Economic Development Through State Ownership of Oil and Gas: Evaluating Alaska's Royalty-in-Kind Program

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Abstract

Government owners of petroleum subsurface rights often face constituent pressure to exercise control over the disposition of these resources in pursuit of economic development objectives. At the same time, states cannot simply dissipate the potential rent from their resources without losing a principal revenue source. The paper takes a retrospective look at the state of Alaska's policies and programs regarding disposition of oil and gas resources, focusing on the evolution of the royalty-in-kind program. It examines the relative success of different programs in achieving objectives of import substitution and value-added export relative to the cost in foregone revenue. The analysis leads to general conclusions about programs of this type, along with specific insights as the state prepares to embark on the biggest test yet related to the disposition of North Slope natural gas.

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Introduction

Governments in remote regions often possess few options for economic development. At the same time, their narrow economic base provides few options for raising revenue. A dilemma arises for such states that are fortunate enough to own rights to rich natural resource assets. Constituent pressures to exercise control over the disposition of these resources in pursuit of development objectives may conflict with constituent pressures to fund public services. Governments in remote resource-rich regions can stimulate economic development by giving away their natural resources to sponsors of projects that promise attractive economic benefits. Yet such states cannot simply dissipate the potential rent from their resources without losing a principal revenue source.

The greatest potential for conflict between these two objectives occurs in oil-producing states, because the economic rents -- and associated revenues -- from oil are so large. Alaska is unique among North American sovereign jurisdictions in its per-capita state-owned petroleum wealth. The challenge of economic development in Alaska's remote, petroleum-based economy in some ways more closely resembles that of oil-rich developing nations than it resembles that of other US states and Canadian provinces. In other respects, Alaska's situation resembles that of other remote regions in more developed nations (Morehouse and Huskey, 1992). The state of Alaska's experience with balancing the conflicting pressures over the use of oil and gas for revenue enhancement versus economic development provides a laboratory for understanding the opportunities and limits to government-sponsored development programs based on natural resources. Alaska attempted to resolve the dilemma by leasing its oil lands competitively, while retaining the option to dispose of its royalty share -- the share retained by the landowner of oil and gas produced from leased lands -- in kind to prospective industrial developers.

In this paper, I discuss how the State of Alaska has approached the tradeoff between revenue and development through administration of its royalty-in-kind program. In the next section I provide the economic context by summarizing the state's development problem and the role that disposition of the royalty share could play in economic development. Next, I review the history of the state's policy and programs for the disposition of its royalty oil and gas. Then, I discuss the outcomes of the program, describing industrial facilities built, economic benefits, and impacts on state oil revenues. I also discuss disposals that failed to achieve their promise. Following the analysis of outcomes, I evaluate the program to try to explain the pattern of successes and failures, and analyze their implications for likely future royalty disposals. I conclude with broader lessons for economic development policy for Alaska, other remote regions, and for developing areas with petroleum resources.

Petroleum and Alaska Economic Development

The United States is one of the few nations in the world in which petroleum and other subsurface resources may be privately owned. The history of oil and gas development in most of the nation is a history of struggles among private owners over the development and disposition of petroleum (Lovejoy and Homan, 1975; McDonald, 1971). Two factors made Alaska an exception to this rule when it entered the union in 1959. First, the federal government awarded the new state a 102-million-acre land entitlement, including subsurface rights, to be selected from unreserved public domain. Second, the 1953 Submerged Lands Act settling intergovernmental disputes over offshore resources had recently awarded coastal states offshore mineral rights within three miles of land. Alaska's long coastline entitled the state to a vast nearshore estate. The geology was fortuitous, rewarding the state handsomely with oil and gas resources on both onshore and offshore entitlements.

Objectives and constraints of economic development

At the time Alaska entered the union, oil and gas resources in the Cook Inlet region were seen as key to the new state's economic viability (Rogers, 1962). Discovery of the largest field in North America at Prudhoe Bay in 1964 entrenched and enhanced Alaska's status as a petroleum state. The oil and gas industry provided new high-paying jobs, but many of these were held by non-resident workers.[1] "Downstream" vertical integration in the form of petroleum refining and petrochemical industries provided a logical opportunity for increasing resident employment and other economic benefits from oil and gas production. Downstream development does not remove the link to world energy markets, so it does not really make the state economy less dependent on petroleum. Nevertheless, it provides a direct opportunity to increase value added in the state from the state's resource endowment.

Alaska economists have defined three objectives for regional industrial development. New industry can (1) increase jobs and personal income, (2) expand the state and local tax base, and (3) increase share of economic activity retained in the region (increase the economic multiplier) (Kresge et al., 1984: 192). To these one might add a fourth objective of providing benefits to regional consumers. Consumers benefit from development that reduces the cost of living or cost of doing business, or provides products and services that were not previously available locally. This was a particularly relevant objective in Alaska in the 1960s, where the high cost of living and high cost of business posed significant barriers to economic development and diversification.

Two key factors that determine how expansion of different industries might differently achieve the development objectives are: (1) whether wages in the industry are relatively low or high, and (2) the relative capital intensity (Kresge et al., 1984: 198-199). Oil and gas processing industries are capital intensive -- meaning that they provide relatively few jobs as a percentage of value added -- but those jobs are highly skilled and pay high wages (Tussing and Kramer, 1981). Consequently, one would expect that petroleum processing would be provide relatively few permanent jobs, but relatively more enhancement to the property tax base and per-capita income.

The geology and economics that allow large quantities of oil and gas to be produced in Alaska do not guarantee that petroleum processing in the state will be feasible. Alaska faced -- and still does face -- significantly higher construction costs relative to the nation as a whole. In addition, its remote location makes relative transportation costs of raw materials and manufactured products a key factor in economic viability. Crude oil is very inexpensively moved around the globe by tanker. Natural gas, because of its lower value per volume and the expense to liquefy for marine transport, is relatively expensive to move long distances. Refined products and

[1]Although major oil companies made a concerted effort to move employees to Alaska, non-resident workers still represent 28 percent of oil industry employees (Fried and Windisch-Cole, 2003).

petrochemicals are typically more expensive to move than crude oil but less expensive to move than natural gas over long distances.

These basic facts led Tussing and Kramer (1981: 114) to postulate three axioms for location of petroleum processing facilities based on the transportation economics of oil and gas:

(1) Petroleum refineries tend to be located near their markets.

(2) Naptha and gas-oil based petrochemical plants tend to be located near refineries.

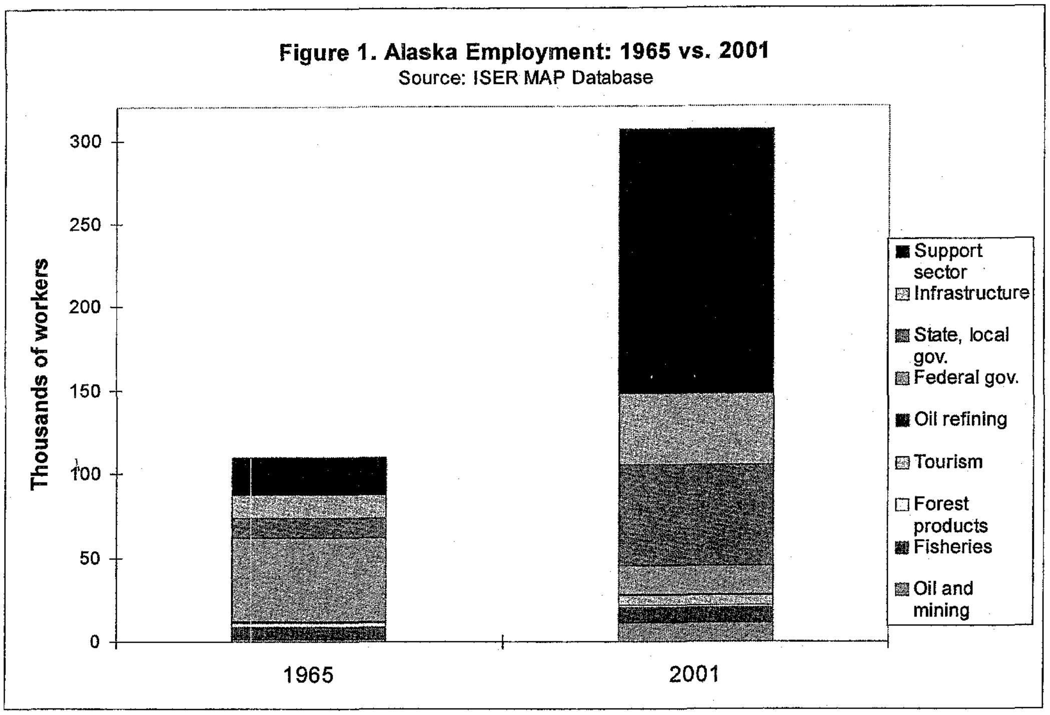
(3) Natural-gas-based petrochemical plants tend to be located near raw-materials sources.

As a result, transportation economics disfavor Alaska locations for export petroleum refineries and oil-based petrochemical plants, but might favor refineries to serve in-state needs. Transportation economics favor converting Alaska gas to petrochemicals in-state, if anywhere (Tussing and Kramer, 1981: 115).

Import substitution vs. export-led growth

Traditional economic wisdom holds that the path to economic development in less-developed regions is through trade; that is, through increased exports. This maxim definitely applies to resource development in remote regions, where exporting minerals to world markets provides the most obvious opportunity for growth. Traditional Alaska "basic" industries such as fisheries, tourism, mining, and forest products, as well as oil and gas, are examples of trade-dependent exports. In Alaska, especially in the early years of statehood, however, federal civilian and military government employment provided the largest source of basic industry employment. Federal government employment is an export industry in the sense that the demand for the services is determined by forces external to the state; i.e., the U.S. Congress.

Figure 1 illustrates the shares of Alaska employment by major industry in 1965, and compares 1965 total employment and employment shares to those in 2001. In 1965 the federal government was by far Alaska's largest employer, employing 50,000 civilian and military workers -- nearly one in two Alaskan workers. All resource industries and tourism combined employed only about 11,000 workers, or 10 percent of the total. The budget shares for 2001 contrast sharply with those of 1965. One obvious difference is the decline in federal government employment (largely due to military staff cutbacks), and the growth in oil and gas and state employment. But by far the biggest change in numbers is the growth in support sector employment. This sector, composed primarily of trade services, grew sevenfold. This growth was largely accomplished through import substitution -- replacement of imported services by locally produced services.



Import substitution also an option to export-led growth in the manufacturing sector. Tuck et al. (1988) used national data to analyze what manufacturing industries were present in Alaska in the 1980s. One of their principal findings was that nearly all manufacturing industries then in Alaska directly served either a basic industry or final consumer demand. That is, Alaska produced relatively few intermediate goods: inputs to other manufacturers. In contrast, the majority of manufacturing industries nationally (at the 4-digit SIC level) produced intermediate goods. Another finding was that a much higher share of Alaska industries than U.S. industries had high transport costs: 60 percent vs. 30 percent. They defined a high-transportation-cost industry as one for which more than three percent of total costs typically paid for transportation. These findings suggest that successful Alaska manufactures are industries that are either favored by a location close to consumers, or have other geographic limitations on location (such as needing to be near a key input with very high transport costs) (Tuck et al., 1988: III.B.4-5).

Another structural feature of the Alaska economy bears on the import-substitution vs. export-led growth question: the state a big petroleum-based fuel-user. Geography -- Alaska's remoteness and sparse population density -- requires that the state burn a lot of fuel per capita in transportation. Its industrial base other than oil -- fishing, tourism, logging, mining, and aviation -- all rely on refined petroleum products as essential production inputs. The statistics confirm these intuitive observations. Energy Information Administration (EIA) 2001 data show that Alaska consumes more than three times as much energy per capita as the U.S. average -- 30 percent more per capita than the next most energy-intensive state (Wyoming). Even without an industrial base using petroleum as feedstock for petrochemicals, Alaska consumes nearly 3.5 times as much petroleum products per capita as the nation, and nearly 40 percent more than the next highest state (Louisiana). Still, the total amount -- about 140 thousand barrels per day -- is relatively small.

Economies of scale

The relatively small size of the Alaska economy can discourage production for local use if there are economies of scale in manufacturing. Petroleum refining and petrochemical manufactures, like most chemical process industries, have substantial economies of scale (Tussing and Kramer, 1981). Scherer et al. (1975) compiled information on minimum efficient scales (MES) -- the smallest size plant that achieves competitive costs -- for a variety of manufacturing industries based on technology available in 1967. They reported an MES for petroleum refining of 1.9 percent of production (Scherer et al., 1975: 80). Using EIA historical consumption data, this translates into a throughput of roughly 230 thousand barrels per day (Mb/d), substantially more than current Alaska consumption and nearly eight times consumption in 1965.

Scherer et al. (1975: 91) also computed the cost disadvantage for plants operating less than the MES. For petroleum refining, a plant with a capacity of one-third the MES in 1967 (approximately 70 Mb/d) faced a cost disadvantage of 4.8 percent relative to an MES plant. For an Alaskan refinery at a scale appropriate for serving the local market in the late 1960s, the projected cost disadvantage might be closer to ten percent.

Petroleum refining will produce a mix of products, not all of which have a market in Alaska. Even configured to maximize recovery of fuels that have large Alaskan demand, a local refinery would have to find a market for some products outside the state. The combination of economies of scale, process limits on the product mix in refinery runs, and the size of Alaska's product markets suggest that a refinery producing for the local market could face significant cost disadvantages that might not be able to be offset by higher transportation costs for competitors' imported petroleum products. It is in this context that I now turn to the issue of disposition of the state's royalty oil.

Royalty-in-Kind program

Many states and the federal government have RIK programs. Alaska has been more aggressive in pursuing this option than other states. Since 1969, Alaska has made upwards of 30 sales involving more than 800 million barrels of oil, or just over half of all state royalty oil. The intellectual roots of the state's development policy toward oil and gas were well established before the oil wealth was realized.

Evolution of the program

Frustration with federal control of fisheries (Cooley, 1963) and national forests (Rakestraw, 2002) played a prominent role in the drive for statehood. In his keynote address to the Alaska Constitutional Convention (Nov. 8, 1955), E.L. Bartlett reflected prevailing views when he said:

> ...The financial welfare of the future state and the well-being of its present and unborn citizens depend upon the wise administration and oversight of these developmental activities. Two very real dangers are present. The first, and most obvious, danger is that of exploitation under the thin guise of development. The taking of Alaska's mineral resources without leaving some reasonable return for the support of Alaska government and the use of all the people in Alaska will mean a betrayal in the administration of the people's wealth. The second danger is that outside interests, determined to stifle any

development in Alaska which might compete with their activities elsewhere, will attempt to acquire great areas of Alaska's public lands in order *not* to develop them until ... they see fit. [emphasis in original] (quoted in Fischer, 1975: 131)

Delegates clearly had Bartlett's ideas in mind when they drafted Article VIII, section 1 of the Alaska Constitution, which reads, "It is the policy of the State to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest"; and section 2: "The legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the state, including land and waters for the maximum benefit of its people." But as a consensus document, the language is suitably vague. To some Alaskans, state ownership of petroleum and other resources gave the government the opportunity to push aggressively for specific utilization and development projects that were deemed in the public interest. This perspective is closely aligned with the so-called *owner-state* model of governance championed by former governor Walter Hickel (2002). To others, the public interest was better served with the state taking a more passive stewardship role, leaving development decisions to private initiative and market forces.

Alaska's royalty-in-kind program resembles production-sharing contracts popular in the developing world in the sense that they reserve a share of the state's oil and gas to the state landowner for disposal to promote economic development. However, Alaska, like the federal government and other U.S. states, never considered creating a state oil company or entering the oil production business. The practice since statehood has been to lease lands competitively to private developers in arms-length transactions, much as economists argued was appropriate for federal lands (McDonald, 1979). The state retains a royalty share from its leases.[2] Alaska law permits the Department of Natural Resources to take its royalty oil and gas in kind or in value (that is, letting the oil companies market it on behalf of the state). Many Alaskans believed that maximizing revenue from oil lands was the only legitimate role for the state. Others, however, favored taking the state's royalty share in kind and making it available to specific projects that would provide additional private-sector jobs, and possibly stimulate additional development. Jack Roderick, Commissioner of Natural Resources for Alaska's first governor, Bill Egan, reported that the governor saw a dual role for royalty-in-kind disposals: job creation and reduced costs for Alaskans. Roderick (1997: 401).

In this regard Alaska, differed from other states and the federal government, where the primary purpose of a royalty-in-kind option was to maximize revenue. Like production sharing contracts in developing countries, Alaska's choice to dispose of royalties in kind for any purpose other than revenue maximization subjected the program to charges of political favoritism, and potentially, corruption. This is exactly what transpired the first time that the Commissioner of Natural Resources entered into a royalty-in-kind contract during the first term of Governor HIckel, who followed Egan. In February 1969, Commissioner Kelley negotiated a deal to sell all the state's Cook Inlet royalty oil up to 15,000 barrels per day for eight years -- at that time all the state's royalty oil -- to a company called Alaska Oil and Refining Company. The company, which

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[2]In 1979 Alaska's oil and gas leasing law was changed to give the state the option of net profit share leases that do not include a royalty share. However, that provision was used only one time -- in the 1979 Beaufort Sea sale -- and has not been used since. According to a former petroleum economist with the Department of Natural Resources, one reason that the state did not use its net profit share lease option is that these leases do not provide the state with royalty oil for disposition (Ed Phillips, personal communication).

appeared to have been created entirely for the purpose of purchasing Alaska's royalty oil, promised to build a refinery in Alaska and pay the state the same price for its oil as the producers received for theirs (the so-called in-value price). Suspicions deepened when the company merged five months later with Tesoro, a small independent oil company. Tesoro did immediately begin construction of a refinery to process the oil in Nikiski, north of Kenai, but the lack of transparency in the negotiations leading to the sale rankled legislators and created lingering doubts about whether the public interest had been served (Roderick, 1997: 248-249).

The euphoria over the $900 million brought in by the 1969 North Slope oil lease sale quickly diverted public attention from the Tesoro case. But legislative debate about the propriety of the 1969 royalty disposal continued, spilling over into the larger question of the appropriate state role in the Trans-Alaska Pipeline System (TAPS) and other projects involving North Slope oil and gas. According to Roderick, things came to a head in a September 1973 special legislative session called by Gov. Egan (elected again after Hickel resigned) to address these issues. Roderick (1997: 367) called this a pivotal time in Alaska's political history, one of two times when the relationship between the state and the oil industry changed in a significant way.[3] Legislators dropped a proposal for a 20 percent equity ownership in TAPS and a right of way leasing law that could set tariffs, and raised severance taxes instead. The following year, the legislature rewrote the statutes governing royalty-in-kind disposals, in a bid to ensure transparency of negotiations for future sales of royalty oil and gas from Prudhoe Bay.

The 1974 statute set criteria and standards for the Commissioner of Natural Resources to meet in royalty-in-kind disposals (AS38.05.183). Royalty-in-kind disposals must be competitive unless the state's best interest required that they be noncompetitive (AS 38.05.183(c)), and earn at least as much as if the oil were taken in-value. Instate domestic and industrial needs had priority over export sales of royalty-in-kind oil and gas (AS 38.05.183(d)). AS 38.05.183(e) defined the constitutionally required "maximum benefits" to the state as based on cash, effects on the economy, benefits of instate processing, provision of products to benefit instate consumers, and specific criteria related to local economic development benefits. The 1974 statute also created a Royalty Oil and Gas Development Advisory Board (ROGDAB) which would hold public hearings on proposed sales, review benefit claims against the statutory criteria, and recommend to the legislature whether to ratify contracts (AS38.06).

The changed climate favoring transparency was evident in the way that governor Jay Hammond, who succeeded Egan, announced the next proposed royalty-in-kind sale: a proposal to sell Prudhoe Bay royalty gas in support of an "All-Alaska Pipeline."[4] In a statewide radio address, the governor carefully articulated the reasons for his best-interest finding. The rationale included how delivery of gas to tidewater improved the chances of using the gas for industrial purposes in Alaska, an assurance that royalty gas in-kind removed in Alaska would not be subject to federal regulation, and a negotiated "takeback" provision if a need developed for in-state use of the gas (Hammond, 1976). By the time Hammond left office in 1983, his administration had sufficiently institutionalized royalty disposals that his deputy commissioner, Geoffrey Haynes, found

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[3]The other time was in 1981, when the legislature bowed to oil company pressure to revise its tax code.

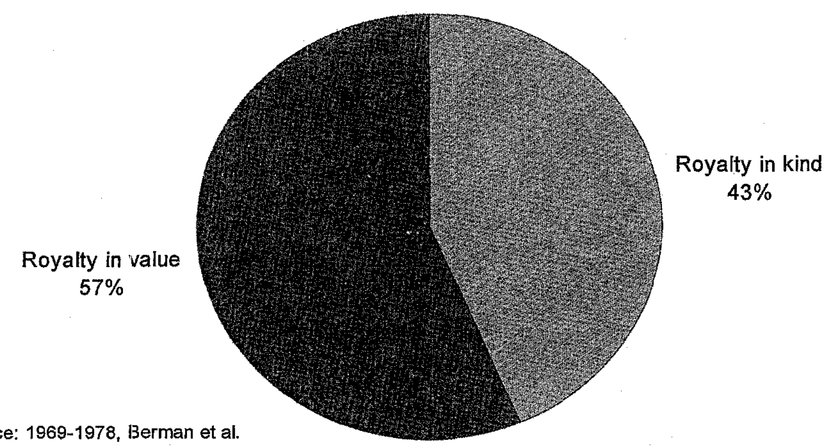
[4]The purchasers of the proposed contract were Tenneco (50% share), Southern Nat. Gas. Co. (25%), and El Paso Natural Gas Company, (the pipeline sponsor (25%). The contract was approved but never implemented because El Paso did not receive federal certification for the project.

it necessary to write a thick handbook explaining the process for the incoming commissioner (Haynes, 1983).

Summary of Disposals

Between 1969 and 2003, slightly more than one-half of all Alaska state royalty oil was taken in-kind (Figure 2). Relatively little gas was taken in kind, however, despite several attempts[5] The state sold 10.4 billion cubic feet -- about one-half of one-year's worth of Cook Inlet royalty gas -- to the local gas distributor, Alaska Pipeline Company (Enstar), from 1977 to 1984 (Division of Oil and Gas, 2004: 5.1).

Figure 2. Disposition of Alaska Royalty Oil, 1969-2003



Source: 1969-1978, Berman et al. (1984); 1979-2003, Alaska Division of Oil and Gas Annual Reports

Figure 3 shows the distribution over time of state royalty oil and the disposals by purchaser. Oil production began in 1958 on federal lands in the Cook Inlet region. Alaska received 90 percent of the revenue from this production but did not control disposition. Production on state-leased lands generating royalties for potential disposal in-kind commenced in 1966. State royalties dramatically increased with completion of TAPS in 1977. Figure 4 shows the distribution of cumulative Alaska oil royalty-in-kind disposals by purchaser through 2003. Two instate refiners -- Tesoro and Mapco (later Williams and now Flint Hills) -- each purchased nearly 40 percent of oil royalty-in-kind oil. Chevron (also an instate refiner), purchased another 10 percent. Two percent was sold to Golden Valley Electric Association (GVEA) -- the Fairbanks area electric utility -- for turbine fuel.[6] Altogether, 94 percent of royalty-in-kind oil was sold to promote instate use, with the remainder sold in competitive auctions. Not all royalty disposals, as we shall see below, successfully served their intended purpose.

[5]In addition to the All-Alaska gas pipeline sale mentioned above, several natural gas pipeline companies and Dow-Shell acquired options to purchase large quantities of North Slope natural gas and gas liquids, but never exercised their options. This project is discussed further in the next section.

[6]GVEA never took physical custody of the oil, but swapped the crude oil in exchange for refined turbine fuel from Mapco (Alaska Division of Oil and Gas, 2004: 5-2).

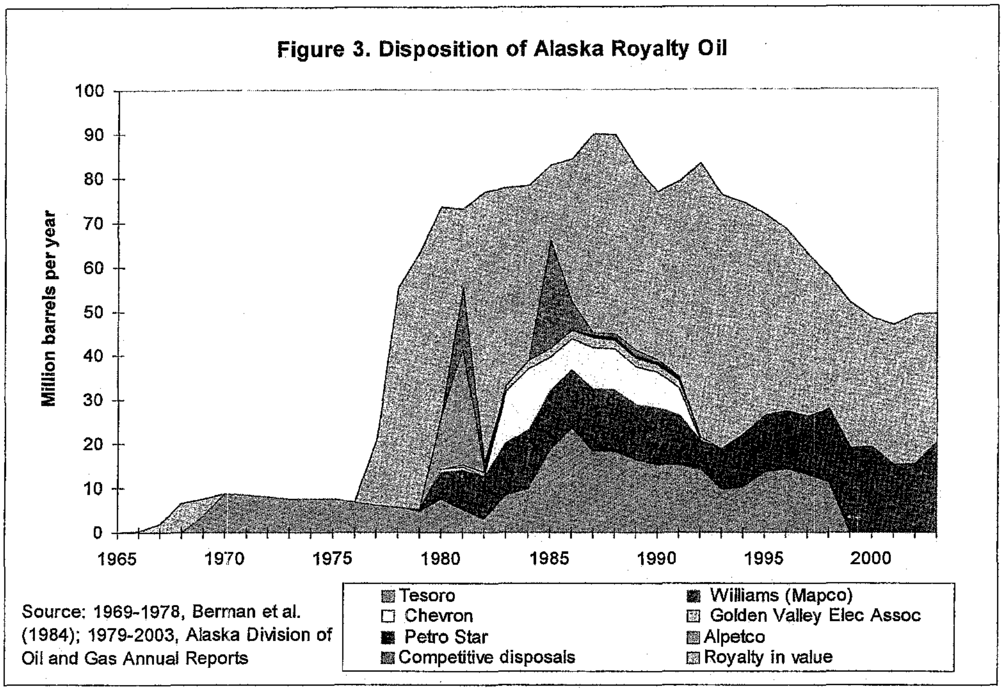


Figure 3. Disposition of Alaska Royalty Oil
Million barrels per year
100
90
80
70
60
50
40
30
20
10
0
1965
1970
1975
1980
1985
1990
1995
2000
Source: 1969-1978, Berman et al. (1984); 1979-2003, Alaska Division of Oil and Gas Annual Reports
Tesoro
Chevron
Petro Star
Competitive disposals
Williams (Mapco)
Golden Valley Elec Assoc
Alpetco
Royalty in value

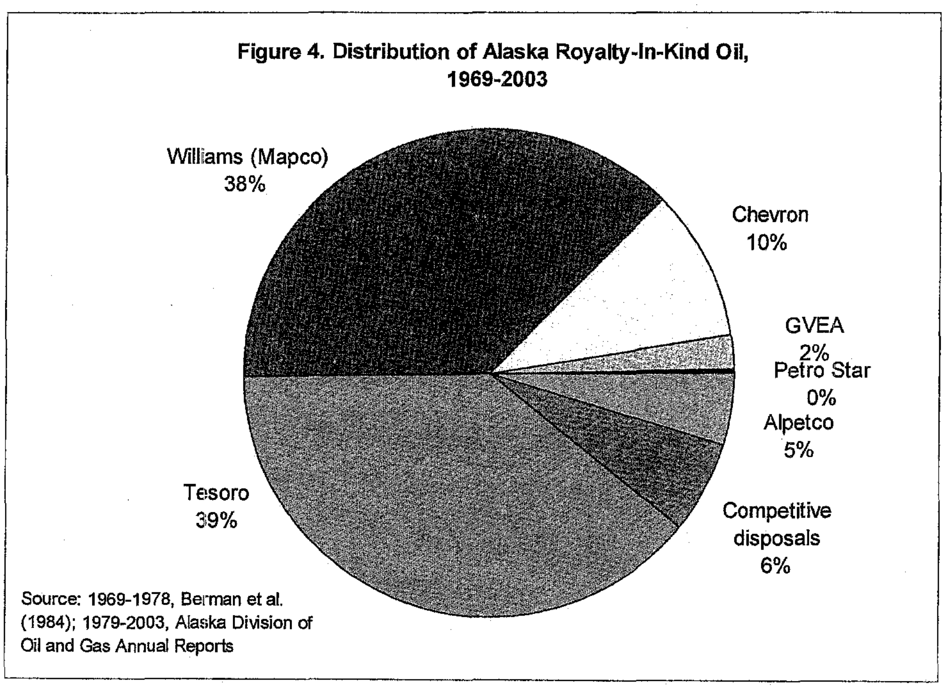


Figure 4. Distribution of Alaska Royalty-In-Kind Oil, 1969-2003
Williams (Mapco) 38%
Chevron 10%
GVEA 2%
Petro Star 0%
Alpetco 5%
Competitive disposals 6%
Tesoro 39%
Source: 1969-1978, Berman et al. (1984); 1979-2003, Alaska Division of Oil and Gas Annual Reports

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Evaluation of Royalty-in-Kind Dispositions

In order to evaluate the success or failure of Alaska's royalty-in-kind program, one needs answers to four main questions. The first and most obvious question is: "What facilities were constructed related to the program?" A second question would be, "What facilities were proposed and supported with RIK disposals but never opened for business? Third is the question of how much it cost the state and the taxpayers. How much more money might the state have made if they had sold all oil competitively? Finally, what can be said about the degree to which RIK oil and gas contracts might have been necessary to get the facilities constructed or their operations successful?

Facilities constructed

When Alaska entered the union in 1959, no oil and gas processing facilities existed anywhere in the state. All petroleum products were imported from the lower '48 states or abroad, and there was no natural gas distribution system.[7] Table 1 summarizes Alaska oil and gas processing facilities constructed between 1959 and 2004. The table shows that many of the early Cook Inlet facilities were constructed without the benefit of any state royalty oil or gas. Chevron constructed the first modern oil refinery in Alaska in 1963, although the company did purchase some royalty oil later. Faced with the need to make large expenditures to convert the refinery from Cook Inlet to North Slope feedstock as Cook Inlet production declined, Chevron closed and dismantled the plant in 1991, after 27 years in operation.

Other Cook Inlet facilities constructed in the early years, in addition to the Tesoro refinery mentioned above, were the Phillips-Marathon LNG plant and an ammonia-urea fertilizer plant, using natural gas as feedstock. The Collier Chemical Company, later merged into Unocal, built the fertilizer plant to serve Pacific Rim demand. Unocal sold the plant to Agrium in 2000. After North Slope oil started flowing through TAPS, two oil refineries were built near Fairbanks and a third was constructed in Valdez. All three take oil from TAPS, refine it into products for Alaska markets, and return the residual back to the TAPS oil stream. They pay a fee, called a Quality Bank adjustment, for reducing the quality of the oil stream. Earth Resources (later Mapco), a partnership involving the Doyon regional native corporation, built the largest of these refineries. The Mapco refinery, later sold to Williams, which recently sold it to Flint Hills, has been expanded several times over the years. Arctic Slope Regional Corporation, another Alaska Native regional corporation, owns an interest in Petro Star, the operator of the other two TAPS refineries.

[7]A small oil refinery had been operation in Katalla in the early part of the 20th century but burned down in the 1930s (Rakestraw, 2002).

Table 1. Alaska Oil and Gas Processing Facilities Constructed

Owner	Location	Start	Feed-stock	Capacity	Royalty-in-kind	Products	Destination	Status (2/2005)
Conoco-Phillips	Prudhoe Bay	1975?	Crude oil	14,000 b/d	No	Diesel	Prudhoe Bay	Operating
Conoco-Phillips	Kuparuk	1981	Crude oil	14,000 b/d	No	Diesel	Kuparuk	Operating
Flint Hills (Williams/Mapco)	North Pole	1977	Crude oil	220,000 b/d	yes	Gasoline	Alaska	Operating
						Jet fuel	Alaska	
						Diesel	Alaska	
						Gas oil	Alaska	
						Asphalt	Alaska	
						Residual	Returned to TAPS	
Petro Star	North Pole	1985	Crude oil	15,000 b/d	Yes	Kerosene	Alaska	Operating
						Jet fuel	Alaska	
						Diesel	Alaska	
						Residual	Returned to TAPS	
Petro Star	Valdez	1992	Crude oil	46,000 b/d	Option, not exercised	Jet fuel		Operating
						Diesel		
						Residual	Returned to TAPS	
Tesoro	Nikiski	1969	Crude oil	72,000 b/d	Yes	Gasoline	Alaska	Operating
						Jet Fuel	Alaska	
						Diesel	Alaska	
						Fuel oil	Export	
						Asphalt	Alaska	
						Propane	Alaska	
						Sulfur	Lower '48	
						Residual	Lower '48, export	
Chevron	Nikiski	1963	Crude oil	18,000 b/d	Initially no, later yes	Naptha	Lower 48	Closed in 1991
						Jet fuel	Alaska	
						Diesel	Alaska	
						Fuel oil	Lower '48	
						Asphalt	Alaska	
Conoco-Phillips-Marathon	Nikiski	1969	Natural gas	235,000 Mcf/d	No	Liquefied Natural Gas	Japan	Operating
Agrium (Unocal/Collier)	Nikiski	1969	Natural gas	160,000 Mcf/d	No	Ammonia	Export	Operating below capacity
						Urea		

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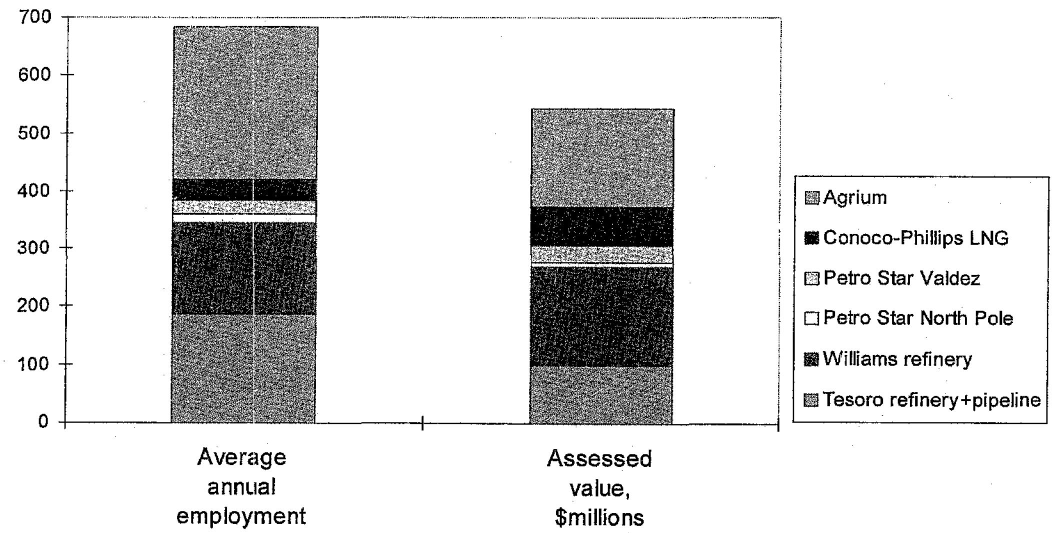
Figure 5 illustrates the magnitude of the benefits to the Alaska regional economy generated by the facilities listed in Table 1. In 2003, the six major facilities employed 685 workers on an average annual basis. Agrium was the largest employer, with nearly 40 percent of the total, followed by Tesoro. The jobs generate a payroll of roughly $550 million annually (precise figures are considered proprietary). The contribution that these facilities make to the local property tax base is about equal to the annual payroll. Alaska has no state property tax for oil and gas processing facilities, but all these facilities are located in local governments -- the Kenai Peninsula Borough, the Fairbanks North Star Borough, and the city of Valdez -- that levy property taxes to support schools and other local government activities. Tax rates vary by jurisdiction, but these capital-intensive plants have probably allowed the boroughs to reduce their overall tax rates somewhat.

Figure 5. Employment and Assessed Value in Alaska Oil and Gas Processing, 2003



Sources: Employment: Alaska Department of Labor, Research and Analysis; Property Tax Assessments: Kenai Peninsula Borough, Fairbanks North Star Borough, City of Valdez Assossors

The economic benefits that Figure 5 summarizes leave out information for the two small North Slope, built by Arco Alaska (now Conoco-Phillips) to serve oilfield operations. Figures for employment and assessed value for these refineries are relatively small and not separately reported from those of the oil production operations.

Facilities proposed but not constructed

Table 2 summarizes Alaska oil and gas transportation and processing facilities that were proposed, and supported by royalty-in-kind disposals, but never constructed. All three were massive undertakings conceived during the national energy crisis in the late 1970s. None of the three could meet a market test after oil and gas wellhead prices were deregulated in the early 1980s.

Alaska Petrochemical Company (Alpetco) was the winning bidder in the first solicitation for offers to purchase royalty-in-kind oil from Prudhoe Bay. Alpetco, a partnership of Alaska Interstate (later Enstar) (60%), Alaska Consolidated Shipping (itself a consortium of Native corporations and Seatrain) (20%), and Barbour Oil (20%), proposed to build a world-scale oil-based petrochemical plant (see Table 2). The plant, to be located at tidewater in Southcentral Alaska, would produce up to 2.1 million pounds per year of polyethylene, polypropylene, styrene and similar products. It would cost an estimated $1.5 billion to build, and require an additional $400 million of working capital, ultimately generating a $2.3 billion tax base. Construction would require 3,500 to 4,000 temporary workers, while operations would generate 2,000 permanent jobs (Alaska Petrochemical Company, 1977). In 1978, the state agreed to sell up to 150 thousand barrels per day (Mb/d) of royalty oil for 27 years to support the project. After review by the ROGDAB, the legislature approved the contract, with minor amendments (Haynes, 1983).

Table 2. Proposed Alaska Oil and Gas Facilities Not Constructed, Receiving Royalty-In-Kind Contracts or Options

Owner	Location	Start	Feedstock	Capacity	Royalty-in-kind	Products	Destination
El Paso Natural Gas	Prudhoe Bay to Valdez	1978	Natural gas	2 billion cf/d	Option, not exercised	Liquefied Natural Gas	Lower '48
Alaska Oil Co. (Alpetco)	Valdez	1977	Crude oil	150,000 b/d	Yes, renegotiated	Polyethylene	Lower '48, export
						Polypropylene	Lower '48, export
						Styrene	Lower '48, export
Alpetco	Valdez	1980	Crude oil	100,000 b/d	Yes, terminated	Naptha	Lower '48, export
						Olefins	Lower '48, export
Dow-Shell	Valdez	1982	Natural gas liquids	210,000 b/d	Option, not exercised	Ethylene	Lower '48, export
						Polyethylene	Lower '48, export
						Ethylene glycol	Lower '48, export

In early 1980, U.S. oil markets were deregulated, rapidly changing the market outlook for Alaska oil. That May, the parties agreed to Alpetco's request to amend the contract to construct. By then, the project's sponsor had changed to the Alaska Oil Company, whose major partner was Charter Oil, a Caribbean refiner. Alpetco's new partnership proposed a 100 Mb/d refinery in Valdez to produce Naptha and Olefins for further processing elsewhere. Alpetco would receive 75 Mb/d beginning July 18, 1980, until the refinery was operational. At that point, the volume would rise to 100 Mb/d. The market outlook continued to deteriorate for Alpetco's project. One year later, the company abandoned the refinery project, and its contract was terminated in January 1982.

As mentioned above, the state entered into a contract to sell Prudhoe Bay royalty gas to a consortium including El Paso pipeline, the sponsor of the All-Alaska gas pipeline project. When the federal government selected the Alaska Natural Gas

Transportation System (ANGTS) as the preferred route for the project, a second proposal emerged for a natural gas liquids (NGL) pipeline following the route El Paso had proposed. After reviewing proposals from several contenders, the state selected a consortium headed by Dow Chemical and calling itself the Dow-Shell Group to perform a detailed feasibility study of the project. As outlined by the proposers, the project would manufacture 210 Mb/d of ethane and liquified petroleum gasses (LPG) -- propane, butane, etc. -- into petrochemicals for export (Dow-Shell Group, 1980; 1981). The project entailed a complex of four interrelated facilities costing roughly $7 billion, including:

1. a $1 billion plant on the North Slope to extract NGLs from produced gas;
2. a 20" pipeline from Prudhoe Bay to Valdez or Cook Inlet, costing $2.3 billion;
3. a $175 million fractionation plant to separate ethane from the LPGs;
4. a petrochemical plant using 90Mb/d of ethane feedstock, costing $3.5 billion.

The petrochemical infrastructure would develop in two phases. In phase 1, the plant would have the capacity to produce up to 4 million lbs/year of ethylene, polyethylene, and ethylene glycol. In phase 2, capacity would expand to produce another 3.5 million pounds of derivative products. Peak construction employment would top 11,000, while 3,500 permanent workers would be needed for operations in phase 1, and 6,800 in phase 2.

In addition to a commitment from the state to sell its entire royalty share of NGLs, Dow-Shell had obtained a right of first refusal from Arco, and an agreement to negotiate in good faith with Sohio. Exxon, the other major North Slope owner, refused to negotiate with Dow-Shell, and instead pursued its own feasibility study. Dow-Shell's (1981) detailed feasibility study concluded that crude oil prices would have to remain at $38 (in 1981 prices) to make the NGL pipeline feasible. Shortly after releasing the feasibility study, world oil prices started to decline. Dow-Shell backed out of the project in 1982, citing adverse market trends.

The first North Slope royalty-in-kind solicitations and the Alpetco and Dow-Shell bids spawned much debate among Alaskans about whether petrochemical development at this scale was appropriate for the state. Although no royalty hydrocarbons ever made their way into a petrochemical product, the official deliberations created a litany of engineering and market feasibility studies. Mostly funded by the state, the state's urgent need to understand the parameters and implications of the industry spread a windfall to engineering firms and other consultants in the state and around the nation.

Since the Alpetco-Dow-Shell episode, state officials have been more cautious about approving royalty oil and gas sales other than for in-state refining. Several gas and NGL offers have been made in recent years. Agrium requested Cook Inlet royalty gas at a low price, but the state balked with other gas purchasers objected. Williams once expressed interest in buying North Slope NGLs for a petrochemical plant, but backed out before making a formal offer when it determined that transportation costs made it infeasible to ship ethylene or polyethylene to the Japanese market.[8] The state continues to get expressions of interest, some more credible than others. The state has not kept a comprehensive record of denied requests. According to Kevin Banks, manager of the

[8]The state has also recently tried to use its royalty gas a leverage to shape the course of negotiations over a North Slope natural gas pipeline. Anadarko and Encana were awarded contract for the option to take up to 70% of the state's North Slope gas royalty share, giving them a right to claim capacity of a common pipeline carrier. The idea was to force the main North Slope producers to increase the design capacity of the pipeline to encourage gas exploration.

program for DNR, most smaller traders lose interest as soon as they see the bureaucratic process involved in obtaining a best-interest finding that is required to complete a sale (Kevin Banks, personal communication, 8/05/04).

How much did RIK disposals cost the state?

By statute, the state must earn at least as much from a royalty-in-kind disposal as it would earn if the oil had been taken in-value: the default method. No one has ever challenged a sale on the grounds that it failed to achieve this statutory requirement. So leaving aside the administrative cost of the analyses leading to the requisite best-interest findings, one could argue that the burden or proof would be on detractors to prove that the program has cost the state anything at all. In truth, however, the question is not so easy to answer.

Most royalty-in-kind disposals involved contracts with a pricing provision that specifies that the purchaser will pay the royalty-in-value price, or a slight premium above it. While this should in principle have guaranteed that the state not lose money on RIK sales, the state and producers have been in litigation over some aspect or another of in-value royalty accounting for more than 25 years (the so-called Amerada-Hess case). Various aspects of the lawsuit have been settled out of court, but not until years had passed from the royalty sales. Limitations of contracts and the passage time have made it difficult if not impossible for the state to collect from all past royalty purchasers when it receives retroactive payments from producers in an in-value settlement. The state must negotiate a separate settlement for each contract (assuming that the firm that held the contract is still in business). The price in the most recent contract with Williams (Flint Hills) is not directly tied to the in-value price. A full and accurate retrospective accounting of the RIK program would be a monumental undertaking.[9]

Arguably, however, the correct test should not be based on in-value prices but on whether the state *expected* to receive at least as much over the long term from its RIK sales as it could have *expected* to have received from the *best opportunity available at the time*. Unfortunately, there are also many reasons why the comparison of expected sales receipts to the opportunity cost would be difficult to make over the years. Why this might be true will become clearer after a brief historical review of the supply and demand for Alaska's oil, natural gas, and manufactured hydrocarbon products.

First of all, most RIK disposals are long-term contracts. Available market indicators for oil and gas reflect short-term, or spot prices. The spot market is extremely volatile, and often diverges substantially from long-term conditions. The outcomes of the state's few competitive short-term disposals illustrate the difficulty of comparing the two markets at any given time.

As illustrated in Figures 3 and 4, the state sold about 6 percent of its oil in competitive sales, totaling about 50 million barrels. In the first North Slope competitive sale, held in 1981 at a time when the state believed that the in-value price was below the true market value, the average premium of winning bidders was $2.57 above in-value. All purchasers in this contract ended up losing money. When it came time to start taking the oil several months later, prices had slid, sending one firm into bankruptcy and causing another to default (Haynes, 1982). Over the life of the one-year contracts, I estimate that the state had received less than $1.82 on average above in-value, not

[9]DNR staff did at one time attempt to construct a retrospective analysis of in-kind vs. in-value sales prices for royalty oil. However, this analysis was never published, due to doubts among agency staff about its accuracy (Kevin Banks, personal communication).

counting substantial legal costs to settle with the largest purchaser. Desiring to avoid repeating this experience in the next competitive sale (1985), the state allowed purchasers an option of early termination. Only three of seven contracts in that sale lasted the full year. The state also offered up to 4,000 barrels a day in competitive sales of Cook Inlet oil for export, beginning in 1987, with a Taiwanese company picking up the contract. In 1991 after the eruption of Mt. Redoubt temporarily shut down operations at the Cook Inlet westside oil terminal, the company claimed *force majeure* and backed out of the contract.

Second, both spot and long-term markets for Alaska oil have been replete with market distortions, causing the value of Alaska oil to diverge from what free, competitive markets would signal. These distortions arose from federal and state regulation, combined with imperfect competition. Between 1974 and 1980, the federal government controlled wellhead oil prices throughout the nation. Cook Inlet and North Slope oil had different regulatory status and traded at very different prices.[10] When Congress authorized TAPS in 1973, it prohibited exports of Alaska oil. This created a surplus of oil on the U.S. west coast, which kept prices for Alaska oil from rising as fast after deregulation as they did elsewhere. Shipping between U.S. ports was subject to the Merchant Marine Act of 1920 (Jones Act), which required that products move in U.S.-built tankers operated by U.S. crews. This increased shipping costs substantially and further depressed Alaska wellhead prices.

The major Alaska oil producers enjoyed significant market power in west-coast markets. Rather than engage in arms-length sales that might reveal the profitability of their Alaska production, these firms sold most of their Alaska oil to their own refineries at artificial transfer prices. One way that they used their market power was to divert some oil through the Panama Canal to the U.S. gulf coast at an apparent loss, in order to relieve downward pressure on west-coast prices. Alpetco had proposed its refining and petrochemical project in the midst of these distortions. Refined products, unlike crude oil, could be exported in foreign vessels at unregulated competitive prices. Export refinery economics were therefore based on a series of market distortions created by the combination of the export ban on crude oil, the resulting west-coast surplus, the lack of transparency in netback prices, and the ability to avoid the Jones Act. When just one of these pillars of this structure gave way -- wellhead price regulation -- the project was revealed to be uneconomic, and started to unravel.

Still another regulatory artifact affecting in-value in oil prices and the value of RIK oil relates to price adjustments for oil of differing characteristics. TAPS ships oil commingled from several different fields with varying chemical properties. Fields producing lower quality oil pay a fee into a Quality Bank, which pays out to fields producing higher quality oil. Alaska refineries at North Pole and Valdez also pay into the Quality Bank when they discharge their residual oil back into TAPS. The Quality Bank charges, like other aspects of royalty pricing, reflect a legal settlement that mediates conflicting interests over a variety of issues. The state obtained a Quality Bank settlement that favored the TAPS refineries, to the displeasure of the refineries' main competitor: Tesoro.

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[10] In 1980, when Congress deregulated oil prices, it passed the Windfall Profits Tax. This tax had a variable rate depending on the previous regulatory status of the oil. Cook Inlet oil was taxed at the highest rate (90% of the difference between the market and the previous regulated price). State royalty oil was exempt from taxation. The tax phased out when the oil market collapsed in 1986.

The history of Alaska natural gas markets is likewise convoluted. Cook Inlet gas was mostly developed during the era of wellhead price regulation. Under wellhead price regulation, consumer prices were based on historical cost, without reference to current supply and demand conditions. During the late 1970s, this practice resulted in acute gas shortages in lower '48 states, leading to passage in 1978 of the Natural Gas Policy Act (NGPA). NGPA further extended regulation to allocate gas to preferential uses. Alaska won an exemption from some aspects of NGPA, allowing it to continue process natural gas into fertilizer and LNG for export, as well as burn gas to generate electric power, as these activities were being curtailed elsewhere in the nation. It was in this environment that the NGL-based petrochemical project appeared. Petrochemicals manufactured from NGLs were exempt from price regulation. If exported, they could also avoid the Jones Act shipping cost penalty. The phased deregulation of natural gas in the 1980s began shifting U.S. natural gas supplies toward higher-valued uses. Concurrently, Dow-Shell lost interest in its Alaska petrochemical project.

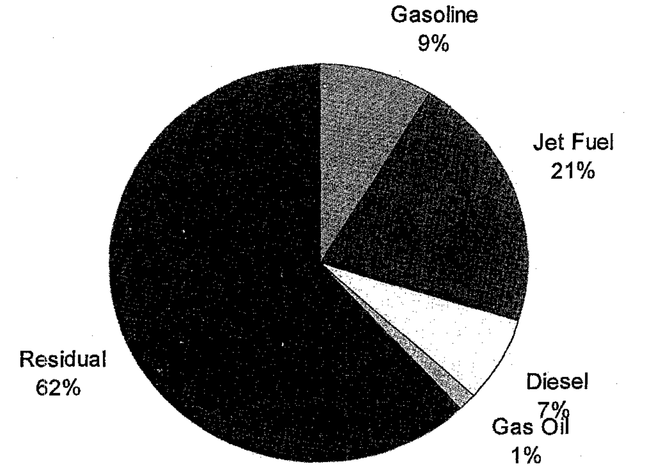
These array of distortions in oil and gas markets make it extremely difficult to determine ex-post whether the state's expected revenues from RIK sales matched or exceeded the expected revenues from the best alternative option. It would have been impossible to expect that the state could have made this determination at the time. It remains unclear that the program made any significant difference in the royalty revenues that would otherwise have been received. The slight premium over in-value prices must be balanced against the cost of administration, especially in dealing with the failed contracts.

Role of RIK contracts

If the net cost of the program was small, one must ask, then, whether the program produced any significant economic benefits for the state and for society? If so, were the RIK contracts important to the success of projects that generated these benefits? Arguably, the wages and taxes paid were just reallocations of economic activity and did not consist of true benefits. Alaska is an open economy, with net migration balancing labor markets relatively quickly. Workers constructing and operating Alaska oil and gas processing plants probably would not have moved to Alaska if these plants had not been built. Once here, they need more local government services which the larger tax base can provide. The local economy is larger, but economic well-being has improved relatively little.

What about benefits to Alaska consumers from import substitution? Figure 6 shows the approximate distribution of products produced. These percentages varied over time depending on market conditions, and the exact distribution at any given time is proprietary. However, the figure gives a snapshot of the approximate product mix. The largest share of production is residual oil, which is all exported from the state into competitive world markets. Three products -- jet fuel, gasoline, and number 2 diesel -- dominate the output of Alaska refineries marketed within the state.

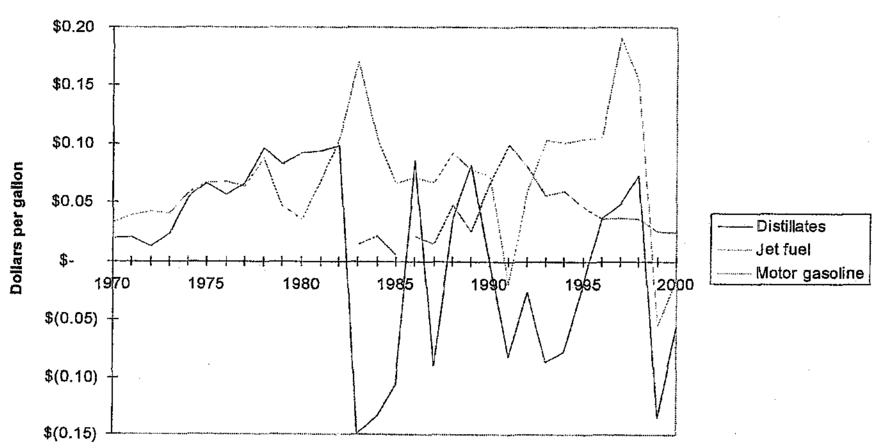
Figure 6. Approximate Alaska Refinery Product Percentages



Source: estimated from Alaska Division of Oil and Gas Annual Reports and data provide by the refining companies

Figure 7 compares price differentials over time calculated from EIA data for distillate fuels (diesel), jet fuel, and motor gasoline. The five to ten-cent premium in the 1970s largely reflects the transportation cost differential. After 1980, competition between Mapco and Tesoro appears to have periodically given Alaska consumers substantial diesel price savings of up to $0.20 per gallon. Substantial gasoline price savings also appeared in 1991 and again after 1998. Jet fuel prices have also been drifting down since 1991, at a time when Alaska refineries have continued to raise jet fuel production, suggesting a benefit from competition of a few cents per gallon. The price differentials in Figure 7 show no huge savings, but do suggest that Alaska consumers and businesses have benefited measurably from the competition among Alaska refineries.

Figure 7. Alaska-Washington Price Differentials for Selected Petroleum Products, 1970-2000



Source: EIA, total energy consumption, transportation sector

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If RIK contracts did not involve a subsidy, then were they really needed for the success of the projects they supported? Royalty-in-kind contracts at fair market value provided three direct benefits to the purchasers. First, the long-term contracts provided an element of security from the volatility of spot oil markets. Large integrated oil producers enjoyed this advantage, and the state's contracts helped level the playing field for independent refiners like Tesoro and Mapco. The security from spot market fluctuations played a significant role in financing refinery expansion. For example, in 1992, Petro Star obtained an option to buy RIK oil to start a refinery in Valdez. After it was able to obtain financing, the company decided it did not need the oil, and elected not to exercise its option (Alaska Division of Oil and Gas, 2004L 5-2). A second, related advantage that the contracts provide independent refiners is the diversification of supplies, in particular, a source outside major oil company control. The major North Slope producers may be perceived to have a vested interest in restraining competition in the west Coast market, which includes Alaska. Once it was clear that the new refineries were going to be built, the producers appeared to have been willing to sell them oil at competitive prices.

If RIK contracts have these advantages, then why has the state not elected to take more of their oil and gas in-kind? In general, according to DNR staff, the refiners have not asked for more oil. They pay a slight premium for long-term contract, and appear comfortable with buying the rest of their needs from the producers (Kevin Banks, personal communication).

Conclusions: Lessons Learned

Alaska's royalty-in-kind program has fostered the development of a local refining industry. The refining plants have employed relatively few workers but contributed significantly to local tax bases. Competition from Alaska refiners appears to have provided benefits to Alaska consumers and businesses. Instate refining has not only made a direct value-added contribution to the economy, it presumably has made an indirect contribution to diversification by substituting instate-manufactured fuel for imported fuel with at least some reduction in price. Since many important Alaska industries are fuel-intensive, any reduction at all in their fuel costs is potentially significant.

Political pressure to give away the state's resources to project sponsors promising economic benefits has been muted by the state's dependence on royalty revenues. The constitutional amendment that created the Permanent Fund requires that at least 25 percent of royalty revenue be deposited into the fund. The distribution of Permanent Fund Dividends to residents ensures that citizens, not just politicians, have a direct stake in the tradeoff between development and revenues. The Permanent Fund Dividend effect will likely protect the transparency that the program has enjoyed since the 1974 legislative amendments.

The successes and failures of the program suggest four lessons for development policy for Alaska and elsewhere. The first lesson is an affirmation of the benefits of transparency. A bad proposal is likely to wither under public scrutiny. Alaska was very fortunate to have avoided the potential economic disaster that would have occurred if it had embarked on either of the massive proposed petrochemical development schemes. Because cautious state officials had built milestones that Alpetco and Dow-Shell had to meet before they received additional help, both companies withdrew from their contracts early before they could inflict serious losses on the state.

The second lesson is that projects that rely on free market forces are more likely to succeed in the long run than projects built around regulatory policies or economic distortions. Market distortions are inherently arbitrary and ephemeral. They can change rapidly due to factors unrelated to Alaska conditions or to global supply and demand. The political risk of relying on these incentives only compounds the inherent economic risks that all projects face.

A third lesson to draw from Alaska's RIK program is that import substitution is as effective as exports for providing economic benefits. In some cases, import substitution can be preferable, as in the case of Alaska fuels, where it might reduce the cost of a critical imported input to a broad range of industrial activities.

The final lesson is that projects that can start at a small scale and expand gradually over time are more likely to succeed than ones that require a huge, risky up-front investment. Alaska's main refineries all started relatively small, and have made a series of upgrades over the years to keep pace with market opportunities. Today, the combined capacities of the two largest refineries substantially exceed the proposed size of Alpetco's export refinery. But unlike Alpetco, which had to raise $1.5 billion at one time, Tesoro and Mapco and its successors had two decades over which to raise a comparable sum.

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