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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 less than 5 million in November 1982, without suffering a fiscal or foreign-exchange crisis. Throughout the 1970s, therefore, Saudi Arabia, with or without the cooperation of other OPEC nations, had much of the wherewithal to stabilize the market in 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 1970s 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.[15] Although the organization had no enforcement machinery, and did not even attempt a prorationing scheme until 1982, its members did reduce production when preservation of the price gains of 1974 and 1979 required it.

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

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

Thus, a short-lived belief in acute scarcity twice created a real scarcity that caused spot prices to soar. A belief that chronic energy shortages would engender a permanent seller's market then led producers and consumers alike to interpret an unusual and otherwise transitory market phenomenon as obedience to holy writ. The self-fulfilling doctrine that oil in the ground was the world's best investment not only encouraged OPEC officially to adopt spot market prices generated by consumer panic; it also enabled those prices to stick. In 1973-74, the world price of crude oil (measured at the Persian Gulf) increased fivefold 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 1970s 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 27 percent in October 1982, and Saudi Arabia's share is already less than the share Texas held as late as the mid-1960s.

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 6 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 that 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 over 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 1970s, 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 1970s, 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 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 U.S. oil consumption was first visible in 1979; the rest of the industrialized world followed a year later. In retrospect, it is remarkable how many were unable to see what was happening.

Exxon in 1977 forecast that U.S. 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 (IPAA) 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 IPAA 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.*[16]

The drop in total oil use over the last 3 years and the experts' tardiness in recognizing the trend of consumption stems from profound changes in the structure of world energy demand that 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 13-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

1970s. 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 housing 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 any large-scale oil-fired boilers of any sort, have been built since the mid-1970s; 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 [illegible] to changed energy-supply conditions also [illegible] that the all-time high oil prices of 1974-1982 [illegible]uence consumption patterns for many more years, *even if world oil prices now fall as rapidly and as far as they rose in the 1970s*.

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 cannot 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 everywhere in 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-1970s. 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.[17] 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. In August, the Saudis, who had already reduced their own output by 45 percent in the hope of supporting the $34 marker price, were also hinting that they would raise their own output if the cheating did not stop.[18]

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 nonmembers—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 turn-around from the situation of 1975. Since 1973, OPEC 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 do not have an immediate cash-flow or foreign-exchange deficit. In the 1980s, 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, cannot 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 noncommunist 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 2 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 the 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 its 1978 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 the 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 at 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 1970s 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 extreme 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 a 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 described above—increase once more. But an oil 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 tranquility of the TRC era and beyond, there are several lessons for the future.

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

The earth'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 artificially-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 long sustained, 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). Except in a small corner of the United States, these low oil prices virtually swept coal from the world's markets for industrial boiler fuels and organic-chemical feedstocks. At the same time, however, the prices were 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 rapidly increase or curtail production in a handful of economically underdeveloped and politically turbulent countries.

The problem, therefore, was not a permanent worldwide scarcity of "cheap" oil. Instead, it was 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 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 area 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 Louisiana, 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 requires and requires 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 sizable *increase in effective oil supply or a sizable 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, through *underpricing*, destroyed 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, through *overpricing*, destroyed 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 U.S. Strategic Petroleum Reserve. However, even if one of them maneuvers itself into the right strategic spot in the world market, 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 advantage 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 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 prices sharply fluctuating farther 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. deBruyne, summarized the new outlook well when he wrote that "we are in for a period of severe and unpredictable discontinuities."[19] 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

[1] None of the several recent price forecasts I have seen, prepared for internal use by major petroleum producers (corporations or governmental), 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 1988. 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 2 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 expectations 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 U.S. Petroleum Reserves: Exploding the Myths" in Salomon Brothers, Inc. Stock Research/Industry Analysis, October 15, 1982.)

The change in the energy market did not take everyone by surprise. For early warnings in Alaska or from Alaskans about the impending turndown in oil prices and state revenues, see my remarks in the minutes of the U.S. Department of Commerce Economic Advisory Board during 1979 and 1980; also 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, "Alpeteo'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).

[2]Alaska Department of Revenue, Division of Petroleum Revenue, *Petroleum Production Revenue Forecast* (Quarterly, Anchorage: June 1980 through September 1982). 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.

[3]Alaska Department of Revenue, Division of Petroleum Revenue, *Petroleum Production Revenue Forecast*, March 1982, p. 5.

[4]Charles Logsdon, Chief Petroleum Economist, Alaska Department of Revenue, personal communication to G.K. Erickson, July 16, 1982. When the Department of Revenue reduced the figures in each of the series of forecasts that corresponded to a specific confidence level, greater attention to the uncertainty of petroleum price forecasts led the department to emphasize its "30-percent" rather than its "50-percent" series. The different percentage figures indicate the Department's judgment about the probability that actual revenues will be *less* than the figure shown.

[5]"OPEC Will Survive," Oilman Hammer Says," Associated Press story in *Seattle Post Intelligencer*, July 12, 1982, p. B8.

[6]Acres American, Inc. (the principal contractor on the feasibility study for the Susitna River hydroelectric project) offered the following list of "major forecasts of oil price trends" in order to refute forecasts of declining oil prices in another ISER report (A.R. Tussing and G.K. Erickson, *Alaska Energy Planning Studies: A review of three consultant studies submitted to Alaska state agencies in fiscal year 1982*. Anchorage: ISER, Final report November 1, 1982):

Source	Date of Forecast	Forecast Trend (%)
Data Resources, Inc.	Summer 1982	+2.6
Int'nl Energy Agency	Spring 1982	−0.5 to +2.0
U.S. DOE Energy Info Adm.	Spring 1982	above +3.0
Canada: Energy Mines & Res.	Summer 1982	+1.7
Ontario Hydro	Spring 1982	+1.5
Energy Modeling Forum Avg. 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 projections cited, it is representative of the kind of forecasting institutions that Acres polled, even in late 1982. Significantly, however, this list does not contain a single petroleum-producing company, financial institution, or agency of an oil-*exporting* political entity (see note 1), while four (half) of the forecasts cited 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.

The published forecasts of government agencies and the big consulting firms indeed 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.

[7]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. 33-87, and Stephen L. McDonald, *Petroleum Conservation in the United States: An Economic Analysis* (Baltimore: The Johns Hopkins University Press, 1971), pp. 29-55.

[8]From the July 1882 *Scientific 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.

[9]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.

[10]Lovejoy and Homan, *Economic Aspects . . .*, pp. 265-295, and the Cabinet Task Force on Oil Import Control, *The Oil Import Question* (Washington: U.S. Government Printing Office, 1970), pp. 24, 121, 216, 242-246.

[11]Adelman, *. . . World Petroleum . . .* For a history of oil prices during the entire era, see pp. 131-191.

[12]M.A. Adelman, "Coping with Supply Insecurity," *The Energy Journal*, October 1982, pp. 1-16.

[13]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, pp. xvii-xviii.

[14]Estimated proved reserves as of January 1, 1982, can be found in Robert J. Enright, "Worldwide Report," *Oil and Gas Journal*, December 28, 1981, p. 66. 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 U.S. Ambassador to Saudi Arabia, told Senator Mike Gravel and me that Saudi Arabia's reserves were "realistically" at least 300 billion barrels and "probably closer to a trillion." At a Central Intelligence Agency briefing I 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.

[15]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. 10):

> 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 Third World governments. This approach ignores the *ideological* content of national policy. 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 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 built on something more substantial than simple opportunism.

My remarks at the same 1975 conference (A.R. Tussing, discussant comments on speeches by Nuel "J.O." Pertoe, Secretary-General of OPEC; Amuzegar; T.O. Enders, U.S. Assistant Secretary of State for Economic Affairs; Adelman; and P.T. Frankel, Director of Petroleum Economics, Ltd., *Topical Problems*, pp. 41-44) 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[16], 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).

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.

[16]As late as September 1980, it was possible for Cambridge economist Nicholas Kaldor to write seriously that, "... OPEC changed everything. By cornering oil it managed to increase the price fourfold, then double it again, and presumably it could be doubled again, *without any really serious impact on consumption*." (Emphasis added. From "The Energy Issues" in T. Barker and V. Brailovsky, *Oil or Industry*: edited proceedings of 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).

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

[18]"Oil Nation Warns its Partners," Associated Press story in the Seattle *Post-Intelligencer*, July 6, 1982, p. B9. On Saudi Arabia's threats, see *Platt's Oilgram*, July 13, 1982, p. 1A.

[19]D. deBruyne, quoted in *Petroleum Intelligence Weekly*, June 14, 1982, p. 6.

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June '79

ASSUMPTIONS

North Slope Oil Prices

On December 17, 1978, OPEC announced from Abu Dhabi that the price of Arabian light crude oil would escalate from $12.70 to $14.54 per barrel by October 1, 1979, an increase of 14.5 percent. The price of oil was increased to $13.33 on January 1, 1979 (an increase of 5 percent over $12.70). However, shortly after the December announcement that OPEC members were increasing their official prices an average of 10 percent during calendar year 1979, a political revolution in Iran eliminated crude exports from that country. The international crude market lost about 5 million barrels a day and spot prices for crude oil soared to as much as $31 a barrel - over twice the official base price. As a consequence of this event, an extraordinary price fixing meeting of the OPEC countries was held in Geneva on March 26 to set prices more in line with spot market levels. At that meeting the base price of Arabian light crude oil was raised to $14.54 per barrel. An increase that was not to have taken effect until October 1, 1979. Since this historic meeting, spot market prices have continued to increase and OPEC is once again expected to significantly raise the base price of its benchmark crude oil when it convenes in Geneva later this month. In this forecast, we are assuming an 11 percent weighted average OPEC price increase for FY 1980 when compared to our March 1979 forecast. In addition, we have assumed an end to the discounting of Alaskan North Slope crude on the West and Gulf coasts.

Weighted average OPEC prices increase over the 17-year forecast period from $12.94 in FY 1979 to $44.78 by FY 1995; roughly a 7.5 percent average per annum increase. Weighted average wellhead values for oil royalty calculations for Prudhoe Bay range from a low of $5.17/B in FY 1979 to a high of $32.95/B in FY 1995. The weighted average annual wellhead values for royalty calculations for FY 1979-FY 1985, given the assumptions made in this forecast, are roughly: $5.17, $8.91, $10.87, $12.99, $14.87, $16.84, and $18.30. Weighted average wellhead values for oil royalty calculations are net of field cost deductions. Field costs are not deducted from wellhead values for purposes of severance tax calculations.

TAPS tariffs in this 17-year forecast were based on a number of scenarios for the estimated gross revenue requirements of the pipeline companies. In the majority of cases it was assumed that the TAPS owner companies would receive the rate base and rate of return which they requested in testimony before FERC.

Tanker tariffs and refinery market delivery forecasts were based on data supplied by the Petroleum Audit Supervisor's office, journal articles, company studies and various studies done by government and private agencies. Tanker tariff scenarios were inflated on the average at

roughly 4 percent per annum due to the capital intensive structure of tanker operations. Market first sales in the March 1979 forecast were assumed to reflect the average of the first sales including July 1978 through December 1978. West Coast first sales (including Alaska) averaged approximately 786,000 B/D and Gulf/East Coast (Trans-Panama) first sales averaged around 403,000 B/D over this period. More recently in FY 1979 (October 1978 through March 1979), West Coast first sales have averaged around 814,000 B/D and Gulf/East Coast first sales 389,000 B/D. West Coast first sales in this forecast were assumed to average only 770,000 B/D. The remaining throughput was assumed to be delivered through the Panama Canal until the Northern Tier line becomes operational. It was assumed that the Northern Tier line would be operational at 700,000 B/D by the third quarter of FY 1982. The Northern Tier line was given a 50 percent chance of being built and it was further assumed that no deliveries to Japan would be made. The Long Beach to Texas pipeline (PACTEX) was not included in this forecast due to Sohio's recent announcement that it was abandoning the project.

North Slope Gas Prices

Under the interim rules of the Natural Gas Policy Act of 1978, the ceiling price of Prudhoe Bay gas as of December 1, 1978 is $1.63 per MMBTU. Given 1.092 MMBTU per Mcf, Prudhoe Bay gas will realize a field value of $1.78 per Mcf. Assuming 6 percent inflation per annum, Prudhoe gas should command $2.52 per Mcf by FY 1985--the earliest date that we are forecasting throughput along the Alcan. FERC recently ruled that conditioning costs to remove the carbon dioxide and natural gas liquids and to compress and chill the gas should be deducted from the ceiling price that producers receive for the gas. Assuming conditioning costs of $1.21 per Mcf in 1985 dollars, the weighted average wellhead value of Prudhoe Bay gas (after deducting conditioning costs) by FY 1985 was assumed to be about $1.31 per Mcf. However, allowances were made in the pricing scenarios for the possibility that the costs of conditioning could be shared by the producers and pipeline companies or that either could end up bearing the full cost burden.

North Slope Oil Production

Multiple well and production scenarios for oil and gas were developed from forecasts furnished by the producing companies and the Division of Oil and Gas Conservation. Simulation run number 3A of the Division of Oil and Gas Conservation served as the baseline case for the throughput and well scenarios. Weighted average North Slope oil production was predicted to increase from a low of 1.184 MMB/D in FY 1979 to a high of 1.540 MMB/D for FY 1986-1989 and then to decrease to .705 MMB/D by FY 1995. North Slope production other than Sadlerochit was assumed to begin in FY 1982-1995. TAPS throughput was not expected to exceed the current 1.23 MMB/D capacity until the third quarter of FY 1980. Weighted average volumes for the next five years, beginning with FY 1979, were assumed to be 1.18 MMB/D, 1.26 MMB/D, 1.35 MMB/D, 1.43 MMB/D and 1.5 MMB/D respectively.

ASSUMPTIONS Sep '79

North Slope Oil Prices

World petroleum market developments during the first three quarters of 1979 have proven to be extremely difficult to forecast. Fears of world crude oil shortages estimated to be from 2 to 5 million barrels per day resulted in near panic buying. The resulting market disorder forced OPEC ministers to meet in extraordinary session twice, once in March 1979 when the official OPEC marker crude price was raised to $14.54/B and again late in June 1979 when the OPEC marker crude price was upped to $18.00/B. Even after these cumulative price increases, which equalled approximately 47 percent for Saudi Arabian Light crude oil (and over 60 percent for other OPEC producers), world demand remained high. Fears were that only minimal amounts of crude oil at "official prices" would be available to refining companies and countries without guaranteed sources of crude oil. For example, U.S. Gulf Coast refiners saw the "official" FOB price of Mexican crude oil rise 72.5 percent from $13.10/B to $22.60/B in six-months time. When petroleum buyers were forced to buy crude on the open market they also found that spot market crude oil prices were even higher (some shipments were quoted in the $35.00/B range on the Gulf Coast). In this kind of market, given the wide range of prices (official versus spot) and differences in specific company transfer pricing practices (sales to affiliated parties versus sales to third parties), it is not surprising that declared, pre-audit destination sales prices for Prudhoe Bay type crude oil are difficult to forecast. In this forecast we assume that no further increases will be announced by OPEC until December 1979. However, due to the decline of the dollar and due to Saudi Arabia's relatively low market prices for crude oil in the face of growing economic pressure to increase that price, it has been assumed that the OPEC marker price will be raised 8 percent effective January 1, 1980. After this point more moderate quarterly increases are projected as OPEC moves to maintain the real dollar price of its crude oil.

Given these conditions, it is assumed that weighted average OPEC prices over the 17-year forecast period will rise from $12.91 in FY 1979 to $18.37/B in FY 1980 to $51.32 by FY 1995--roughly a 9.0 percent average per annum increase. Weighted average wellhead values for oil royalty calculations for Prudhoe Bay range from a low of $5.22/B in FY 1979 to a high of $32.95/B in FY 1995. The weighted average annual wellhead values for royalty calculations for FY 1979-FY 1985, given the assumptions made in this forecast, are roughly: $5.22, $12.05, $15.02, $17.62, $19.70, $22.00, and $23.82. These weighted-average wellhead values for oil royalty calculations are, however, net of field cost deductions. On the other hand, field costs are not deducted from wellhead values for purposes of severance tax calculations.

Projections of TAPS tariffs, as a component of transportation costs, in this 17-year forecast were based on a number of scenarios for the estimated gross revenue requirements of the pipeline companies. In the majority of those scenarios it was assumed that the TAPS owner companies would receive the rate base and rate of return which they requested in testimony before FERC.

Tanker tariffs and refinery market delivery forecasts were based on data supplied by the Petroleum Audit Supervisor's office, journal articles, company studies and various studies done by government and private agencies. Tanker tariff scenarios were inflated on the average at roughly 4 percent per annum due to the capital intensive structure of tanker operations. Market sales by destination in the September 1979 forecast were adjusted to reflect the average first sales reported during the first six months of 1979. During this time roughly 850,000 B/D were delivered to the West Coast (including Alaska and Hawaii) while Gulf/East Coast (Trans-Panama) and four Corners Pipeline deliveries were approximately 340,000 B/D. These actual West Coast shipments were 10 percent above earlier estimates of the ability of West Coast refiners to absorb Prudhoe Bay type crude oil. Undoubtedly, the world crude oil supply crisis during the Iranian crisis period led to increased buyer interest in Alaskan oil. For this reason, peak West Coast sales may decline somewhat from the levels reached during the last several months should world crude oil shortages begin to slacken. This has been allowed for in the current forecast. Until the third quarter of 1982 it is assumed that Prudhoe Bay crude surpluses will be shipped through the Panama Canal and four Corners Pipeline to Texas, Gulf/East Coast markets. Beginning in the second quarter of 1982, it is assumed that there is a 50 percent possibility that the Northern Tier pipeline project will be built.

North Slope Gas Prices

Under the interim rules of the Natural Gas Policy Act of 1978, the ceiling price of Prudhoe Bay gas as of December 1, 1978 is $1.63 per MMBTU. Given 1.092 MMBTU per Mcf, Prudhoe Bay gas will realize a field value of $1.78 per Mcf. Assuming 6 percent inflation per annum, Prudhoe gas should command $2.52 per Mcf by FY 1985--the earliest date that we are forecasting production or throughput along an Alcan route for a gas pipeline. FERC recently ruled that conditioning costs to remove the carbon dioxide and natural gas liquids and to compress and chill the gas should be deducted from the ceiling price that producers receive for the gas. Assuming conditioning costs of $1.21 per Mcf in 1985 dollars, the weighted average wellhead value of Prudhoe Bay gas (after deducting conditioning costs) by FY 1985 was assumed to be about $1.31 per Mcf. However, allowances were made in the pricing scenarios for the possibility that the costs of conditioning could be shared by the producers and pipeline companies or that either could end up bearing the full cost burden.

Dec '79

ASSUMPTIONS

North Slope Oil Prices

Of the many input assumptions which are used in preparing this forecast, none are as important or difficult to forecast as world oil prices for crude oils comparable to those produced in Prudhoe Bay. During 1979, world oil markets have been extremely disorderly. At the last three OPEC meetings, the cartel delegates have been unable to establish a single, coherent pricing structure. During the year at least three distinct pricing tiers existed: (1) the moderate OPEC group led by Saudi Arabia at about $18.00/B, (2) the radical OPEC group led by Iran at about $23.50/B, and (3) the spot market segment (5 percent to 15 percent) used by all OPEC governments at about $30.00/B-$40.00/B. These prices merely represent a snapshot of a highly volatile market which is evolving in a very complex and uncertain world setting. Among the many unsettling factors which complicate the analysis of supply, demand, and price of world crude oil are: (1) confusion as to the onset, severity and duration of the long expected U.S. economic recession, (2) worldwide capital flight from financial paper assets to real assets (gold, silver, art, income producing resources, etc.), (3) threats of continued revolution in Iran with the potential loss of 5 percent of the world's oil production, and (4) continued ambiguity and uncertainty in U.S. energy policy regarding intended plans to completely deregulate U.S. crude oil prices at the wellhead and imposition of the "windfall profits tax." As a consequence, the future for world crude oil prices appears to be highly uncertain and for this reason a wide range of assumptions has been used in the simulation model.

The starting point in assessing potential future price movements in the world oil market begins with the reexamination of recent trends. Between September 1979 and December 1979, most of the major oil exporting nations raised their oil prices to or above the price ceilings established at the June 1979 OPEC meeting. Spot market prices trended upward from $30.00/B to $45.00/B. On December 13, a week prior to the December OPEC meetings, Saudi Arabia, and subsequently three other OPEC countries, announced a $6.00/B increase in the price of its crude oil retroactive to November 1, 1979. This brought the price of the bell-wether, Saudi Light crude, to $24.00/B. With this preemptive move, the Saudi government hoped to moderate further price increases that were to be agreed upon in Caracas, Venezuela on December 17, 1979. At that OPEC meeting, once again no agreement on a unified price structure was reached even though the Saudi's were said to have offered to increase their crude oil prices by an additional $2.00/B or approximately 8 percent. At the close of the meeting, OPEC members were allowed to price their oil as market conditions would allow. In this situation the only fact that is known with certainty is that the oil price assumptions used in the September quarterly forecast were too conservative.

Given these conditions, it is assumed that weighted average OPEC prices over the 17-year forecast will rise from $21.84/B in FY 1980 to $28.62/B in FY 1981 to $81.29/B by FY 1996--roughly 8.6 percent average per annum increase. Weighted average wellhead values for oil royalty calculations for Prudhoe Bay range from a low of $12.66/B in FY 1980 to a high of $70.66/B in FY 1996. The weighted average annual wellhead values for royalty calculations for FY 1980-FY 1985, given the assumptions made in this forecast, are roughly: $12.66/B, $18.37/B, $26.64/B, $30.95/B, $33.51/B, and $37.10/B. These weighted average wellhead values for oil royalty calculations are, however, net of field cost deductions. On the other hand, field costs are not deducted from wellhead values for purposes of severance tax collections.

Projections of TAPS tariffs, as a component of transportation costs, in this 17-year forecast were based on a number of scenarios for the estimated gross revenue requirements of the pipeline companies. In the majority of those scenarios it was assumed that the TAPS owner companies would receive the rate base and rate of return which they requested in testimony before FERC.

Tanker tariffs and refiner market delivery forecasts were based on data supplied by the Petroleum Audit Supervisor's office, journal articles, company studies and various studies done by government and private agencies. Tanker tariff scenarios were inflated on the average at roughly 4 percent per annum due to the capital intensive structure of tanker operations. Market sales by destination in the December 1979 forecast were adjusted to reflect the average first sales reported during the first nine months of 1979. During this time roughly 870,000 B/D were delivered to the West Coast (including Alaska and Hawaii) while Gulf/East Coast (Trans-Panama) and Four Corners Pipeline deliveries were approximately 362,000 B/D. Undoubtedly, the continuing world crude oil supply shortage led to increased buyer interest in Alaskan oil. For this reason, peak West Coast sales may decline somewhat from the levels reached during the last several months should world crude oil shortages begin to slacken. This has been allowed for in the current forecast. Until the third quarter of 1982 it is assumed that Prudhoe Bay crude surpluses will be shipped through the Panama Canal and Four Corners Pipeline to Texas, Gulf/East Coast markets. Beginning in the second quarter of 1982, it is assumed that there is a 50 percent possibility that the Northern Tier pipeline project will be built.

North Slope Gas Prices

Under the interim rules of the Natural Gas Policy Act of 1978, the ceiling price of Prudhoe Bay gas as of December 1, 1978 is $1.63 per MMBTU. Given 1.092 MMBTU per Mcf, Prudhoe Bay gas will realize a field value of $1.78 per Mcf. Assuming 6 percent inflation per annum, Prudhoe gas should command $2.52 per Mcf by FY 1985--the earliest date that we are forecasting production or throughput along an Alcan route for a gas pipeline. FERC recently ruled that conditioning costs to remove the

Mar '83 Forecast

ASSUMPTIONS

Inflation

The outlook for inflation continues to be mixed as uncertainty over the direction of monetary policy at the Central Bank has kept real interest rates relatively high. Whether the Federal Reserve will continue to watch the monetary aggregates soar to provide liquidity for the current economic recovery or cut money supply growth to keep inflation in check is a key question. The overriding consideration is perhaps the economic philosophy and goals of the Reagan administration, which appears willing to swap higher unemployment for lower rates of inflation. In any event, as always, a wide range of inflationary scenarios were considered. The weighted average rate is assumed to be 6.7 percent through FY 1986 rising to 6.86 percent in 1985, 7.5 percent in FY 1986 and roughly 6.5 percent for FY 1987-FY 1990. The weighted average inflation assumption for FY 1987-FY 1990 represents an annual rate of inflation a full percentage point below that assumed in December.

North Slope Oil Prices

International Trends

At its recent meeting in London, OPEC, for the first time in its history, lowered its price structure. The latest accord cut the marker price of Saudi Arabian light crude oil from $34.00/bbl to $29.00/bbl and established a production ceiling of 17.5 million bbls/day. Production quotas were set for individual member countries, with Saudi Arabia playing the role of swing producer by adjusting its production to preserve the crude output ceiling.

This radical adjustment in the cartel's pricing and production policy was reached in the face of rapidly deteriorating crude oil prices world-wide and a shrinking market for OPEC crude oil. The financially weaker members, such as Nigeria, were increasingly under pressure to lower price or lose customers. It is still not clear whether the recent OPEC agreement is sufficient to stem the downward movement in crude oil prices although spot prices have been relatively stable for the last month or so. Many analysts have been watching the British National Oil Company's (BNOC) pricing policy since they are sellers of crude oil who compete for the same market as Nigeria. So far announced price cuts of $.50/bbl by BNOC do not appear to threaten the current price structure.

The current price structure of internationally traded crude oil is as follows:

1. Saudi Arabia and other Arabian Gulf "discretionary producers" and Iraq around $29/bbl.

2. Mexican light crude oil, comparable to Saudi, at $29/bbl; with heavy Mayan crude at $23/bbl, comparable to Venezuelan heavy which is also at $23/bbl.

3. African producers of light sweet crude at $30.00 to $30.50/bbl.

4. North Sea crude oil, comparable to African light oil, at $30.00 to $30.50/bbl.

5. Iran at roughly $26.00/bbl for comparable light crude oil.

As always, with a demand induced supply overhang, resolution of OPEC's current dilemma relies upon demand recovery. Low oil prices should increase oil consumption if the price elasticity of demand is at all significant. At the same time, low oil prices should provide additional stimulus to the economic recovery. Analysts disagree about the magnitude of the effect of an econmic recovery on crude oil demand (income elasticity of demand) since it is unclear as to how much the recent decline in oil consumption is accounted for by structural change (more efficient automobile fleet, increased use of insulation) and how much by the idling of machinery due to the recession. Most analysts do agree that the economic recovery will be slow and for that reason will provide only minor stimulus to crude oil consumption.

Although OPEC's current output is hovering around 24 million bbls/day, current inventory statistics suggest that considerable restocking activity is expected to occur in the short term, which should allow some increase in OPEC production. For the elimination of the current supply overhang, OPEC members must resist the temptation to produce beyond their quotas in response to a demand surge. These two factors result in a March production of somewhat lower near term crude oil prices and lower growth rates over the next three years than was assumed in the December projections.

As always, we have assumed for forecasting purposes a wide range of both optimistic and pessimistic price growth scenarios for the marker crude oil. The average assessment is for generally flat prices through FY 1987 with real or inflation adjusted price growth resuming in the late 1980's. The Saudi pricing asumptions in the short term reflect the assumed market clearing price rather than the official contract price in order to minimize subjective adjustment of price premiums or discounts between Saudi and Alaska North Slope crude oil. In this forecast, it was assumed that the weighted average market clearing price for Saudi Arabian crude oil was $28.10/bbl in February 1983. Price was assumed, on average, to fall to $26.04 in April 1983 and to roughly $25.50 for FY 1984 increasing slowly thereafter (Graph A). Over the 17 year period, weighted average prices for Prudhoe Bay type crudes are forecast to rise from $28.95/bbl in FY 1983 to $72.32/bbl in FY 1999 - roughly 5.9 percent average annual increase in nominal dollar terms.

Domestic Price Trends

Crude oil prices for domestically produced oil began to slide in late December 1982 and generally stopped by the first of February at $3.00/bbl to 4.00/bbl below December levels. The average contract price for Alaska crude oil delivered on West and Gulf Coasts was relatively

DOE DEPT OF ENERGY
DOR DEPT OF REVENUE
DRI DATA RESEARCH INST
RAND RAND CORPORATION
CHASE CHASE ECONOMETRICS
SRI STANFORD RESEARCH INST
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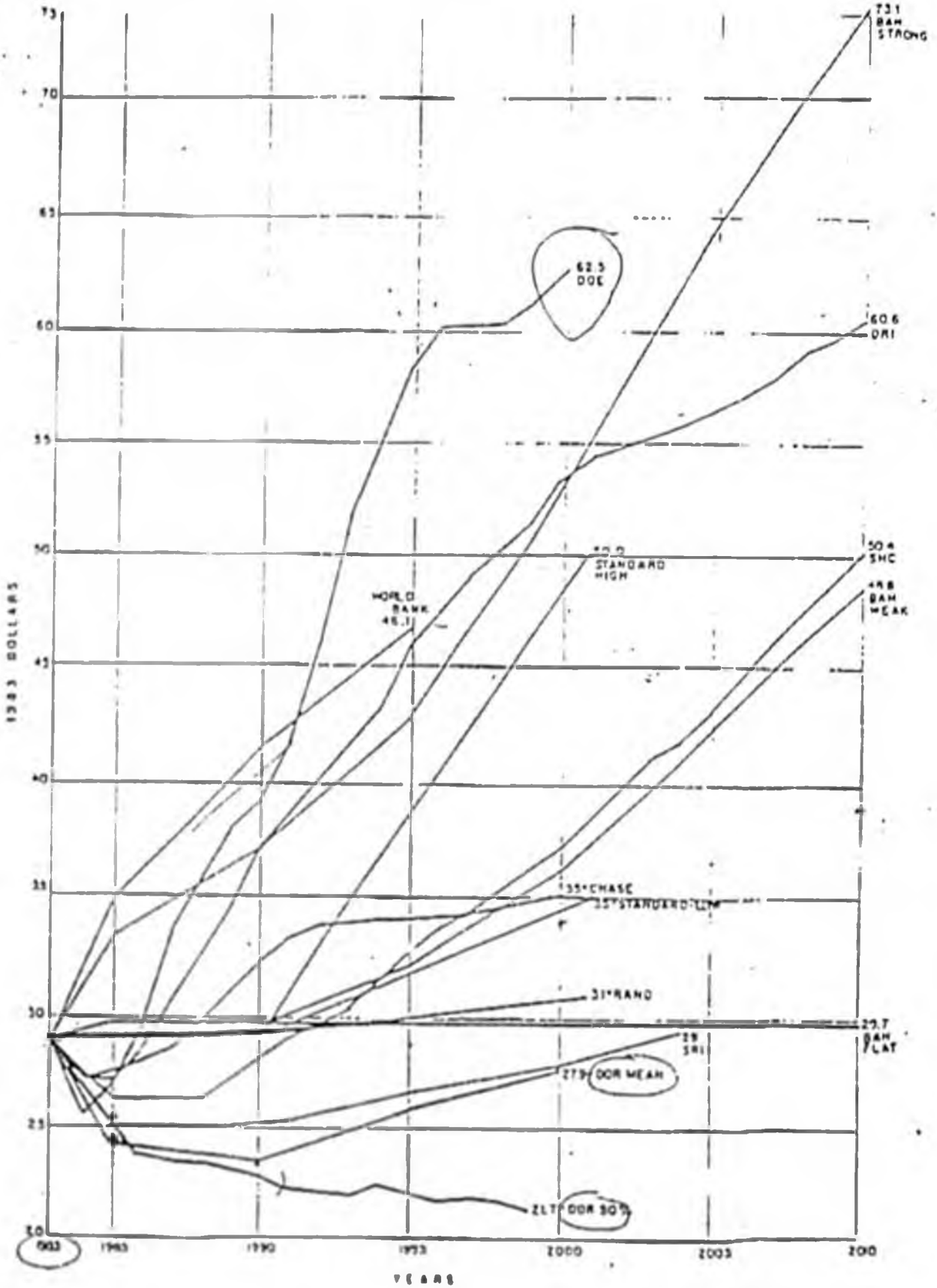
OIL PRICE FORECA COMPARI



OIL PRICE FORECAST
1983 - 2010

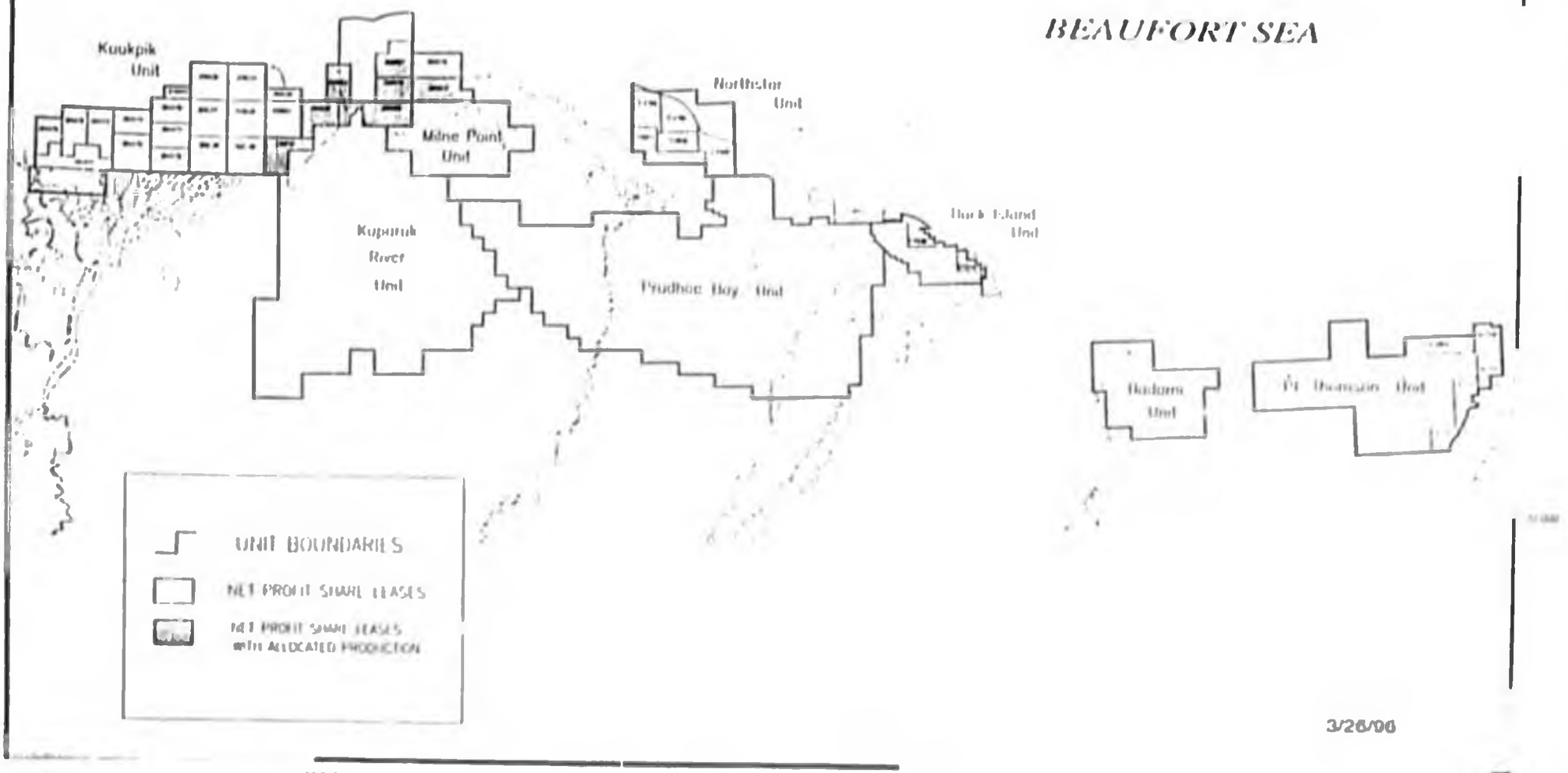
Status of Net Profit Share Leases (NPSLs)

Lease	Sale	Lease Date	Unit	Bonus Bid	NPS Percent	Royalty Percent	Bid Type	Unit Acres	Allocated Production?
Duck Island Unit									
ADL 312828	30	01-Feb-80	Duck Island	$7,524,545 00	79 59350%	20 0%	Fixed Royalty an NPS	3,008 49	Yes
ADL 312834	30	01-Feb-80	Duck Island	$6,266,120 00	48 87031%	20 0%	Fixed Royalty and Variable NPS	1,610 13	Yes
Kuupik Unit									
ADL 355029	39	01-Aug-83	Kuupik	$55,515 20	30 00000%	12 5%	Fixed Royalty and fixed NPS	1,903 00	
ADL 355031	39	01-Aug-83	Kuupik	$64,395 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,724 00	
ADL 355034	39	01-Aug-83	Kuupik	$64,800 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,760 00	
ADL 355035	39	01-Aug-83	Kuupik	$102,000 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,699 87	
ADL 355036	39	01-Aug-83	Kuupik	$117,216 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,760 00	
ADL 355037	39	01-Aug-83	Kuupik	$1,081,212 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,724 00	
ADL 355038	39	01-Aug-83	Kuupik	$241,920 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,760 00	
ADL 355039	39	01-Aug-83	Kuupik	$2,054,867 36	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,645 24	
ADL 355040	39	01-Aug-83	Kuupik	$102,580 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	1,280 00	
ADL 364470	43A	01-Aug-84	Kuupik	$112,700 70	30 00000%	12 5%	Fixed Royalty and fixed NPS	3,180 00	
ADL 364471	43A	01-Aug-84	Kuupik	$119,153 71	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,759 00	
ADL 364472	43A	01-Aug-84	Kuupik	$294,682 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	4,480 00	
ADL 364473	43A	01-Aug-84	Kuupik	$294,682 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	4,480 00	
ADL 364474	43A	01-Aug-84	Kuupik	$2,586 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	3,819 00	
ADL 364475	43A	01-Aug-84	Kuupik	$587,158 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,748 00	
ADL 364476	43A	01-Aug-84	Kuupik	$1,233,216 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	3,840 00	
ADL 364477	43A	01-Aug-84	Kuupik	$3,102,720 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	3,840 00	
ADL 364478	43A	01-Aug-84	Kuupik	$1,255,680 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	3,840 00	
Kuparuk River Unit									
ADL 355023	39	01-Jun-83	Kuparuk River	$2,365,233 75	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,175 00	Yes
ADL 355024	39	01-Jun-83	Kuparuk River	$984,758 40	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,580 00	Yes
ADL 355030	39	01-Jul-83	Kuparuk River	$273,190 40	30 00000%	12 5%	Fixed Royalty and fixed NPS	4,480 00	Yes
ADL 355032	39	01-Jul-83	Kuparuk River	$262,295 80	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,108 00	Yes
Milne Point Unit									
ADL 355016	39	01-Aug-83	Milne Point	$60,691 76	40 00000%	12 5%	Fixed Royalty and fixed NPS	5,071 00	
ADL 355017	39	01-Aug-83	Milne Point	$351,000 00	40 00000%	12 5%	Fixed Royalty and fixed NPS	4,460 00	Yes
ADL 355018	39	01-Aug-83	Milne Point	$808,000 00	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,083 00	Yes
ADL 355021	39	01-Aug-83	Milne Point	$257,177 60	30 00000%	12 5%	Fixed Royalty and fixed NPS	5,120 00	Yes
Northstar Unit									
ADL 312798	30	01-Feb-80	Northstar	$3,843,717 50	93 20000%	20 0%	Fixed Royalty and Variable NPS	4,392 82	
ADL 312799	30	01-Feb-80	Northstar	$3,913,323 75	91 20000%	20 0%	Fixed Royalty and Variable NPS	4,472 37	
ADL 312808	30	01-Feb-80	Northstar	$3,003,805 00	85 25978%	20 0%	Fixed Royalty and Variable NPS	3,432 92	
ADL 312809	30	01-Feb-80	Northstar	$4,638,707 50	85 25978%	20 0%	Fixed Royalty and Variable NPS	5,301 38	
ADL 355001	39	01-Aug-83	Northstar	$72,144 64	40 00000%	12 5%	Fixed Royalty and fixed NPS	5,744 00	

Status of Net Profit Share Leases (NPSLs)

Lease	Sale	Lease Date	Unit	Bonus Bid	NPS Percent	Royalty Percent	Bid Type	Unit Acres	Allocated Production?
Pt. Thomson Unit									
ADL 312866	30	01-Feb-80	Pt Thomson	$4,318,536 25	52 35200%	20 0%	Fixed Royalty and Variable NPS	4,935 47	
ADL 343109	36	01-Aug-82	Pt Thomson	$4,224,852 00	40 00000%	12 5%	Fixed Royalty and fixed NPS	4,263 88	
ADL 343110	36	01-Aug-82	Pt Thomson	$4,109,750 00	40 00000%	12 5%	Fixed Royalty and fixed NPS	1,920 00	
ADL 343111	36	01-Aug-82	Pt Thomson	$15,355,000 00	40 00000%	12 5%	Fixed Royalty and fixed NPS	2,400 00	
ADL 343112	36	01-Aug-82	Pt Thomson	$2,570,026 80	40 00000%	12 5%	Fixed Royalty and fixed NPS	3,440 00	
Not Unitized									
ADL 312827	30	01-Feb-80		$9,880,867 50	74 83000%	20 0%	Fixed Royalty and Variable NPS	0 00	

ACTIVE NET PROFIT SHARE LEASES



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ALASKA NORTH SLOPE
NATIONAL ENERGY STRATEGY INITIATIVE

Analysis of Five Undeveloped Fields

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U.S. Department of Energy
Assistant Secretary for Fossil Energy

Prepared by
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ALASKA NORTH SLOPE NATIONAL ENERGY STRATEGY INITIATIVE (ANALYSIS OF FIVE UNDEVELOPED FIELDS)

ABSTRACT

The U.S. Department of Energy was directed in the National Energy Strategy to establish a federal interagency task force to identify specific technical and regulatory barriers to the development of five undeveloped North Slope Alaska fields and make recommendations for their resolution. The five fields are West Sak, Point Thomson, Gwydyr Bay, Seal Island/Northstar, and Sandpiper Island. Analysis of environmental, regulatory, technical, and economic information, and data relating to the development potential of the five fields leads to the following conclusions:

- Development of the five fields would result in an estimated total of 1.055 million barrels of oil and 4.4 trillion cubic feet of natural gas and total investment of $9.4 billion in 1992 dollars.

- It appears that all five of the fields will remain economically marginal developments unless there is significant improvement in world oil prices. However, the analysis indicates that improved technology and reduced costs through the combined cooperative efforts of industry and government could make it economically feasible to develop some of these fields

- Costs of regulatory compliance and mitigation, and costs to reduce or maintain environmental impacts at acceptable levels influence project investments and operating costs and must be considered in the development decision making process. These costs can result in reduced reserves and delays in development. Efforts to reduce these costs and impacts would be beneficial to the development of the five fields and other potential discoveries.

- The development of three of the fields (West Sak, Point Thomson, and Gwydyr Bay) that are marginally feasible would have an impact on North Slope production over the period from about 2000 to 2014 but cannot replace the decline in Prudhoe Bay Unit production or maintain the operation of the Trans-Alaska Pipeline System (TAPS) beyond about 2014 with the assumption that the TAPS will shut down when production declines to the range of 400 to 200 thousand barrels of oil/day.

- Recoverable reserves left in the ground in the currently producing fields and soon to be developed fields, Niakuk and Point McIntyre, would range from 1 billion to 500 million barrels of oil corresponding to the time period of 2008 to 2014 based on the TAPS shutdown assumption.

EXECUTIVE SUMMARY

1. Introduction

The National Energy Strategy (NES) issued in February 1991 sets out two fundamental objectives to enhance energy security. One objective is to expand U.S. and worldwide oil production capacity and strategic stocks, the second is to reduce U.S. oil consumption through a combination of measures aimed at increased efficiency, introduction of alternative transportation fuels, and aggressive research and development of new energy and oil saving technology. As part of the objective to expand oil production capacity, the NES calls for accelerated development of five undeveloped Alaskan North Slope fields. These five fields are West Sak, Point Thomson, Gwydyr Bay, Seal Island/Northstar, and Sandpiper Island. These five fields are referred to throughout the report as the five NES fields. The U.S. Department of Energy (DOE) was directed in the NES to establish a task force to identify specific technical and regulatory barriers to the development of these fields and make recommendations for their resolution. DOE has established an interagency task force consisting of representatives from DOE, U.S. Department of Interior, Environmental Protection Agency, Department of Defense (Army Corps of Engineers), Council on Environmental Quality, and Department of Commerce (National Marine Fisheries Service) to identify specific technical and regulatory hurdles to development of these fields and make recommendations for their resolution.

The five NES fields are known resource accumulations that have not been developed because of technical or economic conditions or both. These five fields are diverse in terms of geographic location, size of resources (potential reserves), areal extent, depth of productive horizon, type and quality of hydrocarbons, age and lithologic character of the rocks of the productive horizons, physiographic position, and other factors that ultimately must be addressed in the decision-making process. All of the fields are currently in a non-producing status and most will require further exploration/delineation before development decisions can be made. One result of this non-producing status is that public information is limited on all five fields.

This report provides the environmental, regulatory, technical, and economic information and data relating to the development potential of the five discovered but undeveloped fields. Information and data were obtained from open literature, industry, federal agencies, and state and local agencies in Alaska. The production forecasts, investment forecasts, and operating costs used in the analyses were developed

by the authors based on the available information and were not provided by any agency or company. The environmental, regulatory, and technical issues and the interaction of these issues with the economic factors that control the development of each of the five NES fields are analyzed. Sensitivity analyses illustrate the relative influence of these factors for a variety of potential technical, regulatory, and economic options providing the basis for the interagency task force to develop recommendations to assist in the development of these fields

Summary of Approach

In 1990, the DOE Office of Fossil Energy, in cooperation with the state of Alaska, conducted a study of the Alaska North Slope oil and gas resources. A report titled, "Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity" was released in March 1991. The report presented an analysis of several potential scenarios concerning future production from the North Slope. The five North Slope producing oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott), two fields that were nearing development (Niakuk and Point McIntyre), four of the five NES fields (West Sak, Gwydyr Bay, Seal Island/Northstar, and Sandpiper), and the potential development of three exploration areas were analyzed for their effect on the lifetime of the Trans-Alaska Pipeline System (TAPS). The same basic methods used in the 1991 DOE report are used for this analysis.

The status of the five currently producing North Slope oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott) and the two fields nearing productive status (Niakuk and Point McIntyre) are updated to provide a background for operations on the North Slope and expectations for continued operation of North Slope infrastructure. Production forecasts and economics are updated to 1/1/92 using actual 1990 and 1991 production. An important factor affecting the future of these fields and all future development on the North Slope is the continued operation of TAPS. Although the actual minimum throughput rate for TAPS has not been established, a range of 400 to 200 MBPD is assumed to illustrate the effects of a shutdown of TAPS. The minimum rate for operation of TAPS will be determined by both mechanical and economic factors.

The development decision-making process for development of new fields on the North Slope of Alaska is driven by economic considerations and acceptability of the environmental impacts. Although the development decision-making process may differ by company, the fundamental steps are (a) defining the scope, (b) designing environmentally acceptable development plans, (c) estimating uncertainty,

(d) optimizing project design, and (e) finalizing the development decision. The analysis of the five NES fields is designed to take into account the evolving business environment, which includes (a) increasing labor and materials costs, (b) increasing technological costs and risks associated with developing more marginal prospects in a harsh environment, (c) an increasing level of industry responsibility and costs in dealing with environmental laws and regulations, (d) highly unstable oil prices, and (e) the continuing need for additional revenue by both federal and state sectors.

The method used to quantify the value of the projects is the present worth (PW) of the project, where PW is the cumulative after tax cash flow generated from the project's time sequenced revenues and expenses discounted to 1992 dollars. Nominal discount rates of 10 to 15% are used in the analysis. An inflation rate of 3.5% is used. Four oil price cases are used to show the effects of oil price on the project economics. The four cases include the NES Low oil price case from the *Technical Annex 2. Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results*, U.S. Department of Energy, 1991 (DOE/S-0086P) and three cases for the Energy Information Administration's (EIA) *Assumptions for the Annual Energy Outlook 1992*, January 1992 [DOE/EIA-0527(92)]. The NES Low oil price case lies between the EIA Mid-level and Low price cases as shown in Table 1. These are world oil prices defined as the average cost to U.S. refiners of acquiring imported oil. All four cases contain some level of real price increase and include the effects of economic growth, conservation, fuel substitution, and supply.

Table 1. World oil price cases ($/BBL, constant 1/1/92$)

	1992	1995	2000	2005	2010	2015	2020
EIA High	22.07	26.97	33.90	39.34	42.86	45.04	47.35
EIA Mid-Level	20.15	22.17	28.15	32.52	35.61	38.36	41.32
NES Low[a]	20.41	15.86	22.01	27.03	29.47	30.61	32.50
EIA Low	15.88	17.06	19.08	21.43	24.09	26.87	29.95

a. NES Current Policy Base Case includes three oil price projections: High, Base, and Low

Economic uncertainty is addressed through sensitivity analyses performed to test the economic effect of changes in the variables including oil price, recovery and rate, operating costs, capital investment, federal and state taxes, and discount rate. Methods such as Monte Carlo techniques, sometimes applied by industry and government agencies, are not used. Effects of changes in individual

variables and combinations of variables are evaluated to test the impacts of the economic driving forces on the economic viability of the five fields.

Data are not available to accurately quantify the costs of environmental and regulatory issues. Regulatory and environmental requirements are factors that influence investments, operating costs, reserves, and development schedules. The effects of these factors and costs on the technical and economic viability of developing the five NES fields are evaluated in the sensitivity analysis.

Technical and environmental issues related to each of the five fields are analyzed on a field by field basis. Input data, forecasts, and economic results are developed for each field. The economic analysis is on a project basis and does not involve integrated economics, which would involve additional complex evaluation including TAPS ownership, shipping, refining, and marketing activities for major integrated oil companies. Although the majority lease ownership on the North Slope is generally limited to major oil companies, large and small independents, native corporations, and individual groups of investors have ownership in some leases. Hence, the use of integrated economics is outside the scope of this study.

Environmental and Regulatory Issues

The complex, and often controversial, nature of the regulatory permit processes on the North Slope of Alaska is a direct result of the sensitive environmental issues surrounding exploration and development of oil and gas reserves. Environmental impacts as a result of the loss of wetlands through gravel mining and placement, disturbance of subsistence hunting and fishing, and disruption of coastal flow patterns or fish migrations by solid-fill causeways are major issues on the North Slope. The regulatory processes (lease sales and permits), including the National Environmental Policy Act process, are sensitive to these environmental issues. In fact, major regulatory Acts (e.g., Section 404 of the Clean Water Act, the Coastal Zone Management Act, Endangered Species Act) are focused at regulating impacts to wetlands, the coastal zone, and subsistence resources. In addition, the question of waste management on the North Slope will become increasingly important as fields mature and field shutdown becomes a reality. Waste management regulation will likely be costly to industry, requiring remediation of existing and abandoned sites.

The cost of regulatory compliance affects the amount of crude oil reserves that are economically viable. However, the distinction must be made between the *cost of compliance* (e.g., mitigation, foregone oil revenues) and the *cost of administering* the regulatory process (e.g., labor and material associated with permit applications, Environmental Assessments, and Environmental Impact Statements). Regulatory processes (e.g., lease sales, permits) are necessary in order to provide for protection of the environment. The steps and timing associated with these processes are well defined. Consequently, the costs associated with the administration of these processes are part of operating costs and are known to industry. While the costs of the administrative process are not small, the majority of the regulatory costs are associated with compliance. The cost of breaching a causeway or moving a well pad affects the viability of a project to a greater degree than the administration of the lease sale and permit process. The exception is when delays are caused by agencies invoking the *elevation process*. These kinds of delays could take several months to several years to resolve and the resulting administrative costs can be substantial.

Several steps can be taken to reduce the cost of administrative and regulatory costs, or at least some of the risk associated with the uncertainty of these costs on project economics. First, streamlining the lease sale and permit processes could save some time. These processes, however, are well defined, and little can be done to reduce the time between steps. For example, the documentation for National Environmental Policy Act (e.g., Environmental Assessments and Environmental Impact Statements) will likely require substantial time to complete. This is especially true on the North Slope where most large projects will be controversial and require environmental impact statements. A second step that could be taken to reduce cost of regulatory compliance is avoidance of areas where mitigative costs will be high. The identification of high valued resources (e.g., wetlands with important functions and values, endangered species habitat) using the Clean Water Act Section 404 Advanced Identification process or similar method would help industry avoid areas with demonstrated value where mitigative costs are likely to be high. In a field such as West Sak where the reservoir is shallow and pads and facilities must be much closer together than is currently the case for the Kuparuk field, this may result in lost reserves. This would also help reduce delays associated with controversial issues such as subsistence resources, wetlands, endangered species, and causeways. A third step that could help reduce the uncertainty in mitigative costs would be more effective use of *pre-consultation* and coordination with regulatory agencies.

Technical and Economic Analysis

Major Fields--Prudhoe Bay and Kuparuk fields are the No. 1 and No. 2 producing rate fields in the U.S. and produce about 18% of the nation's daily output of oil or about 1.6 million barrels (MMB) of the total 8.9 MMB. Prudhoe Bay production is declining; Kuparuk production is expected to remain fairly steady for several more years before a significant decline begins.

Remaining reserves are estimated at 5,300 MMB for Prudhoe Bay and 1,300 MMB for Kuparuk. It is these two fields with their reserves and rate of production that dominate predictions for the duration of economic oil production on the North Slope of Alaska. Using a TAPS shutdown ranging from year-end 2008 (400 MBPD) to year-end 2014 (200 MBPD), the possible "lost" recoverable liquids from these two fields would be about 1,000 MMB to 500 MMB, respectively.

The impact of the Prudhoe Bay field discovery, development, and creation of infrastructure, including TAPS, can be appreciated in total only by realizing that all of the other producing fields and all of the potentially productive fields are dependent upon the existing infrastructure. If TAPS does, in fact, shut down by year-end 2008, then the timeline for bringing discovered fields on production is rapidly approaching criticality because of the lengthy period between decision to develop and first production. The time factor is even more critical for potential undiscovered fields, such as in ANWR or offshore, because the time from lease sale to first production is greater than 10 years.

Recently Developed Fields--The recently developed fields, Endicott, Milne Point (including Schrader Bluff), and Lisburne, provide examples of fields that have been developed with the benefit of the infrastructure and TAPS that are in place as a result of the discovery and development of the super-giant Prudhoe Bay field. These fields illustrate the advancement of arctic technology that has reduced the size of the footprint required in the arctic since the start of Prudhoe Bay development. Factors influencing these technological advances are low oil prices, environmental and regulatory concerns, and relatively small reserves.

Although sizable by Lower 48 standards, Endicott, Milne Point, and Lisburne fields are not major factors on the North Slope in terms of reserves or production rate. Nevertheless, these three fields are more typical of the five NES fields. Their history provides a comparison for evaluation of factors affecting future development.

Long delays ensued between discovery and production of the recently developed fields; i.e., Endicott - 9 years; Milne Point - 16 years; Lisburne - 18 years. A similar pattern can be assumed for other relatively small North Slope fields, discovered or undiscovered.

These three fields combine to total 592 MMBO of remaining reserves and begin to decline in 1993 for Endicott, 1994 for Lisburne, and 2008 for Milne Point/Kuparuk and Schrader Bluff. Production limits are reached in 2010, 2007, and 2016, respectively, for the three fields. Except for a minor amount by Schrader Bluff, they have no effect on extending TAPS beyond 2010.

The major lessons to be learned from these fields are the economic and environmental benefits derived from careful engineering design for facilities down-sized for lower reserves and rates than those of the Prudhoe Bay field. Another major factor in viability of these fields is the use of, and integration into, the Prudhoe Bay infrastructure.

From an industry perspective, the additional 650 ft breach in the Endicott causeway adds a $56 MM burden to capital investment totalling $106 MM over the remaining productive life of the 240 MMBO reserve. At an ultimate reserve total of 404 MMBO, Endicott ranks third among North Slope fields. Smaller fields, or large ones with lesser remaining reserves, may be unable to achieve or continue economic recovery under similar circumstances.

Fields with Development Potential (Point McIntyre and Niakuk)--Contrary to the normal long delays between discovery and production, Point McIntyre field should set a record of only 6 years from the 1988 discovery to the 1994 beginning of production. Located adjacent to Prudhoe Bay and Lisburne fields, Point McIntyre benefits from proximity to existing infrastructure to a remarkable degree. In addition, it benefits (as does Niakuk) from the pending agreement to share in the Lisburne Participating Area (LPA) production facilities. Investment savings to Point McIntyre total about $262 MM, indicating the substantial positive impact facilities sharing can have on prospects on the North Slope. Facilities sharing also reduces environmental impact through reduction of footprint size.

Reserves are estimated at 300 MMBO for Point McIntyre and 70.4 MMBO (53.4 MMBO proven) for Niakuk. Production will begin in 1994 from both fields. Point McIntyre will begin to decline in 2002 and could produce through 2015. Niakuk begins to decline in 1998 and maintains production through 2008. Thus, the later production from these fields helps to offset the earlier declines of

production from the bigger fields. Nevertheless, the impact is insufficient to alter the overall North Slope production decline to an extent that would prolong the life of TAPS. Many more Point McIntyre si' fields or one or more super-giant field discoveries are necessary to significantly prolong the life of TAPS.

The Niakuk Kuparuk field was discovered in 1985, followed by two confirmation wells. The initial plan provided for development from an enlarged offshore island connected to shore by a causeway. Plans to develop from the offshore island were abandoned in 1991 and a study of development from shore was undertaken. Onshore development includes facilities sharing with the LPA and reduces the investment required by about $70 MM (1/1/92$). A loss of 29 MMBO of recoverable oil (proven plus potential) is expected from onshore development because the reservoir that can be reached from shore is limited by current directional drilling technology. The estimated recoverable oil volume (proven plus potential) from the onshore development is about 70.4 MMBO.

Summary of Currently Producing Fields and Fields with Development Potential--The total estimated remaining recoverable oil in the seven fields described above is about 7,600 MMBO. It is evident that the declines of Prudhoe Bay and Kuparuk fields impose the dominant time constraint on future North Slope production and exploration.

West Sak--West Sak sands are encompassed by three producing units, the Prudhoe Bay Unit (PBU) established in 1977, the Milne Point Unit (MPU) established in 1979, and the Kuparuk River Unit (KRU) established in 1981. West Sak and Ugnu sands containing low gravity, heavy oil sands of Upper Cretaceous and Tertiary age have been demonstrated to extend over an area of about 200,000 acres and contain an estimated total of between 25 and 44 billion barrels in place (BBOIP). West Sak sand contain oil at depths from 2,000 to 4,500 ft in the MPU and KRU, with the deepest portion in the northeast in the MPU. Average depth of permafrost in the area is less than 1,500 ft. Oil production from the Schrader Bluff oil pool in the MPU operated by Conoco started in March 1991. The "O" sands of the Schrader Bluff sands are equivalent to the West Sak sands in the KRU but the "N" sands are more equivalent to the lower Ugnu sands. Reservoir temperatures range from 45 to 100°F in West Sak sands with Schrader Bluff averaging 90°F at 4,000 ft subsea. Hence, direct comparisons of Schrader Bluff with the balance of the West Sak area should be approached with caution.

West Sak contains the largest resource volume of the five NES fields, with estimates of up to 20 BBOIP. West Sak crude properties and reservoir conditions present formidable challenges to economic

development. Low gravity, high viscosity oil in a shallow, thin bedded, low temperature reservoir that is highly faulted presents a number of problems to be resolved before any development can take place. With production coming from unconsolidated beds, completion techniques must be developed or existing techniques adopted to the West Sak conditions. Laboratory testing and a hot-water injection pilot indicate that a miscible water-alternating-gas (WAG) process, using close well spacing is the most likely recovery process. Further work may be required before final selection of a process is made. Because of the shallow depth of the reservoir, drilling pads would be required on every section developed, which would result in more numerous and concentrated surface impacts on the environment. Environmental concerns could lead to pattern changes to reduce surface environmental concerns resulting in loss of reserves because of the concentrated pads and facilities necessary to develop the shallow reservoir.

Although considerable study has apparently been conducted by the operator, little of this proprietary information is public. Based on available data, is it estimated that between 500 and 600 MMBO can be recovered from better quality reservoir on about 30,000 acres. The timing of the development of these potential reserves is dependent on having an adequate oil price and an economical source of miscible injectant (MI). The volume of MI on the North Slope is limited at present and will be used in the most economical projects first. This places West Sak at least third behind PBU and KRU. The timing of obtaining MI for West Sak is critical when considering the time frame of TAPS shutdown. About 239 MMBO would be unrecovered under these development scenarios, if TAPS shuts down at year-end 2008.

Results of the economic evaluation of West Sak, using the four oil price scenarios indicate that the EIA Mid-level oil price case is required to obtain a rate of return between 10 and 15%. These economic results clearly indicate that West Sak is an economically marginal project for development.

Point Thomson--The Point Thomson Unit (PTU) covers a gas condensate field about 50 mi east of TAPS pump station (PS) No. 1. The unit contains about 83,800 acres, much of which is offshore. The current reserve estimates for the PTU carried by the Alaska Department of Natural Resources are 5 TCF gas and 300 MMB of oil and condensate. Recent seismic results indicate that the reservoir may be about one-third smaller than originally thought. Thus, a reduction in reservoir size is considered for comparison purposes.

The Point Thomson field is different from the other five NES fields because the main resource is gas condensate from a deep overpressured reservoir that is located mostly offshore. In addition, it is the only one of the five NES fields that is not located within or close to the PBU/KRU infrastructure. It does not appear that development of Point Thomson for sales of liquids alone is economically feasible. However, with no major gas purchase line on the North Slope, and none anticipated in the foreseeable future, the date that Point Thomson might be developed is unknown.

By itself, the resulting Point Thomson reserve volume will not justify sale of gas from the North Slope. Sales from the much larger PBU gas cap, or a similar size gas reserve, will be required to justify any sales scenario. The earliest this might occur from PBU is about 2005. However, before any gas sales can occur from the North Slope, a gas market must be available that will provide a purchase price for the gas that can justify development of the gas resources and the required infrastructure and facilities. In addition, the Point Thomson project faces the construction of field delivery lines to the Prudhoe Bay area that will encounter five major river crossings and be in the coastal plain. The impact of these conditions will not be determined until environmental assessments are conducted.

Provided a gas sales line is available as assumed for the analysis, the economics of developing PTU for the base case and reduced reserves case assumptions indicate that either of these scenarios could provide at least a 10% rate of return for all price cases except the EIA Low price case. Gas prices are related to the oil price cases in the analysis.

Gwydyr Bay—The Gwydyr Bay Unit (GBU) is located north of the PBU and contains hydrocarbon accumulations in its eastern and western tracts. The eastern accumulation will be included in the Point McIntyre development. The western accumulations are not well defined; therefore, experience factors are used to estimate potential reserves of from 40 to 56 MMBO with 48 MMBO used for analysis. The joint use of existing facilities does not appear feasible for GBU due to its isolated location. Independent development is assumed except that a portion of the Kuparuk pipeline is used to deliver crude to PS No. 1. Because additional delineation is necessary, initial production is assumed for early 1999. Recovery is expected to last 16 years or through 2014. If development of this small project is economical, about 11.5 MMBO recoverable oil would be lost if TAPS is shutdown at year-end 2008.

The economics of developing GBU, assuming the reserves are confirmed and that development in the Kuparuk River Delta can be accomplished in an environmentally acceptable manner at the assumed

costs, this project would provide a rate of return of 10% or greater for all price cases except the EIA Low case.

Seal Island/Northstar--The Seal Island/Northstar prospect, or Northstar Unit (NU), is located about 6 mi offshore in the Beaufort Sea, about 15 mi northwest of Prudhoe Bay. NU has been partially delineated by the drilling of six exploratory wells. Other than test rates and bottomhole well locations, little information is available on the size of the accumulation. Recoverable oil estimates range from 150 to 300 MMBO, and a reserve volume of 200 MMBO is used for evaluation. The development scenario, including production/drilling structures and subsea pipelines, is based on arctic studies because there are no offshore arctic Alaska developments that can be used as a guideline. The analysis assumes current technology can be adopted or will be developed as required. The greatest deterrents to the development of this field are confirmation of the reserves and the high net profits interest (NPI) applicable to five state tracts. Economics results indicate that with the NPI in place this prospect is not economic for any of the oil price cases. Economic sensitivities indicate that with removal of the NPI, this prospect is similar to the previous three fields. Using an assumed start-up of 1/1/98, recovery of oil would extend into 2011. Shutdown of TAPS in 2008 would result in an estimated loss of about 23 MMBO should development occur as assumed.

Sandpiper--The Sandpiper discovery, located 9 mi offshore and about 10 mi west of NU, has been explored by only two wells. Approval of the Sandpiper Unit by the MMS in November 1992 may indicate that future exploration or delineation drilling may take place. Previous to the formation of the Unit, there were no indications that further exploration efforts were planned. Based on the very limited information available, potential reserves of 93 MMBO were estimated. An operator's estimate of potential reserves of about 87 MMBO is used. The development scenario is based on arctic studies. As with the NU evaluation, it is assumed existing technology can be adapted or will be developed as required. Using an assumed start-up date of 2000, the life of the project would extend through 2012. Shutdown of TAPS in 2008 would result in an estimated loss of about 19 MMBO should development occur as assumed. Economics of development of this discovery under the scenario described for four oil price forecasts indicate that this prospect will remain uneconomic unless greater reserves are confirmed.

Summary of the Five NES Fields--The five NES fields are diverse in terms of geographic location, size of resources, areal extent, depth of producing horizon, type and quality of hydrocarbons, and type of

reservoir rock. All are currently in a non-producing status and most will require further exploration/delineation before development decisions can be made.

Consequently, where data are missing, comparisons to producing North Slope fields, empirical relationships developed by industry, and personal knowledge are used in forecasting rates, reserves, operating costs, and development investments. It is assumed that existing technology could be adapted to the arctic North Slope developments or that technology can be developed to meet the particular conditions that would be encountered. For example, technology will have to be proven for the development of Northstar and Sandpiper that are about 9 mi offshore in 50 ft of water, and Point Thomson where highly deviated wells will encounter an overpressured reservoir. In addition, it appears that added study would be helpful in determining the best recovery and completion methods for West Sak.

Even the smallest of the five NES fields would be a major economic discovery in the Lower 48. However, the high investment and operating costs on the North Slope and technical constraints such as lack of availability of MI and a gas sales pipeline make development of any of the fields questionable at this time. Even though a large gas reserve exists at Point Thomson, it is not large enough by itself to justify a gas sales line for North Slope gas. A gas cycling project for liquid recovery at Point Thomson was not analyzed, but development on this basis could become feasible if additional large discoveries are made and developed that would support the development of a pipeline and related infrastructure, such as the strike announced on October 15, 1992 by ARCO at the ARCO Kuvlum No. 1 in the eastern Beaufort Sea 60 mi east of Prudhoe Bay and 16 mi offshore.

Investments are forecast taking into consideration each field's particular circumstances, such as location, size of accumulation, possibility of facilities sharing, estimated maximum recovery rate, and timing of development. Total estimated recoverable hydrocarbons are 1,055 MMB and 4.4 TCF (Point Thomson 5 TCF case) of natural gas and total investment requirements are $9.4 billion in 1992 dollars as shown in **Table 2**.

Sensitivity Analysis—The components of the economic evaluation are (a) revenue, (b) operating costs, (c) investment, and (c) taxes and royalties. These components are driven by (a) oil and gas prices, (b) technical aspects of the accumulation, (c) environmental and regulatory issues, (d) federal and state revenue needs, (e) cost reduction measures used by the industry, and (f) technical advances. For example, the costs of environmental/regulatory requirements are included in both operating costs and

Table 2. Forecasts of recoverable hydrocarbons and investments for the five NES fields.

Field	Liquids (MMB)	Gas (TCF)	Investments - $MM (1/1/92$)	1st Year Production	Forecast Life
West Sak A	402	(a)	4,078	2001	2013
West Sak B	106	(a)	1,085	2008	2013
Point Thomson - 1 TCF	112	4.4	1,579	2008	2035
Point Thomson - 3.4 TCF	99	3.0	1,367	2008	2026
Gwydyr Bay	34	(a)	340	1999	2014
Northstar	200	(a)	1,405	1998	2012
Sandpiper	57	(a)	960	2000	2012

a No estimate made - gas used in field operations only.
b Condensate and NGL reserves limited by TAPS shutdown at 200 MBPD (2014) and gas sales less CO2 and NGL.

investments. Initial planning and coordination with regulating agencies can potentially reduce some of the uncertainty associated with environmental and regulatory costs but cannot be expected to eliminate them. Operating costs are affected through such things as the labor costs to perform environmental assessments, permitting activities, increased fluid handling costs, waste management, and mitigation requirements. Investments, and sometimes reserves, have been affected by requirements for causeway breaches and alternate or less optimum pad locations; e.g., events at Endicott, Point McIntyre, and Niakuk provide examples of effects of the causeway issues and Kuparuk Drillsite 3-L illustrates effects that can result from pad location issues. The comparison of the Niakuk onshore project with the offshore Niakuk project illustrates the effects environmental requirements can have on reserves and economics. The proven and potential reserves for the onshore project are estimated to be 70.4 MMBO compared 99.0 MMBO for the original offshore project resulting in a potential loss of reserves of 29 MMBO. The cash flow to industry and revenue to the state of Alaska and federal government are reduced by a total of $135 MM (1/1/92$) using the NES Low oil price scenario. Project delays causing increases in time between investments and production also affect the economics of projects and illustrate the importance of early planning and cooperation by industry and regulating agencies.

Decreases in operating costs and investments and increases in reserves can be achieved through improved technology for drilling, facility design, production technology, streamlining of environmental permitting, reduced costs of environmental compliance, and improved recovery processes.

The magnitude of the impact on project economics by changes (on the order of 10 to 15%) in selected factors and combinations of factors for the five NES fields show that various combinations of reductions in investments and operating costs, reserves increases, and reductions in taxes, royalties, and net profits interests could potentially provide rates of return between 10 and 15% for portions of West Sak, Point Thomson, Gwydyr Bay, and Seal Island/Northstar. Basic technical requirements for development to be feasible include availability of MI for West Sak, a gas pipeline from the North Slope for Point Thomson, confirmation of adequate reserves in Gwydyr Bay, and adaptation of existing offshore pipeline technology to arctic North Slope environments for development of Seal Island/Northstar.

Summary Observations

(1) Under the assumptions used, the economic results for three of the five NES fields (West Sak, Point Thomson, and Gwydyr Bay) indicate that only price forecasts with significant real growth can provide industry with a positive PW at a discount rate of 10%. The two offshore fields (Seal Island/Northstar and Sandpiper) do not provide a positive PW at a 10% discount rate for any of the price scenarios.

(2) The economic sensitivity analyses show that combinations of reduced operating costs, investments, tax and royalty rates, net profits interests, and increased reserves could make development of these five fields potentially economic provided the following requirements are met:

- MI is available for use in West Sak, which will be at least third after PBU and KRU.
- A gas sales line is developed for PBU gas before Point Thomson can be developed.
- The potential reserves at Gwydyr Bay must be proven and the uncertainty of costs related to development in the Kuparuk River delta resolved.
- The Northstar Unit does not appear feasible without removal of the NPI burden.
- Larger reserves at Sandpiper must be confirmed.

(3) The Alaska North Slope production profile (**Figure 1**) is based on the EIA Mid-level oil price. At these prices, using a cut-off of a 10% discount rate, West Sak, Point Thomson, and Gwydyr Bay provide a positive PW and are included in the production profile. Point Thomson and Gwydyr Bay also provide a 10% rate of return at the NES Low oil price. Seal Island/Northstar and Sandpiper do not meet this economic hurdle rate and are not included. At the EIA Low oil price case none of the five NES fields provide a positive PW at a 10% discount rate and result in an Alaska North Slope production profile as shown in **Figure 2**.

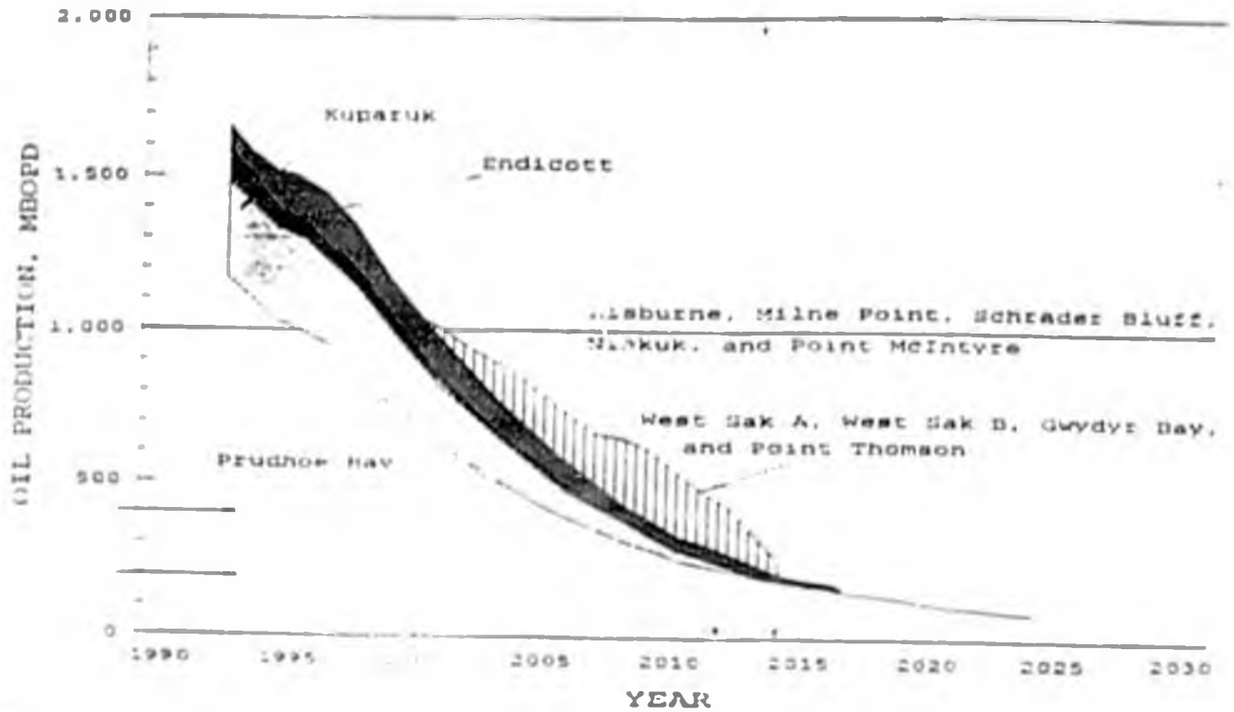


Figure 1. Alaska North Slope production rate forecast including forecasted production from West Sak, Point Thomson, and Gwydyr Bay (arrows indicate the potential range of TAPS shutdown).

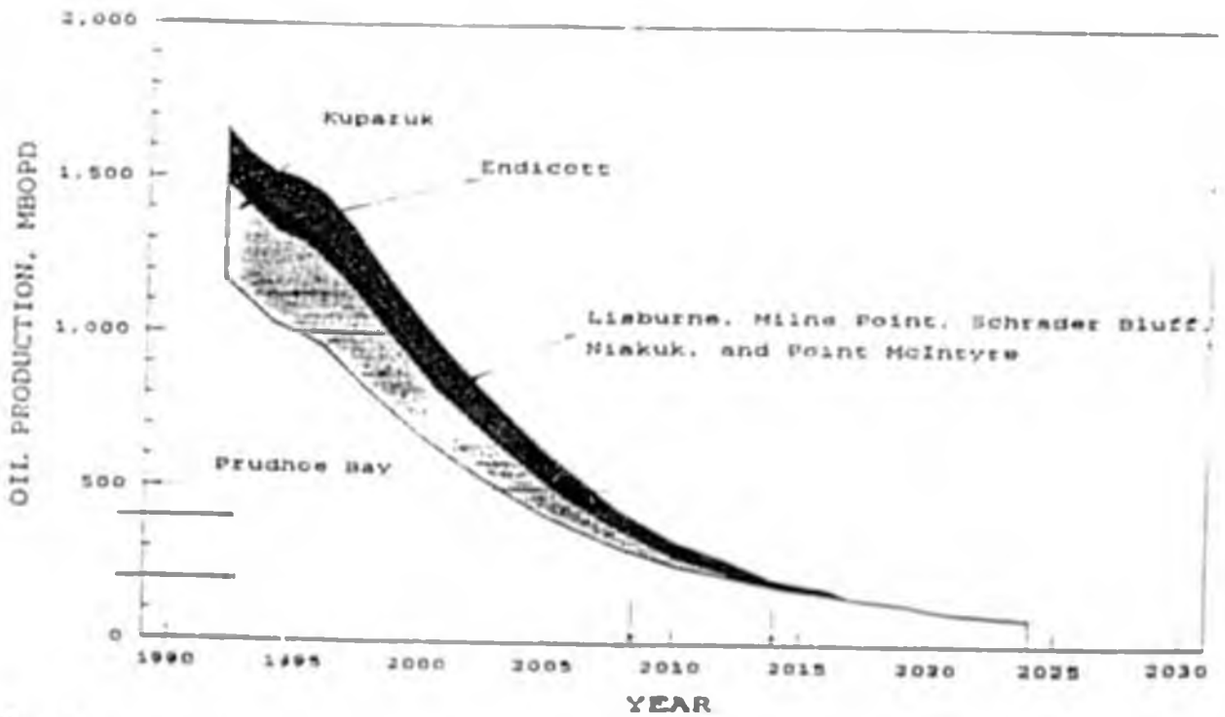


Figure 2. Composite production for seven North Slope fields (arrows indicate the potential range of TAPS shutdown).

(4) Alternate investment opportunities would be expected to seriously compete with the investment capital for the five NES fields at any oil price that provides industry with only a 10% rate of return.

(5) State benefits from the development of each of the five NES fields are significant. Federal benefits, although limited at the two lowest oil price cases, are significant at the higher oil price cases. State and federal benefits and those for industry demonstrate the different levels of benefit that accrue to industry and to state and federal governments with the current royalty and tax rates and illustrate the possibility for share redistribution to encourage development.

(6) State and federal benefits from the currently producing fields are significant. Prudhoe Bay has been beneficial to all parties (industry and state and federal governments). The other four producing fields have provided value to the state and to industry. The federal government has benefitted to a lesser degree. However, these four fields, on a stand-alone basis, have not provided a positive cumulative discounted (10%) after-tax cash flow to the industry (1992 base year) and may not unless oil prices increase to levels at or above the EIA Mid-Level oil price scenario. It is significant that the decision to develop all four of these fields was made during the period of time between 1975 and 1986 when world oil prices were about $30/BBL or above.

(7) Stable world oil prices, high enough to provide adequate rates of return to offset the financial risks involved in development in the harsh environmental conditions of the North Slope, would be the most sure guarantee of development of the five NES fields and other similar fields on the North Slope. However, the sensitivity analyses indicate that reductions in operating costs and investments and increases in recovery volume through combinations of improved technology and streamlined processes for environmental and regulatory requirements or both can feasibly move some of these fields to development. Reductions in tax and royalty rates would provide additional incentive.

Conclusions

- Development of the five fields would result in an estimated total of 1,055 million barrels of oil and 4.4 trillion cubic feet of natural gas and total investment of $9.4 billion in 1992 dollars.

- It appears that all five of the fields will remain economically marginal developments unless there is significant improvement in world oil prices. However, the analysis indicates that improved

technology and reduced costs through the combined cooperative efforts of industry and government could make it economically feasible to develop some of these fields.

- Costs of regulatory compliance, mitigation, and costs to reduce or maintain environmental impacts at acceptable levels influence project investments and operating costs and must be considered in the development decision making process. These costs can result in reduced reserves and delays in development. Efforts to reduce these costs and impacts would be beneficial to the development of the five fields and other potential discoveries.

- The development of three of the fields (West Sak, Point Thomson, and Gwydyr Bay) that are marginally feasible would have an impact on North Slope production over the period from about 2000 to 2014 but cannot replace the decline in Prudhoe Bay Unit production or maintain the operation of TAPS beyond about 2014 with the assumption that the Trans-Alaska pipeline (TAPS) will shut down when production declines to the range of 400 to 200 thousand barrels of oil/day.

- Recoverable reserves left in the ground in the currently producing fields and soon to be developed fields, Niakuk and Point McIntyre, would range from 500 million to 1 billion barrels of oil corresponding to the time period of 2008 to 2014 based on the TAPS shutdown assumption.

and costly because of locations in the Kuparuk River delta. Proximity to the producing infrastructure of Milne Point, Kuparuk, and Prudhoe Bay fields will improve economics. However without a dramatic, and unexpected, increase in the oil exploration potential in Gwydyr Bay area, it appears that the likelihood of significant production is low

B.7 Seal Island/Northstar History

In 1979, a joint lease sale was conducted by the state of Alaska and the U.S. Mineral Management Service (MMS) in the offshore waters of the Beaufort Sea. One group of successful bidders, with Shell as initial operator, formed a joint effort to explore their state/federal leases centered about 15 miles northwest of Prudhoe Bay. Shell completed the construction of Seal Island in 1982. The first well, BF-47 No. 1, resulted in a discovery testing 4,750 BOPD from the Ivishak formation of the Sadlerochit group, the main producing interval in the Prudhoe Bay field.

Ultimately, four wells were drilled from Seal Island resulting in two certified producers, another that encountered hydrocarbons, and one dry hole (MMS 1989a). In 1985, Amerada Hess constructed Northstar Island about 4½ mi northwest of Seal Island and drilled a successful confirmation well, the BF 46 No. 1 in 1986. This well tested at rates of up to 3,500 BOPD from the Ivishak with oil gravity "similar to that in the Seal Island wells, in the 40°s." A subsequent well, deviated to the southeast, encountered mechanical problems and was abandoned without reaching the Ivishak. Shell estimated the structure held more than 300 MMBO total (OGJ 1986).

B.7.1 Data Summary

In 1989, the working interest owners (Amerada Hess Corporation, Murphy Oil USA, Inc., Shell Western E&P, Inc., and Enterprise Oil Ex Co Inc.), formed the Northstar Unit (NU) (**Figure B.18**) with Amerada Hess as operator and submitted a POD to the MMS and ADNR. This plan called for a total expenditure of $21 MM during the 1990 to 1994 period. The plan included island maintenance, a petrophysical/petrographic study, production facility design, about 250 mi of 2-D seismic, seismic analysis and interpretation, reservoir engineering studies, extension fee payments (in lieu of drilling) that will escalate from $1 MM to $4 MM over the 5-year period, and a unit area reevaluation to be conducted in 1993 (MMS 1989a). In 1991, a $1 MM payment to the state was made in lieu of drilling. The petrophysical/petrographic study and conceptual production facilities design were initiated. Island

maintenance was done in July to August 1991 and the 1991 summer seismic program acquired 210 line miles of data (ADNR 1991d; ADNR 1991e).

During 1991, the petrophysical/petrographic program was completed by Neil Barry and Associates and Core Lab, Inc. The conceptual facilities design was also completed by R.M. Parsons Company. A modification of the seismic plan proposes additional coverage during the 1992 winter season, which will exceed that of the original plan. Because a delineation well was not drilled during 1991, Amerada Hess paid $2 MM to the state in January 1992 (ADNR 1992a).

At the time NU was formed, an estimated total of $280 MM had been expended on lease acquisition, island construction, and exploratory drilling. If all estimated expenditures for the POD are spent, the total cost prior to initial development or an eventual decision to cancel the project will exceed $300 MM.

Limited public technical data, consisting only of well logs and histories, preclude a reliable independent assessment of potential reserve volume. Published data specific to Seal Island/Northstar indicate a range of potential reserves from 150 to 300 MMBO (OGJ 1986; ADNR 1991a). However, data representing undeveloped reserves for the Beaufort Sea published by the state of Alaska in June 1991, indicate a range of 180 to 225 MMBO (mid to high). It is assumed that those reserve estimates apply specifically to Seal Island/Northstar (ADNR 1991). Using the available data, a conservative estimate of 200 MMBO as a potentially recoverable resource is made and used for evaluation purposes (see **Figure B.18**).

B.7.2 Lease Summary

Leases were acquired at Seal Island/Northstar from both the state of Alaska and the federal government in sale BF-79. Federal leases carried a 10-year primary term with expiration on July 31, 1990 with a 1/6 royalty. State tracts were also for a 10-year primary term expiring January 31, 1990, with four leases carrying a 20% royalty and one carrying a 12.5% royalty. All the state leases also include a net profit share percentage, ranging from 40% to 93.2% (see **Figure B.19**) (MMS 1989; ADNR 1991f).

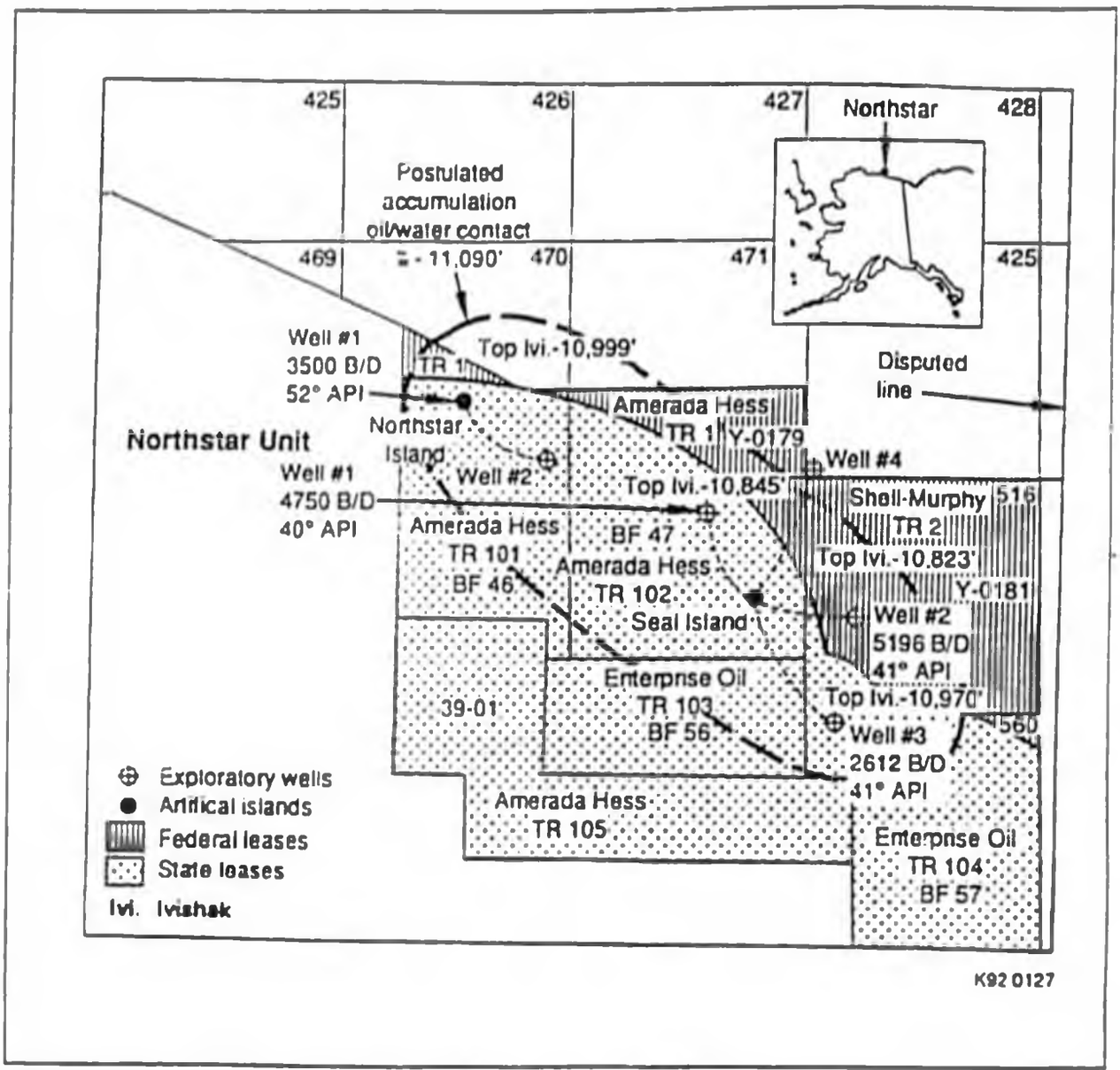


Figure B.18. NU map and postulated outline of the accumulation.

Current status of ownership provides that costs will be shared (unless otherwise stated in the Unit Operating Agreement) as follows (ADNR 1991f):

- Amerada Hess (operator) 80.85%
- Murphy Oil USA, Inc. 1.92%
- Shell Western E&P, Inc. 17.23%

Total NU area is 30,837.99 acres comprised of 7,494.50 acres of federal land and 23,343.49 acres of state land (see Figure B.19).

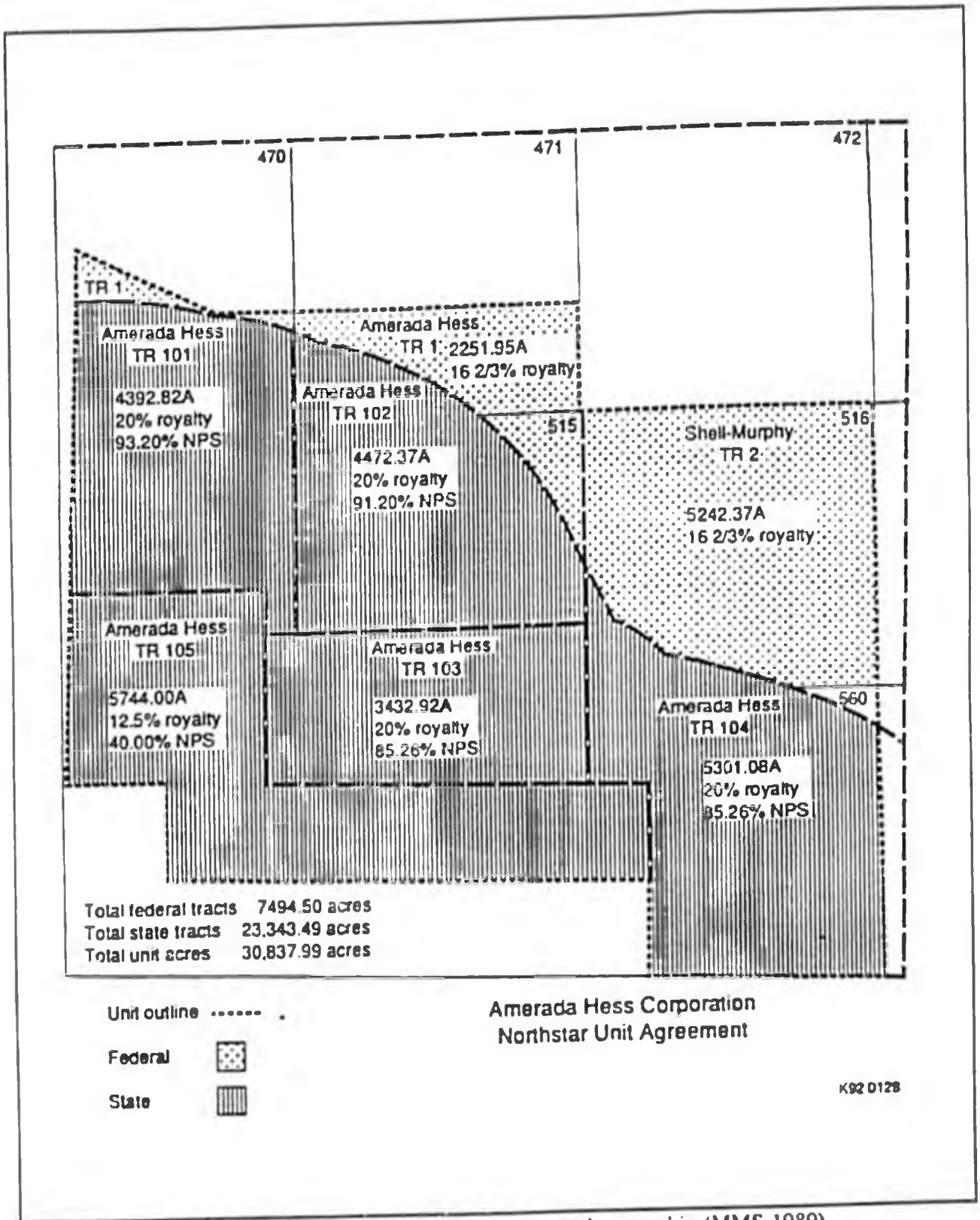


Figure B.19. NU royalties, net-profit share percentages, and ownership (MMS 1989).

B.8 Seal Island/Northstar Issues

As the NU evaluation process continues during the current POD covering the period from 1990 to 1994, the primary technical issues are the size of the accumulation, development costs, and the field production rate.

It appears the NU owners currently think the accumulation is too small to be economically developed. The high test rates in the exploration wells indicate good reservoir rocks in the Sadlerochit and the high gravity reported indicates good quality crude. The economics of construction of development and production facilities, including ice-resistant platforms and subsea pipelines in 50 ft water depths 15 mi offshore, present formidable challenges. For comparison, Endicott field, lies 2 mi offshore in about 4 ft water depths, produces from a gravel island, and is connected to shore by a gravel causeway. Total, ultimate reserves for Endicott are 403.8 MMBO.

Ultimately, the working interest owners will have to decide whether the accumulation is economic to produce. The net profit share provisions of the state leases add a very significant burden to the economic viability of NU.

B.9 Sandpiper Island History

Leases were first acquired in what would eventually be called the Sandpiper Island area in OCS Lease Sale 71 in 1982. It is located approximately 25 mi northwest of Prudhoe Bay. Six leases in the immediate area totaled $73,731,567 in successful high bids at the federal sale. Shell Western E&P Inc. became the operator for a group consisting of Shell, Amoco Production Co., Murphy Oil USA, Petrofina Delaware Inc., and Koch Industries Inc.

By 1986, Shell had constructed Sandpiper Island to drill the first well on the group's Harvard prospect. The gravel island was built for an estimated cost of $29 MM (OGJ 1986a). That year Shell drilled the OCSY-370 No. 1 (Sandpiper No. 1) to a total depth of 12,575 ft. During tests of the Sadlerochit, the well flowed at a rate of 2,419 BOPD, 275 BWPD, 3613 GOR, 41.2°API gravity from a lower zone and 409 to 2,325 BPD condensate, 2.9 to 18.6 MCFPD, 49 to 51°API gravity from an upper zone (AOGCC 1986). The well bottomed approximately 3,300 ft north of the island.

SEAL ISLAND / NORTHSTAR, WITH NET PROFITS INTEREST - PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
OIL PRODUCTION RATE, Mbbl/day	0.00	0.00	0.00	0.00	21.92	41.10	54.80	54.80	54.80	54.80	54.80	46.58
OIL PRICE	$18.94	$17.89	$19.95	$22.14	$24.45	$26.90	$29.49	$31.91	$34.46	$37.17	$40.01	$43.01
WELLHEAD OIL PRICE	13.22	12.42	14.66	17.05	19.38	21.61	23.91	26.16	28.37	30.70	33.32	35.99
GROSS REVENUE	$0	$0	$0	$0	$155	$324	$478	$523	$567	$614	$666	$612
TOTAL OPERATING COST	0	0	0	0	51	93	151	157	162	168	174	180
COST SHARING FEE	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	0	0	0	0	41	72	113	113	113	113	113	113
CUM OP COST IN CONST $	0	0	0	0	41	113	226	339	452	565	678	791
ROYALTY	0	0	0	0	30	62	92	100	109	118	128	117
SEVERANCE TAX	0	0	0	0	5	10	19	18	19	25	27	15
AD VALOREM	0	0	0	0	28	28	28	28	28	28	27	27
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	1	1	1	1	1	1	1
STATE NET PROFIT INTEREST	0	0	0	0	28	89	127	149	170	187	211	186
STATE INCOME TAX	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	0	0	0	0	91	190	267	297	326	359	394	345
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	0	0	0	0	13	42	59	70	79	87	98	87
TOTAL INVESTMENT	0	434	450	538	75	78	40	42	14	0	0	0
CUM INVESTMENT IN CONST $	0	385	770	1,215	1,275	1,335	1,365	1,395	1,405	1,405	1,405	1,405
TOTAL CASH FLOW	$0	$-434	$-450	$-538	$-62	$-36	$19	$28	$65	$87	$98	$87

NOMINAL DISCOUNT RATE IS 10%

CUM PW TOTAL CASH FLOW	$0	$-311	$-603	$-921	$-955	$-972	$-964	$-952	$-929	$-899	$-870	$-846
CUM PW STATE REVENUE	0	0	0	0	49	141	260	380	500	620	739	835
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0	0	0

SEAL ISLAND / NORTHSTAR, WITH NET PROFITS INTEREST PAGE 2

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
OIL PRODUCTION RATE, Mbbl/day	39.59	33.65	28.60	24.31	20.67	17.57	14.93	0.00	0.00	0.00
OIL PRICE	$45.31	$47.73	$50.27	$52.92	$55.70	$58.08	$60.58	$63.18	$65.89	$68.75
WELLHEAD OIL PRICE	37.90	39.76	41.83	43.66	45.38	46.48	47.05	48.69	46.99	47.89
GROSS REVENUE	$548	$488	$437	$387	$342	$298	$256	$0	$0	$0
TOTAL OPERATING COST	186	186	186	186	186	186	186	0	0	0
COST SHARING FEE	0	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	113	109	105	102	98	95	92	0	0	0
CUM OP COST IN CONST $	904	1,013	1,119	1,221	1,319	1,414	1,506	1,506	1,506	1,506
ROYALTY	105	94	84	74	66	57	49	0	0	0
SEVERANCE TAX	9	8	7	6	5	4	4	0	0	0
AD VALOREM	26	25	25	24	23	22	21	0	0	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	1	0	0	0	0	0	0	0	0	0
STATE NET PROFIT INTEREST	150	119	92	66	43	19	-2	0	0	0
STATE INCOME TAX	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	291	247	208	170	136	103	71	0	0	0
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	70	56	43	31	20	9	-1	0	0	0
TOTAL INVESTMENT	0	0	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405
TOTAL CASH FLOW	$70	$56	$43	$31	$20	$9	$-1	$0	$0	$0

NOMINAL DISCOUNT RATE IS 10%

CUM PW TOTAL CASH FLOW	$-828	$-815	$-807	$-801	$-797	$-796	$-796	$-796	$-796	$-796
CUM PW STATE REVENUE	908	964	1,007	1,039	1,062	1,078	1,089	1,089	1,089	1,089
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Real 1996 Dollars)	
State Revenues			
State Royalty	256	256	257
State Supplemental Royalty	37	0	0
NPSL	0	85	41
State Share of Federal Royalty	16	16	16
Severance Tax	58	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	42	42	46
Income Tax	24	22	23
Total	435	481	444
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	215	198	213
Total	259	243	258
BPXA Cash Flow			
After Tax Funds Flow	349	318	346
Real Rate of Return	20.0%	19.9%	20.4%

Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '96 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
	(Discounted Net Present Value*)		
State Revenues			
State Royalty	169	169	140
State Supplemental Royalty	20	0	0
NPSL	0	37	14
State Share of Federal Royalty	11	11	9
Severance Tax	43	43	36
Spill & Conserv. Tax	2	2	1
Ad Valorem Tax	27	27	25
Income Tax	15	14	12
Total	286	303	237
Federal Revenues			
Royalty (Net of State Share)	29	29	44
Income Tax	133	127	213
Total	162	156	258
BPXA Cash Flow			
After Tax Funds Flow	167	155	139

*Assuming 10 percent nominal discount rate. Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

CORRECTION

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

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Real 1996 Dollars)	
State Revenues			
State Royalty	256	256	257
State Supplemental Royalty	37	0	0
NPSL	0	85	41
State Share of Federal Royalty	16	16	16
Severance Tax	58	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	42	42	46
Income Tax	24	22	23
Total	435	481	444
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	215	198	213
Total	259	243	258
BPXA Cash Flow			
After Tax Funds Flow	349	318	346
Real Rate of Return	20.0%	19.9%	20.4%

Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Nominal Dollars*)	
State Revenues			
State Royalty	317	317	350
State Supplemental Royalty	51	0	0
NPSL	0	127	69
State Share of Federal Royalty	20	20	22
Severance Tax	67	67	75
Spill & Conserv. Tax	3	4	4
Ad Valorem Tax	53	53	63
Income Tax	30	27	32
Total	541	615	615
Federal Revenues			
Royalty (Net of State Share)	55	55	61
Income Tax	273	247	295
Total	328	302	356
BPXA Cash Flow			
After Tax Funds Flow	478	429	516
Real Rate of Return	20.0%	19.9%	20.4%

*Assuming 3.2 percent inflation rate from DOR Fall 1995 Base Price Forecast. Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
	(Discounted Net Present Value*)		
State Revenues			
State Royalty	169	169	140
State Supplemental Royalty	20	0	0
NPSL	0	37	14
State Share of Federal Royalty	11	11	9
Severance Tax	43	43	36
Spill & Conserv. Tax	2	2	1
Ad Valorem Tax	27	27	25
Income Tax	15	14	12
Total	286	303	237
Federal Revenues			
Royalty (Net of State Share)	29	29	44
Income Tax	133	127	213
Total	162	156	258
BPXA Cash Flow			
After Tax Funds Flow	167	155	139

*Assuming 10 percent nominal discount rate. Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '93 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

Accounting for the effects of "Price Volatility"	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Real 1996 Dollars)	
State Revenues			
State Royalty	255	256	257
State Supplemental Royalty	50	0	0
NPSL	0	107	41
State Share of Federal Royalty	16	16	16
Severance Tax	56	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	40	40	46
Income Tax	24	22	23
Total	444	502	444
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	218	198	213
Total	262	242	258
BPXA Cash Flow			
After Tax Funds Flow	355	319	346
Real Rate of Return	20.8%	21.1%	20.4%

*Assuming 3.2 percent inflation rate from DOR Fall 1995 Base Price Forecast. Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

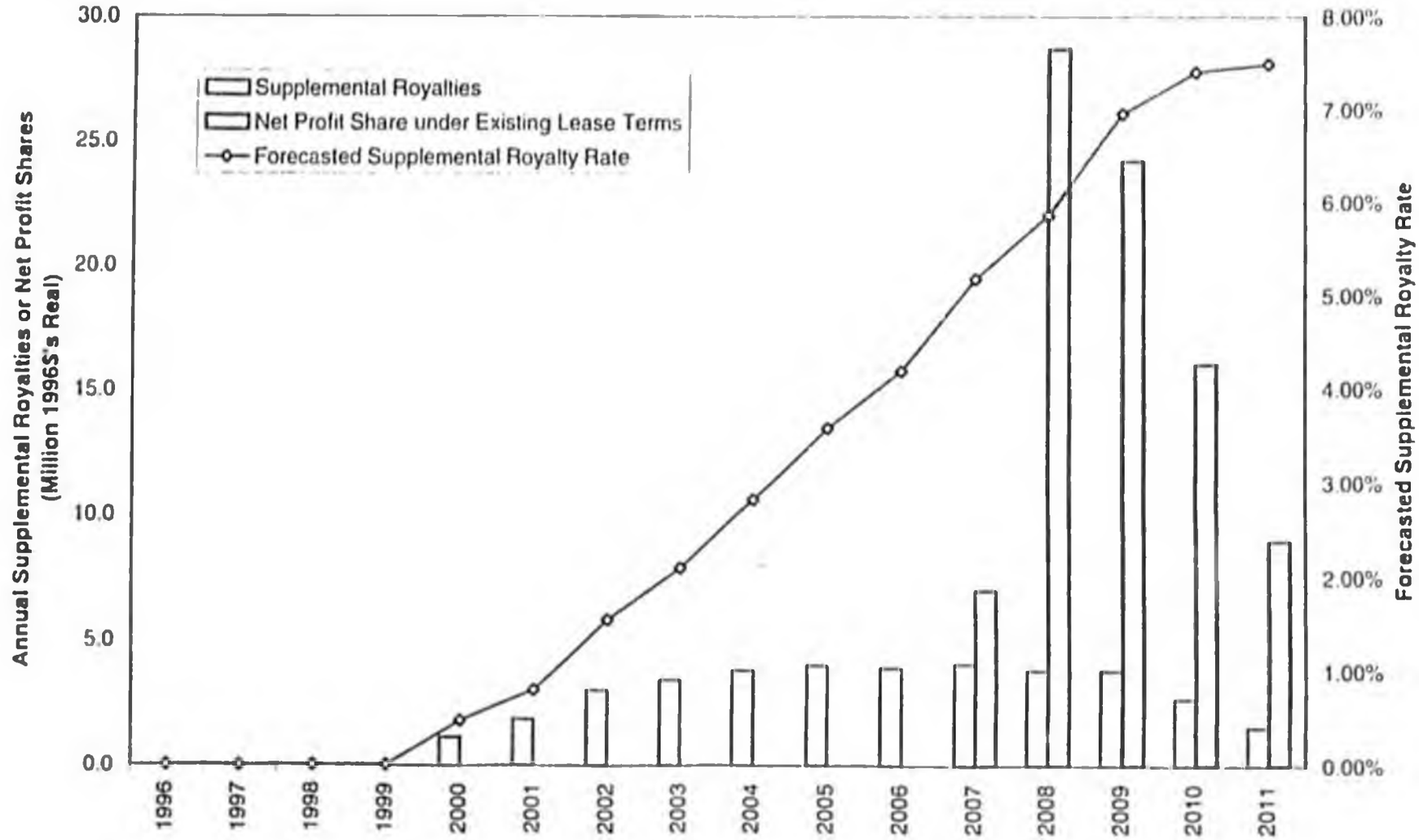
Accounting for the effects of "Price Volatility"	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Nominal Dollars*)	
State Revenues			
State Royalty	317	318	350
State Supplemental Royalty	64	0	0
NPSL	0	158	69
State Share of Federal Royalty	20	20	22
Severance Tax	65	67	75
Spill & Conserv. Tax	3	4	4
Ad Valorem Tax	50	50	63
Income Tax	30	27	32
Total	551	643	615
Federal Revenues			
Royalty (Net of State Share)	55	55	61
Income Tax	277	245	295
Total	332	300	356
BPXA Cash Flow			
After Tax Funds Flow	486	427	516
Real Rate of Return	20.8%	21.1%	20.4%

*Assuming 3.2 percent inflation rate from DOR Fall 1995 Base Price Forecast. Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Proposal

Forecast of Net Profit Shares, Supplemental Royalties and Rates



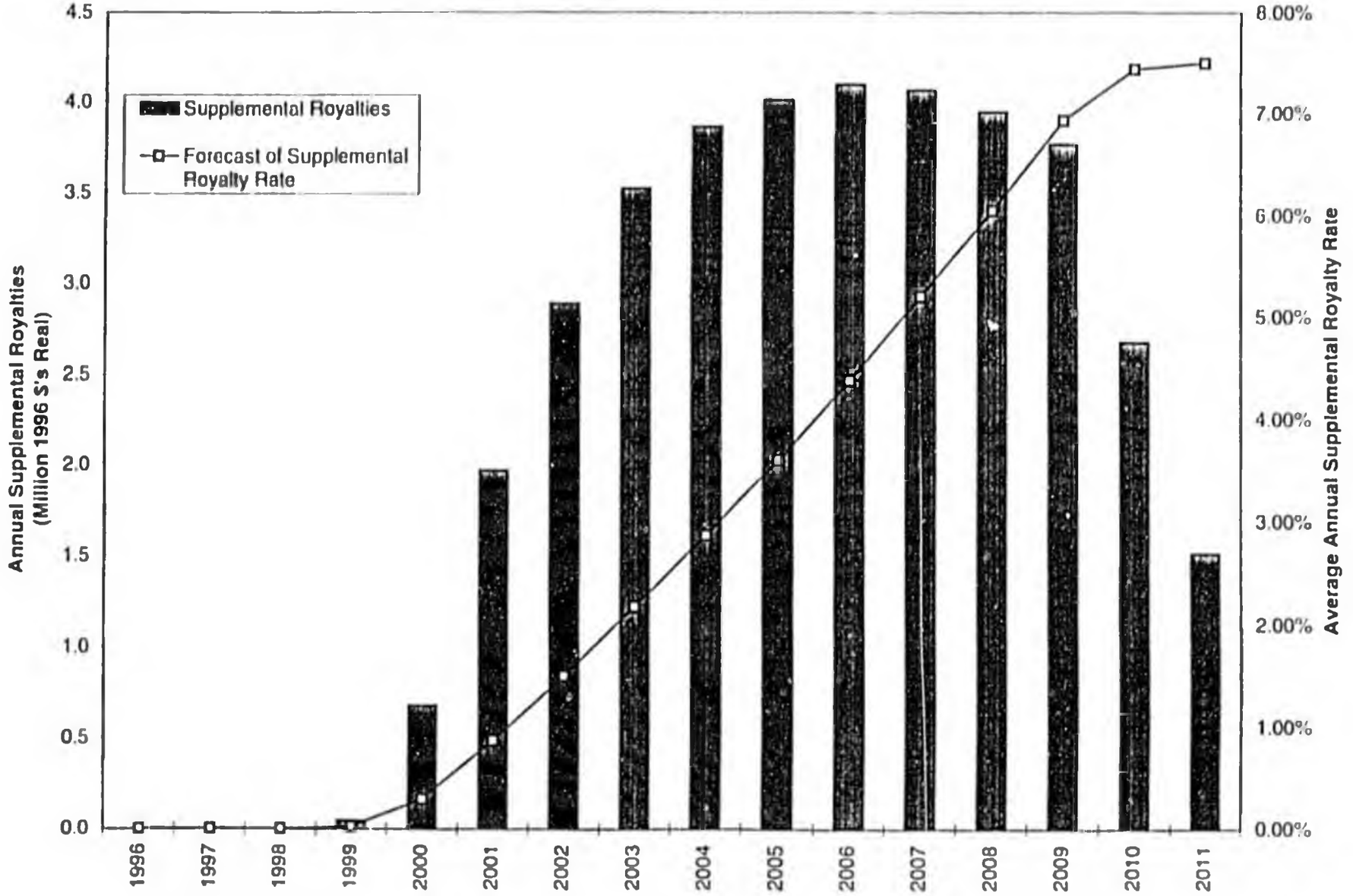
(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

BPNSU9A 320, SR&SRR (2)

3/28/96, 2:12 PM

Northstar Proposal

Forecast of Supplemental Royalties and Rates



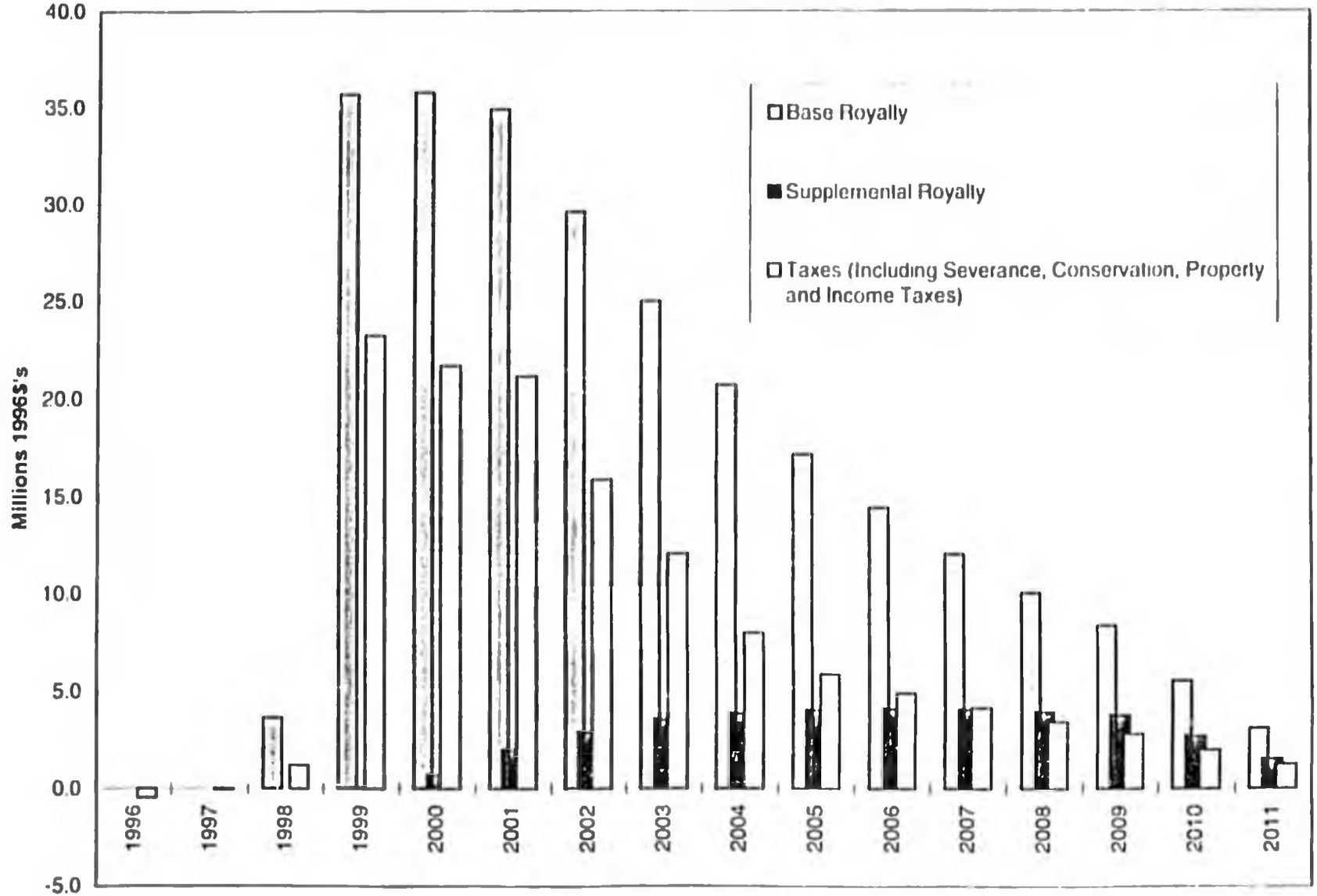
(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

BPN3U8B 311, SR&SRR

3/18/96, 10:27 AM

Northstar Proposal

Forecast of State Revnues



(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

MEMORANDUM

State of Alaska
Department of Law

TO: Honorable John T. Shively
Commissioner
Department of Natural Resources

DATE: March 26, 1996

FILE NO.: 663-96-0441

TELEPHONE NO.: 465-3600

FROM: James L Baldwin
Assistant Attorney General
Governmental Affairs - Section

SUBJECT: Necessity for legislation to implement net profit share reduction

We were asked whether the Commissioner of Natural Resources has the statutory authority to reduce the net profit share payments required under the Northstar leases held by BP Exploration (Alaska) Inc. After considering that question, we conclude it would be prudent to seek express statutory authority for this action. We also discuss other legal issues that bear on proposed remedial legislation.

1. Authority Under Existing Law.

Alaska Statute 38.05.180 is a comprehensive statute which sets out the Commissioner of Natural Resources' authority regarding oil and gas leasing. Section 180 contains express authority in two subsections for the commissioner to modify the royalty provisions of an oil and gas lease. However, neither section 180 nor the Alaska Land Act (AS 38.05) defines the meaning of the term "royalty." To add to the difficulty of statutory construction, section 180 lacks express authority for reduction of a net profit share interest.

The Northstar leases are within the Northstar unit. To implement unitization of a field,

> The commissioner may, with the consent of the holders of the leases involved . . . change . . . royalty requirements of the leases . . . .

AS 38.05.180(p); (emphasis added). Section 180(p) provides that a change may be made "in connection with the institution and operation of a cooperative unit plan." The Department of Natural Resources (department) interprets section 180(p) to be applied only at the institution of a unit. For this reason, section 180(p) is not germane to the instant transaction. In any case, section 180(p) was amended during the first session of the Nineteenth Alaska State legislature to provide in part that the commissioner

> "may not decrease royalty on leases in connection with a cooperative or unit plan except as provided in (j) of this section.

Sec. 3 , ch. 85, SLA 1995. Section 180 (j) permits the commissioner to

> provide for an increase or decrease or otherwise modify royalty, to allow for production that would not otherwise be economically feasible. . . .

Section 180(j) contains intrinsic evidence that the legislature meant only to cover the royalty share in amount or value of production removed from the lease. For example, in section 180(j)(3)(C)(i) and (4)(A) limits are imposed on the commissioner's power to reduce a royalty using the terms "royalty percentage" or "royalty rate." The use of these terms is evidence that the legislature meant section 180 (j) to apply only to a share in the amount or value of production, not to a reduction of a share of the net profit derived from the lease. The foregoing intrinsic evidence of meaning is consistent with your testimony given when section 180(j) was under consideration before enactment by the legislature. You testified, "there was no reference made in [SB 207] to 'net profits leases'. . . . There could be negotiation on the base royalty, but not the net profit portion." Senate Finance Committee Minutes, SB 207, May 11, 1995 . Senate Bill 207 was never subsequently amended to cover the omission highlighted by the commissioner. Senate Bill 207 was passed by the legislature was signed into law by the governor and became ch. 85, SLA 1995.

There is no commonly understood definition of a net profit share.[1] A net profits interest may be interpreted to be either the equivalent of a royalty which is an interest in land, or it could be considered only a contract right which is severable from an interest in realty. We would be remiss if we did not acknowledge that the department has without discussion, on occasion, interpreted the term "royalty requirements" in section 180 (p) to include a net profit share interest. Similarly, the Minerals Management Service, the federal agency equivalent to the Division of Oil & Gas, has interpreted the term "royalty," in the context of a royalty reduction, to include net profit share payments. See 30 C.F.R. § 203.50. The past administrative interpretations of the department are limited in number and of fairly recent origin. For this reason, we are unable to conclude there has been a contemporaneous construction that a net profit share is included within the meaning of "royalty." For these reasons and the analysis of the relevant provisions discussed above, we believe there is substantial doubt that section 180 prescribes a method for reducing a net profit share interest.

We believe that it would not be prudent to assume that the term "royalty," as used in subsection (p), includes net profit share payments. If that were the case, the commissioner's only statutory authority to reduce the net profit share payments required under the Northstar Unit leases

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[1] See Christy v. Petrol Resources Corp., 691 P.2d 59, 61 (N.M. App. 1984)("net profits interest" has no independent meaning, and nature of the interest must be determined from provisions of the instrument creating it).

is set out in AS 38.05.180(j). For the reasons stated above, we believe that a decision to reduce a net profit share using the authority contained in section 180(j) would be vulnerable to a judicial challenge. Further, under section 180 (j), the commissioner may reduce royalty on unitized leases if the lessee makes a "clear and convincing showing that a modification of royalty meets the requirements of this section and is in the best interests of the state." AS 38.05.180(j)(2). The purpose of subsection (j) is "to allow for production that would not otherwise be economically feasible." You have informed us that the Northstar Unit development does not meet this standard. It would be preferable to seek independent authority for the Northstar net profit share reduction in a way that would bring certainty to the state and the leaseholder while avoiding these difficult legal issues.[3]

2. Local or Special Legislation

The department intends to seek the narrowest possible provision to specifically authorize amendments to only the Northstar leases. Consistent with your instructions, we have prepared a bill to accomplish this goal. You ask whether such a bill would violate the Alaska Constitution. The prohibition against local or special legislation provides:

> The legislature shall pass no local or special act if a general act can be made applicable. Whether a general act can be made applicable shall be subject to judicial determination.

Alaska Const. Art. II, Sec. 19

Section 19 has not been recently applied by the Alaska Supreme Court. In 1975, section 19 was applied to invalidate a statute that mandated the creation of an Eagle River-Chugiak Borough. Abrams v. State, 534 P 2d 91 (Alaska 1975). In Abrams, the court recognized that a statute may affect only one of a few areas and yet relate to a matter of statewide concern or common interest.

In 1977, section 19 was again applied to validate a statute authorizing a trade of land between the federal government, the state, and a Native regional corporation. State v. Lewis, 559 P.2d 630 (Alaska 1977), cert. denied, 432 U.S. 901 (1977). The court found that the land trade was unique, but of statewide concern. The Lewis court propounded a test to be used in determining whether a statute violates the special or local prohibition. It was substantially the same as the test used to determine the validity of nonsuspect classifications challenged as violative of equal protection. The state merely had to show a rational basis, a good reason, to justify the special treatment.

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[3] There may be implied authority to amend the net profit share term of an oil and gas lease granted under AS 38.05.180. While that authority may exist, it has never been used to reduce a net profit lease. On a matter of such significance, this transaction should not become the test case.

In 1978, the court articulated a unified equal protection analysis that avoids distinguishing between suspect and nonsuspect classifications by using a sliding scale to weigh the interests involved in any classification. State v. Erickson, 574 P.2d 1 (Alaska 1978). The court applies a single test that is flexible and dependent on the importance of the rights involved. The more fundamental the right involved, the more compelling the interest the state must have for preferring one classmember over another. Commercial Fisheries Entry Commission v. Apokedak, 606 P.2d 1255 (Alaska 1980).

There has not been a case involving the local or special legislation prohibition since the unified equal protection test was adopted by the court. It remains to be seen how the court will apply an equal protection analysis to a statute claimed to violate section 19.

According to the department, there are approximately 39 leases carrying net profit share provisions. It is possible that other leaseholders will claim discrimination if they are not also given relief from a corresponding net profit share provision. We doubt that a leaseholder would prevail in a claim that a statute permitting the reduction of a leaseholder's net profit share interest implicates a fundamental right. It is not a foregone conclusion that the other leaseholders are similarly situated to the Northstar leaseholder. We doubt there is a class of similarly situated leaseholders who would be discriminated against by a bill that only applies to the Northstar leases. The effect of a net profit share on a specific field will be subject to different economic assumptions (except price).

The state's interest advanced by the proposed statute is to bring the Northstar leases into production in a way that also encourages other employment and economic activity in the state. The state depends on petroleum revenues for approximately 85 percent of its general fund revenues. For this reason, a statute specifically directed to the Northstar leases can be said to have statewide significance. The reduction in net profit sharing is tied to promises of local manufacture and assembly of facilities to develop the leases. This will lead to substantial economic activity in the railbelt region of the state in which over half of the population of the state resides. There will be a direct economic benefit to the North Slope Borough derived from increased tax revenues. Production from the Northstar Unit will decrease the TAPS tariff for all existing North Slope fields and will likely extend the life of TAPS thereby making it more likely that fields not currently in production can be brought into production.

It will be the department's responsibility to carefully articulate the state's interest during legislative hearings on the bill proposing the net profit share reduction. This must be done with the goal in mind of establishing a detailed legislative history supporting the interests of the state. The legislative history will be important because the ultimate decision "whether a general act can be made applicable" rests with the Alaska Supreme Court.

3. Public Purpose.

The proposed reduction in the net profits share provisions of the Northstar leases raises the question of whether there might be an expenditure of future state revenues without a valid public purpose. It is debatable how much revenue, if any, would be foregone if the reduction in net profit share takes effect. The amount is dependent on when the leases go into production, the value of oil and other production from the lease, and when the leases become profitable under 11 A.A.C. 83.210 - .295.

The Alaska Constitution requires that state money be expended only for public purposes. Alaska Const. art. IX, sec. 6. To satisfy the public purpose doctrine, the benefit to the public must be the direct and primary purpose of an expenditure. It is permissible if the expenditure also has an indirect private benefit. However, the reverse (direct private benefit with only secondary, indirect public benefit) constitutes violation of the public purpose doctrine.

The analysis is similar to a determination whether there is adequate consideration to support a contract. If there is valuable consideration received by both the state and the leaseholder, the benefit to the state may be characterized as direct. In the case of the Northstar leases, there is a trade-off between expedited development of the leases and the loss of uncertain future revenue. The expedited development comes combined with in-state manufacture and assembly of production facilities. The magnitude of the loss in revenue is highly speculative because the value of production from the leases depends on the whims of the marketplace.

Because the State leased the oil rights at the Northstar field pursuant to the constitutional mandate to obtain the maximum public benefit, an effort to expedite production vitally affects the public interest. See Swindel v. Kelly, 499 P.2d 291, 298 n 27 (Alaska 1972)(ruling that State Constitution recognizes value of all public lands); Alyeska Ski Corp. v. Holdsworth, 426 P.2d 1006, 1011 (Alaska 1967)(ruling that "our constitution reflects . . . the importance of our land resources and of the concomitant necessity for observance of legal safeguards in the disposal or leasing of state lands.") See also Trustees For Alaska v. State, 736 P.2d 324, 335 (Alaska 1987)(finding that State was granted large land holdings under the Statehood Act to "ensure the economic and social well-being of the new state.") Given the public's vital interest in deriving the maximum benefit from the leasing of state lands, the court would likely liberally construe the proposed net profit share reduction provisions in the State's favor. See State v. Moncrief, 720 P.2d 470, 475 (Wyo. 1986)(stating that if a governmental mineral lease is ambiguous, a court must then recognize that the government officials' duty "to realize the largest possible proceeds is a surrounding circumstance which must be considered when interpreting these leases.")

The Alaska Supreme Court tends to give a certain amount of deference to the judgment of the legislature concerning whether and how state resources may be expended for a particular purpose. See, DeArmond v. Alaska State Development Corporation, 376 P.2d 717, 721

(Alaska 1962)(court will not set aside finding of public purpose unless it clearly appears that such finding is arbitrary and without any reasonable basis in fact). To be sure, there will be some uncertainty if this question is litigated. The Alaska Supreme Court has stated that the phrase "public purpose" represents a concept which is not capable of precise definition. DeArmond, 376 P.2d at 721; Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966). The concept is an evolving one for which "it would be a disservice to future generations for [the Supreme Court] to attempt to define . . . ." Id. The court will examine the "entire factual and governmental context to determine whether a particular plan of action serves a public purpose." Wright v. City of Palmer, 468 P.2d 326, 330 (Alaska 1970)(citation omitted). In essence, a determination of public purpose must be made in each case on the basis of the particular facts and circumstances. DeArmond, 376 P.2d at 721.

We believe that a compelling case can be made that there is adequate consideration to support a finding of a direct and substantial public benefit flowing from the reduction of the net profit share. We assign a low probability to the possibility of a successful challenge based on the public purpose doctrine.

4. Competitive Bidding Principles

It may be possible to consider a net profit share to be a contract right of the leaseholder. A public contract can be amended by the contracting parties. The power to amend a public contract is a necessary element of contract administration. It is not certain that judicial constructions of the ability of an administrative officer to amend a public contract will apply to the power to amend a contract right conveyed along with an oil and gas lease.

The power of amendment has its limits. The ability to amend is greatly restricted if the contract was awarded through the competitive bidding process. The reason for this is the premise that a material change in a competitively bid contract amounts to a new contract. McKinnon v. ALPETCO, 633 P.2d 281, 287 (Alaska 1981). A new contract can only be awarded through another round of competitive bids. Id.

The rule against material amendments was applied in Kenai Lumber Co., Inc v. LeResche, 646 P 2d 215 (Alaska 1982). In Kenai Lumber, the Alaska Supreme Court offered factors for determining when an amendment is material. These factors include:

(1) the legitimacy of the reasons for the change;

(2) whether the reasons for the change were unforeseen at the time the contract was made;

(3) the timing of the change;

(4) whether the contract contains clauses authorizing modifications; and

(5) the extent of the change relative to the original contract.

646 P.2d at 221.

It may be possible to formulate an argument that the reasons for amending the Northstar leases are legitimate and were unforeseen at lease formation. The timing of the change is sufficiently distant from formation of the leases to negate any claim that it is a pretext to avoid resolicitation of the leases. However, the extent of the change is substantial enough to raise serious questions as to whether factor (5) above can be satisfied. Other persons who competed for the leases may claim that since the net profit share was the sole variable in the lease sale, it is such a material term that a change cannot be made without violating the competitive bidding statute. Uncertainty concerning the state's prospects for prevailing in any litigation on this issue gives an additional basis for our advice that the department seek independent statutory authority for the Northstar transaction. The Alaska Supreme Court has held that competitive bidding is not necessary unless "required by constitution, statute, ordinance or regulation." McKinnon, 633 P.2d at 287. If the legislature were to directly authorize the amendments to the Northstar leases, that authorization would take precedence over any other statute requiring competitive bids, just as section 180(j) takes precedence over any other competitive bidding statute.

We hope that the foregoing memorandum adequately addresses the reasons why it would be prudent to seek specific authority from the legislature to reduce the net profit share provisions applicable to the Northstar leases. We are prepared to assist the Department of Natural Resources in seeking passage of a bill to accomplish this purpose.

JLB/clh

LEGAL SERVICES

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Juneau, Alaska 99801-2105

MAR 2 5 1996

MEMORANDUM March 25, 1996

SUBJECT: Renegotiation of State Oil and Gas Lease

TO: Senator Drue Pearce
President of the Senate

FROM: Jack Chandler
Legislative Counsel

I am responding to three questions set out in your March 22 memo.

1. I have not found explicit statutory or regulatory authority to renegotiate an oil and gas lease as seems to be contemplated in the North Star field lease. See, by way of specific example, 11 AAC 71.205 authorizing amendment of timber and materials contracts except that the amendment "may not materially affect or change the meaning or intent of the contract," 11 AAC 71.205(b). The lease documents applicable to the North Star field lease may authorize or provide for renegotiation under specific circumstances, but I don't know this.

Even absent an explicit statute or regulation or provision in the lease, as a matter of general law, negotiations may be initiated to amend a competitively bid public contract. 72 C.J.S. Supp., "Public Contracts," sec. 24. However, amendments to competitively bid contracts are prohibited if the amendments proposed are "material," that is to say, competitively bid contracts may not be materially amended. McKinnon v. Alaska, 633 P.2d 281, 287 (Alaska 1981), Kenai Lumber Company v. Lafferty, 646 P.2d 215, 221 (Alaska 1982). Amendments to a contract are "material" if they involve the alteration of factors that influence the judgment or decision on the award of the contract. Brown v. Ward, 593 P.2d 247, 250 (Alaska 1979), Cowdrey v. Walker, 613 P.2d 608, 613 (Alaska 1980). Based on the pre-lease analysis, the state's choice of leasing method--including the decision to take net profit share using the amount reserved as the bid variable (which I think is what is at work in the award of the original North Star field lease)--seems to be "material" by any measure.

2. Without having a notion of what the administration may choose to offer, still, I think the administration will, in one way or another, ask the legislature to ratify or validate modifications proposed to the North Star lease

An Act or public enactment to validate the modification of a public contract is a form of curative legislation. Yellen v. Plants, 69 N.E.2d 540 (Indiana 1960); C. Sands, Sutherland Statutory Construction, sec. 71.07. As a general rule, curative legislation is valid (1) when the legislature originally had power to authorize the acts that were done and (2) the curative legislation does not impair a vested right in violation of constitutional provisions prohibiting impairment of contract. Fairbanks North Star Borough v. State, 753 P.2d 1158, 1160 (Alaska 1988). The legislature might have authorized renegotiation of public contracts, and, depending on what is examined, it is more probable than not that the proposed legislation would not impair a vested right (assuming that the state administration is prepared to waive the right to receive revenue under the original lease by shifting from one choice of leasing method to another).

A validating or curative act is usually subject to the "local or special" act limitations of a state constitution. C. Sands, Sutherland Statutory Construction, secs. 41.11 - 41.13. Even if it was a consideration in this instance, there is, it seems to me, good chance that the court would find the test of Abrams v. State, 534 P.2d 91 (Alaska 1975) to control and determine that the modification of an oil and gas lease with significant potential revenue-producing capacity is a matter of common interest to the whole state, having, through the contributions to the state treasury, probable statewide interest and impact, and therefore not subject to the local and special legislation prohibition provision.

It is also possible, of course, that the legislation sponsored by the administration will be general, in that it will authorize renegotiations of all or some types of oil and gas leases. That type of legislation, potentially applying to other leases as well as the North Star lease, would avoid the "local or special act" question altogether.

3. Your memo describes legislation that addresses the possibility that the state may receive less revenue than originally anticipated. It does not propose to withdraw money from the state treasury, therefore an act addressing renegotiation of the lease is not to be regarded as an appropriation.

JBC:gle
96-177.gle

BIDDING PROCESS

waived, either expressly[11] or impliedly.[12] We have no difficulty finding a waiver under the facts of this case. The plaintiffs diligently sought adjudication of the class action issues by twice moving for certification. The defendants initiated summary judgment proceedings while plaintiffs' second motion for certification of the class action was pending. Under these circumstances, the trial court did not err in ruling on the merits and then certifying the class.

B. *Did the Trial Court Err in Finding that the Named Plaintiffs Provided Adequate Representation for the Class?*

Civ. Rule 23(a)(4) provides that a class action can be maintained only if "the representative parties will fairly and adequately protect the interests of the class." The defendants contend that the plaintiffs could not provide adequate representation for the class because they had interests antagonistic to other members of the class.

[7] First, the determination of the adequacy of representation is a class action is a question of fact. *Garrison v. J & W Investment, Inc.*, 544 P.2d 903, 906 (5th Cir. 1977); 7 C. Wright & A. Miller, Federal Practice and Procedure § 1765, at 622-23 (1972). As a question of fact, the trial court's finding will not be reversed unless clearly erroneous; in other words, the trial court will not be reversed unless, in light of the whole record, it can be said with a definite and firm conviction that the trial judge was clearly mistaken. *Alaska Finals, Inc. v. American Mfrs. Mut. Ins. Co.*, 482 P.2d 842, 848 (Alaska 1971).

[8] Second in order to bar a suit, the antagonism "must be as to the subject matter of the suit." *Berman v. Narragansett Racing Ass'n*, 414 F.2d 311, 317 (1st Cir. 1969), cert. denied, 396 U.S. 1037, 90 S.Ct. 682, 24 L.Ed.2d 681 (1970); 7 C. Wright & A. Miller, supra, § 1768, at 620; 3B J. Moore, supra note 8, ¶ 23.07[3], at 23-227.

Third, it should be noted that in a suit to strike down a statute as unconstitutional, the requirement of adequate representation loses vitality. The effect of a finding of unconstitutionality will affect everyone, not just the parties before the court. "Thus even if [a] plaintiff is not a proper representative in the traditional sense, striking a class claim will not effectively change the end result if the party successfully proceeds on an individual basis." 7 C. Wright & A. Miller, supra, § 1771, at 644. *See also* 3B J. Moore, supra note 8, ¶ 23.40[3], at 23-299 n.15. In the present case, this would simply mean that the named plaintiffs would be burdened with the expenses of the suit without reimbursement from a class recovery. The effect of the action on the defendants and the rest of the class is the same whether the suit is brought as a class or as an individual action.

Finally, it should be noted that in a suit seeking to have a statute declared unconstitutional there are only two sides to the argument; either the statute is constitutional or it is not. In such a case where there are no inherent conflicts inter se among class members (such as rights to differing shares in a limited fund), the interests of class members antagonistic to the representatives' constitutional attack will usually be adequately represented by the defendants.

[9] In the present case, the trial court was not clearly erroneous in finding the representation of the class to be adequate. First, the major antagonism claimed was that most of the fishermen in the region had supported, by their votes, the voluntary assessments. Since the basis of this suit is the seeking of a declaration of the constitutionality of a statute, the rights of all class members are affected in the same way, whether or not it is brought as a class action. Moreover, the defendant associations and the state have vigorously opposed the constitutional attack of the plaintiffs and have thereby necessarily represented the interests of antagonistic class members to have the statute declared constitutional.

V. DID THE TRIAL COURT ERR IN FINDING THE DOCTRINE OF LACHES INAPPLICABLE?

The trial court held that the doctrine of laches was inapplicable on the facts of the present case. On appeal the defendants have contested this finding and both sides have extensively argued the traditional elements of laches, unreasonable delay and resulting prejudice. However, the discussion of the elements of laches is irrelevant since laches is simply inapplicable to any of the remedies sought in this case.

[10, 11] The suit seeks three basic forms of relief. First, a refund of all assessments paid under the statute is sought on a common count. Since this is a general assumpsit common law cause of action for the refund of taxes wrongly paid, the six-year statute of limitations contained in AS 09.10.05(3) would apply to this action at law. *State v. Wakefield Fisheries, Inc.*, 495 P.2d 166, 172 (Alaska 1972). The other two types of relief sought, a declaratory judgment and a permanent injunction, are prospective in application and seek to prevent future threatened harm. A laches analysis is simply inappropriate, since each new assessment would give rise to a new cause of action.

VI. DID THE COURT ERR IN FINDING THE DOCTRINE OF EXHAUSTION OF ADMINISTRATIVE REMEDIES INAPPLICABLE?

[12] The trial court was correct in holding inapplicable the doctrine requiring the exhaustion of administrative remedies before seeking relief in the superior court. *See* Davis, Administrative Law Treatise § 20.04 (1st ed. 1958). This was not an administrative adjudicatory proceeding which had various routes of administrative appeal. Rather, the implementation of the salmon assessment was administrative legislative action not subject to appeal. The only action which the fishermen could take in the administrative process was to vote in the election on a proposed assessment. There simply were no administrative remedies to exhaust.

The judgment of the superior court is AFFIRMED in all respects.

KENAI LUMBER COMPANY, INC., Appellant,

v.

Robert LeRESCHE, Commissioner of Dept. of Natural Resources of the State of Alaska; Geoffrey Haynes, Director of Division of Lands of Dept. of Natural Resources; Frederick H. Boness, Deputy Commissioner of Dept. of Natural Resources, and South-Central Timber Development, Inc., Appellees.

SOUTH-CENTRAL TIMBER DEVELOPMENT, INC., Cross-Appellant and Appellee,

v.

KENAI LUMBER COMPANY, INC., Cross-Appellee and Appellant.

Nos. 5722, 5735.

Supreme Court of Alaska.

June 11, 1982.

Competitive timber company brought action challenging amendment to timber harvesting contract. The Superior Court, Third Judicial District, J. Justin Ripley, J., entered summary judgment, and appeal was taken. The Supreme Court, Matthews, J., held that: (1) rule prohibiting material modifications to competitively bid contracts did not apply to amendment to timber harvesting contract similar to the amendment

waived primary manufacturing requirement and altered harvesting economics by removing certain lands from contract area and substituted other lands; (2) timber harvesting contract amendment substituting land for land originally included in contract area was not "material" for purposes of rule prohibiting material changes in public contracts let under competitive bidding, even though substituted land was never subject of competitive bidding process; (3) fact that losing party's attorney fees amounted to far less than sum prevailing party paid its attorneys did not demonstrate that award to prevailing party of attorney fees was manifestly unreasonable; and (4) competitor timber company's economic incentive to bring action challenging amendment of public timber harvesting contract, even if suit did not involve issue of alleged circumvention of competitive bidding process prevented claimed public interest from precluding award of attorney fees.

Affirmed.

Rabinowitz, C. J., dissented and filed opinion.

1. States ⇐106

Rule prohibiting material modifications in competitively bid contracts did not apply to amendment to timber harvesting contract insofar as the amendment waived primary manufacturing requirement and altered harvesting economics by removing certain lands from contract area and substituting other lands where price of timber harvested was, at time of amendment, to be determined by state appraisals, such appraisals were to be based on current market and cost conditions and were not indexed to original bid price, primary manufacturing requirement detracted from rather than added to value of end product, and changes in harvesting economics were conditions to be reflected in price reappraisals to be made under the contract. AS 38.05.115, 38.05.123.

2. States ⇐106

Timber harvesting contract amendment substituting land for land originally included in contract area was not "material" for purposes of rule prohibiting material changes in public contracts let under competitive bidding, even though substituted land was never subject of competitive bidding process, where reason for amendment was discovery by Department of Fish and Game that included area contained important winter habitat for mountain goats, the Department requested the sale be modified by deleting such area, and importance of the deleted area as wildlife habitat was not appreciated when original contract was made. AS 38.05.115, 38.05.123.

3. Public Contracts ⇐18

Not all amendments to competitively bid contracts are prohibited, only those regarded as material. AS 38.05.115, 38.05.123.

4. Appeal and Error ⇐984(5)

The determination of court-awarded attorney fees is committed to discretion of trial court and reviewable on appeal only for abuse of discretion; such abuse is regarded as present only where trial court's decision appears to be manifestly unreasonable or motivated by inappropriate purpose.

5. Costs ⇐172

Fact that losing party's attorney fees amounted to far less than sum prevailing party paid its attorneys did not demonstrate that award to prevailing party of attorney fees was manifestly unreasonable.

6. Costs ⇐172

Competitor timber company's economic incentive to bring action challenging amendment of public timber harvesting contract, even if suit did not involve issue of alleged circumvention of competitive bidding process, prevented public interest from precluding award of attorney fees.

Richard Hoin and Mark L. Fly, Jr., Burr, Pease & Kurtz, Inc., Anchorage, for appellant.

Shirley J. Higgins, Asst. Atty. Gen., Anchorage and Wilson L. Condon, Atty. Gen., Juneau, for appellees.

Leroy DeVaney and James N. Wanamaker, Wanamaker, DeVaney & Crabtree, Anchorage, for cross-appellant, South-Central.

Before RABINOWITZ, C. J., and CONNOR, BURKE, MATTHEWS and COMPTON, JJ.

OPINION

MATTHEWS, Justice.

In this case we are asked to review the legality of a negotiated amendment to a long term timber sale contract between the State of Alaska and South-Central Timber Development, Inc. The amendment has been challenged by Kenai Lumber Company, Inc., which operates a currently underutilized sawmill in Seward, and competes with South Central in the purchase of timber. The basis for Kenai's claim is that the changes which the amendment makes are so significant that they amount to a circumvention of the competitive bidding process under which the original contract was let. The trial court on cross motions for summary judgment ruled that the amendment was lawful. We agree for the reasons expressed herein.

I

The original timber sale contract, designated Icy Cape No. 1, was made on December 1, 1969 following advertisement for public bids pursuant to AS 38.05.120. South Central was the only bidder at the auction and received the award at the minimum stumpage prices established by the state.[1]

The sale area consists of approximately 13,760 acres in a remote location on the coast of south-central Alaska adjacent to Icy Bay. The contract estimates that some 20,000,000 board feet of timber can be taken from this area.[2] The contract requires all timber within the boundaries of the sale area meeting certain minimum specifications to be cut. The contract is to expire 20 years from the date of execution unless extended by the state. It contains a provision concerning the primary manufacture of the timber cut as follows:

> Timber cut under this contract shall not be transported for primary manufacture outside the State of Alaska without written approval of the state. Primary manufacture shall be as defined under Section 406.101 of the "Timber Sale Regulations" and as further defined in the Governor's Policy Statement for primary manufacture dated April 8, 1968, a copy of which is attached hereto and hereby made a part of this contract.[3]
>
> [illegible] (subject to a field showing of no severe or serious [illegible] on the basis of product)
>
> Primary manufacture, when used in reference to pulp ventures, means the breakdown process to a point where the wood fibers have been separated. Chips made from timber presently, wastes shall be considered to have received primary manufacture. With respect to veneer or plywood production, it means the production of green veneer. Poles and piling, whether treated or untreated, when manufactured to American Standards Association specifications are considered to have received primary manufacture.
>
> The Governor's Policy Statement for primary manufacture, referred to in the contract, provides:
>
> Chips may be manufactured from all species for export and shall be considered to have received primary manufacture when sawed up to a maximum thickness of 12 inches and may be of any width. Timber cut thicker than 12 inches must be squared on four sides along three entire length with allowances for one third of such dimensions (thickness and width) allowed as waste.

1. The prices were $7.00 per 1,000 board feet (net bd. ft.) for 10001 spruce saw logs and $2/m bd. ft. for hemlock saw logs.

2. Of the estimated approximately 19,200 m bd. ft. were Sitka spruce saw logs and 940,000 m bd. ft. were hemlock saw logs.

3. Section 406.101 of the Timber Sale Regulations in existence as of the date of execution of the contract provides:

> Primary Manufacture
>
> The Director may require that primary manufacture of logs, cants, boards, or other similar products be accomplished within the State of Alaska.
>
> The term primary manufacture means manufacture which is first in order of time in the shipping route. When used in relation to sawmilling, it means
>
> (a) The breakdown process wherein logs have been reduced to size by a headsaw or gang saw to the extent that the resultant cants, slabs, or planks can be processed by resaw equipment of the type customarily used in log processing plants, or
>
> (b) Manufacture of a product for use without further processing, such as structural

The contract calls for reappraisal of the prices of the timber at the end of five years after the effective date of the contract and thereafter in three year intervals.[4] A section of the contract incorporates by reference the state timber sale regulations. Of interest here is section 185 of the regulations pertaining to amendments and modifications:

> Amendments to and modifications of the contract may be made in writing and become a part of the contract upon mutual agreement of the director and the purchaser, provided that such amendment or modification does not materially affect or change the meaning or intent of the contract.[5]

From 1970 through 1978 South-Central cut timber from the sale, squared it in compliance with the primary manufacturing requirement at its mill on Jakolof Bay, several hundred miles from the sale area, and exported the squared timber, called "cants," to Japanese markets. During this period the contract was amended on six occasions. These amendments included two price changes under the reappraisal provisions of the contract,[6] and one amendment allowing 3,230,000 board feet of spruce and hemlock to be exported as round logs, that is, logs not subjected to primary manufacture.

The sixth amendment, agreed to in January of 1979, is the amendment in question in this case. The most important change it makes is that it waives the primary manufacturing requirement. Another important change deletes from the sale area all lands at an elevation above 400 feet and substitutes additional acreage. The deleted lands contain approximately 40,000,000 board feet of timber. About 14,000,000 board feet may be cut from the added acreage. The amendment also changes the stumpage prices, increasing the price of spruce to $80.00/m b f and of hemlock to $28.00/m b f. Other aspects of amendment No. 7 include a provision that South-Central must also take logs available only for the manufacture of wood pulp or pay a fine, a provision which on the whole increases the penalty imposed on South-Central for failing to remove trees meeting the contract specifications, a provision increasing the penalty for leaving high stumps, and a provision making the new state Forest Resources and Practices Act, AS 41.17.010-.950, applicable to the sale immediately rather than one year following the amendment as would otherwise be the case. At the time of the amendment it was estimated that the total harvestable timber remaining was some 87,000,000 board feet.

Due to a change in the administration of the air pollution control laws it became apparent in 1978 that South-Central's Jakolof Bay mill could not continue to operate beyond June of 1979 without making extensive changes in the burner used to dispose of the slabs created by primary manufacture. These changes were judged by South-Central to be economically untenable. South-Central therefore sought a waiver of the primary manufacture requirement from the state. The state granted the waiver, making the following findings:

> Chips made from timber processed under this waiver shall be considered to have received primary manufacture and export will be permissible on action of the Commissioner. Timber processing wastes as hereby defined as all timber, mill residue, logging residue or other material not presently being utilized or in demand for higher valued products.
>
> With the advance approval of the Commissioner, limited quantities of all species, excluding spruce and hemlock, may be exported in the form of round logs for experimental purposes only, e.g. to introduce a new product to market. Round logs may not be exported as a marketable commodity.
>
> The above statement is intended to clarify and/or define Section 606.104 of the "Timber Sale Regulations" and supersedes all previous policy statements and/or resolutions.

4. Apparently the intent of the contract was to allow two years for construction of the roads and loading facilities which would be needed before timber cutting and transportation could take place. A special provision of the contract required that a minimum of ten million board feet be cut and paid for by the end of the third year.

5. 11 A.A.C. 76.185.

6. The first effective December 1, 1974 changed spruce saw logs to $16.25/m b f and hemlock saw logs to $12.00/m b f and the second effective December 1, 1977 changed the price for spruce saw logs to $25.90/m b f and hemlock saw logs to $16.20/m b f.

> (1) Actually, only four jobs, those of sawyer, off bearer (of slab), millwright and night watchman, are added by the primary manufacture milling operations.
>
> (2) That the waiver of primary manufacture will provide economic incentive for the more intense utilization of additional timber and will create at least as many jobs in the woods as were created through the milling operation.
>
> (3) That given the limited volume in the sale, it will not be economic to install chipping operations to permit chip shipping facilities. Also, there is no other economic method of salvaging the slab created by primary manufacture.
>
> (4) The one known economic method of disposing of the slab is by burning in a wigwam burner.
>
> (5) That since Icy Bay is an area of [illegible] air quality at present, it is doubtful that the required permit could be obtained (see the case of *National Asphalt Pavement Assn. v. Train*[D.C. Cir.], 539 F.2d 775 (1976).
>
> (6) That rather than continue a practice which requires waste of commercially valuable sapwood (by slabbing) and also causes potential air quality deterioration (by burning), it is submitted that it may be preferable to permit round log export.
>
> (7) That the outer ring, or sapwood, of the log is the most commercially valuable portion because of close grain, freedom from knots and consistent color and grain.
>
> (8)[7] That under present primary manufacture requirements, a significant percentage of the valuable sapwood is cut, burned and wasted.
>
> (10) It is further found that there is a strong market for the valuable sapwood and because of that strong market there will be a higher utilization of the forest products from this state if round log export is permitted.
>
> (11) Also a higher price will be obtained for the state's timber sources if primary manufacture is waived.
>
> (12) Also, there will be benefits in the long-term management of Alaska forest lands resulting from higher utilization.

The justification for deleting those portions of the sale area lying above 400 feet and for making a partial substitution of adjacent less timbered areas is also expressed in several findings made by the state:

> REDUCTION OF SALE AREA FOR PROTECTION OF GOAT HABITAT
>
> Based upon the representations of the Habitat Division of the Alaska Department of Fish & Game, the following findings are made:
>
> (1) That at the time this Contract was let in 1969, there had been no funds for studying the fish and game habitat protection. Accordingly, no area reviews had taken place which might otherwise have been the case.
>
> (2) That subsequent investigation has revealed that timber stands at the elevations and along certain streams are vital to the protection of the goat population at Icy Bay.
>
> (3) That those designated steep areas are necessary for providing a proper goat wintering habitat for the goat population of Icy Bay.
>
> (4) That it will support the goal of conservation of wildlife resources in Icy Bay if these needed habitat areas are deleted from the Timber Sale

7. There is no finding number 9.

(5) That although the timber purchaser has made certain capital investments based on the volume of timber within the contracted sale area, the purchaser is willing to amend the sale area by deleting the area essential to goat habitat if the stumpage is amortized over the lower volume.

II

Kenai's challenge to amendment No. 7 in this court is based solely on the ground that the amendment violates the rule that material modifications may not be made to a contract let under a competitive bidding statute. This sale was made pursuant to AS 38.05.120 which requires that timber sales larger than 500,000 board feet be made by competitive bidding.[6] We alluded to the rule relied on by Kenai in *McKinnon v. Alpeter Co.*, 623 P.2d 281, 287 (Alaska 1981):

> [G]enerally a government contract that was initially competitively bid cannot be materially amended because that is tantamount to forming a new contract, which should be accomplished by starting all over again with competitive bidding.

This rule has been judicially imposed in order to guard against circumvention of competitive bidding requirements. Competitive bidding itself is designed to ensure that government obtains the most favorable terms possible in its contracts, and to protect the public from the possibility of favoritism, fraud, and corruption on the part of public officials. *Libby v. City of Billings*, 612 P.2d 1, 42 (Alaska 1980) (plurality opinion), *cf.* at 44 (Rabinowitz, C. J., concurring).

[1] Under the terms of this contract, competitive bidding can only be effective to accomplish these purposes for the first five years of the contract. Thereafter, the price of the timber is to be determined by state appraisals. These appraisals are based on current market and cost conditions and are not indexed to the original bid price. Kenai has not challenged this aspect of the contract and we therefore assume it to be legal for the purposes of this case. Based on this assumption we believe that, with one exception which we will discuss later, the rule prohibiting material modifications of competitively bid contracts has no application to amendment No. 7. That rule could not operate to ensure that the state receive the best price possible because price under this contract is determined privately, nor could it prevent favoritism, fraud or corruption on the part of state officials for the same reason.[7]

The evidence in the case indicates that the primary manufacture requirement detracts from rather than adds to the value of the end product. Thus a prospective purchaser of state timber would be willing to pay a higher stumpage price if there were no such requirement. If, therefore, an amendment to the contract had been made eliminating primary processing within the initial five year period a persuasive argument could be made that the protections which are meant to be afforded by competitive bidding had been by-passed. However, once the initial period is over the competitively established price is no longer effective and the removal of the primary pro-

6. AS 38.05.120 provides in relevant part:
> Timber and other materials shall be sold at their by sealed bids or public auction, depending on which method is determined by the commissioner to be in the best interests of the state, to the highest qualified bidder as determined by the director.

The 500 mbf exemption is expressed in AS 38.05.118.

7. This does not mean that the state officials are entirely free to modify long term timber sale contracts after the five reappraisal date has passed. As we have previously noted, 11 A.A.C. 76.130 prohibits contract amendments which "materially affect or change the meaning or intent of the contract." Kenai, however, did not brief or do anything about the question whether amendment No. 7 violates this regulation and we therefore do not pass on that point. In its reply brief it made no more than a conclusory assertion that § 130 prohibits material modifications, with no analysis or citation of authority. Under these circumstances we consider this point to have been waived. *See Hill v. J. B. Cordiff, Inc.*, 641 P.2d 211, 213 n.6 (Alaska 1982); *State v. O'Neill Investigations, Inc.*, 630 P.2d 520, 525 (Alaska 1980).

cessing requirement is merely another market condition to be taken into account during reappraisal.

Essentially the same observations can be made with respect to the economic aspects of the change removing from the sale lands above 400 feet and substituting adjacent low lands. Kenai contends, quite plausibly, that the costs of harvest are less and the product value is higher in the newly substituted acreage than in the lands deleted from the sale. If these changes had been made during the first five years of the contract a legitimate question whether competitive bidding had been improperly circumvented would be presented. As it is, however, these changes are now simply new conditions to be reflected in each reappraisal.

[2] The one aspect of amendment No. 7 to which the rule prohibiting material changes potentially applies is the physical addition of timber land in partial substitution for the deleted acreage. The additional land has never been subject to the competitive bidding process. However, for the following reasons, the rule does not prohibit this change.

[3] Not all amendments to competitively bid contracts are prohibited, only those regarded as material. The concept of materiality in this context has not been satisfactorily captured in a single phrase. One court has spoken of "an essential change of such magnitude as to be incompatible with the general scheme" of competitive bidding,[8] another has phrased the question to be whether the amendment "so varied from the original plan, was of such importance, or so altered the essential identity purpose of the contract, that it constituted a new undertaking."[9] These formulations simply recognize that the statutory concept prohibits those changes which would be subversive of the purposes of competitive bidding. In determining whether an amendment has this tendency, courts have found the following factors to be relevant:

(1) the legitimacy of the reasons for the change;[10]

(2) whether the reasons for the change were unforeseen at the time the contract was made;[11]

(3) the timing of the change;[12]

(4) whether the contract contains safeguarding modifications;[13]

(5) the extent of the change, relative to the original contract.[14]

Applying these factors to the addition of timber lands in this case leads to the conclusion that the substitutions are not material for purposes of the rule prohibiting material changes.

The reason for the change was that the Department of Fish and Game had learned after the contract was awarded that the mountainside included in the area contained important winter habitat for mountain goats. The Department therefore requested that the sale be modified by deleting this area. Since this deletion would eliminate approximately 40,000,000 board feet which the state had contractually committed to South Central, it was necessary in order to obtain the agreement of South-Central to substitute timberland.

8. *Albert Elia Building Co., Inc. v. New York State Urban Development Corp.*, 54 A.D.2d 217, 220, 387 N.Y.S.2d 462, 467 (1976).

9. *Myers v. Wood*, 175 Misc.App. 564, 568, 24 N.W.2d 912, 915 (1941).

10. *See Albert Elia Building Co., Inc. v. New York State Urban Development Corp.*, 54 A.D.2d at 467.

11. *Albert Elia Building Co., Inc. v. New York State Urban Development Corp.*, 54 A.D.2d 217, 220, 387 N.Y.S.2d 462, 467 (1976).

12. *See Myers v. Wood*, 175 Misc.App. 564, 568, 24 N.W.2d 912 (1941).

13. *See Schreyer v. Lake County Board of Commissioners*, 345 N.E.2d 862, 866 (Ind.App. 1976); *Myers v. Wood*, 24 N.W. at 915.

14. *See Albert Elia Building Co., Inc. v. New York State Urban Development Corp.*, 54 A.D.2d at 467.

This appears to be a legitimate rather than a pretextual reason for modifying the contract. It furthers the state's strong interest in maintaining or increasing existing population levels of game animals.[17] Nor was the importance of the deleted area as wildlife habitat appreciated when the original contract was made. There is nothing suspicious about the timing of the change since it was made more than nine years after the initial contract was entered into, and timber cutting had taken place under the contract for seven years with about 50% of the total estimated volume in the original sale having by then been cut.[18] While the contract does not specifically authorize replacing one timber area with another, the change here was relatively small, the substituted timber amounting to less than 7% of the total originally sold.

In a contract of this magnitude and duration it is to be expected that changes in circumstances will occur and that new perceptions concerning needed environmental protections will develop. A measure of flexibility is obviously required to be able to respond intelligently to the needs created by these changes. The substitution of timber here does not exceed permissible bounds.

III

The court awarded attorney's fees to South Central of $40,000.00. Kenai challenges this as unreasonable, and contends further that no attorney's fees should have been awarded since this case is within the public interest exception to the rule that the prevailing party is entitled to an award of partial attorney's fees.[19]

[4, 5] The determination of court awarded attorney's fees is committed to the discretion of the trial court and reviewable on appeal only for an abuse of discretion. Such an abuse is regarded as present only where the trial court's decision appears to be manifestly unreasonable or motivated by an inappropriate purpose. *Alaska State Bank v. General Insurance Co.*, 579 P.2d 1062, 1370 (Alaska 1978). South Central's attorneys reported they spent 845.8 hours in the defense of this case and South Central paid them $75,626.00. The only argument made by Kenai that the court's award of $40,000.00 is unreasonable is that Kenai's actual attorney's fees were less than that sum. This, however, does not demonstrate that South Central's attorneys' billings were unreasonable for opposing sides in a lawsuit do not necessarily have equal burdens. We therefore conclude that Kenai has not demonstrated that the court's award was manifestly unreasonable.

[6] We have recognized that in cases involving issues of genuine public interest an unsuccessful plaintiff should not be burdened with payment of a part of his opponent's attorney's fees under Civil Rule 82. *Thomas v. Bailey*, 611 P.2d 536, 539 (Alaska 1980); *Harrowitz v. Alaska Bar Association*, 609 P.2d 29, 42 (Alaska 1980); *Gilbert v. State*, 530 P.2d 1131, 1136 (Alaska 1974). This exception has been made because of a fear that "awarding fees in this type of controversy will deter citizens from litigating questions of general public concern for fear of incurring the expense of the other party's attorney's fees." *Id.* at 1126. *Accord, Anchorage v. McCabe*, 565 P.2d 856, 860 (Alaska 1977).

In *Anchorage v. McCabe*, we identified three criteria useful in identifying public interest litigation:

(1) Is the case designed to effectuate strong public policies?

(2) If the plaintiff succeeds will numerous people receive benefits from the lawsuit?

(3) Can only a private party have been expected to bring the suit?

17. *See Frank v. State*, 604 P.2d 1068, 1071 (Alaska 1979); *Stone v. Tanana Valley Sportsmen's Ass'n*, 583 P.2d 854, 859 n.18 (Alaska 1978).

18. *See* p. 218 *supra*.

19. Kenai argues that the public interest is best served by vindicating law in protecting the integrity of the competitive bidding process.

668 P.2d at 901. *Accord, Thomas v. Bailey*, 611 P.2d at 539 n.7. The foregoing can arguably be answered favorably to Kenai in this case. However, our cases establish what can be regarded as a fourth criterion which excludes this case from the public interest exception.

In *Weaver Bros., Inc. v. Alaska Transportation Commission*, 556 P.2d 819, 823 (Alaska 1976); *Lynden Transport, Inc. v. State*, 532 P.2d 700, 717 (Alaska 1975), and *Mobil Oil Corp. v. Local Boundary Commission*, 518 P.2d 92, 104 (Alaska 1974), we upheld attorney's fee awards against parties who had raised important questions of public interest but did not prevail. In *Mobil* we stated:

> Because the sums at stake in this controversy are large enough to prompt a suit without consideration of the public interest, the superior court could have concluded that the property owners were acting in their private interests and not in behalf of the public.

Id. at 104. In *Lynden* we quoted with approval the foregoing language, 532 P.2d at 717, and in *Weaver Bros.* we stated, citing *Lynden* and *Mobil Oil*:

> [I]t appears to us that the competitive advantage sought by appellant in this litigation takes the case outside of the notion of public interest litigation.

556 P.2d at 823. Based on these authorities what we have called the *fourth* criterion may be expressed as whether the litigant claiming public interest status would have had sufficient economic incentive to bring the lawsuit even if it involved only narrow issues lacking general importance but a litigant of means and thus a party lacking this incentive to be deterred from bringing a good faith claim by the prospect of an adverse award of attorney's fees.

On this record, since Kenai was a competitor of South Central and was seeking a continuing source of timber to process in its mill, the court could have concluded it had sufficient economic reasons to challenge the amendment regardless of grounds for the challenge. Under these circumstances we decline to hold that the award of attorney's fees to South Central was an abuse of discretion.

AFFIRMED.

RABINOWITZ, Chief Justice, dissenting.

I do not agree with the court's ruling that the state and South Central were free to eliminate the primary manufacture requirement of their timber sale contract. I review the court places its imprimatur on previously the kind of modification to competitively bid contract that the judicially imposed rule against material modification is designed to prevent.

The Alaska legislature has declared an important state resource and asset, or to be disposed of only by competitive bidding.[1] This legislative mandate and underlying policies are rendered ineffective if the state and South Central may change their competitively bid contract and substitute in its stead a significantly different agreement. On the record presented in this case I must conclude that the primary manufacture requirement was an integral term of the timber sale contract and that waiver of that requirement brought about impermissible material change in the contract. I so conclude for several reasons. First, the primary manufacture requirement was an express condition of the state's enabling legislation, and the state carefully admits that this requirement was "a significant part of the consideration for the State's agreement to sell timber to South Central." Second, administrative regulations authorizing primary manufacture requirement in timber contracts[2] and the governor's state-of-the-state message urging primary manufacture, both of which were incorporated into the contract between the state and South Central,

1. AS 38.05.115, 120.

2. *See* Section 816.104 of the timber sale regulations, 11 AAC 76.120, the full text of which is reproduced as note 3 of the court's opinion.

3. This policy statement, which provides that "[p]rimary logs may not be exported unless unobtainable domestically," is set forth at note 4 of the court's opinion.

trial, were undoubtedly designed to further the strong state interest in not exporting jobs in the often depressed forest products industry,[4] this state policy is subverted by elimination of the primary manufacture requirement. Third Xenai Lumber plausibly suggests that the timber sale might have attracted different bidders and bids had the primary manufacture requirement not been included in the state's request for bids,[5] and the court concedes that such a requirement affects the price that potential bidders are willing to pay for state-owned timber. In light of these factors I am unable to agree that the state and South Central were at liberty to waive the primary manufacture requirement of their competitively bid contract.

I further disagree with the majority's conclusion that the question of the materiality of the primary manufacture requirement need not be reached because the original contract authorized renegotiation of its terms after five years and at regular intervals thereafter. If the statutory competitive bidding requirements are to have any continuing viability, the parties to a competitive bid contract may not circumvent the legislature's mandate by including in their contract a provision which authorizes any and all modifications.[6] I recognize that the parties to a long-term contract for the sale of state-owned timber must be afforded a fair degree of latitude to make good faith modifications to their agreement in order to account for inevitable fluctuations in the market for timber and to respond to a myriad of factors which may not have been foreseeable at the time the timber was placed on bid. It does not follow, however, that the parties must be afforded unfettered license to rewrite their agreement, the judicially-imposed rule prescribing material modifications limits the power to alter a competitively bid contract and, in my view, that limit was exceeded when the state and South Central removed the primary manufacture requirement from their contract.

Leslie NEWELL, Appellant,

v.

NATIONAL BANK OF ALASKA, Appellee.

No. 5437

Supreme Court of Alaska

June 18, 1982

Plaintiff brought suit in connection with default on promissory note which purchasers had executed in favor of plaintiff when they purchased his mobile home. The Superior Court, Third Judicial District, Anchorage, James K. Singleton, J., granted summary judgment in favor of defendant bank, and plaintiff appealed. The Supreme Court, Dimond, Senior Justice, assigned, held that mobile home, which was moved once, from dealer's lot to mobile home park, was not within exemption in Motor Vehicle Act for vehicles which "transit the highway," and therefore, was subject to registration under that Act, and filing and notation on certificate of title provisions of Act were exclusive method of perfecting security interest in mobile home.

Affirmed.

Burke, J., concurred in result.

4. I note also that both California and Oregon prohibit the export of state owned timber without primary manufacture. *See* Cal Pub Res Code § 4628.1 (West Supp 1982); Or Rev Stat § 526.805 (1979).

5. South Central was the only bidder on the contract in question.

6. The court recognizes that "a clause authorizing modifications may not be so broadly read as to negate the statutory requirement of competitive bidding" but in my view fails to apply this rule to the state's and South Central's power to alter their competitively bid contract.

Automobiles ⇨17

Mobile home, which was moved once, from dealer's lot to mobile home park, was not within exemption in Motor Vehicle Act for vehicles which "transit the highway," and therefore, was subject to registration under that Act, and filing and notation on certificate of title provisions of Act were exclusive method of perfecting security interest in mobile home. AS 28.10.040, 28.10.041(b), 28.10.490, 28.10.510, 28.10.570 (Repealed).

M. Ashley Dickerson, Anchorage, for appellant.

Thomas E. Yerbich, Anchorage, for appellee.

Before RABINOWITZ, C. J., CONNOR, BURKE and MATTHEWS, JJ., and DIMOND, Senior Justice.*

OPINION

DIMOND, Senior Justice.

Appellant Leslie Newell brought the action against Ray and Samantha Charlton, the National Bank of Alaska (NBA), and one other party in connection with the default by the Charltons on a promissory note which they had executed in favor of Newell when they purchased his mobile home or house trailer[1] in 1978. The suit against the Charltons sought judgment against them on the note, and asserted a lien against the mobile home which Newell had retained[2] as security on the purchase price. NBA was later joined as a party in the suit when Newell learned that NBA also claimed a security interest in the mobile home.

The suit over between Newell and NBA concerns which party has the superior se-

* Dimond, Senior Justice, sitting by assignment made pursuant to article IV, section 11 of the Constitution of Alaska and Alaska R. Admin. P. 23(a).

1. Newell, throughout the trial refers to the mobile home as a trailer or house trailer.

curity interest. NBA sought to perfect its interest by filing the requisite documents with the Motor Vehicle Division, pursuant to the certificate of title provisions of the Motor Vehicle Code. Newell sought to perfect his interest by filing the promissory note with the Anchorage district recorder several months later.[3] Each party claims that its method of filing its respective security interest was the exclusive method of perfecting a security interest in the mobile home. Summary judgment was granted in favor of NBA, and Newell has appealed.

Perfection of security interests and priority of perfected interests in personal property and fixtures is generally governed by the provisions of the Uniform Commercial Code—Secured Transactions.[3] Under the UCC, the filing of a financing statement to perfect a security interest in property covered by the code would properly be made in the office of the recorder in the recording district of the debtor's residence, or in case of fixtures, in the office where a mortgage on the real estate concerned would be filed or recorded. AS 45.09.401 (formerly 45.09.704).

There are certain exceptions to the filing provisions of the UCC. AS 45.09.302 (formerly AS 45.05.734) provides in part:

(c) The filing provisions of AS 45.09.301-45.09.307 do not apply to a security interest in property subject to a stat-

(2. of the state which provides for a notation, filing of, or which requires indication on a certificate of title of, the security interest in the property, unless the property is inventory held for sale by a dealer which has not been previously sold at retail and for which no certificate of title has been issued.

2. Although the validity of Newell's security interest, a promissory note, was challenged by NBA in the superior court, this issue is not raised on appeal.

3. At the time of the transaction in question UCC—Secured Transactions was set out in AS 45.05.734. The article was since repealed and is now AS 45.09.101-.507.

FIRST AMENDMENT TO THE NORTHSTAR UNIT LEASES BETWEEN THE STATE OF ALASKA AND BP EXPLORATION (ALASKA) INC.

The State of Alaska ("State") and BP Exploration (Alaska) Inc. ("BPXA") are parties to the following leases in the Northstar Unit: ADL 312798, effective February 1, 1980; ADL 312799, effective February 1, 1980; ADL 312808, effective February 1, 1980; and ADL 312809, effective February 1, 1980 (collectively the "1980 Leases"); as well as ADL 355001, effective August 1, 1983 (the "1983 Lease"). The parties agree to amend the 1980 Leases and the 1983 Lease as set forth in this first amendment to the Northstar Unit leases.

1980 Leases

1) Paragraph 6(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

2) Paragraph 7 is replaced in its entirety as follows:

7. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraphs 8, 10, and 11 below, Lessee shall pay to the State a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the

trigger price per barrel times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to as "ANS (USWC)" in the ANS Agreement. The trigger price is $17.35 per barrel through April 30, 1997. On May 1, 1997, and each May 1 thereafter, the trigger price shall be adjusted by an inflation factor equal to fifty percent of the "inflation rate" defined as the Producer Price Index for Industrial Commodities ("PPI") for December of the previous year, as reported by April 30 of the current year, divided by the PPI for December of 1995, as reported by April 30, 1996. The supplemental royalty value for oil, gas, natural gas liquids and associated substances is defined in paragraphs 10 and 11 below. Exhibit B is a sample calculation to demonstrate the method of calculating supplemental royalty for oil.

3) Paragraph 9 is replaced in its entirety as follows:

9. REDUCTION OF ROYALTY. Except as provided in paragraph 7 above, Lessee shall not be entitled to any reduction of royalty paid under paragraph 8 above or supplemental royalty paid under paragraph 7 above based on any current or future agreement, State statute, or State regulation.

4) Paragraph 10 is replaced in its entirety as follows:

10. ROYALTY IN VALUE. Unless the State elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 12 below, Lessee shall pay to the State the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 11 below. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the State shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the State may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

5) Paragraph 11 is replaced in its entirety as follows:

11. VALUE. For purposes of computing supplemental royalty due under this lease, the value of supplemental royalty oil, gas, natural gas liquids and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute the value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received be Lessee for such associated substances;

(2) Lessee's posted price in the field for such associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The State may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by Lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by Lessee and/or other producers from

sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after Lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

6) The following provision shall be added to the end of paragraph 12:

(e) Supplemental royalty under paragraph 7 above may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 12.

7) Paragraph 14 is replaced in its entirety as follows:

14. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The landowner's royalty and supplemental royalty share of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of it paid to, the landowners, free and clear of all unit expense and free of any lien for it. Under this provision, the State's royalty and supplemental royalty share of any unit production allocated to the leased area shall be regarded as royalty to be distributed to, or the proceeds of it paid to, the State, free and clear of all unit expenses (and any portion of such expenses which is incurred away from the unit area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas or associated substances for transportation off the unit area, and free of any lien for it.

8) Paragraph 28 (c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, State statute, or State regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the Lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the Lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11:59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The State may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation

required under the project schedule is subject to the provisions of paragraph 32.

9) Paragraph 32 is replaced in its entirety as follows:

32. FORCE MAJEURE. If the State determines that Lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond Lessee's reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, State, or federal permits or environmental impact statements), whether similar to those enumerated or not, Lessee's obligation to comply with such provision shall be suspended, but not voided, and Lessee shall not be liable for damages for failure to comply therewith. If Lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the State.

10) Paragraph 41 is replaced in its entirety as follows:

41. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid federal, State and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, Lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job service organizations to notify the Alaskan public. For work in connection with this lease, Lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, Lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of Lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of

Labor, a report that details the specific measures Lessee and its contractors and s[illegible] contractors have taken or are planning to take to recruit qualified Alask[illegible] residents for available jobs, describes on-the-job training opportunities, and describes Lessee s efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

1983 Lease

1) Paragraph 4(f) and paragraph 34(7) are deleted and replaced in their entirety with the following paragraph 4(f):

(f) FORCE MAJEURE. If the state determines that lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond lessee s reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, state, or federal permits or environmental impact statements), whether similar to those enumerated or not, lessee's obligation to comply with such provision shall be suspended, but not voided, and lessee shall not be liable for damages for failure to comply therewith. If lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the state.

2) Paragraph 5(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

3) Paragraph 7 is replaced in its entirety as follows:

7. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The state's royalty and supplemental royalty share of the unit production allocated to each separately owned tract must be regarded as royalty to be distributed to or among, or the proceeds of it paid to, the state, free and clear of all unit expenses and free of any lien for them. Under this provision, the state's royalty and supplemental royalty share of any unit production allocated to the leased area will be regarded as royalty to be distributed to, or the proceeds of it paid to, the state, free and clear of all unit expenses (and any portion of those expenses incurred away from the unit area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas, or associated substances for transportation off the unit area, and free of any lien for them

4) A new paragraph 20(c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, state statute, or state regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11:59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The state may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation required under the project schedule is subject to the provisions of paragraph 4(f).

5) Paragraph 31 is replaced in its entirety as follows:

31. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid federal, state and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job

service organizations to notify the Alaskan public. For work in connection with this lease, lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of Labor, a report that details the specific measures lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes lessee's efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

6) Paragraph 35 is replaced in its entirety as follows:

35. ROYALTY ON PRODUCTION. Except for oil, gas, and associated substances used on the leased area for development and production or unavoidably lost, the lessee shall pay to the state as a royalty 20 percent in amount or value of the oil, gas, and associated substances saved, removed, or sold from the leased area and of the gas used on the leased area for extraction of natural gasoline or other products from the leased area.

7) Paragraph 36 is replaced in its entirety as follows:

36. VALUE. For purposes of computing supplemental royalty due under this lease, the value of supplemental royalty oil, gas, natural gas liquids, and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received be lessee for such associated substances:

2) Lessee s posted price in the field for such associated substances:

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The state may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by lessee and/or other producers from sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

8) Paragraph 37 is replaced in its entirety as follows:

37. ROYALTY IN VALUE. Unless the state elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 38, lessee shall pay to the state the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 36. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning

dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the state shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the state may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

9) The following provision shall be added to the end of paragraph 38:

(f) Supplemental royalty under this lease may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 38.

10) Paragraph 39 is replaced in its entirety as follows:

39. REDUCTION OF ROYALTY. Except as provided in paragraph 40 below, lessee shall not be entitled to any reduction of royalty paid under paragraph 35 above or supplemental royalty paid under paragraph 40 below based on any current or future agreement, state statute, or state regulation.

11) Paragraph 40 is replaced in its entirety as follows:

40. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraph 35, 36, 37 above, lessee shall pay to the state a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the trigger price per barrel] times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to