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 ---

The Susitna project has disturbing parallels with WPPSS.

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 too low 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 essentially correct may combine with unrealistic forecasts of Railbelt electricity demand and fossil-fuel prices to encourage an Alaska investment in a project that would be uneconomic even in the absence of construction-cost overruns.
>
> 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.

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 consi-

dered 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.

This, rather than the fickleness of construction-cost estimates, is the real lesson of the WPPSS disaster for Alaskans.

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 contradic-

tory. 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 nominal-dollar and a level constant-dollar 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 I-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, 1982.

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 mainter ce costs, and present Cook Inlet gas prices. (loc. cit.) The cost esti te would probably be somewhat high even if the Acres-Battelle gas-pri 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 amaple 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

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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. His-

tory 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.[6] 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.[7]

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.[16] 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 $55-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. 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.

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. 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.

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

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. These generalizations do not warrant a forecast of a $13 price or any other specific price at any specific future time.

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. 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.

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 disappointment 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 T 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, OPEC Behavior and World Oil Prices, 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.

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(FILE 5)

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

FINANCE DIVISION
POUCH WF-STATE CAPITOL
JUNEAU, ALASKA 99811
PHONE: (907) 465-3795

M E M O R A N D U M

DATE: February 21, 1983

TO: Honorable Vic Fischer
Chairman
Senate State Affairs Committee

FROM: Milt Barker, MB Fiscal Analyst
Legislative Finance Division

SUBJ: Funds Available for Capital Projects

Through the end of the next decade, under current law, total capital projects are almost four times the amount available for capital. Even if Permanent Fund earnings were to be entirely utilized for capital, total projects would still exceed the amount available by almost 50%.

The amount proposed for Susitna alone would consume all funds available under current law. Together with other hydro projects, hydro would require over half of the funds available if Permanent Fund dividends and inflation-proofing are repealed.

Tables I and II (attached) compare the amount of general funds and general obligation bonds available for capital projects with proposed capital projects. The "amount available for capital projects" from the general fund is assumed to be all funds remaining after providing for the operating budget. These amounts were calculated in the attached computer runs using the Department of Revenue's January 1983 revenue estimates at the 30th percentile.

The only difference between Tables I and II is in the amount available for projects. The main source of this difference is that Table I assumes no change in current statutes while Table II shows more funds available as a result of repealing Permanent Fund dividends and inflation-proofing. Table II reflects the entire amount of Permanent Fund earnings in arriving at the amount available figure.

-Q1LH

Two other differences between Table I and II are:

1) Table I assumes operating budgets at the spending limit ($1986.7 million in FY 84) while Table II assumes the Governor's FY 84 budget of $1911.8 million (including longevity bonus and municipal aid); operating budgets are assumed to increase 10% per annum in both cases;

2) because of greater unrestricted revenues in Table II, a greater amount of G.O. bond issues are assumed; the amounts of G.O. bonds in both tables are based on the statements of APA's financial advisers in the January 1983 Susitna financing plan (see footnotes to Tables).

The amount of capital projects shown in the Tables includes traditional capital projects, in the form of the last year's Governor's Six Year Capital Budget, only through FY 88. No amounts have been estimated for legislative capital projects nor has any amount been included for purchase of the Alaska Railroad or cashing out interim financing on Tyee, Swan, and Terror Lakes ($200 million).

attachments

MB:ro

cc: Honorable Al Adams
Honorable John Sackett
Honorable Don Bennett

FUNDS AVAILABLE FOR CAPITAL PROJECTS
WITH REPEAL OF DIVIDENDS & INFLATION-PROOFING
($ Millions)

FISCAL YEAR	(1) FUNDS AVAILABLE FOR CAPITAL PROJECTS: GENERAL FUND	(2) FUNDS AVAILABLE FOR CAPITAL PROJECTS: GO BONDS	(3) FUNDS AVAILABLE FOR CAPITAL PROJECTS: TOTAL	(4) SB 68 STATE FUNDING FOR SUSITNA	(5) OTHER APA CAPITAL PROJECTS	(6) TOTAL HYDRO PROJECTS	(7) LOAN PROGRAM APPROPRIATIONS	(8) GOVERNOR'S SIX YEAR CAPITAL BUDGET	(9) TOTAL CAPITAL PROJECTS
ACTUAL DOLLARS									
85	1196.0	350.0	1546.0	403.7	244.5	648.2	300.0	2035.0	2983.2
86	1281.0	190.0	1471.0	472.7	282.3	755.0	300.0	742.9	1797.9
87	1157.0	95.0	1252.0	479.7	125.8	605.5	300.0	961.2	1866.7
88	1269.0	235.0	1504.0	499.5	--	499.5	300.0	1066.2	1865.7
89	1110.0	50.0	1160.0	938.3	--	938.3	300.0	?	1238.3+
90	580.0	25.0	605.0	738.4	--	738.4	300.0	?	1038.4+
91	--	160.0	160.0	--	--	--	300.0	?	300.0+
92	--	35.0	35.0	--	--	--	300.0	?	300.0+
93	--	170.0	170.0	--	--	--	300.0	?	300.0+
Total	6593.0	1310.0	7903.0	3532.3	652.6	4184.9	2700.0	4805.3	11690.2+
FY 84 DOLLARS									
85	1118.0	327.1	1445.1	364.5	228.5	593.0	280.0	1901.9	2774.9
86	1119.0	166.0	1285.0	398.9	246.6	645.5	262.0	648.9	1556.4
87	944.0	77.5	1021.5	378.3	102.7	481.0	248.0	784.7	1510.7
88	968.0	179.3	1147.3	368.2	--	368.2	229.0	813.4	1410.6
89	790.0	35.6	825.6	646.4	--	646.4	214.0	?	860.4+
90	390.0	16.7	406.7	475.4	--	475.4	200.0	?	675.4+
91	--	99.6	99.6	--	--	--	187.0	?	187.0+
92	--	20.4	20.4	--	--	--	175.0	?	175.0+
93	--	92.5	92.5	--	--	--	163.0	?	163.0+
Total	5329.0	1014.7	5343.7	2631.7	577.8	3209.5	1955.0	4148.9	9313.4+

NOTES:
1. From attached Legislative Finance computer run labelled "Repeal of Dividends and Inflation-Proofing"; see note 1 to Table I;
2. See note 2 to Table II; amount of GOB's based on estimates of revenues at the 50th percentile made prior to the current January 1983 estimates; those revenues are higher than the January 1983 estimates even including monies that would have been used for dividends and inflation-proofing; thus, the estimate of GOB's is somewhat high;

For other items see notes to Table I.

FUNDS AVAILABLE FOR CAPITAL PROJECTS UNDER CURRENT LAW
($ Millions)

FISCAL YEAR	(1) FUNDS AVAILABLE FOR CAPITAL PROJECTS: GENERAL FUND	(2) FUNDS AVAILABLE FOR CAPITAL PROJECTS: GO BONDS	(3) FUNDS AVAILABLE FOR CAPITAL PROJECTS: TOTAL	(4) SB 68 STATE FUNDING FOR SUSITNA	(5) OTHER APA CAPITAL PROJECTS	(6) TOTAL HYDRO PROJECTS	(7) LOAN PROGRAM APPROPRIATIONS	(8) GOVERNOR'S SIX YEAR CAPITAL BUDGET	(9) TOTAL CAPITAL PROJECTS
ACTUAL DOLLARS									
85	593.0	--	593.0	403.7	244.5	648.2	300.0	2035.0	2983.2
86	611.0	300.0	911.0	472.7	282.3	755.0	300.0	742.9	1797.9
87	447.0	90.0	537.0	479.7	125.8	605.5	300.0	961.2	1866.7
88	503.0	125.0	628.0	499.5	--	499.5	300.0	1066.2	1865.7
89	280.0	--	280.0	938.3	--	938.3	300.0	?	1238.3+
90	--	50.0	50.0	738.4	--	738.4	300.0	?	1038.4+
91	--	140.0	140.0	--	--	--	300.0	?	300.0+
92	--	--	--	--	--	--	300.0	?	300.0+
93	--	--	--	--	--	--	300.0	?	300.0+
Total	2434.0	705.0	3139.0	3532.3	652.6	4184.9	2700.0	4805.3	11690.2+
FY 84 DOLLARS									
85	554.0	--	554.0	364.5	228.5	593.0	280.0	1901.9	2774.9
86	534.0	262.0	796.0	398.9	246.6	645.5	262.0	648.9	1556.4
87	365.0	73.0	438.0	378.3	102.7	481.0	245.0	784.7	1510.7
88	384.0	95.0	479.0	368.2	--	368.2	229.0	813.4	1410.6
89	200.0	--	200.0	646.4	--	646.4	214.0	?	860.4+
90	--	33.0	33.0	475.4	--	475.4	200.0	?	675.4+
91	--	87.0	87.0	--	--	--	187.0	?	187.0+
92	--	--	--	--	--	--	175.0	?	175.0+
93	--	--	--	--	--	--	163.0	?	163.0+
Total	2037.0	550.0	2587.0	2631.7	577.8	3209.5	1955.0	4148.9	9313.4+

(Notes to Table I on next page.)

NOTES TO TABLE I

1. From attached Legislative Finance computer run labelled "current law"; beginning GF balance based on 2/9/83 schedule of amount available per Senate Finance of $918.3 million reduced by $230 million for the Rainy Day Fund and $600 million for the Permanent Fund that has been appropriated but was included in the $918.3 million; includes Permanent Fund undistributed income;

2. From Table I, Susitna Hydroelectric Project, Task II: Financing Options, Acres, January 1983; amount of GOB's based on statement of First Boston Corporation, John Nuveen & Co., and First Southwest Co. which assumed higher projected revenues at the 30th percentile than the current January 1983 Department of Revenue estimates; thus the estimate of GOB's must be somewhat high;

4. From Table 18.4.7, Susitna Hydroelectric Project, Task II Reference Report, Acres; this is the $2.3 billion (January 1982 $) state contribution case; SB 68 proposes $2.3 billion in January 1983 dollars; if the Acres funding schedule is intended it would be necessary to adjust SB 68; otherwise the estimated Susitna costs shown here would be 4% to 7% too high as measured by various "Engineering News Record" construction cost indices;

5. From Table I, "Acres", January 1983;

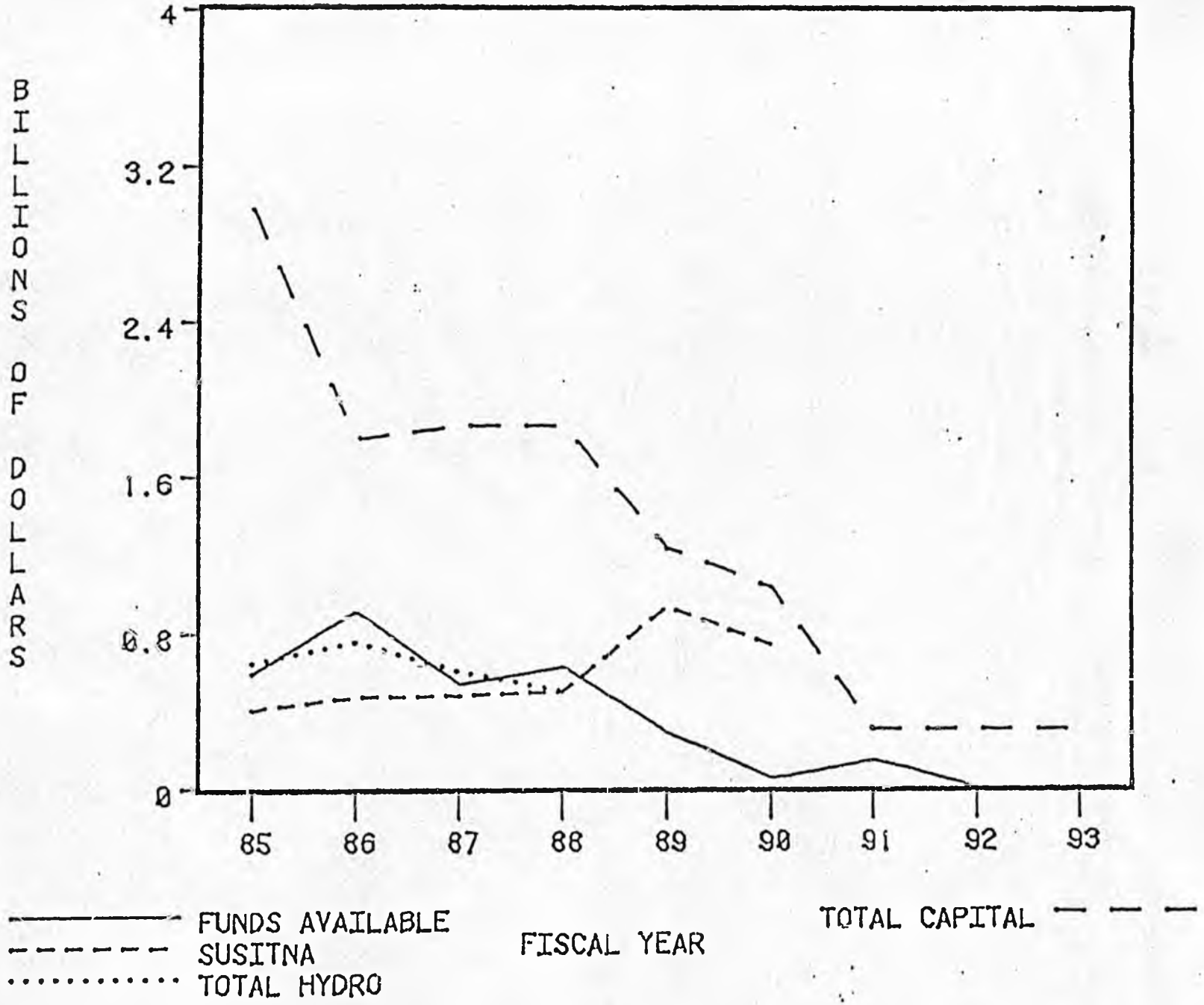
7. Assumes loan program appropriations remain at roughly the Governor's FY 84 budget level, $294.5 million;

8. Total of general fund capital projects (including voter approval) contained in Executive Budget, Book 2, Capital Budget and Six Year Capital Program, FY 83, Jay Hammond, Governor; FY 85 amount is sum of FY 83-85 amounts less amounts appropriated for capital and loans for FY 83 and less the amount of capital projects proposed by Governor Sheffield for FY 84.

FY 84 $ amounts are based on a 7% inflation factor: the Acres Susitna numbers appear to be on a calendar year basis and are thus adjusted for an extra 1/2 year.

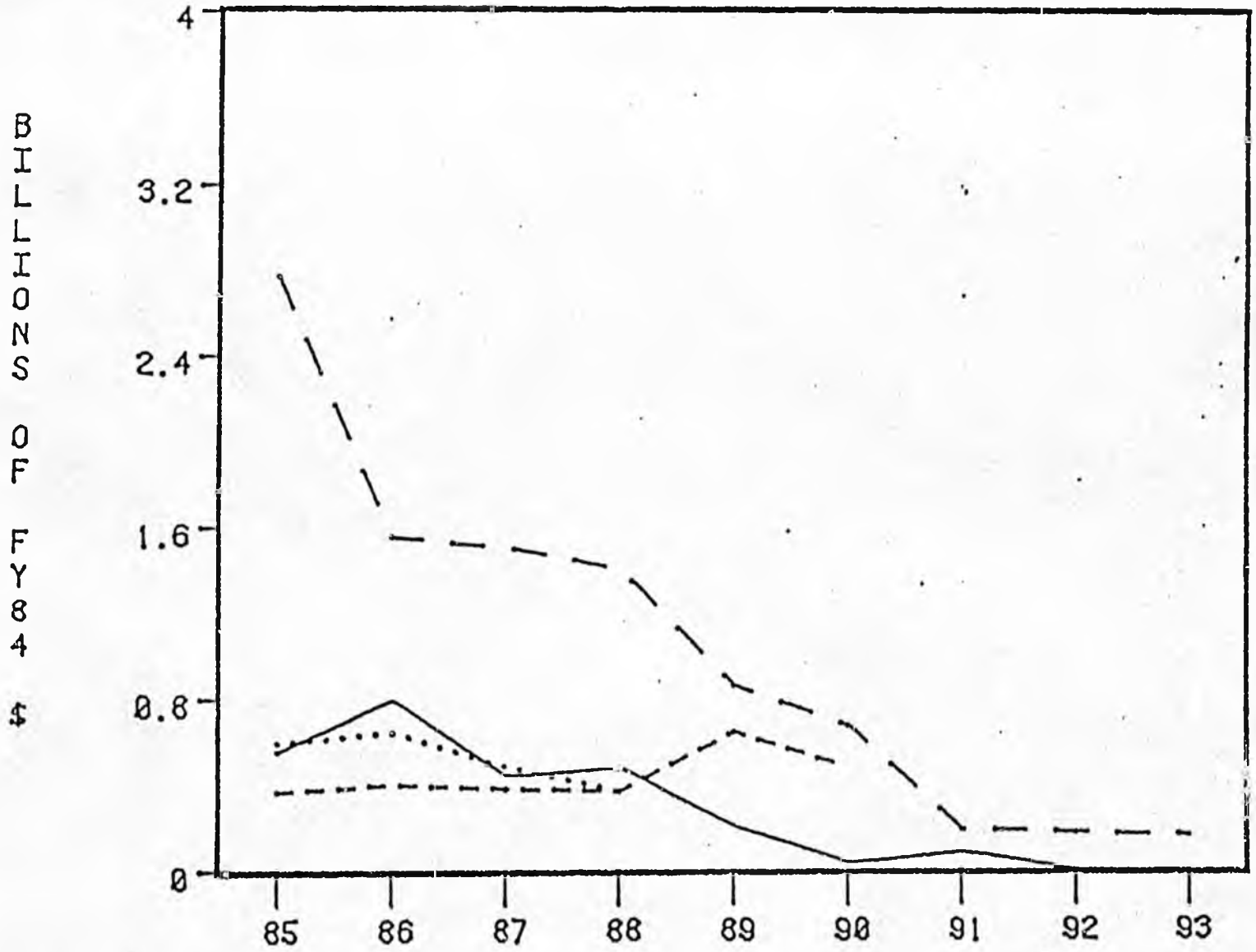
FUNDS AVAILABLE FOR CAPITAL PROJECTS

CURRENT LAW

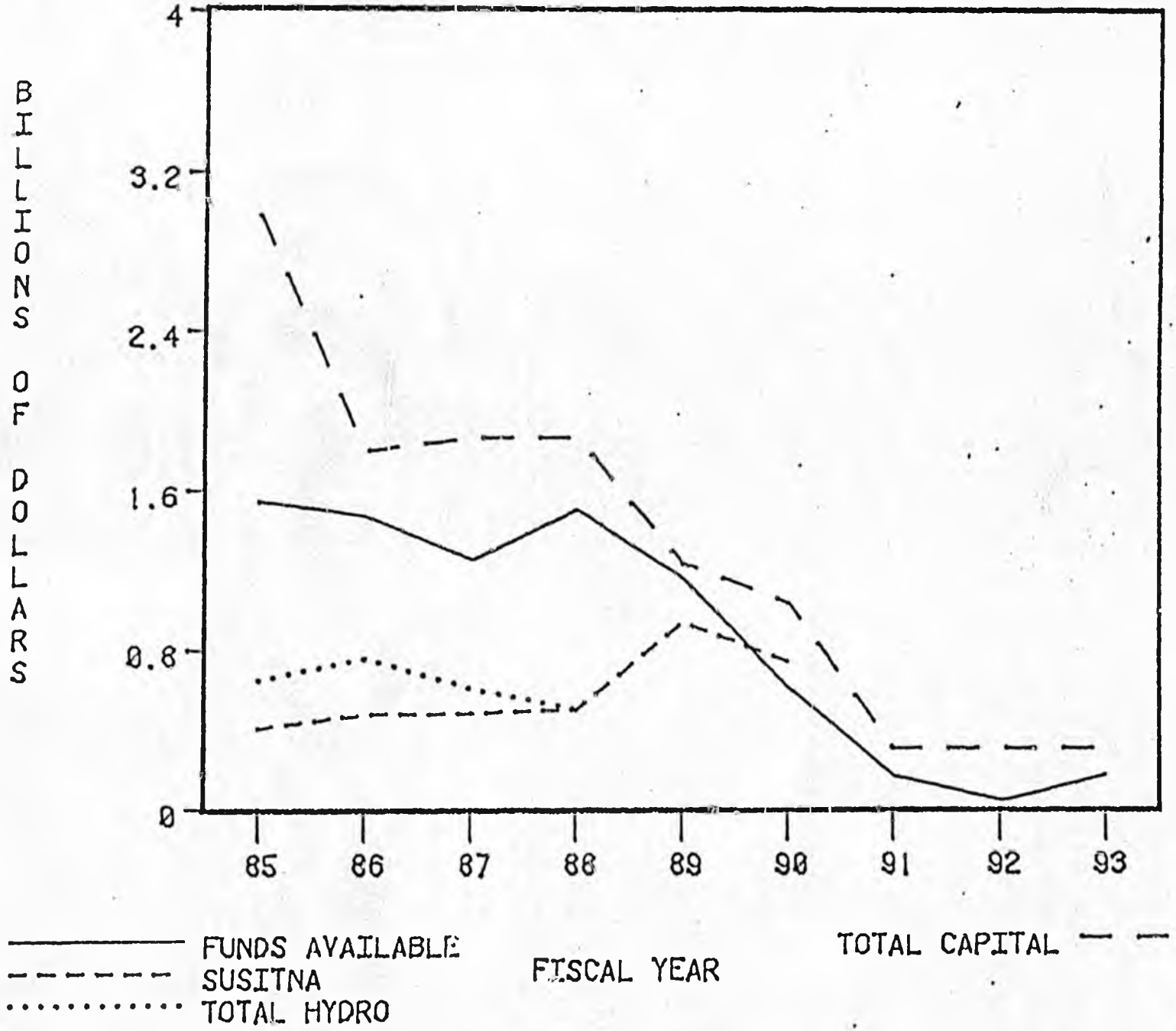


FUNDS AVAILABLE FOR CAPITAL PROJECTS (FY84 $)

CURRENT LAW

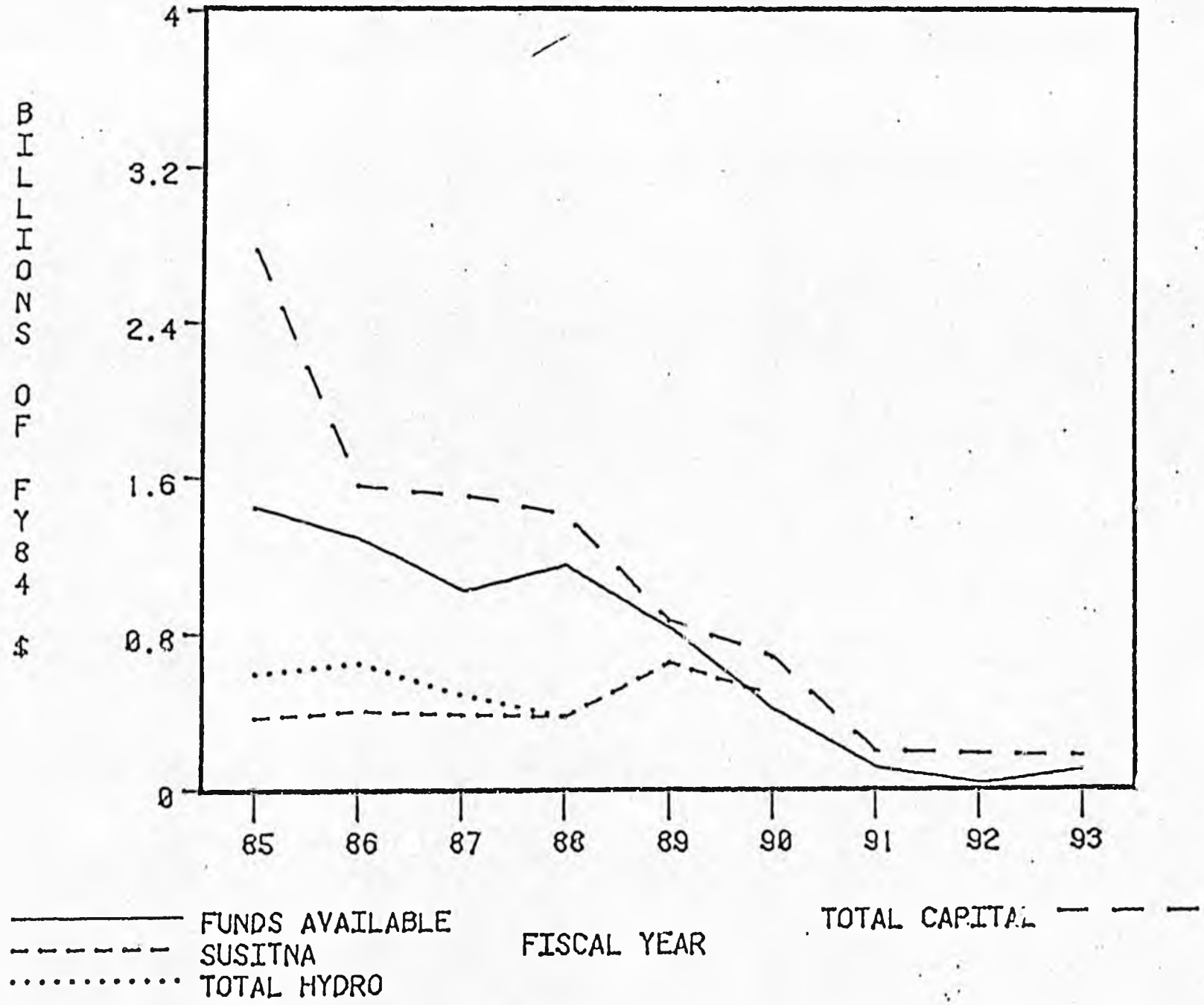


FUNDS AVAILABLE FOR CAPITAL PROJECTS
REPEAL DIVIDENDS & INFLATION-PROOFING



FUNDS AVAILABLE FOR CAPITAL PROJECTS (FY84 $)

REPEAL DIVIDENDS & INFLATION-PROOFING



STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

*** ACTUAL DOLLARS IN MILLIONS ***

JAN 83 DEPT OF REVENUE ESTIMATES
OPERATING BUDGET AT SPENDING LIMIT
SPENDING LIMIT INCREASES 10% PER ANNUM
SURPLUS SPENT ON CAPITAL
INFLATION 7% PER ANNUM
PERMANENT FUND INFLATION-PROOFED
PERMANENT FUND EARNS 12% PER ANNUM
GO BONDS PER ACRES JAN 83 SUSITNA FINANCING PLAN

FISCAL YEAR	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $ 0 MIL
1983										3790	88	
1984	2703	333	3036	1987	837	167	134	3124	-88	4361	0	0
1985	2775	352	3127	2185	593	164	185	3127	-0	4979	0	0
1986	3029	381	3410	2404	611	163	231	3410	0	5676	0	0
1987	3112	410	3522	2644	447	166	265	3522	0	6433	0	0
1988	3456	448	3904	2909	503	179	313	3904	-0	7287	0	0
1989	3540	490	4030	3200	280	190	360	4030	00	8250	00	00
1990	3300	520	3810	3520	00	190	400	4110	-300	9240	00	300
1991	3000	550	3560	3870	00	180	450	4500	-940	10270	00	940
1992	2890	610	3500	4260	00	160	510	4920	-1430	11350	00	1430
1993	2700	670	3360	4680	00	160	570	5410	-2050	12480	00	2050
1994	2610	740	3350	5150	00	130	630	5920	-2570	13680	00	2570
1995	2520	810	3320	5670	00	140	690	6500	-3180	14950	00	3180
1996	2380	890	3270	6240	00	140	760	7140	-3870	16280	00	3870
1997	2440	970	3410	6860	00	90	830	7780	-4380	17710	00	4380
1998	2510	1060	3570	7540	00	80	910	8530	-4960	19240	00	4960
1999	2660	1160	3820	8300	00	50	990	9340	-5530	20900	00	5530
2000	2800	1260	4060	9130	00	50	1080	10250	-6190	22690	00	6190
TOTAL	48410	11640	60060	80550	3270	2390	9320	95530	-35470			35380

FEBRUARY 15,1983

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

*** FY 1984 DOLLARS IN MILLIONS***

JAN 83 DEPT OF REVENUE ESTIMATES
OPERATING BUDGET AT SPENDING LIMIT
SPENDING LIMIT INCREASES 10% PER ANNUM
SURPLUS SPENT ON CAPITAL
INFLATION 7% PER ANNUM
PERMANENT FUND INFLATION-PROOFED
PERMANENT FUND EARNS 12% PER ANNUM
GO BONDS PER ACRES JAN 83 SUSITNA FINANCING PLAN

FISCAL YEAR	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $ 0 MIL
1983										3790	88	
1984	2703	333	3036	1987	837	167	134	3124	-88	4361	0	0
1985	2594	329	2923	2042	554	154	172	2923	-0	4653	0	0
1986	2645	333	2978	2100	534	143	202	2978	0	4957	0	0
1987	2540	335	2875	2159	365	136	216	2875	0	5251	0	0
1988	2636	342	2978	2219	384	137	239	2978	-0	5559	0	0
1989	2520	350	2870	2280	200	140	250	2870	00	5880	00	00
1990	2200	340	2540	2350	00	130	270	2740	-200	6160	00	200
1991	1870	340	2220	2410	00	110	280	2800	-590	6390	00	590
1992	1680	350	2030	2480	00	90	300	2870	-830	6610	00	830
1993	1470	360	1830	2550	00	90	310	2940	-1110	6790	00	1110
1994	1330	370	1700	2620	00	70	320	3010	-1300	6960	00	1300
1995	1190	380	1580	2690	00	60	330	3090	-1510	7100	00	1510
1996	1060	390	1450	2770	00	60	340	3170	-1720	7230	00	1720
1997	1010	400	1410	2850	00	40	350	3230	-1820	7350	00	1820
1998	970	410	1380	2930	00	30	350	3310	-1920	7460	00	1920
1999	960	420	1380	3010	00	20	360	3390	-2000	7570	00	2000
2000	950	430	1380	3090	00	20	370	3470	-2100	7690	00	2100
TOTAL	30330	6240	36570	42520	2870	1580	4790	51760	-15190			15100

STATE OF ALASKA

LEGISLATIVE FINANCE WORKING DOCUMENT

BUDGET FORECASTING MODEL

*** ACTUAL DOLLARS IN MILLIONS ***

JAN 83 DEPT OF REVENUE ESTIMATES
GOVERNOR'S OPERATING BUDGET (INCLUDES LONGEVITY & MUNICIPAL AID)
OPERATING BUDGET INCREASES 10% PER ANNUM
SURPLUS SPENT ON CAPITAL
INFLATION 7% PER ANNUM
NO PERMANENT FUND DIVIDENDS
NO PERMANENT FUND INFLATION-PROOFING
PERMANENT FUND EARNS 12% PER ANNUM
GO BONDS PER ACRES JAN 83 SUSITNA FINANCING PLAN

FISCAL YEAR	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF$ 0 MIL
1983										3790	88	
1984	2703	629	3332	1912	1341	167	0	3420	-88	4085	0	0
1985	2775	688	3463	2103	1196	164	0	3463	0	4388	0	0
1986	3029	741	3770	2313	1281	176	0	3770	0	4724	0	0
1987	3112	784	3896	2545	1157	194	0	3896	0	5072	0	0
1988	3456	833	4288	2799	1269	221	0	4288	-0	5462	0	0
1989	3540	880	4420	3080	1110	230	00	4420	00	5890	00	00
1990	3300	910	4210	3390	580	240	00	4210	00	6300	00	00
1991	3000	910	3910	3730	00	230	00	3960	-50	6660	00	50
1992	2890	910	3800	4100	00	210	00	4310	-510	7020	00	510
1993	2700	950	3650	4510	00	220	00	4730	-1080	7350	00	1080
1994	2610	1000	3610	4960	00	200	00	5150	-1540	7660	00	1540
1995	2520	1050	3560	5450	00	200	00	5660	-2100	7960	00	2100
1996	2380	1090	3470	6000	00	160	00	6160	-2690	8250	00	2690
1997	2440	1140	3580	6600	00	130	00	6730	-3150	8530	00	3150
1998	2510	1190	3700	7260	00	110	00	7370	-3680	8830	00	3680
1999	2660	1240	3900	7990	00	70	00	8060	-4160	9150	00	4160
2000	2800	1290	4100	8780	00	60	00	8840	-4750	9500	00	4750
TOTAL	48410	16240	64650	77510	7940	2990	00	88440	-23790			23700

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

*** FY 1984 DOLLARS IN MILLIONS***

JAN 83 DEPT OF REVENUE ESTIMATES
GOVERNOR'S OPERATING BUDGET (INCLUDES LONGEVITY & MUNICIPAL AID)
OPERATINC BUDGET INCREASES 10% PER ANNUM
SURPLUS SPENT ON CAPITAL
INFLATION 7% PER ANNUM
NO PERMANENT FUND DIVIDENDS
NO PERMANENT FUND INFLATION-PROOFING
PERMANENT FUND EARNS 12% PER ANNUM
GO BONDS PER ACRES JAN 83 SUSITNA FINANCING PLAN

FISCAL YEAR	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $ 0 MIL
1983										3790	88	
1984	2703	629	3332	1912	1341	167	0	3420	-88	4085	0	0
1985	2594	643	3237	1965	1118	154	0	3237	0	4101	0	0
1986	2645	648	3293	2021	1119	154	0	3293	0	4126	0	0
1987	2540	640	3180	2077	944	158	0	3180	0	4140	0	0
1988	2636	635	3272	2135	968	168	0	3272	-0	4167	0	0
1989	2520	630	3150	2200	790	170	00	3150	00	4200	00	00
1990	2200	610	2800	2260	390	160	00	2800	00	4200	00	00
1991	1870	560	2440	2320	00	140	00	2460	-30	4150	00	30
1992	1680	530	2210	2390	00	120	00	2510	-300	4090	00	300
1993	1470	520	1980	2450	00	120	00	2570	-590	4000	00	590
1994	1330	510	1840	2520	00	100	00	2620	-780	3890	00	780
1995	1190	500	1690	2590	00	100	00	2690	-1000	3780	00	1000
1996	1060	480	1540	2660	00	70	00	2740	-1190	3660	00	1190
1997	1010	470	1480	2740	00	50	00	2790	-1310	3540	00	1310
1998	970	460	1430	2820	00	40	00	2860	-1430	3420	00	1430
1999	960	450	1410	2890	00	30	00	2920	-1510	3320	00	1510
2000	950	440	1390	2980	00	20	00	3000	-1610	3220	00	1610
TOTAL	30330	9360	39690	40920	6670	1920	00	49510	-9820			9740

LETTER OF INTENT
CCS FOR HB 9

In this and other legislation, the Legislature has authorized and funded the Alaska Power Authority to continue preliminary work on the Susitna hydroelectric project and to submit a F.E.R.C. license application. The Board of Directors of the Authority expects to resolve the issue of license application timing no later than June 30, 1982. It is the intent of the Legislature that the Authority board submit the license application at a time which it determines will result in the most expeditious and favorable treatment of the application.

It is the intent of the Legislature that the Alaska Power Authority proceed to expend funds previously appropriated to it for the construction of the transmission intertie between Anchorage and Fairbanks. If the First Session of the Thirteenth Legislature fails to appropriate sufficient funds to complete this project, the Authority will need to arrange the necessary financing at that time.

The Conference Committee considered the issue of prohibiting contractors who had been responsible for studies and design of an energy project from participating in the construction of that energy project. The committee concluded that the public policy issues regarding contractor prohibitions are of valid concern to the citizens of the state. It is the intent of the Legislature that the Board of Directors of the Alaska Power Authority discuss and evaluate these issues, including changing contracting procedures to avoid structural incentives for project cost underestimation and construction cost overruns, and report to the First Session of the Thirteenth Legislature with recommendations regarding contractor prohibitions.

It is the intent of the Legislature that the Alaska Power Authority proceed with the Bradley Lake hydroelectric project by expending funds received and by securing, if necessary, additional financing.

Regarding Sec. 8, it is the intention of the Legislature that the authorized construction cost be a number expressed in current year dollars.

It has been pointed out to the Conference Committee that there may be some ambiguity regarding the application of Sec. 9 to projects already undertaken by the Alaska Power Authority. It is the intention of the Legislature that this section not apply to the Terror Lake hydroelectric project for which contracts are currently being reviewed and soon to be signed.

The Committee has briefly discussed the relationship of project financing to utility contracts for power purchase. The committee recognizes the complexity of this issue and requests the Board of

Directors of the Alaska Power Authority to conduct a study of the financial and policy issues involved in the interim finanacing of power projects and the advisability of assuring power marketability through contracts with utilities. The Legislature requests the board of the Authority to recommend statute or policy changes regarding these issues to the First Session of the Thirteenth Legislature.

It is the intent of the Legislature that the Department of Administration develop a proposal for energy efficiency in state procurement for submission to the First Session of the Thirteenth Legislature.

Subsection (h) of section 16 provides for the phasing-in of a project's payment of its proportionate share of all power project debt service. The legislature intends, in establishing this "cap" formula, that the weighted average share of debt service be computed by dividing the total annual debt service of all projects in the energy program for Alaska by the total annual electricity sales. An eligible project's share is then annually raised by 4% above the average until it reaches its actual share under the system described in (g), at which point the "cap" for that project terminates. Thus, in FY 1984, no eligible project would pay more than 104% of the average share; in FY 1985, no eligible project would pay more than 108% of the average share; and so forth. The "cap" assures that the allocation of debt service among projects does not place an undue burden on those projects which were begun under the previous hydro financing system. Further, it is the legislature's intent that the difference between an eligible project's share of the total debt service and the amount paid under the "cap" shall be made up by the shares paid by all other projects in the energy program for Alaska for which debt service is not limited under the "cap."

Rep. Brian Rogers,
chairman

Sen. M. E. Dankworth,
chairman

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE - ANCHORAGE, ALASKA 99501

Phone: (907) 277-7641
(907) 276-0001

August 4, 1982

Arliss Sturgulewski
Senator, District 10-H
1024 W. 6th Ave., Rm. 204-D
Anchorage, Alaska 99501

SUBJECT: CONFERENCE COMMITTEE ON HOUSE BILL 9; "take or pay" and "contractor/multi-phase project work."

Dear Senator Sturgulewski:

With reference to the two issues addressed in your letter of inquiry dated July 12, 1982, the Alaska Power Authority is currently conducting a thorough review of the items, as follows:

The "take or pay" item involves complex legal issues and directly impacts power sales contracts and bond financing provisions. Legal Counsel for the Authority, as well as our underwriters, are presently addressing this issue.

The "contractor/multi-phase project work" item is being addressed by the Engineering, Construction and Finance Staff of the Authority. The Authority Staff will prepare a report upon completion of their study.

A complete report covering both issues will be available for your review by August 25, 1982.

Sincerely,

Eric P. Yould

Eric P. Yould
Executive Director

ALASKA POWER AUTHORITY

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Phone: (907) 277-7641
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September 8, 1982

Arliss Sturgulewski
Senator, District 10-H
1024 W. 6th Avenue, Room 204-D
Anchorage, Alaska 99501

SUBJECT: "Take-or-pay and multi-phase project work"

Dear Senator Sturgulewski:

In response to your letter concerning "take-or-pay" contracts and "contractor/multi-phase project work", the following write up is presented. Our response has treated these issues in the general context of the Power Authority's power project development program.

Should you have a more specific case in mind, we will attempt to address either of the two issues in that context.

I. TAKE-OR-PAY CONTRACTS

DEFINITION OF CONTRACT TERMS:

TAKE-or-PAY	Generally, an unconditional obligation of a purchaser to take a fixed percentage of the capacity of a project and pay a fixed percentage of power costs (including debt service) whether or not the project is completed, operable or operating. The purchaser will normally begin payment on a set certain date.
TAKE-and-PAY	Generally, a purchaser obligates itself to purchase all of its power and energy requirements (total or supplemental) from a supplier for a specific period of time thereby precluding itself from purchasing power from another source or constructing generating facilities. Payments normally do not begin until the purchaser is receiving power from the supplier.

TAKE-OR-PAY CONTRACTS

A "take-or-pay" contract for the purchase of electric power from a hydroelectric project is commonplace when the project is debt financed.

The take-or-pay contract obligates the purchaser of power to pay (at the contracted-for rate) for a specified amount of power regardless of whether the purchaser ultimately elects to actually take the power -- that is, the purchaser obligates itself to "take or pay". In addition, the purchaser is also typically obligated to pay for the specified amount of power regardless of whether the power is delivered as in a situation where a catastrophe has caused production to cease. This variation on the take-or-pay contract is referred to as a "hell-or-high-water" contract. Clearly, the take-or-pay contract is different from other simple sales contracts whereby the purchaser makes no promise to take anything, but does promise to pay at a contracted-for rate when power is taken.

POWER SALES CONTRACTS

The power sales contract is the primary credit document for purchasers of revenue bonds, the proceeds of which are used to finance the construction of a hydroelectric project. The only assurance that a holder of a pure revenue bond will have of a continued source of revenue is a guarantee of payment for power produced and that guarantee lies in a take-or-pay contract. The purchaser of power , while undoubtedly preferring the flexibility inherent in a "pay as you go" contract which would not obligate it to purchase any specific amount of power, nevertheless faces the simple fact that but for debt financing (especially debt financing through revenue bonds dependent on the purchaser's contract), the project would not have been built and the purchaser's recourse for energy would otherwise have been limited. Consequently, the purchaser will and must enter into take-or-pay contracts.

REVENUE BONDS

Since most tax-exempt electric utility bonds are revenue rather than tax-supported general obligations bonds, several general comments on revenue bond analysis are important. Revenue bond analysis is in many ways less difficult than general obligation bond analysis. Generally, it involves a closed system with a definite number of variables and greater possibilities for qualification. This pledge of security involves an enterprise where the debt is related to an earning asset. The principles of credit analysis are the same, but the analysis shifts from the use of sovereign power of government to extract a tax to the operation of a user enterprise involving benefit analysis. Generally, there is a measurable benefit for which people either are or are not willing to pay. Thus, we have bonds secured by pledges of electric, water, wastewater, toll bridge, college dormitory, off-street parking, toll road, airport, hospital, marine terminal, stadium, and multipurpose civic center/convention revenues.

Since bondholders and the marketplace look to assurances that debt service on bonds will be paid in a timely fashion, covenants are generally reflected in the trust indentures to assure that power rates will be sufficient to satisfy at least the debt service obligation and more

typically the debt service obligation plus an additional amount (i.e., a provision requiring that revenue derived from the sale of power in a particular fiscal year will be equal to at least 1.25 times the aggregate debt service for such fiscal year). Both a prospective bondholder and the rating agencies will test the assurances that debts will be repaid in fixing the interest rates on bond issues by reviewing the guarantees underlying those bonds. Take-or-pay contracts provide the primary assurances, although additional support for such bonds may come through letters of credit or, if specified, the moral obligation of either the issuer or perhaps the state to repay the debt.

TAX CONSIDERATIONS

To the extent that take-or-pay contracts are necessary ingredients of revenue bond issues, certain tax implications arise. This is so because the interest earned by a bondholder on a bond is tax-exempt only as specified. Bonds issued by public entities such as the Alaska Power Authority are tax-exempt unless they are industrial development bonds (IDB's) 26 U.S.C. 103(a) and (b). If the bond issue to finance a hydroelectric project is an IDB, the interest on the bond may still be tax-exempt if, for example, the proceeds will be used to finance an electric energy facility furnishing service to the general public in no more than two contiguous "counties". 26 U.S.C. 103(b)(4)(E) and Reg. 103-8(f)(2)(iii)(D). "Counties" in Alaska generally refer to boroughs. Since the Susitna Project, the Anchorage-Fairbanks Intertie, and the Bradley Lake Project would probably serve more than two such counties, it becomes important to recognize when an IDB has been created and triggers the two-county rule. If a bond is not an IDB, the two-county rule simple drops out of the picture as an issue.

A take-or-pay contract may well establish whether or not "nonexempt persons" are guaranteeing the repayment of debt service on the bond issue or whether those persons are in fact utilizing more than 25 percent of the output of the facility. Reg. 103-7(b)(5) provides:

> (5) Trade or business test and security interest test with respect to certain output contracts. (i) The use by one or more nonexempt persons of a major portion of the subparagraph (5) output of facilities such as electric energy, gas, or water facilities constructed, reconstructed, or acquired with the proceeds of an issue satisfies the trade or business test and the security interest test if such use has the effect of transferring to nonexempt persons the benefits of ownership of such facilities, and the burdens of paying the debt service on governmental obligations used directly or indirectly to finance such facilities, so as to constitute the indirect use by them of a major portion of such proceeds. Such benefits and burdens are transferred and a major portion of the proceeds of an issue is used indirectly by the users of the subparagraph (5) output of such a facility which is owned and operated by an exempt person where --

(a)(1) One nonexempt person agrees pursuant to a contract to take, or to take or pay for, a major portion (more than 25 percent) of the subparagraph (5) output (within the meaning of subdivision (ii) of this subparagraph) of such a facility (whether or not conditional upon the production of such output) or (2) two or more nonexempt persons, each of which pays annually a guaranteed minimum payment exceeding 3 percent of the average annual debt service with respect to the obligations in question, agree, pursuant to contracts, to take, or to take or pay for, a major portion (more then 25 percent) of the subparagraph (5) output of such a facility (whether or not conditioned upon the production of such output), and

(b) Payment made or to be made with respect to such contract or contracts by such nonexempt person or persons exceeds a major part (more than 25 percent) of the total debt service with respect to such issue of obligations. A bond may become an IDB if a nonexempt person -- i.e., a cooperative such as Chugach Electric Association or the like -- is the purchaser under the power sales agreement. If that nonexempt person purchases more than 25 percent of the output of the project and the manner of purchase is linked to the repayment of debt service, the "use" and "securities" tests are met and the bonds issued by a public entity would be deemed to be IDB's. The consequence is then the need to meet the electric energy facility exception and the two-county test described above. In any event, however, the Internal Revenue Service will look past the specified terms of a contract which on its face is not take-or-pay and analyze whether it is of a type which still meets the use and securities tests and would thus be an IDB. Such an analysis is generally based on a case-by-case basis. See Rev. Reg. _1.103-7(b)(4).

IMPLICATION OF STATE LEGISLATION

Aside from the Internal Revenue Code implications of take-or-pay contracts, the legislation established in the Energy Program for Alaska (AS 44.83.360-425) favors take-or-pay contracts. This is so because the legislation prescribes the calculation of a particular wholesale power rate for the sale of power from projects within the Energy Program. Included within the calculation is a component representing a particular project's "proportionate share of debt service". As 44.83.398(b)(1)(B). While the Energy Program for Alaska legislation does not specifically require power sales contracts to be take-or-pay contracts, a take-or-pay contract logically follows from the calculation. First, legislation enacted in 1982 provides that the wholesale power rate cannot be annualled or changed by the Legislature when wholesale power rates have been set by virtue of a contract with bondholders. AS 44.83.398(c) and (e). In order to assure bondholders that sufficient receipts are derived from the sale of power from a particular project or several projects (if the financing is premised upon the pledge of revenues from the sale of power from several projects), the contract would undoubtedly

be take-or-pay. Second, the calculation of the proportionate share of debt service and indeed the wholesale power rate itself require an estimation of the amount of energy to be sold in the particular year for the calculation. Under AS 44.83.398(h), the expression of a project's proportionate share of debt service "as a rate" and the average of all proportionate debt service rates require program wide estimates of power to be sold (debt service comprises the numerator and sales comprises the denominator). Similarly, a project's individual wholesale power rate (which equals specific operation and maintenance and inspection fees plus the project's proportionate share of debt service divided by the estimated sales of energy from that project) also require a consistent estimate of what the sale of energy will be. In order to make those estimates stand and be meaningful, little flexibility would be allowed to the purchaser to reduce the amount of energy to be purchased. If a purchaser is free to simply pay for the amount of energy it decides it needs at any one particular point in time, the validity of the calculation is thrown into substantial doubt. As such, the methodology for calculating the wholesale power rate under the Energy Program for Alaska necessarily restricts the ability of a purchaser to alter the amount of power that it would be willing to obligate itself to purchase in a particular period of time. That restriction proximates a take-or-pay contract.

TAKE-OR-PAY SUMMARY

As the above discussion indicates, take-or-pay agreements involve complex legal and financial issues. Take-or-pay contracts facilitate revenue bond financing of power project by serving as the prime credit source of the power sales contract.

It should be noted that take-or-pay contracts may not fulfill the same credit facilitating function in Alaska as they have in the lower forty-eight. The reason for this is that the power purchases in Alaska are likely to be small REA cooperatives or small municipal utility systems. These small utilities would not be rated by the rating services and therefore the take-or-pay provision would have a very limited usefulness on the overall credit standing of the bond issue.

The Alaska Power Authority is currently evaluating take-or-pay agreements as a part of our long range revenue bond financing plan.

II. CONTRACTOR/MULTI-PHASE

The Authority Staff has identified two issues related to the multi-phase question.

1. The "multi-step" project development process as mandated by Alaska Statutes and the preferred use of different contractors for each "step" of the work.

2. The "multi-phase" project design/construction as necessitated by "multi-year" funding appropriations the "multi-phase" project design/construction arising from characteristics inherent in the project, i.e., discreet stand-alone sub-elements of the total project.

I - MULTI-STEP PROJECT DEVELOPMENT

The Power Authority has been mandated by State legislation to use a multi-step power project development process.

STEP ONE: The process begins with reconnaissance studies to identify the electric production needs of communities or regions and to assess energy alternatives available to these communities. The reconnaissance study serves as a data collection/data analysis tool and as a source of information upon which to recommend more detailed studies, or detailed feasibility studies of one or more specific energy alternatives.

Project funding for reconnaissance studies is either for a specified community or on a regional basis. In the event that a project is identified and constructed the cost of the reconnaissance study is allocated to the project and is returned by project operating revenues. The reconnaissance study represents a discreet and clearly identifiable step in the power development process.

STEP TWO: Once a reconnaissance study is completed and a proposed power project is identified, a feasibility study is initiated to assess the detailed technical, economic and environmental aspects of a particular project. The feasibility study provides sufficient detail to allow decision making with regard to licensing, permitting and further investment in detailed engineering and design. The feasibility study will include information about the project, a statement of all assumptions which affect the economic feasibility of the project and a comparative analysis of all reasonable alternatives. The feasibility study and project plan of finance form the basis for an appropriations request to initiate project design and construction.

STEP THREE: Design and permitting is the final project planning phase prior to starting construction. This again is a discreet function but will carry over the construction and end only with project completion.

STEP FOUR: Project construction is undertaken when design is complete enough to allow firm-fixed price bidding of contract work. Once project construction is in process, the termination of the project would result in some form of penalty payments for termination at owner's convenience.

In conjunction with multi-step project development, the entire project is divided into discrete contracts with clearly defined work scopes. When a reconnaissance study is to be performed, and RFP is issued with the contract scope of work defined as "reconnaissance". This scope of work can not be expanded to the level of a feasibility

study. If a feasibility study is appropriate, following the completion of the reconnaissance study, an RFP must be issued for the feasibility study. The Power Authority believes that a more objective report is obtained by having different contractors perform the project reconnaissance and feasibility reports. This result is normally obtained by issuing a separate RFP for each phase of the "multi-step" process.

On very small projects it may be appropriate to use the feasibility study contractor for the project design work. If feasibility and design function are combined, then the RFP must clearly require both in the scope of contract work description.

It is the Power Authority's policy to clearly divide and separately contract project work in accordance with the "multi-step" development process. We believe that this policy results in greater objectivity and control of contractor work performance. Reference attachment I.

This multi-step process allows for legislative review at three significant junctures with each review point allowing for more detailed analysis based upon the increased amount of data and increased reliability of data presented to the legislative decision makers. The review junctures are:

1. Appropriation for reconnaissance study
   - little specific information other than general definition of needs

2. Appropriation for feasibility study
   - community or region specific detail
   - detail concerning alternatives or proposal for specific project
   - some preliminary cost data

3. Appropriation for design and construction
   - project specific detail
   - specific and detailed cost/economic information with plan of finance and second cost estimate

As the above discussion indicates, the multi-step process is a time consuming process covering several years. At each review/approval phase, the quantity and quality of information is increased which should allow for correct decision making prior to the committment of significant amounts of State funds.

II - MULTI-PHASE PROJECTS FROM MULTI-YEAR FUNDING

On large construction projects multi-year funding may be the only practical means of funding a project. Multi-year funding may also be the most economically astute funding method since monies appropriated in the first year of construction may not be expended for several years.

The problem encountered in multi-year funding is that most power project construction projects do not lend themselves to discreet phases which can be independently financed into defined units. As an example, the recent Anchorage-Fairbanks Intertie Project was initiated with State funding of $76,000,000 but total project costs were estimated at $130,000,000, leaving the unfunded balance of $54,000,000. A contractual obligation is established upon issuance of firm-fixed price construction or material procurement contracts. In the event that a project is terminated due to the lack of funds, a significant exposure to termination claims will occur.

A power project such as the intertie cannot be easily "packaged" to accommodate an obligation of funds approach. The construction contract is for $65.1 million and is firm-fixed price. In order to accommodate an obligation of funds construction schedule (this would limit contract value to funds-on-hand) cost economics of scale would be forfeited.

An example of a multi-phase project with discreet sub-projects is the Susitna Project. Susitna constitutes two distinct dam projects, Watana and Devil Canyon. Other projects with discreet sub-projects would involve power generation projects with associated power transmission projects. This type of project could be funded and constructed as a total project or on a multi-phase basis with one sub-project being completed prior to initiating the follow-on project components.

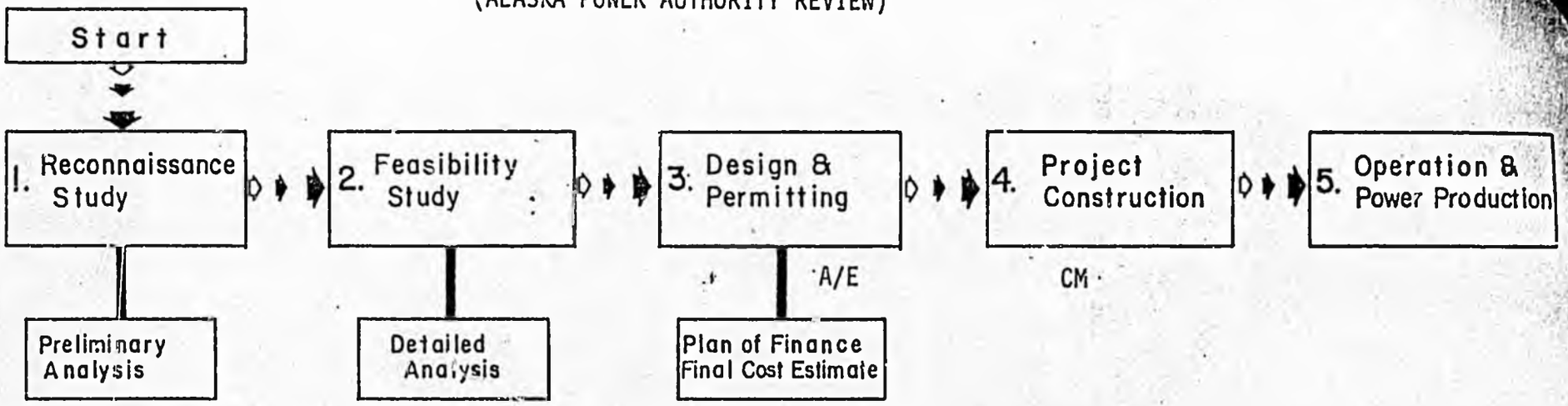
Sincerely,

R. P. Jenish

Eric P. Yould
Executive Director (for)

FIVE STAGES OF POWER PROJECT DEVELOPMENT

(ALASKA POWER AUTHORITY REVIEW)



CONTRACTOR "A"

CONTRACTOR "B"

Reviews RECON STUDY DATA

CONTRACTOR "C"

REVIEWS FEASIBILITY STUDY DATA

CONTRACTOR "D"
FINAL COST ESTIMATE
REVIEWS CONTRACTOR C's COST ESTIMATE

CONTRACTOR "E"

REVIEWS DESIGN FOR CONSTRUCTABILITY

32 ANALYTIC STATEMENT (Six-year Capital Program)

CATEGORY _____

AGENCY _____

PROGRAM _____

ATTACHMENT I

Page of

Revised Date

FY 84

September 15, 1982

Eric P. Yould, Executive Director
Alaska Power Authority
334 West 5th Avenue
Anchorage, AK 99501

Dear Mr. Yould:

Thank you for your letter of September 8, 1982 regarding "take or pay and multi-phase project work." I was pleased to read the results of your first exploration of these issues and look forward to subsequent task products.

I would hope that in the next analytical work on "take-and/or-pay" contracts you will build on this definitional work, elaborating on the potential advantages and disadvantages of pre-construction purchase contracts by type, as well as showing the projects that might fall under the IRS non-exempt definition. In passing, I would like to note that I believe there are crucial differences between purchase contracts and the kind of obligations which might be realized under AS 44.83.360-425, not only in terms of the strength of contractual obligations but also in terms of local commitment to and understanding of a project prior to construction. I would also think that having "take-and/or-pay contracts" would have contributed favorably to your current deliberations on pooled revenue bonds versus moral obligations. I will appreciate being kept informed of your efforts on take-or-pay agreements as a part of your long range revenue bond financing plan, which I assume is part of your long term capital budget request.

Regarding contractor/multi-phase issues, I believe that your staff has identified the relevant issues. In addition, the discussion provided interesting information about the current policies and practices of the Alaska Power Authority. I assume future work will address the issue

identified as "the preferred use of different contractors for each 'step' of the work," and the advantages and disadvantages of full or partial restructuring of those identified AFA policies and practices.

Again, I appreciated your initial efforts and look forward to hearing from you again as work on the HB 9 letter of intent issues progresses.

Sincerely,

Arliss Sturgulewski
Senator, District 10-H

cc: All Board Members

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE - ANCHORAGE, ALASKA 99501

Phone: (907) 277-7641
(907) 276-0001

October 11, 1982

Mr. Charles Conway, Chairman
Alaska Power Authority
2481 Belmont Drive
Anchorage, Alaska 99503

Subject: Interim Financing for Alaska Power Authority Projects

Dear Chuck:

To date the Alaska Power Authority has issued interim financing having a total outstanding par amount of $200 million for the following projects:

Swan Lake	$ 35 million
Tyee Lake	50 million
Terror Lake	115 million

In each instance the interim financing was incurred in order to proceed with the award of contracts which would otherwise have exceeded the amount of funds on hand. It is expected that when due, the interim financing will be replaced with permanent financing in the form of long-term revenue bonds or additional direct State appropriations.

Interim financing offers advantages of cost and flexibility where the following circumstances apply:

1) Full funding at project costs is required to obtain the best bids and to avoid project completion delays.

2) The Legislature has evidenced a desire to consider additional direct funding for a project out of funds available in a subsequent fiscal year.

3) Short-term rates offer a significant cost savings at the time of issuance and market risks are hedged.

4) The Authority and its financial team have determined that it should defer long-term financing until market conditions are more favorable.

The use of interim financing need not constrain future debt issuance policies of the Authority, but purchasers or providers of credit facilities will want enforceable agreements regarding the Authority's intention to issue a long-term debt that is properly secured and. hence, marketable. In this regard, interim lenders normally expect

that long-term financing will be secured by contracts for the sale of the power produced by the project being constructed. This expectation is not unreasonable, especially in view of the fact that it is standard industry practice to conclude such power sales agreements prior to award of contracts and initiation of construction.

Therefore, it is the policy of the Alaska Power Authority to use interim financing under the following guidelines:

1. Permanent financing for the project can be obtained when the interim financing matures.

2. The interim financing matures no sooner than six months after the expected date of project completion.

3. Short-term rates offer a substantial advantage over long-term financing and future market risk has been incorporated in this segment.

4. At least 75% of the project cost is under contract when the interim financing is authorized.

5. Where possible, the interim financing combined with the available resources should fully fund the remaining cost of the project, plus an adequate contingency.

This brief letter is the Authority's response to the request in the Letter of Intent filed with H.B.9 concerning interim financing.

Sincerely,

Eric P. Yould

Eric P. Yould
Executive Director

Review Letter of Intent.