OIL AND GAS CONSERVATION REGULATION IN ALASKA

Because of the importance of oil and gas to Alaska’s future, there is a growing interest among many Alaskans in the oil industry and particularly state regulation of oil and gas development and production for purposes of conservation. Such regulation is vitally important to the state, for it is intended to guarantee the maximum yield from each oil and gas reservoir with minimum physical waste and minimum harm to the immediate environment.

The type of conservation regulations under discussion pertain primarily to oil and gas field development and production and are an administrative concern of the Alaska Oil and Gas Conservation Committee and the Alaska Division of Oil and Gas. They should not be confused with those broader forms of state and federal environmental conservation regulations which deal with such matters as oil exploration, pipeline construction, and oil tanker and transport facilities.

Oil field conservation regulation, however, cannot be understood apart from certain basic technical information on oil—the types of underground structures in which it is found and the different ways in which it can be brought out of the earth.

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The following section on oil and oil reservoirs contains basic information intended for lay readers. Those knowledgeable in these areas may wish to begin instead with the discussion that starts with “Alaska State Regulation,” page 10.

Oil and Oil Reservoirs

Oil and natural gas derive from decayed, compressed organic matter that died millions of years ago.* Layers of earth gradually built up over this

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*The following discussion is very general, and the interested reader can pursue the points raised in several good books on the subject. Two such books are Norman J. Clark, Elements of Petroleum Reservoirs (Dallas: Society of Petroleum Engineers, 1960) and Stephen L. McDonald, Petroleum Conservation in the United States: An Economic Analysis (Baltimore: Johns Hopkins Press, 1971). Both have been drawn upon for much of the following material.
organic material and became sedimentary rock. Under the pressures and temperatures developed by the overlying strata, the organic matter gradually changed into liquids and gases which became trapped in porous rock formations.

The oil and gas migrated in the direction of least pressure; hence, both moved upward toward the surface or upward along an angled plane of permeable sands or limestone. In addition, oil and gas liquids float on water, and water encroaching from below through permeable formations flushed the oil and gas ahead of it. Eventually the oil and gas became trapped by impervious rock. Here a deposit of hydrocarbons built up against the impenetrable wall.

Exploration for Oil

In the normal method of seeking oil, prospectors first study the basic terrain of a potential petroleum-bearing province to determine if it was once a sedimentary basin below the sea. If they find it to be such a basin, they then try to determine if the surface formations have sufficient porosity to contain oil or gas. If these studies prove positive, geologists then chart sub-surface rock strata with seismic methods to determine the existence of underground structures. They drill shallow holes, usually about a hundred feet deep, and plant small explosive charges* which, when detonated, send downward shock waves that bounce off the various rock strata and return to the surface where they are recorded by electronic instruments.

Interpretation of these seismic recordings indicate the depth and general pattern of underground formations. The process of interpretation itself is a delicate and exacting one. On Alaska's North Slope, for example, permafrost extending downward to unknown depths makes correct interpretation of seismic data very difficult. Various oil companies have developed their own methods of interpreting this data from permafrost terrain, and they use these interpretations along with other data as a basis for all their planning as well as for bidding on state leases.

While seismic and other geological data can suggest the presence of oil-bearing formations, only an exploratory well can confirm it. Exploratory or "wildcat" wells in new areas are expensive undertakings, especially in Alaska. For example, Prudhoe Bay State No. 1, the wildcat that was first drilled into the Prudhoe structure, cost roughly $5 million. Susie Unit No. 1, an Atlantic Richfield wildcat some 50 miles south of Prudhoe, was drilled in 1966 at a cost of $3.5 million—and was unsuccessful. According to industry spokesmen, most of the expenses of drilling exploratory wells in remote Alaska locations such as the North Slope are incurred in supply and transportation. Moving a rig by air from Fairbanks, the railhead in Interior Alaska, to a winter airstrip at the wildcat site can mean as many as 72 round trips by Hercules C-130 cargo planes.*

Once a field has been located and the drilling of "development" or producing wells begun, the cost of drilling is greatly reduced. Prudhoe Bay is now in the development-drilling phase, and because the rigs are already there and supply systems worked out for greatest long-range economy, wells can be drilled for approximately $1.5 million each. Another expense factor is time spent drilling a given well. Wildcat drilling is slow, since drillers working in relatively unknown geology tend to drill slowly and cautiously. The drilling of production wells, however, is more routine, with the geology and reservoir depths generally known in advance.

*Explosives are not always used. Other seismic techniques use a "vibrator" device which creates a subterranean shock in the same manner as an explosive charge.

*Source: Atlantic Richfield Company, 1966 Airlift to Susie No. 1 location, Alaska North Slope.
Types of Reservoirs

Three common types of petroleum reservoirs are: the dome or closed fold trap (also called structural), the fault-sealed trap, and the stratigraphic trap. (See Figure 1.) Of these, oil is most commonly found in the closed fold, which can often be detected from the surface. The closed fold results from an upfolding in rock strata which creates a structure like an overturned bowl. Trapped by the impenetrable top of the fold, oil is held in place by its natural buoyancy in the soft, porous rock or sand over a layer of water, generally salty.

The second reservoir type, the fault-sealed trap, occurs when a stratum is abruptly broken by a fault deep below the surface. This creates a “wall” of different rock material which terminates the stratum. If the porous rock stratum is tilted, hydrocarbons will migrate upwards along the plane until they are stopped by the impenetrable wall at the fault-zone. Here they form a pool of oil or gas.

The third type, the stratigraphic trap, is caused by a change in permeability of a geologic stratum instead of by a fault. However, the result is the same; the permeable stratum terminates against a different kind of rock. If the rock is nonpermeable, it will trap the oil and gas.

Oil Drives

Once a well is drilled into a formation containing oil and gas under pressure, it creates an escape point for the pressurized fluid. Oil will move into the well-bore, up the pipe and to the surface. The process is like sticking a pin into a balloon in very slow motion, the balloon being the reservoir, the pin and hole being the drill and well-bore. Oil fluids flow up the well-bore like air rushes from a pin-hole in a balloon.

In the reservoir itself, three different forces, singly or in combination, can push the oil to the surface: a gas cap above the oil, gas in solution with the oil, and water encroaching from beneath the oil. (See Figure 2.) A gas cap pressurizes the oil from above so that when a low-pressure point is created by a well drilled into the oil zone, the oil flows into the well-bore and to the surface. Gas held in solution pressurizes the oil internally with the same effect: oil is forced up the well-bore. Water-drive pressure created by the upward encroachment of water from strata below the oil pushes the oil above it into the well-bore.

Primary, or natural, reservoir energy is usually the most economical method of getting the oil out of the ground. There are times, however, when this primary energy may have to be supplemented by artificial (or secondary) recovery means to allow the maximum efficient recovery of oil. For example, several Cook Inlet Basin fields contain comparatively small amounts of solution gas and have no gas cap or significant water drive. To overcome this problem, inlet operators have artificially injected gas and water into the wells to help force the oil out. In the land-based Swanson River field near Kenai, for example, natural gas and water has been injected through converted and new wells to create an artificial gas and water drive. In nearby offshore fields, operators faced with an early loss in producing pressure have begun injecting water through converted production wells and new injection wells to provide supplemental driving force for the oil.

Other methods used by oilmen to recover oil where natural drive forces are exhausted or nonexistent are surface pumps, down-hole electric centrifugal pumps, and hydraulic pumps. Surface pumps known as “pumping jacks” are common in the lower states and are often used on marginal wells producing 5, 10, to 15 barrels per day (BPD). However, pumping jacks, because of their small capacity, will probably have limited use in high-cost Alaska, since in order to be profitable here, a well must produce much more oil than this type of pump can efficiently handle.

Occasionally, a reservoir will contain energy enough to drive the oil, but the rock or sand formation will not be permeable enough to allow migration of the liquid into the well-bore. This condition exists in some Cook Inlet formations which are particularly tightly packed. In these situations, recovery can sometimes be improved by artificial means. One such method is “hydraulic fracturing,” in which liquids are pumped down the well-bore at pressures high enough to “fracture” the formation, improving
Figure 1
THREE COMMON TYPES OF PETROLEUM RESERVOIRS

DOME OR CLOSED FOLD TRAP

FAULT-SEALED TRAP

STRATIGRAPHIC TRAP
Figure 2

TYPES OF NATURAL (or Primary) OIL DRIVES

The three forces illustrated on this page, either singly or in combination, can push the oil to the surface.
permeability for oil passage. At least one Cook Inlet well has received this treatment. In the other oil-producing states, some experiments have made use of small nuclear devices in attempts to fracture a tight producing formation.

Despite all of the artificial means available to help recover oil from the ground, a point is finally reached at which it is no longer economical to maintain a well. Depending on geological conditions, the composition of the fluids, the nature of the primary drive and other factors, between 15 to 75 percent of the oil in a reservoir can be recovered. Oilmen expect to recover approximately 40 percent of the original in-place Prudhoe oil.

To maximize the ultimate yield of a reservoir, it is often necessary for operators to control the rate of production. In gas-cap drive and water-drive reservoirs, an excessive rate of production will often allow the driving water or gas to bypass tight rock sections, leaving some oil trapped in the rock. In such cases, a slower rate of production would allow the water or gas to advance more slowly along a uniform front and more thoroughly flush the oil. Generally, reservoirs that do not have a gas cap or water drive such as some of those in Cook Inlet, are not rate sensitive; the producing rate does not significantly affect the ultimate recovery.

For every gas-cap and water drive reservoir, it is possible to determine the highest rate at which oil can be produced without causing an avoidable premature loss of reservoir energy. This calculation is called the maximum efficient rate (MER) of production, and as we shall see, restricting the rate of oil production to the MER (for particular fields) is one of the prime objectives of state conservation regulation.

**State Regulatory Activity**

In years past, the absence of government regulations often led competitive oil producers to adopt practices that were environmentally destructive and economically wasteful. Thus, the purpose of oil and gas field regulation today is to minimize the environmental dangers of oil development and to make such development as efficient, economic, and equitable as possible. To accomplish this, states have passed regulations to:

- Protect the environment adjacent to the well.
- Encourage the development of a reservoir as a single unit.
- Restrict production in particular reservoirs to their calculated MER.
- Regulate the spacing of wells.
- Protect the rights of all leaseholders on a reservoir.
- Regulate gas flaring.
- Limit production by means of prorating.*

**Environmental Protection**

State regulations attempt to limit the external damages of well drilling in several ways. One is to prevent the contamination of fresh water with the brine that usually accompanies oil production. A well-bore penetrates many strata, some of which contain fresh water and some which contain salt water. Brine and petroleum under pressure will attempt to rise to the surface in the well-bore. If the well-bore is not adequately encased as it is drilled, the rising salt water and petroleum can contaminate the fresh water strata frequently found near the surface that may be valuable for human and animal consumption or agricultural uses.

A high proportion of salt water is frequently produced with oil, and during the early days of the oil industry in the United States, this salt water sometimes created a disposal problem. It was often stored in surface pits, and upon occasion it migrated into fresh water sources and contaminated them. In recent years, however, more enlightened methods of overcoming this problem have included injection of the water back into the producing reservoir. Often, producers in a field have formed cooperative unit agreements just for the purpose of dealing with the salt water disposal problem.

Contamination of surface resources by petroleum itself is another danger. The day of the dramatic gusher has long passed, for not only is a gusher waste-

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*Prorating, or setting production limits on particular reservoirs was a practice used by some states to stabilize oil prices by controlling the supply. Most states have discontinued this practice today.
ful of oil, it can also cause damage within a wide radius of the well. These days, gushers are called blowouts, and oilmen have devised an array of methods and equipment to prevent them.

In attempts to prevent damage to surface areas, states have devised regulations specifying minimum standards for casing, outlawed the contamination of one stratum by circulation of fluids or gases from another, and specified installation of various types of safety devices such as blowout prevention equipment while drilling and safety shut-in valves after well completion.

Unitization

Unitization is the process whereby several producers will develop a reservoir cooperatively as a single unit. This is in contrast with a situation where each producer tries to capture as much oil as fast as possible from each leasehold. By eliminating competition between leaseholders, unitization avoids many wasteful practices, prevents the drilling of unnecessary wells, and may substantially increase the long-term recovery of oil from a reservoir.

Oil is a migratory fluid that, in the reservoir, does not acknowledge the existence of man-made lease boundaries on the surface. Early court cases developed the "right-of-capture" concept, according to which oil was fair game for any leaseholder, and each could take as much as he was physically capable, whether it was originally below his land or his neighbor's.* This gave a leaseholder incentive to drill as many wells as were possible on a given leasehold. His neighbors were then forced to drill their own wells in self defense. This trend, together with the fact that many farmers owned small plots above oil reservoirs, led to fields so densely drilled that oil derricks were as thick as trees in a forest. Of course, the effect of all this below ground was rapid, wasteful depletion of reservoir pressure and subsequently, oil reserves. In the end, everyone lost, because acting independently, they produced only a fraction of the oil that would have been possible under a planned unitized production scheme.

Not only does unitization, in certain situations, avoid waste of the oil resource, it offers a compelling economic incentive to the companies involved in a single reservoir. The pooling of facilities will allow the sharing of cost burdens among the companies in the unit. Also, by developing the field as a unit, production facilities are planned for optimum use, which avoids the expensive duplication of facilities (roads, wells, gathering lines, tanks, and other surface installations). From an environmental standpoint, unitization will conserve surface facilities and minimize the environmental impact.

Most states today have enacted statutes that require unitization of a petroleum pool when proper conservation practices require it. Some of the older oil-producing states, such as Texas, encourage the voluntary unitization of fields but do not authorize their regulatory agencies to require it.

Oil operators in Alaska have reached unitization plans voluntarily, and the state has not yet had to rely on its compulsory unitization statute. A primary difficulty involved in reaching an agreement on a unitization scheme among the operators, of course, is the problem of who gets how much of the oil—that is, the division of equity shares of the reservoir. This is a matter which is best resolved by the operators themselves. Any division of equity shares that the state would make under its compulsory unitization statute would surely be challenged in court by a company which felt that its assigned share was too small. Thus, as a practical matter, compulsory unitization is a last resort on the part of the state. However, the threat of compulsory unitization could provide a strong incentive for the operators to reach mutual agreement on a fair division of the oil in a reservoir.

Where unitization is not desirable, the state can limit production, where necessary, to protect correlative rights.

Maximum Efficient Recovery (MER) Restrictions

Another way state regulatory agencies attempt to ensure conservation of oil and gas is to establish a
maximum efficient recovery rate (MER) for individual fields.* Once calculated, the MER rate is used to avoid waste of a reservoir's natural expulsive energy and thus maximize its long-term yield.

In states that prorated production (tied it to market demand), most fields were limited to production lower than MER. Now that market prorating is being limited in older states, most fields are now producing their full MER's.

Not all oil reservoirs require a MER calculation. For instance, in fields which are not rate-sensitive, such as most of those in Cook Inlet, one production rate will not ultimately recover any more oil than another.

It is the fields with two or more natural driving mechanisms that often do require a MER calculation. An example of such a field is Prudhoe with its combination of gas-cap, gas-expansion and probable water drives. The state regulatory agencies, in all likelihood, will closely monitor Prudhoe's production rate to prevent it from exceeding the calculated MER.

Well Spacing

Regulation of well spacing is another means of regulating production that is common among oil-producing states. Spacing regulations set minimum acreage for each well and the minimum distance between wells and the lease boundary. These regulations are intended to prevent unnecessary or excessive drilling, increase the ultimate recovery from a reservoir, help protect the rights of neighboring leaseholders, and limit the extent of pipeline and storage facility development on the field.

Alaska has regulations which limit oil wells to one per 160 acres and gas wells to one per 640 acres. However, exceptions may be allowed where it can be shown that closer or wider spacing is necessary to efficiently drain the reservoir.† For example, preli-

*It is often difficult or impossible to establish a true MER (in the theoretical sense) for every reservoir; more common is the establishment of a maximum economic rate.

†It has often proved prudent to limit the number of wells at the beginning of production, and then allow a gradual increase in well-density as production falls or as more well information comes available.

Prohibition of Correlative Rights

Most of the oil states, Alaska among them, make an effort to prevent one producer or purchaser from discriminating against neighboring leaseholders on a competitively shared reservoir. One producer, for example, may be able to produce and sell more oil than his reservoir neighbor. Such uneven production could cause an unbalance in the reservoir and injure its ultimate production capability. This can happen when one producer has an exclusive purchase agreement with a buyer, or if he connects a pipeline to the field and refuses to share it with other producers. Some states consider crude oil pipeline companies to be "common carriers," and require them to buy crude oil from anyone making a reasonable offer to sell. In addition, federal law considers oil pipelines which cross state boundaries to be "common carriers." The law does not allow owners of such pipelines to discriminate among customers.

States are also generally watchful for other inequities. Alaska's regulatory agency is charged by statute to protect common rights of operators sharing a field. In the non-unitized fields of Cook Inlet, for example, competitive producing is carried out under close scrutiny of the state regulatory agency. In some cases, water-injection wells must be placed on or near lease boundaries so that the injected water drives oil away in all directions and prevents the fluid from directly crossing the lease boundary. In this manner, an operator is able to recover a fair share of the oil originally present under his lease near the boundary.

Gas Flaring

Gas flaring regulations pertain both to the natural "casinghead" gas that is a byproduct of oil production as well as to dry gas. The state regulatory agency will typically consider the case of each producer individually to determine if the flaring (burning) of casinghead or dry gas should be permitted. The agency will prohibit flaring if it appears that a commercial market exists for the gas. This seldom causes conflict between agency and operator, since
the latter will not want to waste a product that can be profitably sold. However, conflicts have occurred in which a state agency prohibited the flaring of gas over the objections of the operator. A classic case of this sort developed in Alaska and is discussed on page 16.

Prorating

Certainly the most controversial aspect of oil and gas conservation regulation has been the system of production restrictions known as prorating. These production restrictions were unrelated to reservoir dynamics, but served the interest of conservation through economics—by keeping the price of oil steady to ensure investment in the industry.

In the early days of oil, the market was often flooded with oil from new discoveries. This depressed prices and upset the economics of the industry. Many companies went out of business. Exploration incentive dropped, profits disappeared, and oil companies suddenly found it difficult to obtain financing for new exploration. The scarcity of oil that followed caused prices to rebound to new heights. To counter such undesirable production practices and resulting market reactions, the oil-producing states adopted systems of market prorating of production. Under this system, market demand for a given month, based on nominations by crude oil purchasers, was used by the state regulatory agency as a basis for imposing “allowable” production quotas on producing wells. This system kept production tailored closely to market demand.

Because of current demand, prorating is no longer necessary to stabilize the price of oil. The oil-producing states that previously engaged in prorating have abandoned production restrictions and have now gone to “100-percent allowables.”

It is doubtful that prorating will be revived in the United States. For its part, Alaska will probably not be forced to restrict oil production on the North Slope to maintain a favorable price. Demand for oil is such that North Slope production will not significantly depress the market for any significant length of time.

The Evolution of Field Regulations

Individual states, rather than the federal government, took the lead in developing modern oil and gas conservation practices. These practices date from the early part of this century when massive oil discoveries were first made in Oklahoma and Texas. Between 1909 and 1915, Oklahoma enacted the first series of laws designed to prevent the waste of oil and gas. A regulatory agency, the Oklahoma Corporation Commission, was created and authorized to limit well production and allocate production among reservoirs in the interest of conservation. Also, the new commission prohibited discrimination in the use of pipelines by oil and gas producers by declaring pipelines common carriers, and it subsequently enacted broad conservation statutes. The Texas Railroad Commission, then involved in transportation of oil from the field to refineries, was empowered to regulate Texas oil and gas production.

The federal government first took a look at the matter of oil conservation in the mid-1920's with the idea of standardizing state practices. A report in 1926 from a special investigative commission, the Federal Oil Conservation Board, cleared the way for state ascendency in the matter of conservation regulations on all lands other than federal; it stated that the federal government lacked constitutional authority to regulate oil production on state and private land, and recommended that the federal government cooperate with, rather than attempt to supplant, the states' regulatory activity.

To aid in the development of uniform state practices, the federal government urged formation of an interstate organization. In 1935, Congress and the six major oil-producing states formally ratified the Interstate Compact to Conserve Oil and Gas. The compact, now with a membership of 30 states, including Alaska, coordinates the regulatory activity of the states, disseminates technical and legal information, and serves as a focus for state oil regulation matters in general. An administrative body, the Inter-state Oil Compact Commission (IOCC), carries on the daily work of the organization.

For 3 years during World War II, the federal government took a direct hand in all oil field regulation in the United States. Through the Petroleum
Administration for War (PAW), the federal government enforced a set of conservation measures generally stricter than current practices in most states. These higher federal standards (in such matters as well spacing, compulsory unitization, and MER production) were subsequently incorporated into regulations of many oil-producing states.

On lands under its jurisdiction, including public domain, Indian reservations, and the outer continental shelf, the federal government enforces its own conservation regulations through the Conservation Division of the U.S. Geological Survey. However, oil production on federal lands is also subject to the rules and regulations of the state within which that land is located. Theoretically, in this case, state law prevails, but in practice the stricter law prevails.

In Alaska, the federal government supervises all operations on wells within its jurisdiction. The state, however, also exerts jurisdiction and receives applications for drilling, well data, and other information about work on federal leases. There seems to have been no major regulatory conflicts between the state and federal governments in Alaska, and any minor management conflicts have been resolved informally. At the present time, none of the outer continental shelf land off Alaska’s coast is under lease.

**Alaska State Regulation**

Alaska’s first oil and gas conservation statute was enacted by the territorial legislature in 1955 (Ch. 40 SLA 1955).* At that time no significant discoveries of either oil or gas had been made in Alaska, but parts of the Kenai Peninsula were leased, exploration was underway, and hopes were high. To implement the new act, a three-member Oil and Gas Conservation Commission was created that included the Governor of the Territory, the Commissioner of Mines, and the Territorial Highway Engineer.

The commission did not issue regulations until 1958. By then commercial deposits of oil had been discovered on the Kenai Peninsula, and Alaska was about to have producing wells. Public hearings were held in March 1958 on a set of proposed rules and regulations. These regulations, which were based on IOCC model statutes, became effective in October, 1958.

**The Alaska Oil and Gas Conservation Committee**

After statehood, responsibility for implementation of the oil and gas conservation statutes passed to the newly created Department of Natural Resources. By departmental regulation,* authority now rests with a three-member group known as the Alaska Oil and Gas Conservation Committee. Administrative support for the committee was one of the functions of the Division of Mines and Minerals within the department. By executive order in 1968, Governor Hickel created the Division of Oil and Gas as a separate division of the Department of Natural Resources, and this division now provides technical support to the committee.

The conservation committee is composed of the head of the Division of Oil and Gas (chairman), the division’s chief petroleum engineer, and the division’s chief petroleum geologist. This committee of three is the policy-making body. It is quasi-judicial and conducts its business in accordance with the provisions of the Oil and Gas Conservation Act. The committee publishes notices of proposed orders and holds public hearings when there is any protest against the proposed order—and frequently does so when there are no protests. It holds hearings on application by companies and on its own motion. The bulk of its work concerns applications for drilling, applications to perform secondary oil recovery, rules covering the development of a new oil field, and statistical reporting and dissemination of information.

An applicant may request a rehearing if it is not satisfied with an order. Although the committee is not required to grant a rehearing, it usually does. A dissatisfied party has 20 days after issuance of the last order to file suit in State Superior Court if it wishes to contest the committee’s decision. This has happened

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*Now AS 31.05 (Oil and Gas Conservation Act).

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*Alaska Administrative Code, Title II, Division 2, Chapter 1.
once on a regulatory matter when Mobil Oil Corporation went to court over the Committee’s refusal to permit flaring of casinghead gas in Cook Inlet (discussed on page 16).

The Division of Oil and Gas provides technical support for the committee. Its duties include inspecting wells, compiling statistical and geological data on reservoirs, and keeping production records. At the present time the division has a professional staff of ten: the director, five petroleum engineers, three petroleum geologists, and a systems analyst on loan from the Department of Natural Resources.

The members of the conservation committee as well as the director (who generally has legal training) are also staff members of the State Division of Oil and Gas. This is somewhat unique, since regulatory and policy-making boards are generally independent from their supporting agencies. An example of such independence can be seen in the Alaska Public Utilities Commission (PUC), whose members are not also staff members of the Department of Commerce. Another example is the State Fish and Game Board members who are not on the staff of the Department of Fish and Game.

The reason for this unusual relationship between members of the oil and gas conservation committee and the Alaska Division of Oil and Gas is the general lack of petroleum expertise outside industry. Staff professionals hired by the state must perform many functions. The conservation committee is the regulatory board, ruling on technical policy decisions. As the regulatory agency, the division polices these decisions. Filling a third function, as we will see later, division personnel also act on behalf of the Alaska Division of Lands and Department of Revenue, policing leases and royalty matters for production on state lands (apart from its statutory regulatory duties), and on production tax matters for the Department of Revenue.

There is considerable uniformity in the conservation measures of all of the IOCC members; thus Alaska’s petroleum conservation regulations are basically similar to those of the older producing states. In general, however, Alaska’s regulations are streamlined and simple, and they incorporate several progressive provisions. One of these is a compulsory statute to compel unitization in those situations where voluntary unitization efforts have failed and nonunitization may result in loss of the oil and gas resource.*

Also exemplifying Alaska’s progressive approach is the considerable discretionary power left to the three-member committee. This is in contrast to older oil-producing states where procedures and policies are often specified in minute detail. This flexibility permits the committee to make allowances for varying field conditions, a particularly important factor in Alaska where field conditions vary greatly from one region to the next.

**Land Ownership Patterns**

A unique feature of oil and gas regulation in Alaska is the simplicity of land ownership patterns and the fact that the state itself is a major landowner. At the time of this writing, all of Alaska’s producing oil fields, with the exception of Swanson River, were on state-owned lands.

The vast majority of Alaska’s lands are publicly owned, by federal or state government. Lands may be leased in fairly large blocks. This is necessary, in fact, to carry out economically efficient oil and gas exploration in Alaska’s high cost operating environment. In other states, ownership of oil-producing areas divided among farms, ranches, and other landholdings can create problems in efficiently producing (and regulating, from a governmental standpoint) a commercial field.

*Alaska’s compulsory unitization law is not totally compulsory. AS 31.05.110 gives the state conservation commission the authority to order unitization, but subsection (d) stipulates that 62.5 percent of the lease-equity owners must agree, aside from the state’s royalty interest. This means that the state cannot arbitrarily force unitization if the majority of leaseholding interests do not want it, and where the majority interest-holders wish unitization and minority interest-holders disagree, the state can step in with its compulsory authority. The concept is based on the model Interstate Oil Compact Commission statutes, as are most of Alaska’s oil and gas conservation statutes. In late 1972, state officials told the author that they may seek a legislative change in this law, giving the state unilateral unitization authority, if unit negotiations between companies in the Prudhoe reservoir should break down completely.
This pattern will change somewhat when Native regional corporations created under the Alaska Native Claims Settlement Act begin selecting, and leasing, their lands. But even these lands will probably be leased in large blocks, thereby avoiding many difficulties experienced in older, more settled states.

A State Computer Model

The State of Alaska's decision, through the Division of Oil and Gas, to construct a computer model of the Prudhoe Bay reservoir was an important milestone in state regulation. Only one other state (California) has so far used computers in reservoir regulation (on a reservoir on state land near Long Beach), although computer models are in use in the Province of Alberta in Canada as well as on many fields in U.S. federal lands. In the private sector, companies commonly use computer models of reservoirs as a basis for formulating production plans, and it is possible that they will also be used by Prudhoe Bay operators.

Division of Oil and Gas planners feel an adequate analysis of an engineering problem in the Prudhoe reservoir will require a computer model of the reservoir. They believe such a model is needed to protect the state's proprietary interests.

The Prudhoe reservoir is so complex and the equities so sensitive to different production methods that the oil and gas conservation committee found they would ultimately have to reach a decision on proper methods of production. Because any decision they made would affect millions of dollars of both state and private income, the committee wanted to become better acquainted with the intricacies of reservoir performance at Prudhoe Bay. In a public hearing, the operator generally testifies only to factors which benefit him. Operators have many research people and outside consultants working on the problem. It was obvious that the committee eventually would have to rule on voluminous technical and research testimony. A computer simulation study was inaugurated to help the committee evaluate the testimony, which eventually will be presented. Since the different operators have different objectives in reservoir operations, the study is also intended to help decide if the operations proposed are best from a conservation standpoint.

Alaska's Oil Fields

A survey of Alaska's oil fields (Figure 3) provides a glimpse of the types of management problems with which state oil and gas technicians must contend.

The Cook Inlet Area

Swanson River: Alaska's first commercially significant oil field was Swanson River, discovered on federal land in 1957 by Richfield Oil (now Atlantic Richfield). Richfield sold half interest in the field to Standard of California in return for capital to develop the field, and SOCAL became operator. The first Swanson River unit formed did not cover all of the reservoir structure, which is now known to extend beyond earlier unit boundaries. A second unit was formed to cover these added parts of the structure, and by 1965 two units had been successfully combined into one larger working unit.

Two interesting features of the Swanson River field are the large quantities of oil which are being recovered beyond the original forecasts for primary production, and the large reservoir repressurizing program which uses natural gas and limited water injection. The original forecast for total field production was 50 million recoverable barrels, but production from the field had exceeded 118 million barrels by the end of 1972. The gas used to repressurize the formation is rented from the nearby Kenai gas field. It is one of the largest natural gas repressurizing projects ever carried out. The Swanson River production in excess of the original forecast by over 100 percent is a direct result of early field repressurization and wise reservoir management.

Kenai Gas Field: The Kenai gas field, south of the city of Kenai, was discovered in 1959. It is mostly owned by Union (of California) and Marathon Oil companies. Though mainly on federal land and organized as a federal producing unit, a part of the Kenai gas field underlies privately owned land—the only leases in Alaska producing royalties for private landowners.

Some of the lands (2.5 percent) within the field are patented homestead lands, and private leases were
negotiated by the exploration companies. The small Sterling gas field, also discovered in 1959 by Union and Marathon Oil, has just one producing well. Such early unitization helps preclude disputes between leaseholders and makes for efficient field operating conditions.

Cook Inlet Oil Fields

The four oil fields in Cook Inlet (Middle Ground Shoal, Trading Bay, Granite Point, and MacArthur River fields) provide interesting examples of problems which operators encounter in attempting to form units. They also give us examples of difficulties the state encounters in encouraging unitization.

Unitization was not necessary at Middle Ground Shoal and Granite Point because the reservoirs there were structurally simple enough that injection line wells could be used to discourage migration. In Northeast Trading Bay, however, unit cooperation in waterflood was necessary to prevent loss of production energy in the reservoir. At Trading Bay, unitization was not needed because the faulted oil traps did not interconnect. Also, leases were so arranged that one combine of owner companies covered one faulted oil trap—with a few exceptions covered by intercompany agreement.

MacArthur River was easily unitized because the basic simplicity of the structure and the high cost of platforms and pipelines necessitated agreement.

Of the many reasons for breakdowns in unit negotiations, the most common seems to be disagreement over reserve equities assigned to leases within the proposed unit area and disagreement over development costs charged to the proposed unit by operators who have already installed development facilities. This disagreement over development costs makes it especially difficult to form units once such production facilities as platforms and underwater pipelines have already been installed. Companies spend money for development facilities in different ways, and the charge that Company X has spent more than is necessary on a given facility is frequently heard from Company Y, who under unit operations would have to share in the cost of X’s facility. Thus, it is obviously an advantage to unitize a field or potential field as early as possible, before any substantial amounts of development capital have been invested.

Middle Ground Shoal Field: The first of the offshore Cook Inlet fields was Middle Ground Shoal Field, with the discovery well drilled by a company group with Pan American (now Amoco) as operator in June 1962. Middle Ground Shoal is a long, narrow anticline pinched by a fault, and the Pan Am group wound up with lease-blocks on the north and south ends of the structure with another group (Shell as operator) owning leases in the middle. The lease owners began unitization talks in 1964, but these were suspended in 1965 and were never resumed. Due to lack of gas-cap and significant water-drive, unitization was not as necessary here as it was in fields with natural water and gas drive, because the fluids tended to be less migratory. This situation changed when the field was represurized by injected water (“water flood”).

The Middle Ground Shoal reservoir contained undersaturated crude oil with very little gas in solution. In order to maintain reservoir pressure near the bubble point (the pressure at which gas comes out of solution from the oil), pressure maintenance by water injection was initiated early in the life of the field to lessen the rate at which the reservoir pressure was declining. However, the water-injection added a new driving mechanism in the reservoir. Where before there had been no significant migration problems it was now possible that the fluids could cross lease boundaries, creating an inequity in the non-unitized fields.

To cope with this situation, the operators worked out an agreement where water-injection wells were placed at the lease boundaries between the two company groups. The injection wells, driving hydrocarbon fluids away from them in all directions, tended to minimize the problem of fluid migration across lease boundaries. This program was carried out by the companies with the approval of the State Division of Oil and Gas.

Trading Bay Field: The main Trading Bay field, on the west side of Cook Inlet, was discovered in
June 1965 by Union Oil. The field is a highly complex series of faulted oil traps which appear to be singular with little or no connection to one another. At present there is no unit agreement for this field.

In the northeast corner of Trading Bay is an area known as Northeast Trading Bay. Here, a unit was recently formed after several years of unsuccessful negotiation between two industry combines with Texaco as operator for one group and Atlantic Richfield as operator for another group. The field was unitized before the water-flood program was initiated to prevent declining bottom-hole pressures and falling oil production. This structure did not have the simplicity of Middle Ground Shoal, where jointly owned injection wells on the property lines minimized fluid migration. Because water flood in this case would have created a substantial fluid migration in Northeast Trading Bay, the situation required a unit agreement. The agreement was concluded in 1972, and the field is now under water flood. Atlantic Richfield is now operator for all parties.

Granite Point Field: Granite Point Field, discovered just after Trading Bay in 1965, is another field where unit negotiations broke down early. Like the Middle Ground Shoal, this field is also comprised of a long, thin structure. A Mobil-Union combine holds acreage in the south, and Pan Am, heading a five-company group, holds acreage in the north. Also like Middle Ground Shoal, the necessity for unit formation preceding a water repressurizing program was bypassed by conversion of wells to injectors near the lease boundaries between the two groups. As at Middle Ground Shoal, the producers have discouraged fluid migration.

MacArthur River Field: MacArthur River Field, last of the producing offshore Cook Inlet fields discovered to date, was unitized after its discovery in late 1965. The field is a broad anticlinal structure, and like other Inlet fields has no gas-cap. Union and Marathon hold the strong central lease positions on the field, with other companies controlling the periphery. In a case like this, one dominant owner-group makes field management more simple, since outer leaseholders will generally be quick to share costs of expensive producing platforms and undersea platform-to-shore pipelines.

Though the MacArthur River oil field was discovered in 1965, a dry gas pool of possibly one trillion cubic feet of gas was subsequently discovered above the oil zone in December 1968. This gas field, which will be managed under the existing unit agreement for the MacArthur field, is helping to make economically feasible the recently completed gas pipeline from the west side to the east side of the Inlet.

Prudhoe Bay

The lessons of a decade of oil and gas production in Alaska are being applied to the Prudhoe Bay field on the North Slope. The Prudhoe Bay reservoir is a large anticline, faulted on one side. It has a large, powerful gas-cap, and substantial solution gas as well as a potential, as yet unmeasured, water-drive.

The nature of the Prudhoe reservoir will probably make essential the forming of a unit agreement among leaseholders at some time in the future. Different operators holding acreage in different parts of the field may have different production potentials and goals because of their position on the structure. The state is obliged to see that any such conflicts are resolved in a way that will protect the rights of all leaseholders, insure the state’s recovery of royalty and severance taxes, and maximize the ultimate recovery of oil and gas.

Disagreements could also possibly occur at Prudhoe over equity interests in the assignment of reserves to a particular lease. In fields the size of Prudhoe, a fraction of a percent of the total reserves may mean millions of dollars to a tract owner.

A unit agreement will be necessary for efficient operation of the Prudhoe reservoir.* Unlike the Cook Inlet fields in the south, a large gas-cap is present, as well as a possible large waterdrive. If the current disagreement over equity interests cannot be resolved, the state may have to make and enforce orders under statutes authorizing compulsory unitization.

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*At the time of this writing, a multiple unit agreement for the Prudhoe Bay field had not yet been finalized.
Prudhoe Oil and Gas Production: A delicate interrelationship will likely exist between optimum gas production and optimum oil production from the Prudhoe reservoir. The method that operators choose to optimize oil and gas production will depend on an accurate assessment of the dominant drive mechanisms in the reservoir. It is unlikely that these mechanisms can be positively identified and measured until fluids are produced from the reservoir and reservoir performance has been observed.

During the initial phase of production, information can be obtained for this purpose, and based on these findings a long-term production plan can be formed to optimize oil and gas production.

Any plans of the field operators to achieve these objectives must be submitted to the State Conservation Committee for their review.

In a typical anticline field such as Prudhoe, with a large gas cap, the normal production technique would be to emphasize production from the oil zone, preserving as much pressure (and therefore, driving energy) in the gas zone as possible. Such a technique would postpone direct gas production from the gas-cap. But if the field also had a water drive, as may be true for Prudhoe, a second technique could be used. This technique, used commonly in the Middle East where large water-drives are present, would theoretically allow direct dry gas production from the gas-cap to reduce pressure in the gas-cap and allow the encroaching water below to become the main driving agent for the reservoir.

The idea behind this approach is that water is a much more efficient driving mechanism for oil than is gas. Water drives the oil before it on a fairly uniform front, while gas sometimes has a tendency to bypass isolated globules of oil, leaving them behind where they cannot be recovered. In the situation of these fields, the driving mechanism of the gas-cap is replaced by water as a driving agent. Direct gas production from the gas-cap will then often aid in efficient oil recovery.

The importance of these reservoir management decisions by the companies, as well as the need for their close scrutiny by the state, is well illustrated by the fact that if unlucky reservoir decisions altered reservoir balances and reduced ultimate recovery by just 2 percent, the State of Alaska would lose some $55 million in royalty and tax income.*

Another problem faced by the committee with respect to Prudhoe Bay is the large volume of casing-head gas (gas produced at the casing-head or wellhead along with oil—also known as solution or wet gas) that will be produced with the oil. The state will prohibit venting or flaring (open burning) of this gas at Prudhoe Bay except in the event of dire operational necessity. Prohibited from flaring the gas, operators will inject the solution gas back into the reservoir, where it will replenish reservoir energy and await future production.

At some time after the beginning of oil production, a commercial gas pipeline will probably be laid in order to carry natural gas to market from Alaska's North Slope. The Prudhoe reservoir might not be the only source for a commercial gas line. A quantity of gas has been discovered at Kavik, some 45 miles southeast of Prudhoe, but the extent of this field has not yet been determined and announced as of this writing. There is a great deal of exploration activity by companies in the Kavik area, and state geologists feel that there is an excellent potential for finding additional reserves of natural gas in the Brooks Range foothills south of Prudhoe.

Natural Gas Flaring

Current deliberations over the use of North Slope gas coincides with a recent policy decision regarding Cook Inlet casinghead gas. As in other states, flaring (open air burning) of natural gas is prohibited in Alaska, except when permitted by the committee. Offshore Cook Inlet operators maintained that they could realize no profit from casinghead gas produced from their wells, because of expenses involved in cleaning, dehydrating, compressing, transporting, and marketing. Thus, no commercially feasible alternative to flaring existed. The conservation committee allowed the operators to flare the gas

*Figuring 2 percent of 9.6 billion barrels estimated field recovery at $2.65/bbl wellhead value (see "Revenue Sources, State of Alaska, 1972-1978," page 13).
that they could not use on the platforms, especially since the value of the gas under optimum conditions was only 1 percent of the value of the oil being produced.

In 1971, however, the conservation committee reversed its position and gave offshore operators one year to build pipelines and shore facilities to handle the gas and find a market for it. This decision followed recent growth in local gas markets around Anchorage and pressure from the state legislature against continued flaring. Furthermore, the conservation committee was now prepared to rule that the cost of saving the gas, even if greater than its market value, should be considered an expense of producing oil from the offshore wells.

As a result of the committee's decision, natural gas pipelines were built on the west side of Cook Inlet and below Cook Inlet to carry gas to the east side of the inlet. Union Oil of California and Marathon Oil are acting as operators of the pipeline construction, because both companies have heavy investment in Cook Inlet production and want to prevent the state's ban on gas flaring from interrupting their oil production. Construction of a 26-mile, 16-inch land line which runs along the west side of the inlet was begun during the winter of 1971-72. This line gathers the gas and transmits it to the terminus of a twin 10.75-inch submarine line at Granite Point. From Granite Point, the two submarine lines will run in an arc up around Middle Ground Shoal and to the eastern inlet shore at east Forelands, a distance of 21 miles.

The state's refusal to renew flaring authority is currently undergoing a legal test. After the June 1971 order, Mobil Oil, a major inlet operator, appealed the decision. In a rehearing, the state reaffirmed its earlier decision. Mobil has now taken the state to court over the issue, but despite litigation, all other operators are now using—to their benefit—the excess casinghead gas.

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**SUMMARY OF ALASKA'S FIELD REGULATIONS**

**Drilling**

Under drilling permit regulations, the state requires:

- Drilling permit applications, with survey plots showing surface and bottom location (if directional).
- A program of how the well will be drilled (if directional).
- The proposed casing program showing size, weight, grade, and depth at which each string is to be cemented.
- Minimum amount of cement to be used.
- Blowout prevention program or any other information the committee requests.
- Drilling must commence within 24 months of permit issuance, or the permit will become invalid, and a new application must be filed.
- Operators must advise the committee of any re-entry into the hole other than for routine repair or cleaning that does not affect the producing interval.

Unless modified by special field rules, the following statewide rules apply:

- In rotary drilling, suitable and safe casings will be run deep enough to safely control all pressures encountered, and the casing shall be sufficiently tested. (Surface casing shall be set into an impervious formation and cemented to the top of the hole. For all casing strings below the surface pipe, cement shall be set for 50 feet above the bottom of casing on each string.) A minimum cement strength of 300 psi at bottom hole conditions is required, according to the manufacturer's index for that cement. All drilling wells will be equipped with blowout preventers after the surface casing is cemented.
- In cable-tool drilling beyond the above measures, gas shall not be blown into the hole while drilling is in progress, nor shall any oil and gas horizons be contaminated with water in such a way as to injure the producing mechanism.
- All strata through which the well-bore passes will be sealed off. Water above the producing horizon will be sealed off in a manner to prevent contamination by oil and gas. All oil and gas strata will be sealed to prevent migration into other strata. In either drilling or abandoning, special precautions will be taken to protect fresh water strata from contamination by objectionable water, oil, or gas.
In vertical wells, deviations from the vertical may be made to straighten the hole, sidetrack junk, or to correct other mechanical difficulties. For an intentionally deviated hole, an operator must apply for a new drilling permit before drilling has commenced.

Abandonment and Plugging

Operators must file a sizeable bond, not less than $5,000 on each well to insure proper plugging and completion of abandonment procedures. In lieu of this, operators may file a continuing bond of not less than $10,000 to cover all their wells. The $5,000 and $10,000 are actually minimum bonds. In practice, the committee requires far higher bonds. At the time of this writing, a bond of $25,000 was being asked for land-based wells in the Cook Inlet area and $100,000 for offshore wells and wells in remote areas.

When abandonment is planned, operators must notify the committee of their intention. This notice must specify detail on kind, location, and size of plugs to be installed, plans for mudding, cementing, testing, and removal of casing.

- Unless otherwise specified by committee, the abandonment procedure will be to fill the bottom hole with cement or place a cement plug at the top of each hydrocarbon-producing formation open to the well-bore. A 50-foot plug will also be placed near the surface. The interval between the cement plugs will be filled with a heavy, mud-laden fluid in order to seal formations.

- An abandoned land-based well will require a 10-foot high marker extending above the concrete base, at least 4 feet above ground level. Surface markers must have the name of the operator, the well name, number, and exact location.

- In seismic or core holes, if a usable water formation is penetrated, the hole must be plugged to protect the water formation.

- If a well is temporarily instead of permanently abandoned, the operator must place a plug at the bottom of the casing, fill the casing with mud-laden liquid, and then plug the top of the casing.

- Operators will clean their drill locations and fill all mud pits within a year of leaving the well location unless delayed by weather conditions.

Well Spacing

In fields of proven production, establishment of drilling units and spacing patterns will be governed by special rules determined by committee hearings. In the absence of this, the following statewide rules shall apply:

- No exploratory well may open any pay zone closer than 500 feet from the lease boundary, nor can any bottom hole be located closer than 900 feet to any lease boundary or 1,000 feet from another well location drilling to or producing from the same formation. Only one oil well is permitted per governmental quarter-section (approximately 160 acres).

- Gas wells are limited to 640-acre spacing with no well closer than 1,500 feet to a property line or 3,000 feet from another well in the same pool. These rules attempt to allow for an efficient drainage area and protect common rights by requiring adequate stand-back distances.

- All rubbish and debris must be removed at least 100 feet from any well or tanks to avert a fire hazard. Waste oil must be burned to prevent fire hazard.

Production Practices

- Operators must measure gas-oil ratios and bottom hole pressures periodically.

- The committee will be notified immediately in the event of loss of oil or gas from fire or leaks.

*Sometimes drilling bits and other equipment are lost in the hole, and even elaborate recovery operations cannot recover them. In these cases, the equipment must be abandoned as junk and the holes cemented in and rerouted.
• No well will be put into multiple-zone production without the approval of the committee. Oil from one pool will not comingle with oil from another pool without prior approval of the committee.

• Waste oil will not be stored in earthen reservoirs, unless special permission of the committee is given.

• Except for initial testing, no dry gas may be vented into the air. Approved uses for gas are:
  • As a circulation medium in drilling.
  • Light or fuel.
  • Efficient chemical manufacturing.
  • Injection into formations to increase recovery.
  • Extraction of liquid hydrocarbons from gas.
  • Artificial lighting of oil. (In cases of operational necessity, the committee may grant an exception to this ruling.)

The state reserves the power to restrict production of crude oil in cases where gas saturation in the oil reaches beyond 2,000 cubic feet per barrel. This measure, by limiting excessive gas removal, is intended to prevent damage to the gas-drive mechanisms in a reservoir.

Salt water or brine produced with oil must be disposed of in a manner that avoids contaminating fresh water zones or other resources.

The committee may limit gas production in cases where production exceeds consumption needs and storage capability. A pool producing both oil and gas, in this event, may be assigned as gas “allowable” which will correspondingly limit oil production. In this event, allowable production will be equitably distributed among wells in the pool.

Automatic shutting devices are required below the mud-line in offshore wells. This device must automatically close in the event of a sudden increase in flow or pressure from below. *

When necessary, the committee has the authority to request additional information from well operators to prevent waste of a resource.

Artificial Recovery Methods

Any method of recovery other than primary must be approved by the conservation committee. The operator applicant must show in his application a plat of the unit and the lease or group of leases that will be affected. The plat must show:

• Location of proposed intake wells.
• Location of producing wells.
• Geologic information.
• Names of lease owners and operators of the affected leases.

Further, the operator must show:

• Logs of intake wells.
• Description of intake well casing.
• Proposed method of testing casing before use.
• Identification of injection medium.
• Estimated amounts to be used daily.
• Source of medium.
• Tabulation showing recent gas/oil ratios and water/oil production tests for each of the producing oil and gas wells in the lease area.

* The State of Alaska has always required these devices in offshore wells. The lack of enforcement of similar regulations by the U.S. Geological Survey in federal offshore waters brought on the much-publicized oil spills at Santa Barbara and the Gulf of Mexico.
The operator must mail copies of these plans to each operator affected by the project. If no objections are brought forward, the application may be granted.

Under "miscellaneous orders" the state requires that:

- Well logs and other information from wells drilled on federal, state, or private lands be furnished.
- Hearings be held to determine field rules or any departure from statewide rules in the discovery of new pools. The state is authorized to restrict production from any pool in order to prevent waste and protect correlative rights. In the event of such restriction, equitable shares of production will be assigned to each well.
- Detailed written records, posted daily and accessible to the committee shall be kept during drilling or deepening of any well.
- Electric or radioactivity logs, mud logs, or other descriptions of geologic strata encountered, and samples of drill cuttings and core chips will be provided the state within 30 days after halt of drilling operations. The information will be kept confidential for 24 months following filing of the information, then released to the public. (This rule can be waived by the state for some routine development wells.)

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Since preparing this paper, the author, Tim Bradner, has joined the staff of BP Alaska, Inc. The material included in the paper represents the author's personal interpretations based on interviews with industry representatives, personnel in the State Division of Oil and Gas, and on source material drawn from reference books. Although Mr. Bradner is now an employee of BP, the opinions and interpretations offered in this paper are his own and do not necessarily reflect the position of BP.

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