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POLICY ANALYSIS PAPER NO. 82-13

Alaska Energy Planning Studies

A review of three consultant studies
submitted to Alaska state agencies
in fiscal-year 1982

November 18, 1982

STATE OF ALASKA

OFFICE OF THE GOVERNOR

Division of Policy Development and Planning

POUCH AD

JUNEAU, ALASKA 99811

(907) 465-3577

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for Division of Policy Development and Planning
Office of the Governor
State of Alaska

by Arlon R. Tussing

and

Gregg K. Erickson

INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH
UNIVERSITY OF ALASKA

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APPENDIX

ALASKA ENERGY PLANNING STUDIES

Introduction and Summary

Introduction. During the first half of 1982, Alaska state agencies received three major energy-policy reports they commissioned in 1980 and 1981. The fir t of these is the second annual "Long Term Energy Plan" mandated by the Legislature.[1] Two others specifically address issues raised by the proposed Susitna hydropower project (hereinafter the "Acres" and "Battelle" reports).[2,3]

> **Unfortunately, these newly-delivered reports are already largely obsolete.**

Their critical assumptions regarding price trends for various fossil fuels, the growth of population and economic activity in Alaska, and the resulting growth of energy demand in the state, are based upon a conventional wisdom about future energy prices that subsequent experience has made nearly untenable.

The Division of Policy Development and Planning (DPDP) of the Governor's Office engaged the University of Alaska Institute of Social and Economic Research (ISER)[4] to review the three study reports and to identify and discuss those areas that are central to the reports' conclusions, particularly with regard to investment in new electrical-generation facilities in Alaska's "Railbelt" (roughly the corridor from Fairbanks through Anchorage to the Kenai Peninsula).

Readers should be aware that this paper is only a **review** and not intended as a successor to or substitute for any of the existing studies. The following pages are intended to cover a few crucial issues in sufficient depth to determine whether or not the reports make a solid case for their findings. In large, the answer is "no", but any new recommendations about an optimum energy-development strategy will have to await a new study or amendment of one of the existing studies.

Summary. Briefly, the findings of this review are that:

1. World Oil Prices and Alaska Energy Demand. The dramatic change in oil-price expectations since 1980 calls for reconsideration of the levels of Alaska economic activity and energy demand assumed in the Acres and Battelle studies, and to a lesser extent in the Long Term Energy Plan.

2. Alaska Coal and Natural-Gas Supply. The assumptions in the Battelle and Acres studies concerning the prices and availability of Alaska coal and natural gas for local electric power generation are not well supported.

3. Capital-Market Conditions. Recent high interest rates and capital-market conditions not dealt with by the contractors cast serious doubt on the Acres and Battelle conclusions regarding the risks, costs, and financing arrangements of the Susitna hydroelectric project, and with respect to capital-intensive energy-supply projects generally.

4. Implications for Susitna. Findings 1-3 imply significantly less favorable conclusions from those of Acres and Battelle regarding the relative economic attractiveness of the Susitna hydroelectric projects for serving electricity demand in the Railbelt region.

5. All of these findings point toward a conclusion that now is not the time for major initiatives in publicly financed power development in Alaska.

Despite the erosion of some of their fundamental assumptions, the analytical framework and much of the data presented in the reports remain useful --- even essential --- to evaluating Alaska's choices with respect to the Susitna project in particular, and energy issues in general.

Background to the Studies

Energy looms bigger in Alaska's public-policy deliberations than in any other state. Elsewhere --- even in states with a history of economic activism, like Wisconsin or California --- no one would consider as even plausible a scheme to invest public funds equivalent to two or three times expected annual state tax revenues (or about $15 thousand per capita) in all energy ventures as a class, let alone to devote such funds to a single electric-power generation project like Susitna.

Nor would the legislature of any other state countenance anything remotely similar to the energy-cost subsidy programs that Alaska now has on its books --- programs which in Fiscal-Year (FY-) 1983 can be expected to account for more than one-sixth of the state budget.[5] The sources of this unique perspective on the state's role in energy policy are not the focus of this review, but they surely include the fact that oil production has --- almost painlessly --- put unprecedented fiscal resources at the command of state policy-makers.

Regardless of its origins, the deep involvement of Alaska state government in energy decisions that would be left to the private sector in any other state has evoked a demand for information and analysis on an awesome range of engineering, economic, and financial topics. Because the responsible state agencies (including the legislature and the governor's office) do not have the experience or staff to assemble this information, evaluate it critically, or assimilate it effectively, they have had to depend on outside consultants to generate and process the relevant data, propose policies and programs, and monitor them.

The legislators and executive-branch officials who promoted and authorized these three studies viewed them as complementary to one another --- overlapping in places so that decision-makers could view certain crucial issues from more than one perspective but, on the whole, dealing with different aspects or segments of an interrelated whole. These officials expected that, together, the various reports would put the decisions they had to make in some kind of rational order, and resolve some of the uncertainties they faced in making these decisions. One hope, for example, was that rigorous engineering and economic analysis by nationally renowned experts would give them objective and politically acceptable answers, for each of the state's regions, about ---

> 1. The amount of electrical-generating capacity Alaska would need over the next two decades;
>
> 2. Which generation technologies and/or specific generating projects would be most cost-effective; and
>
> 3. What was the optimum strategy for financing the chosen investments?

Most of the information sought from these three studies is clearly relevant to the issues the state intended to address. And, although the quality of the three reports varies widely, as a group they present the bulk of the requested information --- in one place or another --- in a professionally competent fashion.

> Nevertheless, these studies, together with the march of events since they were commissioned, have conspired to leave the responsible state officials facing even more uncertain and contradictory signals than when the various studies were commissioned.

The Three Studies

Acres' study of the Susitna hydroelectric project. The Feasibility Study of the Susitna Hydroelectric Project prepared by Acres American Inc. was conceived as a detailed examination of the technical and economic feasibility of the the proposed project. In addition, it was to provide searching analyses of the project's environmental and social impacts. The studies leading up to the report were carried out over a two-year period at a cost to the state of nearly $40 million. The report itself is organized in three hierarchical tiers, a Summary Report of 56 pages, a main report titled Draft Susitna Hydroelectric Project Feasibility Report, consisting of three weighty volumes and four equally weighty appendices, and a multitude of "task reports" which, unlike the others, have not been widely circulated. Our review has focused on the Summary Report, volume 1 of the Feasibility Report, and the the Task 11 Reference Report: Economic, Marketing and Financial Evaluation.

The centerpiece of the Acres study is a "multivariate risk analysis", which uses the probabilities the investigators have attached to different assumptions about the key variables (fuel prices, construction costs, interest rates, etc.) to produce an array of economic judgments (about whether the Susitna projects are the least-cost approach to serving Railbelt electrical demand, for example) ranked by their respective probabilities.

Of the three works reviewed here, the Acres study deserves the greatest praise. Not only is it physically the largest, but it is also --- particularly in the Summary Report --- the most carefully and readably written. In most areas of interest a reader has the option of delving deeply or superficially, and in either case will usually find a clear and appropriately detailed explanation of the assumptions used, the evidence supporting those assumptions, and the methodology by which they were incorporated into the analysis.

The fact that the Acres report is analytically the most interesting of the three studies --- and will clearly be the most influential --- has caused us to devote more attention to it than to the others --- and to emphasize its failings. Readers should not be misled by this concentration. The methodology by which the Acres team evaluated the project's economic feasibility is elegant, and largely sound. While the report's errors come at sufficiently critical points to invalidate Acres' "bottom line", namely the economic ranking of the various electrical generation alternatives for the Railbelt, most of these errors are correctible, and Acres' general approach will survive them.

The Battelle "Alternatives" study. Both authors of the present review were professionally involved in the process that led to the choice of Battelle to conduct a Railbelt generation-alternatives study. This involvement gives them a special insight into what was expected of the study, but it inescapably colors their assessment of the work that resulted. Readers should be aware of this fact, and draw their own conclusions taking it into account.

The Battelle study has generated several documents, but we have reviewed only two of them here: Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans (February 1982), and Railbelt Electric Power Alternatives Study: Fossil Fuel Availability and Price Forecasts. Although the former volume is labeled "comment draft", we understand that it is in substance the final report.

Because Acres and the other contractors were directed to use scenarios and vital assumptions from Battelle, we have dealt with the Acres and Battelle analyses of individual issues, like load forecasting and coal prices, in one place.

"The Long Term Energy Plan". In 1978, Alaska adopted legislation requiring the state Department of Commerce and Economic Development, in conjunction with the Alaska Power Authority, to prepare an annual "long-term energy plan". The law (AS 44.83.224) mandates that the plan shall contain: (1) an "end-use" study of Alaska energy consumption, (2) a plan for meeting "projected energy needs", (3) a review of conservation efforts, (4) an emergency energy supply plan, and (5) a review of ongoing energy research. The Division of Energy and Power Development (DEPD) has been responsible for the preparation of both the 1981 and 1982 plans, but in both cases has made extensive use of contractors. The 1982 report was largely written under a $390,000 contract with the national accounting and consulting firm of Booz, Allen & Hamilton. However, the firm's name does not appear on the cover or in the introduction, and we do not know how much of the report's content and format should be attributed to Booz-Allen, and how much to the DEPD staff.

The 1982 report was designed, in its own terms, "to focus existing energy information to support current decision-making needs and to provide a sense of priority across state projects and programs."[6] The report is well written, contains few serious errors of fact or obviously faulty analysis, and provides the mandated "existing energy information" in a convenient format.

The "plan" does not fare well in its attempt "to provide a sense of priorities," however. With respect to the really tough social and political issues raised by Susitna and the state's hydropower program generally it largely leaves the field to Acres and Battelle; the Plan's treatment of the Railbelt hydroelectric construction proposals is confined to less than two pages of text. After urging the state to continue planning for Susitna, the report warns that the project's "impact may be to severely limit the consideration of less costly alternative Alaskan based resources such as coal or residual oil."[7]

In other areas, including the treatment of Alaska's complex system of energy subsidies, the authors develop an extensive and unique data collection, but seem reluctant to draw the prescriptive conclusions that clearly follow from it. Finally, many of the study's featured findings are pedestrian, for example the conclusion that "opportunities exist to increase the completeness and accuracy of Alaska's energy data." [8]

Some of these deficiencies are probably the result of the short time in which the state's contractor was required to produce a draft report. In one of their concluding sections the authors seem to recognize these shortcomings, proposing that next year's energy plan focus on developing a "strategic energy planning process." The discussion of how that might be accomplished is one of the most interesting in the entire report.[9]

The Conceptual Framework for Considering Electrical-Generation Alternatives for the Railbelt

The Acres report sets out most clearly the conceptual framework shared by all three studies. In the Railbelt, the key issue is to identify the combination of electrical generating facilities that is most likely to be the cheapest in the long run. The main choices are: (1) a two-stage strategy involving Susitna River hydroelectric power; (2) continued reliance mainly on gas-fired combustion turbines (either "simple-cycle" or "combined-cycle" plants), or on some combination of gas turbines and coal-fired steam plants; (3) and a combination of smaller hydropower facilities with thermal generation.

> **The crux of the economic comparison between Susitna and thermal generation is the comparison, over time, of hydro construction costs and thermal-plant fuel costs.**

The chief hydroelectric option, which centers on the Susitna River projects, involves a relatively high front-end capital expense per unit of capacity but very low continuing costs for maintenance and operation. Combustion turbines, on the other hand, are relatively cheap to install per unit of generating capacity, and the cost of the electricity they produce is principally the cost of the natural gas used as fuel. Coal-fired steam turbines would be less capital intensive than hydro, and while they would cost considerably more to build per unit of capacity than gas turbines, they might still provide the cheapest base-load power if the price of coal (per unit of electricity generated) were sufficiently below that of natural gas.

Out of the many issues that are relevant to this choice, the present review focuses on the way the various reports deal with ---

a. Future world oil prices;
b. Future Railbelt electricity demand;
c. Future Railbelt fossil-fuel prices;

d. Construction costs for hydro projects;
e. The appropriate interest or discount rate; and
f. Risk and uncertainty regarding these and other issues.

The six issues fit together as follows:

(a) World oil prices will powerfully influence Alaska economic activity, and through it electricity demand, by determining state revenues from petroleum royalties and taxes, and thus state spending. Oil prices are also a major influence on Alaska economic development and thereby on electricity demand, by way of their impact on energy-related private investment --- in oil and gas exploration, coal export projects, the Alaska Highway gas pipeline (ANGTS), petrochemicals manufacturing, and the like.

World oil prices, moreover, may influence the prices of natural gas and coal for electrical generation in the Railbelt. Indeed, the Acres and Battelle analyses seem to treat world oil prices as the crucial force determining fossil-fuel prices in the region.

(b) Electricity load growth. Susitna generating capacity would be very "lumpy" as well as capital-intensive; additions would come in multi-billion-dollar packages or not at all. Gas-turbine capacity can be added in small increments, however, with coal-fired steam turbines and some smaller hydroelectric options falling between the Susitna projects and gas turbines in "lumpiness".

If projected power demand and demand-growth rates are high, they can be expected to liquidate any excess generating capacity rapidly; high load-growth forecasts therefore improve the prospective economic ranking of the Susitna projects, all other things being equal.

With low or uncertain load growth, however, the larger hydro projects pose a greater risk than do thermal plants that underutilization of capacity would result in high unit costs for electricity. Thus, the risk of temporary or permanent overbuilding would be least in a strategy built around gas-fired combustion turbines, with the risks somewhere in-between for smaller hydroelectric projects and for coal-fired steam generation.

(c) Future fuel costs and (d) expected construction costs. In the framework described here, the comparison of electricity costs must focus most sharply on the cost of fuel for gas-fired combustion turbines, and on the original construction cost for the proposed hydroelectric plants. The relative cost of electricity from coal-fired steam plants will depend more on capital costs than electricity from gas turbines, but more on continuing operating (fuel) expenses than hydroelectric power.

Estimates of construction costs and future fuel costs are both subject to great uncertainty --- and the treatment of this uncertainty (f) below is itself a major issue in any comparison.

(e) Discount rates. Because the Susitna plants would be capital-intensive, long-lived, and take many years to build, the long-term cost of electricity from these projects would be highly sensitive to interest rates. This would be true whether the interest rates in question were the rates the state would have to pay to borrow for Susitna construction, or the rates it could have otherwise earned on money appropriated to build Susitna. The net benefit from the Susitna option is, therefore, most sensitive to the choice of interest rates used to "discount" future costs and benefits.

(f) Treatment of risk and uncertainty. The various factors that influence future Alaska economic activity and thus electricity demand (including but not limited to future world oil prices); Susitna and other generating-plant construction costs; future Alaska fossil-fuel prices (which may or may not be closely linked to world oil prices); and future interest rates are all unknown today. Important assumptions that the analysts plug into their models are thus essentially guesses.

These guesses may be informed or ignorant, and insightful or obtuse, but their impact on the final comparison will reflect both the raw values assumed by the analysts, and the way in which the analysts deal with the risk and uncertainty that surround them. Subsequent sections of this review reveal considerable disagreement with some of the raw values Battelle and Acres have assumed in the studies, and the probabilities they have assigned to these values, but not with Acres' design and execution of the "multivariate risk analysis" used to integrate these assumptions.

Future Oil Prices

World oil prices and Alaska state revenues. From the standpoint .. Alaska policy-makers, no aspect of the current scene is more confusing than the recent radical change in the the state's official oil-price forecasts, and the forecasts of state revenues that depend directly on oil prices.

> **This change in the oil-price outlook invalidates virtually every important economic and policy conclusion in the studies reviewed here.**

Between June 1980 and January 1982, the Alaska Department of Revenue's quarterly Petroleum Production Revenue Forecast predicted that nominal-dollar ("inflated") oil revenues would increase over the four years beginning on the forecast date at a compound annual rate between 12.2 and 25.8 percent. **In its March 1982 Forecast, the Department's three-year estimate of the expected annual change in state revenues fell abruptly to a negative 0.8 percent.**[10]

Specifically, the "most likely" projection in the March Forecast was that the weighted average wellhead value for Alaska North Slope (ANS) crude oil in fiscal year (FY) 1983 would be 29 percent lower than in FY-1982, and that world prices would then resume their nominal-dollar increase, at a compound annual rate of about 7 percent. Not until the beginning of FY-1987 did the Department expect prices to regain FY-1982 levels. With respect to constant-dollar ("real") oil prices, the March Forecast boldly reported "a consensus that oil prices will continue to fall,"[11] and projected declining real oil prices through 1998.[12]

> **The authors of the present review agree that world oil markets cannot sustain the level of prices reached in early 1981, and that prices in any given year during the remainder of the century are likely to be considerably lower in real terms than they are today.**

There was, however, no consensus on the long-term oil-price outlook that one could prudently rely upon last March, and none exists today.

What has happened, instead, is that the near-consensus which did exist at the beginning of 1981 has been shattered, namely the assumption that the long-term trend in oil prices was inexorably upward.

Abrupt changes in expectations have not been a problem unique to Alaska's official revenue forecasters; a review of the energy literature generally confirms that a widespread reevaluation began in late 1981 and early 1982. Few authorities any longer confidently assume that the energy-price increases of 1973-1981 will continue unabated through the rest of the Century, and an increasing number are suggesting, as the present reviewers have done since 1980,[13] that the price rises of the 1970's may never resume. The crude-oil price slump of late 1981 and early 1982, which few industry and government forecasters anticipated, drew attention to the difficulties of predicting energy prices, but is also pushing forecasters into a more general reexamination of both the demand and supply of petroleum, and the way in which they determine oil prices in the long run.

As late as September 1980, it was possible for Cambridge economist Nicholas Kaldor to write seriously that, " . . . OPEC changed everything. By cornering oil it managed to increase the price four-fold, then double it again, and presumably it could be doubled again, **without any really serious impact on consumption.**" (emphasis added)[14] It is now clear that the world economy has a much greater capacity and willingness both to substitute other fuels for high-priced petroleum and to economize on energy generally than had been widely supposed. Over the past six months, virtually every published authority in the area of petroleum demand has radically altered its expectations regarding future U.S. and world petroleum demand.[15]

On the supply side, so much excess oil-producing capacity now exists that it is hard to contrive any scenario in which OPEC, Saudi Arabia, or anyone else, can long function as a "price-maker" in world oil markets. To the extent that there is any consensus about world oil markets among the experts today, the managing director of Royal Dutch-Shell summarized it well when he wrote that "we are in for a period of severe and unpredictable discontinuities."[16,17]

> <u>An advance draft of Tussing's "Reflections on the End of the OPEC Era", included as an appendix to this review, takes a backward look at the events that led most forecasters in the late 1970s to expect ever-increasing world oil prices, and the reasons such an outlook seems untenable today.</u>

<u>Consequences for Alaska</u>. These changes in outlook have extraordinary significance for Alaska, because its economy, like that of (say) Kuwait, is a net **exporter** (seller) of energy. Well over half of Alaska economic activity depends directly or indirectly on crude-oil production. The largest such influence operates directly through state oil royalties and production taxes, and if prices continue to fall, resulting reductions in state revenues will make it impossible for state spending to continue its new-found role as the main prop and guarantor of Alaska's economy.

Table 1 below compares the state's June 1981 and June 1982 forecasts.

> At the same time the Department of Revenue was reducing its revenue expectations generally, it also decided to emphasize the uncertainty of petroleum-price forecasts, and began highlighting its "30-percent" rather than its "expected value" series. The different percentage figure indicates the Department's judgment about the probability that actual revenues will be less than the figure shown.

Table 1

1982-Dollar Petroleum-Revenue Projections by the Alaska Department of Revenue, June 1982 vs June 1981

Fiscal Year	Oil and Gas Revenue ($ Millions)		
	June 1981 Forecast	June 1982 Forecast	
	"Expected Value"	"Expected Value"	"30%" Series
1983	4030	2654	2399
1984	4137	2657	2250
1985	4271	2623	2177
1986	4448	2953	2411
1987	4713	3305	2644
1988	4851	3196	2507
1989	4983	3365	2595
1990	4742	3095	2246
1991	4544	2714	1862
1992	4382	2477	1668
1993	3979	2285	1427
1994	3637	2149	1265
1995	3144	1826	1059
1996	2701	1622	936
1997	2289	1608	908

Alaska Department of Revenue, Petroleum Production Revenue Forecast, Quarterly Report, June 1981, p.13; June 1982, p. 18, Personal Communication, Charles Logsdon to Erickson.

In 1981, state and local government employment directly accounted for 21 percent of Alaska non-agricultural wage and salary employment.[18] State government expenditures, in turn, were 86 percent financed in FY-1982 by oil production revenue,[19] and Alaska local governments received about two-thirds of their revenues from the state government. State aid to the City and Borough of Juneau, for example, will equal 262 percent of local property tax revenues in FY-1983.[20] Much of the revenue received by several other local governments in Alaska, moreover, comes from direct taxes on oil industry activity and property.

These illustrations do not begin to encompass the **indirect effect of expectations** regarding future oil prices on the state economy. These expectations largely determine the level of **private-sector** investment in oil and gas, coal, and other energy-extraction, conversion, and transportation ventures; energy-industry service activity; and have an added "multiplier" impact on the Alaska economy via the income flowing from such investment activity into the trade, finance, and service industries. A large, if not precisely measurable, part of the present boom in the Anchorage area reflects private investment commitments made in 1979-1981 on the basis of a bullish outlook about future oil prices. This boom is unlikely to survive long once those expectations have been shattered or drastically modified.[21]

The situation is quite different for energy-**importing** states like New York or California, where a radical increase or decrease in energy prices would at the most, over the short run, cause no more than a three or four percent change in the major economic indicators such as employment, gross state product, or disposable income. In these importing regions, the dominant impacts of energy price changes will operate rather diffusely, through the influence of fuel prices on the real incomes of consumers, and through the impact of changed fuel prices on production costs, and thereby on prices, sales, and profits in manufacturing, transportation, and commerce. In Alaska, the potential response is an order of magnitude larger, and is dominated by impacts on employment and population that flow directly from the primary role that petroleum production and state government spending (89 percent supported by petroleum production) play in the regional economy.

Load Forecasts

The studies reviewed here pay close attention to the usual income and price-factors that affect energy demand, and carefully evaluate the impacts of different oil price scenarios on the electrical-power costs implicit in various energy development schemes. But remarkably, they largely ignore the possibility of a major decline in oil revenues, and the direct effects such a decline would have on the Alaska economy. [22]

The Battelle reports base their forecasts of energy demand on scenarios and econometric modeling studies generated by ISER in 1980 and 1981, using its Man-in-the-Arctic (MAP) model. Acres' growth scenarios are, in turn, adapted from those of Battelle, and the Battelle reports provide the clearest explanation of the economic-development and state spending assumptions that went into the forecasts of Alaska Railbelt economic activity. Battelle offers five "scenarios", ranging from "low" to "superhigh", and a sixth scenario (tagged "fiscal-crisis") which shows very high spending in the 1980s, followed by a drastic decline in the 1990s.

The "moderate-growth" case. Battelle's "moderate" case (which the report defines as having a 50-percent probability of being exceeded) shows population in the Railbelt growing at a compound annual rate of 2.15 percent.[23] This scenario is powered by assumptions that state spending will increase from the FY-1981 level (when general-fund appropriations were about eleven thousand dollars per capita) proportionally with per-capita personal income, that the Alaska Highway gas pipeline (ANGTS) will be under construction by 1983,[24] that the PacAlaska LNG project will come on line between 1985 and 1987, that a 100,000-barrel per day refinery will be built in Valdez, and that 7 billion barrels of oil will be discovered and developed on federal outer continental shelf (OCS) acreage leased through 1989.[25]

The Acres study adopts the Battelle load-growth scenarios[26] with some modifications, which are not always described in sufficient detail to allow critical examination. Acres summarizes the outcome, however, as follows:

> *Between 1981 and 2010, the mid-range forecast suggests that electrical and energy demand will grow at an annual rate of about 3.5 percent, with the high and low range limits at about 4.6 percent and 2.8 percent, respectively. . .*
>
> *Under the mid-range forecast, currently scheduled additions are sufficient until 1993 to meet rising demand as well as to replace aging units which must be retired. Between 1993 and 2010, about 1400 megawatts of capacity must be added to the system to meet additional demand as well as to replace aging units.*[27]

<u>The "low-growth" case</u>. The Battelle report states that there is only a 5 to 10-percent chance economic activity will at any point dip below the values projected in the "low-growth" scenario.[28] A review of Battelle's assumptions underlying this boundary case show population increasing at a compound rate of 3.4 percent in the 1980-1985 period,[29] and constant <u>per capita</u> state spending (based on the exceedingly high FY-1981 base) and construction of ANGTS, but with a lower level of offshore oil activity and no Valdez refinery or Cook Inlet LNG plant.

None of Battelle's moderate-case assumptions, as listed above, now appears likely to materialize. The gas pipeline has, for example, been put on indefinite hold; with the most optimistic outlook, construction could not get under way before 1985 at the earliest. The Valdez refinery project was scuttled about a year before the Battelle report was delivered (and never did achieve much credibility among petroleum experts).[30] And Battelle itself has elsewhere virtually written off the LNG project.[31]

The most stunning discrepancy between Battelle's assumptions and what now seems realistic concerns the state government budget. Even in Battelle's low-growth scenario (given the low-case population growth projections), total state spending in FY-1985 would have to be in the neighborhood of $4.3 billion.[32] However, state appropriations for FY-1983 were only $2.7 billion, or $6,590 per capita, a fall of 45 percent from the previous year's peak and about 27 percent less than the low-case figure used by Battelle. The Division of Legislative Budget and Audit expects that even this spending reduction will leave the state budget with a deficit of $400 million relative to projected revenues.[33]

As we noted previously, the state's official March 1982 forecast expected real prices to remain below their FY-1982 levels through FY-1998. Total petroleum-production revenues projected for FY-1985 were $2.8 billion.[34] If non-petroleum revenues add another half billion dollars, the state would have $3.3 billion to spend in FY-1985. The "low-case" population estimate therefore means that $3.3 billion is $6,952 per capita, or only about three-fourths of the figure implied by Battelle's "low-case" assumption that state spending will remain at FY-1981 levels.

In short, the median, "most-likely" revenue projections of the state's Division of Petroleum Revenue imply a level of state spending that is far lower than, and inconsistent and incompatible with, even the "low-case" boundary conditions assumed in the Battelle analysis of electricity demand and the Acres analysis of Susitna feasibility. None of the contractors has used the model to beget a scenario given by falling real prices for crude oil, but it is clear that oil-price declines of the magnitude implicit in the state's most recent revenue forecasts would, if cranked into the model, result in demand-growth projections below those of the most pessimistic cases considered by either Acres or Battelle.

We have not calculated the quantitative effect on Alaska's economy of these actual and projected changes in state spending, the stalemate and possible demise of ANGTS, or the bleak outlook for other large capital projects (including, by the way, Susitna) whose construction lies explicitly or implicitly behind the load forecasts.

> **Clearly, however, a realistic, up-to-date view of state revenues and private-sector investment plans implies a "most-likely" future in which electricity demand will be lower than the lowest case postulated by Acres or Battelle.**

Lessons for the future. Predicting future economic activity is and always has been a tricky business, and Alaska's thin, open economy makes it exceptionally so. Recent Alaska electrical load forecasts have consistently overestimated the growth of demand --- **even without the kind of downturn in Alaska economic activity that is likely to proceed from the current oil-price slump.** In 1977, ISER forecast that state electricity consumption would grow between 1974 and 1980 at an annual rate of nearly 12 percent, with the lowest possible rate 8.7 percent. The actual growth rate was 8.2 percent.[35] The forecasts ISER furnished Acres in 1980 implied a 4.6 percent annual growth of Railbelt electricity consumption in 1978-1981 in the moderate-growth case, and 4.0 percent in the low-growth case. The actual increase was 3.4 percent.[36] It appears, however, that the forecasting performance of other parties has been even less satisfactory.

If there is a lesson to be learned from this experience it is that grave dangers lurk in relying on a single consultant or institution for insights about the future. The purpose of the Battelle Railbelt Alternatives study was (at least originally) to provide a check on the assumptions and analysis used by the Alaska Power Authority and Acres. One reason the governor's office sponsored and the legislature mandated this study was their concern that Acres' stake in Susitna construction might affect the credibility of its load forecasts and other elements of its economic and financial analysis.

Events show that the original purpose of an independent study of Railbelt generation alternatives was frustrated when Acres and Battelle were directed to standardize their assumptions on a number of issues, (e.g., load forecasts) and to rely only on ISER's 1980 economic-development scenarios as the basis for projecting future electricity demand --- probably the most important variable of all in evaluating the wisdom of the massive commitment of present and future resources to a project like Susitna.

Long Term Energy Plan. The Long Term Energy Plan describes its assumptions concerning the variables that drive the Alaska economy as derived from Battelle's work.[37] However, in the case of expected population and employment growth The Long Term Energy Plan respectively assumes compound rates of 1.1 and 0.6 percent through the year 2000, figures that are clearly inconsistent with the Battelle projections.[38] Unaccountably, the authors of the Plan nevertheless adopt Battelle's Railbelt electricity-demand forecast.[39]

Alaska Fossil-Fuel Availability and Cost

The Cook Inlet basin, which contains the bulk of the Railbelt's population and economic activity, is a major natural-gas producing area and contains large deposits of steam coal close to tidewater. Indeed, the bulk of the electricity produced in the Anchorage-Kenai peninsula area today comes from gas-fired combustion turbines, and much of the Interior's electricity comes from a coal-fired steam plant at Healy. Thus, the most obvious alternatives to the Susitna project for new electrical generating capacity in the Railbelt are coal- and gas-fired plants, or a combination of smaller hydro projects with coal-and/or gas-fired plants.

The Acres Summary represents both Acres' and Battelle's position with respect to this choice:

> *. . . If required generation expansion occurs by continued use of the thermal generating plants, a shift toward increased use of coal will be necessary not only because the Cook Inlet gas reserves may be insufficient to sustain long-term reliance upon natural gas in the face of increased demand but also because sharp increases in gas prices will occur in the next decade as old supply contracts expire. The installation of thermal (coal- or gas-fired) plants to meet the demand would offer the consumer no protection against rising costs, since fuel prices will continue to be exposed to inflation and to extraordinary escalation occasioned by world market conditions.*[39]

Despite the central role that fossil-fuel availability and cost must play in comparing generation alternatives, neither Acres nor Battelle has attempted to assess the probable future cost of fossil fuels for generation in the Railbelt from local coal or gas supply conditions. The reports give little if any attention to the incremental cost of gas or coal production in the region, the ownership and regulatory or contractual status of proved and potential reserves, or the other physical, economic, and institutional features of the local supply picture for either fuel. Indeed, the Acres reports and Battelle's Railbelt Alternatives reports do not even cite Battelle's own 1982 forecasts of Alaska oil and gas supply and demand for the Alaska Department of Natural Resources (whose conclusions appear to conflict with the assumptions used in the reports reviewed here), or the coal-supply study conducted by Ebasco Services, Inc., under a subcontract to Battelle for the Railbelt alternatives study.

Both contractors have, instead, deduced Railbelt coal and natural-gas supply costs from (1) recent LNG and coal import prices in Japan, (2) assumptions about future world oil-price movements, and (3) the relative processing and transport costs between the mine mouth or gas field and markets in Alaska and Japan. The following passage on the relationship between coal prices and the economics of the Susitna project sets out the implicit pricing model Acres shares with Battelle:

> *. . . Coal mining is assumed to occur at Beluga and an export market for Beluga coal is assumed to exist. To recover the investment in these plants and to account for anticipated major increases in gas costs, as well as inflation and fuel price escalation* ***above the underlying inflation rate****, the wholesale price per kWh for electricity will have risen by 1994 to 145 mills (+14.5¢) per kWh and will continue to rise thereafter.* ***It is this trend against which any proposed hydroelectric development on the Susitna River must compete.***[40]*(emphasis added)*

The assumption of "fuel price escalation above the underlying inflation rate" stems directly from the proposition Acres shares with Battelle that the price of coal to new electrical generating plants in Alaska's Railbelt will reflect its **market value in Japan** (less transportation costs between Alaska and Japan) and that this market value is in turn, directly determined by world oil prices. The Acres and Battelle assumptions regarding natural-gas prices follow the same logic: The cost of natural gas to electric utilities in the Railbelt will be the price of LNG landed in Japan (which will move with world oil prices), less liquefaction costs and transportation costs from Alaska.

The relevance of "opportunity cost" to Railbelt natural-gas and coal supply. The concept at the heart of Acres' and Battelle's treatment of both coal and gas prices is **opportunity cost.** The opportunity cost of Alaska-produced natural-gas or coal is the **highest price their owners could have got** for the fuel, even if they actually made a deal at some lower price. Acres succinctly states the principle as follows:

> *. . . if export markets exist for LNG (or coal) at the prices which have been determined in the Report, then it must be assumed that any rational gas (coal) producer in Alaska would select the opportunity to receive the highest price which is offered for the gas (coal). If the gas (coal) producer chooses to sell gas (coal) in Alaska at a lower price instead, then should the Susitna project evaluation be based on this economically inefficient price? If this is so, the project evaluation will not be consistent with generally accepted principles of public investment appraisal. (parentheses and "coal" added)*[41]

The principle set out in the previous citation is generally a sound one. The cost figure the state ought to use in calculating the net benefits to Alaska of selling royalty oil to an in-state refiner or petrochemical producer is not the actual transaction price (which state officials may decide to discount for the purpose of fostering industrial development) but, rather, the revenue the state **would have got by selling its royalty oil to the highest bidder.** Likewise, the cost to Alaskans of electricity from the Susitna project includes all interest the state **could otherwise have earned** on money appropriated to the project, even if the legislature or the Power Authority decides to set electric rates on the basis of a lower (or even zero) rate of return on that money.

Opportunity cost in this sense measures the true cost of state royalty oil sold to an in-state processor and establishes the proper discount rate for evaluating investments of surplus state funds within Alaska, **but only because there are ready, and for practical purposes unlimited, export markets for royalty crude oil and surplus state money.** Thus, it is reasonable to assume that any royalty oil which is not processed within Alaska can and will be sold at world market prices (as limited, of course, by the federal prohibition on exports of crude oil shipped throught the Trans Alaska pipeline). It is also reasonable to assume that any state money that is not spent or invested within Alaska can and will be invested elsewhere to get the highest available yield (consistent with the degree of security sought by the state's money managers.)

> **It is not, however, reasonable to suppose that all Alaska gas or coal that is burned in Alaska would otherwise have been exported at the netback prices assumed by Acres or Battelle.**

If **effective** export markets in fact existed for **all** of Alaska's potential coal and natural gas production at current Japanese import prices less transport costs, export markets would exist at comparable prices for all of the natural gas that is now shut in or being flared (close to tidewater at least) **anywhere** in the world. Trillions of cubic feet of gas would not be flared each year in the Middle East, for example, and LNG from Cook Inlet would **already** be flowing into foreign markets to the limit of the region's producing capacity. Likewise, if there were really an **effective** export market at recent Japanese import prices for any coal that is economically feasible to produce in Alaska's Railbelt, there would be little uncertainty about the future development of Beluga (or Bering River, or other Alaska) coal, while coal prices almost everywhere in the world would have reached levels comparable with the netback "opportunity cost" that the two reports posit for Alaska coal.

What the "opportunity-cost" approach of Acres and Battelle ignores is the fact that the world's known reserves of coal and natural gas, technically capable of development and delivery to Japan at resource costs below that nation's recent import prices, are **many times greater than potential Japanese or global markets** for coal and LNG at those prices. Since 1974, Japanese consumers (among others) have been willing to pay prices for coal and LNG related to the rising cost of imported oil, but only because the construction of export and import terminals, on-shore transportation facilities, and the specialized bulk carriers **could not keep up with the worldwide growth of demand** for fuels capable of underpricing OPEC petroleum in the electric-utility and industrial boiler-fuel markets.

In 1981-82, however, a combination of falling oil prices, the economic slump, and completion of the first generation of major LNG and coal-shipment projects initiated after the 1973-74 oil crisis, have (1) marked an end to the period of frantic growth in Japanese and worldwide demand for both coal and LNG, and (2) permitted new supplies to catch up with and perhaps outstrip that demand. Of the more than twenty new coal-export terminal developments that were under active consideration on the West Coast of North America in early [illegible] it now appears that the growth of East Asian demand will economically support **at most** two such projects between now and the year 2000. There is likewise a growing conviction in industry that LNG-export projects already committed to construction will satisfy Japanese demand for the rest of the century, and that even some of these "committed" projects (the British Columbia LNG venture, for example) may yet be scuttled.[42]

<u>Coal prices and oil prices.</u> Acres and Battelle combine (1) the peak 1981 spot prices for coal imported to Japan, (2) the assumption

that world oil prices will continue to escalate in real terms, apparently without limit, and (3) their "opportunity-cost" netback pricing methodology to arrive at the following most-likely constant-dollar price-escalation rates for Beluga Coal (at Anchorage) and Healy coal (at Nenana):[43]

Table 2. Alaska Coal-Price Assumptions

	Coal Source	
	Beluga	Healy
	(01/82 cents per mmbtu)	
Acres	1.43	1.75
Battelle	1.69	2.43
	(annual constant-dollar escalation rate in percent)	
Acres	2.5	2.7
Battelle	2.1	2.0

Two weaknesses in the Acres and Battelle coal-market assumptions compromise the usefulness of their comparisons between Susitna and coal-fired generation costs: Firstly, if constant-dollar oil prices are not likely to increase at the rates that Acres and Battelle assume throughout their studies, the rationale for similarly-increasing coal prices is mortally damaged. Thus, a more realistic, up-to-date oil-price outlook would call for a reevaluation of the probable cost of coal in Alaska, and of electricity generated from coal, just as it calls for reevaluation of most of the important assumptions and conclusions of the two studies.

Secondly, even if Acres and Battelle oil-price scenarios had remained plausible, their supposition that Alaska coal-price movements will be driven by world oil prices in some straightforward and easily predictable way is unwarranted. The effect of this mechanistic assumption is to evade one of the most difficult, yet one of the most crucial, issues in choosing among generation alternatives --- the need to forecast the change in **relative** prices among various fossil fuels over time.

Historical evidence. Acres gives a number of good reasons why production costs alone are not sufficient to predict coal prices at any given time and place. For example,

> *. . . "economic rents" (that is, a price that exceeds production costs including a normal return on investment) may be earned by the producers, mine labor and/or governments. For example, in the interests of supply security, a coal importer may be willing to pay a price much higher than actual coal production costs. In addition, oil price increases induce increased demand for coal, thus exerting upward pressure on coal prices.*[45]

The report then remarks that "(h)istorical trends support these observations." "Historically, it has been observed that export prices of coal are highly correlated with oil prices, and that production cost analysis has not predicted accurately the level of coal prices."[46] Acres follows with evidence from a number of sources that real coal prices have increased in recent years, presumably at rates exceeding the increase in production costs, and with citations from a number of other authorities who have also predicted or assumed that coal prices will continue to increase at rates comparable with, or tied to, world oil prices.

The historical data Acres cites do show that rapidly growing coal demand can cause real-price increases, but they do not, in fact, support the notion that coal prices have been tightly linked to oil prices in the recent past. Examine the following three illustrations, for example:

Coal prices (bituminous, export unit value, FOB U.S. ports) grew at real annual rates of 1.5 percent (1950 to 1979) and 2.8 percent (1972 to 1979).[47]

In fact, the constant-dollar price of imported crude oil rose at an average rate of 3.9 percent --- almost 2½ times that of the average FOB export value of coal --- between 1950 to 1979, and at an average rate of 29.2 percent --- almost ten times as rapidly as coal prices --- between 1972 and 1979.[48] The 1.5-percent average coal-price increase cited by Acres for the longer period was actually less than the average increase in hourly compensation of bituminous coal miners in the U.S. over the same period (1.9 percent).[49]

In Alaska, the price of thermal coal sold to the GVEA utility advanced at real rates of 2.2 percent (1950 to 1978) and 2.3 percent (1970 to 1978).[50]

The contrast between Alaska coal and oil-price trends depends wholly on the years chosen. The constant-dollar price of No. 2 fuel oil in Fairbanks actually **decreased** at an average annual rate of 0.4 percent between 1970 and 1978. Between 1973 and 1981, however, GVEA's real coal price increased at an average rate of 2.1 percent, while No. 2 fuel oil prices were increasing at an average rate of 15.6 percent.[51]

In Japan, the average CIF prices of steam coal experienced real escalation rates of 6.3 percent per year in the period 1977 to 1981.[52]

The constant-dollar price of Japanese crude-oil imports, however, increased at an annual rate of 17.6 percent over the same period --- about three times as rapidly as the country's average coal-import price.[53]

Table 3 compares the cost of coal and oil at electric generating plants in the United States over the last decade, and is further evidence against the direct relationship between coal and oil prices

Table 3. Cost of Fossil Fuels Delivered To Electrical-Generating Plants in the United States 1973-1981

	Current Prices (cents per mmbtu)		GNP Deflator	1981 Prices (cents per mmbtu)		
Year	Coal	Residual Oil	(1972 = 100)	Coal	Residual Oil	Oil-Coal Differential
1973	40.5	78.8	105.8	74.1	144.2	70.1
1974	71.0	191.0	116.0	118.5	318.7	200.2
1975	81.4	201.4	127.2	123.9	306.6	182.7
1976	84.8	195.9	122.7	133.8	309.0	175.3
1977	94.7	220.4	141.7	129.4	301.1	171.7
1978	111.6	212.3	152.1	142.1	270.3	128.2
1979	122.4	299.7	165.5	143.2	350.6	207.4
1980	135.2	427.9	177.4	147.6	467.0	319.5
1981	153.3	529.0	193.6	153.3	529.0	375.7
				Change, 1973-1981		
Absolute				79.2	384.8	305.6
Multiple				2.07	3.67	5.36
Annual rate (%)				9.51	17.64	23.35

Source: Monthly Energy Review

asserted by Acres and Battelle. The real price that utilities paid for coal did indeed more than double between 1973 and 1981, but at the end of the period, **the fuel-cost advantage of coal- over oil-fired generation** (in constant dollars per million btu) was 5.4 times as high as it was at the beginning.

Whatever limited validity there might be in the model behind the Acres and Battelle coal-price assumptions, it would exist only for spot markets and only for short-term fluctuations. The oil-price surges of the 1970's, without doubt, stimulated increases in the demand for coal that outran the ability of the industry to open new mines. As a result, excess demand did pull up world coal prices dramatically --- particularly the spot prices of steam coal. But Acres ignores the fact that slack demand and overinvestment in coal-producing capacity can just as easily cause **reductions** as surges of demand can cause increases in spot-market coal prices relative to production costs.

Moreover the Acres report offers the reader no reason to believe that the excess-demand conditions that existed during the 1970's will continue unbroken for the next twenty to forty years. The historical record, which stretches back more than two centuries, shows both cyclical and random fluctuations in coal prices, but no evidence of rising real costs over the long term. It is likely the peak of the most recent cycle was reached in 1981; at any rate, **nothing in the world supply-demand picture suggests further real coal-price rises in the foreseeable future.**

> **In the long-run and on the average, coal prices must reflect the real resource cost of opening and operating new mines.**

The real world of coal-purchase contracts. No major coal-fired electrical generating plant will be planned or built by Alaska utilities or the Alaska Power Authority (or financed with revenue bonds) unless it has secured "dedicated" coal reserves and producing capacity sufficient to supply it with fuel over its economic life, or at least over the period of its long-term financing. A prospective mine operator must, in turn, have a long-term coal-purchase contract from the utilities or the Power Authority in order to get financing for mine development and production equipment, and working capital.

That long-term coal-purchase contract will, in every likelihood, be a **cost-of-service** contract. It will probably provide automatic price adjustments for certain production-cost items, and may allow the return to the mine-owners and/or operators (assuming they are different parties) to increase in proportion to the Anchorage consumer price index (CPI) or the gross national product deflator.

It is almost inconceivable that Chugach Electric Association (CEA) or the Alaska Power Authority would sign long-term contracts containing a floating-price term that was not firmly tied to some element of production cost.

It is even less likely that the Alaska Public Utilities Commission (APUC) or the Legislature (in the case of a facility built by the Power Authority) would approve any coal-or electricity-purchase arrangement that was subject to such a floating-price term. There are two reasons for this judgment:

(1) The cost-of-service arrangement described above is the way that utilities actually purchase coal on long-term contract from dedicated mines.

Indeed, we have not been able to locate any instance in which a state public utilities commission approved a utility's long-term coal-purchase contract whose price was tied to the price of oil. Moreover ---

(2) Mine financing will depend on the existence of long-term coal-purchase contracts. The preponderance of bargaining power in negotiations over such a contract will be on the side of the utilities or the Power Authority, rather than the mine owner.

If CEA, for example, offered one or more of the owners of Beluga coal reserves (or any other coal reserve in the Railbelt) a 20-year cost-of-service take-or-pay contract to provide coal for a 200-megawatt generating plant, with a reasonable rate of return to the operator(s) and a reasonable royalty to the owner(s) of the mineral rights, that offer would be much too good to refuse (assuming, of course, that this production volume is sufficient to cover the mine's startup costs). It would indeed be a more attractive business proposition than anything yet offered by potential customers in East Asia.

Any opportunity the mine owner(s) may have to export coal to the Far East over the same period will, incidentally, make them more, not less eager to deal with an Alaska utility on a long-term cost-of-service basis, because of the ability added sales for export would give them to capture economies of scale by spreading fixed costs over a larger volume of production.

Gas-fired vs Susitna generating costs. The current average cost of Cook Inlet natural gas to Railbelt electric utilities is $0.86 per million btu (mmbtu).[54] Simple-cycle gas turbines that can be bought "off the shelf" would produce electricity at capital costs of about $630 per installed kilowatt.[55] At today's Cook Inlet gas prices, the bus-bar cost (the price at the plant) of power from such a facility will be in the neighborhood of 4.3 cents per kilowatt-hour.[56] The generation cost per kilowatt-hour would presumably be even lower for combined-cycle gas plants, and lower yet for gas-fired steam turbines operated at high plant factors (say, 80 percent) in base-load service. The 4.3-cent estimate, however, contrasts impressively with projected Susitna electricity prices of 14 cents per kilowatt-hour (assuming the state subsidizes the project with a $2.3 billion appropriation) and 30 cents (the full cost of power based upon 100-percent debt financing).[57]

Given these relative costs, it is reasonable to wonder why the Susitna project is even being considered. The Acres Summary gives the answer in brief:

> . . . between 1982 and 1993, many of the long-term contracts now held by utility companies for very favorably priced Cook Inlet gas will expire. Not only will major increases in electric energy costs result from the requirement by local utility companies to purchase gas at **market prices**, but also known Cook Inlet gas reserves may have been depleted in the early 1990's to the point that reliance upon natural gas as the principal fuel for electrical energy generation would no longer be possible.[58] (emphasis added)

Acres and Battelle have thus assumed that the "market prices" of Alaska natural gas will rise dramatically. Acres' "low" fossil-fuel price case, to which the report assigns a 25-percent probability, projects Cook Inlet natural-gas costs at a constant $3.00 per mmbtu, which is three and one-half times present gas prices. The Acres "medium" ("50-percent probability") fossil-fuel price case assumes that these prices will skyrocket between now and the year 2000 at an average annual real rate of 9 percent, to $4.80 per mmbtu. The "high" case (25-percent probability) projects the trend at 11.2 percent annually, with its end-point at $7.22 per mmbtu, a more than eightfold increase over present gas prices.[59] (All prices are in constant 1982 dollars.)

The weaknesses of Battelle and Acres in their analyses of gas prices closely parallel those that fatally compromise their analysis of coal prices. The assumption of high future prices in both reports flows from two basic postulates, (1) that world oil prices will keep increasing in real terms, apparently without limit, and (2) that Cook Inlet natural-gas and Railbelt coal prices are, or at any rate presently will be, tightly coupled to these rising world oil prices.

The Cook Inlet gas-price/world oil-price nexus. Acres assumes that the "opportunity value" of Cook Inlet gas is now $3.00 per mmbtu, 2.5 times more than prices currently paid by Anchorage utilities. This assumption is based on the contractor's analysis of LNG export opportunities, LNG processing and transportation costs, and the btu relationship between gas and oil. Since the assumption applies to all three cases --- "low", "medium", and "high" --- it is an essential element in the analytical process by which Acres discards natural-gas-fired plants as an economical long-term generation option, and by which the report finds Susitna to be the preferred option.[60]

More importantly, there is enough evidence to make at least a plausible case that Cook Inlet gas prices will be established largely on the basis of factors local to the region. Proved gas reserves, for example, are far in excess of current demand, sufficient to supply the local utilities for roughly 75 years at present rates of consumption.[61] If the full capacity of the existing LNG and ammonia-urea plants is regarded as part of regional demand, the same proved reserves are good for about 23 years at existing production rates.[62] In other regions of North America (Alberta, for example), similar reserve-to-production (r/p) ratios are considered evidence of a gas glut.[63]

Even these measures tend to understate the potential gas supply in Cook Inlet. **"Proved"** reserves (or "identified economically recoverable reserves", in the terminology of Alaska's Oil and Gas Conservation Commission) constitute only that fraction of the resource base which producers have had a commercial incentive to explore to the point at which the producible volumes are a near certainty. This kind of exploration is expensive and, absent credible near-term market prospects, there is no reason for the lease owners to spend the money.

The known reservoirs of the Cook Inlet basin contain considerably more **unproved** gas (or "indicated" reserves) than the 3.9 trillion cubic feet (tcf) reported as proved at the end of 1981. Nobody knows the volume of indicated gas in these reservoirs with much confidence (otherwise they would be counted in the "proved" column), but unpublished estimates in the industry tend to be in the 5 to 10 tcf range.[64] Acres and Battelle disregard the high r/p ratios and the region's additional gas-development potential, on the ground that new demands will arise for Cook Inlet gas in the form of additional LNG exports to Japan or California. This may indeed turn out to be the case, but it is a proposition not very well supported by the experience of the only new LNG export scheme to be seriously proposed --- the PacAlaska project, whose sponsors in September 1982 announced the project's indefinite postponement.[65]

Most importantly, overwhelming evidence has accumulated in the last few months that the final-market value of natural gas is considerably lower, and total demand in either the Lower-48 or Japan much more limited, than the industry believed during the 1970's. The new gas-market outlook has cast a serious cloud over all "supplemental-gas" projects --- ANGTS and synthetics --- as well as LNG.[67] At any rate, there are no other proposals to establish new Cook Inlet LNG facilities (or increase the capacity of existing facilities).[68] Until serious industry interest appears in some such project, it is unrealistic to assume that Cook Inlet gas prices will be dictated by "netback" gas values in export markets.[69]

<u>The world oil-price assumption once again.</u> Acres' and Battelle's Alaska gas-price model, in which Cook Inlet gas prices reflect world oil prices, is driven by the contractors' assumption of continuously rising real prices for crude-oil. In Acres' "most-likely case" the rate is 2.0 or 2.6 percent, depending on which of the Acres reports one reads.[71] The report states that its scenarios for gas-price escalation are expected to "follow closely the crude oil-price scenarios."[72]

For the years through 1998, however, the Department of Revenue assumes that the real price of Saudi "marker crude" (which underlies and drives the state's official revenue forecasts) will decrease at a compound annual rate of almost one percent. At least for the period through FY-98, the state's recent oil-price forecasts are as incompatible with the Acres and Battelle assumptions regarding gas-price escalation in the Railbelt as they are with the consultants' forecasts of economic activity and energy demand.

Susitna Construction Costs

The Acres base-case estimate for the original cost of the Watana unit is $5,081 per kilowatt, and for the Devil Canyon unit $2,265 per kilowatt. (Several other figures appear for the two units in the Battelle and Acres reports, but the distinctions among them are not crucial here.) These figures contrast with an estimate of only $636 per kilowatt for a 70-megawatt simple-cycle gas turbine. Costs per kilowatt of capacity for combined-cycle plants, coal-fired steam plants, and some smaller hydroelectric projects considered for the Railbelt fall between these two extremes. Thus, the Susitna project is by far the most capital-intensive of the major electrical-generation options considered by Acres and Battelle, and this capital-intensiveness means that the unit cost of Susitna power is much more vulnerable to capital-cost overruns than power from combustion or steam-turbine plants.

The authors of this review are not in a position to scrutinize the Acres estimates of Susitna construction costs as such; the way in which Acres deals with cost-overrun and related risks is within the scope of this review, however. Large construction projects have become notorious in recent years for costs running far above and sometimes many times higher than the cost estimates on which the owners --- private corporations and public agencies alike --- based their decision to go ahead. The TAPS and ANGTS experiences, among others, have made Alaskans particularly sensitive to the cost-overrun issue.

One obvious question in evaluating and comparing any large project proposal like Susitna is how much credibility anyone can place in the cost estimates and budgets. Public officials and the general public have become increasingly sophisticated about the tendency of project sponsors, their engineers, and their consultants to underestimate costs, and to downplay the risk of delay, false starts, and other causes of overruns. They have become increasingly skeptical about the figures offered by project promoters.

Overruns and other cost-estimation errors are not a new phenomenon,[73] however, and there are a few generalizations that the research literature supports with a good deal of confidence.[74] Errors in construction-cost estimates can be separated, at least conceptually, into two components: variance and bias. Variance is a measure of the expected departure of the actual cost **either** up or **down** from the estimated cost, and bias is the expected departure **in one consistent direction** (usually upward) from the estimated cost. These measures of error depend in different degrees on (1) the specific features of the project, (2) the general economic environment, and (2) the institutional framework in which the project is carried out.

Character of the project. Cost-estimation variance clearly tends to increase with the size of project; novelty in design, location, or construction technique; the time required for conception, authorization, design, construction and shakedown; and the number of licenses, permits, and degree of regulatory surveillance. Both measures of estimation error decline with the amount of experience in similar or related construction on the part of the owners, designers, and contractors. Many of these features are intercorrelated: larger projects tend to be custom-designed, more complex, take longer to complete, and involve a greater number of regulations and regulatory entities. The larger the project, moreover, the fewer similar projects the owners, designers, and contractors are likely to have had experience with. Because of these intercorrelations, the effects of the various factors are nearly impossible to distinguish in practice, but ---

On their face, the specific features of the Susitna project suggest a high risk of cost-estimation error.

Among other things, Susitna would be (a) one of the highest dams in the world, (b) the largest enterprise anywhere, ever, of its particular type, (c) the highest-latitude large-scale hydroelectric project in the world and, so far as we can find, the largest civil works project ever attempted above 55th parallel.

The Acres study has attacked these project-specific features of the cost-estimation risk from two angles; at the core of the whole Sustina feasibility study is an impressively designed, comprehensive engineering-type "multivariate" risk analysis. Acres then checked the findings of this analysis against a comparison of cost-estimates and actual costs on a large sample of completed federal water projects.

In the core analysis, Acres has created a model of the construction process in which the study team has identified each major uncertainty, including everything the designers think might go wrong, in the following areas:

- 8 categories of natural risks (flood, ice, etc.),
- 2 categories of design-controlled risks (seepage, etc.),
- 6 categories of construction risks (equipment availability, labor disputes, etc.),
- 4 categories of human risks (including contractor capability and quality control), and
- 2 categories of special risks (including regulatory delay)

The Acres team assigned probabilities to the various contingencies in each category and then combined these probabilities mathematically, to create a schedule that shows the probabilities of various levels of total cost (and a number of other outcomes of the construction process).

With the availability of computers capable of manipulating huge arrays of variables each of which is paired to a probability coefficient, this kind of risk analysis has become common in the engineering of large and complex projects, where it is a powerful tool for helping designers choose the project configuration that minimizes expected costs, subject to certain maximum acceptable cost, schedule, and operations risks. The general method used by Acres is probably the best available technique for comparing expected costs and risk factors among variants of a single project concept, and it is reasonably reliable for projecting which of (say) three proposed configurations of the project would have the lowest expected cost, and which would have the lowest risk of unacceptable cost overruns or operating failure.

For a number of theoretical and practical reasons, however, such risk analysis is probably less valid and reliable for comparing widely different technologies, facilities, or strategies, or for generating absolute-dollar cost estimates, cost-overrun, or schedule-risk estimates to be used **outside the design process**, particularly as input to benefit-cost analysis. No matter how competent and objective the analysts are, it is almost impossible for them to escape a certain amount of misplaced specificity,[75] subjectivity and over-optimism,[76] institutional blind spots,[77] and underallowance for non-completion.[78] Nevertheless ---

> **The Acres approach to controlling cost-estimation variance stemming from the character of the project is as rigorous as any we have seen.**

More importantly, perhaps ---

> **We have not found any evidence of bias in the cost-estimation procedure or in the construction-cost aspects of Acres' multivariate risk analysis.**

In the second phase of its risk analysis the Acres report implicitly recognizes the inevitable subjectivity of any engineering-type risk analysis, and checks its results against a sample of actual project experience. Acres' discussion acknowledges shortcomings in the survey data base --- particularly the fact that the sample is made up of projects completed before passage of the National Environmental Policy Act, the Endangered Species Act, and other environmental legislation had their present great impact on project schedule and completion. Further examination reveals that the sample offered by Acres has virtually no resemblance to the Susitna projects in type, location, scale, or timing. More comforting historical evidence that overruns can be controlled exists, however, in the construction record of the 5,225 MW Churchill Falls hydroectric project on James Bay in Canada. Churchill Falls is probably the closest parallel to Susitna in scale or location anywhere in North America.[79]

> **The Churchill Falls project, whose design and construction were managed by a joint venture of Acres and a Bechtel subsidiary, was completed essentially on time and on budget.**

General economic conditions. It is inevitable that overruns (which correspond to a **downward** bias in cost estimates) are more frequent and generally larger in periods when inflation is accelerating, and also in periods when environmental, safety, and other kinds of regulation are getting more complex and demanding. The upward push that these factors give to costs is even stronger when inflation proceeds out of (or coincides with) an economic boom, because accelerating real economic growth tends to push construction wage rates, building-materials prices, and other construction costs (including contractor markups) ahead of general inflation (as measured by the Gross National Product deflator or the Consumer Price index).

Accelerating inflation also tends to mean rising interest rates, which result in higher interim financing costs (in utility parlance, "allowance for funds used during construction" or AFUDC), and thus cause final project costs to increase even faster than the wages of construction labor and the cost of building materials (themselves racing ahead of the rest of the economy). As the 1960s and 1970s saw all of these conditions, it is not surprising that the experience of this period fostered a belief that large overruns are the rule rather than the exception in large projects.

The economic and regulatory forces that generated the construction-cost overruns of the 1970s have largely run their course. General inflation will probably **decelerate** (meaning that escalation rates built into construction-cost estimates will typically be too high rather than too low). This trend probably means lower nominal interest rates as well and, as a result, pre-construction estimates of interim-financing costs (AFUDC) will tend to be too high. Real economic growth rates are likely to be lower than in the 1960s and early 1970s, moreover, causing the construction-cost indexes to increase less rapidly than general inflation.

Finally, the impact of environmental and safety regulation on costs and schedules will tend to be less severe than at present. While we do not anticipate a significant retreat from the **goals** motivating today's environmental and safety regulation, regulation will tend to be more sensitive to cost-effectiveness criteria and on balance less dilatory. For these reasons ---

> **Big cost cost and schedule overruns are not likely to be the rule over the next decade as they have been over the last.**

A number of large projects are likely to surprise their sponsors and the public by coming in on time and under budget. Susitna might be one of these.

Institutional considerations: The Road to WPPSS. It seems reasonable to expect governmental entities to have weaker incentives for cost-minimizing design and cost-effective contracting than private enterprise, and for regulated private utilities (which profit by enlarging their "rate base" and are not supposed to profit from cost-cutting) to have weaker efficiency incentives than unregulated private enterprises. The existing literature on defense-procurement costs seems to support the first thesis, but we do not know of any systematic comparison relating the costs of otherwise similar plants owned by different kinds of organization.

A casual survey by the reviewers shows mixed results: the publicly-owned Washington Public Power Supply System (WPPSS) is likely to ride its overruns into the biggest financial default of any industry in US history. On the average, public entities in the United States have worse schedule and cost performance on nuclear plants than private utilities. (TVA's reactors seemed to be doing better than the average, however, before construction was stopped, making their effective unit cost of capacity infinite.) But Ontario Hydro's performance in nuclear plant construction (and operation) has been better than any private utility in the United States (a result that stems at least in part from its choice of a much less troublesome reactor technology). Clearly, this issue needs further investigation. Nevertheless ---

<u>The Susitna project has disturbing parallels with WPPSS.</u>

Like WPPSS, Susitna is sponsored by a single-purpose entity (the Alaska Power Authority) whose importance in the world rests primarily on this enterprise; and like WPPSS, that entity has had little or no experience in designing or building works of a similar kind or scale. The technical case for the project is built to a large extent on exaggerated projections of future electricity "needs" and on unrealistic projections of alternate-fuel costs. More importantly, however, the decision process is highly political, and a large part of the political constituency for the project is indifferent to its power-generation economics, sound or otherwise. Many advocates see the project mainly in terms of "jobs" or an undefined thrust for "economic development", in which the perceived benefits increase proportionally with construction costs. And like WPPSS' "net-billing" agreements with the Bonneville Power Administration, at least some of the financing schemes being considered for Susitna (a direct appropriation from the state treasury, or general-obligation bonding) would bypass the need to convince lenders that the project is prudently conceived and designed and will be implemented efficiently.

In our judgment, the most serious cost-overrun risks connected with Susitna do not flow from oversights or biases in Acres' engineering-cost estimates. Nor do we believe that big cost overruns will be as prevalent on large custom-engineered construction projects as they have been since the mid-1960s.

> **The paramount construction-cost risk connected with the Susitna project is not that the Acres cost estimate is <u>too low</u> and, as a result, encourages the state of Alaska to invest in a project that turns out to be uneconomic.**

The Acres estimates, in other words, may be on target. The most serious cost risk associated with Susitna is, rather, that ---

> **An Acres cost estimate which is <u>essentially correct</u> may combine with unrealistic forecasts of Railbelt <u>electricity demand and fossil-fuel prices</u> to encourage an Alaska investment in a project that would be uneconomic even in the absence of construction-cost overruns.**

> **<u>This is precisely what is likely to happen if the Alaska Power Authority and the Legislature rely on the present Battelle and Acres reports as the last word on project feasiblity</u>.**

Ironically, the latter risk begets the risk, from an entirely different source, of large cost overruns relative to the Acres estimate, no matter how good that estimate in itself may be. If the legislature authorizes construction of the Susitna project on the basis of fanciful economic assumptions, financing the project will likely require state government to shelter consumers from the true cost of Susitna power by means of a direct capital grant, or to shelter lenders from the true economic risks of project investment by means of general-obligation bond financing. These devices, adopted precisely because the Susitna project could not stand on its own feet, would deprive the project of any important constituency for good management and cost control to offset the interests that stand to benefit from overbuilding, gold-plating, and wasteful mismanagement.

Non-completion risk. In the last few years, construction of a large number of electrical generating plants (mainly nuclear, but a few coal-fired) in the United States has been abandoned, suspended, or stretched out. Most of these plants were, at the time, suffering major technical, regulatory, and/or financing problems, but it is a mistake (albeit a widespread one) to regard these problems as the cause of abandonment or delay.

> In almost every recent case of power-plant non-completion in the United States the root cause has been falling load-growth projections.

Systems that had to pare back their construction schedules in line with revised demand forecasts naturally chose to abandon or delay their most troubled projects, while plants that were not justified by prospective load growth naturally became relatively difficult to finance. If the utilities in question really "needed" the added capacity, they would have persevered in trying to build them despite their technical and regulatory problems. Likewise, the utilities would have been able to finance most of the troubled plants if lenders had been confident that consumer demand would generate sufficient revenue to pay their costs.

Acres concluded that there is only a negligible risk of non-completion stemming from those contingencies Acres explicitly considered in its analysis of construction risks; we do not dispute that judgment. In recent years at least, no major hydroelectric project in North America has been terminated or indefinitely postponed for engineering reasons after construction began. Hydro facilities are not, however, inherently immune to cancellation or prolonged delays stemming from some of the troubles that have beset nuclear-plant construction plans, including environmental regulation or litigation.[80] There is certainly no reason to believe that hydropower is any less vulnerable to non-completion risks that arise from changed economic circumstances or bad planning and management than are nuclear and fossil-fueled plants.

If the state does abandon Susitna construction in the face of now-unforseen engineering, environmental, regulatory, or financial problems, it will at bottom be because the state and/or the lenders belatedly realized that the demand for Susitna power at its expected cost no longer justifies the additional outlays necessary for completion.

> **<u>This, rather than the fickleness of construction-cost estimates, is the real lesson of the WPPSS disaster for Alaskans.</u>**

Financing Issues

Real discount and interest rates. Benefit-cost analysis is the technique of comparing all of the benefits created by a project with all of its costs, no matter when they occur. In earlier years, the end product of such an analysis was usually a **benefit/cost ratio:** a worthwhile project was one with a ratio greater than 1.0, and the best of a group of competing projects was the one with the highest ratio. More recently, the concept of net **benefits** (total benefits less total costs) has become more fashionable: a worthwhile project is one that creates a positive net benefit, and the best project from a group of projects is the one that creates the greatest net benefit.

Acres has used a variant of this approach that assumes total benefits to Alaskans of meeting their electric power demand to be the same regardless of how the power is generated. Thus, the system that has the lowest expected cost is the one to be chosen, and under most assumptions, Acres finds that the Susitna project results in lower expected costs than any of its alternatives.

All of these benefit-cost approaches require the analysts to choose a **discount** rate for translating the costs and benefits of various future years to **present value** at the time the investment decision is made. Thus, the stated goal of the Acres analysis is to find the system that has the lowest expected costs as of 1982.

The outcome of benefit-cost analyses involving long-lived capital-intensive investments is very sensitive to the choice of discount rates, therefore making it a consequential and often controversial issue. The various assumptions adopted by Acres, for example, lead to the finding that Susitna is most likely the least-cost alternative if costs and benefits are discounted at a real (inflation-adjusted) rate of 4 percent or less, but that it is probably not the least-cost alternative if costs and benefits are discounted at 5 percent or more. A more familiar way of stating this finding is that money invested in Susitna is likely to earn the people of Alaska more than 4 percent and less than 5 percent per year, in excess of the return necessary to offset inflation.

After a clear discussion of the various discount-rate concepts used in benefit-cost analysis, Acres points out that the proper concept to use depends upon the purpose of the analysis.[81] In the case of the Susitna project, the proper discount rate is one that reflects the investment cost to Alaskans of the money sunk into the project; however, this cost, and thus the discount rate to be chosen, also depend on the specific financing arrangements proposed. The appropriate discount rate to use, and thus the decision whether or not a given project is a good investment, depend on the state of the capital market at the time the evaluation is made. And, benefit-cost analysts need to to take inflation into consideration in choosing a discount rate --- or more precisely, the expected rate of inflation over the life of the investment. Acres makes this adjustment by using "real" or "constant-dollar" interest and discount rates. Even after this adjustment, however, real interest rates vary greatly over time.

Interest rates on tax-exempt municipal bonds are normally lower than those on taxable securities of the same quality and maturity. Thus, it is conceivable that an economic feasibility analysis of Susitna would indciate that the project is a good buy for Alaskans if it can be financed with tax-exempt borrowing, but a loser if the Internal Revenue Code does not permit the Alaska Power Authority to sell tax-exempt securities, or if the legislature were to appropriate funds that otherwise could have been invested in high-yielding federal-government or corporate securities.

To the extent Susitna (or any alternative to Susitna) is to be debt-financed, the appropriate discount rate is the interest rate at which the money would be borrowed and, to the extent the state proposes to underwrite the project with appropriated funds, the proper discount rate is the return the state could otherwise earn by investing the same funds.

The Acres analysis does not explicitly take into account the difference between the state's borrowing and lending costs. Nor is the report clear what Acres assumes about the federal income-tax status of Susitna debt. It does not, at any rate, offer any coherent support for assuming that the Alaska Power Authority will be able to borrow in the tax-exempt bond market. Neither does the report deal with the possible effect of changes in real interest rates over time. Acres, instead, uses an approach that bypasses all of these issues: After some general observations about interest-rate history, the report adopts a discount rate of 3 percent on the following grounds:

> *. . . long-term industrial bond rates have averaged about 2 to 3 percent in the US in real (inflation-adjusted) terms. Forecasts of real interest rates show average values of about 3 percent and 2 respectively. The US Nuclear Regulatory Commission has also analyzed the choice of discount rates for investment appraisal in the electric utility industry and has recommended a 3 percent real rate. Therefore, a real rate of 3 percent has been adopted as the base case discount and interest rate for the period 1982 to 2040.*[82]

This approach might have been workable ten or even two years ago, but it is unsuitable in today's financial environment, in which current real yields have only the most tenuous connection with historic levels.

> The only capital cost or discount rate that really matters is the actual cost of borrowing (or not investing elsewhere) at the time the financial commitment is made.

In August 1982, inflation (in the form of the annualized rate of change in the gross national project deflator) was running below 7 percent, and most forecasters expected even lower rates of inflation in the late 1980's and the 1990's. Long-term municipal bond yields were in the vicinity of 13 percent, and long-term taxable utility and corporate bond yields 14-15 percent. Both nominal interest rates and future inflation rates were generally expected to fall, but the numbers implied that the real interest rate today (current bond yields less expected inflation) was in the 6-8 percent range. In July, 1982, Data Resources Inc., forecast real long-term interest rates remaining above 4.5 percent through 1992.[83] (In late October, bond yields and forecasts of future inflation had both fallen substantially relative to August levels, but the general relationship among them remained about the same.[84])

At a discount rate corresponding to current real interest-rate levels, even the Acres analysis rejects Susitna.[85]

Even with the outdated or questionable assumptions (identified elsewhere in this review) that bias the reports' benefit-cost analysis in Susitna's favor, Acres' own analysis implies that the project is not cost-effective in today's capital market. Thus, it would not be prudent for the state to borrow money at today's market rates to finance the project even with tax-exempt securities, and it would be even less cost-effective to commit permanent-fund or general-fund revenues that might otherwise be invested at today's high yields.

When and whether long-term capital markets will return to normal historical patterns, with long-term (taxable) real-interest rates on the order of 3 percent, is one of the big economic puzzles of the age. The real interest rates that have prevailed recently are about the highest on historical record, and they were not foreseen by any school of economic or financial analysts. The two most fashionable expert explanations for high interest rates today are almost totally contradictory. Stated differently, long-term capital markets are in great disorder and nobody really knows why or what "normalcy" now means.

> A 3-percent discount rate appears much too low to use as a base case for evaluating the economic merits of electricity-generation alternatives for the Railbelt.

Today's capital market is sending a message to the sponsors of big-ticket private investments (like ANGTS, for example) as well as to the state of Alaska with respect to Susitna that now is not the time to lock billions of dollars into them. If the rest of Acres' economic assumptions were sound (they are not), we might reasonably hope that a window would open in (say) two years or five years, in which real interest rates would have fallen to a level that makes the project cost-effective. Under today's capital market conditions, however ---

> Acres' own analysis does not justify or support a state investment in Susitna.

NOTES

Introduction and Summary

1. State of Alaska, Division of Energy and Power Development, State of Alaska Long Term Energy Plan (Juneau: 1982). The "plan" is in two volumes, an Executive Summary (cited hereafter as LTEP Summary), and the main report (cited as LTEP).

2. Acres American Inc. for the Alaska Power Authority, Susitna Hydroelectric Project Feasibility Report (Anchorage: 1982). The report encompasses a "Summary Report" (cited hereafter as Acres, Summary), the main report (cited as Acres), and 73 "reference reports." Reference report R-72, "Task 11: Reference Report: Economic, Marketing, and Financial Evaluation," is cited as Acres, Task 11. Reference report R-73, "Task 11.03, Close-Out Report, Susitna Risk Analysis," is cited as Acres, Task 11.03.

3. Battelle Pacific Northwest Labratories for the Office of the Governor, State of Alaska, Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans (Richland: February 1982), cited hereafter as Battelle. A subsidiary report, "Fossil Fuel Availbility and Price Forecasts" (Richland: March 1982), is cited as Battelle, Fossil Fuels.

4. The present reviewers were not involved in ISER's production of Railbelt economic scenarios or load-forecasts for Battelle (and indirectly for Acres).

Background to the Studies

5. These programs cost the state over $490 million in FY 1982 (LTEP, p IV-6). The 1982 legislature eliminated some programs, including the energy audit subsidies, but the costs of others, such as "power cost assistance," can be expected to increase. If the aggregate costs of these programs stay constant in nominal terms, the energy subsidy programs will account for roughly 18 percent of the $2.7 billion appropriated for FY 1983. For a description of each of the state's 20 subsidy programs, see LTEP, Exhibit IV-4 (following p IV-6).

The Three Studies

6. LTEP, p 1.

7. LTEP, p IV-11.

8. LTEP, p IV-4.

9. LTEP, pp IV-15 - IV-22.

Future Oil Prices

10. Division of Petroleum Revenue, Alaska Department of Revenue, Petroleum Production Revenue Forecast: Quarterly Report. In June 1982 the Department of Revenue's oil-price forecasts were revised slightly upward. In September, however, the Department issued a forecast which in the long term is even more pessimistic (regarding state oil revenues) than the March report. (Anchorage: June 1980 through September 1982), cited hereafter as Pet. Rev. Forecast.

11. Pet. Rev. Forecast, March 1982, p 5.

12. Charles Logsdon, Chief Petroleum Economist, Alaska Department of Revenue, personal communication to Erickson, July 18, 1982.

13. Cf. Tussing's remarks to the quarterly meetings of the US Department of Commerce Economic Advisory Board during 1979 and 1980; A R Tussing, "The 1981 Oil Price Outlook" in The Economic Outlook for 1981, University of Michigan, November 1980; A R Tussing, "Will Oil Prices Keep Rising? Maybe Not", Anchorage Daily News, February 14, 1981; Jon Matthews, "State Revenues Likely Will Drop: Oil Prices are Heading Down", Anchorage Daily News, May 29, 1981; A R Tussing, "Alpetco's Collapse Has Lessons for Budget Planners", Anchorage Daily News, May 23, 1981; Bob Shallit, "State Faces Revenue Loss, Economists Say", Anchorage Daily News, January 15, 1982; "Alaska Cuts Forecasts", January 18, 1982; Erickson & Associates for the Alaska State Legislature, The World Oil Market and Alaska State Revenues: A Fifteen Month Forecast (Juneau: March 1982). Also see the appendix to this review, "Reflections on the End of the OPEC Era".

14. "The Energy Issues" in T Barker and V Brailovsky, Oil or Industry, edited proceedings of a Conference on Policy Issues in Energy Self-Sufficient Economies at Different Stages of Industrialization held at Oaxaca, Mexico in September 1980. (London: Academic Press, 1981, p 3.)

15. The following examples are typical of the lot, as far as the reviewers can tell. In 1977 Exxon forecast that US consumption of petroleum liquids would be 20.3 million barrels per day in 1980, but actual consumption was only 16.3 million. And two years ago, Data Resources Inc. (DRI), an authority upon which Acres and Battelle have relied for fuel-price forecasts, was predicting 20 years of 4-percent annual oil-consumption growth in Europe. However, DRI now expects the conti-

nent's consumption to be below its 1979 peak during the rest of this century. (Reported in Petroleum Intelligence Weekly, 28 June 1982, p 7.) Also see the appendix to this review, "Reflections on the End of the OPEC Era" for further elaboration of the world "flight from oil."

16. D. de Bruyne, as quoted in Petroleum Intelligence Weekly, 14 June 1982, p 9.

17. The published forecasts of government agencies, and the big consulting firms seem to be among the last to recognize the changed outlook --- just as they were among the last to recognize that the high prices established in 1973-74 would be with us for a while. In response to the review draft of this paper, Acres offered the following list of "major forecasts of oil-price trends":

Source	Date of Forecast	Forecast Trend (percent)
Data Resources Inc.	Summer 1982	+2.8
International Energy Agency	Spring 1982	-0.5 to +2.0
US DOE Energy Inform. Adm.	Spring 1982	above +3.0
Canada: Energy Mines & Res.	Summer 1982	+1.7
Ontario Hydro	Spring 1982	+1.8
Energy Modeling Forum		
Average of ten models	February 1982	+1.9 to +5.3
Dr. F. Fesharaki	Spring 1982	+1.7

From Alaska Power Authority, Susitna Hydroelectric Project, "Commentary on 'Alaska Energy Planning Studies' (A R Tussing and G K Erickson)", prepared by Acres American Inc., September 7, 1982.

While the Acres compilation does not reveal the time span of the various projections, it is not unrepresentative of the kind of forecasters polled, even in late 1982. Significantly, however, this list does not contain a single petroleum-producing company, financial institition, or agency of an oil-**exporting** political entity, while four (half) of the forecasts come from governmental entities that have a powerful institutional stake (as does the Alaska Power Authority) in perpetuating the belief that real oil prices will continue to rise.

None of the recent forecasts the reviewers have seen, prepared for **internal** use by major petroleum producers (corporations or governments), expects sustained growth in the real price of oil during the rest of this century. All of them now assume continued constant-dollar price declines through at least 1985. At least two major integrated oil companies that now assume for their own planning purposes that the long-term oil-price trend will fall somewhere **between a level <u>nominal-dollar</u> and a level <u>constant-dollar</u> trajectory,** released **public** forecasts in 1982 that still show long-term real-price increases for oil.

More significant than what the companies are saying, however, is what they are doing.

The dramatic change in industry's long-term oil-price expectations over the last two years is impossible to ignore: The companies have scuttled every major unsubsidized synthetic-fuels project in North America, and most of the subsidized ones to boot. Oil companies are cutting back massively on drilling programs, but the most telling indicator of the drastic change in their expectation is the fact that **they are now paying only about half as much per barrel for proved petroleum reserves** as they were paying in late 1980. (On the last point, see B F Picchi, "The Valuation of US Petroleum Reserves: Exploding the Myths" in Salomon Brothers Inc Stock Research/Industry Analysis, October 15, 1982.)

18. Alaska Department of Labor, Alaska Planning Information: 1982, p 26.

19. Alaska Department of Revenue, Revenue Sources, June 1982, p 7.

20. Calculated from data contained in City and Borough of Juneau, "Notice to Taxpayers," May 1982.

21. Recent preliminary work by one of the reviewers on the actual phasing of state expenditures suggests that there may be a significant lag (as much as two or three years) between the time that revenues and appropriations began to fall (the interval between the FY-1982 and FY-1983 budgets) and the beginning of a decline in actual state expenditures. For example, state appropriations for FY-1981 --- when revenues and appropriations were still **increasing** rapidly --- were $3.1 billion, yet our preliminary data on actual spending (based on warrants redeemed) show that the state actually spent only $1.8 billion in that fiscal year.

Load Forecasts

22. Acres Task 11, pp 18-30. Acres "tests" the possibility of a positive correlation between oil prices and Alaska energy demand; however, as we show below, the "low load forecast" used in the Acres sensitivity analysis is unreasonably high given present expectations concerning state revenue, state spending, and major resource-development projects.

23. Calculated from data in Battelle, p A-6 (Table A-3).

24. Battelle, p A.2 (Table A-7).

25. Battelle, p A.2 (Table A-1). According to O S Goldsmith, the ISER and Battelle moderate case assumed that per-capita state spending moved proportionally with per-capita personal income. (Personal communication, September 6, 1982)

26. Acres, Task 11, pp 18-50. According to Acres, the State directed Acres to use the Battelle load forecasts. (Alaska Power Authority, Susitna Hydroelectric Project, "Commentary on 'Alaska Energy Planning Studies' (A R Tussing and G K Erickson)", prepared by Acres American Inc., September 7, 1982, p 2).

27. Acres Summary, p 5.

28. Battelle, p 3.12 (note a).

29. Calculated from data in Battelle, p A-7 (Table A - 4).

30. A R Tussing & L S Kramer, Hydrocarbons Processing (Anchorage: ISER, 1981).

31. Battelle, Fossil Fuel, p 2.7.

32. This calculation assumes a 1982 population of 410,000, and the 3.4-percent annual rate of population increase in Battelle's forecast. Real dollars are converted to nominal dollars using the seven-percent annual inflation rate assumed by the Department of Revenue (note 13, supra).

33. Pet. Rev. Quart. Forecast, March 1982; Milt Barker, Memorandum to Representative Thelma Buchholdt, 9 June 1982.

34. Pet. Rev. Quart. Forecast, March 1982, p 13.

35. Arlon R Tussing and Associates, Inc., Introduction to Electric Power Supply Planning (Anchorage, 1980), pp 32-33, 90-91.

36. University of Alaska, Institute of Social and Economic Research, "Alaska Electric Power Requirements. A Review and Projection," in Alaska Review of Business and Economic Conditions, June 1977, pp 1, 15. The actual growth rate is calculated from data in Alaska Power Administration, Electric Power Statistics, 1960-1980, August 1981, p 39.

37. Telephone communication, O S Goldsmith to Tussing, July 24, 1982.

38. LTEP, p 1-6 (footnote).

39. LTEP, p I-6. As we noted above, Battelle's "low-case" assumption for Railbelt population growth is 1.8 percent annually through 2000. Another Battelle study gives a "low-case" projection of statewide population in the year 2000 that implies an annual growth rate (1980-2000) of 1.7 percent. (Michael J Scott, et al, Historical and Projected Oil and Gas Consumption. Battelle Pacific Northwest Laboratories for the Division of Minerals and Energy Management, Alaska Department of Natural Resources, January 1982, p D.4)

40. LTEP, Exhibit I-10 (following p I-7). It is not clear, however, which of the many Battelle "cases" was used; the 1980-2000 Railbelt electric energy demand growth rate is listed as 3.5 percent.

Alaska Fossil-Fuel Availability and Costs

39. Acres Summary, p 5.

40. Acres Summary, p 9.

41. Alaska Power Authority, Susitna Hydroelectric Project, "Commentary on 'Alaska Energy Planning Studies' (A R Tussing and G K Erickson)", prepared by Acres American Inc., September 7, 1982, p 9.

42. ARTA, Inc. "Outlook for Proposed Coal-Export Terminals on the West Coast of North America" (unpublished proprietary report, October 1982), "Full Tanks Make Japan a Tough Customer for LNG", in The Asian Wall Street Journal, September 21, 1932.

43. Battelle, p 2.2; Acres Task 11, Table 18.2.3.

44. omitted

45. Acres Task 11, p 18-8.

46. loc. cit.

47. op. cit., p 18-9.

48. Minerals Yearbook, 1980.

49. US Department of Labor, Bureau of Labor Statistics, Weekly and Hourly Compensation of Production Workers in the Bituminous Coal Industry.

50. Acres Task 11, loc. cit.

51. Fuel oil prices: 1950 and 1970, US Department of Labor, Bureau of Labor Statistics, Western Regional Office (San Francisco), telephone communication; coal prices: 1973 and 1981, GVEA public information office, telephone communication; other data from Fairbanks North Star Borough, Community Research Center, The Energy Report.

52. Acres Task 11, loc. cit.

53. Japan, Commodity Trade Statistics.

54. Battelle, p 2.2 (Table 2.1).

55. Acres, p 2-4.

56. This estimate assumes a heat rate (btu/kilowatt-hour ratio) of 10,000, an interest rate of 15 percent, a 50-percent load factor, 5 mills per kilowatt-hour operation and maintenance costs, and present Cook Inlet gas prices. (loc. cit.) The cost estimate would probably be somewhat high even if the Acres-Battelle gas-price assumptions were accepted, as heat rates substantially lower are possible; levelized prices comparable to those used to project Susitna power costs would require the use of "real" (inflation-adjusted interest rates) of 3 percent (6 to 8 percent would probably be more realistic in today's market), and 5 mills considerably exceeds CEA's current O & M costs for gas turbines.

57. Acres, Summary, p 50.

58. op. cit., p 9.

59. All of the data used here are derived or calculated from Acres, Task 11, Table 18.2.3. The Anchorage natural-gas utility has offered to purchase gas from currently shut-in fields on the Kenai peninsula at a price in the neighborhood of $2.25 per Mcf, escalating with the producer-price index. The offer was refused but, in the absence of any visible alternative markets, the refusal could be construed as violating the "diligent development" provision of the state oil and gas leases.

60. In particular, see the sensitivity of the "net benefits" of Susitna to $0.65 MMBtu change in the price of coal. Acres, Summary, p 46.

61. Battelle, Fossil Fuel, p 2.29, 2.30 (Tables 2.9, 2.10).

62. Assuming no change in the consumption of the LNG and chemical plants. See Battelle, Fossil Fuel, p 2.12.

63. US Department of Energy, The Current State of The Gas Market, 1982.

64. The US Geological Survey's latest estimates of undiscovered natural gas in the Cook Inlet area are as follows:

	Low $(F_{.95})$	Mean $(F_{.5})$	High $(F_{.05})$
Onshore			
Associated-Dissolved	neg.	.2	.6
Non-Associated	1.1	3.3	7.2
Offshore			
Associated-Dissolved	0	.4	2.2
Non-Associated	0	1.3	5.9
TOTAL*	3.0	5.2	12.4

* Totals assume resources in the four categories are independent of one another.

Source: US Geological Survey, Circular 860, Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States (1981), pp 76-78.

Industry personnel in Alaska seem to be somewhat more optimistic about the Cook Inlet gas resource than is the USGS. A typical industry view of the Cook Inlet gas-supply situation (the most lucid expression of that view the reviewers have encountered) came from a veteran oil-company geologist:

> Sure, there's gas shows all over the place. How much? Hell, who knows? But I'll tell you one thing. Ain't nobody goin' to drill much of it till some of that shut-in stuff starts movin'.

Similar views are expressed by officials of Pacific Gas and Electric Company. (William L. Cole, personal communication to Erickson, February 6, 1981). See also, another Battelle study: Michael J. Scott, et al, Historical and Projected Oil and Gas Consumption (Battelle Pacific Northwest Laboratories for the Division of Minerals and Energy Management, Alaska Department of Natural Resources, January 1982)

65. At the end of September 1982, the California Public Utilities Commission gave the sponsors of the LNG project 60 days to prove its economic viability. (Inside FERC, October 11, 1982) The companies --- Pacific Gas and Electric, and Pacific Lighting --- responded immediately with an announcement putting off construction indefinitely:

. . . the NGPA has made available substantial added supplies of domestic natural gas, according to Bill Wood, gas company senior vice president and president of Pacific Lighting Gas Supply Co. As a result, Wood said, the company has announced that an affiliate has concluded it will not proceed at this time with construction of a liquefied natural gas (LNG) receiving terminal some 40 miles northwest of Santa Barbara, as well as an LNG liquefaction plant in south Alaska. . .

Alluding to the current adequacy of natural gas supplies, Wood said: We continue to believe the importation of LNG is an extremely valuable energy source for California. Further we believe that within two or three years we will be much better able to determine when these LNG facilities should be put into operation. (Southern California Gas Company press release, October 4, 1982.)

66. omitted.

67. On the export market, see, for example, "Full Tanks Make Japan a Tough Customer for LNG", in The Asian Wall Street Journal, September 21, 1982. For US market conditions see, inter alia, A R Tussing and C C Barlow, "The Rise and Fall of Regulation in the Natural Gas Industry," Public Utilities Fortnightly, March 4, 1982. (An expanded version is to appear as "The Future is Now", in the October 1982 Energy Journal.) Also, Tussing and Barlow, "A Survival Strategy for Gas Pipelines in the Post-OPEC Era", address to the Annual Meeting of the Interstate Natural Gas Association of America, September 27, 1982. (To appear in Public Utilities Fortnightly in January 1983.) See Business Week's cover story, "Gas Pipeliners: Priced into a No-Growth Future, Massacre in the Marketplace", August 2, 1982, pp 44-47.

68. We understand, but have not verified, that current LNG plant siting and safety standards essentially preclude construction of any new LNG facilities on the east side of Cook Inlet.

69. Cook Inlet vs North Slope gas prices. The Acres and Battelle treatment of North Slope gas is curious at best. For the purpose of determining Alaska economic activity and thus electricity demand, all scenarios assume that ANGTS will in fact be built (thus imparting an upward bias to population, gross state product, and electricity-load forecasts). When they are considering fuel supplies for electrical generation, however, the project is treated as doubtful. The Acres Summary is typical; after suggesting that "Cook Inlet gas reserves may have been depleted in the early 1990s to the point that reliance upon natural gas

as the principal fuel for electrical generation may no longer be possible," Acres states that

> *The availability during the study period of North Slope gas near Fairbanks remains uncertain.* ***Even if the gas pipeline is built,*** *however, the gas price is projected to be higher than that for the Cook Inlet resource. (Acres Summary, p 9; emphasis added)*

Acres and Battelle are not only inconsistent in their treatment of the ANGTS construction outlook, but show a double standard in their gas-pricing assumptions. They both use a "netback opportunity-cost" model to project Cook Inlet gas prices (which result in very **high** price forecasts), but they reject that approach in forecasting Alaska prices of North Slope gas (where it would have implied **low** gas prices for generating plants in Interior Alaska).

In the latter case, Battelle obtains a level 1982-dollar price of $5.92 per million btu at Fairbanks by adding the pipeline-transportation cost to the statutory wellhead price for Prudhoe Bay gas, despite the fact that such a price plus transportation charges beyond Fairbanks would surely make the gas unmarketable in the Lower 48. (Indeed, a 1982-dollar price of $5.92 at the lower 48 "tailgate of ANGTS would probably price North Slope gas out of the market.) Thus, the contractors have assumed as a **certainty** that ANGTS will be built on schedule where this assumption imparts an upward bias to load forecasts, and thereby a bias in favor of Susitna, while they treat ANGTS as doubtful when it undermines the crucial assumption that the Railbelt will have run out of natural gas by the 1990's. For Cook Inlet and North Slope gas, they have used quite different pricing models, and in each case they have also chosen the one that results in relatively high gas prices and which are, therefore, most favorable to the economics of the Susitna project. (Battelle, p 2.5.)

70. omitted

71. Acres, Task 11, Table 18.1.1; Acres, Summary, p 46 (Plate 24).

72. Acres, Task 11, p 18-7. In fact, the gas prices used do not follow these scenarios, but are instead substantially higher. See Acres, Task 11, p 18-7. For even more confusion, see Table 18.2.3, which implies a constant gas price of $3.00 per Mcf through 1990, and then a sudden spurt at a compound rate of 4.7 percent annually.

Cost-Overrun Risks

73. For a review of notorious cost overruns beginning in the 19th century, see Myron Kaplan, "Keeping Engineering Within Budget", in Technology Review, January 1976.

74. Our review included: US Library of Congress, Congressional Research Service, "Cost Escalation in Selected Major Construction Projects," an unpublished survey for A R Tussing, chief economist, U S Senate Committee on Interior and Insular Affairs, May 22, 1975; M M Hufschmidt and Jaques Gerin, "Systematic Errors in Cost Estimates for Public Investment Projects," in Julius Margolis (ed), The Analysis of Public Output (New York: Columbia University Press, 1970); Robert H. Havemann, The Economic Performance of Public Investments: An Ex-Post Evaluation of Water Resources Investments (Baltimore: Johns Hopkins University Press for Resources for the Future Inc., 1972) (This volume is the source of the samaple of federal water projects cited by Acres); Walter J. Mead et al, Transportation of Natural Gas from the Arctic (Washington: American Enterprise Institute, 1977), pp 83-94; and E W Merrow et al, A Review of Cost Estimation in New Technologies (Santa Monica CA: The Rand Corporation, 1979).

75. Misplaced specificity. The cost and schedule figures examined in an engineering-type risk analysis apply only to a specified project with a specified design. But almost every major construction project gets redesigned in major respects, both after the risk analysis is completed and before construction begins, and during construction.

Thus, sponsors of the Trans Alaska oil pipeline (TAPS) can in good conscience deny that the difference between their original $900 million estimate and the final $9 billion construction cost was all, or even mostly, an "overrun". Likewise, the pipeline engineers who carried out the first risk analysis (which showed a 95-percent probability that the pipeline would come in at less than $1.4 billion), do not believe that their work was incompetent or misleading, because the pipeline that was ultimately built was a very different thing physically from what these engineers originally had in mind.

What would have been improper and misleading, would have been to place great weight on these estimates of costs and risk parameters, (1) in comparing the pipeline with the icebreaking-tanker technology that Exxon was then testing, or (2) in assessing the economic feasibility of developing and producing the Prudhoe Bay reserves. To the credit of the TAPS sponsors, they never attempted to use their risk analysis in this way.

The Susitna hydroelectric project has already gone through several conceptual changes and considerable escalation in real-cost estimates under the Corps of Engineers and Acres. The design examined in the present Acres Feasibility Study is surely not the final design, we have been unable to determine from the current Acres reports how, and at what cost, the truly final design is expected to differ from the concept now under consideration.

76. **Subjectivity and Overoptimism.** Several kinds of subjectivity tend to flaw engineering risk analyses as a source for point-estimates of expected costs, or probability distributions around those point-estimates. Firstly and utterly fundamentally, risk analysts build into their models only those contingencies that they can foresee. The really major risks are, well, **surprises** . . .

Secondly, the probabilities assigned to most risk factors are frankly arbitrary and subjective. While a few probability factors (stream-flow conditions, industrial accidents, etc.) may reflect physical or actuarial analysis, most of the individual figures that go into the calculations are blind guesses, and many of them are inevitably inexpert and uninformed guesses.

Finally, these subjective features of risk analyses leave them vulnerable to designer and sponsor overoptimism. Only the project's own engineering design team is likely to know enough about it to carry out a competent risk analysis and, as we pointed out above, they often conduct similar analyses in the course of their own design work. Such teams are, however, almost always "believers" in the project analyzed and in its technology (be it hydro or nuclear power, space travel, or whatever); and their organization usually has a material interest in low cost and risk estimates. They are, therefore, among the least likely parties to anticipate all unpleasant surprises, or to assign sufficient weight to those that they do identify.

77. **Institutional blind spots.** Engineering-type risk analyses almost invariably exclude risks arising from certain institutional causes. These include changes in sponsor or public perceptions regarding the need for the project; design error and mismanagement; changes in laws or regulations; political controversies and lawsuits; changed capital-market conditions, etc. Together, these factors have played a large part in the cost-overruns, completion delay, and abandonment of "megaprojects" in recent years. Among these factors, the Acres report appears to consider only "contractor competence" and "regulatory delay".

One famous instance of project failure is the Washington Public Power Supply System (WPPSS) nuclear-plant construction program. Its history included planning and management failures, design errors and frequent redesign, incompetent or dishonest contractors, regulatory delays, unforseen interest-rate increases, ratepayer protests that culminated in a voter initiative to restrict WPPSS' borrowing power, repudiation of purchase obligations by some utilities, and a flock of lawsuits, any one of which may prevent further bond sales.

Very few (if any) of these factors were contemplated in the risk analyses that WPPSS presented to prospective lenders and to Washington State's Energy Facilities Site Evaluation Council (EFSEC). None of them, however, was as important in creating the impending disaster than the **collapse of the load-growth forecasts** prepared for or by the Northwest's utilities. Year after year, demand growth fell below the **minimum** values the utilities had forecast in previous years. (Is there something familiar here?) After billions of dollars had been spent on the WPPSS plants, it turned out that the power from them wasn't needed and couldn't be sold --- even if the system had been able to overcome all its other problems.

Almost all of the generating projects in the United States that have recently been, or will soon be terminated or indefinitely delayed or stretched out, have faced a combination of changing designs, escalating cost estimates, higher interest rates, regulatory problems, and falling demand forecasts. In most cases however, the last element was the most effective cause, as it undermined both the rationale for the projects, and the capacity of the utilities to finance them.

78. Underallowance for non-completion. The "expected final cost" figures generated by risk analyses almost invariably assume that the project in question will be completed. The Acres Susitna study is no exception, as Acres found the non-completion risks flowing from natural and construction factors, regulatory problems, or cost-overruns that cause mid-construction abandonment, to be "negligible" whether taken in isolation or together.

A true "expected-cost" figure for use in a benefit-cost analysis must incorporate the cost of "dry holes", however --- plants that are abandoned in mid-construction or which, even if nominally completed, cannot get an operating license or go on stream. Suppose the expected cost of a finished plant is 120 percent of budget, but that there is a 10 percent probability construction will be abandoned half way to the budget figure, a 5 percent chance it would be abandoned or not operate after the entire budget had been expended, and a 2 percent chance that it would be a washout after 120 percent of budget had been spent. The expected cost of a unit of added capacity would then be 135 percent of the budget figure, rather than 120 percent.

79. See the Appendix to Alaska Power Authority, Susitna Hydroelectric Project, "Commentary on 'Alaska Energy Planning Studies' (A R Tussing and G K Erickson)", prepared by Acres American Inc., September 7, 1982. Also, "Hydropower Broker Robert Byrd, Quebec's Master Energizer of James Bay, in Engineering News Record, February 12, 1981.

80. The Tennessee Valley Authority's Tellico Dam is notorious because of the "snail-darter" case that held up filling of the reservoir for more then two years after the dam was completed. The reason this is the only example that comes to mind is that most of the major hydro sites in the US Lower 48 had already been developed before the plague of cost-overruns, litigation, and regulatory and economic troubles began to overwhelm the nuclear power industry. There are other recent instances of controversies that precluded construction of hydropower projects, however --- the New River project in Virgina and North Carolina, for example.

An interesting aspect of this case is that, by the time that the federal courts finally authorized operation of the project, new studies by TVA showed that it would be uneconomic to install turbines and fill the reservoir **even after the dam itself had been completed.** Tellico had, in the meantime, generated such a political constituency that Congress ordered the TVA to go ahead with it.

Financing Issues

81. Acres Task 11, p 18-3/4

82. ibid.

83. Business Week, July 27, 1982.

84. October 14-15 yields for new utility bonds were 12¾-14 percent; Aa industrials 12.1 percent; US treasury bonds (1994-99) 10.1 percent, and the 20-bond Bond Buyer index of municipals 9¾ percent. Long-term inflation expectations, however, had fallen to the 2-5-percent range. For a summary of current market expectations, see Kenneth H Bacon, "Price Risk: Fed, Forecasters Differ on Inflation Outlook; Firms Have to Gamble. Companies Counting on Rate Staying 5% May Suffer Reserve Sees Further Fall. The Trauma of Disinflation" in the October 14, 1982 Wall Street Journal.

85. Acres Summary, pp 24-25.

REFLECTIONS ON THE END OF THE OPEC ERA

By Arlon R. Tussing*
Institute of Social and Economic Research
University of Alaska

Oil Prices and Alaska's Economy

Alaska's labor force, population, and personal income have been increasing faster than those of any other state for almost a decade. Very little of this growth would have happened without the two great surges in world oil prices that most people identify with the rise of OPEC --- the Organization of Petroleum Exporting Countries.

The five-fold price increase for Middle Eastern crude oil in 1973-74, and the resulting three-fold increase in the market value of US domestic crude oil, made it economically feasible to develop the Prudhoe Bay field and complete the Trans-Alaska oil pipeline (TAPS). Even if real oil prices had remained at their 1975-78 levels, Prudhoe Bay oil royalties and taxes would have made Alaska the richest state government per capita throughout the 1980s, and the spending and respending of these revenues in Alaska would have combined with continuing private investment in energy resources to put Alaska among the faster-growing states in income and employment.

World oil prices took off once more in 1979-80, however. Real prices at the Persian Gulf "only" tripled this time, but the stability of transportation charges between the North Slope and Lower-48 refineries caused the price of Prudhoe Bay oil --- and consequently Alaska's royalty and severance-tax collections --- to grow almost five-fold. At their peak in 1981, oil revenues were flowing into the state treasury at an annual rate of more than $10,000 per capita. The effect of this bonanza on state spending for government operations, transfer payments, loan programs, and public works was as awesome as it was predictable. In 1980 the Legislature abolished personal income taxes, and in 1982 it voted to distribute a "Permanent Fund dividend" check of $1,000 to each resident.

By the second quarter of 1981, when crude-oil prices began their present downward trend, most private and governmental planning in the state had come to reflect the assumption that oil prices and, with them, the prices of other fossil fuels would keep rising without limit. Disagreement about the long-term oil-price outlook was largely confined to the question whether price increases would average two, three, or five percent in excess of general inflation.

The prospect of ever-rising oil prices not only implied that Prudhoe Bay would generate more and more revenue for the state, and that the spending and respending of that revenue would provide more and more public- and private sector jobs. It also promised to sustain a high level of exploration activity on state lands and the federal Outer Continental Shelf (OCS) and, most likely, a series of major new discoveries. Rising oil prices convinced sponsors of the proposed Alaska gas pipeline that they could just about ignore the difficulty of marketing North Slope gas as a constraint on the project's economic feasibility.

An ever-increasing real price of oil on world markets seemed to promise Alaska a petrochemicals boom based on the growing cost-advantage North Slope natural-gas liquids (NGLs) would have over oil-based petrochemical feedstocks used elsewhere; it promised development of Alaska's coal for export, as well. Higher and higher prices for oil meant, moreover, that natural gas and coal would be too valuable to use for generating electric power in Alaska; this outlook has been the main rationale for planning a multi-billion dollar hydroelectric generating plant on the Susitna River, and led many Legislators to believe that the state would be able to finance the Susitna project with a direct appropriation from the General Fund.

The price of oil is thus the biggest single outside influence on Alaska's economy, and in 1982, uncertainty about the oil-price outlook has become the biggest single source of uncertainty about the state's economic future. The possibility that the oil-price boom may be over has profound consequences, which it has thus far been easier to ignore in Alaska than in other energy-exporting areas.

Since the upward movement of oil prices ended in 1981, economic distress has already overtaken many of the top oil-exporting countries. By the end of 1982, all but two OPEC nations are likely to be in a deficit fiscal and foreign-exchange position. In less than a year, a record boom has given way to grave depression in the deep-gas areas of Oklahoma, among oilfield-service contractors, and for the financial institutions that specialized in backing them. All but a handful of synthetic-fuels projects have now been abandoned, and the future of those is doubtful.

Several forces join to to perpetuate a petroleum-driven boom longer in Alaska than in other petroleum-exporting regions. Most crucial has been the fact that the actual spending of state money appropriated in 1980 and 1981 has continued to increase month by month well into 1982. Another factor has been the momentum of North Slope oil exploration and development programs, some of which would be viable at any world oil-price level higher than (say) $10 per barrel. A third element in the present boom is a host of Anchorage commercial building projects for which the key decisions and commitments were made before 1981. Finally, the continuing increase in the amount of state money actually flowing into the economy has combined with the flow of oil-industry investments to perpetuate a mood of high optimism among private investors in Alaska's non-energy industries, particularly residential and commercial real-estate development.

The 1981 Turning Point

This paper is intended to put the OPEC oil-price rises of the 1970s and the more recent oil-price decline into historical perspective. Alaskans can then weigh the chance that energy prices will resume their upward climb, giving new momentum to economic growth in the state, against the prospect that the OPEC era is indeed over --- meaning that Alaska, along with other energy-exporting regions, must accept a radical and mostly downward adjustment in its development expectations.

At the end of 1981, oil prices were suffering their greatest decline in half a century, but many industry executives and forecasters --- even outside Alaska --- cautioned that the attendant "glut" was a temporary phenomenon. Despite many signals to the contrary, that opinion has persisted well into 1982, with Occidental's Chairman Armand Hammer and others predicting $100-per-barrel oil in 10 years. The scarcity mentality that fed the price leaps of 1974 and 1979, plus a belief that unpredictable Middle Easterners control the world oil market through OPEC gave such assumptions nearly axiomatic status during the past decade. But the exporting nations' boast that "oil in the ground is a better investment than money in the bank" is turning out to be so much wishful thinking.

The truth is that neither an end to the recession, nor OPEC attempts at production quotas, nor continued wars in the Middle East will long be able to shore up a sagging crude-oil market. It is, indeed, because oil prices climbed so rapidly and so high in the 1970's that they are now almost certain to fall and keep falling --- perhaps as steeply and as far as they rose. Today's prices are still higher than markets can tolerate, and the forces that led to the enormous price hikes of the past decade work just as effectively in reverse.

While real (constant-dollar) crude-oil prices are unlikely to rise again to their 1980-81 levels any time in this century, forecasting prices for any specific future year is a nearly hopeless task. The fall in crude-oil prices that began last year will some day give way to another price rise, another decline, and so on. For crude-oil markets are inherently **cyclical** and, except during a unique period of almost four decades when the State of Texas dominated both U.S. and world crude-oil markets, oil-price fluctuations have been large and frequent. History shows us no long-term oil-price trends, but only a series of cycles of uneven duration and amplitude. The era of OPEC's opportunistic price-gouging is over, but no other entity is in sight with the power to move oil prices in any consistent direction or to stabilize them at any given level.

Market Control by the Texas Railroad Commission (1935-1972).[2]

To understand OPEC's helplessness in today's crude oil-market, it is useful to review how the market operated before OPEC came to power, and how the Texas Railroad Commission (TRC) managed to exercise control for nearly forty years.

The TRC's rule emerged in the mid-1930's from circumstances quite different from those that nurtured OPEC in the 1960's and 1970's. In the era between 1859, the year Colonel Drake first discovered oil in Pennsylvania, and the Great Depression, crude-oil markets everywhere were dominated by events in the United States, where one black-gold rush after another unleashed an oversupply and sent prices plummeting. Growing oil demand rapidly restored prices after most of these crises, as petroleum captured markets that were previously held by whale oil, gas, or coal, and as the automobile population swelled.[3]

The Yates field in Texas, for example, was first tapped in 1926. It was the biggest field yet found, and over its first year of production, average crude-oil prices in the United States fell 24 percent. Prices recovered quickly, but in 1930, the beginning of the Depression coincided with discovery of the even larger East Texas field. Oil literally ran in the creeks, and prices fell to 10 cents per barrel.

Much of this market chaos resulted from the common-law "rule of capture". The principle that nobody owned oil until it was brought to the surface generated frenzied competition among drillers to lift as much oil as they could from each newly-discovered pool before their neighbors got it. The East Texas drilling rush ended in 1931 only when the governor sent the National Guard into the field to shut down production. The next year, a bitterly divided Texas legislature granted the TRC authority to limit output from individual wells in the interest of conservation and market order. Under "market-demand prorationing", refiners told the TRC how much oil they wanted to buy each month, and the Commission parceled out the "allowable" share of this demand to each well. This system assured every Texas producer a buyer for at least some of his oil, no matter how much excess producing capacity other producers held. The TRC's ability to stabilize the market was bolstered by market-demand prorationing in several other states including Louisiana, the number-two US producer. Under state regulation, physical shortages and surpluses both became a thing of the past, "conservation" replaced physical waste, and the violent short-term fluctuations of crude-oil prices ended.

Even more important were a series of federal actions backstopping TRC authority. In the 1935 Connally "hot-oil" law, Congress made it a federal crime to ship oil produced in violation of state conservation orders. After the War, the executive branch acted to prevent uncontrolled imports of low-cost foreign crude oil from undermining the states' control of US oil supplies. For a while, the handful of largely US-based oil companies that controlled the oil reserves of the Middle East and the Caribbean had cooperated successfully in limiting petroleum production from their foreign concessions to just about the amount demanded by their own foreign refineries.

Nevertheless, by 1948, the huge low-cost oil reserves overseas had become enough of a threat to Texas regulation that the Truman administration started assigning "voluntary" import quotas to the companies. In 1958, after independents like Hunt and Occidental developed enormous new reserves in Libya, President Eisenhower established a mandatory oil-import program (MOIP). The MOIP gave each US refiner the right to import some lower-priced foreign oil, but it enabled the TRC and other state conservation authorities to continue setting the total volume of crude oil supplied to the domestic market.[4]

Critics of market-demand prorationing and import quotas, including the 1970 Cabinet Task Force On Oil Import Control headed by George Shultz, saw the combination mainly as an arrangement that kept US prices artificially high and perpetuated wasteful excess capacity. It did, indeed, shut in much of the nation's lowest-cost oilat the same time that it created an incentive to develop domestic fields that would not have been viable in a free market.[5] But precisely because it sheltered surplus producing capacity, Texas prorationing functioned as the balance wheel of the world oil market for four decades. Texas was the "price-maker": The TRC determined the price all domestic producers received for their oil and it was at the same time the most powerful single force in the world crude-oil market. Other producers were relegated to the passive role of "price-takers" who could always sell as much or as little oil as they wished, once they accepted the price structure established by Texas.

The TRC could play the price-maker's role because it had control over sufficient spare producing capacity to supply refiners with all the Texas oil they wanted at the established price, offsetting any rise in demand prompted by boom conditions or long-term economic growth, or any drop in output by other producers at home or abroad. The Commission also had the power to enforce production cuts if necessary to prevent a surplus from appearing when oil demand waned or production outside Texas increased.

The Texas system worked for nearly 40 years, through World War II, the US recessions of the 1950s, and several supply disruptions caused by Middle Eastern political upheavals in the 1950s and '60s. Oil supplies were seriously curtailed in 1952-54, for example, following Mossadeq's nationalization of the Iranian oil concessions, during the Suez crisis of 1956, and again during the 1967 Yom Kippur War. US and world crude-oil prices remained relatively stable, however, as the majors produced more oil in the unaffected Persian Gulf countries, while the TRC and other state commissions increased production at home.[5] From 1935 to 1972, roughly the period of the TRC's domination of the world market, the average annual change in real crude-oil prices in the United States was only 4 percent, plus or minus, a stark contrast to the average annual change of 21 percent between 1871 and 1935.

One reason for the TRC's success was that it did not exploit its market power opportunistically. The 1952, 1956, and 1967 Middle Eastern conflicts offered Texas producers (and the state of Texas, a major royalty owner) a chance for huge short-run profits, as they did the big international oil companies. But each time, the TRC and the majors opted for long-term stability, forestalling the kind of consumer panic that generated the price run-ups of 1974 and 1979 after the TRC had lost control.

Once domestic production reached full capacity in 1972, the US government had no choice (politically, at least) other than to do away with import controls, leaving consumers exposed to whatever upheavals might occur in the oil-exporting countries. Meanwhile, nationalization of the major oil companies' overseas concessions, plus the growing influence of independents (including national oil companies like those of France, Italy, and Brazil), had stripped the majors of their ability to balance supply and demand outside of North America. A supply curtailment by the Arab oil producers, which would have hardly caused a ripple in oil prices ten years or even two years earlier, transformed world energy markets and, for a few years at least, handed control of those markets to OPEC.

Panic Pricing in 1973-74 and 1979.

OPEC's spectacular successes in the 1970's were due more to market psychology than to anyone's direct manipulation of crude-oil supplies. OPEC per se did not engineer either of the decade's great price leaps; they came instead out of consumer panics that spread through the spot market after the 1973-74 Arab embargo and the 1978 Iranian revolution. In both cases, OPEC merely voted, after the panic had run its course, to establish the prevailing spot prices as the base prices for all crude-oil sales.

Crisis psychology was thus the key to the short-term oil market behavior that ratcheted prices upwards. The physical shortfall that provoked the panic of 1973-1974 was proportionally no greater than the shortfalls (or excess supplies) that the industry faced periodically because of unusual weather or the business cycle, and there was no reduction in output at all immediately before the 1979 price spiral. In neither case was the actual shortage greater than the sum of (1) the oil then being consumed by electrical-generating and manufacturing plants that had the capacity to use other fuels, (2) the standby or underutilized oil-producing capacity of US and uninvolved foreign producers, and (3) the inventory cushions that industry ordinarily would have drawn down in order to prevent market turmoil.

The price fly-ups, rather, began both times with a handful of large buyers who believed that the "shortage" was real, and who were thus willing to pay almost anything. This crisis mentality had a powerfully perverse effect on the market: instead of restraining demand, soaring spot prices gave the shortage credibility and helped propagate the panic to every class of consumer, so that demand actually increased. Much of the apparent supply deficiency was caused by hoarding, the most memorable example of which was fashion of topping-off gasoline tanks daily in private automobiles. This practice alone probably created demand for an additional 600 million barrels of gasoline in the United States --- equal to about three months of refinery output.

However socially irrational that hoarding may have been, it seemed quite reasonable at the time from an individual company or consumer standpoint. In 1973-74, both the Arab producers and the Western media were insisting that the embargo and production cutbacks were in fact harming the consuming countries. Congress had passed an Emergency Petroleum Allocation Act; President Nixon had declared an "energy emergency" and had begun allocating crude-oil and petroleum products.

No one knew how long the apparent shortage would last or how high prices might go before it was over; hence it made sense for anyone with a preferred position in the allocation scheme to take every drop of price-controlled gasoline or fuel oil allowed under the rules, regardless of current need, and for every other consumer to buy as much at the prevailing price as he could store. Motorists, households, and businesses all sought to build up and maintain high inventories in case things "really got bad" later, while producers, refiners, and others expected to profit from holding products for resale at higher prices in the future. All of these anticipations of course validated themselves: supplies did get tighter and prices continued to rise.

The Role of Spot Prices.[8]

Oil producers and refiners usually try to plan their physical operations and to budget their purchase outlays and revenues well in advance. For this reason, the great bulk of the world's crude oil moves in "captive" channels from producing companies to their own refinery affiliates or on relatively long-term contracts between producers and refiners. "Spot" transactions --- sales of a single tanker-load or less --- usually account for only a few percent of world supply, but they are an indispensable part of the total market because they allow any company or government to dispose of a temporary oversupply or fill a temporary shortfall. A general surplus or shortage equal to only (say) three percent of total world demand may thus show up as a surplus or shortage amounting to fifty or one-hundred percent of normal spot-market demand. As a result, spot prices tend to fluctuate daily and seasonally, and to range widely above and below "posted" or contract price levels, which typically change slowly and infrequently.

Changes in crude-oil spot prices occasionally herald deep-seated market changes, but more often they are only exaggerated reflections of unexpected weather or business conditions, the buildup or drawdown of inventories, or political events. After some such contingency has caused spot prices to diverge sharply from contract prices, the spot market normally returns to a relatively narrow band of prices in the vicinity of previous contract-price levels. What was special about the OPEC-dominated markets of the the 1970's is that they twice failed to respond in this normal way. After the panics of 1973-74 and 1979, spot prices did **not** fall back to pre-crisis levels; instead, contract prices rose --- by OPEC decree --- to the peak values to which the panic had carried spot prices. This feat was OPEC's great triumph which, ironically, is now begetting its downfall.

The Power of Saudi Arabia and OPEC.

The TRC determined prices by actively manipulating the aggregate supply of crude oil; as a state agency, it had the power to enforce its orders on the many thousands of Texas producers regardless of their conflicting individual interests and viewpoints. OPEC, on the other hand, has never had any authority over the diverse and sometimes warring sovereignties that make up its membership.

Nevertheless, in the early 1970's, once the surplus capacity of Texas and Louisiana had disappeared, Saudi Arabia by itself conceivably could have taken over the TRC's balance-wheel role. Its potential authority came from a combination of the world's largest reserves of conventional crude oil with a population on the order of only five million. The Saudis have thus had the same mix of assets, at least theoretically, that earlier gave the TRC its power --- the ability to increase or decrease output over a wide range.

Proved and indicated reserves in Saudi Arabia number in the hundreds of billions of barrels --- how many hundreds, no one knows or much cares, because it has never been worthwhile to carry out the intensive exploration and development work needed to get an accurate estimate.[9] The known reserves are, in any event, so large and so easy to develop that it would take Saudi Arabia only a few months to double its exports from the current level of less than 6 million barrels per day. (After all, production was almost 11 million barrels per day only one year ago.) With two or three years for drilling of development wells and construction of gathering lines and terminals, exports probably could rise to something like 18 million barrels per day. Indeed, before the 1973 embargo, the big oil companies (the Aramco shareholders) that controlled the Saudi concession were planning for production on the order of 20 million barrels per day by 1976.

Saudi market power rests on the ability to curtail as well as to increase production. The country's small population has permitted Saudi Arabia to reduce its output by almost half over the last year, from 10.6 million barrels per day in August 1981 to about 5.5 million in May 1982, without suffering a fiscal or foreign-exchange crisis. Throughout the 1970's, therefore, Saudi Arabia, with or without the cooperation of other OPEC nations, had much of the wherewithal to stabilize the market in just the same way as the Texas Railroad Commission once did.

The OPEC Mystique.

It was a worldwide obsession with scarcity, rather than deliberate management of total world supplies, that underpinned the OPEC mystique and locked in the high prices OPEC decreed in 1974 and 1979 after the direct causes of panic had vanished. The doctrine of imminent resource exhaustion was embraced in the 1970's by a broad spectrum of parties who had entirely different world-views and different ends.

Environmentalists hoped to slow the wasteful plundering of the earth's riches; oil companies were seeking to ward off price controls and attacks on their tax preferences; alternative-energy entrepreneurs sought business; politicians found in the energy crisis a moral equivalent of war; civil servants made it the rationale for massive expansion of their agencies and intervention into almost everything; and an army of academics, consultants and journalists waxed rich and famous by studying, interpreting, or advocating national energy policies. Each group wanted to believe, or at least to persuade others, that "the wolf is really here" --- that OPEC's prices might have risen too abruptly for comfort but that, in the last analysis, those prices only expressed the dictates of geological necessity.

"Oil in the Ground is Better than Money in the Bank."

In this intellectual climate, each price increase, regardless of its proximate cause, helped convince the oil-exporting nations that "oil in the ground is a better investment than money in the bank." This doctrine could remain valid for just as long as most producers believed in it, because it encouraged them to hold oil off the market in the faith that its value would be much higher in the future. It was therefore the most effective and durable weapon in OPEC's ideological arsenal.[10] Although the organization had no enforcement machinery, and did not even attempt a prorationing scheme until 1982, its members did reduce production when preservation of the price gains of 1974 and 1979 required it.

When the OPEC nations cut back their total exports in 1974 and again in 1979, it is important to note that they made the required cuts individually. They did so **without coordination or urging by OPEC,** because they had more money than they needed at the moment, and because they believed that their oil would be worth more later. Even the 1973-74 price rise had been so immense that most OPEC countries had substantial financial surpluses; only Algeria, Ecuador and Indonesia were in deficit. In 1975 OPEC as a whole had a $59-billion (or 14-percent) surplus of export revenues over import expenditures. Several countries understandably concluded that their economies couldn't absorb further increases in oil income without generating intolerable inflation and social unrest.

It also seemed obvious to the producers that oil prices would continue to advance at a higher rate than their surplus cash would yield in risk-free financial instruments. Thus, Kuwait, Libya, and Venezuela together reduced their exports by 4 million barrels per day after the 1974 price rises. Saudi Arabia abandoned Aramco's 20 million barrel-per-day target in 1974, and cut production sharply in January 1979 and then again in April --- ostensibly to offset an imminent oil glut, which was in fact an aftermath of the price panic that followed the overthrow of the Shah. In neither price rise did OPEC as such have any role in initiating or orchestrating the curtailments.

Thus, a short-lived belief in acute scarcity twice created a real scarcity that caused spot prices to soar. A belief that chronic energy shortages would engender a permanent seller's market then led producers and consumers alike to interpret an unusual and otherwise transitory market phenomenon as obedience to holy writ. The self-fulfilling doctrine that oil in the ground was the world's best investment not only encouraged OPEC officially to adopt spot market prices generated by consumer panic; it also enabled those prices to stick. In 1973-74, the world price of crude oil (measured at the Persian Gulf) increased five-fold in real terms, and then in 1979-80 it again tripled (a vivid contrast to the decades of tranquility under the TRC).

The End of the OPEC Era.

OPEC's hold over world energy markets in the 1970's was no less real because it was mainly psychological. However, the cartel's mystique is far more fragile than the earlier market power of Texas, which stemmed from the TRC's direct control over production volumes. Today, few of the material requisites for further OPEC success remain. Its share of the world oil market has fallen from 55 percent in 1974 to 31 percent in August 1982; and Saudi Arabia's share is already less than the share Texas held as late as the mid-1960's.

Some recognition of these shifting realities began to strike the Saudi leadership only after two deliberate production cuts in 1979 had locked in a series of huge price increases voted by OPEC. Saudi Arabia's actions have now become more-or-less consistent with the professions of the kingdom's oil minister, Sheikh Yamani, who had long given lip-service to the cause of moderation and market order. Explicitly invoking the memory of the TRC, Yamani claims to have engineered the 1980-81 "oil glut" --- increasing production from less than 8 million barrels per day to almost 11 million, specifically in order to bring prices down to $34 per barrel and to persuade his OPEC partners they should join a prorationing scheme under Saudi leadership. In 1982, after succeeding too well, perhaps, the Saudis have abruptly reversed course, now **cutting** their exports by nearly half in an attempt to support the $34 price.

But Saudi Arabia appears to have been too late in discovering the market power it alone possessed. While the TRC held crude-oil prices in the United States above short-term free-market levels, it still kept them low enough to encourage ever-increasing oil consumption and stave off the development of alternative energy sources. The Saudis, however, wittingly or unwittingly had a key role in both OPEC price hikes of the 1970's, unleashing inexorable and profound reactions from both producers and consumers, which today threatens to make OPEC oil a dispensable commodity.

Contrary to a near-consensus of industry, government, and the academic/consulting community during the 1970's, crude-oil demand does respond --- slowly but massively --- to price changes. In the long run, higher prices have a profound effect on oil supply too, but the relationship is too complex to pursue in detail here. In any event, non-OPEC output has grown rapidly and will continue to grow: Production from the North Sea, Alaska, and Mexico, for example, increased by 4 million barrels per day between 1977 and early 1982, and Mexico's exports --- driven now by economic necessity --- could increase another 3, 5, or more millions of barrels per day before 1990. Most clearly and most importantly, however, high oil prices are shrinking oil demand both by reducing total energy consumption and by making coal, natural gas, nuclear power, and other energy sources more attractive.

The Flight from Oil.

After a modest dip in 1974, total world oil consumption resumed its growth, and finally turned down only in 1979. This experience reinforced the impression that oil demand was insensitive to price changes, misleading economists as well as industry executives and government officials in both oil-producing and oil-consuming countries. An absolute decline in US oil consumption was first visible in 1979; the rest of the industrialized world followed a year later. In retrospective, it is remarkable how many were unable to see what was happening.

Exxon in 1977 forecast that US consumption of petroleum liquids would be **20.3 million barrels per day in 1980.** In 1979, Shell predicted **18.6** million barrels per day consumption in 1980, and both the Oil and Gas Journal and the Independent Petroleum Association of America forecast 18.4 million. As late as mid-1980, Shell had only revised its published estimate downwards to **17.2** million barrels per day, while the Independent Petroleum Association of America had come down to **17.4. At year-end in 1980, however, average consumption for the year stood at only 16.3 million barrels per day.**

The drop in total oil use over the last three years and the experts' tardiness in recognizing the trend of consumption stem from profound changes in the structure of world energy demand, which have actually been under way since 1974. From 1960 to 1973, oil prices were low and declining in real terms. As a result, absolute oil consumption in the industrialized countries grew at an annual rate of 7.6 percent. Japan led this growth with an 18-percent average over the thirteen-year period. After 1974, however, the quadrupled crude-oil price led to a gradual leveling off of demand for oil everywhere. Total oil consumption in the industrialized countries dropped slightly in 1974-75; growth resumed between 1975 and 1979 at an annual rate of about 1 percent, but this partial recovery only concealed the fundamental shift that had taken place in the world's energy-use patterns.

More telling than gross consumption figures is the change in oil use per unit of economic activity, or "gross domestic product" --- the oil/GDP ratio. After rising at an annual rate of 1.3 percent from 1960 to 1973, the oil/GDP ratio for the major industrialized countries showed a 1.5-percent annual **decline** between 1973 and 1979. The 1979 upheaval initiated an even more decisive and long-lasting shift away from oil, reflecting both an immediate reaction to the second OPEC price surge and the delayed but cumulating response to the price increases of the early 1970's. From 1979 to 1981, oil consumption in the industrialized countries fell 7 percent per year, and the oil/GDP ratio fell at an annual rate of 8 percent.

Since the latter measure represents the amount of oil used **per unit of economic activity** rather than an absolute figure, its fall implies that an end to the present recession will not be the panacea that much of the energy industry and many analysts still seem to anticipate. The die has been cast. It is unlikely that individual homeowners will tear the insulation out of their houses if the price of home heating oil drops, or scrap their new fuel-efficient automobiles in response to lower real prices for gasoline. Nor will the construction and automobile industries abandon their new energy-efficient designs. Those who attribute the oil glut and the current "softness" of oil markets primarily to the world recession forget that economic recovery will mean a **more rapid replacement** of existing vehicles, industrial machinery, and buildings with models designed since 1974 in response to high energy prices.

Except in a couple of OPEC countries, no new base-load electrical generating plants fired by oil, or large-scale oil-fired boilers of any sort, have been built since the mid-1970's; over the past decade, industry has been relentlessly converting existing oil-burning equipment to coal, natural gas, and other energy sources. Because changes in the world's fuel-use patterns are generally embodied in long-lived capital-intensive investments such as buildings, transportation equipment, and industrial machinery, the extended period it has taken for the 1974 price rises to produce an absolute decline in oil consumption only reflect the time required to replace these assets. This long lag in adjusting the world's capital stock to changed energy-supply conditions also suggests that the all-time high oil prices of 1974-1982 will influence consumption patterns for many more years, **even if world oil prices now fall as rapidly and as far as they rose in the 1970's.**

The truism that the world's petroleum resource is finite thus does not mean that oil prices will continue to rise. The world has no demand for crude oil as such, but only for the heat, motive power, and chemical building blocks it provides, and only for so long as it is the cheapest source of these goods. No matter how scarce natural petroleum liquids become, their prices can not rise and remain above the cost at which each of these wants can be dispensed with or served in some other way.

It should be fairly obvious now that predictions of $100 per barrel oil are ludicrous. At $15 per barrel, oil was already more expensive than coal in most of the world, and had consequently priced itself out of electrical-generation and other large-scale stationary-heat and boiler-fuel markets. At well under $50 per barrel, given a few years for market and infrastructure development, liquid petroleum products would have become marginal even as transportation fuels, increasingly replaced by some combination of compressed and liquefied hydrocarbon gases and alcohols. A world that is already fleeing from oil at $32 per barrel would hardly have any use for it at two or three times that price.

This dynamic does not bode well for OPEC, or for the ability of Saudi Arabia or anyone else to manipulate or stabilize the market. Only when demand falls is the power of a price-maker tested. Can the OPEC nations, many of whom are deeply in debt, now afford to cut back production as they must?

On this point too, the OPEC of 1982 is as different from its predecessor, the Texas Railroad Commission, as it is from the OPEC of the mid-1970's. In comparing OPEC with the TRC, it is essential to remember that the Commission's power developed during the Depression, and that its institutions were designed expressly to manage a chronic excess of producing capacity. Once that excess was gone, the TRC became impotent and economically irrelevant. OPEC, in contrast, showed its muscle under totally opposite conditions. It twice seized upon a brief moment of consumer panic, convinced itself and consumers alike that a permanent world oil scarcity existed, and for a while reaped the benefits of a seller's market even after the foundations of that market had vanished.

There is little prospect that OPEC can function effectively in a chronic buyer's market, especially in the face of the organization's current internal dissensions and the precarious financial situation of its members. At its March 1982 meeting, the group made its first serious attempts at TRC-style prorationing. The experiment was an instant failure, with at least three members brazenly exceeding their quotas from the beginning.[12] By July 1982, Iran was selling 1.0 million barrels per day above its quota, Nigeria .3 million, and Libya .25 million. Venezuela --- the sole advocate of OPEC prorationing before 1980 --- had threatened to start selling more than its assigned 1.5 million barrels per day if the other countries didn't get in line, and in August, the Saudis, who had already reduced their output by 45 percent in the hope of supporting the $34 marker price, were also hinting that they would increase their exports if the cheating didn't stop.[13]

Even holding the line at today's production level is not enough to bolster OPEC's flagging power, as world oil consumption continues to shrink and the production of non-members --- especially Mexico --- continues to grow. The organization as a whole must somehow manage to reduce production even further if present prices are to hold. Yet its member-nations individually face internal problems and pressures that urge them in just the opposite direction.

The greatest source of downward pressure on prices is the shaky financial condition of the exporting countries, a drastic turnaround from the situation of 1975. Since 1973, the OPEC nations' spending for imports has risen at an average annual rate of 30 percent, because of ambitious industrialization plans in every one of them and extravagant purchases of military hardware in many. Already, the combination of declining oil demand and rapidly rising expenditures has resulted in trade deficits for all but three OPEC members. Unless oil production or prices increase sharply, every member, including Saudi Arabia, could slip into deficit by the end of 1982.

These deficits, exacerbated by the continuing Iran-Iraqi war, are already beginning to take their toll as the most hard-pressed countries, in search of revenues to pay for today's imports, produce as much oil as they can sell. Moreover, with declining or even stable prices and real (inflation-adjusted) interest rates at their highest level in history, the slogan that oil in the ground is a better investment than money in the bank is obsolete even for countries that don't have an immediate cash-flow or foreign-exchange deficit. In the 1980's, it is hard for even a cash-surplus oil-exporter to avoid recognizing that "**oil in the ground is a non-earning asset**", which ought to be cashed out so the proceeds can be invested in high-yielding financial instruments. This doctrine is just as true and may be just as self-fulfilling today as was the opposite notion in 1975 or 1979.

To put OPEC's weakness into further perspective, consider the following:

*In August 1982, world crude-oil production was about 54 million barrels per day. Out of this total, the Saudi share was about 5.5 million, or 10 percent; all of OPEC was producing about 17 million barrels per day, or 31 percent of world supply. If new production in non-OPEC countries plus further declines in consumption were to equal only 10 percent of present world demand, OPEC's members would have to reduce their own production by 32 percent in order to defend any chosen price level.

Saudi Arabia, which has already reduced its exports by 45 percent over the last year, can not and will not accommodate much of this burden, as a 10 percent shift in world supply or demand would be just about equal to the country's current export volume. Further growth in non-OPEC production and a further fall in world consumption are not only plausible but nearly inevitable. Thus Saudi Arabia's reign as world price-maker is ending virtually as soon as it began.

*Conservation, fuel-switching and recession caused the non-communist world's oil consumption to fall by 7.5 million barrels per day between 1979 and mid-1982. If consumption declined by only half as much over the next two years, OPEC's output would have to fall by an amount equal to the combined production of Kuwait, Libya, Algeria and Indonesia in August 1982, or by 68 percent of current Saudi output.

*Crude oil production from Alaska, Mexico and the North Sea increased by more than 4 million barrels per day between 1977 and 1981. If all non-OPEC producers were to increase their output by another 4 million, OPEC could maintain control of prices only if its members could cut production by at least the equivalent of 73 percent of August 1982 Saudi Arabian production.

*Production from Iran, the world's former number-two oil exporter, has fallen 4 million barrels per day from its 1974 peak. The former number three exporter, Iraq, is producing 2.6 million barrels per day less than the peak it reached in 1978. If the war between these countries should end and they returned to the market with their 1978 sales volumes, other OPEC countries would have to curtail production by an amount equal to 90 percent of August 1982 Saudi output.

*Finally, if by chance the last three developments all took place, and if OPEC hoped to sustain world prices at current levels, it would have to find places to cut production by least 12.7 million barrels per day --- 75 percent of the organization's current output, or 231 percent of August 1982 Saudi production.

The range of conditions within which OPEC, Saudi Arabia, or anyone can continue to dictate or even defend the level of world oil prices is thus extremely narrow. The reckless opportunism that held sway in the 1970's is now taking its toll. Long-term changes in supply and demand adverse to OPEC's interests have been under way ever since the cartel's first big coup in 1974. As these changes become visible to everybody, the mystique that has been OPEC's chief source of power will vanish along with forecasts of hundred-dollar oil. The world market will soon be, if it is not already, out of anyone's control.

What Have We Learned?

A big new disturbance in world oil markets could push prices either up or down. It is still conceivable, if only barely so, that a sharp economic upturn and an exceptionally cold winter could combine with the right kind of Middle Eastern political crisis, and send prices soaring for a third time to levels significantly above those reached in 1980-81.

The probabilities, however, weigh heavily on the other side. There is a huge overhang of excess producing capacity in the oil-exporting countries. Several of them are in big fiscal distress; Mexico in particular has both the ability and a desperate need to increase oil exports. Meanwhile, the price-induced flight from oil is still gathering momentum that will not be spent for years **no matter what happens to oil prices today.**

All of these forces together, not to mention a worldwide economic slump that is far from over, add up to irresistible downward pressure on oil prices. Prices must **eventually** go down, and they must go down substantially. The serious questions are whether they will descend smoothly or chaotically, and how deep they will go. There is still a sliver of a chance that prices could firm for weeks or months, or even --- given the unlikely coincidence of events decribed above --- increase once more. But a market collapse this year or next has a far bigger likelihood, a collapse every bit as spectacular as the two price eruptions of the 1970s.

Looking back across the years of OPEC and Energy Crises to the relative tranquillity of the TRC era and beyond, there are a several lessons for the future.

1. **Worldwide scarcity and rising real resource costs had little or no direct responsibility for the worldwide energy-price upheavals of the 1970s.**

The earths's **known** resources still include plenty of crude oil that could be developed and produced at resource costs (capital, material, and labor costs) well below 1973 real prices. Considering these resources alone, there is enough low-cost oil left to satisfy the world's current rate of consumption for several decades.

2. **In the absence of an effective price-maker like the Texas Railroad Commission, crude-oil markets are inherently cyclical.**

Oil demand is highly responsive ("elastic") to price changes, but this response is very slow, because fuel-use patterns are embodied in capital goods whose turnover is measured in decades: buildings, transportation equipment, industrial machinery, and production processes. For the same reason, demand is exceedingly inelastic to price changes in the short run. This contrast between short- and long-term price-responsiveness inevitably fosters cyclical price behavior. In the 1970s **short-term price-inelasticity** spawned a steep cyclical upswing after years of artifically-maintained stability, and in 1981, a high **long-term price-elasticity** finally began to show itself in the beginning of a downswing.

If there is no "surge-tank" or "damping" mechanism comparable to market-demand prorationing, moreover ---

3. **Market structure and psychology can exaggerate an episodic oil-price fluctuation, up or down, far out of proportion to the original supply-demand imbalance that triggered it.**

Inventory accumulation or liquidation, the financial position of major producers, and consumer panic can all cause markets to behave perversely over a "short-run" that can last for several years. In a mockery of the "normal" supply-demand map, an oil-price rise can for a while create an incentive to build inventories, and sustained price rises can encourage the withholding of production. A price reduction, likewise, can provoke liquidation of inventories and the expansion of output. As a result ---

4. **A small excess of demand or supply, real or imagined, can send the market soaring or plummeting far beyond the price level that ultimately could have brought it back into balance.**

Thus, there is no **stable** equilibrium toward which an unregulated petroleum market unfailingly "hunts" once it is disturbed. The upheavals of the 1970s, which carried prices well **above** any level that could be sustained in the long run, have now set the stage for a descent far **below** the range of sustainable prices.

5. **No cartel or regulatory system could have held world oil prices at the low levels of the early 1970s, and none can do so in the future.**

Before 1973, state regulators in the United States and the cartel of international companies maintained prices that were above the shortest-term "market-clearing" levels, but which were still so low that oil totally dominated transportation-fuel markets (even capturing railroads that had earlier been powered by electricity generated from coal) and, except in a small corner of the United States, virtually swept coal from the world's markets for industrial boiler fuels and organic-chemical feedstocks. These prices were, at the same time, too low to perpetuate the surplus oil-producing capacity in the United States, to which the state regulators owed their market power. Though the world's stock of very low-cost oil was still immense, the loss of spare capacity in the United States concentrated the power to increase or curtail production rapidly in a handful of economically underdeveloped and politically turbulent countries.

The problem, therefore, was not a permanent worldwide scarcity of "cheap" oil, but rather, the absence of short-term oil-demand flexibility, together with the disappearance of the short-run supply flexibility that had previously been exercised by governmental and private institutions that had were consciously striving for market order. In these circumstances, a relatively small curtailment of sales by a few producers openly aiming at market disruption could and did trigger an upward explosion of prices. If world oil prices now fell to pre-1973 levels (in constant-dollar terms) once more, a world-wide "energy crisis" would be with us again sooner or later. Likewise, however ---

6. <u>No group of producers could long hold world oil prices at the high levels of the early 1980s, and it is unlikely anyone will ever be able to do so.</u>

Today's prices are not viable because they are well on the way to pricing oil out of both the industrial fuels market and the market for petrochemical feedstocks. If prolonged, today's prices would even begin to erode oil's monopoly in transportation-fuels markets. Oil at $30 and up has, therefore, guaranteed the emergence of excess producing capacity not in just one or a handful of political entities (Texas and Lousiana, for example, or Saudi Arabia, Kuwait, and Abu Dhabi), but all over the globe.

7. <u>Market stability at any price requires the supply-demand balance to respond promptly and in the normal direction to any price change, and prices to respond promptly and in the normal direction to any change in the supply-demand balance.</u>

If the world is to avoid repeated violent swings in oil prices, market arrangements must be such that a small rise in oil prices can cause either a sizeable increase in effective oil supply or a sizeable decrease in oil consumption, or both. A small drop in prices must, likewise, be able to induce a prompt reduction in supply or increase in consumption.

8. <u>Short-term supply-side adjustments that foster price stability rather than instability require a TRC-style price-maker, but none is now in sight.</u>

Any supplier or group of suppliers that hopes to regulate the market must have the ability and the will to swing world oil production upward to satisfy any surge of demand or supply interruption, or (more importantly now) to swing it downward in order to make room for a surge of supply or slump in demand. The system run by the TRC underpriced away its power to increase output whenever it was needed. OPEC as such never had either the will or the capacity to take responsibility, and Saudi Arabia --- out of greed or timidity, we may never know --- blew its chance. It has now overpriced away its ability to reduce production sufficiently to support world prices at present levels or, most likely, at any level.

The only plausible new candidates for price-maker may be PEMEX (Mexico's state oil company) and the US Strategic Petroleum Reserve. Even if one of them maneuvers itself into the right strategic spot in the world market, however, there is only the barest chance that domestic politics in the United States or Mexico would permit either institution to move quickly, independently, and responsibly enough to serve as the world's oil-supply balance wheel.

> 9. The only price level that even a supply-side price-maker can maintain for long is one that fosters demand-side stability as well.

> 10. Specifically, the range of sustainable oil prices is limited to those prices at which oil, coal, and gas are effective and close competitors in the world's markets for electrical-generation fuels, industrial boiler and stationary heating fuels, and petrochemical feedstocks.

If the price of oil remains within a range where oil, natural gas, and coal effectively compete for industrial sales in North America, Europe, and East Asia, many of the world's large energy-consumers will find it worthwhile to install dual or multi-fuel capacity, expressly in order to take advantages of small shifts in relative prices. The ability of a large consuming sector to switch fuels rapidly in response to changes in relative fuel prices or availability would preempt the perverse market behavior that has permitted small market shocks to explode into global crises. Multi-fuel consumers would simply let go of enough oil in a tight market, and absorb enough additional oil in a slack market, to avoid even the illusion of a physical shortage or surplus. The greater this demand-side flexibility becomes, the more modest will be the world's need for a supply-side price-maker like the TRC, the less onerous will be the price-maker's task if one is still needed, and the less damage an incompetent or irresponsible price-maker will be able to cause.

> 11. The most stable and easily sustainable price range is probably on the order of $10 to $18 per barrel (in 1982 constant dollars), delivered to the world's major consuming regions.

Unlike pre-1973 prices, the $10-to-$18 price range is high enough to cover the cost of mining and transporting coal, and of burning it in an environmentally acceptable fashion, almost but not quite everywhere in the world. These prices are also high enough to justify shipping liquefied natural gas (LNG) from any low-cost gas-producing area near tidewater to almost any port in the world, and to justify building transcontinental natural-gas pipelines (though maybe not the Alaska or Yamal pipelines). Prices in this range would still leave oil holding a significant fraction of the markets for electric-utility and industrial boiler fuels and for petrochemical feedstocks. Any price excursion outside of this range, however, would still carry the threat of steep price fluctuations further away from, or substantially overshooting, any attainable equilibrium.

History offers some empirical support for the viability of a long-term world oil price in the $10-to-$18 range. Over 110 years of crude-oil price records in the United States, the average price in 1982 dollars has been almost exactly $13 per barrel and, despite an average constant-dollar price fluctuation of more than 20 percent per year, no long-term trend can be detected. (The average 1982-dollar price between 1871 and 1925 was $12.96 per barrel, and the average price between 1926 and 1980 was $13.04 per barrel.) Thus, the safest guess as to the average crude-oil price over (say) the next 25 years may be about $13 per barrel in 1982 dollars. However ---

> 12. <u>These generalizations do not warrant a forecast of a $13 price, or any other specific price at any specific future time.</u>

In the absence of a secure mechanism for getting world oil prices into this range and keeping them there for several years, and in the absence of a competent and responsible successor to the Texas Railroad Commission, the prospect is for wide and unforeseeable fluctuations in world oil prices, like those that occurred before the TRC took control in the mid-1930s. The managing director of Royal Dutch Shell, D. de Bruyne, summarized the new outlook well when he wrote that "we are in for a period of severe and unpredictable discontinuities."[14] The most ambitious forecast we dare make with any confidence is that --- without some new market-ordering mechanism, which is not now in sight ---

> 13. <u>World oil prices will fluctuate both randomly and cyclically. In any given future year, however, the most likely price will be far below 1979-1982 levels.</u>

In summary, there is no basis in geology, resource-economics or history for predicting a never-ending increase in the real price of oil. Private investments and governmental institutions founded on that proposition are sure losers.

NOTES

*Connie C Barlow, Michelle Celarier, Gregg K Erickson, and Samuel A Van Vactor all helped develop the concepts in this paper and clarify their expression; M A Adelman provided useful corrections and suggestions.

1. "'OPEC Will Survive', Oilman Hammer Says." Associated Press story in Seattle Post-Intelligencer, July 12, 1982, p B8.

2. For the history of oil conservation and the rise of the Texas Railroad Commission, see Wallace F Lovejoy and Paul T Homan, Economic Aspects of Oil Conservation Regulation, (Baltimore: The Johns Hopkins University Press, 1967), pp 33-57, and Stephen L McDonald, Petroleum Conservation in the United States: An Economic Analysis, (Baltimore: The Johns Hopkins University Press, 1971), pp 29-55.

3. From the July 1882 Scientfic American:

> *The history of the discoveries in the Pennsylvania oil fields has been one of a series of disappointments to the producers. From 1866 to 1872 the price per barrel averaged from $4 to $5, and the producers were making money rapidly. Then the field in Butler County was struck, and from that day to this the production has been greater than the consumption. Then came the Bullion pool with its 2,000- and 3,000-barrel wells, which forced the price down to $1.50. This field was soon exhausted, and better times for the producers were at hand when the Bradford field, the largest in extent ever known, was opened. Then Bradford began to decline and again a silver lining was seen, but again disiappointment came.*
>
> *In May of last year the first well was struck in Allegany County, New York, and a new field was opened that soon more than made up for the decline. Then was the great "646" well struck, and with it followed disaster to the owners of wells generally, and lower-priced oil than since the summer of 1874, when for a time it sold for 45 cents a barrel. Where the next field will be is only a matter of conjecture.*

4. For the history of import controls, including the influence of the Texas Railroad Commission on import policy, see M A Adelman, The World Petroleum Market (Baltimore: The Johns Hopkins University Press, 1972), pp 150-154.

5. Lovejoy and Homan, op cit, pp 265-285, and the Cabinet Task Force on Oil Import Control, The Oil Import Question (Washington: US Government Printing Office, 1970). pp 24, 121, 216, 242-246.

6. Adelman, op cit. For a history of oil prices during the entire era, see pp 131-191.

7. M A Adelman, "Coping with Supply Insecurity," The Energy Journal, October 1982, pp 1-16.

8. On the role and operation of spot markets, see Paul H Frankel, Topical Problems (London: Petroleum Economics, Ltd), July/August 1973, p xx, January/February 1976, p iv and June 1979, p xvii-xviii.

9. Estimated proved reserves as of January 1, 1982 can be found in Robert J Enright, "Worldwide Report," Oil and Gas Journal, December 28, 1981, p 86. The Journal lists Saudi Arabia's proved reserves as 164.6 billion. John Blair in The Control of Oil (New York: Vantage, 1978), pp 18-19, quotes Yamani as saying that "Saudi Arabia's 'true reserves' are more than two and a half times the 'ultra conservative numbers' at which 'proved reserves' were being carried."

In 1972, James Akins, then US Ambassador to Saudi Arabia, told Senator Mike Gravel and one of the authors that Saudi Arabia's reserves were "realistically" at least 700 billion barrels and "probably closer to a trillion." At a Central Intelligence Agency briefing one of us attended in 1975, an Agency spokesman gave almost the same estimates (likely from a common source) of the ultimate reserves in the known fields in Saudi Arabia. He added that Iraq's reserves were probably "almost as big".

For our present purposes it doesn't matter which of these reserve estimates is the most realistic --- even the most conservative of them implies that Saudi Arabia is physically capable of producing considerably more than 20 million barrels per day without any new discoveries.

10. See, for example, the remarks of Jahangir Amuzegar, Iranian Ambassador-at-Large and sometime petroleum minister, at a 1975 Salomon Brothers conference in London (World Petroleum: The Economics of Current Pricing and Supply Policies. London: Salbro Press 1976, p 30):

> Notwithstanding Western calculations and projections to the contrary, OPEC members believe that their oil reserves underground will be worth more in the future compared to the present --- even with accumulated returns on the invested revenues.

Adelman makes a plausible case that this notion is economically fallacious and, by implication, cynical and deliberately misleading. (M

A Adelman, "OPEC as a Cartel" in Griffin and Teece, <u>OPEC Behavior and World Oil Prices</u>, pp 38-53)

However, Adelman's argument that oil reserves never earned as much as financial investments rests on discount rates that reflect the short life-expectancies of governments in Third World oil-exporting countries. This approach ignores the ideological content of national policy in such countries. Economic policy in most OPEC nations is either made by nationalist bureaucrats who view their nations as something different from the present government, or by heads of state who believe that their persons are identical with the nation, which is itself immortal. Either case results in lower discount rates and longer amortization periods than Adelman assumes for a non-ideological world.

Adelman's analysis also virtually dismisses the specific ideological role played by the concept of oil-reserves as a long-term investment. OPEC spokesmen were doubtless sincere when they insisted that the asset-value of their resources was appreciating at a higher rate than the real rate of return on risk-free financial investments. My ground for accepting such professions at face value stems both from personal contact with high-placed and lowly Believers, and from the fact that it was in the oil-exporters' interest that they and their customers both believe their motives were something more honorable than greed, and their production-scheduling was built on something more substantial than simple opportunism.

At the same 1975 conference one of us directly addressed Amuzegar's 1975 argument and anticipated Adelman's 1981 argument:

> *To Karl Marx, who gave us the concept, "ideology" was a body of doctrine that provided a religious, moral, or scientific cloak to self-interest. Ideology is in the first place a political weapon: if they believe in it, its sponsors can draw from it moral fervor and confidence of success. And an effective ideology can also captivate or neutralize its adversaries. Believing one's own propaganda uncritically (or that of one's opponents) has, however, led to some remarkable foolishness, as various Crusades from the Middle Ages to Vietnam have shown.*
>
> *I suppose that my message today is not to take OPEC's rhetoric too seriously, nor the opposing rhetoric . . . The conservationist element in OPEC doctrine deserves more serious attention (than its profession of solidarity with the poor and exploited everywhere), particularly as it is a notion shared by a rich, industrialized non-OPEC oil producer like Canada and by a variety of environmentalists and Malthusian doomsayers in all of the rich countries. The common theme of all these parties is that mankind ought to keep its*

cheapest energy source, petroleum, in the ground because it will be more valuable in the future than it is today.

This proposition cannot be dismissed out of hand. There may well be some producing country or countries with reserves of only ten to fifteen times current production, without the hope of major new discoveries and with only limited opportunities for productive investment at home. Such a country could reasonably estimate the so-called user cost of its petroleum --- the present value of future production given up by producing today --- to be as great or greater than the current world price. Such a country might reasonably believe, in other words, that its oil could appreciate in value over the average life of its reserves at a higher rate than the rate of earnings on risk-free foreign investment. Or it may believe that the risks --- market and political --- of all foreign investments are so great that they make speculation in oil inventories at home a more prudent investment.

I am not certain there is such a country --- **but that country surely is not Iran or Venezuela**, whose ability to absorb foreign exchange in profitable domestic investment ventures is insatiable, **nor is it Saudi Arabia**, whose potential reserves are so huge that the present value of a barrel of oil not produced today is truly negligible.

No, to each of these countries, limiting production is rational not because its oil will be more valuable in the future but because **less production means higher prices today. Conservation, however, sounds more noble in the producers' own ears than maximization of monopoly profit,** and it appeals to a fashionable intellectual current in the rich consuming nations. The conservationist rhetoric is, therefore, a particularly effective ideological weapon of the cartel. (emphasis added)(A R Tussing, discussant, comments on speeches by Chief M O Feyide, Secretary-General of OPEC; Amuzegar; T O Enders, US Assistant Secretary of State for Economic Affairs; Adelman; and P T Frankel, Director of Petroleum Economics Ltd., op cit, pp 41-44)

We need not be overly skeptical about the OPEC nations' belief in a doctrine that helped enrich them, when the same doctrine was believed by so many statesmen and scholars (including the majority of "energy economists") in Europe and America, who used it to rationalize policies that helped impoverish their own nations.

12. Youssef M Ibrahim, "Saudi Role in OPEC Under Siege" in The Wall Street Journal, July 21, 1982, p 33.

13. "Oil Nation Warns its Partners", Associated Press story in the Seattle Post-Intelligencer, July 8, 1982, p B9. On Saudi Arabia's threats, se Platt's Oilgram, July 13, 1982, p 1A.

14. D. de Bruyne, quoted in Petroleum Intelligence Weekly, June 14, 1982, p 8.

C

TASK 11: FINANCING OPTIONS
SUMMARY

Task 11 was prepared by Acres American to set out what they considered the most viable financing options for the Watana phase of the Susitna project. Task 11 also includes comments by the Alaska Power Authority's investment advisors.

The pre-conditions laid out are (1) an acceptable cost of electricity in the early years, (2) meeting the debt coverage, (3) acceptable levels of borrowing, both G.O. and revenue, (4) acceptable level of demands on available revenues of the State.

The four options are:

* Option A -- state appropriations of $1.4 billion in 1982 dollars from 1984-89, with revenue bonds after 1989
* Option B -- the same as A but with $1.8 billion
* Option C -- the same as A and B but with the state appropriations guaranteed through a constitutional amendment

All options assume that no revenue bonds could be obtained in the early years (1985-87), and that revenue bonds sold after 1989 would require the backing of the moral obligation of the state and would be based on "sufficiently rigorous" power contracts so that they would not "to any significant extent" rely upon the state's credit. A key condition would be that "power contracts providing for such Revenue Bond financing are obtained and are in place before any major capital expenditure is undertaken."

The APA's investment advisors have reviewed the options and commented upon them. Their recommendations are:

* state appropriations should be funded during 1983-89
* prior to major expenditures definitive contractual commitments by participating utilities should be in place
* significant borrowing should not commence before the late 1980's
* prerequisites for issuance of bonds should be (1) definitive contractual commitments by utilities, (2) updated economic and financial analysis of the project, and (3) resolution of the question of tax exemption of bonds
* rather than using G.O. bonds, borrowing should be, to the fullest extent possible, by revenue bonds secured by long-term power sales contracts with participating utilities
* over the next two years, the preconditions of financing viability should be resolved

SUSITNA HYDROELECTRIC PROJECT

TASK 11: FINANCING OPTIONS

Prepared by:
Acres American Incorporated

January 1983

ACRES

ALASKA POWER AUTHORITY

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1 - OBJECTIVES

The objective of this report is to set out the currently most viable financing options for the Watana phase (1985-1993) of the Susitna Hydroelectric Development together with the comment of the Power Authority's investment advisors (The First Boston Corporation, John Nuveen & Company, and First Southwest Company) on the impact of these options on the credit rating of the State of Alaska and on other related issues.

2 - ECONOMIC CONTEXT OF THE FINANCING PROPOSALS

The economics, marketing and financing of Susitna will be the subject of a final review by Acres American in March of 1983. The data utilized in this analysis however is, with minor modification, based on the Susitna Task 11 Reference Report. Some amendment of the data used here will then arise in the light of the March 1983 review. Our preliminary indications are however that the probable revisions will not materially impact the conclusions which may be based on the results presented in this memorandum.

3 - BASIC POLICY ISSUES: RISK AND TIMING

The Watana phase alone of Susitna will take 10 years (from the present stage of FERC license application) to complete. It is also clearly apparent that it will not be possible to produce wholly certain forecasts of the underlying energy economics of the project nor of the availability of State revenues or of the competing demands for State resources which may arise over this extended period. The requirement that such forecasts be produced as an initial pre-condition for authorization of development would therefore effectively preclude Susitna or indeed, any long term development of Alaska's natural resources.

It must also be frankly recognized that risks from erroneous forecasts will arise from proceeding with Watana at its estimated capital cost of $3.6 billion (1982 dollars). These are primarily risks associated with load forecasts, interest rates, inflation, etc. But it must be recognized also that risks will arise through <u>not</u> proceeding with Susitna since this will force Alaska electric power consumers to face the alternative risks arising from the estimated $1.7 billion (1982 dollars) of capital cost for fossil fuel plants and the risk that these plants will also require meeting the ever increasing operating costs reflected in Exhibit A. Moreover, these other options also involve risks from forecasting errors in the load forecasts, interest rates, inflation, etc.

In the Watana investment decision, therefore, the issue is not between risk and no risk, or investment and no investment, but only between one set of risks and another and one set of capital expenditures and another. The financing options as developed below therefore endeavor to reflect these risks in a realistic manner and provide for development/financing options which effectively minimize these risks.

It is an inherent characteristic in the very magnitude of their financial requirements and the complex political and economic issues which they pose, that "mega-projects" such as Susitna, have a "window of opportunity" during which they can proceed. If this "window" is missed the opportunity to proceed may not recur for many years.

Ultimate development of the hydroelectric potential of Susitna must be considered as highly probable given the authoritive estimates (see Exhibit C) and forecasts of Alaska's own Department of Revenue of continued significant long term real increase in alternative energy prices. Hence the essential issue is whether we proceed in the immediate future with this window of opportunity or whether the project is postponed-- possibly for a long period. Here, the following considerations must be taken into account:

(a) On present forecasts, postponement of Susitna wholly delaying its net benefits, would cost $43 million p.a. in 1982 present value terms.

(b) The possibility, referred to above, that the "window of opportunity" for Susitna may not recur for a very long period. This could result in the cost of postponement being a multiple of that given in (a).

Finally, we would stress that the Susitna Project would also be re-assessed by the Power Authority in 1984 before any major outlays were undertaken in 1985. By this date we will have two more years of economic and financial data with which to re-evaluate the situation and the uncertainties regarding the scale of the world economic recovery. The existing uncertainty of near-term future petroleum prices and revenues should be substantially reduced.

4 - THE FINANCING OPTIONS

The Essential Pre-conditions

The essential pre-conditions for any financing scheme is taken as the requirement that they meet:

(a) An acceptable cost of energy in the early years of operation. This is taken as effectively meaning that the cost of power must be close to or below the cost of energy that would result from pursuing the best Thermal Option as shown in Exhibit A.

(b) Meeting its debt coverage. All the residual financing requirements are assumed to be met (long-term) by borrowing in the form of tax-exempt bond financing at 10% with a coverage requirement of 1.1. This requirement must be met or the borrowing could not be regarded as meeting the basic requirements of acceptability to investors.

(c) Acceptable and viable levels of borrowing. The level of borrowing which the project requires to be met by G.O. bonds will depend upon the capacity of the State of Alaska to raise G.O. Bonds either without effect on its bond rating or with an effect that is regarded as an acceptable price for proceeding with the project. The other source of borrowing will be Revenue Bonds which, as discussed below, depend upon the power contracts which are in place.

(d) An acceptable level of demands on the funds available to the State of Alaska. The funds here are taken as the estimate of the uncommitted funds for capital appropriation as estimated by John Nuveen & Company and shown in Tables 1 and 2. (These take into account the estimated maximum G.O. Bonds as a source of funds.)

The Financing Options

A very large number of financing options have been considered. The four options: A, B, C, and D summarized in Tables 3 and 4 appear those most likely to fulfill the essential criteria stated above. These options are:

Option A

This option calls for $1.4 billion 1982 dollars in State appropriations phased over the period 1984 to 1989. This option may also indirectly involve drawing upon G.O. Bonds since these (see Tables 1 and 2) are built into the final total "available for Susitna". (The phasing of the appropriations year-to-year is, of course, arbitrary in that it can be adapted to the flow of funds represented by the "available for Susitna", providing the total remains the same.)

Option B

This option is precisely identical to that of Option A except that it involves a State appropriation of $1.8 billion in 1982 dollars phased over the period 1984-1989.

Options C and D

These options involve the concept of dedicated funds of the same magnitude as Option A and B being made available through a constitutional amendment. Since these options are of a markedly different character, they are discussed separately below.

Phases and Forms of Borrowing

Before reviewing the characteristics of the schemes proposed, it is necessary first to deal briefly with the phases and forms which the borrowing may involve.

In the Preliminary Phase between 1985 and 1987, the dam itself will not be under actual construction and only preliminary work will be in progress. Under these circumstances, it must be accepted that no Revenue Bond financing could be obtained and that the project at this stage would have to rely wholly upon State appropriations from the resources shown in Tables 1 and 2.

In the final and major phase of construction between 1989 and 1993 the objective of any financing or scheme must be to ensure that the fina at this stage is based upon Revenue Bonds which, although they will require moral obligation of the State of Alaska, are based on sufficiently rigorous power contracts that they wholly meet their debt coverage requirements when Watana comes into operation and do not to any significant extent rely upon the credit of the State of Alaska.

Whether this objective can be attained will depend first on the levels of State appropriations. This might be seen as the "equity" investment in the project which provides security to the investors and reduces the total amount of borrowing which the project requires.

The second factor is the precise magnitude and terms of the power contracts with the utilities. Since this depends upon detailed negotiations and organizational considerations it is not possible to comment definitively on whether or not the objective of 100% Revenue Bond financing would be possible for the final stage of the Watana development. In what follows, therefore, the Revenue Bond requirement is simply stated as a total sum which follows from the level of State appropriations A, B, C and D.

Hence any financing scheme must be seen at this stage as simply conditional with a key condition being that power contracts providing for such Revenue Bond financing are obtained and are in place before any major capital expenditure is undertaken. Since any significant capital expenditure could not, in any case, take place before the end of 1984 when the FERC license is expected to be granted, there are at least two years during which to secure such power contracts and meet this condition.

Assessment of the Financing Options

Details of the financing options are given in the computer printouts (attached) and the basic details are summarized in Tables 3 and 4 and Attachment E. In order to make the data conform as far as possible with the data on State revenues and the sums described in Tables 1 and 2 as "uncommited capital funds", the inflation assumptions in the Acres Task 11 March 1982 report, were revised to conform to those of the State revenue projections. Other minor revisions were also made.

Subject to maintaining the State's present double A rating, the assessment of the options given in Table 3 must be seen as a trade-off between the criteria of cost of power and State appropriations, (the higher the State appropriations, the lower the cost of power). Where these objectives are in conflict, it is left to the political decision-makers to resolve this conflict by modification of the criteria.

Considering Option A first, it is seen from Table 3 to involve State appropriations of $1.4 billion over the six year to 1989 and to require Revenue Bond financing of $2.7 billion (all in 1982 dollars).

Turning first then to the criterion of acceptability in terms of the percentage of uncommitted capital funds in Tables 1 and 2, this is shown in Table 4 as an average over the appropriation period 1984 to 1989. It varies from 57% for the 30th percentile projections to 38% in the 50th percentile case. It is left, of course, for the political assessment whether the percentages shown are acceptable in the light of other priorities.

No year-by-year figures of this percentage is given since in Acres' assessment the year-by-year engineering estimates of costs are, in the early years, subject to very considerable choice and could be changed significantly with rescheduling if this was thought desirable to reduce the claims on the funds available.

Turning then to the criterion of the cost of power, it is found that this option, because of the high level of borrowing (assuming a 10% rate of interest), would involve significant deficits during operation in early years unless the cost of power were increased above the level set by the Best Thermal Option.

In these early years the essential problem facing Watana in marketing its power is that, in the first year or two of its life, it is in competiton with power sources with the advantage of being based on the cost of facilities purchased years earlier at much lower cost than will be involved either in their replacement or in the additional coal-fired units which would be required in 1995 and 1996 if Watana power were not available.

As shown in Tables 3 and 4 and in Exhibit E, the only means of meeting the deficits without further State appropriations would be to allow the cost of power to rise above the best Thermal Option in these three transitional years. Whether this would be regarded as an acceptable option is again an issue of political judgment. It might reasonably be supposed given that the only alternative option would be to face the dramatically escalating cost of the best Thermal Option only a few years later, the increase in the cost of power above the Best Thermal Option might be acceptable in turn for the very considerable long-term advantages afforded by a source of power which would be virtually fixed in cost even in nominal dollars.

It is also possible that appropriate levelizing provisions could be devised in the rate base to bring about a phased increase in price closer to the price set by the Best Thermal Option ceiling.

Option B might be seen as defining an alternative to any increase in the cost of power by increasing the level of State appropriation to $1.8 billion over the period 1984 to 1989. This is seen from Table 2 and the attached Exhibit E, to produce a cost of power below the Thermal Option even in the earliest years. It also has the advantage of reducing the Revenue Bond requirement in the Final Phase of Watana by $0.52 billion (in 1982 dollars). It would, however, mean committing between 50% and 75% of the uncommitted capital funds to the project over the period 1984-1989 and thus heavily competing with other priorities in the 30th percentile revenue forecast case.

The Dedicated Fund Options C & D

A significant difficulty in the development of any long-term financing scheme such as would be required for any long term development of Alaskan resources is the uncertainty of the year-by-year political appropriation process. This applies generally throughout North America, but is of particular relevance in the context of Alaska given the constitutional considerations and the relative importance of appropriations for capital spending in the State.

It is of understandable concern to investors in State of Alaska securities related to long-term developments, that through the political process these projects could be subject to deferral, limitations of State contribution, or even cancellation in the course of their development phase. This may be considered a serious handicap to the long-term development of Alaska's natural resources.

In the light of this, we have been asked to consider the dedication of 50% of the Permanent Fund income to a Power Development Fund which would be designed to provide a relatively more secure and certain source of appropriations for the major long-term development potential for Alaska represented by hydroelectric power and which could offer most Alaskans permanent low-cost power as a basic domestic and industrial resource. This proposal is regarded as representing an important contribution to securing long-term appropriations for such major developments in a manner which would be regarded by investors as offering much greater assurance of on-going systematic development and hence greater security for borrowing in the course of construction.

The scheme, as provisionally formulated, involves the principle of $4,500 to $6,000 per capita being the normal contribution from the fund for a hydro development serving a particular area. In the context of Susitna this would involve a total State appropriation from the fund of approximately $1.4 to $1.8 billion. Its results are shown as Options C and D in Tables 3 and 4 and in Exhibit E. Its impact on cost of power and the level of Revenue Bond financing required is seen to be very close to that of Options A and B.

A further important characteristic of this particular proposal, however, is that such funding would provide the Power Authority with a substantial financial base that would make it capable of raising finance or providing guarantees where these were important to secure financing under changing market conditions or secure funding for developments lacking an adequate independent credit base.

It is recognized that this proposal would involve a constitutional amendment, but it is precisely the constitutional nature of such a dedicated fund that would be most effective in terms of development of Alaska's resources.

5 -STATEMENT BY THE FIRST BOSTON CORPORATION, JOHN NUVEEN & COMPANY, AND FIRST SOUTHWEST COMPANY

The First Boston Corporation and John Nuveen & Company (the Alaska Power Authority's co-senior managing underwriters) and First Southwest Company (the Power Authority's financial advisor) have reviewed the financing options described in this memorandum and have made the following observations regarding the financing of the Susitna Project. Together these investment firms are referred to as the Power Authority's Investment Advisors. Their opinions stated herein are based primarily upon the State's projected revenues using the "30th Percentile". First Boston Corporation, John Nuveen & Company and First Southwest Company have concurred in the following statement:

"It is our opinion that prior to major State expenditures, of State appropriations definitive contractual commitments by participating Railbelt Utilities be in place and that such appropriations should be funded by the State during the period 1983-1989, a period within the estimated life of Alaska's oil and gas reserves, so that appropriations provided during this period will provide the crucial "equity" to assure the most economical bond financing of the remainder of the project.

In view of the magnitude of Susitna and the relatively long construction period, the Power Authority should not commence significant borrowing for Susitna before the late 1980's at which time major risks have been defined and completion and start-up dates are known with a high degree of reliability.

In our opinion, in order to maintain the financial integrity for the State of Alaska, prerequisites for issuance of bonds of any type for the project are:

(a) Definitive contractual commitments by participating Railbelt utilities;

(b) Up-dated economic and financial analysis of the project; and

(c) Resolution of the question of tax exemption of such bonds.

With regard to the utilization of State G.O. Bonds, it is our opinion that the issuance of such bonds will be of limited importance to financing Susitna because of the substantial borrowing required for this project. If a major portion of such borrowing were met from State G.O. Bonds, Alaska's present double A ratings would be endangered. The following are some major limitations of State G.O. Bonds:

(1) A crucial feature of Alaska's double A rating is the Rating Agencies' concurrence with the State's present debt policy of amortizing G.O. Bonds rapidly (i.e., within 10 to 15 years (a period within current estimates of oil/gas revenues (the principal source of State revenues) and we believe this policy should be continued.

(2) Using the State's December, 1982 Department of Revenue forecasts, we estimate that the State can issue a relatively small volume of G.O. Bonds while maintaining it's double A rating (see Tables 1 and 2). Based on the "30th percentile" of the Department of Revenue projections, the State could "safely" issue $565 million (nominal dollars, assuming 8% inflation) G.O. Bonds during the period fiscal 1983-1990. This amount would rise to $945 million if the "50th percentile" revenue projections were achieved during this period.

A reduction in the State's rating from double A to single A could correspondingly lower the rating of Alaska Power Authority's own revenue bonds backed by a Capital Reserve Fund with a moral obligation to a rating as low as Baa by Moody's and BBB by Standard & Poors. Such a rating would substantially raise the

Authority's borrowing cost and could impair the viability of the project. The volume of debt contemplated under all scenarios would be extremely difficult to market if rated less than "A".

The Power Authority, rather than utilizing State G.O. Bonds, should utilize, to the fullest extent possible, revenue bonds secured by the income derived from participating Railbelt Utilities pursuant to long-term power sales contracts. Additional security for the bonds would be provided by the Capital Reserve Fund provided in the Alaska Power Authority Act whereby to the extent that revenues from Susitna were insufficient to service the bonds, the Legislature may, but is not legally obligated to, appropriate monies to make up such deficiency in the Capital Reserve Fund. Alaska Power Authority's credit perception will be enhanced by a simple and straightforward debt structure comprised solely of revenue bonds backed by the State's "moral obligation" pledge.

Any dedicated stream of State appropriations covering the entire construction and start-up period will enhance confidence of investors, participating utilities, and the rating agencies in the completion of the project. Such an appropriation would, however, require a constitutional amendment.
In conclusion, as Investment Advisors to the Authority, we strongly prefer the financing plan developed as Option B and D which requires greater appropriations prior to issuance of Revenue Bonds because the credit status of the State is least affected and the credit quality of the Authority's bonds is enhanced, maintaining project feasibility. Should oil revenue and projections, however, dramatically improve we would be in a position to more favorably consider alternate financial options."

6 - CONCLUSIONS

Our conclusions relate primarily to Options A and B since the dedicated fund proposals C and D can be seen in the present context as primarily a legislative route to these options.

It may be appropriate in conclusion first to state our own assessment of the decision issues involved at this stage. First, the decision issue is not an irrevocable commitment to proceed with Watana. As already noted, the FERC license will not be available for another two years and no major expenditures could be undertaken until 1985.

It would therefore appear that the essential issue is that of maintaining and planning for the Watana option. The only grounds for not maintaining this option with its very substantial long-term economic advantages, would be that we had concluded that no viable and politically acceptable financing scenario was possible.

Given the very wide range of uncertainties for future State revenues, and hence the levels of State appropriations which might be available at the first point of major commitment in late 1985, such an adverse conclusion certainly cannot be substantiated at this time on the basis of the preceding analysis. If, for example, State revenues were as high or higher than the 50th percentile, the State capital fund available for Watana would be substantially increased and the $1.4 billion appropriation (Option A) would represent 38% of the uncommitted capital funds over the period 1984-1989. Moreover, the circumstances which would bring about such an increase in State funds--mainly a recovery in world oil prices--would confirm the economic desirability of advancing with Watana and obviating dependence on fuels with prices related to that of oil.

We must also note again that the levels of spending in individual years used in the analysis was constructed on normal engineering criteria without reference to phasing the engineering expenditures to conform (without significant additional cost) to year-to-year budget constraints.

Subject to political decisions and priorities, therefore, our assessment is that all the financing options proposed in this memorandum are viable. In consequence, we recommend that over the two-year decision period to 1984, the remaining preconditions of financing viability, both political and contractual (in terms of power contracts and tax exempt bond financing) are resolved. A reconsideration of the financing options might then be undertaken in 1984 when, as aleady noted, some of the major economic uncertainties affecting the economics of generation options and the revenues of the State of Alaska are also likely to be resolved. It should also be possible within this time frame to review the time profile of potential cash demands for construction and bring them more closely into conformity with available appropriations.

If this conclusion were adopted, it might also be considered appropriate, in order to avoid undue "bunching" of demands for Susitna financing, to establish a level of funding for the project of the order of perhaps $100 million in FY 1984. This, in our view, would be seen as a positive step which should appreciably assist in the negotiations of power contracts since it would indicate the State's conditional intent to proceed with the project. This would give such negotiations the credibility essential to a successful outcome.

ALASKA POWER AUTHORITY
CAPITAL FUNDS AVAILABLE FOR SUSITNA
30th PERCENTILE PROJECTION

Fiscal Year	General Fund Unrestricted Revenues (1)	Total Capital Spending Limits	Estimated Maximum G.O. Bond Issues (2)	Total Available Capital	Committed Capital Grants and Loans (8%)	Remaining Capital	APA Capital Budget Excluding Susitna	Uncommitted Capital Funds	Planned Susitna Expenditures (nom. $) (3)
1984	2908.2	969	0	969	475	494	174.2	320	0
1985	2939.9	980	0	980	513	467	244.5	222	183
1986	3472.9	1158	300	1458	554	904	282.3	622	405
1987	3870.4	1290	90	1380	598	782	125.8	656	437
1988	3917.0	1306	125	1431	646	785	0	785	442
1989	4293.8	1431	0	1431	698	733	0	733	639
1990	3679.9	1227	50	1277	754	523	0	523	1121
1991	3295.9	1099	140	1239	814	425	0	425	1270
1992	3186.4	1062	0	1062	879	183	0	183	862
1993	2919.4	973	110	1083	950	133	0	133	584
1994	2779.0	926	0	926	1025	0	0	0	0
								4602	594[illegible]

(1) 30th percentile projection of Department of Revenue net of Debt Service on the State G.O. Debt.

(2) Maximum General Obligation Debt that can be issued (10 year, equal annual principal amortization at 7.5%) and keep total G.O. Bond Debt Service below 5% of General Fund Unrestricted Revenues.

(3) Source: Acres American Incorporated (Converted to June 30 Fiscal Year).

TABLE 1

ACRES

ALASKA POWER AUTHORITY
CAPITAL FUNDS AVAILABLE FOR SUSITNA
50th PERCENTILE PROJECTION

Fiscal Year	General Fund Unrestricted Revenues (1)	Total Capital Spending Limits	Estimated Maximum G.O. Bond Issues (2)	Total Available Capital	Committed Capital Grants and Loans (8%)	Remaining Capital	APA Capital Budget Excluding Susitna	Uncommitted Capital Funds	Planned Susitna Expenditures (nom. $) (3)
1984	3369	1123	0	1123	475	648	174.2	474	0
1985	3492	1164	350	1514	513	1001	244.5	757	183
1986	4116	1372	190	1562	554	1008	282.3	726	405
1987	4553	1518	95	1613	598	1015	125.8	889	437
1988	4645	1548	235	1783	646	1137	0	1137	442
1989	5103	1701	50	1751	698	1053	0	1053	639
1990	4848	1616	25	1641	754	887	0	887	1121
1991	4345	1448	160	1608	814	794	0	794	1270
1992	4221	1407	35	1442	879	563	0	563	862
1993	4017	1339	170	1509	950	559	0	559	584
1994	3957	1319	0	1319	1025	294	0	294	0

(1) 50th percentile projection of Department of Revenue net of Debt Service on the State G.O. Debt.

(2) Maximum General Obligation Debt that can be issued (10 year, equal annual principal amortization at 7.5%) and keep total G.O. Bond Debt Service below 5% of General Fund Unrestricted Revenues.

(3) Source: Acres American Incorporated (Converted to June 30 Fiscal Year).

TABLE 2

ACRES

SUSITNA-SUMMARY OF FINANCING REQUIREMENTS
-------------REAL 1982 DOLLARS------------

	STATE APPROPIATION TAKEN AS NEEDED				DEDICATED STATE APPROPIATION			
	----$1.4 BN----- (REAL)		----$1.8 BN----- (REAL)		----$1.4 BN----- (REAL)		----$1.8 BN----- (REAL)	
	DEBT $M	STATE APPROP. $M	DEBT $M	STATE APPROP. $M	DEBT $M	STATE APPROP. $M	DEBT $M	STATE APPROP. $M
1983	-	-	-	-	-	160	-	160
1984	-	81	-	81	-	222	-	222
1985	-	225	-	225	-	276	-	276
1986	-	336	-	336	-	318	-	318
1987	-	317	-	317	-	345	-	345
1988	-	306	-	306	-	79	-	378
1989	409	94	9	535	337	-		101
1990	884	-	847	-	878	-	770	-
1991	757	-	718	-	750	-	710	-
1992	505	-	466	-	498	-	457	-
1993	146	-	146	-	146	-	146	-
	----	----	----	----	----	----	----	----
TOTAL	2701	1400	2186	1800	2609	1400	2083	1800
	====	====	====	====	====	====	====	====

COST OF ENERGY TO MEET 1.[illegible] DEBT SERVICE COVER AND PERCENT IN EXCESS OF BEST THERMAL OPTION

	MILLS		MILLS		MILLS		MILLS	
	-----		-----		-----		-----	
1993	74	46 %	61	17 %	72	41 %	58	14 %
1994	77	25 %	64	5 %	75	22 %	62	-
1995	73	21 %	61	1 %	70	17 %	58	-
1996	72	-	57	-	69	-	55	-
1998	68	-	54	-	65	-	51	-
1999	63	-	51	-	61	-	48	-
2000	60	-	48	-	57	-	46	-

TABLE 3 -- SUSITNA: SUMMARY OF FINANCING REQUIREMENTS IN REAL TERMS

ACRES

SUSITNA-SUMMARY OF FINANCING REQUIREMENTS

-------------<u>NOMINAL</u> DOLLARS-------------

	STATE APPROPIATION TAKEN AS NEEDED				DEDICATED STATE APPROPIATION			
	----$1.4 BN----- (REAL)		----$1.8 BN----- (REAL)		----$1.4 BN----- (REAL)		----$1.8 BN----- (REAL)	
	DEBT	STATE APPROP.	DEBT	STATE APPROP.	DEBT	STATE APPROP.	DEBT	STATE APPROP.
	$M	$M	$M	$M	$M	$M	$M	$M
1983	-	-	-	-	-	175	-	175
1984	-	100	-	100	-	257	-	257
1985	-	276	-	276	-	338	-	338
1986	-	436	-	436	-	413	-	413
1987	-	437	-	437	-	475	-	475
1988	-	447	-	447	-	115	-	552
1989	633	208	13	828	522	-		157
1990	1465	-	1403	-	1454	-	1275	-
1991	1341	-	1274	-	1329	-	1259	-
1992	958	-	883	-	945	-	868	-
1993	296	-	296	-	296	-	296	-
	----	----	----	----	----	----	----	----
TOTAL	4693	1904	3869	2524	4546	1773	3698	2367
	====	====	====	====	====	====	====	====
PERCENTAGE OF UNCOMMITTED STATE CAPITAL FUNDS		38 to 57 %		50 to 75 %				

COST OF ENERGY TO MEET 1.1 DEBT SERVICE COVER AND PERCENT IN EXCESS OF BEST THERMAL OPTION

	MILLS		MILLS		MILLS		MILLS	
1993	150	46 %	123	17 %	145	41 %	118	14 %
1994	168	25 %	140	5 %	163	22 %	134	-
1995	169	21 %	141	1 %	164	17 %	135	-
1996	179	-	143	-	172	-	137	-
1998	180	-	144	-	173	-	137	-
1999	181	-	145	-	175	-	139	-
2000	182	-	147	-	176	-	140	-

<u>NOTE</u>: PERCENTAGE OF UNCOMMITTED FUNDS CALCULATED FROM 30 AND 50 PERCENTILE PROJECTIONS

TABLE 4 -- SUSITNA: SUMMARY OF FINANCING REQUIREMENTS IN NOMINAL TERMS

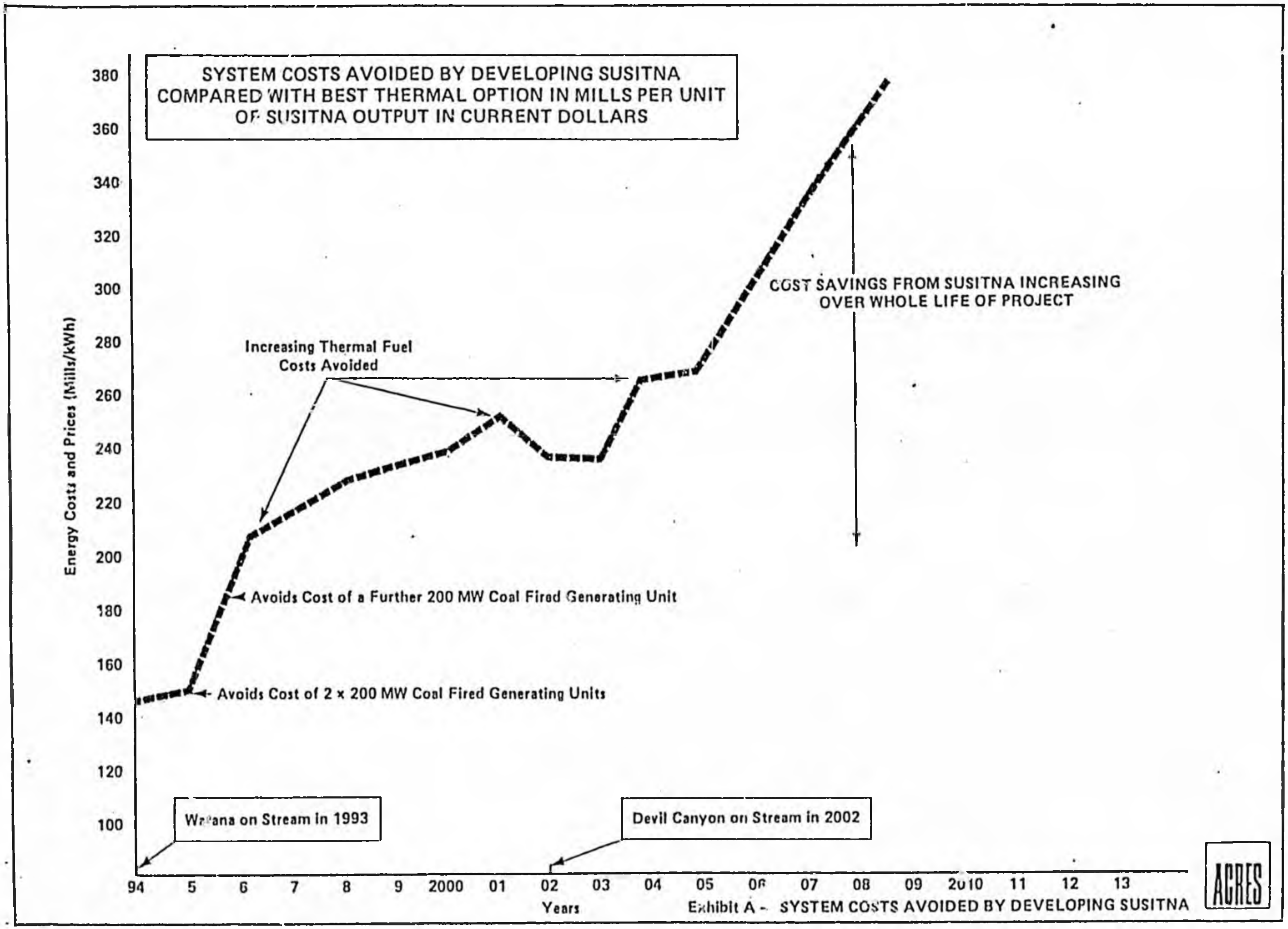


Exhibit A - SYSTEM COSTS AVOIDED BY DEVELOPING SUSITNA

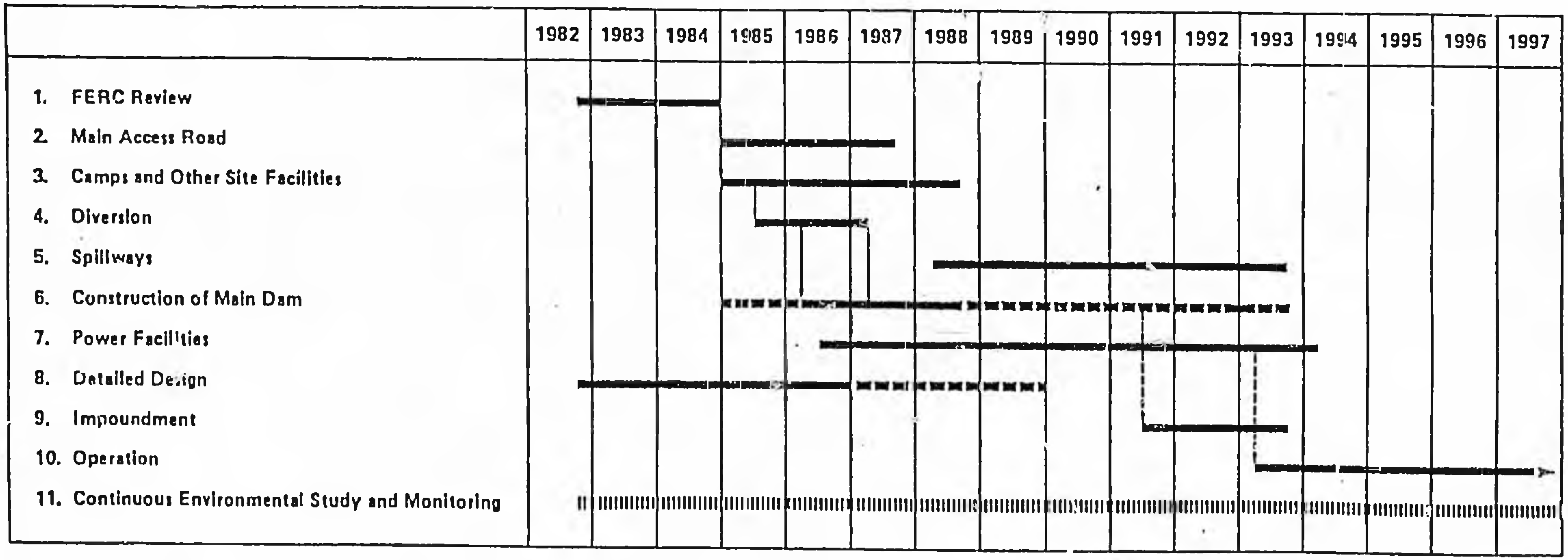


EXHIBIT B -- WATANA CONSTRUCTION SCHEDULE

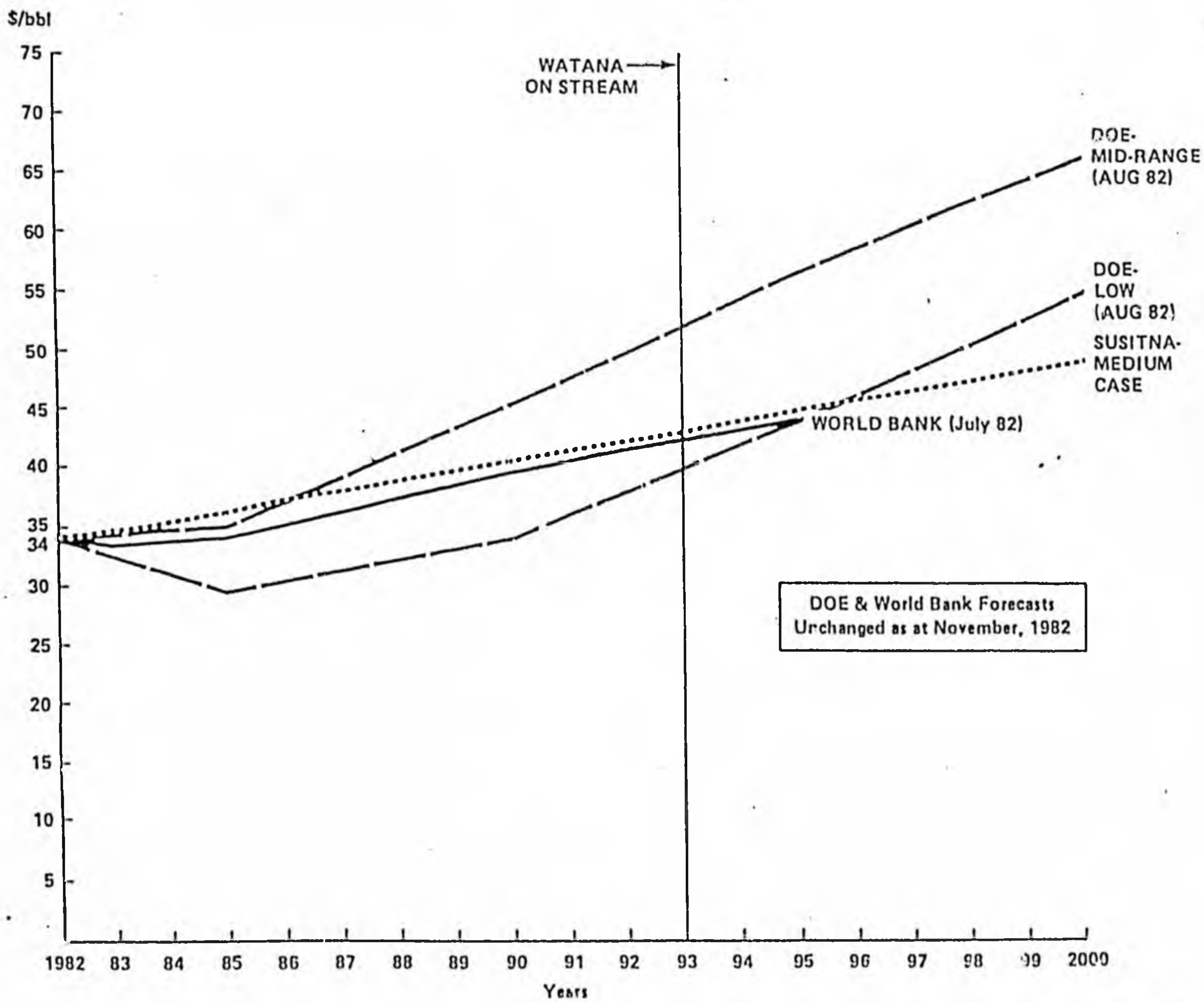
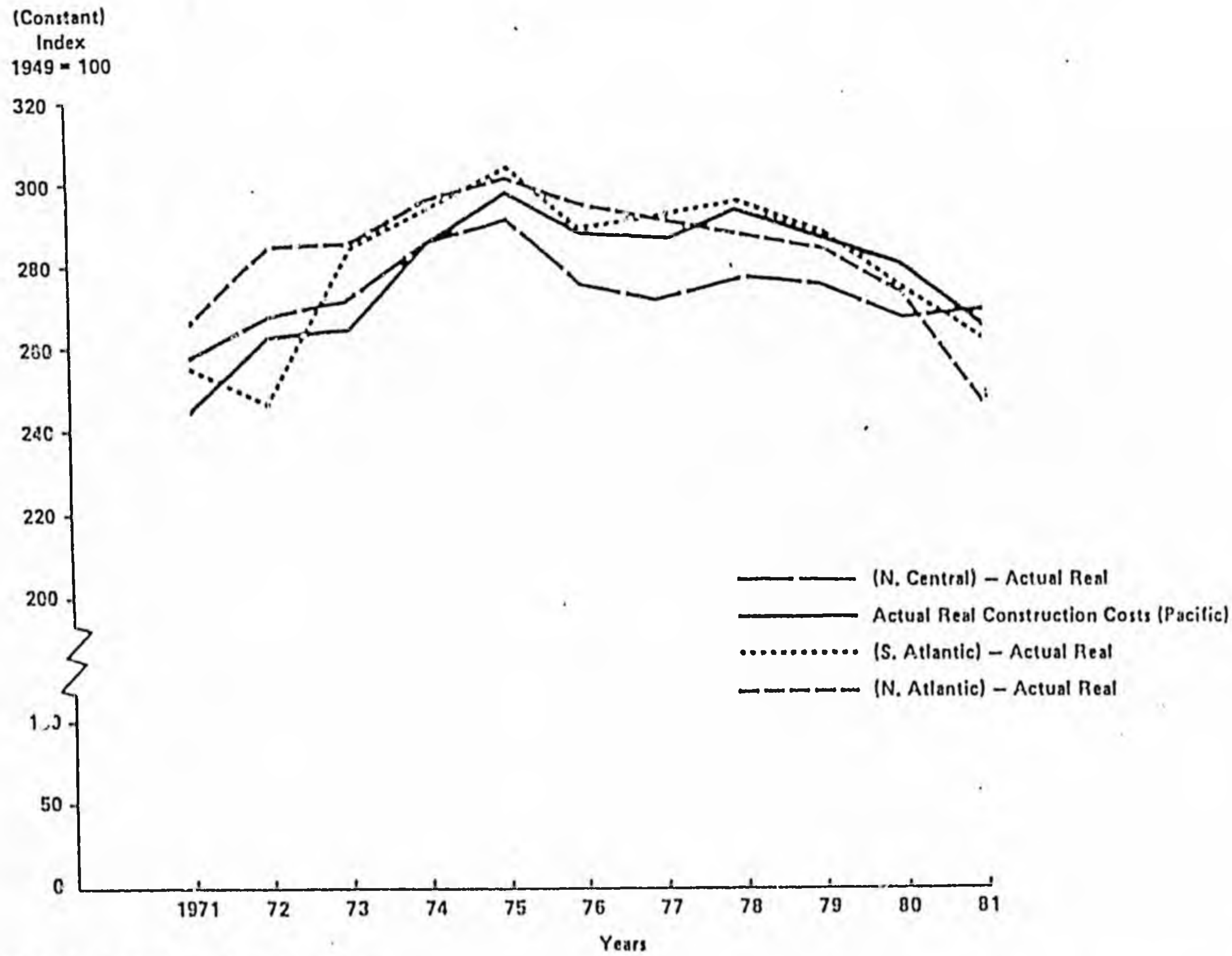


Exhibit C
WORLD OIL PRICE FORECASTS
(Constant 1982 Dollars)

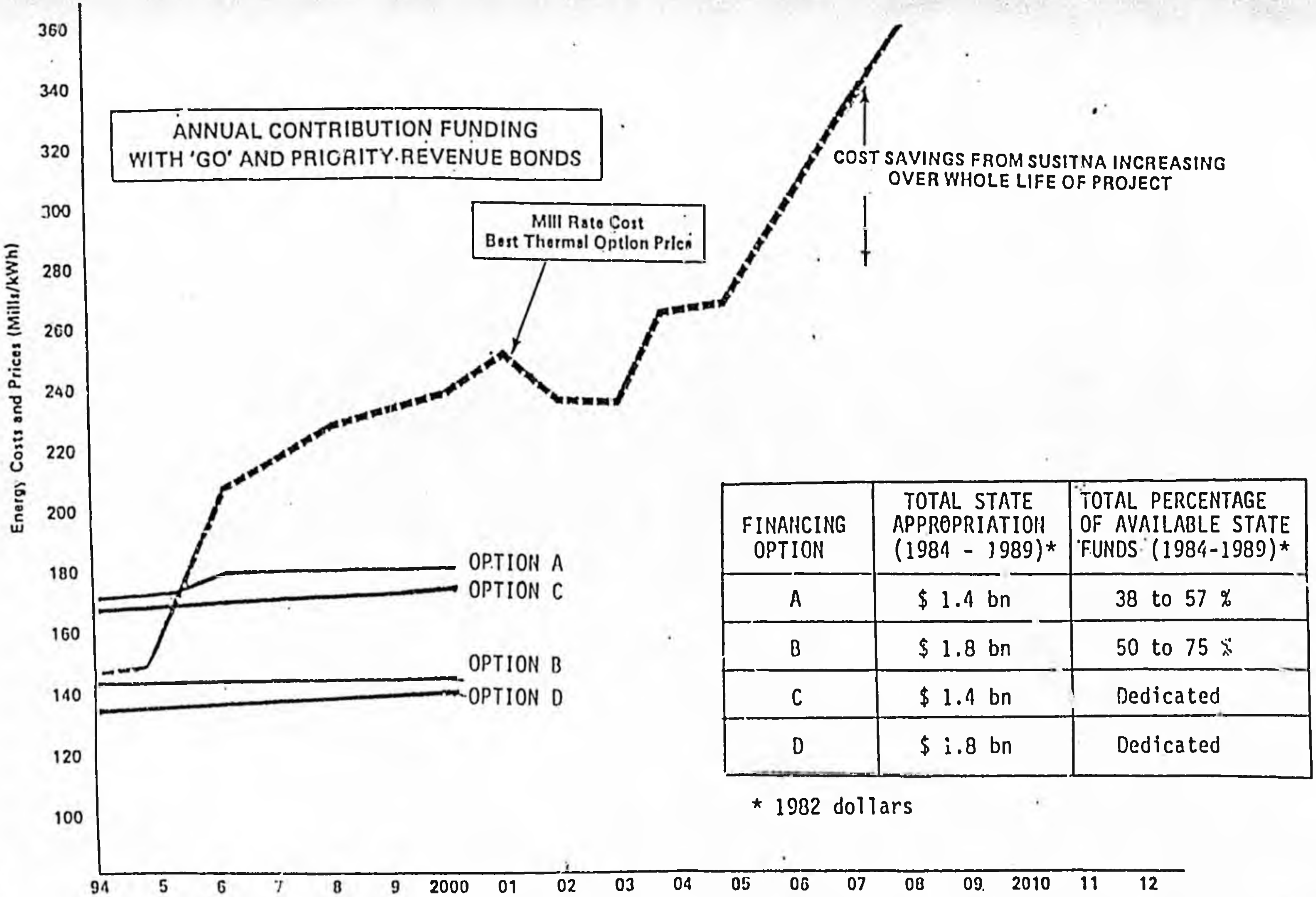
ACRES



Source: ENR Utilities, December 17, 1981 for nominal costs;
Monthly Labor Review, US Dept. of Labor November, 1982 for Consumer Price Index

EXHIBIT D -- US HYDROELECTRIC PLANT CONSTRUCTION COST INDEXES

ACRES



FINANCING OPTION	TOTAL STATE APPROPRIATION (1984 - 1989)*	TOTAL PERCENTAGE OF AVAILABLE STATE FUNDS (1984-1989)*
A	$ 1.4 bn	38 to 57 %
B	$ 1.8 bn	50 to 75 %
C	$ 1.4 bn	Dedicated
D	$ 1.8 bn	Dedicated

* 1982 dollars

EXHIBIT E
ENERGY COST COMPARISON
WITH VARIOUS FINANCING OPTIONS

ACRES

FINANCIAL ANALYSES

DATA10M5.D11 WATANA (ON LINE 1993)- STATE FUNDS TO 1989 ($1.4 BN)- INFLATION 6%.7%-INTEREST 10%-CAPCOST $3.647 BN 8-JAN-83

CASH FLOW SUMMARY
===($MILLION)===

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.05	154.81	165.65	177.24	189.65	202.92	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.0	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	439.7	469.3
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-114.7	-59.0
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-114.7	-59.0
443 STATE CONTRIBUTION	375.7	436.1	437.2	447.4	208.2	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	632.6	1464.8	1341.6	957.8	411.1	102.0
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	375.7	436.1	437.2	447.4	840.8	1464.8	1341.6	957.8	387.8	58.5
320 LESS CAPITAL EXPENDITURE	375.7	436.1	437.2	447.4	840.8	1464.8	1341.6	957.8	296.4	25.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.3
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	49.4
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	375.7	811.8	1248.9	1696.3	2537.1	4002.0	5343.5	6301.3	6597.7	6623.4
465 CAPITAL EMPLOYED	375.7	811.8	1248.9	1696.3	2537.1	4002.0	5343.5	6301.3	6689.1	6730.3
461 STATE CONTRIBUTION	375.7	811.8	1248.9	1696.3	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-114.7	-173.8
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.8
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	632.6	2097.4	3439.0	4396.8	4807.9	4892.7
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	408.6	884.3	756.9	505.0	202.6	47.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	408.6	1292.9	2049.8	2554.9	2757.5	2804.5
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.74	0.84

Option A -- $1.4 Billion Drawn From Uncommitted State
Funds Available For Capital Construction

ACRES

DATA10M5.D11 WATANA (ON LINE 1993)- STATE FUNDS TO 1989 ($1.4 BN)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 BN 8-JAN-83

CASH FLOW SUMMARY
($MILLION)*

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	60.24	71.94	67.56	63.34	59.44	55.81	52.45	49.36	46.51	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.53	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	139.96	178.84	179.71	180.28	181.02	181.87	182.87	184.15	185.64	0.00
-----INCOME-----------------										
516 REVENUE	474.0	605.7	608.6	610.6	613.1	615.9	619.3	623.7	628.7	6202.6
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	444.2	573.1	573.1	571.8	570.7	569.7	568.9	568.6	568.7	5759.3
214 ADD INTEREST EARNED ON FUNDS	5.7	6.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	32.4	42.8	43.2	42.4	41.9	41.5	41.3	41.7	42.4	390.1
391 LESS INTEREST ON LONG TERM DEBT	467.6	465.7	463.6	461.3	458.7	456.0	452.9	449.5	445.8	5030.1
548 NET EARNINGS FROM OPERS	-50.1	70.9	73.1	75.6	78.2	81.2	84.5	88.0	92.0	419.7
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	-50.1	70.9	73.1	75.6	78.2	81.2	84.5	88.0	92.0	419.7
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1904.5
143 LONG TERM DEBT DRAWDOWNS	96.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5006.6
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
549 TOTAL SOURCES OF FUNDS	54.3	95.5	83.6	86.8	88.4	91.1	98.0	102.4	107.3	7555.0
320 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6953.0
448 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	19.0	22.1	24.3	26.8	29.4	32.4	35.6	39.2	43.1	289.2
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	19.3	17.3	15.1	12.8	10.2	7.6	4.7	1.6	88.6
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.8	75.0	79.4	82.2	83.9	88.6	93.3	98.0	98.0
454 CASH SURPLUS RETAINED	0.0	19.3	36.6	51.7	64.5	74.7	82.3	87.0	88.6	88.6
370 CUM. CAPITAL EXPENDITURE	6651.0	6680.4	6711.9	6745.6	6781.7	6820.3	6861.6	6905.7	6953.0	6953.0
465 CAPITAL EMPLOYED	6765.5	6838.9	6898.2	6958.2	7017.2	7076.0	7138.3	7201.6	7265.8	7265.8
461 STATE CONTRIBUTION	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5
462 RETAINED EARNINGS	-223.8	-152.9	-79.8	-4.2	74.0	155.2	239.7	327.7	419.7	419.7
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	4970.2	4948.1	4923.8	4897.0	4867.6	4835.2	4799.6	4760.5	4717.4	4717.4
542 ANNUAL DEBT DRAWDOWN $1982	41.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2846.0
543 CUM. DEBT DRAWDOWN $1982	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0
519 DEBT SERVICE COVER	0.86	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

DATA10H5.D11 WATANA (ON LINE 1993)- STATE FUNDS TO 1989 ($1.8 BN)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 BN 8-JAN-83

CASH FLOW SUMMARY ($MILLION)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.05	154.81	165.65	177.24	189.65	202.92	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.0	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.4
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	357.3	386.9
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-32.3	31.6
-----CASH SOURCE AND USE-----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-32.3	31.6
446 STATE CONTRIBUTION	375.7	436.1	437.2	447.4	827.4	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	13.3	1402.9	1273.5	882.9	328.7	8.3
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	375.7	436.1	437.2	447.4	840.8	1402.9	1273.5	882.9	387.8	55.4
320 LESS CAPITAL EXPENDITURE	375.7	436.1	437.2	447.4	840.8	1402.9	1273.5	882.9	296.4	25.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
280 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.3
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET-----										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	49.4
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	375.7	811.8	1248.9	1696.3	2537.1	3940.0	5213.5	6096.4	6392.8	6418.5
465 CAPITAL EMPLOYED	375.7	811.8	1248.9	1696.3	2537.1	3940.0	5213.5	6096.4	6484.1	6525.3
461 STATE CONTRIBUTION	375.7	811.8	1248.9	1696.3	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-32.3	-0.7
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.8
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	13.3	1416.3	2689.7	3572.6	3901.3	3895.4
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	8.6	846.9	718.5	465.5	162.0	3.8
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	8.6	855.5	1574.0	2039.5	2201.5	2205.4
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	1.04

Option D -- $1.8 Billion Drawn From Uncommitted State Funds Available For Capital Construction

ACRES

DATAIONS.D11 WATANA (ON LINE 1993)- STATE FUNDS TO 1989 ($1.8 BN)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 BN   8-JAN-83

CASH FLOW SUMMARY
---($MILLION)---

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	60.24	57.33	54.00	50.76	47.76	44.98	42.39	40.03	37.85	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.53	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	139.96	142.51	143.63	144.46	145.45	146.55	147.81	149.34	151.08	0.00
-----INCOME-----------------										
516 REVENUE	474.0	482.6	486.4	489.3	492.6	496.3	500.6	505.8	511.7	5242.3
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	444.2	450.1	450.9	450.5	450.2	450.1	450.1	450.7	451.6	4799.0
214 ADD INTEREST EARNED ON FUNDS	5.7	6.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	14.7	14.9	16.3	16.4	16.9	19.5	18.3	19.7	21.5	168.6
391 LESS INTEREST ON LONG TERM DEBT	385.5	383.9	382.2	380.3	378.2	375.9	373.4	370.6	367.5	4141.5
548 NET EARNINGS FROM OPERS	49.7	57.6	59.3	61.2	63.3	65.6	68.2	71.0	74.1	569.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	49.7	57.6	59.3	61.2	63.3	65.6	68.2	71.0	74.1	569.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2523.8
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3909.7
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
549 TOTAL SOURCES OF FUNDS	57.4	82.2	69.8	72.4	73.5	75.6	81.7	85.4	89.4	7227.0
320 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6748.0
448 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	15.7	17.4	19.2	21.1	23.2	25.5	28.1	30.9	34.0	229.2
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	6.5	10.7	8.6	6.4	4.1	1.5	-1.1	-4.0	-7.1	25.5
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.0	75.0	79.4	82.2	83.9	88.6	93.3	90.0	90.0
454 CASH SURPLUS RETAINED	6.5	17.2	25.8	32.2	36.3	37.8	36.7	32.6	25.5	25.5
370 CUM. CAPITAL EXPENDITURE	6446.0	6475.4	6506.9	6540.6	6576.7	6615.3	6656.6	6700.8	6740.0	6740.0
465 CAPITAL EMPLOYED	6567.0	6631.8	6682.4	6733.8	6784.1	6834.1	6887.8	6942.3	6997.8	6997.8
461 STATE CONTRIBUTION	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8
462 RETAINED EARNINGS	49.0	106.6	165.9	227.1	290.4	356.1	424.3	495.3	569.4	569.4
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	3879.7	3862.2	3843.1	3822.0	3798.8	3773.3	3745.2	3714.4	3680.4	3680.4
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2205.4
543 CUM. DEBT DRAWDOWN $1982	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4
519 DEBT SERVICE COVER	1.00	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

DATA10M5.D11 WATANA (ON LINE 1993)-$1.4 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 8-JAN-83

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.05	154.81	165.65	177.24	189.65	202.93	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.0	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.1
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	424.9	454.6
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-100.0	-42.8
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-100.0	-42.8
446 STATE CONTRIBUTION	806.8	413.3	475.3	115.4	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	521.8	1453.8	1329.4	944.4	396.4	85.3
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	806.8	413.3	475.3	115.4	521.8	1453.8	1329.4	944.4	387.8	57.9
320 LESS CAPITAL EXPENDITURE	373.3	390.5	389.2	390.9	811.8	1453.8	1329.4	944.4	296.4	25.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.8
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	433.5	22.8	86.1	-275.5	-290.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	49.4
454 CASH SURPLUS RETAINED	456.6	479.4	565.5	290.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	373.3	763.8	1153.0	1543.9	2355.7	3809.4	5138.8	6083.2	6379.6	6405.3
465 CAPITAL EMPLOYED	829.9	1243.2	1718.5	1833.9	2355.7	3809.4	5138.8	6083.2	6471.0	6512.1
461 STATE CONTRIBUTION	806.8	1220.1	1695.4	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8
462 RETAINED EARNINGS	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	-76.9	-119.7
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.8
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	521.8	1975.5	3304.9	4249.3	4645.7	4714.2
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	337.0	877.6	750.0	498.0	195.3	39.3
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	337.0	1214.6	1964.7	2462.6	2658.0	2697.2
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76	0.87

Option C -- $1.4 Billion Dedicated From
Permanent Fund Income

ACRES

DATA10MS.D11 WATANA (ON LINE 1993)-$1.4 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.6$7 8-JAN-83

CASH FLOW SUMMARY

===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	60.24	69.32	65.13	61.09	57.35	53.87	50.65	47.69	44.96	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.53	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	139.96	172.33	173.25	173.87	174.65	175.55	176.60	177.92	179.46	0.00
-----INCOME-----------------										
516 REVENUE	474.0	583.7	586.7	588.9	591.5	594.5	598.1	602.6	607.8	6030.7
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	444.2	551.1	551.2	550.1	549.2	548.3	547.6	547.5	547.7	5587.4
214 ADD INTEREST EARNED ON FUNDS	5.7	6.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	29.2	37.8	38.4	37.8	37.4	37.2	37.2	37.7	38.7	350.5
391 LESS INTEREST ON LONG TERM DEBT	452.9	451.0	449.0	446.8	444.3	441.6	438.7	435.4	431.8	4871.0
548 NET EARNINGS FROM OPERS	-32.2	68.5	70.6	73.0	75.6	78.4	81.5	85.0	88.8	446.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	-32.2	68.5	70.6	73.0	75.6	78.4	81.5	85.0	88.8	[illegible]
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	[illegible] 0.8
143 LONG TERM DEBT DRAWDOWNS	78.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	[illegible]9.1
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
519 TOTAL SOURCES OF FUNDS	53.7	93.1	81.1	84.2	85.7	88.3	95.0	99.4	104.1	7290.5
320 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6734.9
448 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	18.4	21.3	23.4	25.7	28.3	31.1	34.3	37.7	41.4	278.4
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	17.8	15.7	13.5	11.2	8.7	6.0	3.1	0.0	53.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.8	75.0	79.4	82.2	83.9	88.6	93.3	98.0	98.0
454 CASH SURPLUS RETAINED	0.0	17.8	33.5	47.1	58.3	67.0	73.0	76.1	76.1	76.1
370 CUM. CAPITAL EXPENDITURE	6432.8	6462.3	6493.8	6527.5	6563.5	6602.1	6643.4	6687.6	6734.9	6734.9
465 CAPITAL EMPLOYED	6547.4	6619.2	6677.0	6735.5	6792.9	6850.1	6910.9	6972.6	7035.2	7035.2
461 STATE CONTRIBUTION	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8
462 RETAINED EARNINGS	-151.9	-83.4	-12.7	60.2	135.8	214.2	295.8	380.7	469.5	469.5
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	4773.9	4752.6	4729.3	4703.5	4675.2	4644.1	4609.8	4572.1	4530.7	4530.7
542 ANNUAL DEBT DRAWDOWN $1982	33.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2730.9
543 CUM. DEBT DRAWDOWN $1982	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9
519 DEBT SERVICE COVER	0.89	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

(B).

References cited SB 69 and 71

Sec. 44.83.181. Feasibility study and finance plan. (a) Unless the reconnaissance study has been disapproved by the division of budget and management under AS 44.83.179, the authority shall complete a feasibility study and plan of finance for each proposed project.

(b) A feasibility study shall include

(1) information about the proposed project, including but not limited to estimates of total project construction costs, total project operating costs, the costs of transmission systems and reserve power requirements, the timing and amount of anticipated returns from the completed project, a benefit-to-cost ratio, the potential effect of the project on the environment of the area which will be served by the project when completed, and the availability of alternative government financing;

(2) a statement of all assumptions which affect the economic feasibility of the project, including but not limited to the discount rate and interest rate of amounts of money to be used for the project, anticipated fuel prices, an escalation rate, state and local electric load growth, and estimates of indirect costs and benefits;

(3) a comparative analysis of all reasonable alternatives to construction of the proposed project; and

(4) information based on engineering and design work which meets the requirements for submission of a license application for the project to the Federal Energy Regulatory Commission.

(c) The plan of finance shall include recommendations of the most appropriate means to finance a project, including, but not limited to,

(1) the issuance of revenue bonds of the authority;

(2) the issuance of

(A) general obligation bonds of the state; or

(B) revenue bonds of the authority which are guaranteed or partially guaranteed by the state;

(3) an appropriation from the general fund

(A) to pay debt service on bonds or for other project purposes; or

(B) to reduce the amount of debt financing for the project;

(4) a loan from the general fund;

(5) financing arrangements with other entities using leveraged leases or other financing methods;

(6) assistance from any federal agency, including, but not limited to, the Rural Electrification Administration;

(7) a loan from the power project fund (AS 44.83.170(a)), or from the renewable resources investment fund (AS 37.11.050); or

(8) any combination of financing arrangements listed in this subsection.

(d) When financial assistance from the state is necessary for a project to meet financial feasibility criteria, the plan of finance shall include an estimate of the minimum amount of financial assistance required from the state. The plan of finance shall include an estimate of the present value of the financial assistance from the state, computed as the difference between

(1) a market rate of interest, which is

(A) the rate determined under AS 44.83.170(f)(2)(B)(i); or

(B) the estimated interest rate for revenue bonds to be issued by the authority for the project; and

(2) the effective rate of interest because of state financial assistance provided.

(e) The authority, in consultation with the division of budget and management, shall adopt regulations defining

(1) the techniques which it shall apply to determine that the information required by (b) — (d) of this section is obtained; and

(2) standard criteria and measures for comparative analysis of alternative financing arrangements. (§ 24 ch 83 SLA 1980; am § 6 ch 133 SLA 1982)

Effect of amendments. — The 1982 amendment, effective June 25, 1982, inserted "the costs of transmission systems and reserve power requirements" in paragraph (1) of subsection (b).

Sec. 44.83.183. Review of feasibility studies and plans of finance by division of budget and management. (a) The division of budget and management in the Office of the Governor shall review the feasibility study and plan of finance for a project of the authority for compliance with the provisions of AS 44.83.181(b) — (d).

(b) In its review under this section, the division of budget and management may obtain an independent evaluation of a feasibility study and plan of finance to determine compliance with the provisions of AS 44.83.181(b) — (d).

(c) When the division of budget and management has completed a review of the feasibility study and the plan of finance for a project under this section, it shall submit a report to the governor. The report shall examine the feasibility study and plan of finance for compliance with the requirements of AS 44.83.181(b) — (d). The report of the division of budget and management shall include a recommendation to the governor and legislature for approval or disapproval of the project based on the division's review of the feasibility study and plan of finance for compliance with the requirements of AS 44.83.181(b) — (d).

(d) The report required by (c) of this section shall be prepared and submitted not later than 60 days after the feasibility study and plan of finance for a proposed project have been received by the division of budget and management.

(e) The report required by (c) of this section shall include a financial analysis of the proposed project of the authority that evaluates proposed bond resolutions or other financial arrangements or financial plans, security plans and arrangements, cost and demand uncertainties, and debt volume, as they relate to the total direct and indirect indebtedness of the state. In preparing the financial analysis required by this section the division of budget and management may use the services of outside agencies or institutions that are not otherwise involved in the project. (§ 24 ch 83 SLA 1980; am § 7 ch 133 SLA 1982)

Effect of amendments. — The 1982 amendment, effective June 25, 1982, added subsection (e).

Sec. 44.83.185. Submission to the legislature. (a) The authority shall submit a feasibility study and plan of finance for a proposed new project to the legislature. When the report of the division of budget and management examining the feasibility study and plan of finance is completed as required by AS 44.83.183, it shall be submitted to the legislature.

(b) The authority may not proceed with work on the engineering or design phase of a proposed new project for which legislative approval is required until the legislature approves the proposed new project. However, the authority may proceed with the engineering or design work necessary to meet the requirements for submission of a license application for the proposed new project to the Federal Energy Regulatory Commission without obtaining legislative approval of the proposed new project.

(c) The legislature shall consider and must approve all proposed new projects except proposed new projects that are exempt under AS 44.83.187. The legislature may approve a proposed new project only by enacting law that authorizes the project and approves a construction cost for that project. (§ 24 ch 83 SLA 1980; am § 8 ch 133 SLA 1982)

Effect of amendments. — The 1982 amendment, effective June 25, 1982, substituted "that authorizes the project and approves a construction cost for" for "authorizing" in the second sentence of subsection (c).

Sec. 44.83.186. Final cost estimate and reauthorization by the legislature. If a project is approved under AS 44.83.185(c), the authority shall obtain a final cost estimate for the project from an independent source qualified to make such an estimate. If the final cost estimate does not exceed the construction cost authorized by the legislature under AS 44.83.185, adjusted for inflation, by more than seven and one-half percent, the authority may proceed with the construction of the project. If the final cost estimate exceeds the construction cost authorized by the legislature under AS 44.83.185, adjusted for inflation, by more than seven and one-half percent, the authority shall revise its feasibility study and, if it determines that the project remains feasible, the authority shall submit the revised feasibility study and the independent cost estimate to the legislature. A proposed project that is returned for reconsideration by the legislature under this section may not be constructed unless the legislature reauthorizes it by enacting law for that purpose. (§ 9 ch 133 SLA 1982)

Effective dates. — Section 22, ch. 133, SLA 1982, makes this section effective June 25, 1982, in accordance with AS 01.10.070(c).

Sec. 44.83.130. Nonliability on bonds. (a) Neither the members of the authority nor a person executing the bonds is liable personally on the bonds or is subject to personal liability or accountability by reason of the issuance of the bonds.

(b) The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, except the authority, but shall be payable solely from the income and receipts or other funds or property of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state, except the authority, to the payment of a bond and the issuance of a bond by the authority does not directly or indirectly or contingently obligate the state or a political subdivision of the state to apply money from, or levy or pledge any form of taxation whatever to the payment of the bond. (§ 1 ch 278 SLA 1976)

Article 7. Susitna River Hydroelectric Project.

Sec. 44.83.300. Description of project. The Susitna River hydroelectric project consists of dams and related reservoirs, and power plants located in the Upper Susitna River Basin, and related transmission lines, facilities, and load centers, as described in the Alaska Power Authority's report required by AS 44.83.320(b). (§ 2 ch 169 SLA 1980)

Sec. 44.83.310. Purpose of project. The primary purpose of the Susitna River hydroelectric project is to generate, transmit and distribute electric power in a manner which will

(1) minimize market area electrical power costs;

(2) minimize adverse environmental and social impacts while enhancing environmental values to the extent possible; and

(3) safeguard both life and property. (§ 2 ch 169 SLA 1980)

Sec. 44.83.320. Preliminary reports. (a) By March 30, 1981, the authority shall prepare and submit to the governor and to the legislature a preliminary report recommending whether work should continue on the Susitna River hydroelectric project, and, if the recommendation is to continue on the project, the report shall explain in detail

(1) economic evaluations and preliminary environmental impact assessments for the Susitna River hydroelectric project and all viable alternatives;

(2) the federal and state permits required to be obtained before construction can begin and the expected construction start date; and

(3) any other information the authority considers appropriate or necessary to adequately inform the governor and the legislature of the status of the Susitna River hydroelectric project.

(b) By April 3[illegible], 1982, the authority shall prepare and submit to the governor and to the legislature a preliminary report recommending whether work should continue on the Susitna River hydroelectric project, and other viable alternatives. If the recommendation is to continue on the Susitna River hydroelectric project, the report shall explain in detail

(1) the proposed conceptual design and phases of construction of the Susitna River hydroelectric project;

(3) the expected cost of each phase of construction;

(4) the costs to the state and consumers of the project under alternative methods of project financing, including revenue bonds, general obligation bonds, and general fund appropriations; and

(5) any other information the authority considers appropriate or necessary to adequately inform the governor and the legislature of the status of the Susitna River hydroelectric project.

(c) The preliminary reports required under (a) and (b) of this section are in addition to any reports required under AS 44.83.180 — 44.83.224. (§ 2 ch 169 SLA 1980)

Sec. 44.83.325. Restrictions on contracting. The authority may not enter into contracts under AS 44.83.300 — 44.83.360 other than those contracts necessary to complete (1) feasibility studies, (2) the preliminary reports required by AS 44.83.320, or (3) construction of the Anchorage-Fairbanks intertie, until the legislature approves by law the preliminary report required under AS 44.83.320(b). (§ 2 ch 169 SLA 1980)

Sec. 44.83.330. Construction, maintenance and operation of project. Within one year after approval of its preliminary report submitted under AS 44.83.320(b), the authority may enter into a contract for the construction of the Susitna River hydroelectric project in a manner consistent with the purpose of the project as described in AS 44.83.310. (§ 2 ch 169 SLA 1980)

Sec. 44.83.340. Annual report. (a) If the Susitna River hydroelectric project is approved by the legislature under AS 44.83.320(d), beginning in 1983 the authority shall prepare an annual report which explains in detail

(1) the status of construction on the Susitna River hydroelectric project;

(2) the completion date of any phase of the Susitna River hydroelectric project which has been completed and the reasons for any deviation between the completion date and the expected completion date stated in the preliminary report required under AS 44.83.320(b);

(3) the actual cost of any phase of the Susitna River hydroelectric project which has been completed and the reasons for any deviation between the actual cost and the expected cost stated in the preliminary report required under AS 44.83.320(b);

(4) the federal and state permits necessary to begin or continue construction of the Susitna River hydroelectric project, the actual dates on which the federal and state permits necessary to begin or continue construction were obtained, and the reasons for any deviation between the actual dates and the expected dates stated in the preliminary report required under AS 44.83.320(a) or in the earlier annual reports required under this section;

(5) any other information the authority considers appropriate or necessary to adequately inform the governor and the legislature of the status of the Susitna River hydroelectric project.

(b) The annual report required under (a) of this section is in addition to any reports required under AS 44.83.180 — 44.83.224 and shall be submitted, by March 30 of each year, to the governor and to each member of the legislature. (§ 2 ch 169 SLA 1980)

Sec. 44.83.350. Legislative and executive oversight. The legislature or the governor may provide for ongoing oversight, review and selected in-depth analysis of the Susitna River hydroelectric project plan of study. The authority shall provide all data, analyses, reports, and other information to whomever conducts the oversight, review, or analysis activities. Selected in-depth analyses shall include assessments of the power alternatives, financing, and power marketing sections of the Susitna River hydroelectric project plan of study. (§ 2 ch 169 SLA 1980)

Sec. 44.83.360. Project financing. The Susitna River hydroelectric project shall be financed by general fund appropriations, general obligation bonds, revenue bonds, or other plans of finance as approved by the legislature. (§ 2 ch 169 SLA 1980)

Article 7. Susitna River Hydroelectric Project.

Sec. 44.83.325. Restrictions on contracting.

Editor's note. — Section 21, ch. 133, SLA 1982, provides: "Notwithstanding the provisions of AS 44.83.325, the Alaska Power Authority may enter into contracts under AS 44.83.300 — 44.83.360 for preliminary work without the approval required by AS 44.83.325. In this section, 'preliminary work' means the preparation of plans and studies and the preparation and submission of license applications, as well as other types of work, that must be completed before actual construction of the Susitna River hydroelectric project, described in AS 44.83.300, may begin. This section does not authorize the Alaska Power Authority to enter into contracts for the actual construction of the Susitna River hydroelectric project or for the preparation of the site of the Susitna River hydroelectric project without the approval required by AS 44.83.325."

SEE FILE
HB 120
HSA
FOR THIS REPORT

POLICY ANALYSIS PAPER 82-14

Potential for Industrial Development in the Railbelt Region of Alaska Based on the Availability and Cost of Electric Power

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Prepared by: SRI International
333 Ravenwood Ave
Menlo Park, CA 94025