NATURAL GAS AND ELECTRIC POWER: ALTERNATIVES FOR THE RAILBELT

By

GREGG K. ERICKSON

For

The Legislative Affairs Agency
Alaska State Legislature

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FOREWORD

This study could not have been completed without the assistance -- and in some cases, the forbearance -- of many individuals. Foremost among these are Mark Wittow and Brian Rogers, who provided encouragement and moral support when it was most needed.

Ward Swift was generous in sharing his hard won knowledge of the gas situation in Cook Inlet. Lois Kramer provided indispensable assistance in making convoluted sentences more understandable, and in other important ways, as did Constance Barlow. Frederick Boness, who prepared the appendix on the Fuel Use Act, and Arlon Tussing were the author's sources for many useful insights.

For important lessons long ago taught, in this and other areas, a special debt to Dale Teel is acknowledged. Like the others, he bears no responsibility for the conclusions presented here.

The work which follows was scheduled for completion some months ago. Though the delay is regrettable, the result has been fortunate: It has allowed the author to use and build upon the work of the many other consultants to the House Power Alternatives Committee. More importantly, the issues raised by the Susitna proposal remain very much before Alaska's decision-makers, and the questions addressed here are, as the lawyers say, more "ripe" than they would have been.

INTRODUCTION

This study was commissioned by the House Power Alternatives Committee of the Alaska Legislature to review the "economic, technical and political feasibility of future development of a natural gas-based electrical economy in the Railbelt area of Alaska."[1] Although not specifically mentioned in the contract under which it was prepared, an underlying purpose of this report is to assist the legislature in its consideration of the proposed Susitna hydroelectric project, and Railbelt energy needs generally.

Other investigators have reviewed the potential of natural gas as an alternative to Susitna. All have concluded that natural gas is not a "realistic alternative" for "equivalent power supplies".[2] I agree completely. The Susitna project will presumably produce power for centuries, whereas the life of Alaska's known gas resources, at any reasonably projected rate of consumption, are measured in decades.

But posing the question in terms of alternatives for "equivalent power supplies" evades the issues of real concern to policy-makers, whether they are already convinced that Susitna should proceed, or still harboring doubts about the project.

In either case, the first real issue of concern is whether there is likely to be sufficient natural gas physically available to meet Railbelt power needs between now and 1995 or 2000. To this question my answer is an only slightly qualified "yes."

The second real issue is what must be done to assure that the physically available gas will actually be provided to power producers when they need it, and at prices they (and their customers) can afford to pay.

Here the answer is not so simple, but this much is certain: During the next 20 years the lowest possible energy costs will not be approached unless there is a substantial realignment of the decentralized and largely uncoordinated decision-making that has guided Railbelt power development in the past.

These are the issues to which this study is addressed. In analyzing them I have assumed that questions of natural gas availability and price will remain central to Railbelt power planning through the end of this century. There is no doubt that this will be the case if Susitna (or a very large coal-fired generation facility) is not built. Even if the decision to go ahead with Susitna is made this year or next, it is still prudent to carry the analysis to 2000, since long completion delays on construction projects of Susitna's magnitude are certainly possible. In any event, the policy conclusions I have reached would not be much different if the analysis had been cut off at 1995, or even 1993: There is plenty of gas, even under very conservative assumptions, but a substantial rethinking of the state's role is necessary if it is to be made available for Railbelt power needs on a timely and economical basis.

I.

In comparison with any reasonable projection of in-state demand for energy, Alaska's natural gas resource base is immense. The annual consumption of all electrical utility natural gas users in the Railbelt accounts for a little over one percent of the remaining proved reserves of non-associated gas in the Cook Inlet Area.[3] Even if the Railbelt's entire electricity production came from natural gas, it would not exhaust the known Cook Inlet resource base until the year 2071.[4]

Looking at the question of physical availability another way, electrical energy that may be produced annually by the combined Watana and Devil Canyon Dams of the Susitna Project could also be produced for 37 years with existing reserves of non-associated gas in the Cook Inlet Basin.[5]

Inclusion of the North Slope gas reserves moves these calculations out of the impressive, into the mind-boggling: The state's royalty share of the gas moving from Prudhoe Bay in the proposed gas pipeline would be sufficient to supply the Railbelt's entire electrical energy requirement (apart from existing coal and hydro capacity), and have enough left over to meet the requirements of an as yet unbuilt natural gas distribution system for Fairbanks.[6]

These rather startling figures do not prove that natural gas will actually be available for power generation well into the next century, but they do show the relative magnitudes of Alaska's natural gas supplies. If enough natural gas is not available to meet the region's electric power needs between now and 2000, the reasons will not include <u>physical</u> unavailability of natural gas; they will relate instead to factors such as competitive demands for gas that could push prices too high to compete with other generation modes, or federal policies that could forbid the use of gas for making electric power. These are important considerations, but before turning to them, a more rigorous discussion is necessary of the expected magnitude of Railbelt energy needs and the quantities of gas available to meet them.

II.

According to the Alaska Oil and Gas Conservation Commission the Cook Inlet Region contains a little more than 3.7 trillion cubic feet (Tcf)* of "estimated remaining recoverable reserves."[7]

*I have denominated natural gas in trillion cubic feet (Tcf) when discussing reserves, in billion cubic feet (Bcf) when considering flows (as in "2 Bcf daily pipeline through-put"), in thousand cubic feet (Mcf) in relation to prices, and in cubic feet (cf) when considering output ratios (as in "15.5 cubic per KWh).

Throughout this study I have used the slightly higher (3.9 Tcf) figure published by the Battelle group,[8] since the latter includes the gas which has been "rented" to oil producers for reinjection, and which is clearly a relevant part of the resource base. The Battelle figures, like those of the Oil and Gas Conservation Commission, are very conservative.[9]

Conservative figures are appropriate for this type of analysis, where an over-estimation could lead to serious problems. This is particularly true since recent discoveries and additions to known reserves have not kept pace with withdrawals for local consumption and export. Exploratory drilling in the southern part of the Cook Inlet area on offshore federal leases, as far as is publicly known, has been discouraging.

On the other hand, officials of the Pacific Alaska LNG Associates, which hopes to export Cook Inlet gas in liquefied form to California, a project about which I will have much to say later, argue that it is foolish to assume that no further discoveries of gas will be made in the Cook Inlet Basin, and suggest that additional discoveries have already been made in several areas which are not reflected in the official reserves figures.[10]

The critics of the current official reserves figures are almost certainly right: More gas has been discovered than the reserves owners have publicly announced. More will continue to be discovered. Moreover, the state intends in May, 1981, to offer leases on more than 200 tracts scattered about the region, and reports that industry interest is higher than expected. Still, no one can say with any reasonable certainty how much additional gas will be discovered. In any event, the reserves are already so large in relation to local energy needs that their expansion is not very significant from the standpoint of physical availability. Indeed, as I will show later, the growth of Cook Inlet reserves might actually make it <u>harder</u> for local utilities to obtain commitments of gas to serve their customers.

Assessing the significance of North Slope gas reserves presents a different problem. The state estimates that between 33.5 and 37.8 Tcf of gas are physically available in the Prudhoe Bay area. Of this amount, 29.0 Tcf are essentially certain to be recoverable if and when a pipeline is built to the rest of the U.S.[11] Available on the North Slope does not mean available, even physically available, for generating electricity, however.

If the Alaska Northwest pipeline is built, these reserves will become physically available in the Railbelt area. But it is clear that this will not happen unless most of the gas is destined for markets outside Alaska. Nevertheless, even a tiny percentage of this gas stream would be a very large increment to the Railbelt's energy resources. Moreover, as discussed below, it could have a most dramatic impact on energy prices throughout the region.

Unfortunately for Alaska energy consumers, construction of the pipeline is far from certain, requiring power planners to assume that in the worst case only Cook Inlet gas will be available.

III.

The uncertainties surrounding natural gas reserves are mirrored -- and perhaps magnified -- on the other side of the supply/demand equation. Fortunately, much recent investigation has been devoted to elucidating the components and determinants of Railbelt energy demand over the period between now and the year 2000.[12]

All investigators agree on one key point -- any prediction of Railbelt needs beyond the next five to ten years is extremely uncertain. The range of possibility is wide, stretching from possible decreases in consumption to growth rates well above the national average, the latter being associated with substantial increases in population and economic activity, coupled with continued low energy prices.

Despite their uncertainties, the demand studies show very clearly that the Cook Inlet gas resource is more than adequate to meet any conceivable Railbelt power needs between now and the year 2000, <u>even if one chooses to plan for the highest possible growth scenario</u>.

Assume, for example, that the "high" estimate of Railbelt power demand published by Goldsmith and Huskey, which calls for growth at a compounded rate of almost 6 percent annually is closest to the mark.[13] Assume also that an Anchorage/Fairbanks powerline intertie is completed in 1984, allowing all Fairbanks power needs save those met by existing coal plants to be supplied by gas-fired equipment. Assume also that no new hydro projects, such as Bradley Lake, are constructed. And lastly, assume that only minor improvements in the efficiency of gas usage are associated with this almost fourfold increase in energy production from gas.

The demands on the gas resource under this most extreme of scenarios come to 1.69 Tcf, or only 42 percent of the <u>proven</u> Cook Inlet reserves of 3.93 Tcf.

Interestingly, the same assumptions applied to the Goldsmith and Huskey "low" case (which "projects" a compounded electricity demand growth rate of four percent per year) is not that different a scenario: 1.35 Tcf, or 34 percent of proven Cook Inlet reserves would be required.

Goldsmith's work is the current conventional wisdom on Railbelt power demand; more importantly, it is the only rigorous study of the subject. This, and my desire to be conservative, is the reason I use it here without modification, even though I believe he will (once again) revise his "projections" downward.[14] A four percent compounded growth rate over the next 20 years is substantially above what I judge to be the lowest reasonable growth scenario.

The details of these calculations are given, with perhaps more precision than they deserve, in Appendix A. The point that they make is not dependent on precision: There is much more gas in the Cook Inlet area than Alaskans themselves can reasonably expect to consume in the next two decades, even allowing for profligacy in resource use and population growth beyond a boomer's wildest expectation.

The data already adduced to support this view are so nearly self-evident that it would be redundant to say more on the question of <u>physical availability</u> were it not that several respected experts have apparently reached exactly the opposite conclusion. Goldsmith and O'Connor are typical.

> State royalty gas, from both Cook Inlet and Prudhoe Bay, is insufficient to meet total projected instate gas requirements through 2000. In addition, <u>total present Cook Inlet reserves are not sufficient to meet total Cook Inlet gas market demand through 2000 as projected.</u>[15]

Part of the problem with this approach is semantic: Goldsmith and O'Connor use the phrase "instate requirements" to include <u>exports</u> of liquefied natural gas (LNG) from facilities <u>not yet constructed</u>. This is a substantial amount -- 1.2 Tcf over 20 years.[16]

Apart from the semantic confusion over what constitutes an "instate demand," the real problem with using the Goldsmith and O'Connor study (and similar studies) for policy purposes is that it contains a fundamental inconsistency -- the assumption that exports will grow and that reserves will not. Total Cook Inlet "demand" is difficult to determine from their figures, but it appears that they project about 7.0 Tcf over the 20 year period, or about 180 percent of existing reserves. Obviously this is an impossibility; without at least a doubling of reserves the Goldsmith/O'Connor demand scenario has no chance at all of coming true.[17]

IV.

Although sufficient natural gas is physically available in the Cook Inlet basin to meet the Railbelt's electricity and gas utility needs until well beyond the year 2000, the question of whether the power producers and gas utilities would be able to purchase it is another matter. The barriers to acquisition of the gas might be directly economic, in the form of prices too high to pay, or in the nature of arrangements under which the resource has been locked up with contracts that dedicate the known reserves to competing purchasers.

Long term contracts are common in the natural gas business. Moving gas to distant markets, whether by pipeline or LNG tanker requires large fixed investments. The same applies to almost all uses of gas as a feedstock for chemical manufacture, such as ammonia synthesis. Investors require certainty of supply before they will finance facilities that would be worthless, or nearly worthless without it.

About 60 percent of the natural gas reserves in Cook Inlet are dedicated to specific purchasers under contracts of this sort, of which .68 Tcf is committed to Alaska utilities.[18] Thus, if the utilities were to use gas for essentially all Railbelt power production during the next 20 years, they would require an additional .67 Tcf to satisfy the "low" demand scenario, and an additional 1.01 Tcf to satisfy the "high" demand scenario.

According to preliminary data from Battelle, 1.85 Tcf of the Cook Inlet area's proven reserves are currently uncommitted more than enough to meet even the "high" demand scenario.

Even the fact that gas reserves are currently uncommitted doesn't necessarily mean that they will be available. Producers will try to get the best deal possible when they negotiate the sale and dedication of their gas. How good a deal that is depends on several factors, the most important of which are the number of potential purchasers that want the gas, and how badly they want it.

The competitors for Cook Inlet gas are therefore worth surveying in some detail. At the top of the list are those users which already have invested in facilities that require an uninterrupted gas stream if they are to continue earning profits for their owners. These are (apart from the local utilities) the ammonia/urea manufacturing plant and the LNG facility (which ships gas to Japan), the two of them located at Nikiski on the Kenai Peninsula.

The aggregate requirements of the two plants from 1980 to 2000, assuming current levels of output, comes to about 2.3 Tcf.[19] Battelle's tabulation of existing contractual commitments indicates that only about 32% of this "requirement" (.73 Tcf) has thus far been secured by contracts with producers.[20]

Individually, the ammonia/urea plant has a commitment from its supplier (Union/Marathon) for about a 9-year supply, and the LNG plant, which supplies the Tokyo gas and electric utilities, has a commitment equal to only a little over 3 years' output. Between the two of them, the existing facilities will require about 1.57 Tcf of additional commitments to keep themselves operating through the year 2000. If they get that amount (assuming no new discoveries or extensions of existing fields) there will only be .28 Tcf of uncommitted reserves left to meet local power and utility requirements, not even enough to satisfy the .67 Tcf required for a gas-based electrical economy through 2000 under the "low" demand scenario.

There are at least two good reasons to expect that these two plants will be able to obtain the commitments they require to keep operating between now and at least the mid-1990's. The first is directly economic. Both plants were built many years ago (1966 for the fertilizer complex, 1968 for the LNG plant),[21] and the original capital costs of both have presumably been long since recovered or written off.

The owners of these facilities have a strong incentive to make sure their requirements are met; they have essentially no alternative apart from scrapping the plants. This alone is sufficient reason to expect them to be very aggressive competitors for future gas commitments.

Another reason for expecting that the LNG and ammonia/urea plants will obtain the commitments they need to keep operating, is that they are owned by Cook Inlet gas producers. It is no accident that the majority of gas used by each comes from the field in which the parent company holds a major interest.[22] In both cases the facilities were initially developed by producers as an outlet for gas which was then an essentially unsalable by-product of oil exploration. In both cases they currently take a product for which it is illegal to charge market prices, and transform it into a product which is not so regulated.[23]

I have made no quantitative estimate of how high Inlet gas prices would have to ascend before these vertically-integrated producers would foresake their own facilities in favor of other purchasers. At some price they would obviously be willing to do that. Between now and the time they run out of their current dedications of gas, that price is not likely to be reached.

In my judgment, Alaska's power planners (and the proponents of Susitna) are justified in assuming that the additional 1.57 Tcf necessary to keep these plants operating at current levels through the year 2000 will, in fact, go to them, and will be unavailable for in-state use for power generation.

Where, then, can policy makers expect the 1.35 to 1.69 Tcf necessary to support a natural gas-based electrical economy to be found?

As noted earlier, .69 Tcf is already dedicated to Alaska utilities, reducing the requirement to between .67 and 1.01 Tcf. Existing and expected contracts between the LNG and ammonia/urea facilities and their producer/owners will generate an additional .1 Tcf in royalty gas, which presumably will be available for local gas and electrical utilities, leaving between .57 Tcf (under the "low" scenario) and .91 Tcf (under the "high" projection) necessary to assure that natural gas can be counted on to provide for the major part of the Railbelt's electrical needs between now and the year 2000.

Where this gas comes from depends almost entirely on what happens to the state's two long-pending, gas-related construction projects, the facility proposed by the Alaska Northwest Gas Pipeline Company to carry gas from the North Slope to South 48 markets (hereinafter, Northwest), and the Pacific Alaska Associates LNG Plant (PacAlaska).

If the Northwest pipeline is operational by 1990 then the vast (in comparison with Railbelt power needs) supply of royalty gas which it will make available at Fairbanks, will supply whatever power requirements cannot be more economically met from other sources.

If the Northwest Pipeline is not constructed, disposition of PacAlaska becomes the critical element. If the LNG project does not go forward, producers' commitments of 1 Tcf (more or less) to that project will expire,[24] leaving more than sufficient gas to meet even the "high" projection of power demand. If (in the worst case) Northwest does not go forward and PacAlaska does, then a real shortfall would appear. In the extreme case the "deficit" could be as much as 38% of the total requirements for a gas-based electrical economy in the Railbelt between 1980 and 2000.

V.

Since the PacAlaska and Northwest projects clearly are crucial elements in the Railbelt gas supply, the two of them deserve a closer look. As originally filed with the Federal Power Commission in 1974, the Pacific Alaska LNG Company (now Pacific Alaska Associates) proposed to ship Cook Inlet natural gas to Southern California, to provide gas to its principal sponsor, Southern California Gas Company. The shipments were to start at a level of 73 Bcf per year, and later increase to twice that amount.[25] The project, however, encountered early regulatory and environmental review difficulties. Moreover, the reserves commitments that the sponsors (later including Pacific Gas and Electric Company) were able to obtain from Cook Inlet producers fell far short of the amount necessary to secure financing for the project.

At this writing, most of the environmental objections (which were largely to the regasification facility in California) and regulatory difficulties have been resolved, but the project seems further than ever from completion. In early 1981, Pacific Gas and Electric Company withdrew its commitment to assist in the project's financing.

Southern California Gas Company continues to support the project, though it admits that additional partners will now be necessary. Major oil companies holding gas reserves in Cook Inlet have been approached, but no commitments have been forthcoming. An additional problem is that "Phase I" is no longer considered by the sponsors to be economically viable by itself. According to them, if the facility is to go forward it must now be, on the basis of the full 146 Bcf annual output.[26]

The reasons for the declining fortunes of the PacAlaska project are significant, since they throw light on important factors which will very likely continue to influence out-of-state demand for Alaska gas. These are:

1. The largely unexpected (to the utilities) ability of consumers to reduce gas consumption in response to higher prices.

2. The increase, and expected increase, in South 48 and Canadian gas supply offerings, at least partially in response to those same price increases.

3. The failure of Cook Inlet gas reserves to grow as rapidly as projected.[27]

In my judgment, the probabilities of the PacAlaska project going forward depend on the discovery of the necessary additional reserves in Cook Inlet, and a tightening supply situation in South 48 gas markets. Since the project's successful implementation could be one of the worst things that could happen from the point of view of preserving Alaska's ability to meet in-state power needs from relatively low cost fuel sources, the result is paradoxical: Discovery of substantial additional gas resources in Cook Inlet will make it <u>more</u> difficult to meet southern Railbelt power needs in the interim period between now and whenever Susitna comes on line.

This difficulty will be of little long-term significance as far as "availability" is concerned if the Alaska Northwest Gas Pipeline is constructed as proposed, annually bringing almost 100 Bcf of state royalty gas through Fairbanks.[28] Indeed, this royalty gas stream would be sufficient, by itself, to meet almost all of the Railbelt's electricity requirements. For example, even under Goldsmith's "high" case, I calculate that the royalty stream from the Northwest project would exceed the requirement for fuel for electrical generation through 1998.[29]

VI.

It is the independent completion of one major project (PacAlaska) and the non-completion of the other (Northwest), that presents Railbelt power planners with the only potential problem with natural gas availability. The probabilities of Northwest or PacAlaska being complete by a certain date are matters about which even well informed observers are likely to disagree.[30] In any event, few of those observers are anxious to hazard their public reputations on an explicit probability estimate for this kind of event.

Neither am I. Unfortunately, this analysis requires such estimates, though -- thankfully -- no great precision is necessary to provide policymakers and power planners with reliable insights. Using plausible "high" and "low" estimates of the projects' prospects for completion indicates that the chance of a gas "availability" problem developing (due to completion of PacAlaska and non-completion of Northwest) is somewhere between three and 18 percent, with the most reasonable range of probability being between six and nine percent.

The process by which I arrived at this judgment is shown in Figures 1 and 2, and isn't the least complicated. To each project I assign an "optimistic" and a "pessimistic" probability estimate, thereby bracketing a zone of reasonable expectations about each. In the case of Northwest I consider it unreasonable to give the project less than a 40 percent chance or more than a 70 percent chance of being completed by 1990. For PacAlaska the parallel "pessimistic" and "optimistic" estimates are 10% and 30%.

Readers with different views of what is reasonable should substitute their own estimates, and work through the calculation. It isn't difficult. The exercise will show that anyone's definition of reasonable probabilities for these projects will lead to conclusions not far different from my own.

Since the only adverse outcome is the conjunction of two discreet events (completion of PacAlaska and non-completion of Northwest), the risk factor is determined by multiplying the two individual probabilities by each other. For example, the completion probability for PacAlaska of 10% (.10), shown in figure 1, is multiplied by the Northwest non-completion probability of 60% (.60) to arrive at the 6% (.06) probability in that case of an "unfavorable" railbelt gas supply situation in the 1990's.

FIGURE 1a

ASSUMPTIONS:

1. Optimistic assessment of Northwest's chances
2. Optimistic assessment of PacAlaska's chances

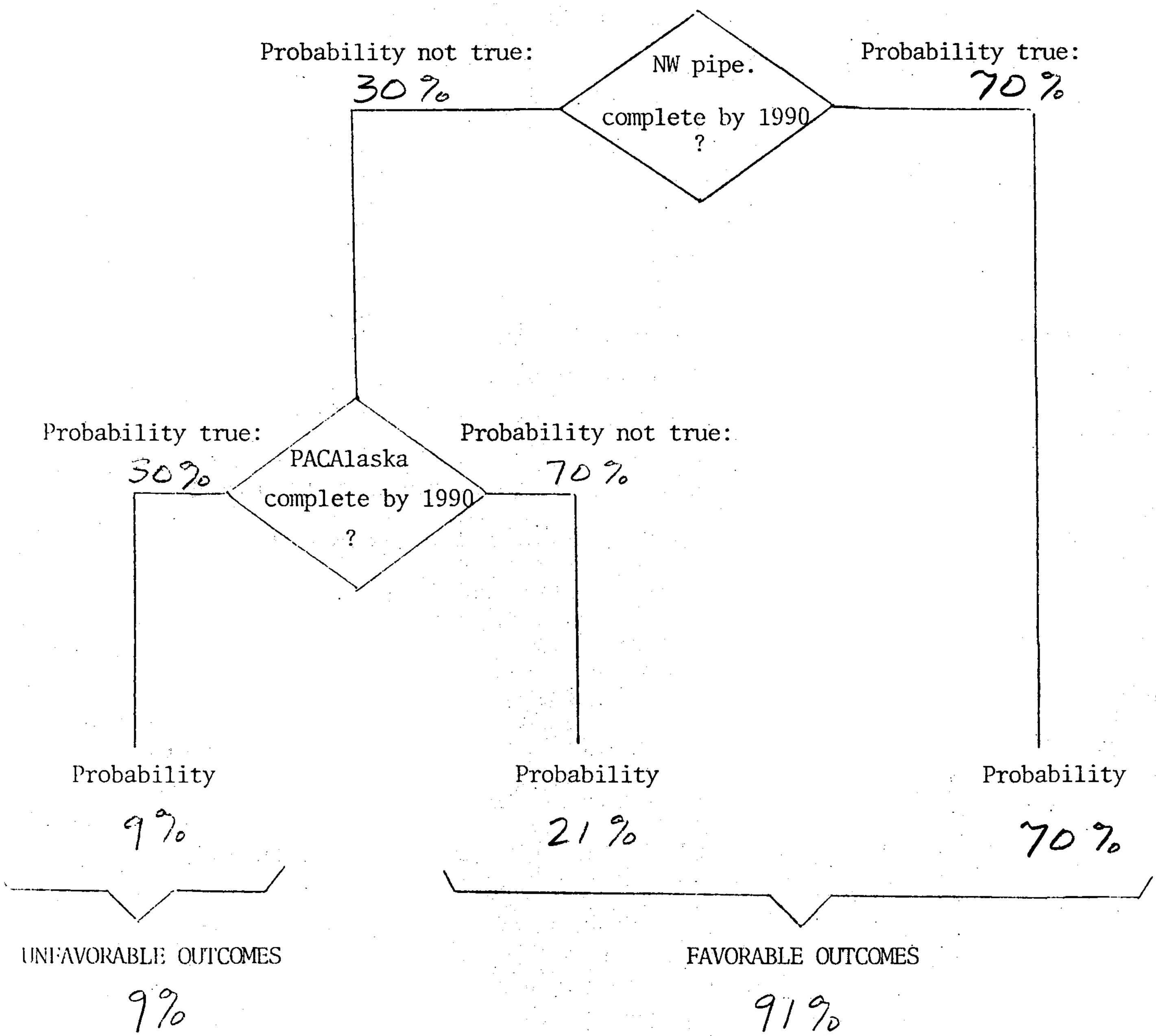


FIGURE 1b

ASSUMPTIONS:

1. Pessimistic assessment of Northwest's chances
2. Pessimistic assessment of PacAlaska's chances

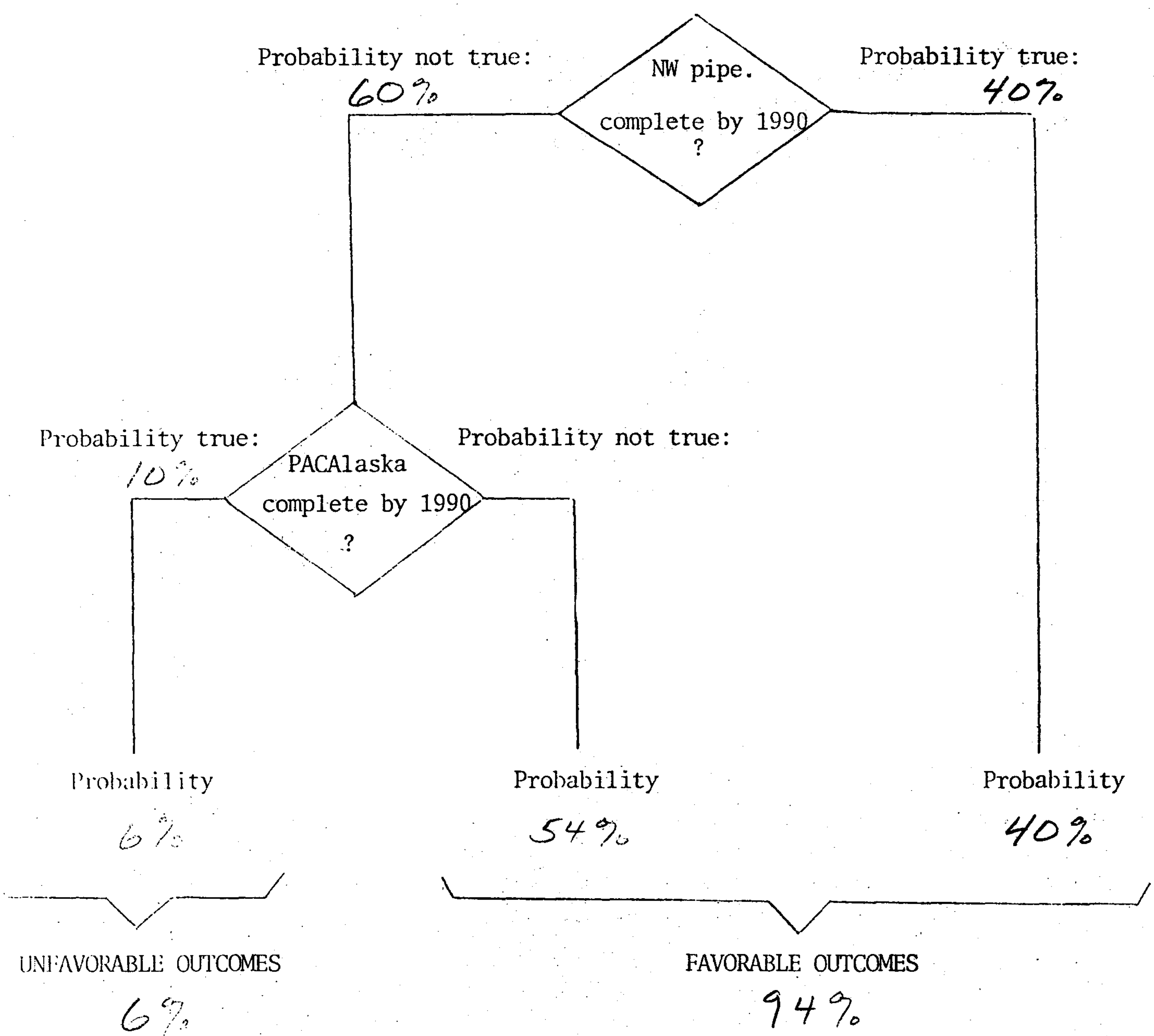


FIGURE 2a

ASSUMPTIONS:

1. <u>Pessimistic</u> assessment of Northwest's chances

2. <u>Optimistic</u> assessment of PacAlaska's chances

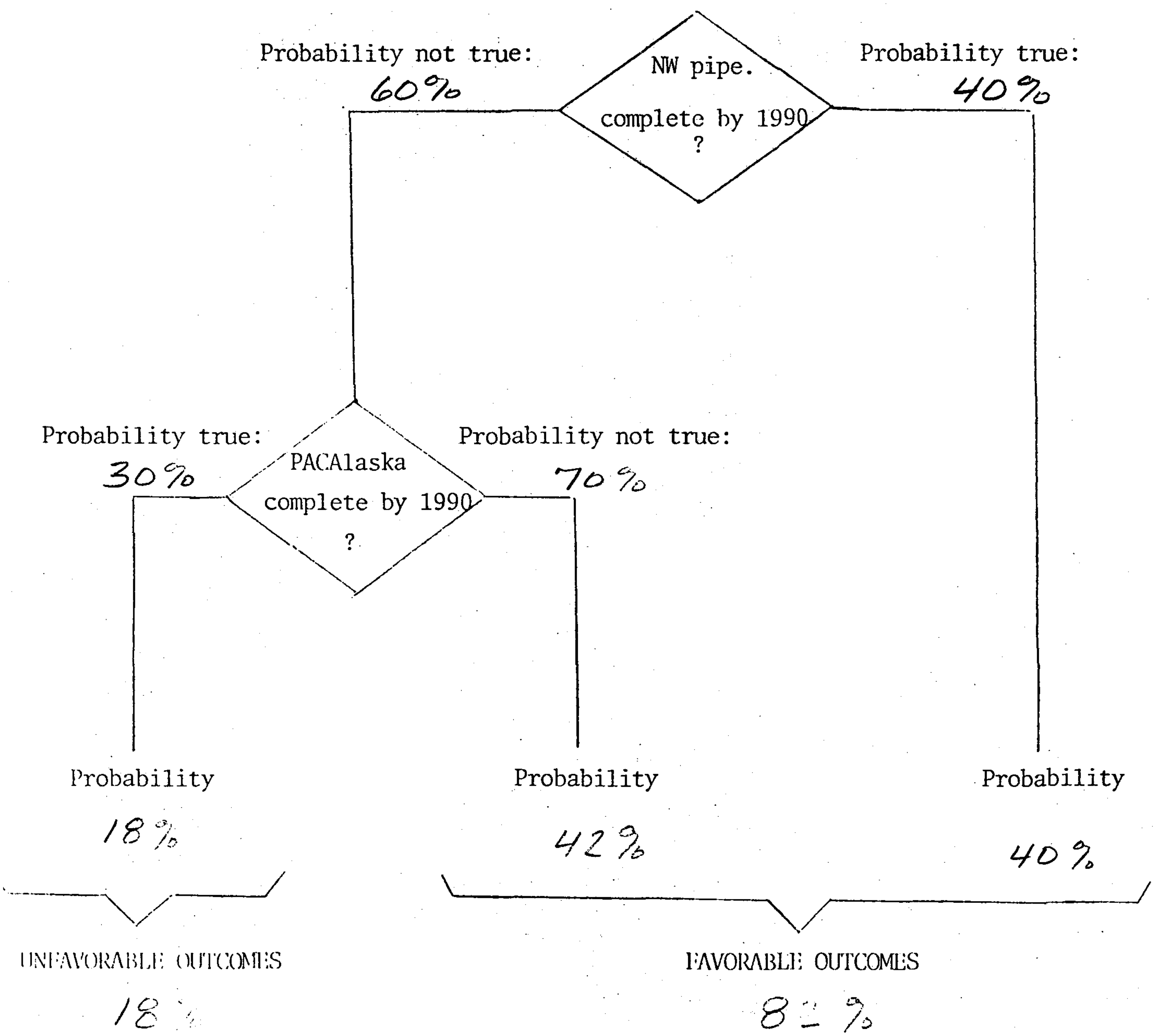
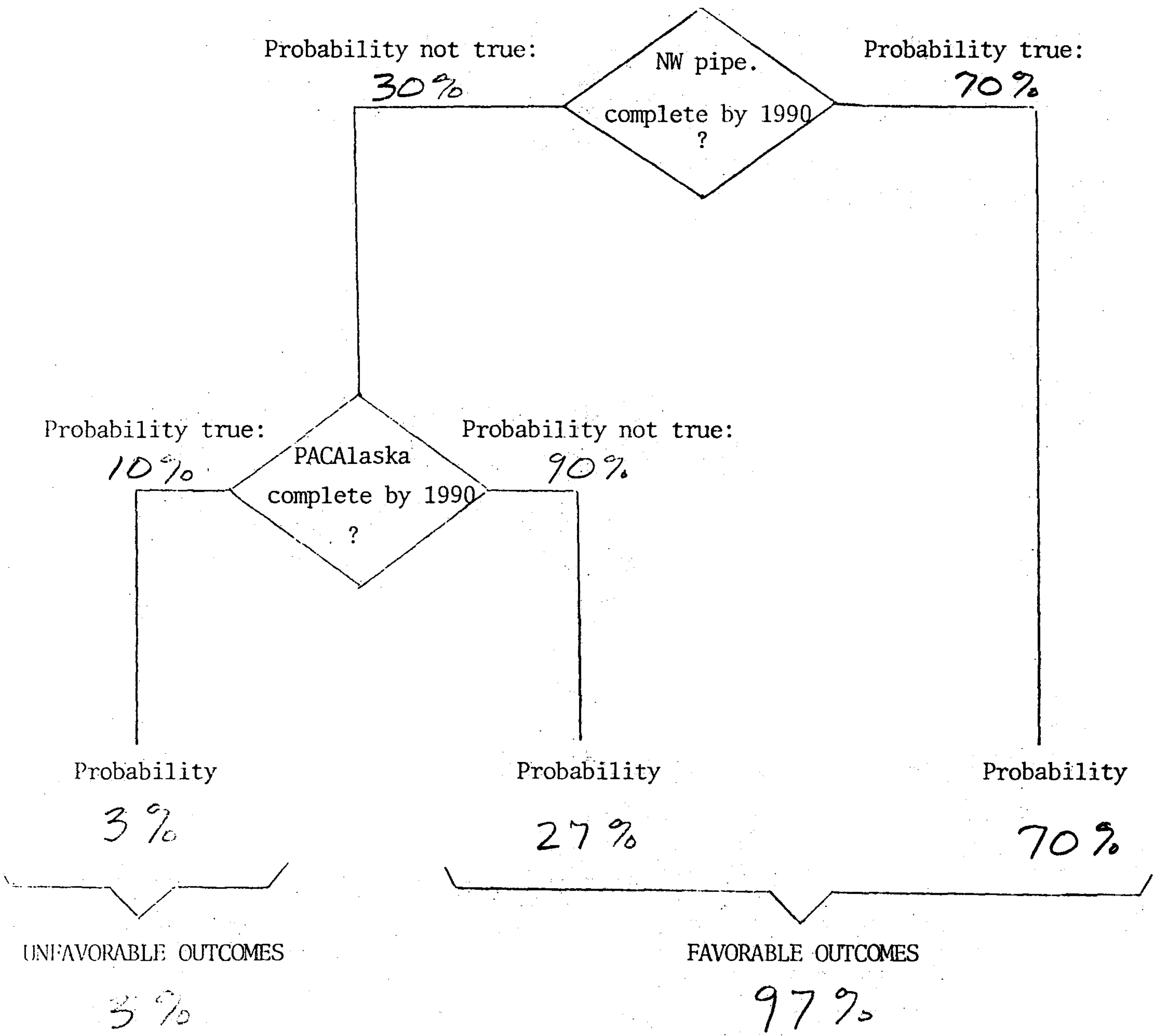


FIGURE 2b

ASSUMPTIONS:

1. Optimistic assessment of Northwest's chances
2. Pessimistic assessment of PacAlaska's chances



Of the four cases shown, the first two (Figure 1) are the most relevant, since their assumptions (optimistic-optimistic, and pessimistic-pessimistic) reflect the fact that both projects will tend to be hurt or enhanced by many of the same factors. For example, an increase in domestic demand - or a less than anticipated increase in domestic natural gas supply - would tend to enhance the prospects of both. The cases shown in Figure 2, on the other hand, assume that the major determinants of projects success differ between the two.

Obviously there are some factors that will influence one project and not the other, such as the discovery of additional reserves in Cook Inlet. But these seem far less important than those which are common to both. In any event, the cases illustrated in Figure 2, show that though the confidence interval is widened (from three percentage points in the first instance to 14.5 percentage points in the second), the midpoint estimate of an adverse outcome is not much affected by the assumption of causal independence, shifting from a 7.5 percent probability to a 10.5 percent probability.

To be conservative, and to avoid any uncalled for appearance of precision, I conclude that <u>there is about a 10 percent chance</u> that construction of PacAlaska in conjunction with the non-construction of the Northwest pipeline will create a problem of physical availability.

A 10% chance is a small but not negligible probability. The consequences of the adverse availability situation that would exist in the event PacAlaska is constructed and Northwest isn't would not be disastrous. Substantial royalty gas would remain available for power generation and gas utility use. This gas, with that already dedicated to Chugach Electric Association (CEA) and the Anchorage gas utility, would make it possible to meet the demands of the "low" growth scenario in their entirety through 1994, or the requirements of the "high" scenario through 1991. After that, however, the deficit would be very large, ranging from 70 percent to 81 percent of annual requirements for a gas-based electric economy.[31]

Under the worst circumstances, the gas turbines from which most of the region's electricity would be coming, would be converted to middle distillate fuel oil, and consumers in the entire Railbelt would pay somewhat more for their electricity.

This would be a situation not much different from that experienced today by power consumers in Fairbanks, where oil-fired gas turbines account for 55% of installed generating capacity;[32] the prices they pay for electricity are two to three times as high as those paid in Anchorage, but this is still well below the prices paid by most other consumers in Alaska and in many parts of the U.S.[33] Moreover, the prices <u>currently</u> paid for electricity in Fairbanks may not be that much different from the prices (in real terms) that all Railbelt consumers could be paying for Susitna-generated power in the 1990's.

Before moving to the much more interesting - and difficult - task of analyzing future gas prices, it is necessary to address the possibility that the use of natural gas by Railbelt utilities will be prohibited by federal law, through end-use controls of the sort contained in the Powerplant and Industrial Fuel Use Act of 1978 (hereinafter, FUA).

VII.

In its 1979 review of the alternatives to the Susitna Project, the Corps of Engineers concluded that:

> "The primary reason for not considering natural gas-fired generation as the alternative to Susitna hydropower development is not gas availability, but national energy policy. The Powerplant and Industrial Fuel Use Bill of the National Energy Act of 1978 clearly indicates that the intent of the Administration and Congress is to strongly discourage the use of natural gas for electrical generation."[34]

Even in 1979, a careful reading of FUA should have raised doubts about the clarity and strength of federal policy in this area. As noted in the analysis of FUA contained in Appendix C, most of the language in both the act and the regulations issued under it are taken up with the exemptions from its general prohibitions. For example, <u>all existing</u> powerplants in Alaska are given a special blanket exemption from its provisions. With respect to new facilities, one observer has cataloged 14 separate grounds for permanent exemptions, including "lack of capital" and inability to meet state and local environmental standards.[35]

Appendix C lists the specific grounds which are likely to be most relevant for Alaska utilities when they seek their exemptions. Although environmental constraints may be sufficient by themselves to require an exemption, I believe it more probable that Alaska exemptions to use natural gas will be obtained by either showing that a coal is not available in sufficient quantities, or that power from a coal plant would sufficiently exceed the cost of power from a plant using foreign oil.[36]

The current federal administration's well-known aversion to the kind of market tinkering that end-use controls represent is another reason to doubt that they will be imposed in any meaningful way, at least in Alaska. Neither does the mood of the 97th Congress appear particularly receptive, and substantial amendments weakening the Act are likely -- if it is not repealed outright.

Finally, the most compelling reason to believe that exemptions will be available for new Alaska power plants is that the utilities will largely be able to say, truthfully, that absent the ability to add new natural gas-fired turbines they will be unable to carry their peakloads (the "lights out" argument). Even the smallest coal-fired plant that could be built in the southern Railbelt area would require six years or more to bring on line.[37] Without new natural gas-fired turbines, any significant load growth in the interim simply won't be served.

Although exemptions from FUA will almost certainly allow natural gas to be used for power generation, there is an important provision of the act which may tend to concentrate the exemptions in the hands of the larger utilities, particularly Chugach Electric Association (CEA), which is Alaska's largest utility.[38] Except for "peakload powerplants" where failure to use natural gas would create environmental problems, FUA requires the utility to demonstrate

> that there is no alternative supply of electric power which is available within a reasonable distance at a reasonable cost without impairing short run or long run reliability of service and which can be obtained by the petitioner, despite reasonable good faith efforts.[39]

Under this section, and the associated regulations, it doesn't matter that power to be purchased is also generated by natural gas.

The exact impact of this provision on Alaska is not yet clear, but it is possible that a large utility with some excess capacity could prevent other interconnected utilities from adding any new gas-fired generators, even while the larger utility is expanding its own gas-fired plant. Municipally owned electric utilities have protested the regulations implementing this part of FUA, arguing that they would force the municipal companies to give up generation and become simply distributors for the large, predominantly privately-owned utilities.

The Railbelt electric utilities contemplating the expanded use of natural gas have no doubt already made plans for how to deal with this aspect of FUA. Since it could have substantial implications for the institutional pattern of power development, it deserves more intensive study by anyone with responsibility for the coordination of Railbelt power development.

VIII.

In recent years the prices of natural gas and electricity in the Southern Railbelt have been among the lowest in the world's developed countries. Gas rates in Anchorage are below those in every major city in the U.S. Anchorage electricity costs are the third lowest,[40] and in all probability will soon be the lowest. Barring unforeseen developments in technology or government regulation, these remarkably low relative prices can be expected to continue over the coming two decades.

The Cook Inlet area's low energy prices have resulted from the fortuitous conjunction of abundant natural gas and a remoteness from major energy markets. If natural gas or any other fuel is to have value, it must be transported to where the consumers are. The differential between its price near where it is available and where it can be sold is a function of that transportation cost.

If costs of transporting a fuel are high, as is the case with natural gas, the differential will be high. If the energy fuel is both dense and fluid, as oil is, the costs of moving it to where it can be used are relatively low, and the differential between prices in producing and consuming areas is similarly low. This explains why natural gas has historically tended to displace oil in those areas near oil and gas production (the Southwest U.S., Alberta), and why oil has tended to retain the markets distant from those areas (Northeastern U.S., Eastern Canada).

The principal has been working in Alaska over the past twenty years. In Cook Inlet we ship the oil to California and use the gas here.

Forces entirely apart from economics can distort or even reverse these facts, but only at great economic cost. The federal government may say that Alaska gas cannot be used in

Alaska, and thereby make additional gas available in states that have more congressional clout, but the economic welfare of the nation as a whole will be reduced. No amount of posturing will make it otherwise.

The best illustration of how this principal will work in the future is found in the Northwest Gas Pipeline. If gas prices are deregulated, Alaska North Slope (ANS) natural gas will not be salable in the South 48 unless it is priced, on a btu basis, at levels competitive with alternate fuels, possibly coal, but more likely heavy (residual) oil. At current U.S. prices for heavy oil ($33-42 per barrel, depending on location and sulfur content [41]) this implies a maximum delivered price for ANS gas in the $5.25-6.75 per Mcf range. If natural gas is not deregulated, there may be a sufficient volume of low cost gas flowing under old contracts to allow a rolled-in price for ANS gas of up to $9 per Mcf in 1986 when it first reaches the South 48 markets. This is the expectation of the project's chairman.[42] Although the price in 1986 could be much lower than this, perhaps as low as $3.00 per Mcf, hardly anyone expects that it would be salable at a higher price.[43]

If ANS gas reaches South 48 markets in 1986 at a price of $9 per Mcf, its price in Fairbanks will be . its well-head price plus the proportionate cost of transporting it 14 percent of the distance to those markets.[44] Under the

Natural Gas Policy Act of 1978, the well-head price cannot be more than $1.45 per Mcf, with escalation for inflation after 1977. North Slope gas, unlike most categories, would remain subject to this limit even after the phase-out of other gas price controls in 1985.

An average inflation rate over the 1977-1986, period of 10 percent would establish a ceiling price of $3.42 per Mcf, leaving 5.58 per Mcf to be collected by the pipeline in tariffs ($9.00-$3.42 = $5.58).

Most observers believe that there is no way the producers (and the state) will be able to collect the permitted ceiling price[45], but even if this was possible, the $4.20 per Mcf, price in Fairbanks of North Slope Gas would still be a tremendous bargain. For example, the equivalent price in today's (1981) dollars is $2.61 per Mcf, or $2.47 per million btu[46]. Golden Valley Electric Association is currently paying $6.42 per million btu for fuel oil for their combustion turbines, over 2.5 times as much.[47]

If, as some suggest, the well-head price of ANS gas will approach zero, and the transportation costs of ANS gas to South 48 markets can be "levelized" at about $4.00 per Mcf in 1986 dollars[48], the 1986 gas price in Fairbanks could be an amazing $.56 per Mcf, (14 percent of $4.00), or $.35 per Mcf in 1981 dollars.

Using current generation equipment at Fairbanks, gas priced at \$2.61 per Mcf (1981 dollars) could produce power at about 3.3¢ per KWh. At \$0.35 per Mcf the electricity generating costs would be 0.9¢ per KWh.[49] By way of comparison, most calculations of power costs from the Susitna Project place it in the 5¢ to 7¢ per KWh range at the busbar, assuming that the capital costs of the project would need to be paid back through power revenues.

The same principles which, if the Northwest Pipeline is built, will make ANS gas relatively inexpensive in nearby Alaska markets also govern the sale of Cook Inlet gas. Cook Inlet gas must meet or equal the prices of competing fuels in its major markets. To achieve this, its price in Alaska can be no higher than the difference between those prices and the costs of moving Cook Inlet gas to those markets.

The logical markets are, of course, Japan and California. The prices that must be met in those markets are closely if not directly related to the prices of oil.

The cost of moving Cook Inlet gas to Japan or California will be higher than the costs of moving ANS gas to its markets, since the distances are comparable, the volumes lower, and the technology (liquification verses pipeline) more expensive. Unless these conditions change in some fundamental way, the differential between world oil prices and gas prices (on a btu basis) in Cook Inlet will be greater than the differential between the ANS gas well-head price and its price in South 48 markets.

Other forces will no doubt effect how this principle will work in practice. Transportation cost to Japan will be less since less expensive foreign ships may be used, but approvals for future foreign exports of gas may be difficult to obtain. Exports of LNG to the U.S. West Coast may be economically viable, but impossible due to the lack of a receiving terminal, its construction being blocked by environmental objections.

The owners of the existing ammonia/urea plant and the existing LNG facility may be able to pay more for Cook Inlet Gas, because their fixed costs are close to zero.

A more serious distortion of the underlying economics could come if the Cook Inlet producers perceive that the only way to market <u>large</u> quantities of Cook Inlet gas is to commit it <u>all</u> to a single major project. PacAlaska is this sort of project, which is why I devoted so much attention to it earlier in this study.

The odds of PacAlaska being constructed within the next few years have become increasingly slim. Nevertheless, the project could continue to cast a shadow on Railbelt gas availability for many years, even if the producers decline, as they have thus far, to provide the necessary financial backing. The gas purchase contracts between PacAlaska and the producers, covering between .8 and one Tcf, have become subject to unilateral cancellation by the producers (and thus are not properly counted as dedications). Yet they have not been canceled.[50] The most plausible explanation is that the producers simply have not had any other offers.

The lack of other offers is not surprising. Natural gas prices in the United States are in a state of flux as the nation moves, haltingly, toward a less regulation-oriented energy market. Alaska utilities are not in any immediate supply problems, and further long-term commitments to purchase gas would probably be imprudent if they involved any significant requirements to purchase specified quantities. The economic environment is too uncertain; if Susitna is built the utility that agreed to take-or-pay for a large quantity of gas in 1995, even at favorable prices, could find itself in a very difficult position.

Moreover, the state is increasingly perceived as a credible guarantor against adverse supply contingencies. A project exporting large quantities of Cook Inlet gas could make it difficult for the Anchorage gas utility to obtain additional reserves, but it would also generate, as I noted earlier, substantial royalty gas flows, the disposition of which will be determined as much (if not more) by politics as by economics.

Readers will note that my discussion of Cook Inlet gas prices has been cast in general rather than specific terms. This is appropriate, since the difference between Pacific Basin oil prices and Cook Inlet gas prices is the only overall principle that should govern policy thinking in this area. To be specific is to be misleading, as Alaska policy-makers have indeed been misled by the calculation of how much Cook Inlet gas and electricity prices will increase if PacAlaska is constructed.[51] All these calculations have assumed, explicitly or implicitly, that a particular future pricing structure has validity because it can be found written down in a contract or a statute.

The calculation of how a particular contractual arrangement will work is useful and important, but is no substitute for analysis of the underlying economic and political forces, even if the results of that analysis must be presented in general terms.

Battelle has made preliminary estimates of future Cook Inlet gas prices, assuming that any new contracts for additional gas by Alaska utilities will have to meet the prices that producers supplying the existing LNG facility will receive. This calculation is misleading since it ignores (1) the fact that no new arrangement for sale of LNG could be made on terms anywhere as favorable to the producer, and (2) the political barriers to any increase in LNG shipments to Japan.[52]

The calculation leads us further astray by assuming a compounded increase in real, constant dollar oil prices (to which the LNG price is contractually tied) of four percent annually over a 20-year period. An increase in real terms of this magnitude is plausible, but so is an increase of only one percent. The difference is significant -- $4.59 per Mcf with the Battelle assumption versus $2.52 with the one percent assumption -- and policy makers should be aware of it.[53]

Finally, legislators need to know the significance of the numbers. An estimate for the year 2000 of a price of $4.59 per Mcf (in 1981 dollars) looks pretty high, but it is in no way inconsistent with the principle described earlier in this section: If world energy prices increase at a rate of four percent compounded, then a gas price of $4.59 per Mcf would be about one-third of what just about everyone else in the developed nations would be paying for energy. It would be, as I said at the beginning of this section, a "remarkably low relative [energy price]."

Further, gas at $4.59 per Mcf could produce electricity (assuming 11,000 btu per KWh) at about 5.5¢ per KWh and deliver it to the residential consumer at about 8¢ per KWh, a price not that much different from what fully costed Susitna Power would sell for.

IX.

The construction of the PacAlaska project, or some other scheme designed to use large quantities of Cook Inlet gas, is the only major threat to continued availability of reasonably priced gas in the Cook Inlet area. So far, the state has actually supported the PacAlaska proposal, looking ahead perhaps to the economic activity and resource revenues it will create.

I have made no analysis of these prospective benefits, but on the surface they appear very small in relation to the problems the project could create. The construction of the project, particularly the necessary network of gas-gathering pipelines, would create a short and -- by recent Alaska standards -- small construction boom. After that, the employment impact would be minimal. Resource revenues would also be minor, probably not more than a few tens of millions dollars per year, due to the low well-head value and the fact that much of the gas would come from federal leases.

If it wishes to discourage the project, there are a number of steps the state could take. Firstly, its earlier statements to the Federal Power Commission (now FERC) supporting the project could be withdrawn, pointing out that the failure to develop additional reserves, delay in the Susitna and Northwest projects, and increasing local gas demand have materially altered the situation. The state could also reiterate its intention to take in kind any state royalty gas which is generated by sales to PacAlaska.

A bolder and potentially much more effective way to discourage the project and possibly achieve other objectives would be a state purchase of substantial Cook Inlet reserves. The acquisition of, say, .5 Tcf or more by direct sale or through a trade for North Slope gas, would assure that Railbelt consumers would be protected.

The terms of such an arrangement would need to be examined carefully; it could be that the conditions necessary for a nutually attractive deal between the current owners and the state are not present. The Alaska Power Authority, or some other state entity, should be directed to determine the mutual interests and the alternative methods of acquiring additional Cook Inlet gas, and the potential benefits of doing so.

The issues raised by the state's possible role in the Northwest project go far beyond the effects that project will have on the Railbelt power situation. This impact seems, however, to have received little analysis. As I have shown here, that impact is likely to be dramatic, and should be considered carefully as the state evaluates its posture toward the Northwest project.

A third area that this study has identified as requiring particular state attention relates to the marketability of Susitna power in the face of potentially very low cost gas. If Susitna power is to be essentially given away, its marketability will not be a problem,[54] but if there is to be a charge for Susitna power, planners need to be aware that it may be difficult or impossible to sell to utilities that have lower cost alternatives. If the Susitna project is financed by a more or less conventional use of capital markets, this won't be a problem: the bond purchasers will insist that the region's utilities commit to take the power. With full state funding of the project now a possibility, if not a likelihood, the question needs to be carefully examined.

Finally, my work on this study has emphasized the truth of what other investigators have pointed out many times before: The uncoordinated and decentralized system of power planning and development that has served the Railbelt remarkably well over the years is probably not suited to the needs of the next 20 years.

If Susitna is built, the region's generation capacity, and the decisions relating to it, will be centralized as a matter of course, though the institutional arrangements for bringing that about are still unclear. The utilities, essential partners in any such arrangement, are in no hurry to surrender their independence and freedom of action.

If Susitna is not constructed, or if its construction is delayed, the role of the state in power planning and development is also bound to increase, as an increasing share of generation fuel is obtained from royalty sources.

It is too early to say what sorts of institutional rearrangements are possible or appropriate. But it is clear that the utilities will find themselves increasingly involved with the state government, and vice versa. Both parties should plan for the new relationships that will engender.

NOTES

1. "Railbelt" as used here includes the Fairbanks North Star Borough, the Matanuska-Susitna Borough, the Municipality of Anchorage, and the Kenai Peninsula Borough. The terms "southern Railbelt" or "Cook Inlet Area" refer to the latter three jurisdictions, and the electricity distribution and transmission grid centered on Anchorage. The southern Railbelt and Fairbanks area electricity grids are not now interconnected.

2. Corps of Engineers, Southcentral Railbelt Area, Alaska, Supplemental Feasibility Report (February, 1979), Appendix - Part II, p. 71.

3. Consumption was approximately 47.3 billion cubic feet (Bcf) in 1979, on a reserves base of 3.933 trillion cubic feet (Tcf). Both figures are from Battelle Pacific Northwest Laboratories, Cook Inlet Natural Gas, Future Availability and Price Forecasts, Comment Draft Working Paper No. 1.1, pp. 3.4, 3.11 (February, 1981) The Battelle data differ slightly from those published elsewhere. Other sources are Goldsmith, Scott, and O'Connor, Kristina, Alaska Historical and Projected Oil and Gas Consumption (January, 1981), and Alaska Power Administration, Regional Summary, unpublished data sheets, (March, 1980). For other sources for reserves figures, see notes 9 and 11, infra.

4. The efficiency of natural gas used for electrical generation is assumed at 15.5 cubic feet (cf) per kilowatt/hour (KWh) (see Appendix B). The total 1979 Railbelt electricity production for utilities and national defense was 2.7895×10^9 KWh (from Alaska Power Administration, op. cit.).

5. The project would annually produce 6.9×10^9 KWh. The natural gas required to produce this amount of electrical energy is 106.95 Bcf, assuming the efficiencies of existing equipment (see note 4, supra).

6. The calculation assumes that the state's royalty share would be 91.25 Bcf annually. Current (1979) electrical energy needs would require 43.2 Bcf per year (using assumptions in Note 4, supra and Appendix A). A Fairbanks' gas utility would presumably require less than the 14 Bcf taken for gas utility uses in Anchorage in 1979.

7. Alaska Oil and Gas Conservation Commission, 1979 Statistical Report, as quoted in Goldsmith and O'Connor, Op. Cit.

8. Battelle, Op. Cit., p. 3.4.

9. For other estimates, see Sweeney, et al, Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South-Central Alaska, (Stanford Research Institute, November, 1977) Table 18, p. 38. Sweeney reports six different estimates of "potential additional resources of natural gas in Cook Inlet." They range from 6.7 Tcf to 29.2 Tcf.

10. Personal communication, William L. Cole, (Vice President, Southern California Gas Company) 6 February 1981.

11. Van Dyke, William D., Proven and Probable Oil and Gas Reserves, North Slope, Alaska, (Alaska Department of Natural Resources, September, 1980), p. 10.

12. Crow, Robert, et al, An Evaluation of the ISER Electricity Demand Forecast (Energy Probe, June 1980); Goldsmith, Scott, and Huskey, Lee, Electric Power Consumption for the Railbelt (Institute of Social, Economic and Government Research, June, 1980); Love, James, et al, Energy Alternatives for the Railbelt (Alaska Center for Policy Studies, August, 1980); Tuck, Brad, A Review of Electric Power Demand Forecasts and Suggestions for Improving Future Forecasts (University of Alaska, Anchorage, May 1980); Goldsmith and O'Connor, Op. Cit.; Battelle Pacific Northwest Laboratories for the Alaska Division of Energy and Power Development and the Alaska Power Authority, Alaskan Electric Power: An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region (1978).

13. Goldsmith and Huskey, Op. Cit.

14. Compare the projections contained in Goldsmith's 1977 study, "Alaska Electric Power Requirements," Review of Business and Economic Conditions, (University of Alaska, June, 1977), with those in Goldsmith and Huskey, Op. Cit.

15. Goldsmith and O'Connor, Op. Cit., P. 41 (Emphasis supplied).

16. Ibid., p. 34. Their exact figure for LNG exports is 4.96 Tcf. They use the Oil and Gas Conservation Commission's estimate of proved reserves, 3.766 Tcf (p. 39).

17. The stated purpose of the Goldsmith and O'Connor report is satisfaction of the requirements of AS 31.05.183(d):

    (d) Oil or gas taken in kind by the state as its royalty share may not be sold or otherwise disposed of for export from the state until the commissioner

> determines that the royalty-in-kind oil or gas is surplus to the present and projected intra-state domestic and industrial needs. The commissioner shall make public, in writing, the specific findings and reasons on which his determination is based and shall, within 10 days of the convening of a regular session of the legislature, submit a report showing the immediate and long-range domestic and industrial needs of the state for oil and gas <u>and an analysis of how these needs are to be met</u>. [Emphasis supplied]

Their report, however, contains no "analysis of how these needs are to be met." Indeed, on the face of it one would conclude, absent massive new discoveries or the shipment Prudhoe gas to Cook Inlet, that they simply cannot "be met." If there are additional new discoveries, allowing the LNG exports to come to fruition then the available royalty gas will (assuming discoveries are at least partially on state land) increase as well. The report ignores this fact. Indeed, if the necessary reserves are discovered on state land the <u>royalty</u> gas available would approach one Tcf.

18. The contracts are summarized in Battelle, <u>Op. Cit.</u>, p. 3.4. Unless otherwise indicated, the information on contractual dedications is from this material.

19. This figure is calculated from Goldsmith and O'Connor, <u>Op. Cit.</u>, p. 6., based on their data for the 1979 consumption of these plants. Using the Battelle preliminary data for 1979 would have given a slightly lower amount, 2.2 Tcf. Goldsmith's estimated 1980 consumption figures for the LNG facility (based on the "first nine months of the year") indicate a substantial reduction (from 64 Bcf to 50 Bcf. To be conservative, I have ignored this reduction.

20. Battelle's preliminary estimates detail the existing contractual commitments as follows in (Tcf):

Anchorage Gas Utility	.368
Chucagh Electric Association	.310
Collier Carbon & Chemical	.499
Pacific Alaska LNG	.829+
Phillips/Marathon LNG (to Japan)	.231
Reinjection for Enhanced Oil Recovery	.106

21. Erickson, Gregg, "The Natural Gas Industry in Alaska," <u>Alaska Review of Business and Economic Conditions</u>, (Feb, 1967).

22. Phillips Petroleum Company and Marathon Oil Company are the owners of the LNG facility, the principal supplier of which is the north Cook Inlet field, the principal owner of which is Phillips, with a smaller interest held by Marathon. Additional gas (31 percent of 1979 consumption) comes from the Kenai field, major owners of which are Marathon and the Union Oil Company.

The ammonia/urea facility is owned by Collier Carbon and Chemical Company, a wholly-owned subsidiary of Union. Its major supplier is Union/Marathon's Kenai Field, with additional gas (13 percent) coming from the McArthur River Field, owned largely by Union.

23. The sale price of LNG in Japan is not subject to U.S. regulation, although its export from the U.S. requires federal approval. The current authorization expires in 1984, but could be extended. If a terminal is available to receive it, the LNG could also be shipped to the U.S. West Coast.

24. PacAlaska officials state that they currently have "just a shade over 1 Tcf under contract" in Cook Inlet (William Cole, personnal communication, February 6, 1981). Battelle (Op. Cit., p. 3.4) has identified contracts which call for delivery of .829+ Tcf. What was described as a typical example of these contracts was supplied to me by Southern California Gas Company. It contains provisions which, in effect, allow cancellation if PacAlaska has not obtained its FPC Certificate and arranged financing commitments for its project by July 1, 1979. This date has been amended three times, most recently in the fall of 1978, when the option-to-cancel date was changed to June 1, 1980. This date is, of course, long past; according to James Schroeder, manager of supply acquisition for Southern California Gas Company (personal communication, March 12, 1981), the options to cancel have not yet been exercised.

25. Pacific Alaska LNG Company, Application for a Certificate of Public Convenience and Necessity [to the Federal Power Commission], November, 1974.

26. "Alaska-California LNG Project Suffers Two Major Setbacks," Western Energy Update (16 January 1981), p. 19; William L. Cole, personal communication, 6 February 1981.

27. The judgments presented here for the declining fortunes of the PacAlaska project are my own. See, however, Pacific Gas and Electric Company, Long-Term Resource Planning, 1981-2000 (December, 1981), and the Western Energy Update Article (supra).

28. This assumes pipeline through-put of 2 Bcf per day, which is what Alaska Oil and Gas Conservation Commission orders currently permit. I do not assume that the 2.4 Bcf per day through-put which has been approved by the Federal Energy Regulatory Commission will be allowed.

29. I calculate that the 1998 requirement, under the assumptions given in Appendix A, not counting Anchorage's gas utility requirement, is 89.2 Bcf. The royalty stream would be 91.3 Bcf.

30. See, for example, Tussing, Arlon, and Barlow, Connie, Marketing and Financing Supplemental Gas: The Outlook For, and Federal Policy Regarding, Synthetic Gas, LNG, and Alaska Gas (University of Alaska, 1978), and, by the same authors, The Alaska Highway Gas Pipeline: A Look at the Current Impasse (Legislative Affairs Agency, January, 1979).

31. These figures are based on the following assumptions with respect to royalty gas:

    (1) Production from the North Cook Inlet field for the existing LNG plant and/or the ammonia/urea facility will yield 5 Bcf/year of royalty gas throughout the entire period;

    (2) An additional 2 Bcf/year of royalty gas will be available from other fields serving these two plants, commencing in mid-1988; and,

    (3) PacAlaska's gas stream will yield 15.8 Bcf/year of royalty gas, based on an annual input gas requirement of 160 Bcf and an average royalty rate of 9%.

32. Alaska Power Administration, Op. Cit. (note 3, supra).

33. The least expensive residential block rate for use (over 1500 KWh/mo.) in the Golden Valley Electric Association's Fairbanks service area is 7.46¢/KWh. The comparable rate in Chugach Electric Association's Anchorage Service Area is 2.00¢/KWh. The November 1980 average unit cost of electricity to U.S. residential consumers was 5.61¢/KWh, according to the Monthly Energy Review (Energy Information Administration February, 1981).

34. Corps of Engineers, Op. Cit. Part 1, pg. 26.

35. Cavanaugh, H.A., "How to Get a Fuel Use Act 'Cost-Test' Exemption," Electrical World (May 15, 1980), pp. 33-36.

36. There is an "Alice-in-Wonderland" quality in FUA and its regulations as they apply to Alaska that is remarkable, even in these days. One can only ponder the possible relevance to public policy of the costs that Chugach Electric Association would incur if it decided to generate its power using Saudi or Indonesian crude oil.

37. For a discussion of the coal alternative, see Erickson, Gregg, and Boness, Frederick, Alaska Coal and Alaska Power, Alternatives For Susitna (Legislative Affairs Agency, May, 1980).

38. CEA is also the largest Rural Electrification Administration (REA) cooperative in the United States.

39. PL 95-620, "Powerplant and Industrial Fuel Use Act of 1978", Sec. 213(c)(1).

40. Battelle, Op. Cit., note 3, supra, p.2.3

41. Oil and Gas Journal (March 9, 1981), p. 283.

42. Foster Associates, Inc., Foster Report No. 1291 (1980), p.9.

43. See Tussing, Arlon, "Only State Financial Aid Can Save The Natural Gas Pipeline," Anchorage Daily News, (March 28, 1981), p.E-2.

44. I assume that the average distance from wellhead to U.S. city gate would be 3,239 miles, and that the gas going to Fairbanks would travel just under 14 percent of this distance (450 miles), paying therefore, just under 14% of the tariff, in accordance with the method established by the Federal Energy Regulatory Commission (FERC). Federal Energy Regulatory Commission, Determination of Incentive Rate of Return, Tariff, and Related Issues, Docket RM-78-12, (June 8, 1979) p. 194. The "dekatherm per mile" method chosen by FERC is the same result as an "Mcf per mile" tariff, as long as the quality (btu content) of the gas removed at all offtake points is the same.

45. See Tussing, Op. Cit., note (42), supra; Chomski, Joseph M., Testimony to the Joint Natural Gas Pipeline Committee (Alaska Legislature, March 11, 1981), p.22; "Alaska Gas Pipeline: Will it End in Limbo?" Business Week (March 30, 1981) p.48.

46. This assumes a 10 percent inflation rate over the 1981-1986 period. ANS gas is assumed to contain 1056 btu per cf, FERC, Op. Cit.

47. Mr. Bob Huffman, General Manager, Golden Valley Electric Association (personal communication, 30 March 1981).

48. Tussing, Arlon, "Project Costs and First Year Gas Prices [for the Northwest Pipeline]" March 22, 1981 (personal communication), and _supra_, note 43; Chomski, _Op. Cit._

49. This assumes a base loaded heat rate of 11,000 btu per KWh (Huffman, _supra_, note 47), using the existing regenerative cycle turbines. Some modifications to the facilities would be necessary. The figure given here includes an arbitrary 0.5¢ per KWh for non-fuel generating costs.

50. See note 24, _supra_.

51. Kreinheder, Jack, _Memorandum_ "Pacific LNG Project, Research Request No. 30" (House Research Agency, February 29, 1980); Battelle, _Op. Cit._, _supra_, note 12, p. 6.37.

52. Swift, Ward, personal communication, (March 16, 1981). As noted, the estimates are specifically identified as tentative. Though I am critical of the Battelle work for the policy implications it gives, the work itself is extremely valuable, and I have relied on it extensively.

53. The four percent figure is my calculation, from the 1980 wellhead price. (Battelle, _Op. Cit._, note 3, _supra_.) and the year 2000 estimated wellhead price (Swift, _Ibid_.). Annual rate = [LN($4.59/$2.06)]/20.

54. Giving Susitna power away would have many perverse effects, and in the long run would adversely affect the interest of both the power consumer and the state as a whole. In any event, giving it away is not necessary to assure its marketability, or to transfer major benefits to Railbelt power consumers.

Appendix A
HOW MUCH GAS WOULD IT TAKE
TO MEET RAILBELT ENERGY NEEDS FROM NOW UNTIL 2000?*

YEAR	"Low" Demand Scenario: annual projected electricity requirements (KWh X 10^6)	"Low" Demand Scenario: annual natural gas requirements (Bcf)	"High" Demand Scenario: annual projected electricity requirements (KWh X 10^6)	"High" Demand Scenario: annual natural gas requirements (Bcf)
1980	1907	45.7	1907	45.7
1981	1975	46.9	2061	48.3
1982	2044	48.1	2215	50.9
1983	2112	49.2	2368	53.4
1984	2765	55.3	3227	62.8
1985	2868	56.9	3445	66.3
1986	2927	57.8	3589	68.5
1987	2989	58.8	3732	70.7
1988	3052	59.8	3876	72.8
1989	3114	60.7	4019	74.9
1990	3176	61.6	4163	77.0
1991	3323	63.9	4463	81.5
1992	3470	66.1	4764	85.9
1993	3616	68.2	5064	90.2
1994	3763	70.3	5365	94.4
1995	3910	72.4	5665	98.6
1996	4132	75.6	5943	102
1997	4354	78.7	6221	106
1998	4577	81.8	6500	110
1999	4799	84.8	6778	113
2000	5021	87.8	7056	117
TOTAL GAS REQUIRED		1.35 Tcf		1.69 cf

*For methodology, see next page.

The values in this Table were derived for the 1980-83 period as follows:

$$TGD_n = [DA_n\ (a) + GAM\text{-}GRH]\ [E-(n-1980)\ (.125)] + UGD\ (1.02)^{(n-1979)}$$

and for the 1984-2000 period by

$$TGD_n = [DAF_n(a) + GRM\text{-}GMC\text{-}GFC\text{-}GRH]\ [E-(n-1980)\ (.125)] + UGD\ (1.02)^{(n-1979)}$$

where

TGD_n = Total Annual Natural Gas Required in Year n.

DA_n = The projections ("High" or "Low") for Anchorage electric utility sales from Goldsmith and Huskey, Electric Power Consumption For the Railbelt (June 1980), p. 53. Linear interpolation was used to provide data points for years between those for which projections were published.

DAF_n = The projections ("High" or "Low") for Anchorage plus Fairbanks electric utility sales, from Goldsmith and Huskey, Ibid.

GAM = Annual military generation in the Anchorage area, assumed constant at 1979 level (134 x 10^6 KWh).

GRM = Annual military generation in the Railbelt, assumed constant at 1979 level (334 x 10^6 KWh).

GFC = Annual coal fired generation by Fairbanks area utilities, assumed constant at 1979 level (311 x 10^6 KWh).

GMC = Annual military coal fired generation, assumed constant at 1979 level (178 x 10^6 KWH).

GRH = Annual Railbelt hydro generation, assumed constant at 1979 level (200 x 10^6 KWh).

a = Adjustment factor for transmission and distribution losses (assumed to be 1.0925).

E = Gas fired generation efficiency factor of 15.5 cf/KWh. (The calculation reduces this at a rate of .125 cf/KWh/year.)

UGD = Annual gas utility demand in 1979, assumed to have been 14.04 x 10^9 cf. (The calculation escalates this by 2 percent each year)

n = Year

APPENDIX B
Table B-1

UTILITIES' SOUTHCENTRAL NET ENERGY FROM GAS AND CALCULATED EFFICIENCY

YEAR	From Gas ($KWh \times 10^6$)	Total ($KWh \times 10^6$)	Percent From Gas	Gas Use (Bcf)	Efficiency Factor (CF/KWh)
1979	1837.5	2150.4	85.5	28.924	15.40
1978	1696.6	2052.3	82.6	24.431	14.40
1977	1544.6	1920.7	80.7	23.534	15.24
1976	1473.8	1723.0	86.5	22.204	15.07
1975	1246.3	1499.6	83.1	19.619	15.74
1974	1049.1	1267.8	82.7	17.117	16.31
1973	973.1	1169.9	83.2	15.683	16.12
1972	748.2	1033.7	72.4	12.780	17.08
1971	612.6	956.1	64.1	9.980	16.29
1970	503.4**	804.4	62.6	*	*
1965	128.9**	451.3	28.6	*	*
1960	-0-	251.5	-0-	-0-	-0-

* Not available.
**By calculation, using 16.29 cf/KWh.

Sources --
1960-1970: Sweeney, Op. Cit., Note 9.
1971-1976: Alaska Power Administration, Alaska Power Statistics (July, 1977)
1977-1978: Energy Information Administration, Annual Report of Power Production, Consumption and Capacity, (July, 1980).
1979: Alaska Power Administration, Op. Cit., Note 3.

Table B-2

PLANT EFFICIENCIES FOR ELECTIRCITY

FROM NATURAL GAS

(January to November, 1979)

Plant	Energy Generated (KWh x 10^3)	Fuel Use (Mcf)	Efficiency (cf/KWh)
M L & P (1)	243,803	4,451,522	17.47
M L & P (2)	171,768	2,504,042	14.58
CEA (Knik)	23,618	698,007	29.55
CEA (Beluga)	1,092,253	15,063,858	13.79
CEA (Bernice)	76,013	1,769,195	23.27
CEA (Inter.)	17,134	705,622	41.18
	1,635,589	25,192,246	15.40

Source: Utilities' Monthly Report, (FERC Form 4)

APPENDIX C

LAW OFFICES
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MEMORANDUM

To: Gregg Erickson

From: Fred Boness FB

Date: December 31, 1979

Re: Powerplant and Industrial Fuel Use Act of 1978

Introduction

This memorandum contains a general analysis and summary of the Powerplant and Industrial Fuel Use Act of 1978 ("Act"). The discussion contained herein is based on a review of the Act, conference report, final and proposed regulations issued under the Act (and accompanying analysis), and an Environmental Impact Statement prepared after passage of the Act (April 1979). Additional sources of information which could have been, but were not consulted, are the congressional hearings held prior to passage of the Act and statements made on the floors of the House and Senate and reported in the Congressional Record. I have not reviewed these sources because I believe they are likely to contain little additional information towards understanding the basic policies embodied in the Act. Such sources are generally most useful only when one is focusing on specific provisions of the Act. Also not addressed in this memorandum are the disincentives to the use of natural gas as a fuel for power generation created by the Natural Gas Policy Act of 1978 and the Public Utilities Reform Policy Act of 1978. Finally, we should point out that there are likely to be proposals next year from both the Carter Administration and various industry groups advocating modification of the Act. The specific language to be advanced by the Administration and others is not yet available; and, therefore, is not included in this memorandum. (Reports in the energy literature referring to these proposals are attached).

The discussion which follows addresses both the substance of the Act and the procedures under which it is carried out by the Economic Regulatory Agency of the Department of Energy. After a brief discussion of the Act's applicability to several classes of facilities, the remainder of the discussion focuses only upon new electric powerplants.

The Basic Principles and Procedures

The basic purpose of the Act is to require existing powerplants and major fuel-burning installations (MFBI) to switch from the use of natural gas or petroleum to coal or other alternative fuel, and to prohibit newly constructed powerplants or MFBI's from using gas or petroleum as a primary fuel. The Act does this by creating separate rules and requirements for the following four types of facilities: 1) new electric powerplants; 2) existing electric powerplants; 3) new major fuel burning installations; and 4) existing major fuel burning installations. Under the Act, new electric powerplants may not use natural gas or petroleum as a primary energy source and no new electric powerplant may be constructed without the capability to use coal or other alternate fuel as a primary energy source. (Sec. 201).* Likewise, no new major MFBI may use natural gas or petroleum as a primary energy source for boiler fuel. (Sec. 202). Also under the Act, existing electric powerplants may not use natural gas as a primary energy source after January 1, 1990 and in the case of certain electric powerplants, before 1990. (Sec. 301(a)). Where coal is available, the Secretary is authorized to issue orders prohibiting the use of gas or petroleum by existing electric powerplants. (Sec. 301(b)). The prohibitions relating to existing electric powerplants do not apply to Alaska. (Sec. 104). Finally under the Act, the Secretary is authorized to prohibit the use of petroleum or natural gas as a primary energy source in existing MFBI's if he makes certain findings. (Sec. 302). This provision does apply to Alaska but is not analyzed here.

Although the prohibitions in the Act are unequivocal, there are numerous grounds for temporary and permanent exemptions from these prohibitions. Indeed, most of the language in both the Act and the regulations promulgated

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* Simplifying somewhat, a new electric powerplant is one for which construction or acquisition had not begun on or before November 9, 1978 and consists of a stationary (which under the regulations can include certain types of portable) electric generating unit and has a design capability of consuming any fuel at an input rate of 100 million Btu's per hour or greater. A smaller unit can also be a powerplant if it is aggregated, at the same site, with other units which together use at least 250 million Btu's per hour. (Sec. 103(a)(7) and (a)(8) and Part 500.2). Section citations refer to the Act; Part citations refer to the regulations in 10 CFR.

under the Act relates to the exemptions, not to the prohibitions. Temporary exemptions for new powerplants may be granted for a period of up to five years in most cases, and in a few limited situations, for up to ten years. (Sec. 211(e)). A permanent exemption is for the life of the facility. However, the Secretary is authorized to grant both temporary and permanent exemptions upon such terms and conditions as he deems appropriate; and this may include a review of the circumstances upon which the exemption is based. (Sec. 214(a)). Any exemption may be terminated if the holder of the exemption fails to comply with the terms and conditions contained in it. (Part 503.12). We note here that a exemption may be granted exempting a utility only from the gas or petroleum use prohibition. In that case, a new powerplant authorized to burn gas or petroleum may nevertheless be required to possess the capability to use coal or any other alternate fuel as a primary energy source.

The Secretary has adopted, by rule, a comprehensive procedure for parties* to follow in seeking exemptions from the prohibitions of the Act. Proposed rules applicable to new powerplants and MFBI's were first issued on November 17, 1978. (43 F.R. 53974). Hearings were held in February on those proposed rules, and on May 17, 1979 ERA issued final interim rules.** The November proposal had contained a general requirement that to obtain any exemption the applicant had to submit a comprehensive report, called a Fuel's Decision Report, which report presented, analyzed, and ultimately rejected for specific reasons, a wide range of alternatives to the applicant's proposed use of natural gas or petroleum as a primary fuel in its proposed new powerplant. The rules adopted in May retained the Fuel's Decision Report requirement, but reduced the amount of information

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* In most instances, it would seem the party which will apply for an exemption will be the utility which wants to build and own the powerplant.

** That is, the rule is final but ERA will continue to receive comments and may make changes as a result of such comments.

which the report must contain.* The format for the report, as well as the generalized contents of a FDR, are described in 10 CFR Part 502 (44 F.R. 28974, attached).

After the Secretary receives a request for exemption and supporting documentation, he is required to publish a notice in the Federal Register and allow any interested persons to comment thereon. (Sec. 701). The Secretary is also authorized to require any person subject to the Act to "submit such information and reports of any kind or nature directly to the Secretary necessary to implement the provisions" of the Act. (Sec. 711). In the regulations, it appears the Secretary will utilize this provision to require various types of reporting.

The Act contains both civil and criminal enforcement provisions. Any persons who willfully violate the Act, or any rule thereunder, is subject to a fine of not more than $50,000 and imprisonment for not more than one year or both. (Sec. 722). Civil remedies include payment of a penalty of up to $25,000 per violation, with each day being a separate violation. For powerplants granted an exemption, the Secretary may assess civil penalties of up to $10/barrel of petroleum and $3/MCF of natural gas used in operation of the powerplant in excess of that authorized by the exemption. (Sec. 723). Also, the Secretary, <u>or any aggrieved person</u>, may bring a civil action for injunctive or equitable relief. (Sec. 724 and 725).

Exemptions

As noted above, the Act authorizes both temporary and permanent exemptions. Temporary exemptions are for situations where the new powerplant cannot immediately comply with the prohibition against use of natural gas or petroleum but will be able to do so after some period of time. (A simple example would be where sufficient coal

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* The peak load exemption and the emergency exemption (discussed in the next section) do not require a FDR. The applicant is required only to certify a particular (and limited) use of the plant to qualify for these exemptions. By the terms of the Act, the petitioner need not rule out the use of alternative fuels to qualify for these exemptions and thus need not submit a FDR.

supply is not available when the plant comes on line but will be available later.) Generally the grounds for, and standards applicable to, temporary exemptions are the same or almost the same as for permanent exemptions. In the following discussion, we address principally permanent exemtions. The most significant difference is that there are two alternative cost tests, a "general cost test" and a "special cost test," available for applicants seeking a temporary exemption. An applicant seeking a permanent exemption has no choice of cost tests; he must use the "general cost test".

In addition to the specific grounds discussed below for an exemption, the Act establishes a number of general requirements which must be met before any applicant may receive a permanent exemption.* (Sec. 213). These are as follows:

1) The applicant must demonstrate that the use of a mixture of natural gas or petroleum and coal or other alternate fuel is not economically or technically feasible. Under the Act and regulations, "mixture" includes both simultaneous and alternate use of gas or petroleum and coal or other alternate fuel in the same unit. (Sec. 103(28)). An applicant demonstrates that it cannot comply with this mixtures requirement by assuming it is going to use a mixture and then showing that by making such use, the applicant would qualify for a "lack of alternate fuel" (which includes a cost test), "site limitation", "environmental requirement", "inability to obtain capital", or "State or local requirement" exemption, or by showing that use of a mixture is not technically or economically feasible due to design or special circumstances (which circumstances are not defined in the regulations). (Part 503.9).

2) If ERA makes a site specific or generic finding that fluidized bed combustion of alternative fuels is economically and technically feasible, then the Secretary may deny all permanent exemption requests unless the applicant demonstrates that with the use of fluidized bed combustion, applicant would qualify for one of the exemptions listed in 1) above. (Part 503.10).**

3) The Secretary may not grant a permanent exemption

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* Except that general requirements "1)" and "2)" in the text above do not apply to the "mixtures" exemption and the "peak load powerplant" exemption and general requirement "3)" above does not apply to the "cogeneration" and "peak load powerplant" exemptions.

** The Secretary has not made such a finding and thus, at least for now, this requirement seems unimportant.

for a new powerplant if there is available to an applicant a supply of electric power "within a reasonable distance at a reasonable cost without impairing short-run or long-run reliability of service". (Sec. 213(c)). The discussion of this provision in the preamble to the May 17 regulations suggests that this requirement is quite troublesome to many utilities. It appears several municipalities alleged the requirement would force municipal systems to become merely distributors of power rather than generators of power. (44 F.R. 28961). To satisfy this requirement, an applicant for an exemption must show (among other things) that he has solicited contracts to purchase power from other sources (including nonutility sources) within and contiguous to his electric region, and that he is unable to purchase a firm supply for a cost that is less than 10% above the annualized cost of generating power from his proposed gas or petroleum fired plant during the first year of operation of the plant. (Part 503.6). This requirement could result in the use of older, less efficient gas or oil burning plants being used to generate electricity for sale to applicants who wish to build newer, more efficient facilities. There is, however, little flexibility for avoiding this result because the requirement to consider purchased power as an alternative is an express provision of the Act. (Sec. 213(c)). ERA has recognized this possible outcome. (See 44 F.R. 28961).

4) An applicant must also demonstrate that it cannot satisfy the alternative fuels requirement by locating its facility at a reasonable alternative site. (Part 503.11).

After an applicant has made a showing that he has satisfied all the general requirements for an exemption, he must then demonstrate that he can satisfy the requirements for a specific exemption. The grounds for specific exemptions are as follows:

1) The Secretary <u>must</u> grant a permanent exemption if he finds that an applicant has demonstrated that, despite diligent good-faith efforts, an adequate and reliable supply of coal or other alternate fuel for use as a primary energy source will not be avilable for the first 10 years of the useful life of the proposed powerplant; or such alternative fuel is available only at a cost which substantially exceeds the cost of using imported petroleum as a primary energy source during the useful life of the powerplant. (Sec. 212(a)(1)(A)). This exemption specifically requires that the applicant consider the use of coal. It also requires assessment of other alternate fuels, which are defined to include electricity, coal, solar energy, petroleum coke, shale oil, uranium, biomass, municipal, industrial, or agricultural waste, wood, renewable and geotheormal energy

sources, and any fuel derived from an alternate fuel. (Part 500.2). A petitioner is not required to consider all of these alternatives, but only those which are reasonable given his particular circumstances. (44 F.R. 28951). Under the regulations, the applicant demonstrates that such supplies are not available by submitting evidence that he has sought at least five bids from suppliers who could reasonably be

expected to provide an adequate and reliable supply of the quality and quantity of alternate fuel needed during the first 10 years of the new powerplant. (Part 503.31).

To obtain an exemption on the ground that the cost of using alternative fuels substantially exceeds the cost of using imported petroleum, an applicant must demonstrate that the cost of the alternative fuel is at least 1.3 times greater than the cost of using imported oil taking into consideration capital costs and annual operating and maintenance expenses. The cost of using imported oil and the alternative fuel are each discounted to present value before the comparison is made. The procedures and formulas (including a sample calculation) used for making these calculations are set out in Part 503.5 of the regulations which also explain the different standards applicable to permanent and temporary exemptions.

2) A second basis for a <u>mandatory</u> exemption is where there exist specific site limitations which do not permit the use of coal or other alternate fuel as a primary energy source. (Sec. 212(a)(1)(B)). Site limitations include matters such as lack of transportation facilities for alternate fuels, inadequate room for handling or storage facilities, lack of adequate and reliable supply of water, and similar matters. (Part 503.22).

3) The Secretary <u>must</u> grant an exemption where an applicant shows that compliance with the prohibitions would cause him to be in violation of applicable environmental requirements. (Sec. 212(a)(1)(C)); or where the use of coal or other alternate fuel would not allow the applicant to obtain adequate capital for financing of such powerplant. (Sec. 212(a)(1)(D)).

In each of the above instances, the applicant must demonstrate that he has attempted to overcome the difficulty requiring him to seek exemption by considering alternative sites for the powerplant; and that such alternative sites also would require an exemption. (Part 503.11).

4) The Secretary, <u>in his discretion</u>, may grant an exemption where the proposed powerplant could use coal or another alternate fuel supply but for the existence of a state or local requirement (other than a building code, a

nuisance, or a zoning law).* Before an applicant can qualify for an exemption under this provision, he must demonstrate that he has considered obtaining a variance from the State or local requirement or that none is available. He must also demonstrate that alternative sites are not available which would avoid the problem and that granting the exemption would be in the public interest and consistent with the purposes of the Act. (Part 503.36).

5) The Secretary may grant a permanent exemption where an applicant is proposing to construct a cogeneration facility and he demonstrates that the economic and other benefits of cogeneration are obtainable only if he uses petroleum or natural gas or both in the proposed facility. (Sec. 212(c) and Part 503.37).

6) The Secretary must grant an exemption if the applicant demonstrates that the powerplant will use a mixture of petroleum or natural gas and coal or other alternate fuel as its primary energy source, provided the amount of petroleum or natural gas used is the mininum required to maintain plant reliability. (Sec. 212(d) and Part 503.38).

7) The Secretary is required to grant an exemption for a powerplant which would be used only for emergency purposes. (Sec. 212(e)). Under the regulations, emergency is described as an instance where the utility would be required to curtail noninterruptible supply to its industrial customers. (Part 503.39).

8) The Secretary may grant a permanent exemption where the applicant demonstrates that the exemption is necessary to prevent impairment of reliability of service; and the applicant is not able to make the demonstrations that he is entitled to a permanent exemption based on lack of alternate fuel supply, site limitations, environmental requirements, inability to obtain adequate capital, or due to certain State or local requirements in time to prevent the impairment of service. (Sec. 212(f)). In demonstrating its eligibility for an exemption under this provision of the Act, the applicant is required to use the "loss of load probability technique." (Part 503.40). The regulations emphasize that the Secretary's authority to grant such an exemption is discretionary and that he reserves the right to deny the exemption even if an applicant presents a case which

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* If the State or local requirement is an environmental requirement, it is treated under the exemption provision discussed above.

meets the objective criterion set out in the regulation. Furthermore, the regulations make clear that stringent terms and conditions will be attached to this exemption which will allow operation of such powerplant only for the purpose of preventing an impairment of reliability of service, and for no other purpose.

9) An applicant may obtain a mandatory exemption from the Secretary to use petroleum in a powerplant if a petitioner certifies that such powerplant is to be operated solely as a peak load powerplant.* (Sec. 212(g)). The applicant may use natural gas in a peak load powerplant only if the Administrator of the Environmental Protection Agency certifies to the Secretary of Energy that use of coal or an available alternate fuel by such powerplant will cause or contribute to a concentration of a pollutant for which a national ambient air quality standard is or would be exceeded. (Part 503.41(a)(2)(ii)). Under the regulations, a utility must report annually on the use of its peak load powerplant; and if it exceeds the amount of use authorized by the Secretary, the applicant is subject to various penalties. (Part 503.41 (d) and (e)).

10) The Secretary may grant a permanent exemption for intermediate load powerplants provided a rather long list of specific conditions are met; which list includes: 1) that the powerplant to be constructed and operated will replace no more capacity than existing electric powerplants which use natural gas or petroleum as a primary source; 2) that the powerplants be owned by the same person; and 3) that the net heat input rate for the new powerplant will be maintained at or less than 9,500 Btu's per kilowatt hour throughout the useful life of the new powerplant. (Sec. 212(h)). Essentially, this exemption allows for the replacement of inefficient powerplants using natural gas or petroleum as a primary source with more efficient plants using natural gas or petroleum, but only under limited circumstances. (Part 503.42).

Preliminary Conclusions and Recommendations

1) It appears there do exist grounds under which any of the utilities along the Railbelt might qualify for a permanent exemption from the requirement of the Act to use

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* A Fuel Use Report is not necessary to obtain this exemption.

coal or other alternate fuel. Such grounds might include (a) lack of alternate fuel supply for the first 10 years of the useful life of the facility; (b) lack of alternate fuel at a cost which does not substantially exceed the cost of imported oil; (c) site limitations (this seems less likely); (d) inability to comply with applicable environmental requirements, and (e) inability to use alternative fuel because of a State or local requirement.

It should be noted that some of these exemptions are based on economic factors and some are based on legal or political constraints. Generally, where the exemption is based on economics, the Secretary must grant an exemption. Where the constraint is legal or political, the Secretary's obligation to grant an exemption is sometimes mandatory - as in the case of environmental constraints, and sometimes discretionary - as in the case of State or local requirements. Finally, states or localities can influence the use or non-use of coal by the pollution standards they adopt. California's air quality standards are the best example of this.

2) A caveat to the above is that a surplus of electric power by one utility may be regarded as an alternate power supply for another utility which wants to build a new powerplant. The requirement of the Act and regulations to consider surplus power as an alternate fuel before being entitled to an exemption should be carefully analyzed in the context of Alaska utilities. I suspect it has significant consequences for the interplay between the existing (and competing) utilities. The creation of interties among the systems may also effect significantly the availability of excess power as an alternate fuel source.

3) This memorandum is based entirely on the paper record. I strongly recommend discussions with ERA officials and Congressional staff responsible for the Fuel Use Act. For example, it would be useful to know why Alaska is exempt from the prohibitions applicable to existing powerplants but not those applicable to new facilities, (Chugach Electric representatives probably could explain this too). Discussions with program administrators most likely will turn up many nuances in the statute and regulations which one does not glean from a mere reading of them. There are also many questions not addressed in the regulations but which must be dealt with by the agency on a regular basis. These include such things as: To what extent may one utility use the work submitted by other utilities? What kinds of "terms and conditions" are being attached to permanent exemptions based

on cost or lack of alternative fuel? Is the agency requiring reassessment periodically?

4) If it is possible to develop a plan or series of options, (some of) which may be prohibited by the Act, by beginning discussions now with D.C. administrators and Congress, it may be possible to obtain legislation necessary to allow implentation of a plan at the time amendments to the Act are considered in Congress next year.

5) The fact that natural gas (or for that matter domestic petroleum) is available and less costly to use than either coal or foreign petroleum plays no direct role in determining whether a utility may receive an exemption to use that gas or petroleum. It is only the delivered cost of imported petroleum which is relevant for cost comparisons. (Part 503.5(b) and (d)(2)).

Attachments