FY 97 budget was prepared, the likelihood of having to take supporting action of the state's request for quiet title on 42 miles of the Nation River, 80 miles of the Kandik River, and 250 miles of the Black River, was discussed with the AG. At that time, it was not known when the federal court would rule on a motion. The Director also explored the expected costs for DNR to provide support to the AG for these three rivers. Funding arrangements were considered wherein the department support would come from the AG in the form of an RSA. Preliminary estimated costs for the DNR are $88K. This includes a combined AG/DNR field trip to validate available hydrologic information and collect any supplemental information needed as well as technical review of government documents provided the state during the discovery process. Field work requires helicopter support.

It is expected that the federal government will not agree with the state's position, but it is expected that portions of one or more of the three river segments will be considered to be in state ownership because of navigability. The AG does not want to cloud FY 97 budget request with a RSA for DNR support on this litigation. Therefore, DMWM requests a supplemental appropriation of $88K, funding that is not in the Division's FY 97 budget.

A final federal court determination on the upstream boundaries of these three river segments has a major and significant impact on the state ownership of a substantial portion of all small to medium sized rivers in the Interior, Southcentral, Southwestern, and Northwestern Alaska. The BLM also determined that the interconnected sloughs on the Black River were navigable. A final court decision on the interconnected slough issue has significant statewide implications.

If not funded the AG would have to drop this case due to lack of relevant information and data needed to pursue the case to ensure a high probability of a favorable court decision. The State cannot take the chance of losing this critical case due to lack of supporting information and data.

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING AND WATER MANAGEMENT
ALASKA HYDROLOGIC SURVEY

State of Alaska

3601 C Street, Suite 800
ANCHORAGE, AK. 99503-5935

TO: Jules Tileston
Director

DATE: January 19, 1998

FILE NO:

THRU: Mark Ingram
Hydrologist

TELEPHONE NO: (907) 269-8637 FAX 562-1884

FROM: Stan Carrick
Hydrologist

SUBJECT: Black, Kandik, Nation Rivers
Nav Project Cost Estimate

The following is a detailed breakdown of the estimated costs for the river reconnaissance to support the quiet title litigation on the Black, Kandik, and Nation Rivers. These costs include personnel time for one hydrologist (though in reality more than one hydrologist will work on parts of the project), navigability support, Director support, administration costs, helicopter support, per diem, and equipment costs.

PERSONNEL	
–hydrologist	
field prep, field time, 1.5 man-months:	$10,680
report prep, AG support, 3.0 man-months:	$21,360
–navigability support, report research, 1.0 man-months:	$6,110
–admin support, 0.5 man-months:	$2,025
–Director support	
field prep, field time, 0.75 man-months:	$5,028
litigation support, 0.75 man-months:	$6,025
–Total Personnel Cost:	$52,228
CONTRACTUAL	
–helicopter (Tundra or ERA Bell 206L), approx 10 days:	$31,000
–vehicle rental:	$1,000
TRAVEL/PER DIEM	
–approx 12 days, ½ short term rate and ½ field rate for 2 DMWM staff:	$2,000
EQUIPMENT	
–purchase, repair, etc.:	$1,000
SUPPLIES	$500
TOTAL ESTIMATED COST:	$87,728

MEMORANDUM

Department of Natural Resources

State of Alaska

Div. of Mining & Water Mgmt.

TO: Navigability Information & Data Users and DNR Directors

DATE: June 30, 1995

TELEPHONE NO: 762-2573

THRU:

SUBJECT: Navigability Files

FROM: Jules Tileston
Director of Mining and Water Management

This memo is to inform users of navigability information and data users where file material can be obtained after we shut the Navigability Section down as of June 30, 1995. Files will be maintained by Division of Mining and Water Management, Suite 800, Frontier Building, 3601 C Street, Anchorage. The files contain the following

1. Historical information on the past court actions that DNR has filed in federal court. This includes Slopbucket Lake and Gulkana River files.

2. Historical information gathered by DNP and BLM historians

3. Copies of most BLM and State navigability determinations filed by quad sheets.

4. Individual River files containing information on use, hydrology, and other river related research material.

5. Other litigation files such as Moose Creek in the Kantishna

These files will be kept in a secure location that can be accessed by DNR employees, other agencies and the public for in building uses

The navigability maps contain the Quads with navigability overlays. These are important for planning and other purposes. Historical reports and other supporting information for present and past litigation are kept in binders

We have also been asked to put together information so that each Division in DNR and other agencies can make their own navigability determinations. I would suggest that they use the information in DO #125 and the fact sheet titled "Ownership and Management of Navigable and Public Water".

We suggest the following guidelines that may be used by agencies or individuals:

- A water body that is obviously navigable would be a lake or stream with a size, shape, depth and gradient that is capable of floating at least 1000 pounds. This would include rivers such as the Susitna, Kuskokwim, Copper, and Tanana, will also include rivers such as the Sixmile, Placer and Resurrection. For reference a 19 foot square stem canoe is rated by the manufacturer to carry 1000 pounds and a 13.5-foot Avon Adventure is rated by the manufacturer to carry 1700 pounds.

- Streams that are obviously not navigable would be streams that have excessive gradients (generally in excess of fifty feet per mile) or insufficient flows to carry water borne traffic.

- Streams that fall between these extremes will have to be evaluated using the guidelines in Department Order #125 and may require the collection of additional hydrological, historical, and physical characteristic data to support a navigability finding. Once a determination is made the agency may want to run the finding by the Attorney General's Office to ensure that they are not setting precedence that the State cannot defend or that may weaken the State's claim to submerged lands. These are policy issues that the Department will need to address.

These guidelines do not cover many issues associated with ownership of inland submerged lands, such as, prior and current litigation, pre-statehood withdrawals and management agreements.

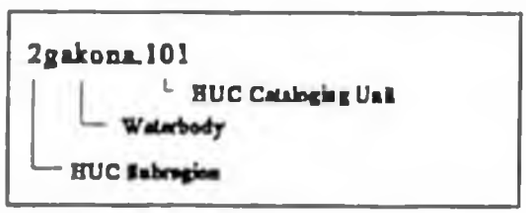


Figure 1. File Naming Convention

There are three primary sources of digital data containing information about the navigability status of Alaska's' waterways. A WordPerfect directory, [navrpt] of navigability library sheets; a Foxpro database, [dailylog dbf], which tracts navigability inquiries and the states response to them; and a Foxpro database compilation of different databases, [waterbod dbf], which includes navigability work done on Mental Heath Trust Land and some of the independent statewide work prior of navigability adjudicators. These source of information are described in more detail below.

WordPerfect Reports

A directory of WordPerfect files containing library sheets that summarize work done by the state in recent years on specific waterbodies. These documents were intended to be dynamic as they were continually being updated with new information by the navigability staff. Brief notes as to the known physical characteristics, historical use, contemporary use, fisheries resources, and navigability determinations are included in these documents. The directory is not comprehensive of all navigability work done in Alaska, but it does provide a valuable overview of the waterbodies contained therein.

Access to these reports are on the GIS network at /net/water/water/navrpt/ directory. These reports are indexed by one of six Hydrologic Unit Code (HUC) subregions within the state. The first number in the file name corresponds to the number of the hydrologic unit subregion where the waterbody is located. A Hydrologic Unit Map can be obtained from the Division of Mining and Water Management to identify the HUC for the area of interest. The file naming convention is designed to eliminate confusion and potential

MEMORANDUM

State of Alaska

DEPARTMENT OF FISH & GAME

TO: Frank Rue
Commissioner
Department of Fish and Game

DATE: September 14, 1995

FAX NO.: 267-2464

TELEPHONE NO.: 267-2342

PREPARED BY: Lance Trasky
Habitat and Restoration Division

SUBJECT: Briefing on Navigability and Related Issues

Kelly Hepler
Sport Fish Division

Doug Vincent-Lang
Sport Fish Division

Christopher Estes
Sport Fish Division/RTS

Tina Cunning
Commissioner's Office

Robin Willis
Habitat and Restoration Division

John Westlund
Wildlife Conservation Division

James Brady
Commercial Fisheries Management
and Development Division

You recently received a memo from Commissioner Shively announcing that the Alaska Department of Natural Resources (DNR) is suspending all work on navigability and that DNR is placing "responsibility" for determination of submerged ownership with the appropriate state official having jurisdiction over a pending action where state approval or a permit is dependant upon state ownership (Attachment 1). Responsibility for defending state ownership of tide and submerged lands and presumably the public's right to navigate state waters would be assigned through an amendment to Department Order 125 (Attachment 2). This amendment has not been distributed and may not be prepared. The memo states that DNR will make their expertise on navigability standards available where ownership of submerged lands involves very important public policy and the issues in dispute have regional or statewide

implications. DNR has not provided examples of threshold projects which would re-involve DNR in the navigability issue. Department staff have contacted DNR but have not been able to find out more about DNR's decision to re-assign navigability and how this would work.

Department staff who work on navigation, public access, instream flow, and state and federal issues, are concerned that DNR's action may jeopardize not only the public's right to use navigable waters, but many other things as well. These concerns include:

1. Delegation of responsibility by permits - Under DNR's proposal, the responsibility for asserting state ownership and navigability would be assigned to the agency who issues a permit for that activity. For example, the Alaska Department of Transportation and Public Facilities (DOT&PF) might exert state ownership when DOT&PF wants to build a state road across a navigable stream. The Alaska Department of Fish and Game (ADF&G) is interested in maintaining public access to and use of navigable waters by watercraft and aircraft for hunting, fishing, and access to hunting and fishing areas. These activities do not require any type of permit from a state agency. ADF&G permits only apply to fish habitat and special areas. DNR's memo does not indicate that any responsibility for determining navigability would be assigned to ADF&G. Under the permit concept, no state agency would have the responsibility for asserting navigability for access to or use of fish and wildlife. It is not clear how permitting relates to navigability or state ownership, or how the public's broad interest in navigability as it applies to access for hunting, fishing, subsistence, or other recreational activities will receive much consideration under this system. Failure to assert navigability for fish and wildlife access and harvest may result in the loss of access to and ownership of literally hundreds of miles of streams and lakes. Habitat protection and management of water allocation for fish and wildlife resources and recreational needs may also be jeopardized. Whatever process the state adopts for asserting navigability has to be comprehensive and protect all navigability interests.

2. Dispersal of responsibility - The delegation of DNR's responsibility to other agencies with no staff, no experience, little interest, and no established process makes it unlikely that navigability will be asserted consistently, if it is asserted at all. DOT&PF, DNR/Division of Mining, DNR/Division of Oil and Gas, etc., may assert ownership where there is mineral potential, oil and gas potential or where state highways cross

streams; however, these criteria apply to relatively few areas of the state. Because these agencies have no statutory responsibility to assert navigability for access to hunting and fishing, and no expertise, it seems unlikely that they will do this. There is even a possibility that there may be navigability disputes between agencies as there has been over the Russian River and over the ownership of avulsed lands in Prince William Sound.

3. Document flow - There is a long-established process between the Bureau of Land Management (BLM) and DNR and from DNR to other state agencies for distributing and receiving comments on land transfers which affect navigation, Alaska Native Claims Settlement Act (ANCSA) Section 17(b) easements, etc. It is not clear how this will work under the new DNR paradigm. If the responsible agency does not receive the document or does not respond within deadlines, not only public access will be lost, but some bad precedents may be set. There is good reason for concern. There may be as many as 2,500 land transfers from federal to private ownership this year, many involving Alaska's estimated 14,000,000 acres of navigable water bodies. Further, we understand that due to budget cuts, BLM is being asked to determine which of their duties could be contracted to private entities. Under the Indian Reorganization Act, several of the Native Corporations have submitted proposals to perform a number of BLM's current duties, including Native Allotment field verification surveys and surveys of lands to be transferred to ANCSA corporations. Although there is currently no move to have these same corporations identify ANCSA 17(b) easements and navigable waters, the potential does exist. The state and federal task force that has been working to establish mutually acceptable criteria for quiet title action on navigable waters has stalled, so no relief can be expected from that process. It seems more likely with both state and federal downsizing, and jettisoning of statutory responsibilities, that there is a much greater chance that very important land use decisions relating to navigability will fall through the cracks. To be successful in this environment, the state will have to assert navigability clearly, consistently, and unequivocally. BLM has already created numerous navigability problems which we thought DNR would rectify. BLM has designated some portions of streams non-navigable and sections above and below navigable. Failure to be businesslike and consistent in handling navigability assertions will invite more of the same.

4. Statutory responsibility - Although it is not clear what DNR intends to do, it seems that DNR has a statutory and perhaps a constitutional

mandate to assert the state's interest in navigable waters and the ownership of submerged lands. It is not clear that DNR can legally assign its responsibilities to other agencies, even if they agreed to accept them. This is akin to ADF&G assigning the subsistence issue to DNR to manage. There also is a question of what legal standing other state agencies such as DOT&PF would have in asserting navigability. Failure to do a credible job in protecting state interests in navigability might also invite litigation from users who feel that they may suffer substantial losses if the state fails to protect navigability. More detailed discussions of these issues are attached for your reference (Attachment 3).

5. Navigability is tied to other state interests - There is a great deal more at stake than the public's right to use navigable water bodies to harvest fish and wildlife or to access other public lands and waters. For example, navigability includes state ownership of submerged lands, and oil and gas and mineral rights. In regions such as the coastal plain, the ownership of mineral rights under rivers and lakes could mean billions of dollars in rents and royalties. State ownership of stream beds allows the ADF&G more freedom to construct weirs and conduct other fish and wildlife management activities without paying rent. The public also has a right to stand on the bed of navigable waters below ordinary high water and harvest fish even if the adjacent uplands are privately owned or in a restrictive federal ownership category. ANCSA 17(b) easements were created to allow public access to state lands and navigable waters. The state constitution provides for public access to navigable waters, even across private property. The department's legal and physical ability to protect fish and wildlife habitat in anadromous streams, prevent blockages in fish streams, and protect aquatic habitat in critical habitat areas and refuges is stronger in navigable streams than non-navigable streams. Failure to assert navigability consistently will consequently affect many other state interests.

ADF&G staff from the divisions of Habitat and Restoration, Sport Fish, Commercial Fisheries Management and Development, and Wildlife Conservation and the Commissioner's Office feel there is so much at stake that you need to discuss this issue with Commissioner Shively at the earliest possible date. Because DNR's actions affect other state agencies, and a wide variety of constituents including sportsmen, subsistence users, miners, oil and gas lease holders, this is an issue which should be discussed at the cabinet level if DNR can't satisfy this vital function. The most desirable outcome would be for DNR to continue to be the state's lead on navigability, and to rigorously defend all of

the state's interests in navigability and ownership of submerged lands. The department is ready and willing to provide substantial assistance to DNR and the Attorney General's Office where fish and wildlife interests are related to navigability, as we have in the past.

If DNR can not meet their statutory responsibilities, an alternate process needs to be established whereby the department can be confident that ADF&G can do a credible job protecting navigability-related fish and wildlife interests. This will require at a minimum: 1) establishing whether DNR will continue to receive and distribute BLM documents or if ADF&G will have to establish its own relationship with BLM and other state agencies such as the Department of Law; 2) if there is a dispute with BLM over navigability, will DNR become involved or will ADF&G and the Attorney General's office have to be prepared to perform all of DNR functions; and 3) if disputes over navigability arise between state agencies, who resolves them? DNR will also have to train staff from other agencies to handle navigability issues. There will also have to be a clear division of responsibilities for asserting navigability between state agencies, and central oversight, otherwise this will not work. Other questions will probably become evident as we get further into this function.

Please let us know how you wish to proceed.

Attachments

cc: Janet Kowalski
Kevin Delaney
Wayne Regelin
Doug McBride
Karl Schneider
Bob Schroeder
Paul Larson
John Hilsinger
Tom Kron
Rob Bosworth
Bob Clasby
Mike Mills

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

TONY KNOWLES, GOVERNOR

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1706
PHONE: (907) 465-2400
FAX: (907) 465-3886

3601 C STREET, SUITE 1210
ANCHORAGE, ALASKA 99503-5921
PHONE: (907) 762-2483
FAX: (907) 562-4871

July 26, 1995

Addressees Below

The enclosed memo summarizes the availability and location of information and provides suggested guidance for criteria used to determine ownership of submerged inland waters of Alaska. With the elimination of the department budget for navigability assertions, all work on a systematic stream or waterbody ownership program has been suspended.

It is recognized that there will be specific situations where disputed ownership of submerged land involve very important public policy and the issues in dispute have regional or statewide implications. When this situation appears to exist, we can make our technical expertise on navigability standards available. These instances, because of the zero budget, must be confined to challenges to state ownership by a federal or private interest where there is a real potential for the waterbody in question to be declared navigable.

We are preparing a supplement to Department Order No. 125 that places responsibility for determination of submerged ownership with the appropriate state official having jurisdiction over a pending action where a state approval or permit is dependant upon state ownership. For example, the division of oil and gas will make any necessary determinations associated with an upland lease and the division of lands would take similar action in response to removal of gravel from sources defined as submerged lands or for access to public lands involves stream crossings where a land use authorization is required. This division will make the necessary decision associated with mining claims. Other state entities, such as the Department of Transportation and Public Facilities for road and airport projects involving submerged lands under inland waters will be responsible for making and supporting ownership issues. This decentralization of the responsibility for asserting inland submerged land ownership makes it very important that the Attorney General's Office be consulted when there is a possibility that an assertion or acceptance of a federal agency determination of ownership may adversely damage the state's long-term capability to achieve successful quite title action in federal court.

Enclosed for you information is a current copy of Department Order No. 125 and a fact sheet titled "Ownership and Management of Navigable and Public Water." Please distribute this information to those within your organization that will have the basic responsibility for and/or are interested in navigability determinations.

Sincerely,

John Shively
Commissioner

Enclosures (3)

Department Order 125, Revision No. 5

POLICIES AND PROCEDURES ON OWNERSHIP
AND
MANAGEMENT OF NAVIGABLE AND PUBLIC WATERS

The Fiscal Year 1996 department budget contains no funding to continue centralized determinations to resolve existing or prospective disputes about State ownerships of inland water bodies. Accordingly, the navigability staff has been disbanded and technical advice on the application of the criteria described in Department Order 125, Revision No. 4 is no longer routinely available. The purpose of this Revision (No. 5) is to establish clear guidance for the department for implementing new or revised determinations of the ownership of the beds of navigable inland waters in Alaska under the new decentralized responsibilities for making these determinations. Revision No. 5 is an addendum to Revision No. 4, it does not suspend, modify, or revoke Revision No. 4 dated November 22, 1994.

It is the policy of the department that each director shall have the responsibility and authority to make a title navigability determination for applications or requests to use state resources involving shorelands[1] that appear to be navigable for title purposes, but not yet found navigable by the State, or Bureau of Land Management, or federal court. In implementing this decentralized responsibility each director shall:

1. Use the navigability information contained in the Division of Mining and Water Management data base to determine whether the application involves a water body for which a navigability determination already exists. These data automated bases (Word Perfect - /navrpt, and Foxpro - /dailylog.dtf and - /waterbody.dtf) includes known BLM and Department of the Interior decisions and federal court decisions about specific water bodies as well and the list of those water bodies contained in a notice to the federal government of intent to file for quite title action in federal court. In addition to this electronic data base, the division has hard copy files with maps and other pertinent information on a water body by water body basis.

2. Use information provided by an applicant requesting use of shoreland or resources showing that the waterbody in question meets the criteria established by Department Order 125, Revision No. 4 when data in the Division of Mining and Water Management files are deemed inconclusive.

3. In the event that existing data, or data supplied by the applicant, are deemed inconclusive, determine whether the application involves a water body that meets the BLM cadastral survey standard for meandering the shoreline as an initial guide on whether the waterbody in question is likely to be considered navigable at some future date, or is a water body that clearly does not meet the criteria described in Revision No. 4 and therefore is shoreland not in State ownership.

4. In the absence of sufficient information to determine the State ownership of shoreland associated with a specific waterbody, all action regarding an application for use or disposition of the shorelands in question shall be suspended and the applicant notified that no further action will be taken because there is substantial uncertainty on whether the State actually owns the shoreland. The applicant

should be provided a copy of Department Order 125 and informed of the navigability files in the Division of Mining and Water Management and that these files are available to the public. The applicant should also be told the type and extent of information that will be necessary for the department to resume processing their application and that this information can be developed by the applicant at their own expense or simply wait until such time as there funds and qualified staff may be available to answer the legal ownership issues associated with the specific application.

5. The division director making the decision is also responsible for updating the existing waterbody file in the Division of Mining and Water Management with the decision of the director on whether the shoreland is or is not deemed navigable together with any supplemental information developed by the appropriate division used to support the director's decision.

6. Questions concerning possible legal ramifications about a pending navigability decision by a division director should be directed to Ms. Joanne Grace, Anchorage Office of the Attorney General, phone 269-5235, FAX 279-2834.

7. In the event there is a dispute between the State and the federal government or private parties, the responsible division director shall consult with the Director Division of Mining and Water Management to develop a position paper for Commissioner action. The paper will focus on three matters that bear on a Commissioner decision about whether technical and budgetary resources should be committed to resolving the dispute:

a. Does the dispute involve substantive issues having statewide or regional application?

b. What level of information will be required to support State ownership, how long will it take to develop that information, and what are the estimated costs and staff time needed to assemble and analyze this information?

c. Is there a realistic chance that the State will prevail in federal court if supplemental information and technical staff commitment by the department are made?

This Revision also provides guidance on interim management of state-owned lands and waters associated with navigable waters. This interim guidance is patterned after the recent Alaska Supreme Court decision No. 4236 dated August 7, 1995 (Totemoff v. State of Alaska) which on pages 12-31 discusses the court's position about the extent of jurisdiction of the federal government over navigable waters and reserved water rights in Alaska. The court's opinion (attached) expressly addresses the issue of management of fish and game resources within the context of the Alaska National Interest Lands Conservation Act provisions dealing with subsistence uses. However, the overall the principal that the federal navigation servitude or reserved water right provides the federal government no management authority other than for navigation or against future water appropriations and is deemed appropriate for other overall resource uses of navigable waters for purposes other than subsistence, (e.g. mining, gravel sales, commercial guiding, and recreation use). This principal will be followed in department decisions for all resource uses associated with navigable waters in Alaska. Please consult with Joanne Grace on this matter when you have a concern about the legal implications of a pending decision by the department.

DRAFT

8. Distribution of navigability state and federal findings, assertions, and court action.....

(To reflect the December 19, 1995 meeting decision)

1. AS 38.05.965.(19) defines this term as follows: "'shoreland' means land belonging to the state which is covered by nontidal water that is navigable under the laws of the United States up to ordinary high water mark as modified by accretion, erosion, or reliction."

DRAFT

Summary:

- Backlog = 1,300 applications involving adjudication of a water right.

- Keep all Temporary Water Permit applications current.

  Available staff in water adjudication are 7.5 positions funded to issue water authorizations.

  Temporarily shift one funded position from the Alaska Hydro Survey to water authorization.

  If needed, will assign all water use authorization work in backlog involving mining to mining. (Continue work by Hydro Survey associated with mining at Illinois Creek and AJ.)

- November 1996, identify and have policy, regulatory, and legislative amendments concepts that avoid future backlogs and streamline the water allocation process under a reduced public funding scenario. This could include:

  Establish a priority date, use and amount through filing with the State Recorders Office.

  Retaining state responsibility for instream flow, federal applications, large water resource projects, and large out-of-basin water use decisions.

  Entering into agreements to place certain water allocation responsibility with cities and boroughs for water uses as part of local zoning and land use decisions. This would include the right to collect fees to defray local administrative costs.

  Applicant notifies all senior water users potentially impacted and provides professional assessment of the effect of the proposed use on those senior users.

  Disputes between water users would be handled at the level having the primary responsibility for the disputed water allocation. (An alternative would be for disputes to be resolved by the courts.)

- January 1, 1997 now existing backlog of water right applications eliminated and all Temporary Water Permits current. Backlog eliminated by working from the oldest to the youngest application. By January 1, 1997 there will be a new backlog of 200 to 300 estimated new applications filed after January 1, 1996.

- July 1, 1997 all water use authorizations are current.

- During the priority effort to eliminate the backlog, other technical services and file maintenance will be set aside when not essential to TWP processing and backlog elimination. These include: permit and/or certificate amendments for the point of take, updates for name and address changes, changes in previously authorized water use or amounts, personally providing case file information, working on a case other than by date of filing, and pre-application technical assistance. Pending resolution of litigation in federal court (Katie John) work on pending and any new instream flow applications involving federal land and federal water rights will be postponed.

ENCL 5

Perceptions to be Confirmed or Revised:

- Water in Alaska is not in short supply except for a few urban areas and parts of the North Slope.
- There is no significant public. user group, or industry support for the water management program in its present form.
- The water management program should be revised to reflect local and individual responsibility for the establishment of water uses and allocations that are implicit in approved local land use plans. zoning, platting decisions, or transportation facilities and utility systems programs with opportunity for full public involvement.
- The annual administrative fee is onerous.
- Fees based on the amount of water used. or in the absence of metering, the amount of water approved for use are onerous.
- Budgets and technical staffing for the water management will continue to decline.

Options for a Comprehensive State Water Management Strategy in Alaska:

The following options have been developed on the basis of input from division staff. In addition, these were discussed informally with several individuals knowledgeable about the water allocation process in Alaska. In general, the existing water allocation process does not appear to be either beneficial or detrimental when there are no other conflicting water uses. There is general concern about assuring domestic water use priority. There is general concern about how to best assure the public trust aspect of water under the State Constitution.

Option 1. Do not modify the existing process with priority remaining with preventing future backlogs.

Impact: Not effective when considering long-term declining state budgets and employees, staff morale, and public/customer expectations. The water element of the DNR budget continues to be an annual "justification" of a constantly reducing fiscal and staff capabilities making effective backlog elimination difficult. This option is viable only with significant public support that the existing system is worth the results now and in the future. .

Recommendation: Not prudent without significant support for the existing process.

Option 2. Eliminate backlog, identify areas where regulations or law can be revised to streamline the allocation process, where appropriate place costs of water allocations with the direct beneficiaries and water permit holders. Shift certain water allocation decisions to local government as part of local land use planning or zoning decisions under their jurisdiction, retain oversight and allocation decisions for new very large water allocations. large out-of-basin diversions, and instream flow reservations.

The basic elements of this option are:

- Identify types of use and amounts of water and localities where water applications are deemed to be automatically approved when filing and notification steps completed. A presumption of public interest and no adverse impacts to senior water users and those elements that must be considered under AS 46.15 when the proposed water use is in conjunction with an approved local, state, or federal land use plan unless there are objections deemed to have merit as a result of the notifications. This presumption would not apply to an instream flow reservation since this is a complex and frequently controversial issue of state or region wide importance. Processing federal water right and instream flow reservation applications involving federal land will be suspended pending the resolution of litigation associated with the

Katie John case. (A process question is whether a piece of paper is issued or that the filing with the Recorders Office and notation to the official DNR land records is the only documentation necessary.)

- Other water allocations will become effective concurrently with state, local, and federal permits at the conclusion of public involvement process when a new use requires a new or revision land use plan, coastal zone consistency review, state best interest finding for another disposal action, National Environmental Policy Act compliance evaluations, etc.

- Require filing water right applications and temporary water use permits with the Recorders Office rather than the division. The filing fee must be sufficient for both the Recorders Office and for notation to the DNR land records. (This filing will establish the priority date, the use, and amount of water in the same manner as does an application now filed with the Division of Mining and Water Management. Actual water rights are not established until the identified amount of water is in full use.)

- The applicant provides *either* a professional assessment of the expected impact of the proposed water use on senior water users of record in the affected part of the watershed or groundwater basin *or* references the local land use or zoning decision that provided for the development (agriculture, domestic, business, recreation, etc.) that is the basis for the water use.

- Require the applicant to publish in a newspaper of general circulation in the area of the proposed use and to notify local government and ADFG, ADEC. Applicant is also responsible for certified notification of senior water users of record likely to be impacted by the proposed water use. Determination of senior water right holders and any pending applications having a date earlier than the applicant would be based on the official DNR land records. (The present process does not require a newspaper notice unless the proposed amount of water to be used is larger than 5,000 gallons per day. A process for resolving any disputes or protests needs to be developed. This could be court of competent jurisdiction, a state entity, local government, a water master or some combination of these according to specific issues and the public interest. Disputes are now handled within the Division of Mining and Water Management, with an appeal to the Commissioner, and finally a court of competent jurisdiction.)

- Require all water permit applicants and water permit holders to keep addresses current in the official DNR land record system. Fees for amending the official records will be required. (This is currently done in the Division of Mining and Water Management as part of its routine duties.)

- The department should enter into cooperative agreements with local governments that place the overall responsibility for the determination of public interest as part of local zoning and land use planning authorities. The cooperative agreement can provide that the local entity can charge reasonable fees to conduct the evaluations and issue the appropriate water use authorization.

- Revise the Water Use Act and regulations as necessary to accomplish streamlining the process.

- Outreach and consensus building can be done by:

  1. Reactivating the Alaska Water Resources Board with a narrowly defined mission of reducing the time and effort spent while maintaining the overarching public ownership theme of "public interest"

2. DNR, ADEC, ADFG conducting workshops to obtain public input and build consensus on items that can be done to improve efficiency.

3. Prepare program and present to the Legislature as part of the FY 97 budget.

Impact: Assures that the regulations and/or revisions in law are consistent with public need to have some form of a water allocation program and if so, who pays. This option will also require a level of funding for water right adjudication at about the current level until the backlog is reduced to instream flow applications and federal water uses. Public outreach also requires a commitment of division time and funding for meetings, follow up summaries of the progress/decisions made and/or pending. The "water board" has the advantage of emphasizing the user and public interest aspect of the rather than the regulator.

Recommendation: Use agency workshop for outreach since there will be policy and budgetary considerations that will strongly influence the final recommendations contained in the November 1996 report.

Option 3. Treat water allocation, except for very large new water uses and Temporary Water Use permits as an unfunded mandate. Shift all available capabilities to processing the backlog with priority given to those having highest potential to create state and local employment and/or revenue. Notify all others that their application will be processed to the extent funding is available with priority given to the oldest date of filing. This would suggest a relatively stable budget for the water allocation program for the next year while the backlog is being eliminated. Based on the past two budget years and the recommendations of the State Long Range Financial Planning Commission report *Closing the Fiscal Gap*, an assumption that were will be stable budget does not seem realistic.

Impact: Continues long-term uncertainty on the proper role of protecting the public interest and public trust in the transfer of water to restricted use/ownership.

Recommendation: Not prudent.

Option 4. Repeal the Water Use Act and substitute a riparian ownership system (eastern water law concept vs. the present western beneficial use-first in time concept).

Impact: Sets up controversy without a solution that protects the public interest where adjacent land is in private or federal ownership. Provides federal agencies additional power to assert management authority over navigable waters and strengthens the arguments about this management becoming a veto of any land and resource use on state owned submerged land.

Recommendation: Not recommended at this time, but it is a potential outcome of the public involvement process and will be evaluated in the November 1996 report.

Option 5. Repeal the Water Use Act and substitute a system of water courts to resolve any conflict. This works when all available water has been appropriated (or over appropriated) in states such as Colorado. Dispute resolutions is handled by lawyers and the courts and is very expensive. At present the majority of the water allocation work in Colorado involves proposals to change the use of prior appropriations and the complex arrangements that must be met to maintain interstate water flow commitments. Colorado also has a major effort to assert state ownership and control of water as a direct result of federal reserved water issues and for endangered species.

Recommendation: Not recommended at this time, but it is a potential outcome of the public involvement process and will be evaluated in the November 1996 report.

Important Aspects of the Water Use Act (AS 46.15) and Regulations (11 AAC 05)

Water Use Act:

Water is reserved to the people. Wherever occurring in a natural state, the water is reserved to the people for common use and is subject to appropriation and beneficial use and to reservation of instream flows and levels of water [1966, 1980].

Senior rights have priority over junior rights. When there are competing applications and insufficient water, priority is given first to public water supply and then to those uses that alone or in combinations with other foreseeable uses will constitute the most beneficial use ['966].

A right to appropriate water can be acquired only as provided in this chapter. A right to the use of water either appropriated or unappropriated may not be acquired by adverse use or possession. This right can be obtained by:

- First making application to the commissioner for a permit to appropriate water.
- Issue a certificate when a permit is granted and the means of appropriation constructed.

DNR *shall* determine and adjudicate rights in the water of the state, and its appropriation and distribution [1966]. The issuance of a permit or certificate does not guarantee that a certain volume, quality, artesian pressure, or cost.

The commissioner shall prepare a notice containing the location and extent of the proposed appropriation, the name and address of the applicant, and other information the commissioner considers pertinent. Written objections may be filed with the director within 15 days of publication or service of notice. Objections must include the name and address of the objector and any facts tending to show the rights of the objector or the public interest that would be adversely impacted by the appropriation. The applicant pays for publication in a newspaper. Notice must be served personally or by certified mail to all who DNR's records show may be affected and the ADFG and ADEC.

Notice may be served on any governmental agency, political subdivision, or person.

The commissioner *shall* exercise all those powers and do all those acts necessary to carry out the provisions and objectives of this chapter. The commissioner *may* enter into contractual agreements necessary to carry out the provisions of this chapter including:

- Agreements with federal, state, and local agencies.
- Apply, accept, administer, and expend grants, gifts and loans from the federal government and any other public or private source.
- Establish a division of water
- Designate types of eppropriations that are exempt from notice and objections.
- Simplify procedures for ruling on applications.

The commissioner *shall* adopt procedural and substantive regulations to carry out the provisions of this chapter, including:

- Consider the responsibilities of the ADEC and ADFG under AS 16.
- Keep a public record of applications for permits and certificates and other documents filed in the commissioner's office.
- Record all permits and certificates and amendments and orders affecting water and the name of the applicant or appropriator.
- Cooperate with, assist, advise, and coordinate plans with federal, state, and local agencies in matters relating to the appropriation, use, conservation, quality, disposal, or control of waters and activities related to water.

- Prescribe the form and contents of the application and the procedure for filing an application to appropriate water.

- Prescribe fees or service charges for any public service rendered.

- An application, permit, and/or certificate creates a right against a later appropriator, including a government agency.

Criteria for issuance of a water permit include a finding that:

- Senior rights will not be unduly affected.

- Means of diversion or construction are adequate.

- Use of water is beneficial.

- In the public interest. (Permits and Certificates may include terms, conditions, restrictions, and limitations necessary to protect the rights of others and the public interest.)

Criteria for determining the public interest include:

- Benefit to the applicant.

- Effect of the economic activity resulting from the appropriation of water.

- Effect on fish and game resources and public recreational opportunities.

- Effect on public health.

- Effect of loss of alternant uses of water with a reasonable time if not precluded or hindered by the appropriation.

- Harm to other persons.

- Intent and ability of the applicant to complete the appropriation.

- Access to navigable or public water.

Applications may be made by an agency of political subdivision, an agency of the federal government or a person for a reservation of sufficient water as a specified instream flow or level of water at a specified point on a stream or body of water, or in a specified part of a stream for the entire year or at specified times. An "instream" reservation may be for:

- Protection of fish and wildlife habitat, migration, and propagation.

- Recreation and park purposes.

- Navigation and transportation.

- Sanitary and water quality purposes.

An "instream" reservation application is approved when the commissioner finds:

- Senior appropriators are not affected.

- The applicant has demonstrated a need.

- There is unappropriated water sufficient for the reservation.

- The appropriation is in the public interest.

Regulations:

No water may be used in excess of 500 gallons per day for more than ten days a year without a permit. (A single family home uses an estimated 500 gallons of water a day.)

A $50 administrative service fee is required of all water users having a permit or certificate, including temporary water use authorizations. State agencies, domestic water users using less than 1,500 gallons of water per day, anyone using less than 500 gallons of water per day, and instr Public water supply has priority over other uses. Instream reservations for a public benefit are exempt.

Existing water rights by type:

Type	Number of Files	Percent of Files
Small domestic users (less than 500 gpd)	13,106	79.1
Mining	810	4.8
Schools, businesses, churches, misc.	660	4.0
Public water supply	486	2.9
Recreation	421	2.5
Farm and livestock	321	1.9
Seafood	187	1.1
Construction	133	0.8
Oil and gas	111	0.6
Hydroelectric power generation	103	0.6
Hatcheries	89	0.5
Instream reservations	78	0.5
Timber	45	0.3
Bottled Water	27	0.2
Total	16,577	99.8

Note: Available records indicate that only slightly more than 50% of the total water used in Alaska is reported. Over the past five years, the percentage of small domestic users has dropped to about 30% of the total number of new applications. In terms of the total amount of water actually allocated; hydroelectric power = 90%, public water supply = 5%, aquaculture (hatcheries) = 3.9%. Domestic water for single family/multi-unit dwellings are not reported, however, it is estimated that this accounts for 9 million gpd or less than 1 percent of the total authorized water allocated in Alaska. (Anchorage uses 25 million gpd and a hydroelectric project like Solomon Gulch uses over 50 million gpd.)

TONY KNOWLES, GOVERNOR

3601 C Street, Suite 800
Anchorage, ALASKA 99503
Phone: (907) 269-8600

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF MINING AND WATER MANAGEMENT

January 3, 1996

Sam McDowell
336 East 23rd
Anchorage, Alaska 99503

Dear Sam:

This is in response to your telephone request of December 21, 1995 requesting the current status of the navigability program and potential changes in the water rights program managed by the Division of Mining and Water Management, Department of Natural Resources.

TITLE NAVIGABILITY

As you probably recall from our discussions about the Russian River this past summer, the last Legislature deleted all funding for the Title Navigability program by Department of Natural Resources, Division of Mining and Water Management. Accordingly, the navigability program was suspended and the technical staff who had been coordinating this work for the State were reassigned to other funded work. Enclosure No. 1 is a copy of the information provided the budget committee on the navigability program and the expected effects if the program was terminated. I alerted Frank Rue, then Director for the Division of Habitat and Restoration, Alaska Department of Fish and Game and requested any assistance his organization and support groups could provide. My staff and I also alerted other individuals and organizations that recently had been using the end products of the navigability work. The Legislature ultimately determined that the Title Navigability program should not be funded.

A memo was prepared on June 30, 1995 (Enclosure No. 2) and sent to navigability information and data us[illegible] explaining how and where the centralized navigability data base could be accessed.

On July 26, 1995 (Enclosure No. 3) information about termination of the Title Navigability program was sent to the heads of state and federal departments and to the AFN. You will note that Commissioner Shively specifically offered the Department's technical expertise on navigability disputes involving very important public interest concerns of regional or statewide significance.

Subsequently, we received several calls from the Anchorage office of the ADFG Habitat and Restoration section that the BLM was about to declare the Russian River in federal ownership as a part of a pending

application by CIRI for certain federal lands adjoining the lower end of the river. Shortly after the ADFG call, you called me to emphasize the importance of the Russian River. At that time we also discussed how the Department would respond to navigability issues when the Legislature had specifically terminated the program. Commissioner Shively agreed that the Russian River was a significant public resource with very important regional and statewide implications should BLM determine the river to be non-navigable. The Division participated in a joint ADFG/DNR field inspection immediately thereafter. That field inspection resulted in a written report asserting that the Russian River was in state ownership because it was navigable. Later, we received a second invitation from ADFG to have our senior hydrologist join in a raft trip down the Russian River. That invitation was declined on the basis that no meaningful new hydrologic information would be collected and that the hydrologic records had already been considered in our just finished assertion that the river was navigable.

On November 15, 1995 (Enclosure No.4) Commissioner Rue wrote Commissioner Shively requesting a meeting. That meeting took place on December 20, 1955. In addition to the Director of the Division of Habitat and Restoration and me, the Director of Land and representatives of the Alaska Department of Transportation and Public Facilities and the Attorney General's Office participated. A representative of the Department of the Interior was invited to be an observer but did not attend due to the Federal Government shutdown. Enclosure No. 5 is a copy of our discussion about the specific issues raised by ADFG and navigability. As a result of the meeting, It has been agreed that the Division of Land will request BLM to provide copies of all land transfer documents to the Anchorage Office of Habitat and Restoration, ADFG. The Division of Land also will develop a computer access system so that new navigability findings can be easily entered into the computer data base. That system will be available to the public for access. The hard copy central files will continue to be kept in this Division. These points will be incorporated in the final revision to Department Order No. 125. Each participant was also requested to review the proposed revision to Department Order No. 125 and to provide any comments to me by mid January 1996.

In summary, the Attorney General will determine the State's position about litigation of navigability issues concerning ownership of lands beneath inland waters. The Department will provide any required technical assistance needed to support the State's position in litigation. It is likely that any budget request for litigation and technical support will be coordinated with the concerned state agencies. In the meantime, we are prepared to respond to specific issues having important navigability issues to the state. The technical evaluation and navigability report prepared by the Division of Mining and Water Management for the Russian River is an example of how this works.

WATER ALLOCATION PROCESS

As state operating budgets and staffing are downsized to meet the fundamental objective of balancing the budget along the lines presented in the report *Closing the Fiscal Gap* by the State Long Range Financial Planning Commission, many state expenditures and processes are being examined to see if they are still necessary and, if so, are there ways to reduce costs and increase efficiency through statutory or regulatory change. The water allocation processes and fees associated with that program are one of these state programs under review. It is our intention to enter into a public outreach process to examine how this public trust responsibility can be properly handled. At one end of the spectrum are water rights associated with in stream flows, large water projects and large out-of-basin water transfers tending to be issues which the state should probably retain a primacy role. At the other end of the spectrum are single-

family and multi-family homes that are generally undertaken only after extensive public input on matters such as zoning, sewers and septic systems, platting, traffic, public services, schools and related public interest matters by local citizen and local, state and federal governmental entities. The fees associated with permit processing also will be evaluated to determine whether they reasonably reflect costs to the state, and the proper level of government that should be administering the water allocation program. For example, a borough or city and the Department can enter into an agreement that would transfer certain water allocation decisions to that local entity. That agreement could also include authority to collect reasonable fees to administer the program from those now, and in the future, having certain water rights. Another option would be to develop a program similar to mining claims in that a person wanting a water right must file with the State Recorders Office certain information about the water use intended. The cost of entering the site specific information, notification of the public at large and senior water right holders potentially effected by the water appropriation, professional evaluation of the availability of the water source, could be the sole responsibility of the applicant. Record changes, such as change of address, could also be accomplished through filing an appropriate document with the State Recorders Office and updating the official State land records. Costs for these changes also could be the sole responsibility of the water right holder.

It is planned that a discussion package of information be available prior to a series of workshops to explore feasible ways the public, local government and state agencies can develop partnerships that reduce the administrative costs while still protecting the Constitutionally guaranteed public trust doctrine for waters of Alaska.

At this time, I envision that there will be an initial round of workshops in late January or early February 1996. These would likely be held in Anchorage, Fairbanks, and Juneau with teleconference tie-ins. The workshop input will be the basis for developing a formal strategy that would be resubmitted for public review and comment during the late summer. The overall analysis of the water a[illegible]cation process needs to be completed by November 1996 in order to the useful in Governor Knowles' submissions to the 1997 Legislature.

I have added you to our mailing list on the water allocation process evaluation. Enclosure No.5 is a preliminary draft on the concepts that we are developing for the workshops. We welcome any thoughts that you may have from a user's perspective.

Sincerely,

Jules V. Tileston
Director

cc: L. Vernelli (ADEC), J. Kowalski (ADFG)

Division of Mining and Water Management
FY 96 – Navigability Project # 45 impacts with Zero budget

March 15, 1995

The following are the impacts with deletion of the Navigability Project # 45 for FY 96.

1. No technical support will be available to determine, assert, or defend State ownership of submerged lands transferred to the State under the Alaska Statehood Act. This places at risk the ownership of millions

2. Technical support will be unavailable to the Attorney General about the three rivers (Kandik, Nation, and Black) presently in Federal court.

3. Technical support to file quite title action in Federal court on all navigable waters associated with the Trans Alaska Pipeline System will be unavailable.

4. Cooperative efforts between the Department of the Interior and the State to develop a strategy that will significantly reduce the State and Federal litigation costs associated with water by water body action in Federal court will be suspended.

5. Technical support to determine whether a water body associated with a transportation project such as a road realignment, bridge, or airport extension, is or is not in State ownership will be unavailable.

6. Technical support to determine the ownership of sand and gravel or other locatable minerals such as gold placers situated below ordinary high water will be unavailable.

7. Technical advise on the ownership of submerged lands to commercial guiding operations using rivers and lakes as a principal focus will be unavailable.

8. Follow up assertions of State ownership of submerged lands in the Chugach National Forest as provided for in the Katella decision will be suspended.

9. Determinations of State ownership of submerged lands associated with the new block leasing oil and gas program will not be made.

10. Technical support will be unavailable to consider the ramifications of the pending declaration of the Secretary of the Interior about Federal sovereignty over navigable waters for subsistence purposes.

ENGR 1

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

SUPPORT SERVICES DIVISION

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2406
FAX: (907) 465-2492

February 14, 1996

The Honorable Rick Halford
Chairman of Senate Finance Committee
State Capitol, Room 508
Juneau, AK 99801

Dear Senator Halford,

At the Senate Finance Committee Overview of the DNR budget three issues came up for which we would like to provide you with additional information. They are:

1. **Navigability** - Current policy compared to what was proposed in the FY96 budget.

Attached is a memo from Jules Tileston addressing this issue.

2. **Parks funding history** - General funds vs. Program receipts.

We have attached a table with graph showing the FY86-FY97 funding history for the Division of Parks. The total funding request in FY97 is less than the general funds for the program in FY86, yet we have more park units and more visitors.

3. **Land Status GIS automation project** - status report.

This project is on schedule and should be 80% complete at the end of this fiscal year. There will be two more years of effort left to have this completed, when funded at the Governor's request level of $350.0. Attached is a write-up showing the status of this project.

I hope this additional information is helpful to you. If you have any further questions please feel free to contact me.

Sincerely,

Nico Bus
Acting Director

10-JRLH

Attachments:
Memo Jules Tileston February 7, 1996
State Park GF funding history FY86-FY97
Land Status GIS project status report

cc: Senator Steve Frank, Chairman DNR Senate Finance Subcommittee
Representative Gene Therriault, Chairman DNR House Finance Subcommittee
Members of DNR's House and Senate Finance Subcommittees
Commissioner John Shively
Deputy Commissioner Marty Rutherford
Director Jim Stratton
Director Jules Tileston
Chief LRIS Rich McMahon

MEMORANDUM

Dept. of Natural Resources

State of Alaska

Division of Mining & Water Mgmt.

TO: Nico Bus
Acting Director
Division of Support Services

Date: February 7, 1996

Telephone: 269-8625
Fax: 562-1384

From: Jules V. Tileston
Director

Subject: Navigability Program

At Commissioner Shively's recent appearance on the department budget, supplemental information was requested on the navigability program as it existed in this Division until it was eliminated from the FY 96 budget. The following describes the former program. Based on our experiences over the past year on handling important navigability issues having regional and statewide implications, I am also outlining the concepts of a navigability program that is both in balance with realistic long-term budget expectations and assuring a continuing and timely ability to resolve and pursue federal court actions to quiet title for all significant issues impacting ultimate ownership and management of resources associated with inland water bodies in Alaska.

Budget-FY96 submitted by the Knowles Administration for the navigatibility project:

Personnel Services:	$122.5
Travel:	$3.0
Contractual Services:	$5.0
Supplies	$2.0
Equipment:	$0.0
TOTAL:	**$132.5 General Funds**

These FY 1996 funds were intended to:

1. Continue systematic assertions on and provide technical support in defense of the state's title to submerged lands that are held in trust by the federal government for the future State of Alaska. It is estimated that there are over 14,000,000 acres of submerged lands associated with inland navigable waters and another 65,000,000 acres of coastal submerged lands.

2. Assemble and maintain a centralized factual and historical data base on the use, physical characteristics and court decisions influencing ownership of and access to Alaskan water bodies.

3. Work with federal agencies through pro-active partnerships and joint state-federal cooperative management agreements to identify navigable waters in Alaska. This includes collecting and exchanging information and data between state and federal land managing agencies. The primary objectives of this effort are threefold; (a) reach agreement on factual and historical data applicable to specific waterbodies, (b) reach agreement on which waterbodies clearly are or are not navigable, those waterbodies where the available data are inconclusive, and those waterbodies where the interpretation of the data are of a nature that only the federal court can resolve and, (c) reduce the necessity for water body by water body litigation. Sometimes, the interest of the federal and state governments differ and the state must be prepared to timely assert and follow through with appropriate action to protect the public's interest.

4. During FY 95, the Navigability Project resulted in navigability determinations for airport improvement projects at Chisana, Kongnignanohk, and Kwigillingok to resolve ownership questions associated with airport improvements by the Alaska Department of Transportation and

Public Facilities. Navigability determinations were made for potential gravel sources for roads, dikes, and power plant construction projects at the Kotsina, Scott, Sheridan, Makushin. Information was provided the Alaska Department of Transportation and Public Facilities and the U.S. Coast Guard both for ownership and for the type of boat traffic in support of highway bridge projects throughout the state.

5. Provide continued technical assistance to the orderly development of mineral deposits located in inland waters. This included a detailed evaluation of available hydrologic and use information and an aerial inspection of the watershed flowing out of the recent addition to the Denali National Park and Preserve. This was in direct response to an administrative appeal hearing held to collect currently available information about the prospective navigation condition of a stream at Kantishna where the ownership of the stream bed for the purposes issuing a state mining permit. The administrative record was reviewed in anticipation of litigation being filed if the state did not issue the permit. In addition, the records were reviewed to validate previous navigatible assertions on parts of the bed of the Fortymile wild and scenic river where federal agencies are attempting to extend federal jurisdiction to state ownerships expressly excluded from conservation systems created by ANILCA.

During FY 96, the Commissioner approved minor reprogramming of funding in the Division to complete several tasks to assure that the state's interest in asserting ownership of inland navigable water bodies. This included :

1. Development of a policy allowing each state entity to make navigability determinations when a permit, lease, or sale of public land or public projects, follow standard guidelines that currently applied to Alaska. The standards and criteria were distributed to state agencies and to federal land managing agencies with a request for comment. Comments were recently received from the Alaska Department of Fish and Game and a final revision to the existing Department Order is underway.

2. Developed a standardized, user-friendly electronic format for easy input to the centralized navigability data base files in the division.

3. At the request of the Alaska Department of Fish and Game, the division reviewed the hydrology and use information in the files associated with a pending transfer of the lower Russian River to private ownership. Based on this review and an onsite visit, a report asserting the Russian River was in state ownership because of its navigable condition was prepared and distributed. ADFG also identified a second river that the department should reexamine as a result of pending BLM land transfers in the Tyonek area.

4. Developed, in close coordination with the Attorney General's office, a strategy to collect information needed to defend the state's assertion in federal court that the Kandik, Nation, and Black rivers are in state ownership because they are navigable. This quiet title action was started several years ago and vigorously fought by the federal government as an issue that was not ripe for federal court action. The 9Th Circuit Court recently rejected that position and directed that quiet title action proceed. After discovery by the AG's office, the division will provide a technical analysis of the information being used by the federal government. A field inspection will be scheduled in late summer to validate hydrologic data that has broad application to a large number of non-glacial streams and small rivers in Interior, Southcentral, and Southwest Alaska. A preliminary inquiry has been made of the Department of the Interior to see if they would join in the field examination to share costs and to share data. The primary objective is to collect hydrologic data for each of the disputed stream reaches in a manner that can be stipulated in court as acceptable to both the state and the federal governments.

Current status:

Navigability determinations are routinely made as part of a land transfer from the federal government. These federal determinations are made in order to keep track of acreage entitlements since if the state

already owns the land under a water body (regardless of size) the acreage does not count against acreages specified in the Alaska Statehood Act, the Alaska Native Claims Settlement Act, and other federal entitlements to the state. To date the state has received title (either as Tentative Approval or Patent) to approximately 89 million acres; whereas, Alaskan Native Corporations have received approximately 30 million acres as Interim Conveyance or Patent. For those lands conveyed to the state, the people of the state own all lands and water. The only question is "Do specific acreages count against entitlements?" For the remaining lands pending transfer to Native Corporations, we understand that BLM is applying the "Gulkana" standard in determining whether certain water bodies are or are not to be counted against a Corporation's entitlement. Most of the remaining acreages to Native Corporations are closely associated with prior conveyances where BLM had already made a determination and acreage charges to many of the same waterbodies.

The Kandik-Nation-Black final determination will provide a supplemental set of criteria for determining ownership of land beneath inland waters.

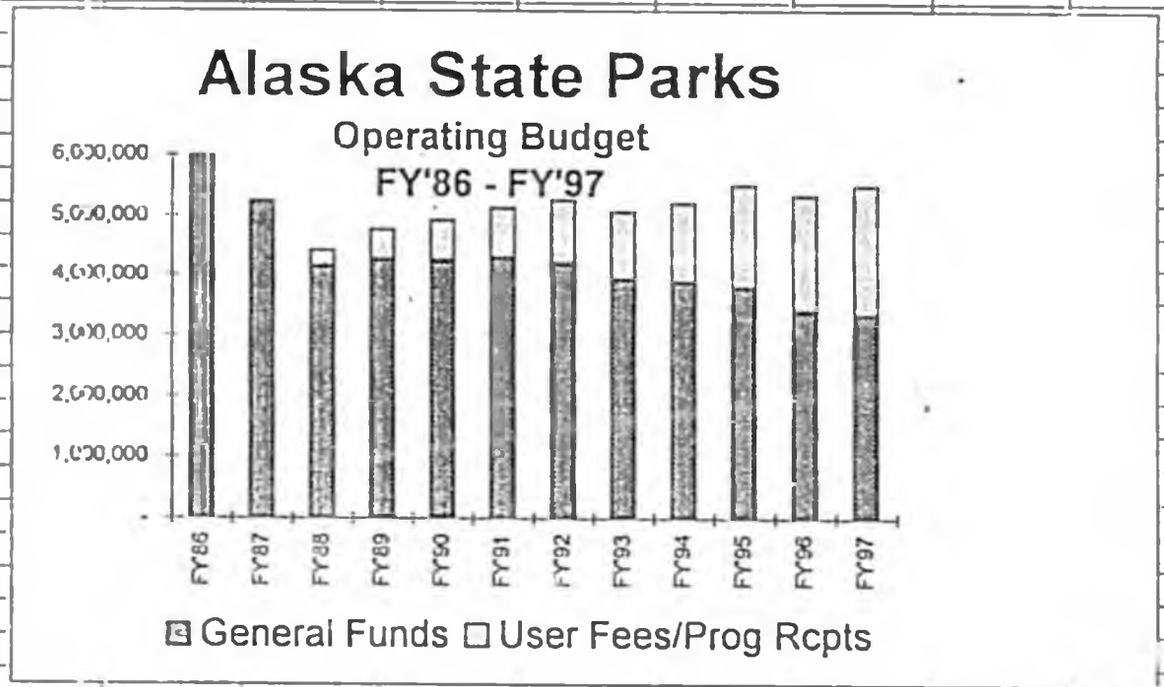
Under Department Order 125, Revision No. 5, the ownership assertion process would continue, but the cost associated with a navigability determination would be responsibility of the agency or party making the request for a use dependent upon state ownership. DNR would still have the overall responsibility to provide technical assistance to the Attorney General and other state departments in resolving, avoiding, or litigating state/federal/private disputes, and preparation of assertions when there are significant public use or resources at risk.

Accordingly, the present policy of the Commissioner to reprogram from available funds seems appropriate for projects that can be done within existing funds. However, we reserve the option to request project funding for a specific project where the work exceeds the capability of available funding and technical staff. The only major work that is not being done that should be seriously considered is the pro-active program between the federal government and the state to reduce water body by water body litigation. At this time it is not known whether there is sufficient funding or commitment at the federal level to re-establish the program that was terminated when the Navigability Project became an unfunded mandate.

cc: J. Shively, M. Rutherford

State Park Operating Budget, FY86-FY97

Fiscal Year	General Funds	User Fees/Prog Rcpts
FY'86	5,982,200	
FY'87	5,238,100	
FY'88	4,134,500	285,068
FY'89	4,245,500	532,701
FY'90	4,229,700	708,662
FY'91	4,276,400	855,127
FY'92	4,190,000	1,069,531
FY'93	3,912,500	1,156,265
FY'94	3,870,600	1,339,850
FY'95	3,772,100	1,731,167
FY'96	3,387,300	1,945,600
FY'97	3,325,800	2,173,200



CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

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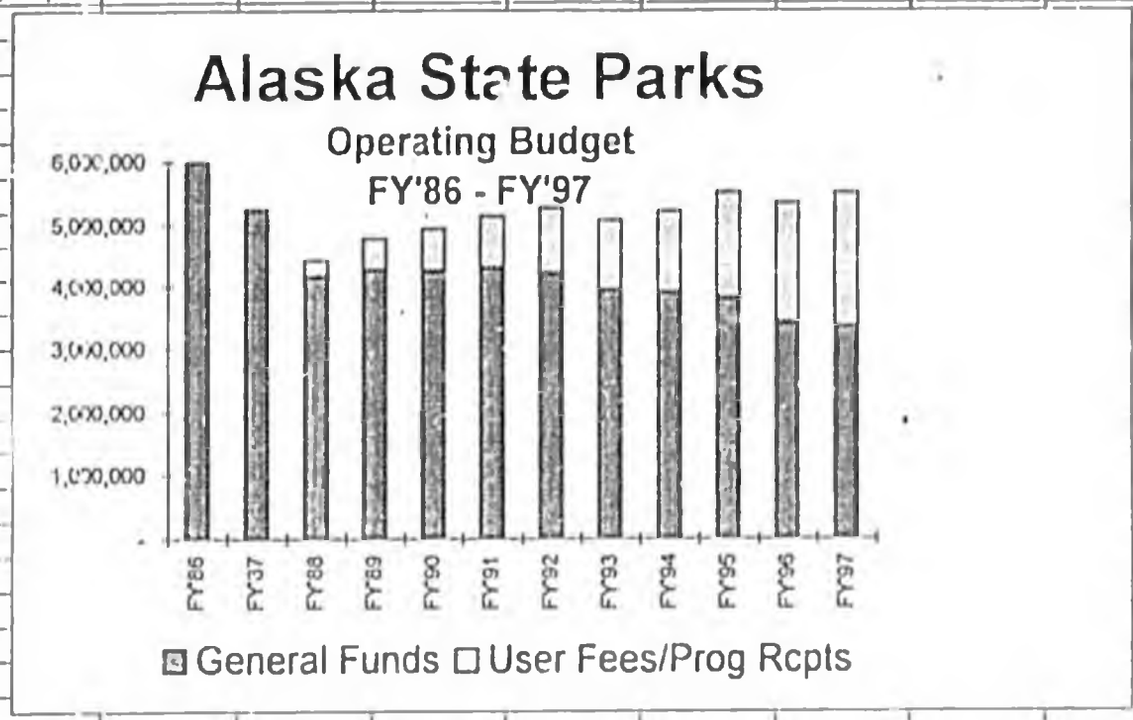

Land Status Geographic Information System Project

Brief Background:

The Land Status Geographic Information System (LSGIS) project automates the Department of Natural Resources graphic land records, called ***status plats***. These are the State of Alaska's official land status maps for all state owned land. They are organized by township, and it takes multiple maps to depict all state activity within one township of state land. This project converts manually drawn mylar maps to a digital database and produces camera ready plat maps that are distributed on aperture card throughout the department and to other land management organizations in the state, such as boroughs and the University of Alaska. Please see the FY97 IRM budget document for a complete description of the information portrayed on the status plats and the project details.

Status Report as of January 31, 1996:

From inception to date, the LSGIS project has converted and automated 6,223 townships, represented by 12,144 separate plat maps. There are currently 1,440 township left to automate. An additional 260 townships will be completed in FY96, leaving fewer than 1,200 townships to complete the job. By July 13, 1996 the project will be over 80% complete.

Why LSGIS is important to Alaska:

The LSGIS project creates a digital database that is at the core of all resource development and environmental work that takes place in Alaska. Before any project begins, the developer, regulatory compliance consultant, or government agency must determine who owns the land and what types of permits are required. For state land, this information is contained on the status plats. By turning this information into a digital database, Alaskans are no longer limited to a particular map in a particular office. The information can be made available electronically statewide through the State of Alaska's wide area network and can be at our citizens fingertips through their computers.

As resource and environmental information is automated, state agencies can re-engineer their permitting processes to take advantage of these electronic databases. For instance, when an application is received by the Department of Natural Resources, the adjudicator can pull up the electronic status plat for the area, determine whether a coastal zone review is necessary, put an electronic package together of the pertinent information for that application, and ship it simultaneously through the state's wide-area network to the other departments responsible for reviewing the application, i.e. Fish and Game, Environmental Conservation, etc. The electronic package can contain a scanned image of the application, an electronic version of the status plat with the new application depicted, and a cover memorandum outlining what needs to be addressed. The receiving agency can take information from their databases, overlay it with the electronic status plat, and intelligently respond to the issues raised in the application. I.e. Fish and Game could pull in anadromous stream data to see if the application affects any critical water bodies and respond accordingly without having to transpose DNR's information onto DF&G's maps, etc.

Without an electronic base, the status plats, agencies and the public are forced to continue the paper process for distributing and reviewing applications - a time consuming endeavor. Agencies and the private sector will continue to make redundant databases because the information is not readily

available in electronic form that is necessary for processing the many applications that are submitted each year to the various agencies. The state cannot realize true government streamlining without re-engineering the basic government processes and utilizing electronic networks to share these government databases.

What it takes to complete the LSGIS Project:

This project is scheduled to be completed in two years using in-house staff who have specialized training in converting land status to digital format. The cost is $350.0 in FY97 and $350.0 in FY98. Funding covers the salaries of the status specialists and incremental supplies. Without CIP funding, the project will not be completed.

Can the Conversion Effort be Contracted Out?

This is really a question of cost. The costs of out-sourcing the remaining work would be significantly higher because the conversion effort is interwoven with our on-going operating requirements. Detailed status records are complex. CIP staff frequently interact with the production staff in the operating budget to resolve questions on the old mylars. The original source documents cannot be released and would require copying and indexing. The quality control portion of work stays with DNR because we are responsible for the legal record. The data required to complete the project are part of the central DNR computers and would have to be duplicated, managing changes and assuring consistency during the contract period would be time consuming. The customized software used for both operating and CIP work would have to be duplicated onto contract computers making it expensive to keep separate systems synchronized.

We are looking into "out-tasking" which would deliver logical portions of the project. We don't know if this will save money or speed the process. The test area will involve automating surveys.

Can the Project be Completed Using the Operating Budget?

The project cannot be completed without incremental funding. The department's operating budget is devoted to maintaining the daily changes on the status plats, not converting manual plats to digital format. On average, the department posts 12,000 annual changes to the status plats and distributes over 80,000 aperture cards of the plats statewide. With the operating reductions over the last several years, the department already has a backlog of over 11,000 actions to post to its records. The operating budget cannot absorb the work being accomplished by the Land Status GIS project.

If you have further questions on this project, please contact Richard McMahon, LRIS Section Chief, at 269-8836 or via email at Richard_McMahon@dnr.state.ak.us.

Attachment: February 1, 1996 Progress Map