



Our resources
Our past
Our future

AOGCC

50 years of Service to Alaska

Alaska Oil & Gas Conservation Commission

Territory of Alaska
Alaska Oil and Gas Conservation Commission
P. O. Box 1391
Juneau, Alaska

Order No. 1
August 7, 1958

By the Commission:

After due notice and hearing in Anchorage, Alaska, on March 25, 1958, the Commission finds that certain rules and regulations of a general nature and Territory-wide applicability are necessary to the administration of Chapter 40, Session Laws of Alaska 1955.

It Is Therefore Ordered:

The following rules and regulations are hereby adopted, effective October 1, 1958.



Mike Stepovich
Governor Mike Stepovich, Chairman

Phil R. Holdsworth
Phil R. Holdsworth, Director

Frank A. Metcalf
Frank A. Metcalf, Member

Attest:

Cathryn A. Mack
Cathryn A. Mack, Secretary

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AOGCC

50 years of Service to Alaska





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Photo credits: Chris Arend, Judy Patrick, David Prediger, Rob Stapleton, Steve McCutcheon Collection, courtesy Anchorage Museum at the Rasmuson Center, AOGCC, BP Exploration (Alaska), ConocoPhillips Alaska, Chevron, Marathon Oil Co. and the Texas Energy Museum.

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Text: Tim Bradner



Drill pipe in storage at a North Slope rig during winter.

MESSAGE FROM THE GOVERNOR



Alaskans are blessed with bountiful natural resources that have been so important to our young state. Discovery of oil at Swanson River on the Kenai Peninsula in 1957 is the event that persuaded Congress to grant statehood to the Territory of Alaska. In the following years there were additional discoveries – first in Cook Inlet Basin, and then on Alaska’s North Slope. These provided the jobs and revenue that allowed our state to attain goals far beyond the dreams of those pioneers who worked for statehood.

The Alaska Oil and Gas Conservation Commission (AOGCC) is celebrating its 50th anniversary. As a former Chair of this venerable agency, I know it is one of the oldest and most important agencies in the state, because it protects the state’s valuable oil and gas resources for the welfare of our people.

Over the last half-century the dedicated staff and professionals of the AOGCC have overseen and guided the wise development of Alaska’s abundant oil and gas resources, as mandated by our Constitution.

I am proud to have played a part in the history of the AOGCC, and on the 50th anniversary of this agency I salute all the men and women who, by their efforts over the years, have contributed so much to the prosperity we all share as Alaskans.

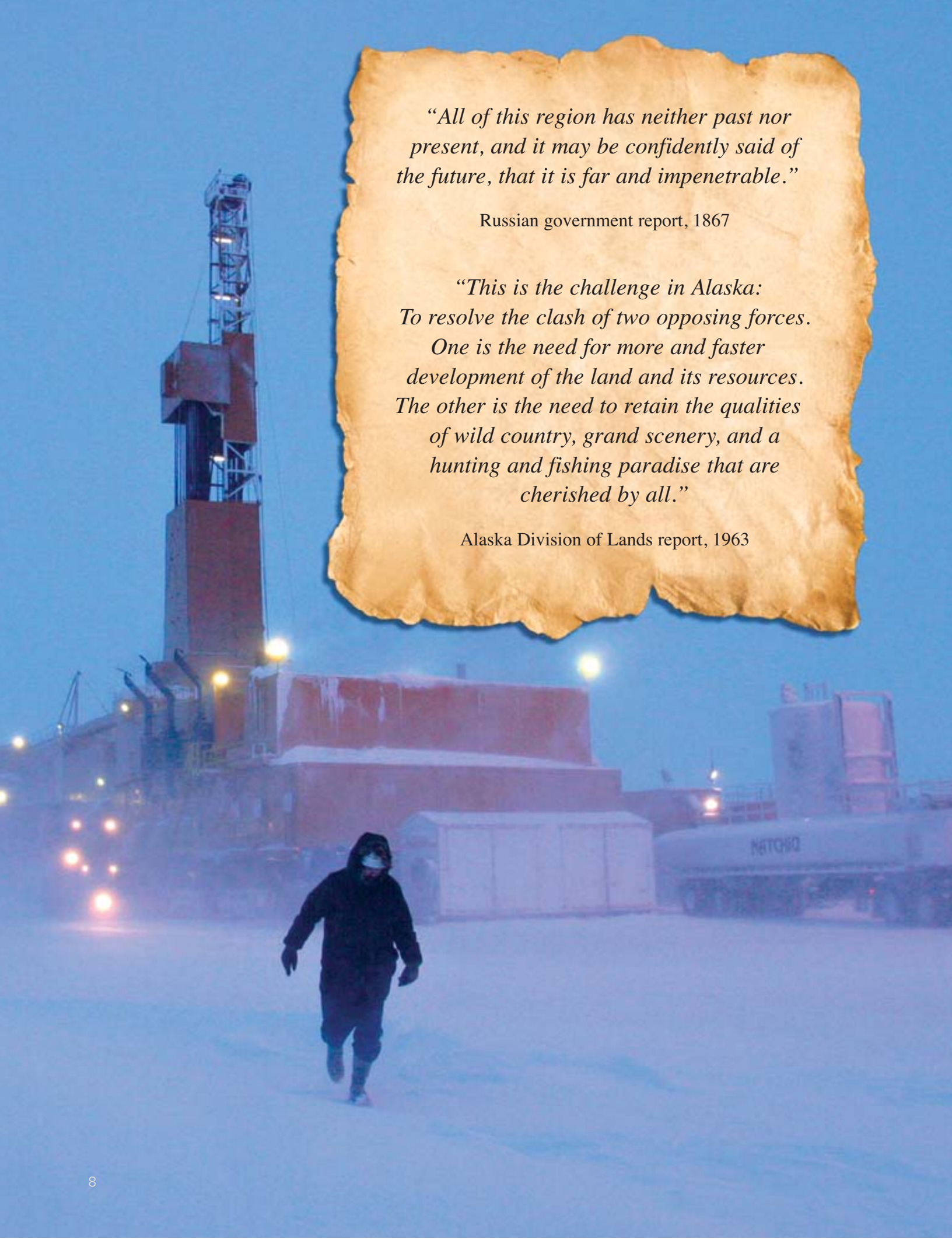
This is their story.

Sincerely,

A handwritten signature in blue ink that reads "Sarah Palin". The signature is fluid and cursive, with the first name "Sarah" being more prominent than the last name "Palin".

Sarah Palin

Governor



“All of this region has neither past nor present, and it may be confidently said of the future, that it is far and impenetrable.”

Russian government report, 1867

*“This is the challenge in Alaska:
To resolve the clash of two opposing forces.
One is the need for more and faster
development of the land and its resources.
The other is the need to retain the qualities
of wild country, grand scenery, and a
hunting and fishing paradise that are
cherished by all.”*

Alaska Division of Lands report, 1963

50 YEARS IN ALASKA

The Alaska Oil and Gas Conservation Commission 50th Anniversary

The Alaska Oil and Gas Conservation Commission (AOGCC) is celebrating its 50th anniversary. For more than half a century – since 1958 – the Commission has been the principal State regulatory agency charged with protecting correlative rights and ensuring that the petroleum industry in Alaska operates safely, avoids waste, achieves greater ultimate recovery of valuable hydrocarbon resources from Alaska’s producing oil and gas fields, and protects underground fresh water resources.

Every oil and gas producing state has a commission or agency comparable to the AOGCC and while regulatory powers and organizational structure vary among states, the broad public mandates of preventing waste, protecting correlative rights, and promoting greater ultimate recovery are similar.

The AOGCC consists of three Commissioners appointed by the Governor and confirmed by the Legislature. The law requires one Commissioner to be a geologist and one a petroleum engineer. The third is a public member who has traditionally been a person with significant knowledge of the petroleum industry or public process and government. Commissioners serve staggered six-year terms, ensuring continuity.

Their responsibilities are set out in State law and carried out with the help of an experienced professional staff. Along with ensuring greater ultimate recovery and the safety and integrity of oil and gas wells, the Commission’s responsibilities include protection of rights among owners of oil and gas interests and safe-

guarding the confidentiality of information that must be filed with the Commission.

As an independent quasi-judicial agency of the State of Alaska, the Commission also verifies the accuracy of the meters that measure the flow of oil and gas production. This is important not only because the field operators need accurate measurements of production volumes, but because royalties and production taxes are calculated on the amount of oil and gas produced.

Currently the AOGCC is located, solely for administrative purposes, within the Department of Administration. At one time, the Commission functioned as a part of the Department of Natural Resources (DNR), but in 1979 the Legislature established it as an independent body to avoid real or perceived conflicts of interest.

Such conflicts of interest could or might arise because DNR’s primary responsibility is to manage State-owned lands and oil and gas resources.

The Commission’s authority, however, is derived exclusively from the State’s police powers and extends to all oil and gas operations in the state, including those on federal and privately owned lands. To make certain that the Commission is perceived as being fair and independent in its decisions, the Legislature established it as an independent commission separate from the Department of Natural Resources. State law specifically provides that DNR shall have the same standing before the Commission, (no more or less) as granted by law to any other proprietary interest.

Every oil and gas producing state has a commission or an agency comparable to the AOGCC's and while regulatory powers and the organizational structure vary among states, the broad public mandates of prevent waste, protecting correlative rights, and promoting greater ultimate recovery are similar.

50 YEARS IN ALASKA...

An important distinction between DNR and the AOGCC is that DNR takes economics into consideration in many of its decisions while the Commission bases its decisions largely on engineering and geological factors. In the prevention of waste the Commission focuses on the loss of physical oil and gas fluids. It also promotes greater ultimate recovery of all hydrocarbon resources. DNR, in contrast, is charged with protecting the State's economic interests in its natural resources.

The integrity of the Commission's process for preserving confidentiality of sensitive well data is critically important. Information from all exploration and production wells is required to be submitted to the agency by law. Most exploratory data is held confiden-

An important distinction between DNR and the AOGCC is that DNR takes economics into consideration in many of its decisions while the Commission bases its decisions largely on engineering and geological factors.

tial for two years and then released to the public so that new exploration is encouraged. In certain circumstances, some well data may qualify for extended confidentiality. The most famous set of exploratory well information that is still confidential and is held in secure storage by the AOGCC is from the KIC No. 1 exploration well drilled on privately-owned lands within the Arctic National Wildlife Refuge in the mid-1980s.

Another responsibility of the Commission is the protection of property rights among owners of oil and gas interests. Although not common, disagreements among such owners do occur from time to time, and the AOGCC acts in a quasi-judicial role to resolve conflicts in cases where an impartial technical review is needed.



Photo: AOGCC field inspector Lou Grimaldi, at right, inspects a Kenai Peninsula oil production well. At left is Steve Tressler, of Peak Oilfield Services Co.



Photo: A hearing underway at the Alaska Oil and Gas Conservation Commission.

As an independent agency, the AOGCC is expected to render decisions that are fair and impartial to all parties, including the State.

The Commission also has responsibility for protecting ground water resources from contamination by the drilling or production of oil and gas wells. In 1986, the U.S. Environmental Protection Agency delegated protection of underground fresh water resources from harm by oil and gas operations to the State of Alaska, and the Legislature assigned this responsibility to the Commission because of its technical competence and familiarity with subsurface geology and oil and gas drilling operations.

There is heightened awareness of the need for protection of underground water resources after Matanuska-Susitna Borough and Kenai Peninsula Borough residents recently voiced concerns over plans to drill for and produce methane gas from shallow coal seams. The pub-

lic's concern was that fluids used in well drilling and production could leak from well bores and contaminate shallow aquifers that supply water to nearby homes and communities. As a result the State Department of Natural Resources and the Legislature implemented specific safeguards in law and regulations to address the concerns that were expressed.

To protect underground sources of fresh water, the Commission reviews plans for all injection wells, including

those used for fluid disposal or as aids to enhanced oil recovery. This is done to ensure that fluids are injected into the proper underground zones and that the reservoir sections receiving the injected fluids are properly sealed so there can be no seepage to

other underground strata or to the surface.

One of the Commission's core responsibilities is to ensure that operators of oil and gas wells follow a prescribed set of procedures and utilize good oil field practices.

Another responsibility of the Commission is the protection of property rights among owners of oil and gas interests. Although not common, disagreements among such owners do occur from time to time, and the AOGCC acts in a quasi-judicial role to resolve conflicts in cases where an impartial technical review is needed.

Milestones

1958 -

The AOGCC was created and its first rules and regulations were promulgated and became effective October 1, 1958, pursuant to the Alaska Oil and Gas Conservation Act. The Territorial Commission was composed of the governor, the Commissioner of Highways and Public Works and the Commissioner of Mines.

1959 -

Alaska became a state. Under the Statehood Organization Act of 1959, the AOGCC was abolished and its authority was transferred to the new State Department of Natural Resources, Division of Mines and Minerals. The Alaska Oil and Gas Conservation Committee was formed within the Division to hold hearings and issue decisions. The Committee consisted of the Division Director, the State Petroleum Geologist, the State Petroleum Engineer, and the Deputy Commissioner of the Department of Natural Resources.

1968 -

The Oil and Gas Conservation Committee was transferred to a new Division of Oil and Gas created within the Department of Natural Resources.

1979 -

The State Legislature reestablished the Alaska Oil and Gas Conservation Commission as an independent, quasi-judicial regulatory agency. The Commission is currently located, solely for administrative purposes, within the Department of Administration.

50 YEARS IN ALASKA...

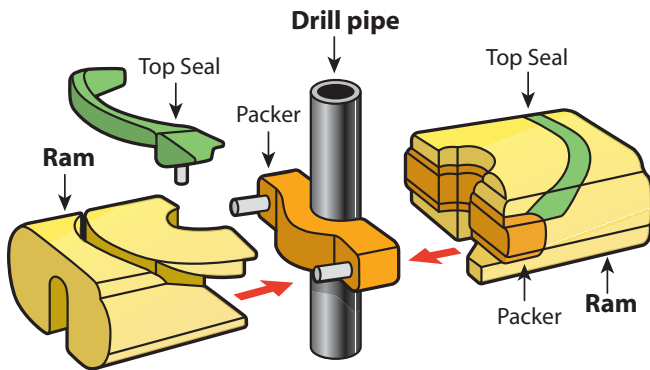
These procedures are laid out in detailed regulations, promulgated by the Commission, that oil and gas operators are required to follow. One of the constant challenges for the Commission is keeping Alaska's regulations up to date with the dramatic technological advances that are continually occurring within the oil and gas industry, including radically new types of wells and drilling technologies.

The Commission not only must approve drilling and production plans and any changes in those plans, but also conducts field inspections to insure compliance with the regulations. There are five full-time Petroleum Field Inspectors on the Commission's staff. They work a rotating schedule, with usually two on the North Slope at all times and three available statewide for inspection duties as needed.



Photo: Attorneys Rob Mintz and Cammy Taylor of the Department of Law have provided legal advice to the AOGCC. Taylor is also a former Chair of the AOGCC and is currently Petroleum Land Manager for the State Division of Oil and Gas.

One component of a blowout preventer (BOP)



One of the most important pieces of safety equipment on a well during drilling, and one which must be inspected and tested regularly with AOGCC inspectors present, is the blowout preventer. This high-strength safety device is installed at the surface, just below the drill rig floor. It can be closed immediately around the drill pipe if high-pressure oil and gas fluids enter the well during drilling or well maintenance (workovers) and cannot be controlled by the weight of the drilling fluid, or “mud,” that is circulated in the well.

A blowout ... is one of the industry's worst nightmares... Alaska has had no oil well blowouts and only a very small number of gas well blowouts, due to constant vigilance by industry and the Commission.

A blowout (the “gusher” of the industry’s early years) is one of the industry’s worst nightmares. Despite elaborate protection measures they can occur from time to time. Alaska has had no oil well blowouts and only a very small number of gas well blowouts, due to constant vigilance by industry and the Commission. If an oil blowout did occur anywhere in Alaska, it could potentially be a disaster for the industry and the environment. It is one of the AOGCC’s responsibilities to prevent such disasters.

AOGCC in brief

As an independent, quasi-judicial agency of the State of Alaska, the Commission operates under the authority of the Alaska Oil and Gas Conservation Act, Title 31 of Alaska statutes. Its regulatory authority is outlined in Title 20, Chapter 25 of the Alaska Administrative Code.

The Commission exercises what is virtually “cradle to grave” oversight for every oil and gas well drilled in Alaska, to ensure good oil field practices. The AOGCC acts to prevent waste of oil and gas, ensure greater ultimate recovery, ensure safety, protect rights of persons owning proprietary interests in oil and gas, protect underground fresh water resources from contamination due to oil and gas operations, and oversee metering operations to verify the quality and quantity of oil and gas that is produced.

Safety and preventing of waste: ensuring the integrity and safety of well control equipment and preventing the loss of valuable oil and gas due to the failure of production equipment or improper reservoir management practices. The Commission reviews each drilling proposal to check for shallow geohazards and high-pressure zones underground, and to ensure proper well design, including casing and cement programs, gas detection and blowout prevention equipment.

Greater ultimate recovery: ensuring greater physical recovery of valuable oil and gas resources through proper reservoir management techniques, well spacing, production rates, injection of fluids to enhance recovery, and reservoir pressure maintenance efforts.

Protection of correlative rights: protecting the rights of resource owners to recover their fair share of the resource. This is primarily accomplished through establishment of drilling and production units. Units are leases that are grouped for efficiency into one administrative unit.

Underground injection control: protecting underground reservoirs and aquifers through verification of the mechanical integrity of injection wells and the competence of confining strata to ensure that materials injected underground stay within the designated zones.

Metering: verifying accuracy of crude oil and natural gas meters used to measure production for royalty and tax determinations.

Abandonment: ensuring that each well, at the end of its useful life, is properly plugged and abandoned so as to leave the well in a safe and permanently stable condition.

1950's

THE EARLY YEARS

THE ROAD TO SWANSON RIVER AND COOK INLET

It was 1955. Statehood for Alaska was still four years away. There wasn't yet a commercial oil discovery in the Territory of Alaska, but people were exploring.

Irene Ryan, Anchorage mining engineer and geologist and a member of the Territorial Legislature, felt confident oil and gas would eventually be found. She was worried, however, that the Territory, soon to become a state, didn't have rules in place to guide a petroleum industry once there was one.

Alaska needed oil and gas conservation laws like Oklahoma, Texas and other oil producing states, Ryan told Ernest Gruening, who was then the Territorial governor. Without these laws there could be reckless, uncoordinated drilling and waste of valuable resources, she warned.

The Governor listened, and the Alaska Oil and Gas Conservation Act was adopted. This showed remarkable foresight, because a commercial oil or gas field hadn't yet been found. The heart of the new oil and gas conservation law was its mandate to prevent wasteful practices and loss of oil and gas, and to conserve these valuable resources.

Two years later Alaska's first real discovery was made, in the Swanson River field on the Kenai Peninsula, and it ushered in a new era for Alaska. Among other things, it made Congress realize that the Territory had natural resources that could support a state government. Work started on a set of regulations to ensure safety and prudent resource conservation.

The Alaska Statehood Act passed in July, 1958 and was signed into law by President Eisenhower. Alaska's first oil and gas regulations were completed and became effective October 1, 1958.

Most Alaskans didn't know a lot about oil in the 1950s, but they understood resource conservation. The fishing industry's depredation of salmon runs with fish traps was one of the main reasons Alaskans wanted statehood. They wanted to manage their resources themselves, and felt they could do a better job than the federal government.

It seemed a foregone conclusion to people familiar with geology that major oil and gas discoveries would

be made someday in Alaska. The petroleum industry was still in its infancy at the time of the Alaska Gold Rush. Col. Edwin Drake had made his historic first oil strike at Titusville,

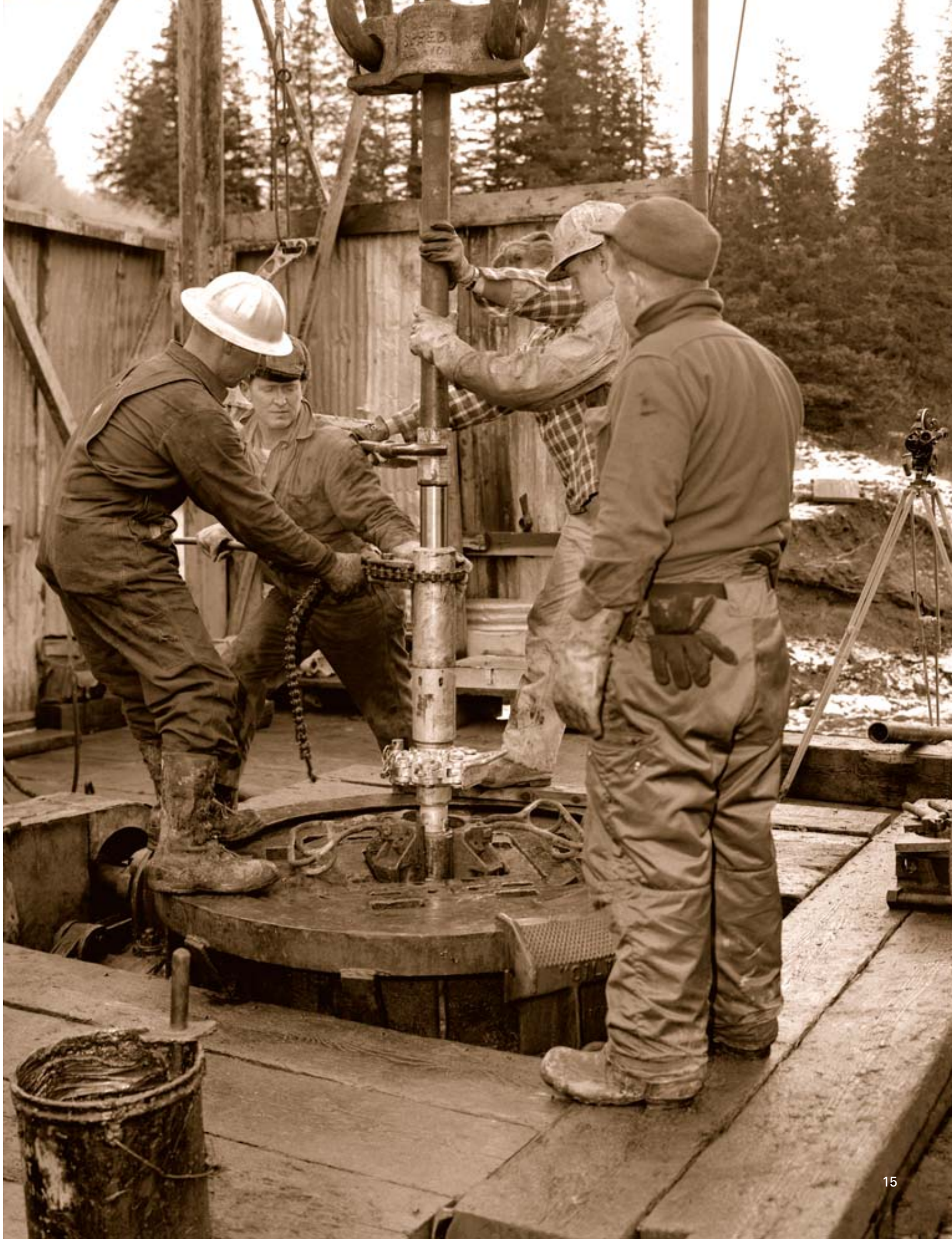
Pennsylvania just 30 years earlier, but as gold prospectors flooded into Alaska at the turn of the century there were also prospectors looking for oil.

The first known reports of oil seeps in Alaska came in 1839 when representatives of the Hudson Bay Co. reported that Alaska Native people at Barter Island and Cape Simpson on the Arctic coast used oil-soaked tundra for fuel. The oil came from natural oil seeps.

In 1886, an explorer for the U.S. Navy brought back samples of oil from the Colville River area of the North Slope. It piqued the Navy's interest, and several geological field parties were sent to northern Alaska after the turn of the century.

Alaska needed oil and gas conservation laws like Oklahoma, Texas and other oil producing states... Without these laws there could be reckless, uncoordinated drilling and waste of valuable resources.

Photo at right: Drilling crew at the Beal No. 1 well near Iniskin Bay on the Alaska Peninsula, an exploration well drilled in 1954 by Alaska Consolidated Oil Co.



Oil and gas conservation – how it began...



Early "gusher" in an East Texas oil field. The gusher symbolizes the wasteful practices of the industry's early years. Pictures (top, and lower right) courtesy Texas Energy Museum, Beaumont, Texas.

Irene Ryan knew a thing or two about oil. She had grown up in Texas in the wild and wooly oil boom times of the 1930s. She had seen the waste that resulted from the rush of frenzied drilling following each big discovery.

Those were wild times indeed. The petroleum industry was still in its adolescence in the early 1930s when the giant East Texas field was discovered. Before the discovery of East Texas, oil was selling for \$1.10 per barrel. After this giant discovery there was a rush of drilling, and new oil flooded into the market. In one hectic week a new well was being drilled every hour in the field. Ten months later, 1,000 wells were flowing and the price of oil had plummeted to 10 cents a barrel.

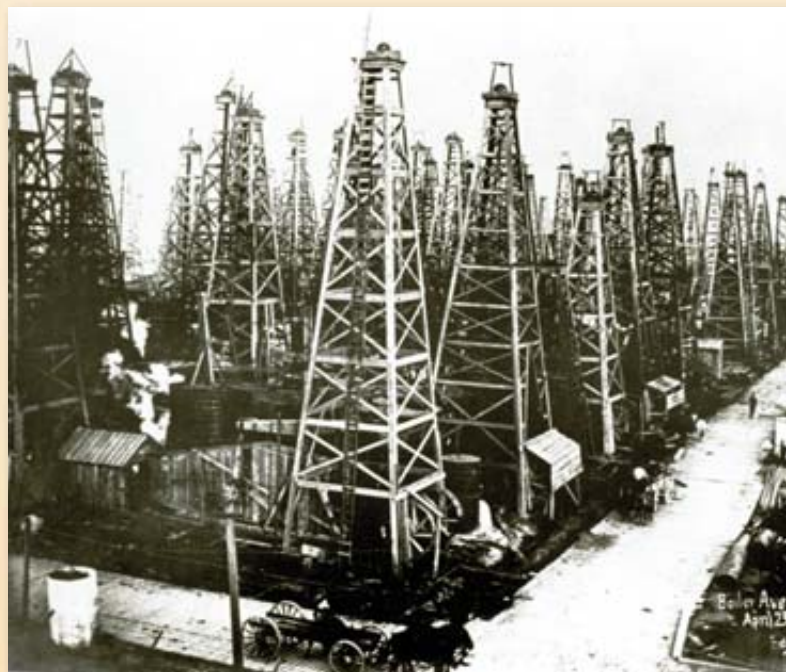
"I sell a barrel of oil for 10 cents and a bowl of chili costs me 15 cents," complained one early-day producer in an East Texas café.

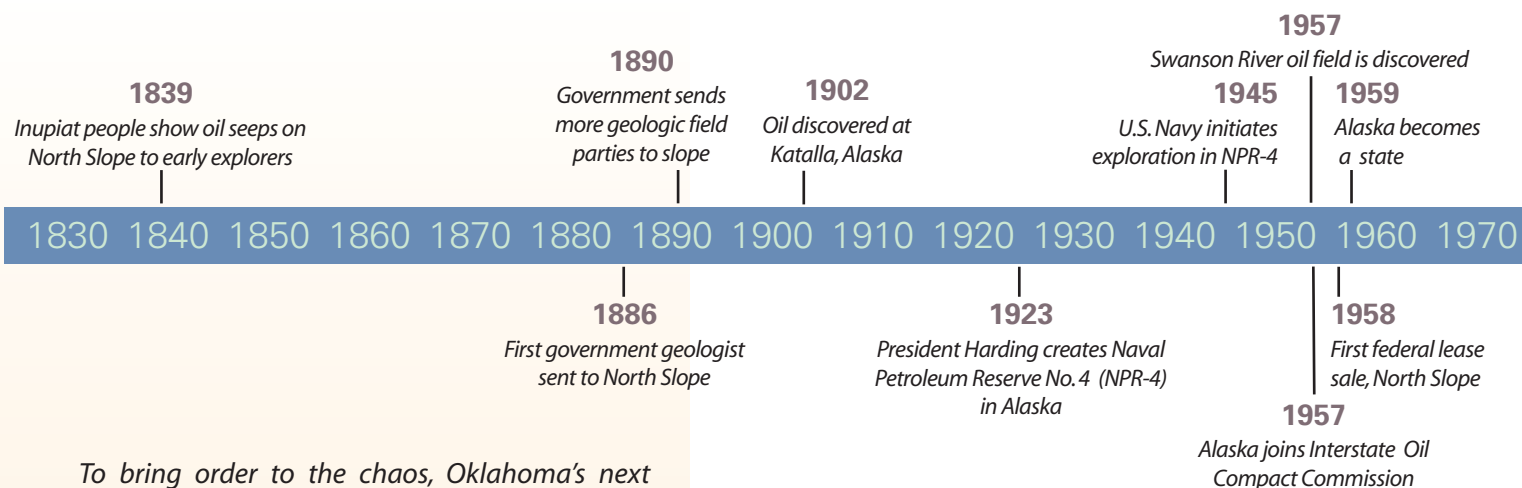
Ruth Sheldon Knowles, the mother of former Alaska Governor Tony Knowles, was a noted historian of the oil industry, and she wrote about those chaotic early days in her book, "The Greatest Gamblers."

Derricks and wells were clustered closely in the industry's early days in Texas.

The 1931 price plunge was self-inflicted by the industry. Wildcatters rushed to drill and produce as much as they could from the big new discoveries, Knowles wrote. Texas Governor Ross Sterling and Oklahoma Governor "Alfalfa" Bill Murray moved quickly to prevent waste of the resource and bankruptcy of their states' young industry. Murray declared martial law and shut down 29 Oklahoma oil fields to restrict production. He vowed to keep the Oklahoma fields closed, "until we get dollar oil." Sterling called out the Texas National Guard to enforce new production restraints in Texas.

The attempts at production and price controls had uneven results as such measures usually do. In her book Knowles recounts that oil bootlegging and midnight drilling were two responses to Governor Sterling's controls, but gradually the oil wildcatters realized that the sheer waste from the drilling of thousands of unnecessary wells was ruining the underground producing reservoirs. Unless the fields were produced scientifically, with the oil withdrawn more slowly, billions of barrels of oil would be forever lost, trapped underground and unproducable. Producing oil too quickly dissipated reservoir energy and allowed a substantial portion of the hydrocarbon fluids to be left behind and lost to production. This was a significant waste of the resource.





To bring order to the chaos, Oklahoma's next Governor, E.W. Marland, persuaded Texas and eventually several other oil producing states to join Oklahoma and form the Interstate Oil Compact Commission (IOCC), a compact under which member states voluntarily agreed to enforce good oil and gas drilling and development practices, including conservation measures.

One early rule required wells to be properly spaced apart from each other. This was a major step. Before such rules existed wells were drilled so closely they almost touched each other. The new conservation rules ended that practice, requiring wells to be spaced in 10, 20, or 40-acre parcels.



Typical modern production pad, North Slope, Alaska

There were horror stories from those early days. When "gushers" blew, oil coated people and machinery, fires often ignited from escaping natural gas and lakes of oil would form around the rigs.

The benefits of managed production gradually became recognized. Without it the wasteful practices would leave a lot of oil in, or on, the ground. The East Texas field, for example, would only have produced a billion barrels of oil under the old wasteful practices. With conservation rules in place, the field's ultimate recovery of oil from the underground reservoir will far exceed that.

THE EARLY YEARS...

The first known reports of oil seeps in Alaska came in 1839 when representatives of the Hudson Bay Co. reported that Inuit people on the Arctic coast used oil-soaked tundra for fuel.

In 1923, after World War I demonstrated that modern armies and navies needed to be fueled with oil, President Harding declared a vast area of the western portions of the North Slope, 23 million acres, as a naval petroleum reserve, though no oil had actually been discovered there. The new Naval Petroleum Reserve No. 4 lay dormant, however, until after World War II.

Meanwhile, Alaska Native people had also long known of seeps along the southern Alaska coast. The first oil claims in Alaska were filed on land where there were seeps in what is now Oil Bay, on the southwest side of Cook Inlet, in 1892 and 1896. The first attempts at drilling started in 1898, the year of the Klondike gold discovery. Drilling efforts continued for eight years. There were oil and gas shows, but efforts to produce the oil were unsuccessful.

Efforts at oil drilling were also being made at Katalla, about 50 miles east of Cordova. The first wells were drilled from 1902 to 1904, but the commercial-scale production was plagued with mechanical and other problems. A small refinery was eventually built. The wells produced approximately 140,000 barrels of oil over a 30-year period, providing an important source of fuel oil for the Territory of Alaska. The refinery operated until it was destroyed by fire in 1933.



THE EARLY YEARS...

In 1886, an explorer for the U.S. Navy brought back samples of oil from the Colville River area of the North Slope. It piqued the Navy's interest, and several geological field parties were sent to northern Alaska after the turn of the century.



The end of World War II in 1945 brought a renewed search for petroleum in Alaska. The U.S. Navy dispatched additional field parties and mounted an active exploration program. Navy explorers found a small oilfield at Umiat, on the Colville River, and small gas fields at Gubik, near Umiat and at Barrow. The Barrow gas field is now producing gas for the community. However, no truly commercial oil or gas field was discovered and the Navy program ended in 1955, the year the Alaska Oil and Gas Conservation Act was adopted. The results, however, were encouraging enough that private companies began their own geologic fieldwork on federal lands east of the Naval Petroleum Reserve.

Several major oil companies including British Petroleum, Sinclair Oil Co. and Richfield Oil Co. had their first geologists exploring in the foothills area of the North Slope in the late 1950s. It was the start of a long journey, first of disappointment and then finally, ten years later, great success.



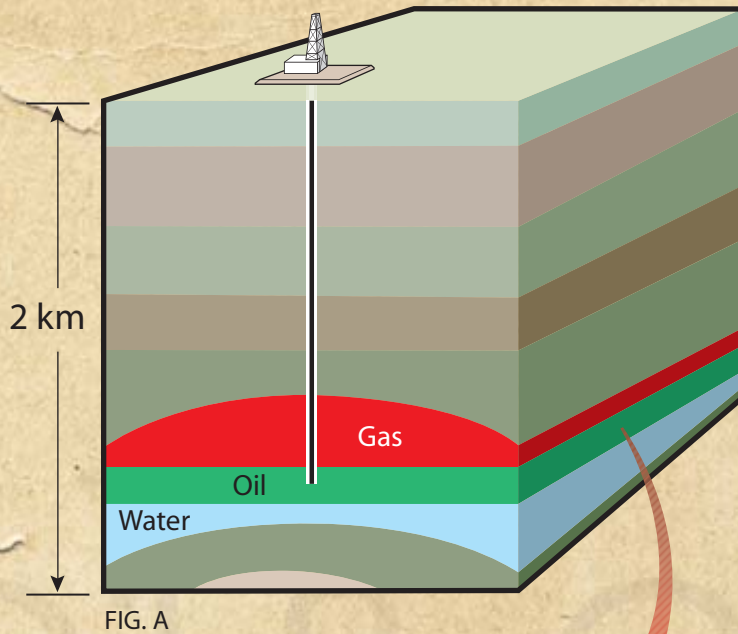
Photos: From top, geologists near Yakutat in the late 1950s; Middle: Richfield Oil's discovery well at Swanson River on the Kenai Peninsula made headlines in 1957; Right, a production well is drilled in the new Swanson River field.



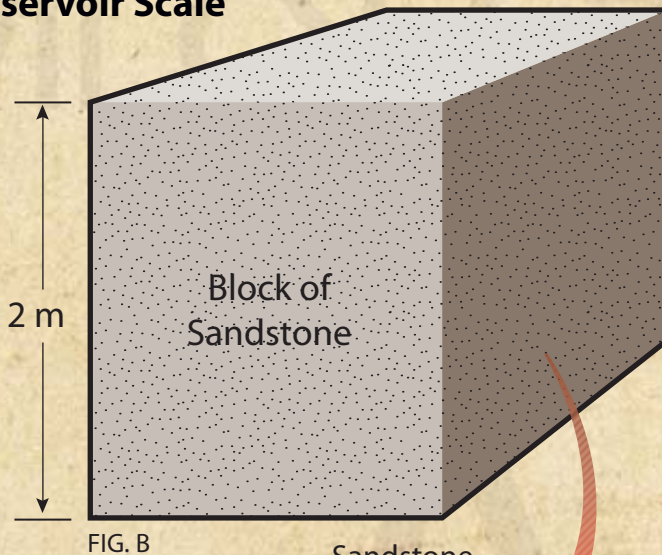
What is Petroleum?

The prevailing theory is that oil and gas were formed over millions of years, starting when plants and small sea animals were buried in sand and mud. Over time, layers of mud, sand and other materials built up until pressure and heat from the earth converted this organic material to complex compounds of hydrogen and carbon – “hydrocarbons” – or petroleum. Natural gas and oil are both petroleum fluids formed under tremendous subterranean pressure and heat. The tendency of these fluids is to migrate upward over millions of years from the “source” sedimentary rock through other rock until an impermeable barrier – “cap” rock – is encountered. When that happens the petroleum fluid is trapped, forming a petroleum reservoir.

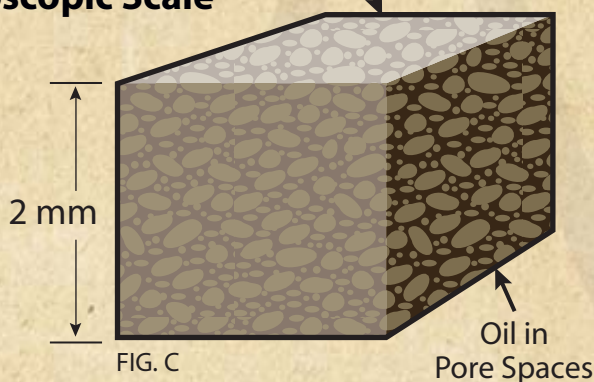
Field Scale



Reservoir Scale



Microscopic Scale



How are oil and gas held in the reservoir rock?

Within the reservoir rock, oil and gas are trapped within microscopic pores much like water is held in a sponge. Often there are connections between the pores, allowing the fluids to flow along pathways toward areas or points of lower pressure, such as shallower reservoirs or producing wells. In looking for petroleum, geologists first want to find “source” rock, where hydrocarbons can be formed, then reservoir rock to hold petroleum and then an impermeable cap rock which can form an oil and gas trap. The reservoir rock must have good “porosity” or pores that are large enough to hold hydrocarbons, and good “permeability,” or connections, to allow the oil fluids to move toward the producing wells.

Three common types of petroleum reservoirs

Dome or closed-fold trap

A closed-fold trap (sometimes called an anticline or "dome" trap) is a common type of underground reservoir that is most familiar to the public. Because it can often be detected from the surface this type of oil trap was commonly discovered in the industry's early years. The closed fold results from an upfolding in rock strata creating a structure like an overturned bowl. Trapped by an impenetrable layer of rock at the top of the bowl, oil and gas are held in place by their natural buoyancy in the porous rock. Often there is a water zone under the oil zone, or hydrocarbon layer, that is frequently larger. As oil is produced the expansion of the aquifer provides pressure to support oil production.

Fault-sealed trap

A fault-sealed trap occurs when rock strata are abruptly broken by a fault, a result of some movement of rock in the earth. This creates a "wall" of different rock material which seals the strata. If porous rock and permeable rock strata are tilted, oil and gas will migrate upward through the strata until they are stopped by an impenetrable rock layer at the fault. Here a pool of oil or gas can be formed.

Stratigraphic trap

A stratigraphic trap is caused by a change in permeability of a rock stratum instead of by a fault. The result is the same, however, as the permeable rock, containing the oil or gas, terminates against a different kind of rock. If the rock is impermeable it will trap the oil or gas.

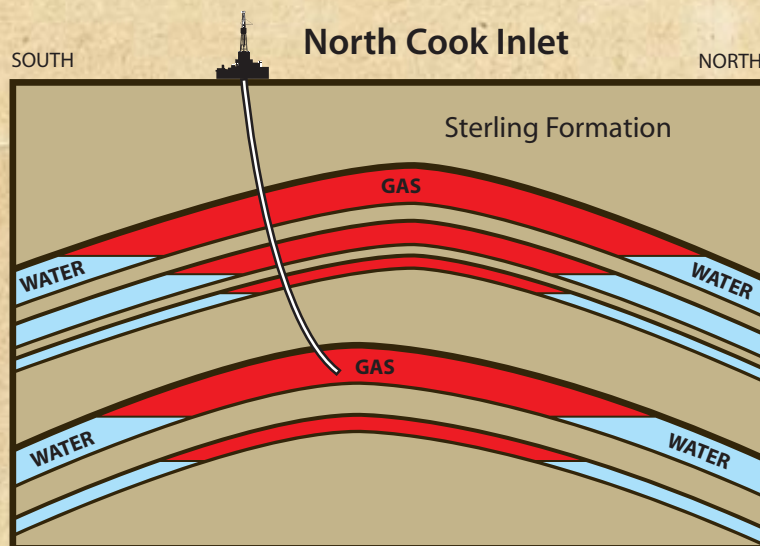


FIG. D

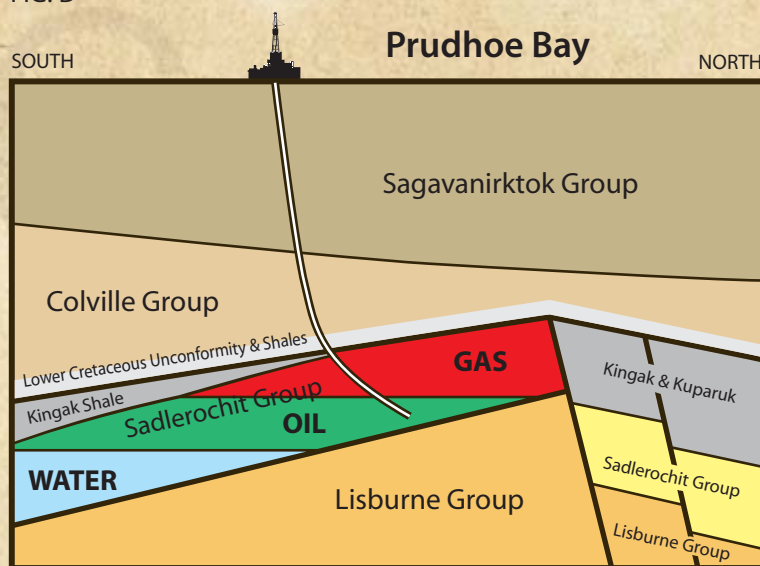


FIG. E

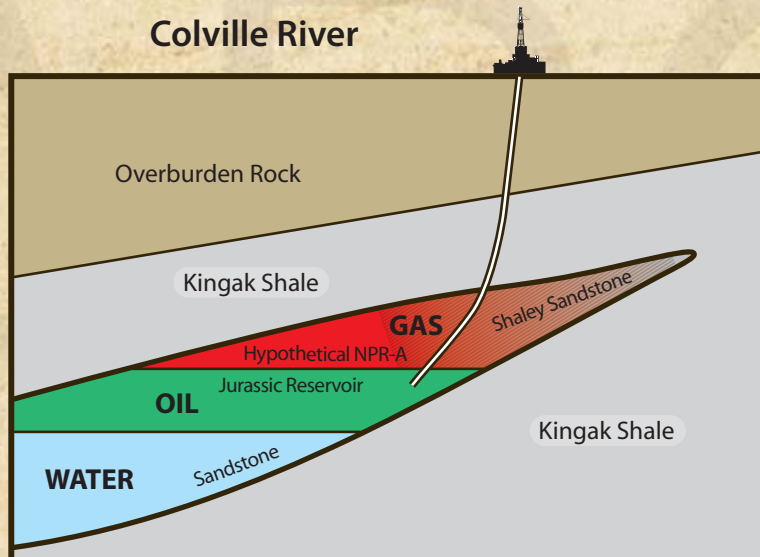


FIG. F

1960's

THE SIXTIES

DISCOVERIES IN COOK INLET, EXPLORATION OF THE NORTH SLOPE

When Alaska became a state in 1959, commercial fishing and timber were the Territory's principal natural resources industries. Alaskans knew there was oil and gas potential but they had no idea of the riches waiting to be discovered in Cook Inlet and later on the North Slope.

As the new State government was organized, the Territorial government's Oil and Gas Conservation Commission was folded into the new Department of Natural Resources and renamed the Oil and Gas Conservation Committee.* At the time it was a logical thing to do. Money was tight for the infant State government and it made sense to put all of the State's resource development expertise in one group.

The 1957 Swanson River oil discovery had been made on federal lands, in what is now the Kenai National Wildlife Refuge, so the rules of the U.S. Bureau of Land Management guided the field's early development.

The young State government was anxious to select its own lands and to encourage more exploration, but it also needed a good, comprehensive set of conservation rules. Alaska was now a member of the Interstate Oil Compact Commission, the organization of oil-producing states, and the IOCC provided Alaska with its set of model regulations as well as technical assistance. Alaska benefited considerably from being able to start with up-to-date regulations.

Alaskans knew there was oil and gas potential but they had no idea of the riches waiting to be discovered in Cook Inlet and later on the North Slope.

For many years the State's oil and gas regulatory functions remained within the Department of Natural Resources, which was also responsible for management of State-owned lands and oil leasing. In the early 1960s, Alaska's government was thin on petroleum expertise. In fact, in all of State government there were just two people with technical knowledge of oil and gas, and they had to wear two hats, serving as regulatory officials on one hand and on the other helping the State manage and promote its lands and royalty interests.

It took time for Alaskans to realize that there might be potential conflicts in this arrangement, such as when the same geologists and State officials who had access to confidential data from wells submitted under the conservation law, even from private lands, were also engaged in managing

State royalty interests and helping plan competitive sales of oil and gas leases on State-owned lands.

To avoid these potential conflicts, the Legislature eventually reestablished the Alaska Oil and Gas Conservation Commission as an independent, quasi-judicial regulatory agency.

However, when young Tom Marshall joined state government in 1960 to help the state select its land entitlement given by the federal government, he was one of the people required to wear two hats.

Photo, at right: Offshore oil production platforms built in Cook Inlet with the Steelhead platform in the foreground. Platforms built in the Inlet were state-of-the-art when they were built. The industry had to deal with very unusual conditions of strong tidal currents and winter ice.

*Editor's note: Between 1959 and 1979 the AOGCC was the Alaska Oil and Gas Conservation Committee, after which its name was changed to Commission. For consistency the AOGCC is referred to as "Commission" throughout this publication.



THE 1960's...

The young, new state desperately needed money and leasing land for oil exploration was one way to get it quickly.

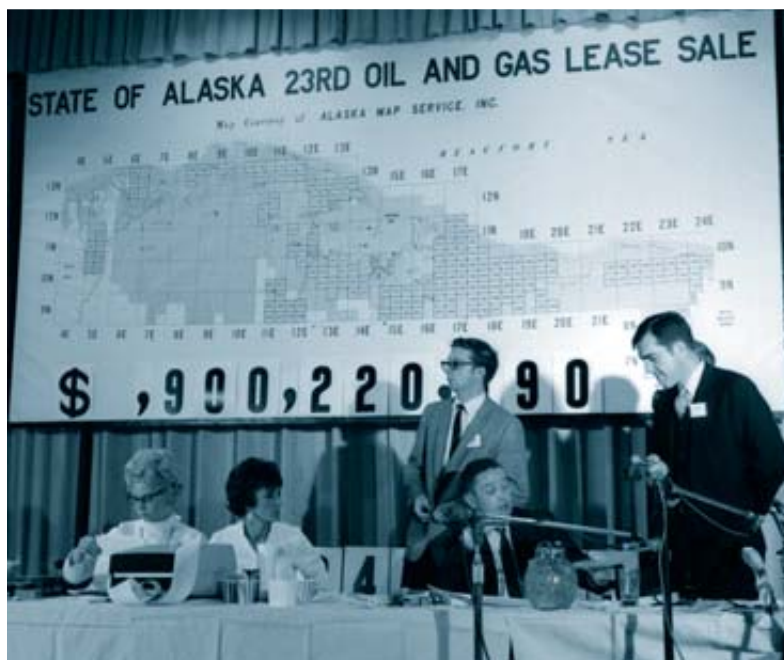
Marshall was a petroleum geologist who had worked in the industry in Wyoming. He had come to Alaska with his family in the late 1950s to homestead, and took a job with the new State government to help make its land selections.

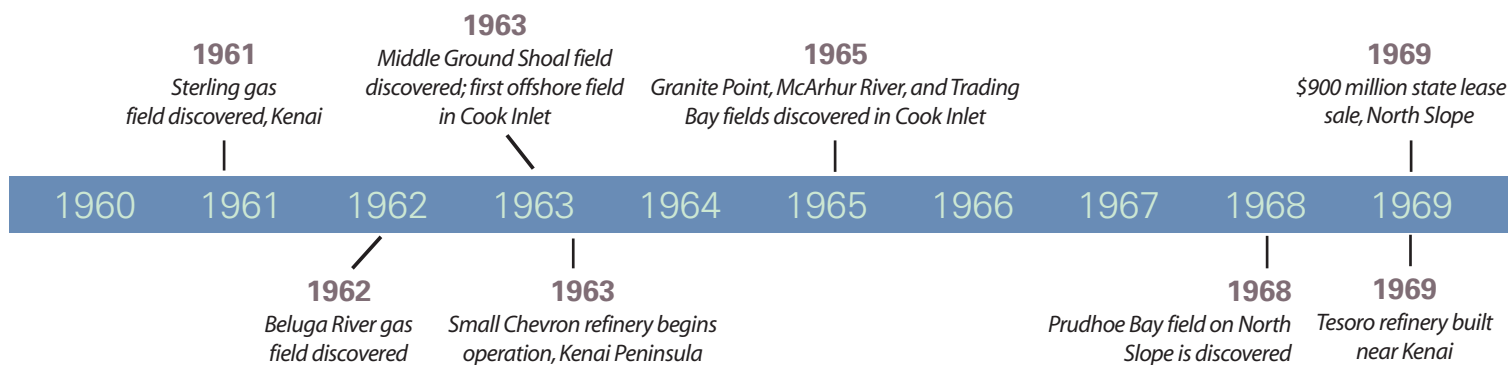
Because of Marshall's background, Natural Resources Commissioner Phil Holdsworth quickly drafted him into undertaking a wide variety of oil-related tasks, including regulatory functions. Holdsworth and Roscoe Bell, then the State land director, were very anxious to get State lands leased and oil discoveries made so revenue could flow to the treasury.

The young, new state desperately needed money and leasing land for oil exploration was one way to get it quickly. There were still only two people in the new state's petroleum section - Tom Marshall was one of them - and there was resistance within State government to spending money to give the petroleum group more help. This stemmed partly from people in the Department of Natural Resources who felt Alaska's future was in mining, not petroleum. Fortunately for Alaska, the people at the top, like Holdsworth, didn't share those views.

Marshall was the petroleum geologist and his one colleague was a petroleum engineer, Karl VonderAhe. They worked in the corner of a room - there were two desks pushed together - in the State Division of Mines offices at 329 2nd Ave. in downtown Anchorage.

Photos: Top, geologists study rock outcropping south of the Colville River in 1960s exploration; Middle, September, 1969 lease sale, which brought Alaska \$900.2 million in bonus bids; Bottom, a flare from an exploration well on the Kenai Peninsula.





Marshall was in that office during the Good Friday earthquake of 1964, and barely escaped out a window as the building collapsed around him. He went back later to retrieve confidential files and kept them at home until a safe storage space was found.

Marshall and VonderAhe were doing all the work, but the pace of industry activity was picking up. Swanson River had gone on production in 1959 and the Cook Inlet oil boom was just beginning. Most of the early-day explorers were new to Alaska too, and many of them were small independent companies.

“We helped them fill out the permit applications and spent a lot of time with them explaining the requirements for proper casing, abandonment procedures, monthly reporting and other requirements,” Marshall recalled.

Marshall and VonderAhe had to make sure the drillers used the proper amount of cement and steel casing so the wells would be safe. They had to inspect the safety equipment on the wells. Requirements were also made for waste fluids to be channeled into receptacles for disposal.

“I also functioned as the Department of Environmental Conservation at the time, and was the State official insuring the operators were following the right sanitation practices,” Marshall recalled. He and others working with him were acutely aware that they were the only real presence of the State on the Cook Inlet platforms, and that they bore responsibility for ensuring that the industry ran tidy as well as safe operations.

Normally, there was good cooperation from industry. O.K. “Easy” Gilbreth, a petroleum engineer who joined the State in 1966, recalled an incident that occurred while a State inspector was on a platform. Finishing his coffee, a worker pitched the paper cup

overboard. The inspector protested, the platform supervisor fired the worker on the spot, and he was on the next helicopter to shore.

The small State staff also had to investigate complaints from the public about the industry’s operations. Marshall recalls many times checking out reports of excessive smoke from the burning of oil fluids following tests. Gilbreth said commercial fishermen in Cook Inlet were quick to report trash and other debris from platform operations.

“We appreciated the vigilance of the fishermen. They gave us an extra set of eyes out there,” helping to keep an eye on industry operations.

“We appreciated the vigilance of the fishermen. They gave us an extra set of eyes out there,” helping to keep an eye on industry operations.

Marshall and his colleagues had to witness flow tests if oil and gas were found in an exploration well. At the time Alaska had a “discovery royalty” incentive that lowered the

State royalty from 12.5 percent of production to 5 percent for discovering a new field, and companies were anxious that their discoveries be properly documented.

To qualify for the lower royalty, the flow test at a discovery well had to be witnessed by the State for verification, and Marshall and VonderAhe were the only ones who could do it. Marshall remembers spending many of his weekends out on wells.

There were quirks in the Alaska rules, too. The Territory’s early regulations were borrowed from other oil-producing states and needed to be modified for Alaska’s unique conditions. A small example, for exploration wells, was a rule that required a rectangular metal sign identifying the well and its owners to be affixed to the wellhead at the surface. That was adequate for Oklahoma, but after Marshall and others at the AOGCC repeatedly found the signs mangled, particularly on the early North Slope wells, changes had to be made.

THE 1960's...



“Upon investigation we found that these signs were convenient scratching posts for grizzly bears,” Marshall said. A new rule was fashioned for steel plates with the identification to be welded onto the wellhead.

There were other issues Marshall and VonderAhe had to deal with, such as whether to allow cable tool drilling in Alaska. Drilling shallow wells with cable tool rigs was common in the older producing states from which Alaska had borrowed its first regulations.

“Cable-tool drilling is fine for drilling into a low-pressure reservoir, but it can’t contain high pressures,” Marshall said. “The way a cable-tool rig is set up there is no way weighted mud can be circulated, or a blowout preventer installed,” he said. No major oil and gas company was pushing for cable-tool rigs to be allowed, but some independent companies proposed the idea because these were less expensive than big rotary drill rigs. In the end Marshall and other State officials came down on the side of caution, and disallowed cable-tool rigs in Alaska’s new regulations.

The Alaska Statehood Act gave Alaska title to submerged lands along its coast out to the three-mile limit, as well as title to lands under navigable inland waters such as rivers and lakes. In 1962 the State held its first Cook Inlet offshore sale, and the companies winning leases were quick to mobilize their equipment and get to work.

A big challenge for the State came when two competing industry groups, one led by Shell and the other by Pan American, discovered Cook Inlet’s first offshore field near Middle Ground Shoal, a shallow area where land becomes visible at low tides.



Photos: Top, Marathon Oil Co.’s Beaver Creek No. 8 well drilled in 1960 to 15,750 feet was Alaska’s deepest producing oil well at its time; Middle: first tanker loads at the Drift River oil terminal, west side of Cook Inlet; Bottom, truck convoy en route to an early BP exploration site on the North Slope.

This was the first discovery on State-owned lands, and it was offshore. Alaska's oil and gas regulations, however, were based on the model Interstate Oil Compact Commission regulations, which were themselves based generally on Oklahoma's regulations. Oklahoma's oil fields were on land, while Cook Inlet development was offshore. Offshore drilling was still relatively new even in places such as in the Gulf of Mexico and off Lower California, but Cook Inlet, with its extreme tides and winter ice, presented unique and formidable challenges.

To deal with these challenges the industry proposed technologies that were leading edge for the times, such as wells drilled out from the platform at angles, an early version of directional drilling.

"The holes were deviated from the vertical, and this was a new concept to us here in Alaska.

Up until then we had worked with straight vertical wells drilled from onshore rigs," Marshall recalled. Drilling at angles presented new issues. "We had no prior experience to go on," when writing the Conservation Order and rules for the Middle Ground Shoal field, Marshall recalled.

Two incidents occurred in Cook Inlet in 1962, however, that dramatically illustrate the dangers associated with oil and gas development and the importance of safety: a shallow gas blowout in June, 1962 on the Middle Ground Shoal State No. 1 exploration well drilled by Pan American (later Amoco) and a second blowout later that summer on Pan Am's Cook Inlet State No. 1 well. Blowouts can involve large volumes of uncontrolled hydrocarbons coming into a well. Explosions and fire can result from mixtures of gas

and oil, causing damage to equipment as well as waste, injuries, loss of life and environmental damage.

Fortunately, there were no injuries or damage at the Pan American blowouts, and the drillers quickly shut down operations, but it took more than a year to bring Cook Inlet State No. 1 under control. The blowouts were caused when the drill bits penetrated unexpected shallow gas accumulations. The presence of the gas accumulations had not been detected in the seismic work that had been done.

Modern seismic technology is now better able to spot these shallow drilling hazards. However, in the early days of Cook Inlet and even the North Slope,

their presence was not always apparent.

While a well is being drilled the heavy drilling fluid pumped into the hole from the surface

keeps the well under control. The fluid circulates in the well bore to lubricate the bit and remove rock cuttings from the hole. It is always "over-balanced," meaning that the fluid pressure is higher than that of the reservoir rock through which it is drilling. At the bottom of the hole the fluid is under high pressure from the weight of the column of fluids in several thousands of feet of the well bore.

When a well is drilled, particularly a new exploration well, the geologists can't be certain of the precise depth of different layers of rock. When reservoir rock containing oil and gas fluids is encountered it is the job of the heavy drilling fluid used to fill the well-bore to overcome the reservoir pressure to keep oil and gas from flowing into the well prematurely, and thus keep the well under control.

Encountering unexpected shallow gas accumulations can be extremely dangerous for drillers.

THE 1960's...

The gas blowing from Pan Am's second well in the North Cook Inlet field caught fire and became a handy navigation aid for pilots landing at night at Anchorage's airports and Elmendorf Air Force Base.

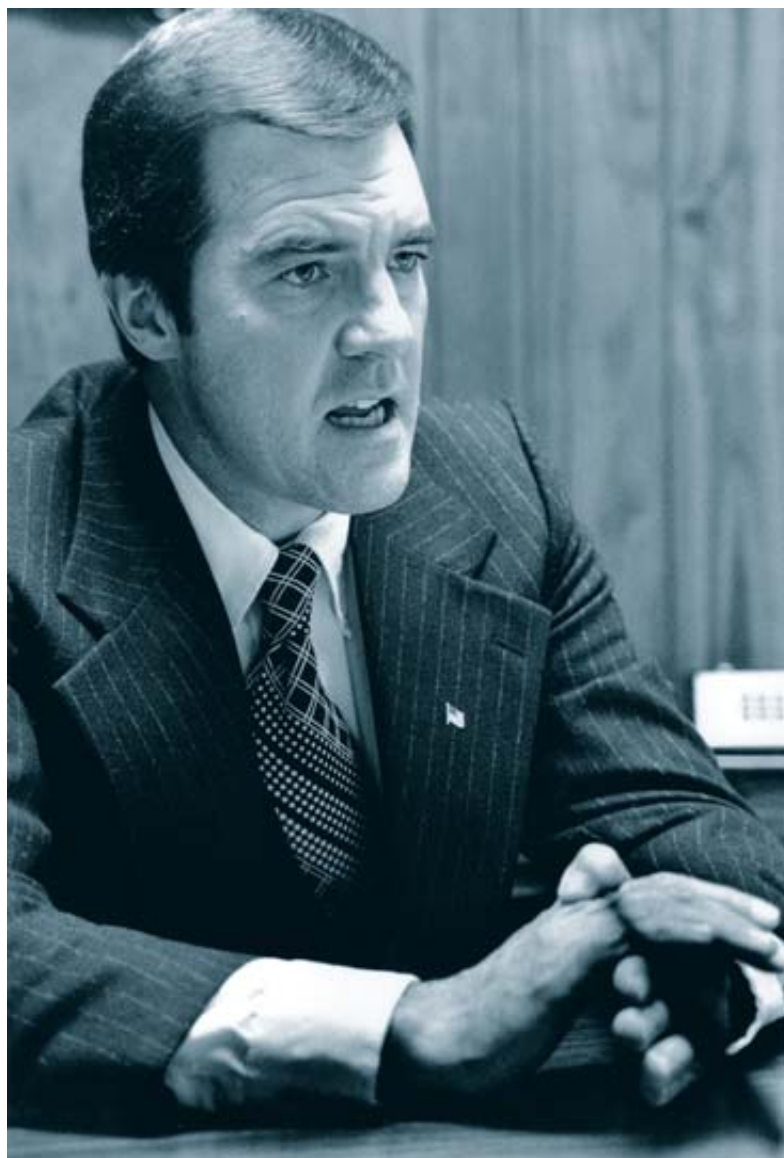
Encountering unexpected shallow gas accumulations can be extremely dangerous for drillers. When the depth is relatively shallow, the well isn't deep enough to have a set of steel casing adequate to support the blow-out preventer and contain the fluids. The fluid volume in the hole is also less, which reduces the time available to respond if the mud weight is less than the pressure in a penetrated formation, or if some of the fluid is lost to the formation.

There are ways drillers can "weight up" the mud with the addition of specially designed solids to offset these dangers, but what appeared to have happened in the Pan American well is that the drill bit penetrated a layer of very porous rock, where the formation pressure was lower. This allowed the drilling fluid to drain off into the lower pressure reservoir. When the fluid level drops too low, pressure is reduced, and hydrocarbons (in this case gas) can rush into the well and up the pipe.

In emergencies like this, the "blowout preventer," a set of huge safety valves at the surface, is the drillers' last line of defense. There was more bad luck at the Pan American well, however. What also happened was that gas escaped outside the steel casing that had been installed around the well and came up through fissures in the rock, bubbling out from the sea floor around the well.

When combustible gas reaches air at the surface it becomes a serious fire hazard. The mixture of gas in water also causes the water to lose its density. If that happens, ships in the water become less buoyant, and can sink. Fortunately Pan American's support vessels had pulled away from the site. Pan American's Middle Ground Shoal well blew out on June 10, 1962, and the

Photos: Top, Thomas E. Kelly was Alaska's Commissioner of Natural Resources during the latter part of Cook Inlet development, and when North Slope oil was first discovered; Bottom, drill rig at Atlantic Richfield's discovery well at Prudhoe Bay in 1968.



drillers worked for several weeks to get the well under control, finally accomplishing that on July 24.

Pan American had its second blowout on August 22, 1962 and drilled a “relief well” to get it under control. A relief well is a new well drilled from a safe distance but angled underground to intersect the problem well.

Heavy drilling fluids were injected from the relief well into the reservoir to stop fluids from flowing into the damaged well. In that manner, the second blowout was contained, and well control was finally achieved on October 23, 1963.

The gas blowing from Pan American’s second well in the North Cook Inlet field caught fire and became a handy navigation aid for pilots landing at night at Anchorage’s airports and Elmendorf Air Force Base, Marshall recalled. An interesting sequel to these blowouts was that a dispute developed between Pan American and Shell Oil Co. over who had drilled the first exploration well discovering oil and gas in the Middle Ground Shoal field, and thus who would be entitled to a reduced “discovery” royalty of 5 percent. Shell claimed it completed the first well that was a commercial producer. Pan American had drilled first, but its well blew out, so completion of its well was delayed.

A long administrative and legal proceeding followed and Tom Marshall helped the State reach a decision. Even though Shell completed the first actual commercial well on Middle Ground Shoal, at a time when Pan American was busy controlling its blowout, the discovery royalty went to Pan American, Marshall and other State officials decided, because Pan American’s well was the first to encounter significant hydrocarbon resources in the reservoir.

Most of the oil operators in the State were major companies with reputations to protect and the resources to do

their work properly. There were concerns, however, that some of the smaller companies, particularly the very small independents, might be tempted to cut corners to save money.

Marshall recalls one such company in the 1960s drilling near Umiat in the southern part of the North Slope without a drilling permit.

When he flew to the Slope to shut the drilling down, Marshall recalled company representatives trying to delay him in Fairbanks so they could finish their well. “They wanted to buy me dinner and talk, but I was having none of it,” he recalls. Marshall flew on to the Slope and ordered the operation shut down. After this experience the State was extra-vigilant to insure the company followed the proper plugging and abandonment procedures with the well.

Most of the oil operators in the State were major companies with reputations to protect and the resources to do their work properly.

The Commission is also charged with protecting the rights of leaseholders. O.K. (Easy) Gilbreth, who joined the Conservation Commission in 1966, said

instances of operators drilling into someone else’s lease, the “slant-hole drilling” made infamous in the industry’s turbulent early years in Texas, were virtually unknown in Alaska. Gilbreth did recall one incident, however, where a lessee complained that another company was drilling into its lease.

Gilbreth headed to the North Slope to investigate and was told on arrival that the company had experienced a malfunction and lost its drill bit and drilling assembly in the hole, and had cemented the well in. The State had the authority to order the operator to pull out of the hole and run a directional log, which is a downhole survey done with instruments that would indicate where the well was bottomed, but with the well permanently sealed there was no way to really check out the complaint. Such incidents were rare, however.

Types of Natural Oil Drives

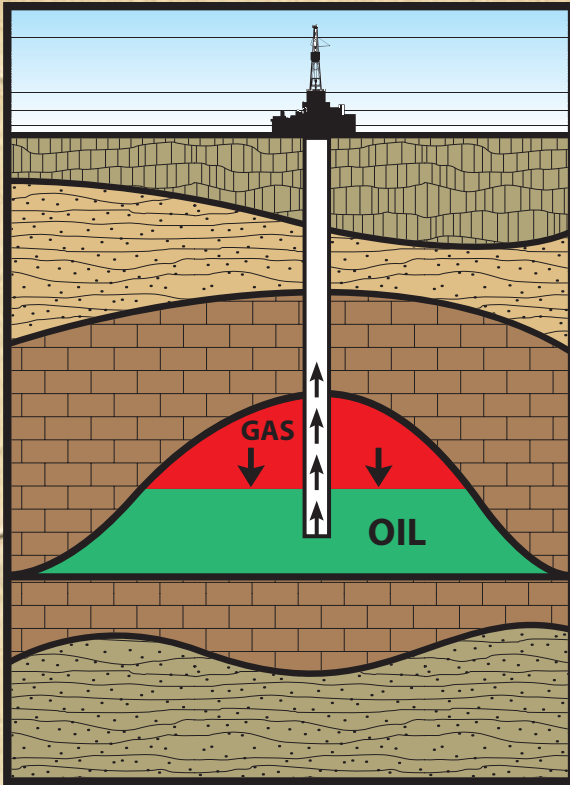


FIG. A

Gas-Cap Drive (left)

Natural gas is sometimes trapped above oil-saturated rocks in a producing reservoir, and when wells are opened to the oil-saturated rocks the expansion of the gas helps push the oil into and up the wells. This is a common mechanism for oil production, and is present in the Prudhoe Bay field on the North Slope.

Water Drive (below)

Pressure from water below oil-saturated rocks is another common type of reservoir energy. When wells are opened to the oil-saturated rocks, water pressure helps push oil into and up the production wells. This mechanism is found in Cook Inlet oil fields.

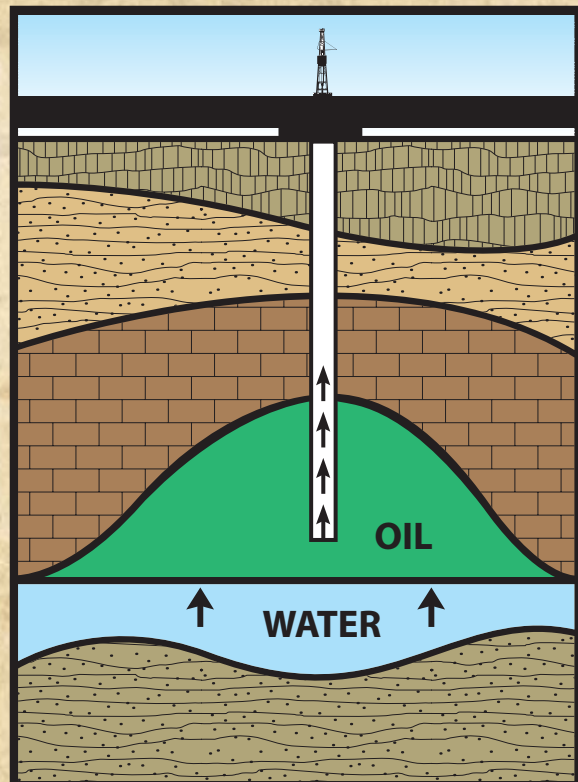


FIG. B

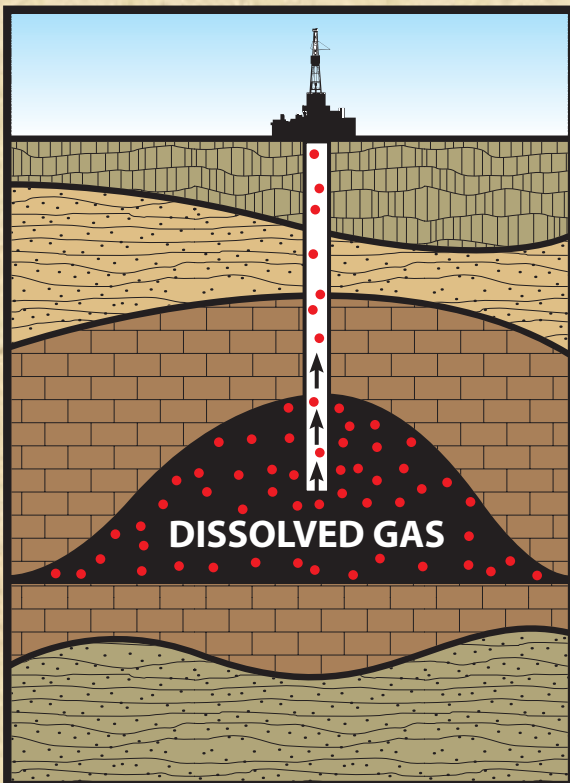


FIG. C

Dissolved (or Solution) Gas Drive (left)

In almost all oil reservoirs some amount of natural gas is in solution with oil. When wells are produced from the oil-saturated rocks the reservoir pressure is reduced and the gas comes out of solution and expands, helping push the oil into and up the wells.

Enhanced Oil Recovery (EOR)

Injection of water and gas through injection wells from the surface can reinforce the natural pressure from water and gas in an oil reservoir. Pumping water down wells into the reservoir –

“Waterflooding” – and reinjection of produced gas commonly are done in the Alaskan oil fields to help sustain pressure in the reservoir and thus recover more oil.

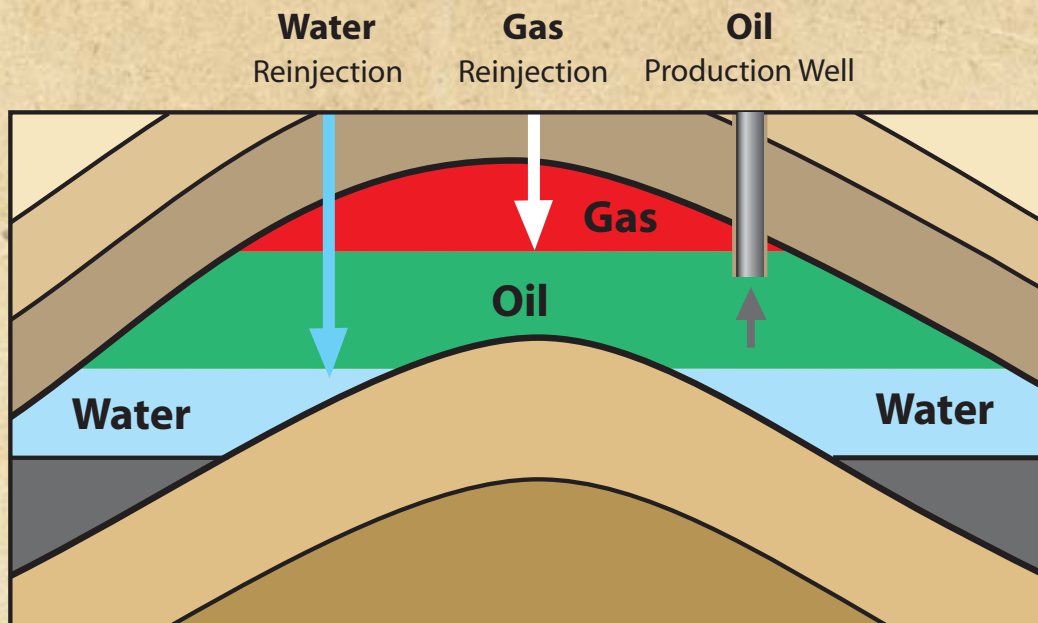


FIG. D

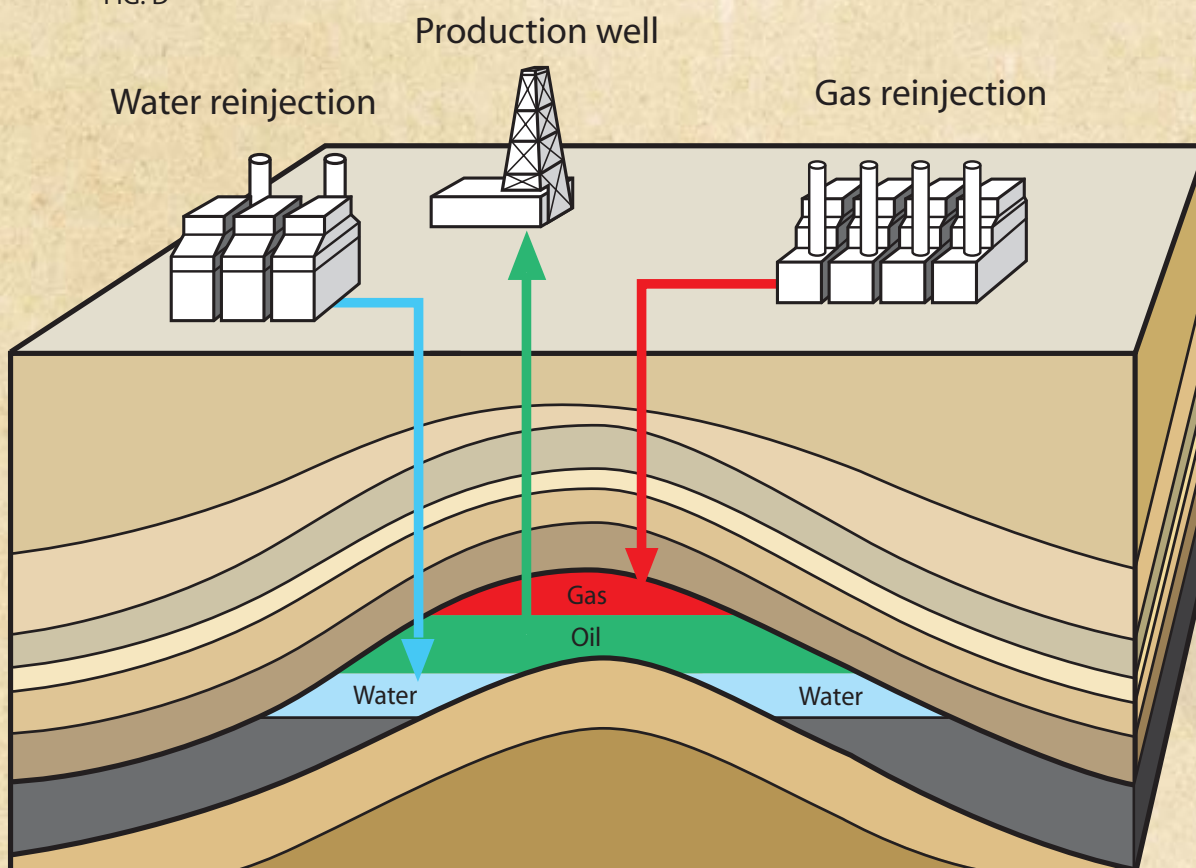


FIG. E

THE SEVENTIES

AN END TO WASTEFUL FLARING IN COOK INLET; TRANS-ALASKA PIPELINE BUILT

In 1971 the Alaska Oil and Gas Conservation Commission took its first significant policy action. Following extensive hearings, the Commission ordered an end to the wasteful flaring of gas produced along with oil from Cook Inlet platforms, except for what was needed for safety flares on the platforms.

Any gas flared after the order, except for the safety flare, was determined to constitute “waste” of the natural gas resource and was prohibited.

The industry didn’t take it lying down. One producer, Mobil Oil, sued to stop the AOGCC Order, arguing the Commission had overstepped its authority. However, the Alaska Superior Court upheld the authority of the AOGCC in its action to prevent waste.

To comply with this directive, the companies operating the offshore oil platforms could either take the gas to shore and sell it or they could inject it back underground, in effect storing it for future use.

All of the operators opted to take the gas ashore.

Although natural gas was available to Southcentral Alaska consumers at the time from onshore gas fields discovered in the 1960s, the AOGCC’s Orders to sell the platform gas added to the supply of gas available for residential, commercial and industrial uses.

“In 1970 alone, nine billion cubic feet of gas were flared from just one Cook Inlet oilfield, Granite Point,” recalled John Norman, then an Assistant Attorney General and a legal advisor to the Conservation Commission. “It was a huge amount of energy just going up in smoke,” recalls Norman, who is currently a Commissioner of the AOGCC.

The Orders to cease flaring were the culmination of years of intense and at times contentious debate between the oil and gas producers and the AOGCC. The public was solidly on the side of the Commission. The gas flares could be seen from Anchorage on a clear night, and they became symbols of what the public considered to be wasteful practices.

“The industry was just dragging its feet,” recalls Tom Marshall, a member of the Conservation Commission at the time. “The companies didn’t want to stop flaring. They claimed there was no market for the gas and that it had no value.”

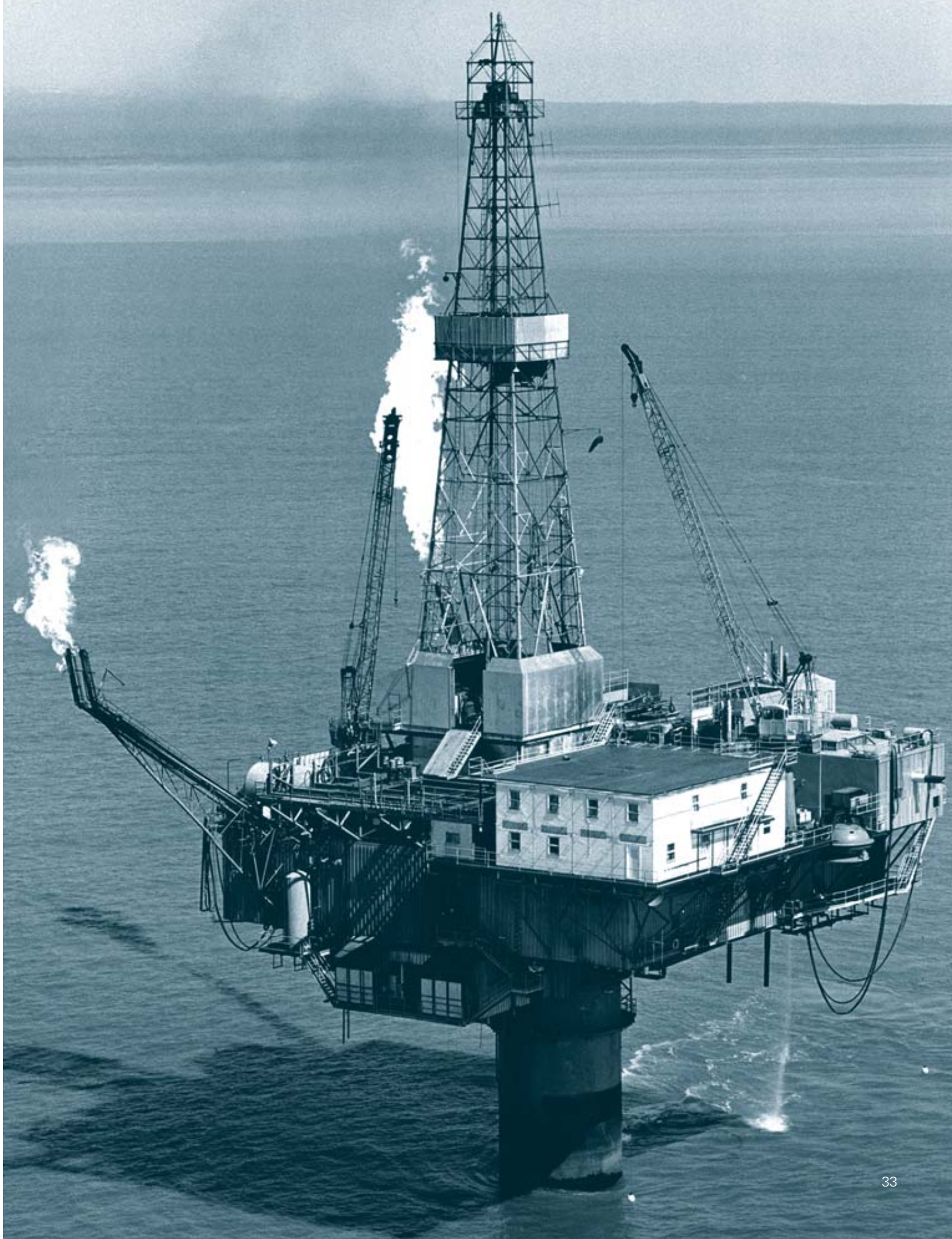
But when forced to do so, the producers did find ways to use the gas beneficially, among other things by making it available to the nearby village of Tyonek and to the ammonia and urea fertilizer plant on the east side of Cook Inlet once a new

pipeline was built across the Inlet. Ultimately, the gas was supplied to the regional utility, Chugach Electric Association, for use in power generation. It was the first time the young AOGCC had asserted its broad conservation authority aggressively and, in a showdown with a reluctant industry, the AOGCC prevailed.

Most oil fields have gas dissolved in the oil. When the oil is produced the pressure on the liquid is reduced and the gas separates from the oil.

Photo, at right: Monopod platform in Cook Inlet. Picture taken in 1971 shows a large gas flare. Flaring of gas beyond what was needed for a safety flare was banned by the AOGCC that year.

Most Alaskans didn't know a lot about oil in the 1970's, but they well understood resource conservation.



THE 1970's...

This gas, called “casinghead” gas, is produced in most oil fields along with liquid crude oil. When the gas is separated from the oil at the surface something must be done with it, or else there will be serious safety hazards and substantial waste. The gas is highly flammable and can be dangerous to people and equipment on the platform. A safety flare is always needed, like a pilot light on a gas furnace, because if there is some upset in the production wells or mechanical failure of equipment on the platform, any sudden release of gas must be ignited and disposed of in a controlled manner or it can cause an explosion.

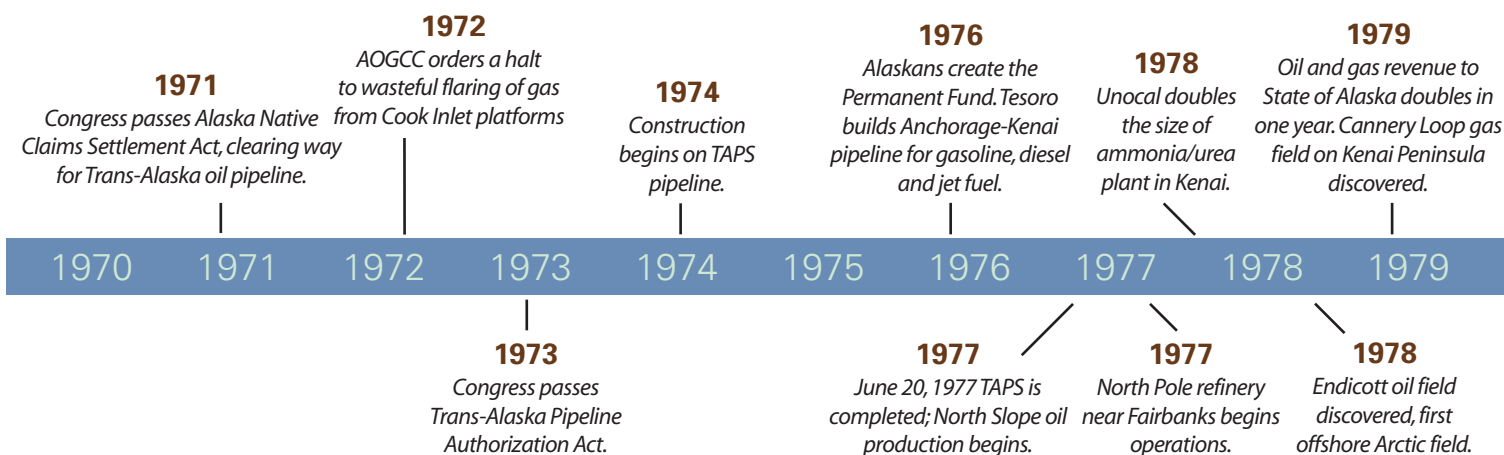
But in the 1960s the amount of gas being flared on the platforms was far in excess of what was needed for safety. From the platform operator’s viewpoint, the simple economic equation was that taking the gas to shore would cost money since it required a compressor unit on the platform, and a pipeline and gas processing facilities on shore. Processing was needed because the gas had to have impurities removed before it could be sold. The producers argued that if the gas couldn’t be sold for enough to pay for the capital investment and earn a profit, then it had zero value and the best thing to do was simply to burn it off.

The situation in Cook Inlet in 1971 neatly illustrates the Commission’s responsibility to prevent physical waste of hydrocarbon resources and the tension between that responsibility and the economic issues that often arise. The Commission normally does not take economics into consideration when it acts to insure greater ultimate recovery of oil and gas. Other State agencies, such as the State Department of Natural Resources (DNR), do consider economics when making decisions, but not the AOGCC.

Economics inevitably enter the dialogue between the Commission and the industry, however, because every action has a cost and there is, understandably, a limit to the Commission’s ability to force operators to do something that may cause them to lose money.

Photos: Top: Agrium Corp. fertilizer plant at Nikiski, near Kenai; Middle: AOGCC hearings on Cook Inlet gas flaring; Bottom: Workers install insulation on the trans-Alaska oil pipeline during construction in 1975.





But because it is the one regulatory agency concerned principally with preventing physical waste, the AOGCC is in a position to push the companies toward conservation when it needs to.

In the case of Cook Inlet flaring, the Commissioners knew they were on the right track because the conservation commissions of other states had banned flaring for years. Commissioner O.K. “Easy” Gilbreth, a petroleum engineer, recalls that the Texas Railroad Commission, the AOGCC’s equivalent in that state, had banned gas flaring since the 1940s. Gilbreth recalled being astounded, when he first arrived in Alaska, to see the huge flares on the Cook Inlet platforms. Alaska was behind the times, he felt. Gilbreth took an active part in the Commission’s historic hearings on gas flaring.

In the end, the Commissioners at the time, Marshall, Gilbreth and Homer Burrell, the Chairman, concluded that the producing companies were not doing enough to find markets for the gas. When pushed to the brink, the industry did find ways to sell the gas and comply with the Commission’s Orders. Among other things the Orders led to the development of gas pipelines on Cook Inlet’s west side and the first cross-inlet gas pipeline, the Cook Inlet Gathering System (CIGS), which allowed gas to be shipped from the west side to the new industrial plants on the east side of the Inlet.

The Commission’s ban on gas flaring was extended to Prudhoe Bay when this giant North Slope field began production in 1977. As in Cook Inlet, gas is produced

along with the oil at Prudhoe Bay. A small amount is allowed to be burned in safety flares and additional quantities are used for fuel in the oil-producing facilities, but there is still a large amount of produced gas remaining.

Planning for a natural gas pipeline from the North Slope started before the Trans-Alaska Pipeline System was even completed, but a gas pipeline was not found to be economic. The North Slope producers’ choice, with the approval of the AOGCC, was to install compression and inject the gas produced with oil back into the oil-producing reservoir. Reinjecting the gas helped maintain pressure in the underground oil reservoir, and this pressure was used to drive the oil up the producing

wells while at the same time ensuring the gas would remain available for sale in the future.

When it was built, the gas handling plant at

Prudhoe was the largest in the world. Building the gas compression plant and injection facilities, and adding to them over the years were to cost the Prudhoe producers billions of dollars. The benefits clearly outweighed the costs, however. Over three decades several billion barrels of additional oil, the equivalent of a giant oil field, have been produced on the Slope largely because of reinjection of the gas. During this time the gas has been produced and reinjected several times, cycling back through the reservoir, helping to produce more oil. The recycled gas will eventually be produced and sold when a natural gas pipeline is built to transport gas from the North Slope.

The Commission's ban on gas flaring was extended to Prudhoe Bay when this giant North Slope field began production in 1977.

THE 1970's...



Other problems were to develop in the 1970s, however, as companies began confronting unusual and unique challenges presented by the Arctic environment. One that concerned the Commission involved the drilling of production wells in the Prudhoe Bay field in the mid-1970s in anticipation of the completion of the Trans-Alaska Pipeline System, which came in 1977.

“Permafrost,” or permanently-frozen soil and rock, underlies almost all of the North Slope to depths of between 1,500 feet and 2,000 feet below the surface. Prudhoe Bay oil, however, is hot when it comes out of the reservoir and even at the surface it is produced from wells at 180 degrees Fahrenheit. Studies by the companies led to worries that a thaw bulb of melted permafrost could develop around the producing wells, leading to subsidence of the permafrost and possible damage to the wells if they were cased and cemented in the traditional manner required by the AOGCC’s regulations.

Tom Marshall was a member of the AOGCC at the time and he recalls a great deal of discussion within the industry and with the Commission about the problem. This was an example, Marshall said, of how the Commission was able to work closely with the producers to solve one of the problems of operating in an Arctic environment that the industry had not dealt with elsewhere.

Similar challenges posed by permafrost and other Arctic conditions were dealt with in construction of the Trans-Alaska Pipeline System, sometimes requiring totally new engineering innovations and designs.

Photos: Top, 1975 sealift en route to Prudhoe Bay, when ice conditions almost prevented modules from being delivered; Middle, modules being moved over Prudhoe road system; Bottom: workers and dignitaries gather on June 20, 1977, for the first flow of oil through the completed Trans-Alaska Pipeline System.

So it was in the oilfields. One innovation developed was a slip-joint casing for the upper part of the well that penetrated the permafrost. This casing was designed so that it could move if there was subsidence and allow the surface casing, inner casing and tubing strings to escape damage. This approach was dropped after some experimentation. An alternate proposal was for the upper casing to be insulated sufficiently to stop any heat transfer to the permafrost. Problems developed with this solution, however, when the insulating material broke apart and got into the well-bores, plugging up some of the wells.

Meanwhile the companies continued to study the thaw problem. Four shallow wells drilled in the early 1970s were converted to test wells. Hot glycol was circulated to simulate crude oil production. The permafrost thawed as predicted but the expected subsidence didn't occur. The engineers found there was both expansion and compression in the soils as they thawed, which counteracted the tendency for the soil to settle. In the end, the producers and the Commission settled on a type of heavy-duty casing that is now standard for all the wells on the slope.

Permafrost was something new for the industry and the Commission, however, and Marshall recalled one incident that was a rude wakeup call to the seriousness of dealing with permafrost. In the early 1970s the Prudhoe operating companies, BP and ARCO, were drilling production wells to have them ready to produce when the pipeline went into operation. The completed wells had been left filled with a water-based drilling fluid, sometimes called "mud", in the "annulus" of the wells, which is the space between the outer and inner layers of steel pipe.

At the surface, every well has heavy "casing", or steel tubular pipe of several diameters set inside each other and cemented in place. When the early Prudhoe production wells were drilled and left to wait for the pipeline, the drilling fluid left between the layers of pipe froze. That was no surprise, but what did catch the companies and the Commission by surprise was that instead of expanding and pushing out the frozen soil as had been expected, the frozen fluid expanded inward and collapsed the steel casing and tubing, damaging the wells. Being new to working in permafrost, neither the Commission nor the drilling engineers realized how strong the frozen rock was through the permafrost layer. "It was a complete surprise," Marshall recalled.

It was a costly one too, because the wells had to be repaired to be ready for safe production when the pipeline was completed in mid-1977. The second time around, the companies and the Commission played it safe and the wells were

Being new to working in permafrost, neither the Commission nor the drilling engineers realized how strong the frozen rock was through the permafrost layer.

filled with a gelled fluid that did not freeze.

In the mid-1970s, construction of the Trans-Alaska Pipeline System and the Prudhoe Bay oil production facilities was going full-bore. One of the world's greatest construction and technological achievements, the first system to deliver crude oil from the Arctic to an oil-thirsty world, was rushing to completion.

As the start of production neared, however, AOGCC, DNR and the producing companies were dealing with an issue of unprecedented complexity, the unitization of the Prudhoe Bay field. State law and the Commission's regulations required that a "unit" a cooperative organization of the producers, be formed before the field could start production.

THE 1970's...

Under the deadline of getting something workable, the companies agreed on what was really an interim plan, and it set the stage for one of the most contentious disputes ever to embroil the industry.

There were serious disagreements that complicated bringing this about, however. Under the deadline of getting something workable, the companies agreed on what was really an interim plan, and it set the stage for one of the most contentious disputes ever to embroil the industry, and which was to involve the AOGCC two decades later.

The seeds for the conflict were sown in 1965 with the first Prudhoe Bay lease sale, when Richfield Oil (later ARCO, now ConocoPhillips in Alaska) and Humble Oil (now ExxonMobil), as partners, wound up with leases that contained most of the natural gas and only some of the crude oil, while BP, and other companies wound up with leases that contained most of the oil but only some of the gas. That split in interests was to result in a field operating arrangement in 1977 that was unusual if not unique.

The separate oil and gas ownership came about mainly because of the complex geology of the Prudhoe Bay field. Rather than being a classic, simple, “dome” structure, Prudhoe’s reservoir is slanted and abuts an imperious fault, which is what caused the oil and gas fluids to be trapped in the first place. Because of this, the shallower portion of the reservoir, where most of the gas is located, is not directly above the part of the reservoir where the oil is located. The gas cap is partly offset to the northeast compared with the deeper part of the reservoir that holds the oil.

Photos: Top, O.K. “Easy” Gilbreth was a petroleum engineer and AOGCC Commissioner, and was involved in key decisions in the 1970s; Middle, final weld on the Trans-Alaska Pipeline System at Atigun Pass; Bottom : first loaded tanker sails from Valdez.



In many less complex reservoirs, the gas is directly over the oil so that leases covering the field have similar shares of oil and gas. But because the gas cap and the oil rim of Prudhoe are offset, and because the field is so large, the locations of the leases resulted in widely differing ownership percentages of gas and oil among the lease owners. Following the 1965 lease sale, leases held by ARCO and Exxon were over the gas cap, in the northeast, while most of BP's leases were over the oil rim.

The problem that bedeviled the formation of the unit was valuation of the gas, since there was no gas pipeline available and therefore no market. To arrive at a cooperative unit agreement, the lease owners had to agree on an allocation of total oil and gas reserves so that there would be a way of sharing revenues from production as well as allocating costs for field development and operation.

The two sets of lease owners couldn't agree on a value for the gas. BP, which owned mostly oil, argued the gas had little or no value because it couldn't be marketed. ARCO and Exxon, in contrast, argued the gas did have value. The two views couldn't be reconciled, so a compromise was reached. The compromise formed two production and cost allocation groupings, or Participating Areas, in the unit, one for the gas cap and the other for the oil rim. This effectively put the decision on integrating the two off into the future and set the stage for future disagreements.

The unit agreements provided the formula for allocating production and costs among the oil and gas cap owners. The agreements provided, for example, that natural gas condensates, which are part of the gas in the reservoir but become liquid at the surface, would be

blended, or mixed, with the crude oil and shipped to market, but the revenues would go to the gas-cap owners. Under the agreement most costs of production, however, were to be borne by the oil-rim owners.

Although the big issue of integrating the oil and gas interests was pushed into the future, the 1977 agreement did provide a way for the costs and benefits of production to be allocated until the issue could be finally resolved. Still, the deal was exceedingly complex. The unit agreement involved 16 interest owners and totaled 1,200 pages.

One highly unusual feature of the unit operating agreement was that it provided for two operators of the Prudhoe Bay field. Normally there would have been just one field operator, as this would be the most efficient arrangement. In 1977, however, it was decided that ARCO was to operate the east side, where the ARCO and Exxon gas leases were

predominately located, and BP would operate the west side where its oil leases were more concentrated. In this manner there was, in essence, an operator in place to look out for the gas cap interests of ARCO and Exxon, and an operator in place for the oil rim interests of BP and the minority companies.

Another reason for this arrangement was that at the time BP's U.S. subsidiary Sohio was the owner of the leases, and it was felt Sohio did not have sufficient operating staff in the U.S. to operate the entire field. BP did have experience with big fields in the Middle East, but was also involved at the time in developing North Sea fields. ARCO and Exxon, in contrast, did have sufficient U.S. operating staff to draw on for a new Prudhoe Bay operating organization.

Although the big issue of integrating the oil and gas interests was pushed into the future, the 1977 agreement did provide a way for the costs and benefits of production to be allocated until the issue could be finally resolved.

THE 1970's...

In 1977 there was considerable discussion of the possibility of a natural gas pipeline, just as there is today.

The arrangement of the separate oil and gas rim participating areas and the two separate operating companies worked reasonably well in the early years of the field's life. But as time went by, oil production declined and production of the natural gas liquids increased. Because the oil rim owners paid operating costs, but the gas rim owners received most of the income from the sale of gas liquids, the oil rim owners were eventually to feel they were carrying a disproportionate share of the costs. Those were issues the AOGCC would have to deal with 20 years later.

The AOGCC was involved in this in the 1970s because it signed off on the final unit agreement after holding hearings on how the field would be managed. There were two other particularly unusual features which involved the AOGCC. In 1977 there were federal price controls on domestic oil production, which meant that North Slope oil would be sold at lower prices than imported oil.

There was also discussion within State government at the time of not producing the State's one-eighth royalty share of the oil and to bank it for the future when prices would be higher.

One producer wanted the Commission, as the major regulator, to agree to a minimum production, or offtake, rate of 1.5 million barrels of oil per day from the field. This was an unusual request but it was accommodated indirectly.

Photos: Top, construction of the Trans-Alaska Pipeline System (TAPS); Middle, in Isabell Pass TAPS is built on lateral steel members to allow flexibility during an earthquake; below, the pipeline is built across one of 30 river crossings. Bottom: the Nikiski industrial complex near Kenai, the Agrium fertilizer plant (now closed) in foreground with the ConocoPhillips/Marathon Oil liquefied natural gas plant and Tesoro refinery behind it.

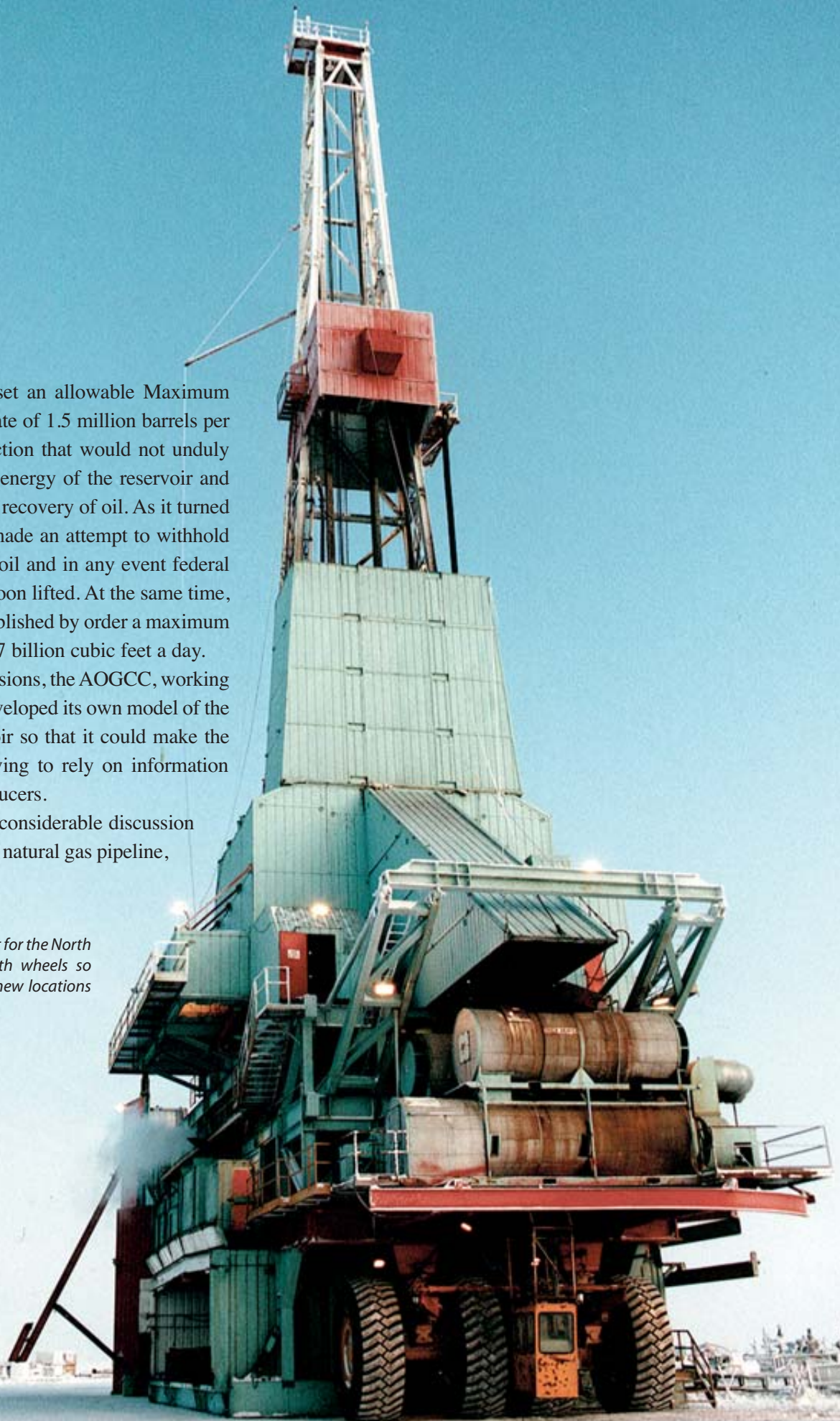


The Commission set an allowable Maximum Efficient Recovery rate of 1.5 million barrels per day, a rate of production that would not unduly diminish the natural energy of the reservoir and jeopardize long-term recovery of oil. As it turned out the State never made an attempt to withhold and bank its royalty oil and in any event federal price controls were soon lifted. At the same time, the Commission established by order a maximum gas offtake rate of 2.7 billion cubic feet a day.

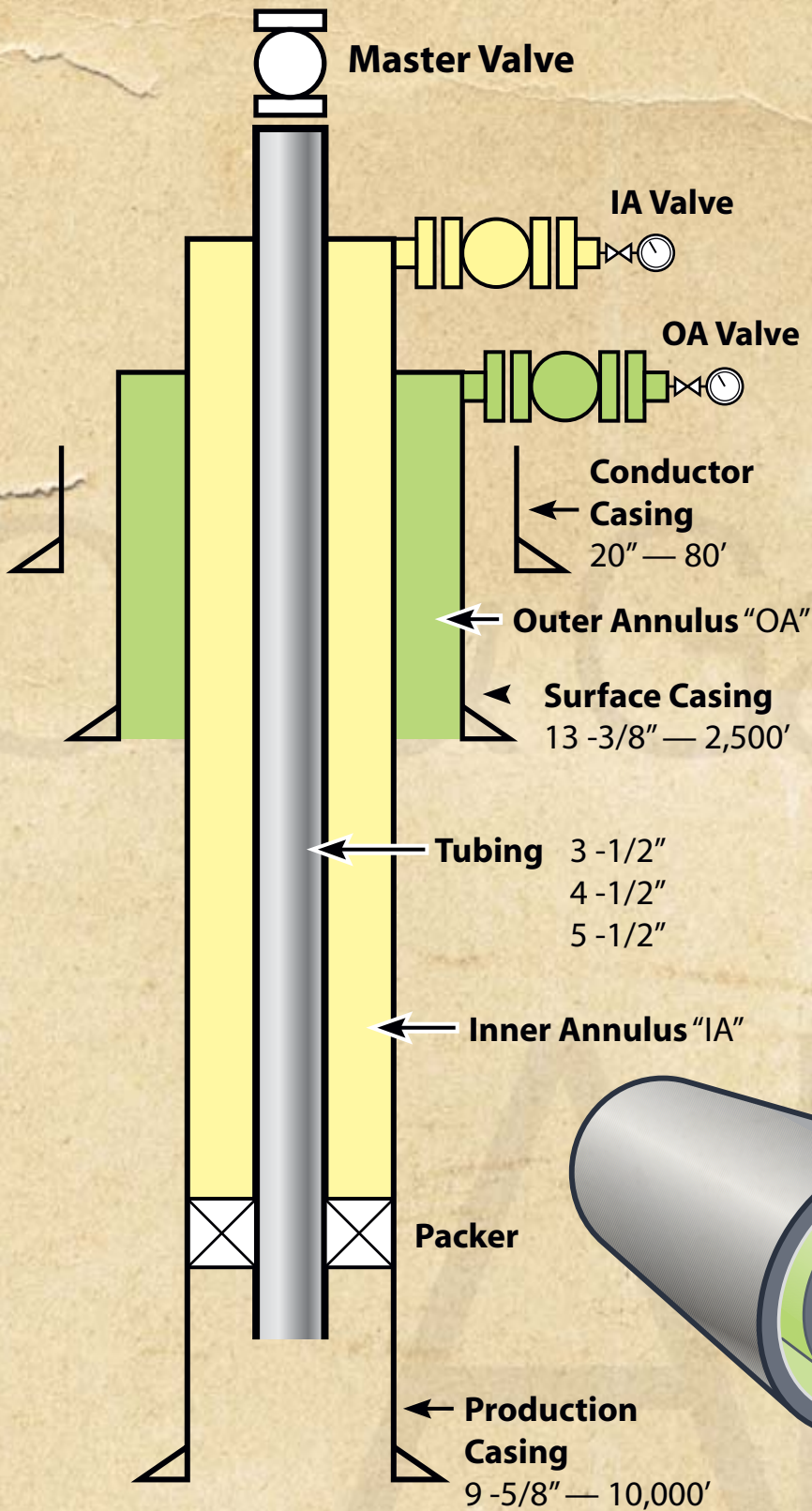
To make these decisions, the AOGCC, working with a consultant, developed its own model of the Prudhoe Bay reservoir so that it could make the decision without having to rely on information provided by the producers.

In 1977 there was considerable discussion of the possibility of a natural gas pipeline, just as there is today.

Photo: Large drill rigs built for the North Slope were mounted with wheels so they could be moved to new locations in the producing fields.



Typical Prudhoe Bay Well Bore



Standard industry practice is for oil and gas wells to have production casing that goes from the surface all the way to the producing reservoir installed within layers of larger-diameter steel piping. This gives the well enough strength to withstand the pressures and temperatures of oil and gas being produced. Production casing in a typical Prudhoe Bay well is 9 5/8 inches in diameter. From the surface to 2,500 feet it is surrounded by "surface casing," which is typically pipe of 13 3/8 inches diameter. From the surface down to 80 feet, there is additional "conductor casing," steel pipe typically of 20 inches. The casing diameters and depths can vary for different oil and gas fields depending on circumstances. The design of the casing for a well drilled in Alaska must be approved by the Commission.

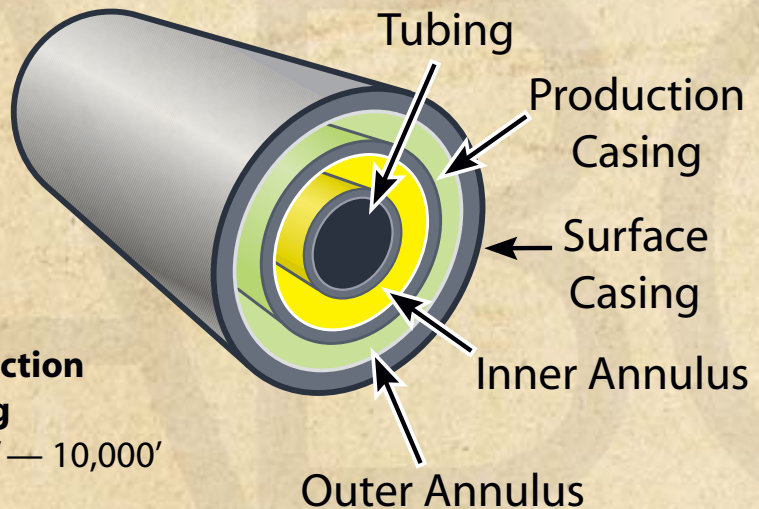


FIG. A

Blowout Preventers

A standard safety system used on all of Alaska's conventional oil and gas wells during well operations is the "blowout preventer," which is designed to halt the uncontrolled flow of oil, gas or water in the well if other safety measures, primarily the high-pressure "mud" system, fail to do so. The AOGCC requires blowout preventers on all drill rigs, and weekly tests are carried out, a percentage of which are witnessed by AOGCC's inspectors.

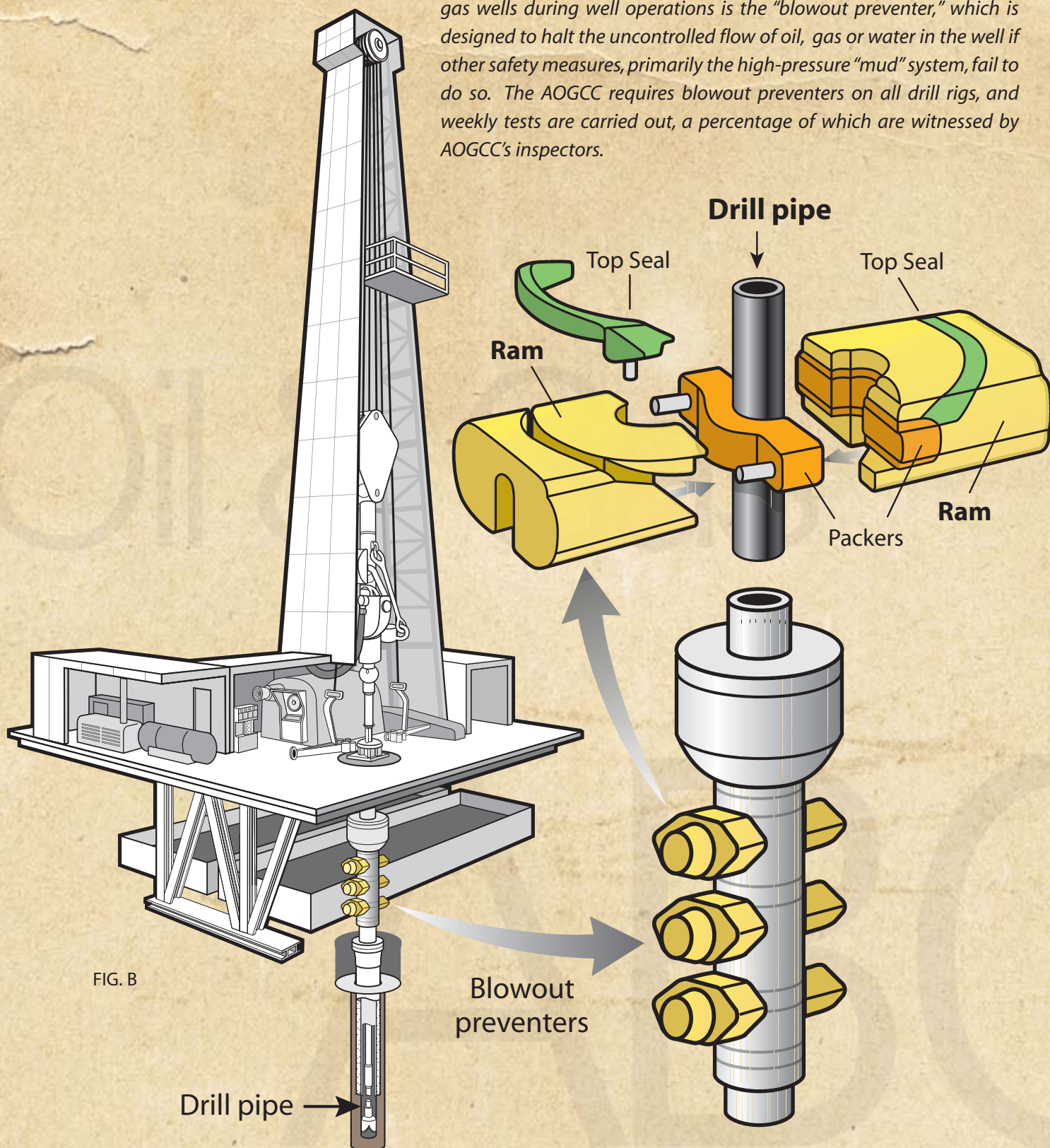


FIG. B

THE EIGHTIES

A CHANGE IN WELL CONFIDENTIALITY RULES; INNOVATION IN OIL FIELD WASTE DISPOSAL

As the 1970s turned to the 1980s, Alaska was undergoing profound changes. Crude oil was flowing from the North Slope and billions of dollars flowed into the State treasury and the Alaska Permanent Fund. Although the Trans-Alaska Pipeline System was newly completed, people were already talking about a natural gas pipeline from the North Slope.

Events were also taking place that would profoundly change the way the Alaska Oil and Gas Conservation Commission did business. Two of these had their genesis with actions by the State Legislature in 1978, but the effects were to be felt for many years.

One of the Legislature's actions was to provide an exception to the two-year period of confidentiality for information required to be filed with the AOGCC on all wells drilled in Alaska. The requirement applied to wells drilled on private and federal lands as well as State-owned lands. Under the statute change in 1978, in certain circumstances the AOGCC would continue to keep information from wells confidential beyond the two-year limit.

This was a major change in State policy and it affected oil and gas exploration substantially. It was also controversial. It would stir litigation over drilling data from the most famous tight hole in Alaska - the KIC No. 1 well in the Arctic National Wildlife Refuge (ANWR), drilled in 1986. The KIC well was drilled not on State lands but on private lands owned by Alaska Natives within ANWR. The information from the KIC well remains a tightly-guarded secret today.

Events were also taking place that would profoundly change the way the Alaska Oil and Gas Conservation Commission did business.

In 1978 the Legislature also acted to remove the AOGCC from the Department of Natural Resources (DNR), and reestablished it as an independent, quasi-judicial regulatory commission. The Commission had been independent in territorial days but was combined with the DNR at statehood mainly for budget reasons.

Legislators again separated the Commission from DNR to eliminate possible conflicts of interest. One of the AOGCC's roles is to act as a neutral party in resolving conflicts among parties holding interests in oil and gas fields, including the State as a landowner.

The AOGCC is the custodian of significant private confidential data and information on oil and gas activities in the State. As a landowner and a royalty-interest holder the State DNR is one of the parties that can become involved in

disputes before the AOGCC.

As long as the Commission was part of DNR, as it was until 1979, there was at least the appearance that the AOGCC might not be able to be entirely neutral in its decisions. There was a worry that the State's proprietary interest as a landowner might be protected at the expense of resource conservation and the rights of others.

Reestablishing the AOGCC as an independent Commission formally severed this link. Since 1979, the State has had no greater standing before the Commission than any other landowner. It is critically important to the credibility of the Commission that it be seen as totally independent and entirely neutral.

Photo, at right: "Chat" Chatteron was the Commission's chairman during much the 1980s, guiding the AOGCC through some difficult years.



THE 1980's...

In the late 1970s the offshore acreage immediately north and northeast of the onshore Prudhoe Bay field was considered very prospective.

There is, however, still one thread that binds the Commission to DNR, and this stirred the litigation over the KIC well. Even today DNR has access to certain confidential well data, including from the KIC well. Although it is held from public release, there are continuing concerns within industry over what DNR might do with this highly sensitive information.

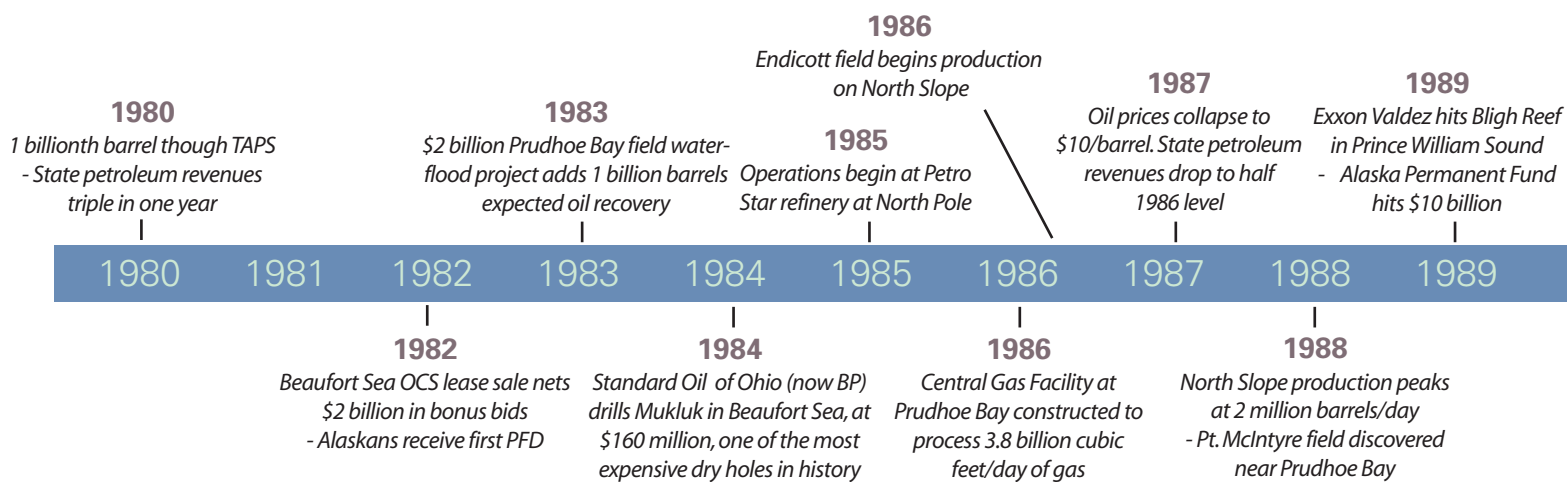
The requirement that information from all wells be filed with the Commission is an important one. If there are decisions to be made involving safety or preventing oil and gas waste, this information must be available to the Commissioners and staff of the AOGCC. Sensitive information is held under confidentiality for two years and can then be released to the public.

The procedure worked well in the 1960s and 1970s, times when there were relatively few lease sales and the litigation controversies over leasing, which were to cause exploration and lease sale delays, were yet to develop. Data from wells was filed with the AOGCC and exploration “scouts” in industry carefully watched the expiration dates of the confidentiality period on exploration wells.

By the late 1970s, however, times were changing for the industry. North Slope onshore oil and gas fields had been discovered and both the State and the federal governments planned offshore Beaufort Sea sales, but concerns were being raised about the environmental effects of offshore exploration and production.

Photos, from top: Sohio's (now BP) offshore Mukluk well was one of the most expensive dry-holes in the industry's history; middle: Endicott, the first Arctic offshore oil field; bottom: BP's operations center on the western side of the Prudhoe Bay field.





Lease sales in the Beaufort Sea were planned but then delayed because of these concerns. The State's two-year data release requirement clearly presented problems for companies who had drilled wells in anticipation of lease sales, and for the State itself in receiving maximum bids on sales.

In the late 1970s the offshore acreage immediately north and northeast of the onshore Prudhoe Bay field was considered very prospective. In anticipation of a State offshore sale at least one company, BP, drilled a number of exploration wells to gain information about the geology.

However, the sale was delayed after the wells were drilled but the two-year confidentiality clock was tick-

... it is the Commissioner of Natural Resources, not the AOGCC, who makes the decision on extending the period of confidentiality.

ing. The State sale was ultimately rescheduled for 1979, and was held simultaneously with a federal OCS sale, but BP as well as the State were in difficult positions. Because two years would have passed by the time the sale was held, all of the data from a number of BP's exploration wells in the area would be public and thus readily available to competitors.

The State was in a dilemma, too. If the results of the BP wells were unfavorable, and the information became public, it could discourage interest in the unleased acreage. In the end the Legislature decided to change the law and protect this valuable and highly sensitive well information. Under the change, in cases where there is unleased acreage in the same vicinity, the Commissioner of Natural Resources is given the authority to extend the period of confidentiality of well data.

The lease sale was held in 1979 and BP and its partners in the bidding, which included several Alaska Native corporations, acquired important offshore leases that became the Endicott oilfield, the first Arctic offshore field in North America.

There are two issues that have developed from the Legislature's change of statute, however. One is the ambiguity in the statute language over how the unleased acreage provision is interpreted. Independent explorers and others complain that the language is not specific enough and that data from too

many wells are being held confidential for extended periods.

The second issue is that it is the Commissioner of

Natural Resources, not the AOGCC, who makes the decision on extending the period of confidentiality. This is one of the threads that still connect the two agencies, in effect blurring to some extent the responsibilities of DNR and the AOGCC. Despite the Commission's separation from DNR, the DNR continues to have access to certain confidential well information in the AOGCC's custody and can apparently use it for internal purposes as long as it is not released to the public. This is a concern to industry and to private landowners as well because it means DNR has access to confidential well data on private lands while private landowners do not always have access to data on State-owned lands.

Alaska's most famous set of private well data is from the KIC No. 1 well within the boundaries of the Arctic National Wildlife Refuge, or ANWR.

THE 1980's...

Alaska's most famous set of private well data is from the KIC No. 1 well within the boundaries of the Arctic National Wildlife Refuge, or ANWR.

The private landowners and the companies who drilled the well challenged access by DNR to the confidential drilling information. The well was drilled on lands owned by Arctic Slope Regional Corp (ASRC) and Kaktovik Inupiat Corp., the Village Corporation for the Inupiat Eskimo village of Kaktovik, which is on Barter Island just offshore from ANWR.

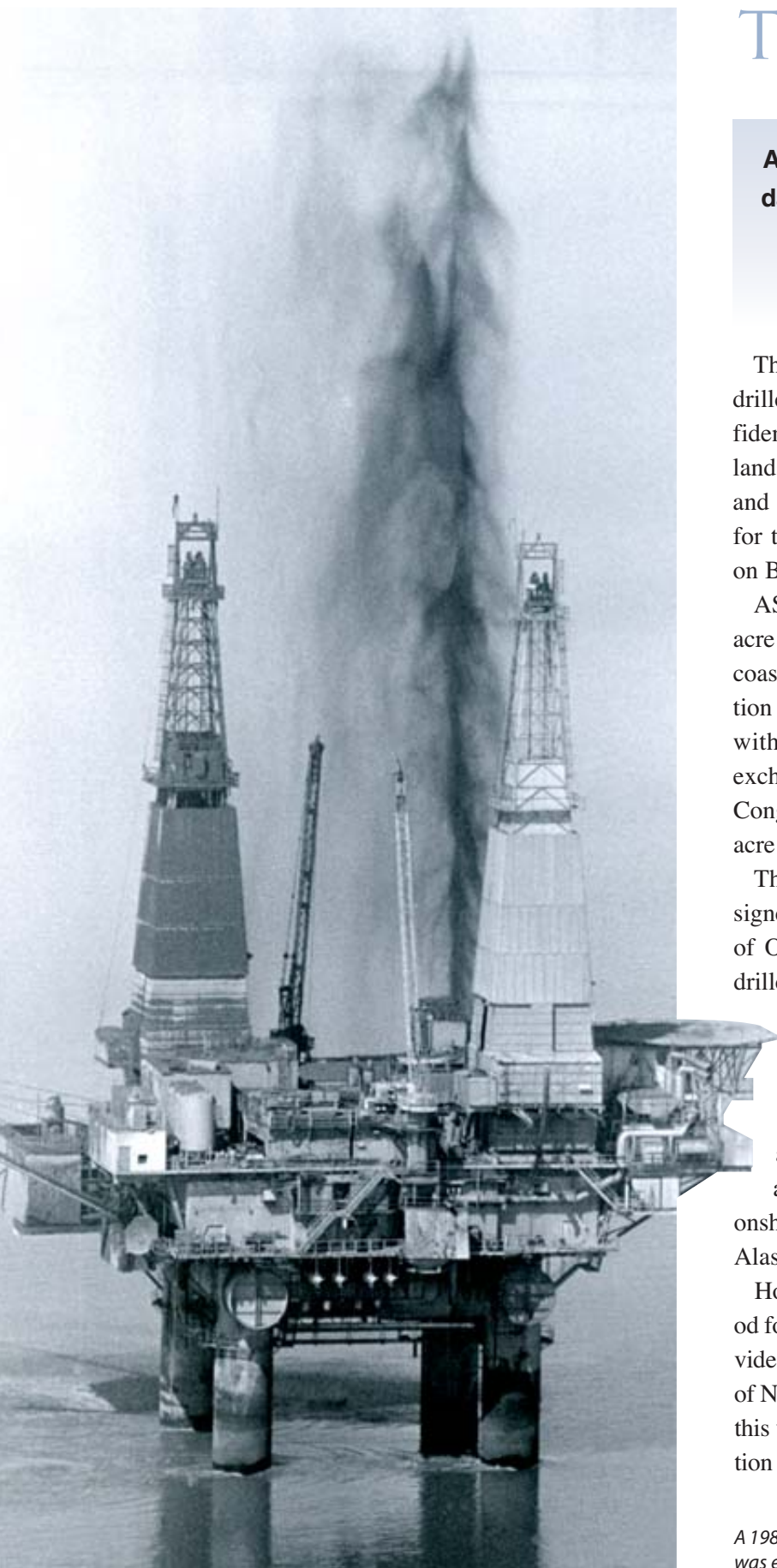
ASRC and the Kaktovik corporation own a 91,000-acre enclave on the northern portion of ANWR's coastal plain. Congress allowed the Native corporation landowners to drill exploration wells on lands within ANWR obtained through selection and exchanges, but not to develop any discoveries until Congress decided to open all or part of the 1.5 million-acre coastal plain.

The Native Corporations did decide to explore and signed agreements with Chevron and Standard Oil Co, of Ohio (now BP) to drill test wells. One well was drilled, the KIC No. 1. The well was completed on April 24, 1986, having been drilled to a depth of 15,195 feet, at a reported cost of over \$40 million.

The drilling generated substantial information about the subsurface geology of the ANWR area and is of particular value because it is the only onshore well ever drilled east of the Canning River on Alaska's North Slope.

However, the standard two-year confidentiality period for the data expired in April 1988. The 1978 law provides that the companies can apply to the Commissioner of Natural Resources to extend the confidentiality, but if this were done the DNR could also review the information and be able to use it for any purpose.

A 1985 gas blowout on the Grayling platform in Cook Inlet. The well was eventually brought under control. One of the AOGCC's responsibilities is to help prevent such occurrences.



To protect their rights, ASRC and the companies sued to protect the information. The State Superior Court upheld the plaintiffs' position, finding that disclosure to DNR could adversely affect the economic value of the well data. DNR appealed to the State Supreme Court and that court reversed the decision. See: State Dept. of Natural Resources v. Arctic Slope Regional Corp., et al; 834 P.2d 134 (Alaska 1991).

ASRC and the companies could have appealed the State Supreme Court decision to the U.S. Supreme Court, but instead negotiated a settlement with DNR that provided guidelines for access to the data. There are strict limits on who may have access to the information within DNR.

The 1980s was also a period in which industry began, with the full support of the AOGCC, enhanced oil

recovery, or "EOR," projects at several North Slope and Cook Inlet fields. EOR projects were approved by the Commission for the Prudhoe Bay, Endicott, Kuparuk River, Milne Point fields on the North Slope, and the Swanson River, Granite Point, Middle Ground Shoal and Trading Bay Unit fields in the Cook Inlet Basin. These projects have resulted in recovery of billions of barrels of additional oil from these reservoirs.

In the mid-1980s the Commission was to play a role in resolving a significant environmental issue that faced Alaska's petroleum industry, one that would also lead to development of advanced technologies in Alaska.

When the first North Slope fields were developed, the companies needed a way of disposing of and storing used drilling fluids and the rock cuttings from wells. Fluids used in drilling are mostly natural materials - water and clay - but chemical additives are also

used. These must be contained and disposed of safely after use.

The standard practice employed by the industry for waste disposal at onshore well locations was to build reserve pits alongside the well pads, equipped with impermeable liners to hold these fluids. In some areas, the existence of shallow sources of fresh water raised concerns over possible contamination from reserve pit fluids. Concerns about discharges to offshore waters were also voiced.

Over time the reserve pits didn't work very well. On the North Slope most of the mud and cuttings became frozen, but spring thaws brought meltwater spilling over the con-

tainment berms surrounding the pits and leaching through the pit walls. Some of the meltwater contained liquid drilling fluids, which

contaminated the tundra near the pits. A lawsuit brought by Alaska environmental groups caused industry to begin looking for better ways to handle wastes generated during drilling and production. Two approaches for managing drilling wastes were pursued, both involving injection into porous formations deep underground. One involved disposal of wastes down the annular spaces in the wells (the open spaces between the steel casings of the well). The other involved injection of waste as a slurry down dedicated injection wells, which had also been done in some Cook Inlet fields in the 1970s.

As this was happening the first offshore oil development in the U.S. Arctic, the Endicott field, was being planned. Endicott is just a few miles offshore of Prudhoe Bay, in shallow waters protected by offshore barrier islands. A causeway connects it to shore, but it is breached to allow for the passage of marine life. In all other ways Endicott is a truly offshore field.

In the mid-1980s the Commission was to play a role in resolving a significant environmental issue that faced Alaska's petroleum industry.

THE 1980's...

... BP developed an entirely new technique, pumping of the drilling wastes down the annulus, or the open space, between the steel casings of the well, and injecting the fluids from the annulus into a subsurface geological formation that could confine the fluids.

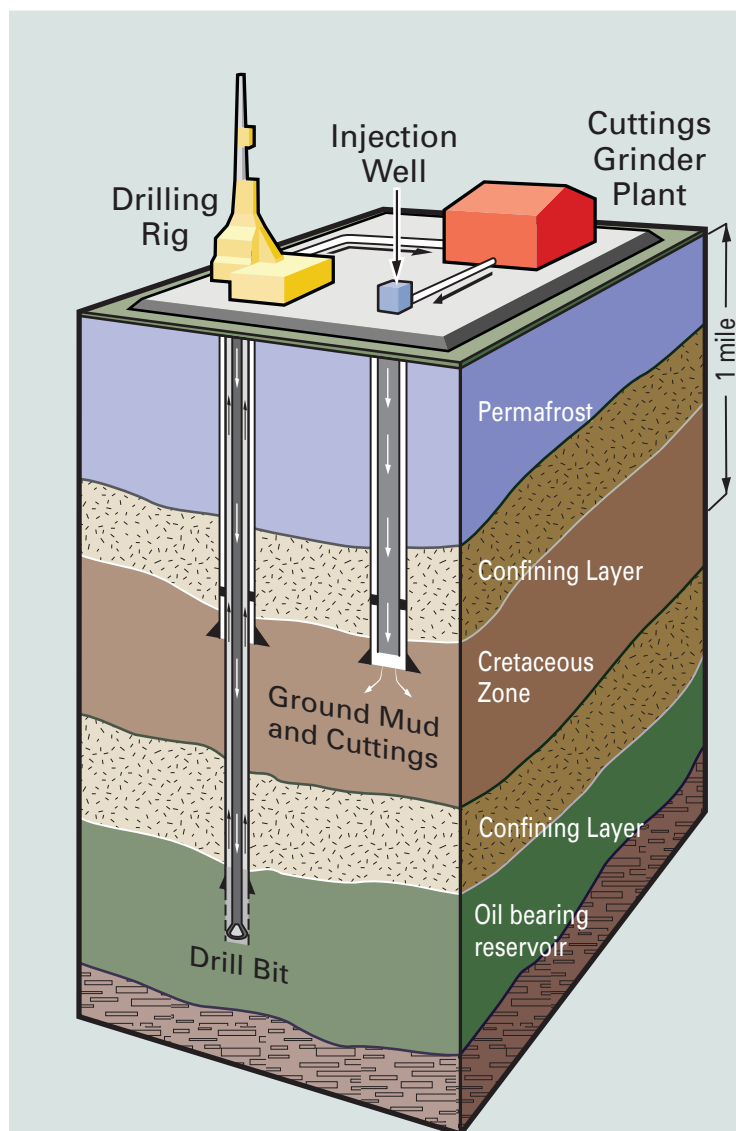
Endicott's production wells and facilities are on two artificial gravel islands, and in the tight space of these islands there was no room for a reserve pit similar to those used with the onshore fields. Endicott's developer, BP, had to come up with an alternative.

Disposing of the mud and cuttings offshore might have been an answer – it is done safely elsewhere, such as in Cook Inlet – but because Endicott is an offshore field where there are special environmental sensitivities, disposal of drilling wastes in the ocean was not an option that would have been acceptable to the local, state and federal regulatory agencies.

To overcome this, BP developed an entirely new technique, pumping of the drilling wastes down the annulus, or the open space, between the steel casings of the well, and injecting the fluids into a subsurface geological formation that could confine the fluids. This procedure is referred to as annular waste disposal.

This is where the AOGCC came in, because the Commission, in its required review of equipment and procedures used in the drilling, had to develop regulations for these procedures.

AOGCC is responsible for regulation of all fluids injected into underground reservoirs. Proper management of fluids injected for Enhanced Oil Recovery, for example, is a major responsibility of the agency. Expertise in this area has allowed the Commission to play a role in solving the problem of safe disposal of



Photos: Top, truck carries drill pipe on the North Slope; Bottom: Illustration shows how mud and cuttings from drilling are disposed down an injection well in the Prudhoe Bay field. The technology was a first for the petroleum industry, leading to zero surface discharge of wastes.

drilling wastes.

By the late 1980s the litigation, brought by the Natural Resources Defense Council, had prompted the U.S. Environmental Protection Agency and the Alaska Department of Environmental Conservation to act. Industry had looked at several alternatives for disposing of wastes in reserve pits including building even deeper, bigger pits and allowing the wastes to freeze permanently into the permafrost. It was decided that removal and underground disposal of the wastes and reclamation of the old reserve pits was the best answer.

In a plan developed with State and Federal agencies, the North Slope producers developed a procedure known as grind-and-inject, using technology from the mining industry. This technique involved grinding drilled solids to a fine powder adequate to make a slurry that was then injected underground.

After the experimental phase of the project demonstrated its effectiveness, a central grind-and-inject plant was constructed to serve the Prudhoe Bay area producing fields. The companies mined the solidified wastes from the old reserve pits and transported them to the new plant. Three wells in the Prudhoe Bay field, no longer producing, were selected to be injection wells.

The Prudhoe Bay grind-and-inject plant was the first of its kind in the world for an oil field. It not only disposes of the wastes from the old reserve pits but also disposes of fluids and cuttings from new drilling in the Prudhoe Bay-area fields. Other fields that are

too far for trucking, such as Kuparuk River and Northstar, which is offshore, inject their drilling fluids down wells at those sites.

The AOGCC played a key role in the grind-and-inject project because if the underground injection of wastes was to become an accepted practice, the agency responsible for regulating underground injection had to certify that it was being done correctly and that wastes were being put in the right place.

It had to be verified, for example, that the wastes were being stored in a suitable rock formation that could contain the fluids, i.e., that the rock was porous and permeable enough and that the formation was surrounded by impermeable rock, such as a layer of clay, that would block any movement of the wastes.

If the underground injection of wastes was to become an accepted practice, the agency responsible for regulating underground injection had to certify that it was being done correctly.

This issue is important enough on the North Slope but it is even more important in other parts of Alaska where shallow aquifers supply drinking water.

The AOGCC has always regulated the injection of fluids underground, but in the mid-1980s the agency was delegated authority to administer the U.S. Environmental Protection Agency (EPA) national Underground Injection Control program in Alaska. The EPA was developing a national program to insure that underground injection operations will not contaminate underground sources of drinking water. Where it can, the federal agency prefers to delegate these responsibilities in states where there are agencies with the competency, expertise and local knowledge of oil and gas drilling. In Alaska this was the AOGCC. A memorandum of agreement was signed between AOGCC and EPA Region 10 in 1986.

Well Completions

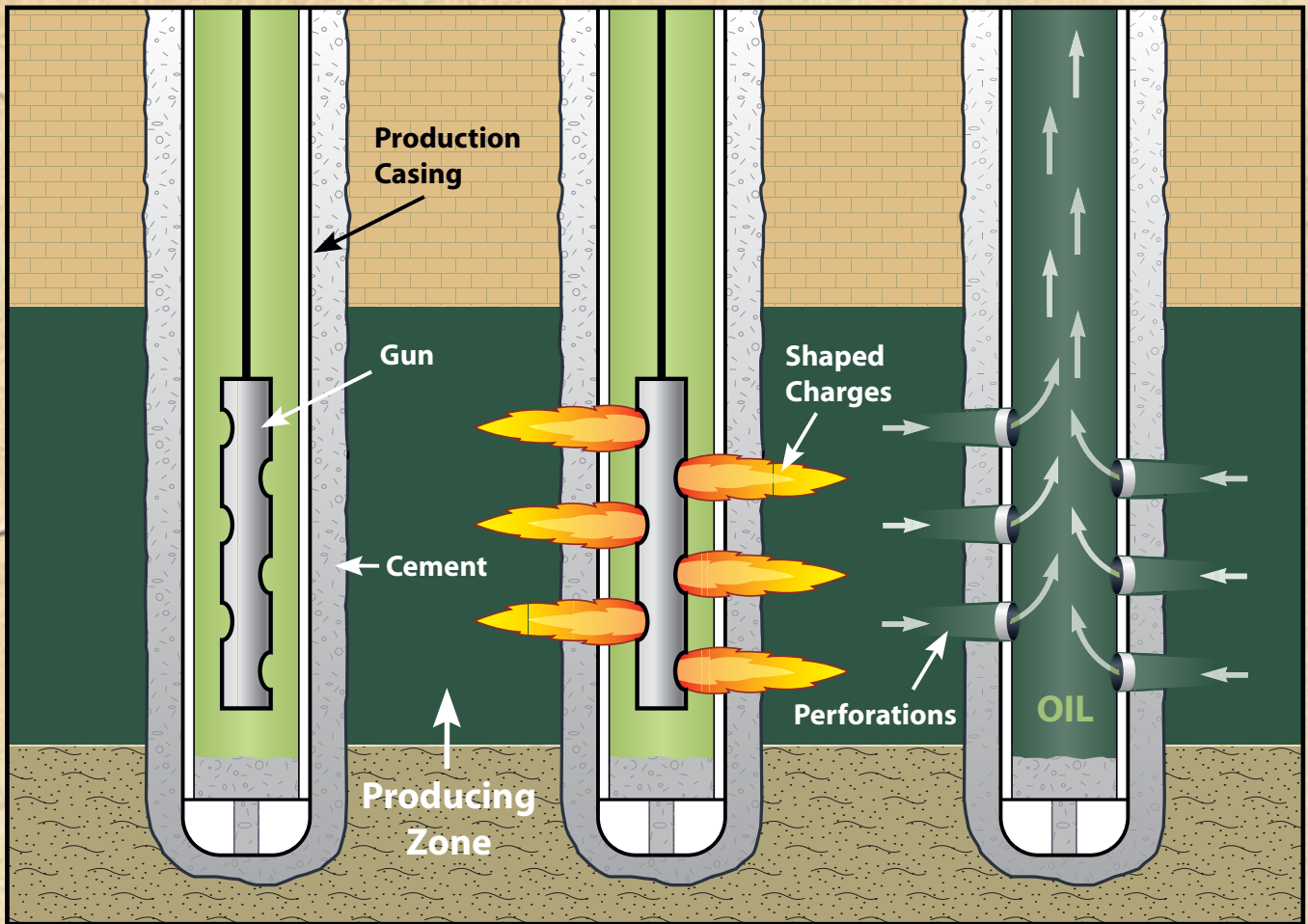


FIG. A

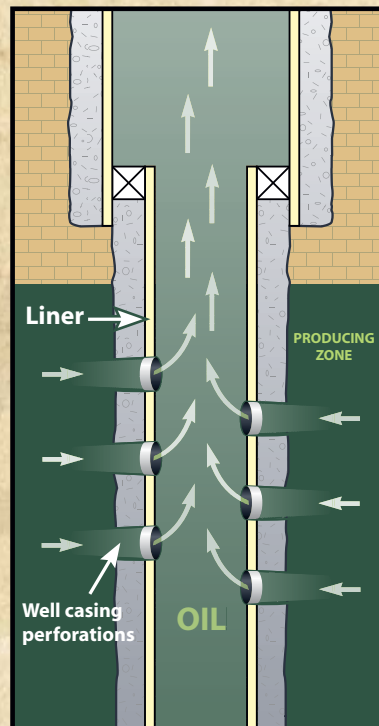
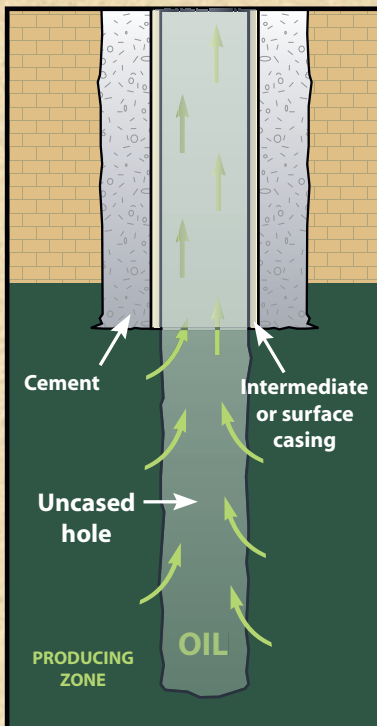


FIGURE A

A perforating gun is used to create holes, or "perforations", in the casing, cement, and producing formation, allowing fluids to enter the well.

FIGURE B

An open-hole completion allows well fluids to flow into an uncased hole.

FIGURE C

A perforated liner completion. Pre-perforated pipe placed within the producing zone.

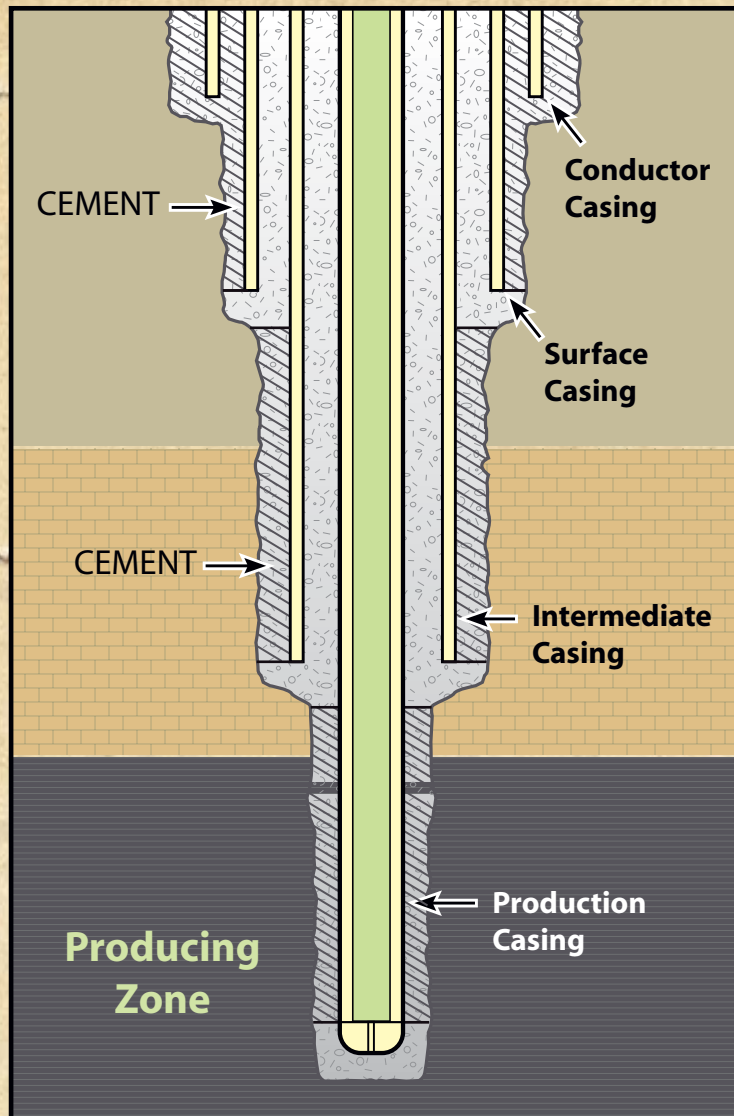


FIG. D

FIGURE D

Conductor, surface, intermediate, and production casing are cemented in the well. Note that the production casing is set in the producing zone.

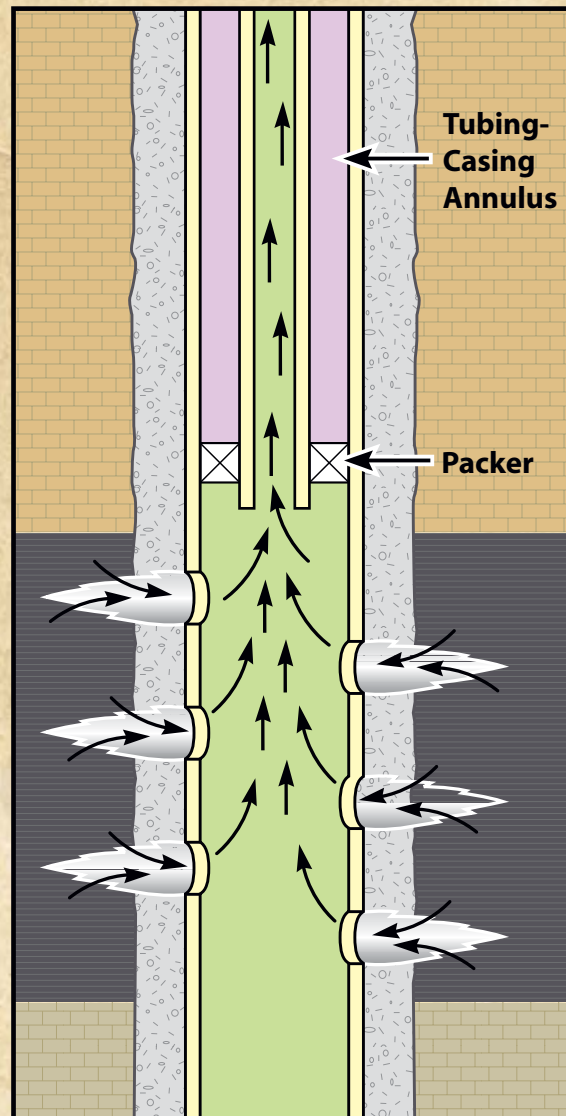


FIG. E

FIGURE E

A packer placed on the outside of the tubing string keeps well fluids out of the tubing casing annulus.

THE NINETIES

AOGCC BECOMES TOO LEAN; REFEREE TO AN INTER-INDUSTRY CONFLICT

Times were difficult for the Alaska Oil and Gas Conservation Commission as the 1980s became the 1990s. Oil prices and State revenues had collapsed in 1986 and legislators made sharp cuts to the Commission's budget along with those of other State agencies. Layoffs had to be made from the AOGCC's small staff, including field inspectors. Inspections of critical safety equipment on wells dropped.

By 1989 the AOGCC's budget had been slashed 40 percent from 1983 levels. The Commission's Chairman, C.V. "Chat" Chatterton, an experienced former Alaska oilman and legislator, pushed his superiors in the State administration for more money while fending off lawmakers who wanted to disband the AOGCC to save money.

One of the Commission's engineers went public with complaints that there were too few inspections being done of critical well equipment, like blowout preventers.

Then, on March 24, 1989, the Exxon Valdez hit Bligh Reef in Prince William Sound, releasing 11 million gallons of crude oil into pristine waters. An outraged public quickly focused attention on State and federal regulators as well as Exxon. It was also realized that a blowout from an oil well in the Arctic or Cook Inlet could cause as much environmental damage as a tanker on the rocks in Prince William Sound.

The complaints of inadequate inspections triggered an investigation by the State Ombudsman and articles in the newspapers. Legislative hearings were held. In the midst of all this Chat Chatterton, already ill with cancer, passed away.

Times were difficult for the Alaska Oil and Gas Conservation Commission... Oil prices and State revenues had collapsed in 1986 and legislators made sharp cuts to the Commission's budget along with those of other State agencies.

It was a very difficult time for the AOGCC. Budgets were so lean that field inspectors, whose ranks had been reduced from five to three, were working long hours of uncompensated overtime. Technical staff in the Anchorage office found themselves mowing the lawn and doing building maintenance.

For the limited field staff, all available time had to be given to witnessing what tests they could of equipment vital to safety and the environment, like well safety valves and blowout preventers.

Staff in the field were told to give a low priority to their

other responsibilities, such as inspecting the meters which measure oil and gas production for purposes of royalty and tax payments. The staff were also instructed to temporarily halt

witnessing tests of oil quality, another of the Commission's many responsibilities.

The AOGCC's commissioners were unhappy the engineer had gone public with his complaints, as they had hoped to address the problems internally. The basic facts of his assertions were not challenged, however.



Photos: Top, old AOGCC office on Porcupine Drive in Anchorage; Right: Drilling rig working on production wells on the North Slope.



THE 1990's...

The Commissioners were dealing with severe budget constraints, but they never felt safety was seriously jeopardized.

In a letter to the Commission, the engineer said that in 1989, with a limited number of inspectors, the Commission was able to witness only 18 percent of tests of Cook Inlet well safety equipment and only 27 percent of safety equipment tests on the North Slope. When the Commission had its full complement of inspectors, 85 percent of tests were witnessed. Many tests, including those for exploration wells, now had to be waived.

The Commissioners were dealing with severe budget constraints, but they never felt safety was seriously jeopardized. However, having a regulatory agency unable to do its job is bad policy. Harry Kugler, a former Commissioner, was quoted in the Ombudsman's Report as saying, "When there are too few inspections, there is a relaxation of the safety regulations. The rig operators begin putting off minor repairs and not following up on previous recommendations."

Unfortunately, however, the Commission did not really know its actual situation because it lacked even basic information on its performance. When David Johnston was appointed to the Commission in the geologist position in 1989, he found no computers or electronic information systems capable of accurately tracking the number of field inspections, much less of helping the agency competently deal with complex questions of reservoir management.

In fact, prior to 1988 the Commission still relied on an old-fashioned typing pool, Johnston recalled. "There was no word processing - everything was still paper and pencil," he said. The AOGCC did have access to an old State mainframe computer, but it was one that had really been

Photo: Blowout preventer (BOP) on a working North Slope rig. AOGCC regulations require this equipment to be installed on rigs when drilling is underway. The Commission requires regular tests of the BOPs. Note lined drip-pans under the BOP to catch small oil drops. Liners are a common environmental precaution employed in Alaska.



1992

Kuparuk field production peaks at
322,000 barrels/day
- PetroStar builds refinery at Valdez

1999

Miscible Injectant "MIX" project expands Prudhoe gas
handling capability, from 7.5 to 9 billion cu. ft./day
- First lease sale in NPR-A since 1980s
- Oil prices drop to \$12/barrel

1990

1991

1992

1993

1994

1995

1996

1997

1998

1999

1995

GHX II project at Prudhoe Bay field increases gas handling
capacity from 5.2 to 7.5 billion cu. ft./day

1998

Alaska institutes areawide
lease sales

designed to track elevator maintenance, not oil field reservoir performance. "We were getting all of the data, well logs and other information from the operators but we had no way to analyze it," Johnston said.

The ombudsman's report and press articles, and the new emphasis on spill prevention, were wake-up calls for Governor Steve Cowper and the Legislature. The purse strings were slowly loosened. In 1990 the Commission got its first computer, bringing the AOGCC into the modern era.

It was a big step, and improvements continued through the 1990s. These were critical for the Commission to do independent analysis of complex proposals the operators brought forward. Some of these proposals, such as the injection of water into the Prudhoe Bay field gas-cap to stimulate oil production, were very innovative. This was approved by the AOGCC in 2001.

In 1995 a dispute surfaced among the Prudhoe Bay Unit owners that was to test the AOGCC severely. The main oil and gas reservoir at Prudhoe Bay consisted of an oil-bearing section, called the oil rim, and a gas-bearing section above but slightly offset from the oil rim, called the gas cap. As a result, the lease owners of the Prudhoe Bay Unit did not own equal proportions of oil and gas, and to further complicate matters, while oil was acknowledged by all owners to have an economic value, gas was believed by some owners to have uncertain value. There was no clear way the lease owners could agree on how costs would be shared, because they could not agree on the relative value of oil versus gas.

When the field was first unitized the lease owners side-stepped this issue by forming two participating, or cost sharing, areas, one for the oil rim and one for the gas cap. In concept, initial costs would be shared primarily by the oil rim owners, who would receive most of the initial production. Later, when it was assumed that gas would be commercially produced, the gas cap owners would assume a greater share of the costs. But

commercial gas production remained uncertain. The field continued to age and the cost sharing arrangement put more and more of the burden of rising costs on the oil rim owners.

At first the lease owners were able to resolve cost issues by negotiation, but by the early 1990's a significant dispute arose. It was

whether to maximize the volume of natural gas liquids (NGLs) made at the Central Gas Facility in the Prudhoe Bay field so these could be blended with the crude oil and sold, or whether to maximize the manufacture of miscible injectant (MI) to be injected into the reservoir to produce more crude oil. If the NGLs were maximized the gas cap owners would profit. If MI were maximized, the oil rim owners would profit. The controversy came to be known as the "the NGL wars."

This time the companies could not resolve the issue by negotiation, and the dispute proceeded to litigation. A lawsuit was filed in State court, a complaint was brought before the Alaska Public Utilities Commission (now RCA) and administrative proceedings were initiated before AOGCC and DNR.



THE 1990's...

The AOGCC's responsibility was to make sure the Prudhoe Bay field was operated as efficiently as possible so as to ensure greater ultimate recovery of both oil and gas.

The AOGCC's responsibility was to make sure the Prudhoe Bay field was operated as efficiently as possible so as to insure greater ultimate recovery of both oil and gas resources. The Commission recognized the potential for inefficiencies in the split oil and gas rim ownership. While the AOGCC has the authority to order the formation of a unit in a field in cases where the lease owners cannot agree on a unified arrangement, it had not done so in 1977 at Prudhoe Bay because the lease owners had worked out a voluntary unit agreement.

As long as Prudhoe Bay was able to sustain crude oil production at peak rates and the pipeline was full, the potential points of conflict between the oil rim and the gas cap owners were not yet obvious.

It was the MI/NGL controversy that brought these conflicts into the open. Not surprisingly, the gas cap owners led the way for maximum production and commercial sales of the gas liquids mixed with oil since they would benefit directly, but most of the costs involved for plant modifications needed for the gas processing facilities were paid by the oil rim owners under the unit agreement.

The competing use of gas liquids as MI after 1991 set the stage for conflict. The MI was injected underground in an alternating sequence with water, to flush portions of oil trapped in the underground reservoir that had been bypassed earlier. As a routine measure the AOGCC reviews and approves changes in field development programs, and in 1995 it approved the field operators' EOR program because it would boost overall oil recovery.

Photos: Top, Blair Wonzell, the AOGCC's senior petroleum engineer from 1991 to 2001; Middle, oil and gas processing facilities in a North Slope field; Bottom, ice road under construction in winter near the Badami oil field.



At first there was an adequate supply of NGL production to meet both needs. In 1995, however, Alyeska Pipeline Service Co., operator of the Trans-Alaska Pipeline System, lifted the vapor pressure limits on the pipeline, which allowed more NGLs to be mixed with oil in the pipeline. The gas cap owners pushed immediately for more of the NGLs to be mixed with oil and sold, but the oil rim owners resisted, arguing that the NGLs were better used to produce more oil.

This was the first time the companies faced such a serious disagreement over operating priorities. Should the NGLs be mixed with oil and shipped through the pipeline for sale, with the revenues going to the gas cap group, mainly ARCO and Exxon? Or should they be used in the EOR project to produce more oil, with the revenues mainly going to the BP-led oil rim group?

For companies used to cooperating in operating the nation's largest oilfield, it was an unprecedented dispute. State regulatory agencies, including the AOGCC, looked on with concern.

Because ARCO controlled the Prudhoe Bay Central Gas Facility, it decided to turn the valves and started making larger volumes of natural gas liquids to ship through

TAPS. Because more of the NGLs were being put through TAPS, it meant fewer liquids for enhanced oil recovery.

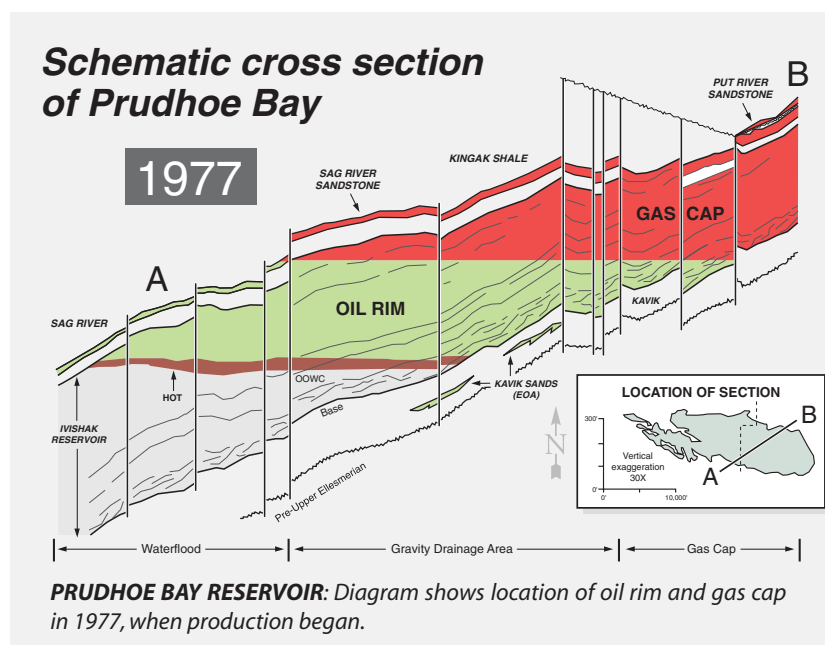
BP, however, controlled Skid 50, where the liquids were blended with crude oil and shipped to Pump Station One of the pipeline. BP closed the tap for the NGLs at Skid 50. ARCO responded by attempting to blend NGLs with crude oil at another point in the system but BP further reduced blending of liquids at Skid 50 to compensate.

Because the MI/NGL issue clearly affected the con-

servation of oil and gas (using MI would produce oil that might otherwise remain trapped in the rock) the parties came to the AOGCC to resolve the dispute. BP argued that selling the NGLs at the expense of EOR resulted in lost oil production and physical waste of the resource. ARCO and Exxon argued the oppo-

site, that failure to maximize sales of NGLs represented waste of the resource.

After extensive hearings the AOGCC concluded that the technical data supported ARCO's and Exxon's position, at least as an interim measure. Conservation Order No. 360 was issued approving the maximum blending of gas liquids with oil. BP complied with the order and opened the tap at Skid 50.



THE 1990's...

... the Commission also determined that the split of the Prudhoe field into two participating areas, an oil rim and gas cap, was becoming a problem.

However, as part of this proceeding the Commission also determined that the split of the field into two Participating Areas, an oil rim and a gas cap, was becoming a problem. If not resolved, the Prudhoe Bay production operations would become increasingly inefficient, more disputes could occur, and loss of oil and gas, which constituted physical waste, might occur. With this in mind, the AOGCC convened a follow-up set of hearings that could lay the groundwork for an integration of the field ownership, by order of the Commission if necessary.

The authority to order compulsory unitization of the largest oil and gas field in North America was, for the Commission, a tool of last resort. The AOGCC could threaten to order it to get action, to get the lease owners to resolve their disputes themselves, but it was something the AOGCC was reluctant to do.

It was unlikely the Commission would be able to reshuffle the Prudhoe Bay ownership interests in a manner that would be satisfactory to all of the companies, and the only certain outcome would be years of litigation.

From their standpoints, the companies were horror-stricken at the possibility that a government regulatory agency would even contemplate devising its own plan for integrating the ownership interests in the field.

The State Attorney General also advised the Commission that it was on weak legal ground in asserting authority to order forced unitization where all parties had previously agreed to a voluntary plan, even if it was dysfunctional. The AOGCC would have been on more firm legal ground to require compulsory unitization had one of the major lease owners supported the action.

Photos: Top, North Slope drill rig; Middle: maintenance worker on a rig; Bottom: West Dock causeway, now used for barge unloading, with seawater treatment plant in background, where water for waterflood is treated.



However, in this case, all of the Prudhoe Bay lease owners, worried about the possible outcome, disagreed with forced unitization.

The Commission ultimately backed away from using its forced unitization option, but Tuckerman Babcock, one of the AOGCC Commissioners at the time, felt that just the threat of it had the desired effect of making the gas cap and oil rim owners realize they must set their disputes aside and negotiate a voluntary unification of interests in the field, to avoid having the government do it for them.

Prudhoe Bay oil and gas processing facilities. In foreground is the field Central Compressor Plant. In the distance is the Central Gas Facility. Together these plants compress and inject 8 billion cubic feet per day of gas back into the Prudhoe Bay reservoir to maintain pressure and produce more oil.

Such an agreement would come five years later, when BP purchased Atlantic Richfield's worldwide assets and sold ARCO's assets in Alaska to Phillips Petroleum, which later became ConocoPhillips. Amid these transfers of ownership, the companies finally agreed to unify the gas cap and oil rim of the Prudhoe Bay field. This set the stage not only for more economical operation of the field, with BP as the single operating company, but also for a natural gas pipeline. David Johnston, who was an AOGCC Commissioner at the time and its Chairman, said that without integrated ownership of the field, the decisions needed to support commercial gas production would have been difficult because of the split oil and gas ownership.



Multilateral Wells

Single Zone "Y"

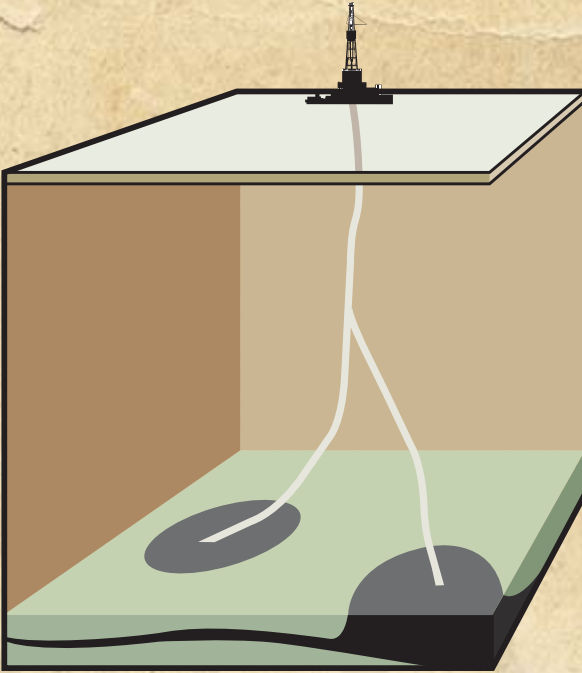


FIG. A

Trunk & Lateral

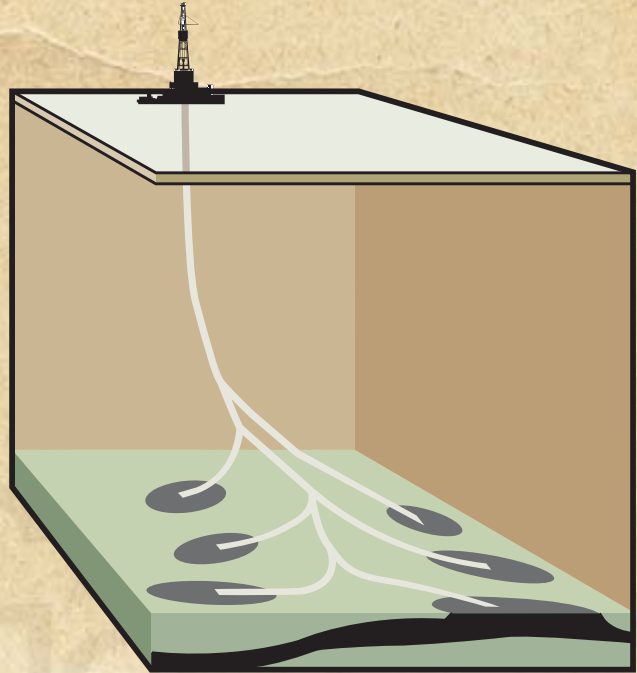


FIG. B

Coiled Tubing Rig

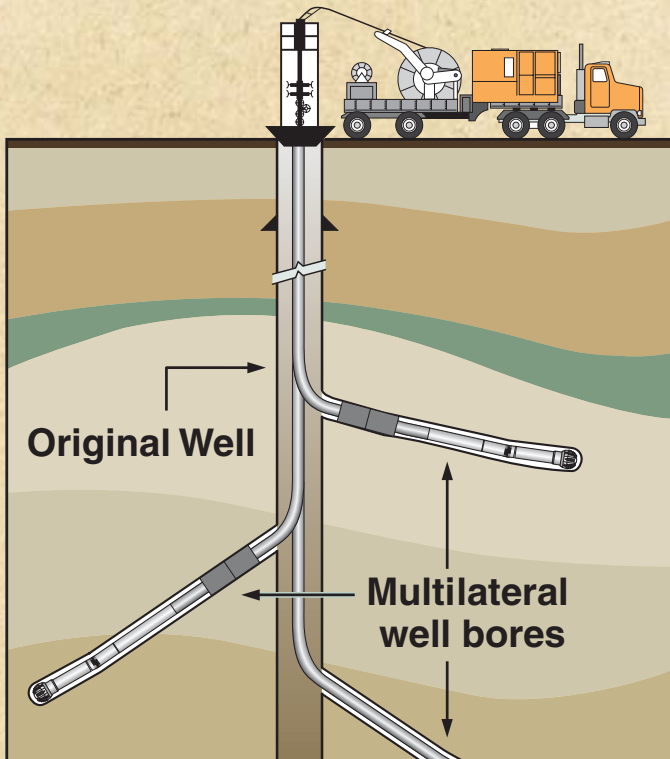


FIG. C

Another kind of well innovation, the "multilateral well" involves drilling several well bores, usually horizontal, from a single older well. Operators in Alaska have now drilled as many as six laterals from one main well. Multilateral wells have sharply reduced the cost of producing oil in the older fields on the slope. They can be done either with a conventional drilling rig or, in some instances, with a more cost-effective coiled-tubing drilling rig. The technology is a step toward helping to make viscous oil economic to produce.

Extended Reach Drilling (ERD)

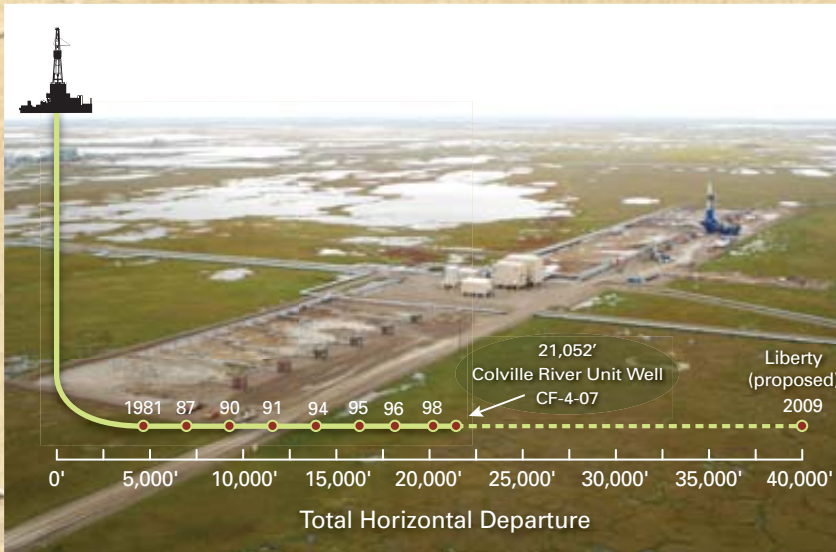


FIG. D

Today drillers can reach underground reservoir targets that are several miles laterally from the surface location of the drill rig. These “extended-reach” wells allow industry, for example, to test oil and gas prospects three to four miles offshore from a rig located onshore. On the North Slope, some offshore accumulations near shore are being produced through extended-reach production wells.

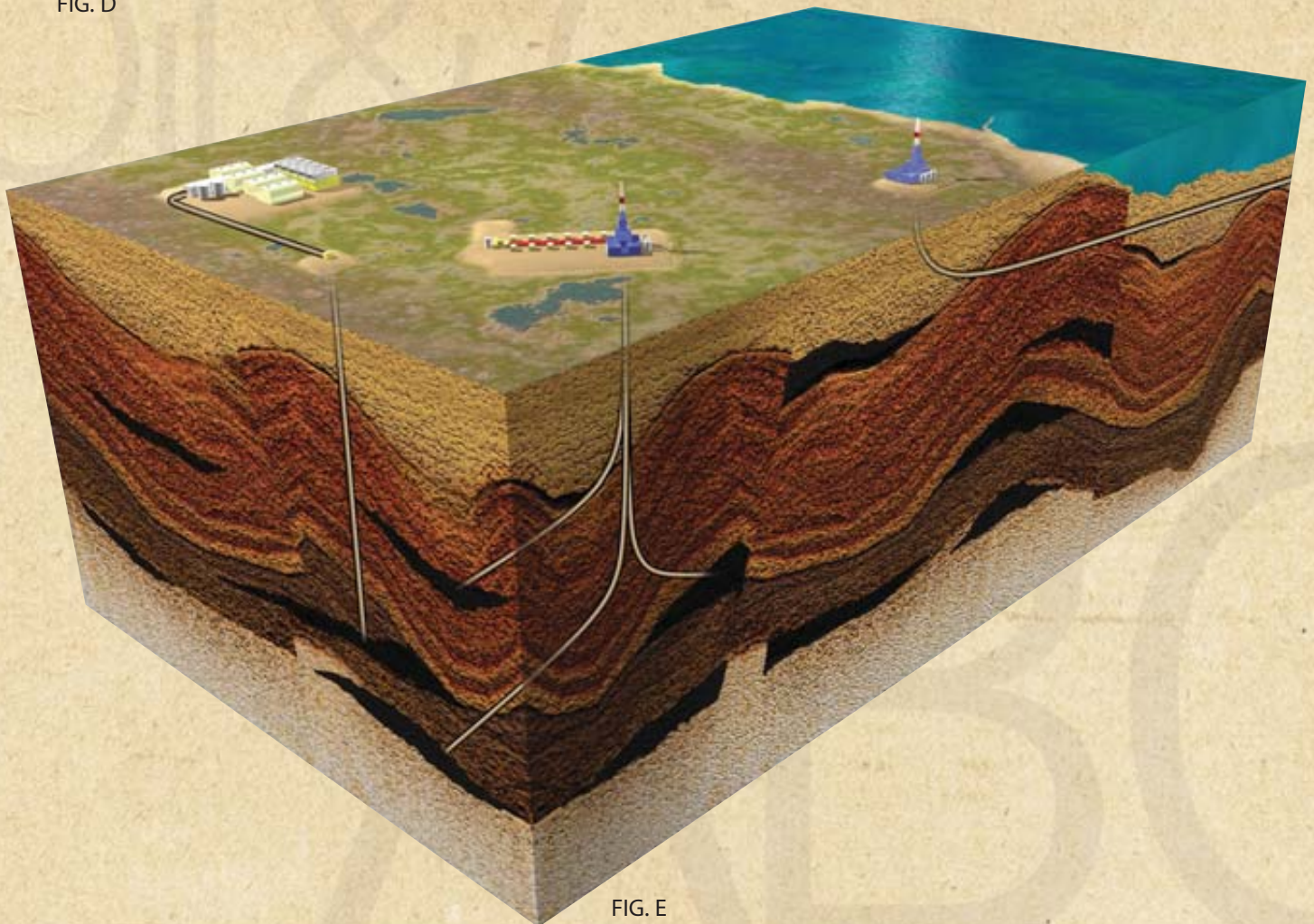


FIG. E

THE NEW MILLENNIUM

RENEWED EMPHASIS ON WELL SAFETY; PREPARING FOR COMMERCIAL GAS PRODUCTION

In 2000, with the start of the new millennium, Alaska's petroleum industry was changing, and new players were arriving on the scene. On the North Slope the prolific Prudhoe Bay and Kuparuk River oil fields were in decline. The industry was able to offset the decline temporarily with innovative new technologies, many of them developed on the North Slope. These made previously uneconomic deposits, like small satellite pools near the big fields, possible to produce.

Cook Inlet operating oil companies, through efficiency measures, kept the aging offshore platforms producing oil. There were concerns over depletion of the large gas fields in the region, but as supplies tightened and prices rose, new exploration resulted in gas discoveries being made on the Kenai Peninsula and the west side of Cook Inlet.

New explorers came to Alaska as the state's petroleum industry matured. In recent years a number of different companies have applied for drilling permits. Many of these are independent companies, new to Alaska and unfamiliar with Alaska's operating conditions.

The industry is in a period of rapid technological innovation. New kinds of production wells are being drilled horizontally through very thin reservoir sections, making previously uneconomic oil pools possible to produce. "Undulating" horizontal wells have been drilled. These rise and dip to reach oil-bearing reservoir rocks at different depths. Multi-lateral wells, with several well branches drilled underground off a single well-

bore are bringing oil to the surface. By 2008 companies were drilling as many as six underground branches from a single well. These sharply lowered the cost of reservoir penetrations and producing from small oil pools, and also increased well productivity.

Extended-reach drilling has allowed companies to drill laterally at high angles to tap underground reservoirs several miles distant from the surface location of the drill rig. On the Kenai Peninsula, Marathon Oil Co. is producing natural gas from an offshore reservoir reached with an extended-reach well drilled from an onshore location. Pioneer Natural Resources is also

exploring an offshore oil discovery near Anchor Point that was reached with wells drilled from onshore.

On the North Slope, extended-

reach wells have allowed the full development of the Milne Point, Niakuk and Alpine fields, and may be used for Point Thomson field development. BP now hopes to develop Liberty, an oil deposit five miles offshore, with extended-reach production wells. Some of these may be drilled laterally as much as eight miles.

To keep up with the industry, the Alaska Oil and Gas Conservation Commission is working to maintain its technical edge and to adapt its rules to deal with new technologies as well as anticipated production from sources of non-conventional gas such as coal-bed methane and gas hydrates.

Photo, at right: Construction workers put finishing touches on BP's Northstar field production modules, which were built in Anchorage and barged to the North Slope.

The industry is in a period of rapid technological innovation. New kinds of production wells are being drilled ... making previously uneconomic oil pools possible to produce.





Marathon Oil Co.'s Wolf Lake well on the Kenai Peninsula. Wolf Lake is a relatively new development on the peninsula.

NEW MILLENNIUM...

Fortunately the Alaska Legislature solved the serious financial problems the Commission was experiencing in the 1990s, and which had inhibited its ability to do its job.

Since statehood the Commission had depended on annual appropriations from the State general fund. However, as oil prices periodically collapsed in the 1980s and 1990s sharp reductions of State budgets were made. These took their toll on the AOGCC, one of the smallest State agencies.

In 1999, the Legislature enacted a statutory change that allowed the Commission to assess the industry with a regulatory cost charge similar to the fees charged to regulated utilities by the Regulatory Commission of Alaska. The new fee system went into effect in State Fiscal Year 2000, allowing the Commission to hire new inspectors and technical staff as well as to purchase more up-to-date information systems. Adequate funding has allowed the Commission to do its job effectively.

For example, since 2000 the Commission has been able to process and issue drilling permits more quickly and efficiently. "It had been taking as long as 30 days to review and issue a permit for drilling. Within two years we were able to reduce this to seven days," said Dan Seamount, a geologist and the AOGCC's current Chair. "Having additional resources helped, but it was also that we had focused on the problem. We made it a performance measure."

A maturing Alaska industry also meant that the number of wells and producing reservoirs had multiplied. By early 2008 there were more than 4,600 wells producing oil and gas from approximately 115 active reservoirs, all requiring monitoring by the AOGCC.

The millennium brought a major new challenge to the Commission, however: the aging of the producing wells and gathering lines of the older North Slope and Cook Inlet fields.

Unfortunately, it was an explosion and fire that focused attention on aging infrastructure.

Unfortunately, it was an explosion and fire that focused attention on aging infrastructure. On August 16, 2002, an explosion and fire in a production well in the Prudhoe Bay field seriously injured an oil company employee. The incident underscored the importance of well integrity and safety and raised concerns about the condition of aging infrastructure in the large North Slope fields as well as in Cook Inlet. The Commission has jurisdiction over producing wells and the responsibility to ensure that operators follow good oil field practices and proper maintenance on wells is being done.

The AOGCC's investigation of the accident showed the well had been shut down while repairs were underway on the Trans-Alaska Pipeline System. Gas had accumulated in the annulus, or space between the outer and inner sets of steel casing pipe.

When the well was restarted, heat from the hot oil being produced was transferred through the pipe to the gas in the annulus, causing it to expand. Because it was enclosed with no way to vent, the pressure gradually built up until it exceeded the strength of the pipe.

Normal oilfield procedure is for the gas pressure to be monitored and bled-off if found to be excessive. In this case that was not done.

After an extensive investigation, the AOGCC imposed a substantial fine on the operator of the well where the explosion occurred. The Commission also acted to implement new requirements for wells with sustained annular pressures.

Conservation Order 492, published in June, 2003, established new annular pressure management requirements for the Prudhoe Bay field, with daily monitoring by the field operators, notification to the Commission, and corrective actions when pressures in the well annulus exceed certain levels. In short order, similar rules were issued for other fields.



Information Technology

Just a few years ago the AOGCC was in the stone age in terms of information technology. Years of budget cuts had left the agency dependent on paper reports and well logs, microfilm, copy and FAX machines, and an antiquated mainframe computer. Anyone in the world doing research on Alaska's petroleum geology and well productivity had to send someone to the Commission's library in Anchorage.

Times have changed. Thanks to the Legislature's action in 1999 changing the way the agency is funded and grants from the U.S. Department of Energy helping to pay for software adaptations, the AOGCC now has one of the best comprehensive electronic and Internet-based oil and gas information systems in the world.

Public-domain well history files and information on well construction and production can now be obtained via the Internet from anywhere in the world. Producing companies can also now file some kinds of required data electronically. "It won't be long until companies can file applications for well permits and send many types of reports electronically," said AOGCC Senior Petroleum Geologist Steve Davies.

"The real benefit of this is that it makes it much less expensive and easier for companies to get information about opportunities in our oil and gas fields and regional geology. Providing more information quickly and at little cost means more companies will be encouraged to come here to explore," Davies said.

Oil and Gas Conservation Act

On July 12, 2007, Gov. Sarah Palin signed into law comprehensive amendments to Alaska's 50-year-old Oil and Gas Conservation Act. The amendments make a number of changes to the law governing the AOGCC, such as clarifying the Commission's authority to regulate not just for oil and gas conservation but also for public health and safety. Other changes clarified the Commission's authority to regulate underground storage of natural gas, that confidentiality of oil and gas well data applies only to exploration and stratigraphic wells and not field production wells, and that information submitted in an AOGCC hearing cannot be held confidential just because it is provided voluntarily. Penalties for violations of AOGCC regulations have been increased and criteria are specified as to how penalties should be determined. The new law also clarified that the uniform appeal provisions in the State judiciary statute apply to decisions by the AOGCC.



Photo: Governor Sarah Palin signs new AOGCC legislation into law at the Commission's offices, July 12, 2007.

NEW MILLENNIUM...

Technology advances and concerns over aging infrastructure and well integrity have caused the Commission to turn its attention to other well safety procedures and the rules that govern them ...

The Commission staff was directed to conduct random inspections of well start-ups and of equipment used to bleed excess gas pressure from the “annulus” of wells, the space between sets of steel tubing installed inside each other, to make sure that they are properly maintained. The AOGCC has also promulgated similar orders for most of the other producing fields on the North Slope as well as most fields in Cook Inlet.

Technology advances and concerns over aging infrastructure and well integrity have caused the Commission to turn its attention to other well safety procedures and the rules that govern them, such as the safety valve systems that are required to be on producing wells.

Safety valve systems are installed in producing wells to prevent the uncontrolled flow of oil and gas. These often consist of the surface safety valve, a low-pressure sensor and subsurface safety valve. The low-pressure sensor is designed to trigger closure of the safety valves if there is a drop in pressure, which could indicate a leak. Historically, the requirements for installation, maintenance and testing of safety valves have been established when the rules are set for each individual producing field. (The Commission calls them pool rules.)

Over the years, as different fields were developed, minor variations in the rules appeared, mainly to reflect the most updated industry practices. This was not a problem until recently because oil and gas fields are normally stand-alone operations, and field-specific rules can easily be managed. But when the North Slope operators began developing and producing satellite pools near the large fields and using the exist-

ing production pads and other existing infrastructure, they were faced with having slightly different rules apply to different wells on the same pad.

“The rules were inconsistent across the North Slope, and even within a field,” said the AOGCC’s Engineering Commissioner Cathy Foerster. “One drill site could be producing from three reservoirs, each with a different set of rules. Just imagine what this is like for the drill site operators.”

While not a dangerous situation, if this were allowed to continue it could lead to confusion and possible mistakes by operations workers in the testing of safety valves and other production safety systems. The Commission resolved this by making the rules consistent.

Alaska has some of the most stringent rules in the nation regarding safety valves on wells. The inspection procedure is for safety systems on producing wells to be tested to ensure proper operation every six months with a representative sample of these witnessed by an AOGCC inspector. Failures must be repaired and retested and may result in the wells being put on a more frequent inspection schedule.

Inspectors from the AOGCC continually witness tests of safety valves. Tests that are witnessed are a representative set of all tests, but some tests must be done with an inspector present based on past performance or particular problems on the wells. The results of all safety valve tests, witnessed or not, are reviewed by the Commission to make decisions on the frequency of testing.

Safety systems used when a well is being drilled are another focus of attention by the Commission. During drilling, if there is an uncontrolled flow of oil, gas or water, the operator relies on blowout prevention equipment located below the rig to close and stop the flow.

“At one time blowouts were a common occurrence in the oil industry although never in Alaska,” Foerster said. “However, the development of engineering safeguards, such as safety valves and blowout preventers, and the regulation of their use, including frequent testing, have all but eliminated loss of well control.”

Improved equipment and controls, redundancy in critical components, attention to training and frequent testing have contributed to the improvements seen in well control. Regulatory oversight and recommended practices developed with industry cooperation have led to the current rigorous requirements for well control equipment and procedures.

The AOGCC has commenced a review of all of its drilling, workover and completion control requirements based on its analysis of historical performance data for Alaska drilling operations. The review has also been motivated by the need to clarify specific requirements. As with production safety systems, Commission inspections of drilling safety systems are based on a goal of periodic inspections guided by the performance of the drilling rig involved.

The major North Slope producers and the State are approaching critical decisions on a possible \$30 billion-plus natural gas pipeline to move gas from the North Slope to the Lower 48 states. The industry has been working almost since oil was discovered in 1968 on ideas for commercializing the natural gas resources found with oil in the Prudhoe Bay field. In 1975, a major gas and condensate oil field was discovered at Point Thomson, 60 miles east of Prudhoe Bay. The combined gas resource, at Prudhoe Bay and Point Thomson, is estimated to be 35 trillion cubic feet.

In the past, there were two major initiatives to build a conventional gas pipeline from the Slope, one in the 1970s and one in the 1980s, both unsuccessful.

NEW MILLENNIUM...

In the 1990s, there were studies of a liquefied natural gas project, which would chill the gas to a liquid suitable for ocean shipment in a plant at Valdez, as well as a gas-to-liquids project on the North Slope that, through chemical changes, would convert the gas into liquid products that could be moved through the Trans-Alaska Pipeline System. None of these initiatives moved forward.

After three decades the producers are now back to a pipeline as the best apparent option. Improvements in steel and construction technology, as well as changes in gas markets in the Lower 48, have combined to make a natural gas pipeline now possible.

The AOGCC will have a small but important role to play in the decisions on natural gas production. The Commission is charged with prevention of waste, or the loss of oil and gas that might otherwise be produced. Before the gas in the Prudhoe Bay and Point

The AOGCC will have a small but important role to play in the decisions on natural gas production.

Thomson fields can be produced the Commission must establish a gas production, or offtake, rate for each field that will minimize the loss of future oil production.

These will be difficult decisions, because there will likely be some loss of oil or natural gas liquids when the gas is produced from both fields. This will occur in the Prudhoe Bay field because the gas in the reservoir is an important source of energy in helping produce oil. The situation in the Point Thomson field is different. There, natural gas liquids are dissolved in the gas in the reservoir. When the gas and condensates are produced, the condensates become liquid and can be transported to the Trans-Alaska Pipeline System, where they would be blended with the crude oil and sold.

Just as depleting the gas in the Prudhoe Bay field would reduce the reservoir pressure and reduce ultimate oil recovery, depleting the gas from the Point Thomson reservoir could reduce the amount of liquid condensates and oil that can be recovered. This will be a major focus of attention for the AOGCC.

The Commission is working cooperatively with the Prudhoe Bay producers to determine the allowable gas production levels that will maximize total hydrocarbon recovery, both oil and gas, from that field. The owners have shared confidential data and reservoir modeling with the Commission and allowed the Commission's technical staff to use the producers' models to run simulations without cost. A similar arrangement is underway for



Photo: Reservoir management is now very high-tech. In BP's office in Anchorage, reservoir engineers and geologists consult with detailed reservoir section models displayed.



Photo: Current AOGCC offices at 333 W. 7th Avenue, in Anchorage.

the Point Thomson field, which involves many of the same companies that have interests in the Prudhoe Bay field.

The allowable gas production rate is critical for a gas pipeline to be built because the amount of gas moving through the pipeline must be known in order to finance construction of the project, which is expected to cost more than \$30 billion. The Commission's goal will be to establish gas offtake rates at the Prudhoe Bay and Point Thomson fields that will ensure greater ultimate hydrocarbon recovery.

Current AOGCC Public Commissioner John Norman has said, "These will be some of the Commission's most significant decisions in balancing its mandate for prevention of waste, and maximizing physical recovery of oil and gas, against the economic needs of the producers and developers of a major gas pipeline project."

Last year Alaska added 284 million barrels of new proved reserves, more than any other state during this period. Most of these barrels are in satellites to existing fields, but of the total new proved reserves in the United States, which are attributable to new discoveries, 70 percent came from recent discoveries in Alaska – proof of the great promise Alaska holds for the future.

The developments that have occurred in Alaska's oil and gas industry over the past half-century have been truly astounding. One can only suppose the next fifty years will be equally exciting. There is one thing however, that is sure. Whatever the challenges the future may bring, Alaska's Oil and Gas Conservation Commission will be prepared to meet them.

AOGCC will play key role in Point Thomson

The AOGCC will play a key role in the development of the large Point Thomson field east of Prudhoe



Bay. Point Thomson is the largest proven yet undeveloped oil and gas field in Alaska, but it will likely be also one of the most difficult to develop and manage properly. The field holds an estimated 8 trillion cubic feet of gas, 200 million barrels of condensate (a natural gas liquid) and an undetermined amount of crude oil. However, it is an unusual type of reservoir. The field is under very high pressure, at approximately 10,200 pounds per square inch, but if gas is produced first, the drop in reservoir pressure could result in a loss of the ability to produce much of the condensates and crude oil. One of AOGCC's primary responsibilities is to prevent waste of hydrocarbons.

Operators typically develop fields like Point Thomson using a "cycling" project, where the gas is produced, the condensates are stripped off for sale and the gas is injected back into the reservoir to maintain its pressure. Some of the gas cycles back through the reservoir to the producing wells, picking up liquid condensate as it moves. After a period of time enough of the condensates have been produced so that gas can be taken out without undo losses of hydrocarbons. Often, the field operator may be able to devise a plan to produce both gas and condensates simultaneously. In the case of Point Thomson it is also possible that reservoir characteristics may limit the effectiveness of cycling and condensate production, and technology limits may thwart production from oil accumulations, in which case straight gas production may be the only option to produce the field.

A gas cycling, condensate and oil production project has been proposed for Point Thomson. The AOGCC will have to evaluate this project as to its technical feasibility and to determine whether it is likely to result in greater ultimate hydrocarbon recovery.

Coiled Tubing Drilling

The drilling of new wells from older wells with mobile Coiled Tubing rigs was pioneered on the North Slope. A drilling assembly, with a turbine motor turning the drill bit, operates at the end of a long flexible tube lowered down the well from the surface.

While Coiled Tubing does not replace traditional rotary drill rigs for exploration wells, coiled tubing rigs can drill complex or high-angle production wells at lower cost.

Cross-section of existing well bore

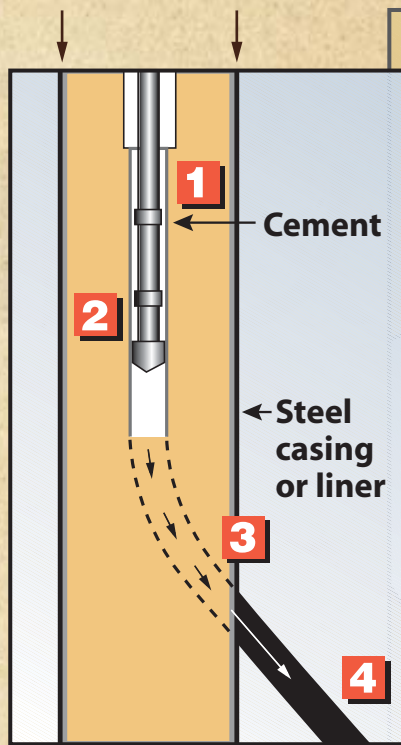
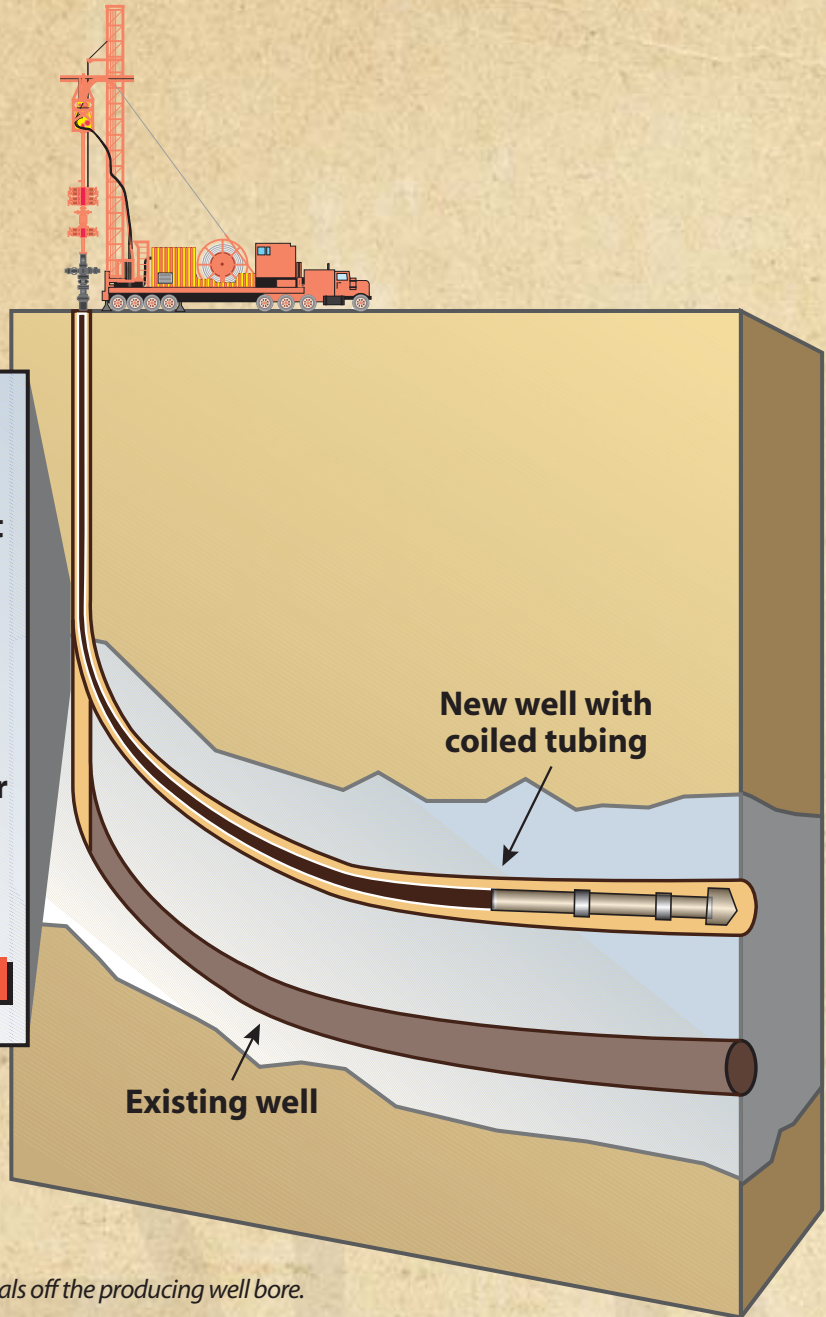


FIG. A

What happens downhole

- 1** The well is filled with cement that seals off the producing well bore.
- 2** A pilot hole is drilled into cement, which helps guide the coil tube drill.
- 3** The drilling bit is steered to exit well casing, opening a window.
- 4** Coiled tubing drilling continues into the formation.



How the Prudhoe Bay field works

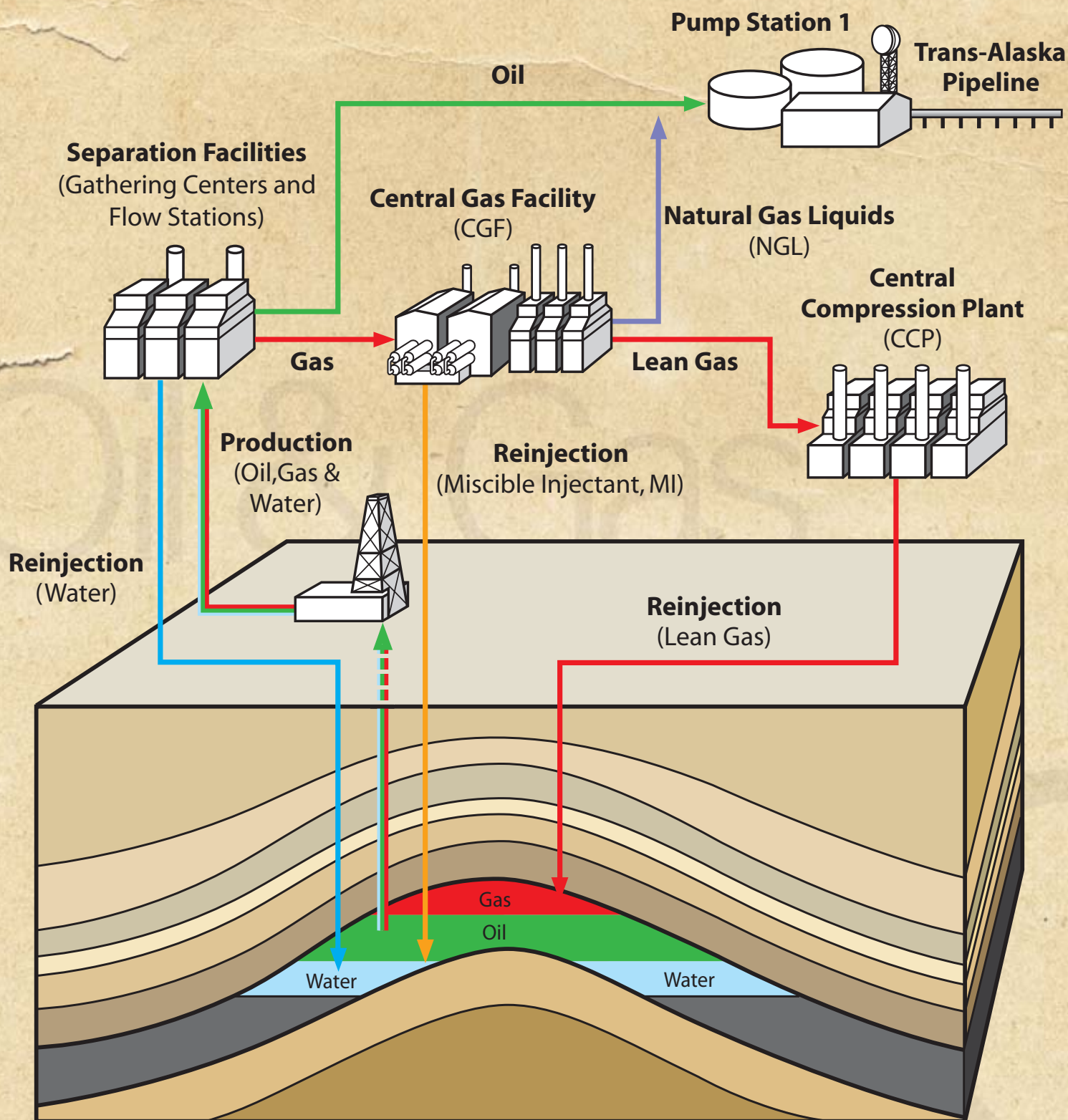


FIG. B

Note: Diagram above is for illustrative purposes only.

For a more accurate depiction of the Prudhoe Bay reservoir, see page 59.

THE DISCOVERY OF PRUDHOE BAY

HOW A HUGE OIL FIND WAS ALMOST MISSED

Alaska came within a whisker of losing out on its Prudhoe Bay land selections in the early 1960s. Had that happened, those lands today would likely be in a national park or refuge, and the giant North Slope oil and gas fields would remain undiscovered. There would be no Trans-Alaska Pipeline System, and no Alaska Permanent Fund. Alaska's oil industry would be centered in Cook Inlet, and the Alaska Oil and Gas Conservation Commission might be back to two desks in the corner of a room at the Department of Natural Resources, as it was in the early 1960s. Certainly, Alaska's economy and population would be mere shadows of what they are today.

What happened is an intriguing tale. Thomas R. Marshall Jr. grew up in Nebraska and Missouri and studied geology at the University of Colorado at Boulder. Before he joined the young State government, Tom had been consulting for people interested in the oil potential of the Territory of Alaska.

The tools used in those days were rudimentary compared with what is available today. On one job Marshall used newly released U.S. Army aerial photographs to map oil and gas prospects on the Alaska Peninsula. The Canoe Bay prospect was identified and a well was permitted and drilled, though it was unsuccessful.

Marshall was then hired to advise clients on the first sale of federal leases planned in northern Alaska by the federal Bureau of Land Management (BLM), and this was his introduction to the North

Slope. The U.S. Navy had drilled exploration wells in what was then Naval Petroleum Reserve No. 4 and found only one small oil field and one small gas field. Both were uneconomic given the remote location, but they showed the region had potential. This 1958 BLM lease sale was the first time lands on the slope would be offered to private industry.

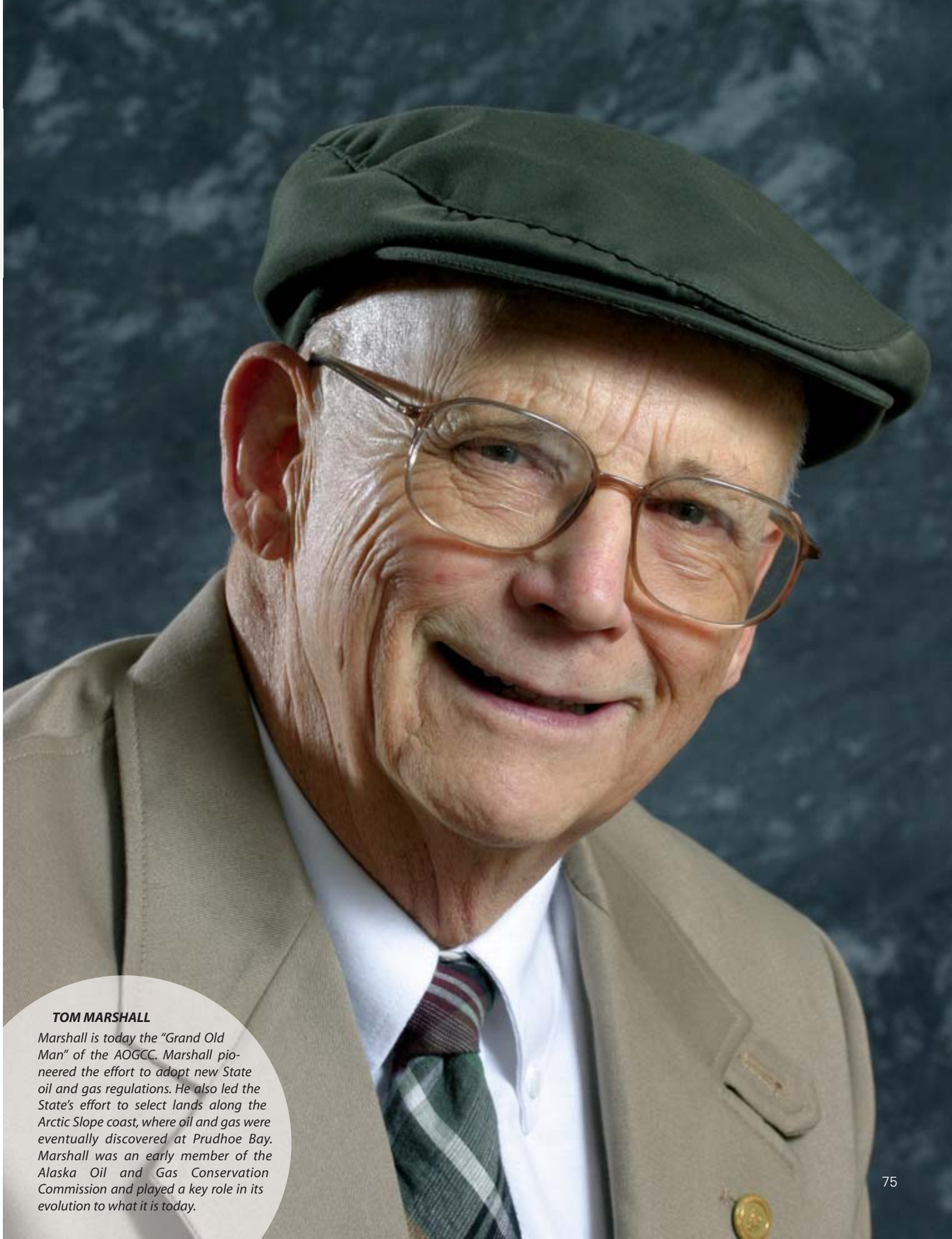
This work gave Marshall an opportunity to develop ideas on the regional geology that he was to use a few years later in recommending that the State select the Prudhoe Bay lands.

Just after Alaska became a state, Marshall signed on as a land selection officer with the newly organized State Department of Natural Resources. Its director, Roscoe Bell, asked Marshall to help the new State choose lands from the 103 million-acre land endowment the federal government had conferred

when the Alaska Statehood Act was passed.

At the time the Oil and Gas Conservation Committee consisted of James A. Williams, Director of the Division of Mines and Minerals, Richard V. Murphy, Petroleum Engineer, and Donald D. Bruce, Petroleum Geologist. Much of Alaska was classified as federal public domain lands managed by the BLM. Other areas were within the Tongass and Chugach National Forests, within parks, or withdrawn in other federal management areas. Congress, showing considerable foresight, felt Alaska needed to own lands and develop natural resources to support itself.

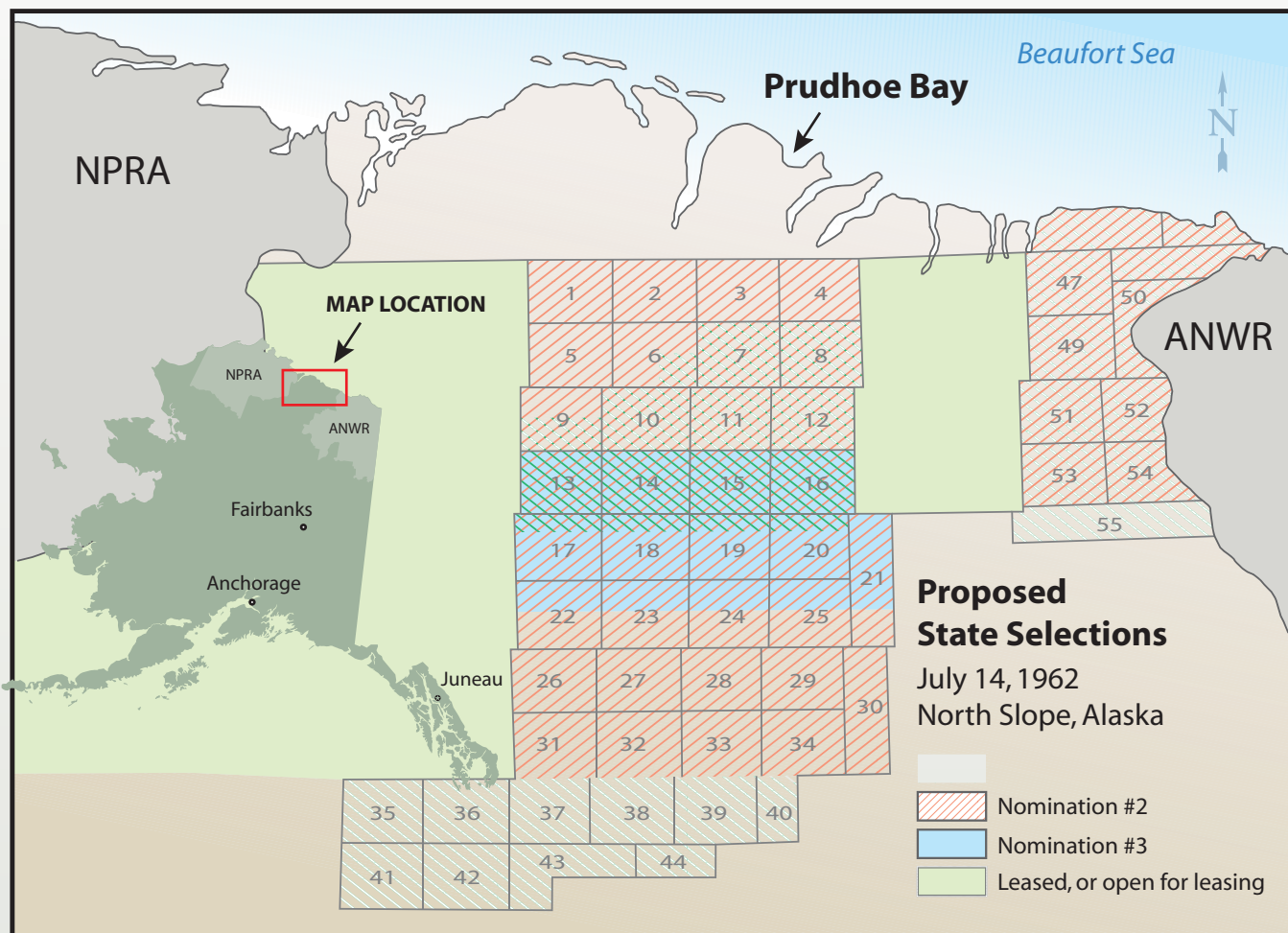
Alaska came within a whisker of losing out on its Prudhoe Bay land selections in the early 1960s. Had that happened ... the giant North Slope oil and gas fields would remained undiscovered.



TOM MARSHALL

Marshall is today the "Grand Old Man" of the AOGCC. Marshall pioneered the effort to adopt new State oil and gas regulations. He also led the State's effort to select lands along the Arctic Slope coast, where oil and gas were eventually discovered at Prudhoe Bay. Marshall was an early member of the Alaska Oil and Gas Conservation Commission and played a key role in its evolution to what it is today.

THE DISCOVERY OF PRUDHOE BAY...



STATE'S EARLY LAND PRIORITIES: The oil and gas industry initially gave priority to land selections further south on the North Slope, as this map developed by Tom Marshall indicates. Blocks indicated show the state's first nominations for selections. The state ultimately selected the coastal lands at the top of the map, however, and that enabled the discovery of the Prudhoe Bay field.

Alaskans were divided, however, on where to select lands and for what purposes, Marshall recalled. The selections had to be done carefully because the BLM had given the State a limit on how many acres it could select each year because of its own budgetary constraints, as the federal agency had to do the necessary surveys and title work.

The State initially selected multiple-use lands near settled communities and land with forestry and agricultural values as well as certain sub-Arctic sedimentary basins considered to have oil and gas potential. Selecting lands in the Arctic, termed at the time as "Arctic wasteland" was a much different story. With his background in oil and gas, Marshall argued in favor of selecting certain Arctic lands for their oil

potential only, and fortunately, some senior State officials like Phil Holdsworth, Alaska's first Commissioner of Natural Resources, shared his views.

Meanwhile, major oil companies like British Petroleum (BP), Sinclair and Richfield Oil had also become interested in the North Slope. BP thought the land formations of the northern Brooks Range looked a lot like Iran, where the company had considerable prior experience.

Roscoe Bell, the State's first lands director, realized that leasing land to the industry was critical to getting exploration underway and he and Phil Holdsworth did their best to convince Governor William Egan of the wisdom of selecting lands on the North Slope.

Historian Jack Roderick, in his book, *Crude Dreams*, a history of the Alaska oil industry, relates the story of a young state desperately needing money, but its Governor, Bill Egan, being highly skeptical about using the state's precious land entitlement to select oil lands.

Egan questioned why Alaska should use its entitlement on the North Slope since the State already received 90 percent of bonus payments and royalties on federally-leased lands, and the small 1 percent State production tax applied to oil production on federal as well as State and private lands also.

Bell and Marshall were also swimming upstream against a tide of criticism from the public and Legislature that the State would be wasting its land selection entitlement on the distant frozen and barren North Slope.

Marshall was criticized further when he went against most industry opinion in 1961 and recommended the State select lands along the Beaufort Sea coast. Marshall thought these had better potential than the Brooks Range foothills area favored then by the industry. The coastal selection recommendation became known as "Marshall's Folly", reminiscent of the derisive term applied to Interior Secretary William Seward's decision to buy Alaska from Russia in 1867.

Most geologists of the time didn't think the coastal lands had much potential. In fact, government geologists had rejected the Prudhoe Bay area in the 1920s for inclusion in the Naval Petroleum Reserve No. 4. It was also rejected, in the 1950s, for inclusion in the Arctic National Wildlife Range, later to become a federal refuge. When the BLM conducted an advisory poll on which lands to offer in a 1958 lease sale, the industry

recommended the BLM offer tracts south of the coast in what is now called the Brooks Range foothills. The BLM received no industry nominations for the coastal area in its preparation for the 1958 lease sale.

In 1962, when the new State government polled the industry on where it should select lands, the companies again recommended acreage on the southern North Slope.

Marshall, then wearing two hats, conservation committee geologist and the State's land selection advisor, understood the industry's position. "This was a logical and safe way to explore, proceeding from the known to the unknown in a province," he said. The small oil discovery had been made at Umiat and a small gas discovery had been made at Gubik, several miles to the east. Oil explorers like to start looking for new oil and gas near where petroleum has been previously found

and the North Slope was a remote, unknown area. The industry was being cautious, Marshall said.

Marshall was cautious too but he came to realize that any discovery on the Slope, to be economic, had to be huge. He had been asked for his opinion on how gas found at the small Gubik discovery could be marketed. When Marshall considered the costs of building a pipeline to Fairbanks, the closest market, he realized that only a very large oil and gas discovery could pay its way.

Looking north, Marshall thought the broad coastal area of the slope looked similar to basins in Wyoming where he had worked before coming to Alaska. He based his judgment on the thick sedimentary rock formations that cropped out on the eastern North Slope and surfaced again in the western and southern areas of the Slope.

**In 1962, when the new State government
polled the industry on where it should select
lands, the companies again recommended
acreage on the southern North Slope.**

THE DISCOVERY OF PRUDHOE BAY...

It was a sheer quirk that caused Marshall's superiors to change their minds and drop the pending State selection in the foothills in favor of the coastal lands ...

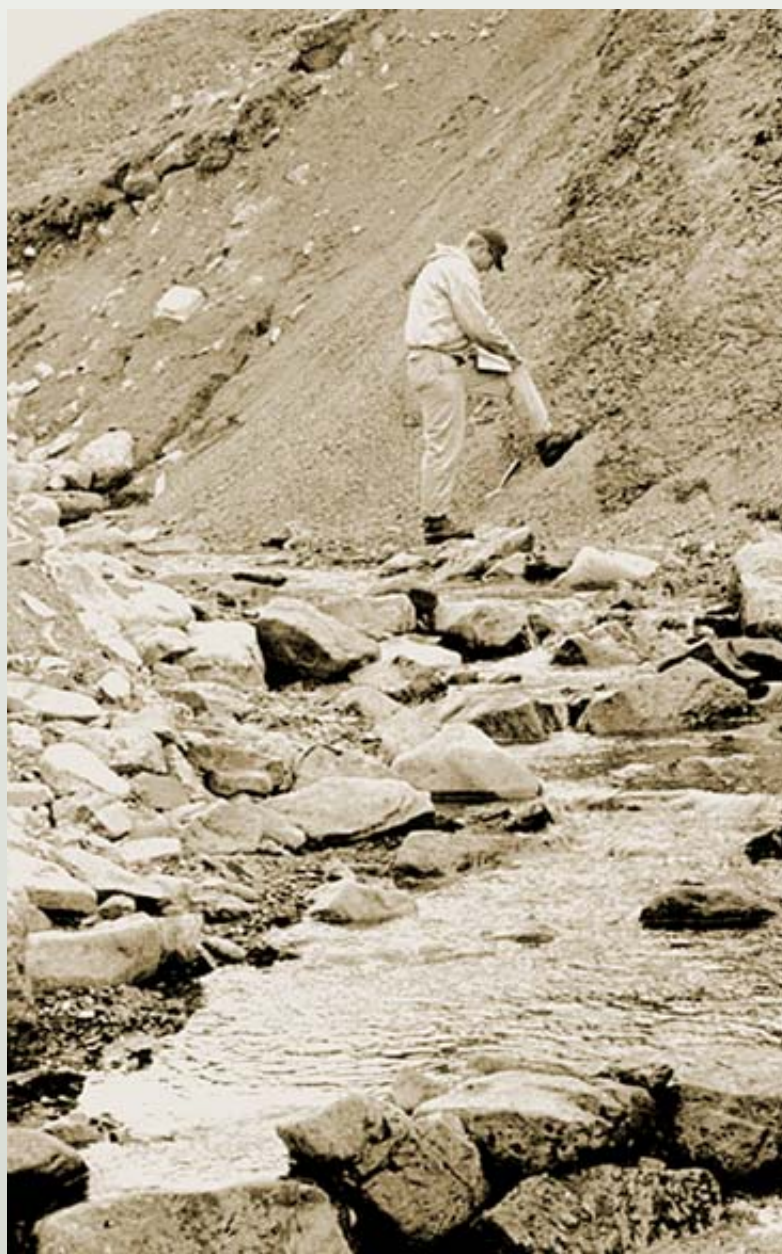
Marshall could see that these rocks had very good oil potential, and he believed they would also underlie a wide swath of lands across the central North Slope and rise to a depth where a drill rig could reach them near the coast along a regional structure geologists call the Barrow Arch.

This was just a geologist's hunch, however, because there were no oil seeps or other indications of petroleum in the region. State leaders didn't take Marshall's advice at the time, in any event. Initially the Division of Lands recommended following the industry advice and using its selection entitlement on the southern foothills area.

Egan still opposed even the selection in the foothills, however, and so the State's selection application for this area was never filed. This was a stroke of luck, as it turned out. Had the selection been filed the state would have used up this portion of its entitlement and any subsequent selection further north would have been delayed.

It was a sheer quirk that caused Marshall's superiors to change their minds and drop the pending State selection in the foothills in favor of the coastal lands, and that caused Governor Egan finally to agree to the selection.

As Roderick writes in *Crude Dreams*, federal officials in 1963 raised a problem of determining the mean high tide along Alaska's shallow northern coast. The State owned the submerged lands from the mean high tide line out to the State territorial limit three miles sea-



Photos: Top, foxes are a common sight on the Slope; Bottom, geologist takes notes on a geologic structure during 1960s field work, North Slope.

ward, but along the marshy, shallow coast itself determining just where the mean high tide line was located would have been a huge chore. Also the BLM would have had to figure out which of the thousands of shallow coastal lakes and streams were navigable, as the lands beneath these would belong to the State also. The BLM also preferred the State to select in large rectangles.

It seemed an impossible task. Bell and Marshall had a solution, however. If the State selected a strip of land along the coast, they argued, it would own the coastal lands and the BLM wouldn't have to determine the mean high tide line or the navigability of streams and lakes.

Acting on Marshall's recommendation, Bell and Natural Resources Commissioner Phil Holdsworth convinced Governor Egan to agree to the plan, and in early 1964 the State filed its first North Slope land selection covering 1.59 million acres of lands along the coast.

Meanwhile, industry was becoming more interested in the coastal region. In 1963 and 1964 BP and Sinclair drilled 6 dry holes on federal lands to the south and determined the area had less potential than first believed. They then turned their attention north. Seismic surveys on the coastal lands showed the region was more prospective than they had first believed.

Richfield Oil also had geologic field parties on the slope, and its lead geologist, Gil Mull, found intriguing rock outcrops that led him to conclusions similar to Marshall's. Richfield was a medium-sized company at the time and it had forged a partnership with Humble Oil (later ExxonMobil) to help finance the costly North Slope exploration.

The State held its first lease sale in the coastal selection area in 1964, on lands west of Prudhoe Bay. BP, Sinclair, Richfield and Humble, as well as Union Oil, acquired acreage and made plans to explore. Although the geologic outline of what was later to be the Prudhoe Bay field had been identified on seismic surveys the companies gave a higher priority to other structures located to the west. They decided to drill those first.

BP and Sinclair drilled a well near the Colville River, but it was a dry hole. Union Oil drilled a well in the same region, also unsuccessful.

The story from this point on is well known. After this string of dry holes the companies were discouraged and questioned whether any commercial oil field would ever be discovered on Alaska's North Slope. BP and Sinclair more or less gave up and "stacked" the rig they had used near the Colville River to await shipment out of Alaska.

The State was holding another lease sale in 1965, however, and offered lands in the Prudhoe Bay

area. BP wanted to bid but Sinclair declined. Its management had become discouraged about the North Slope, so the British company bid alone.

Richfield and Humble were also interested in the lease sale. All the companies had done seismic surveys across the lease sale area and could make out the outlines of a large underground rock structure, although no one knew if the structure held oil.

BP, bidding alone, worried that it would be outbid by the Richfield-Humble partnership and pursued a strategy of bidding for leases across the entire structure but with an emphasis on the flanks, where it not only believed the competition from other bidders would be less but that there might be more oil.

In 1963 and 1964 BP and Sinclair drilled 6 dry holes on Federal lands to the south and determined the area had less potential than first believed. They then turned their attention north.



THE DISCOVERY OF PRUDHOE BAY...

There was significant competition at the 1964 Prudhoe Bay sale. Chevron and Shell bid in partnership, as well as Mobil and Phillips. Richfield and Humble acquired most of the leases on the crest of the structure while BP picked up leases along the flanks.

There wasn't a great urgency to drill the newly acquired Prudhoe leases, however. BP's rig remained "stacked" near the Colville River. Richfield and Humble were paying attention to what they thought were better prospects to the south.

In 1966 Richfield had merged with Atlantic Refining Co. and the new company, ARCO, along with Humble, drilled the Susie Unit No. 1 well, a costly, but disappointing, well in the White Hills region of the southern slope. Thirteen straight dry holes had now been drilled on the North Slope.

There are several tales about what happened next, after the Susie well came in dry. One story is that the newly-merged ARCO and its partner, Humble, were ready to throw in the towel, too, but that managements of the companies were willing to give their field staffs authorization for one more well. There was considerable debate within the companies, however, on whether another prospect on the southern Slope should be drilled, or the new leases at Prudhoe Bay. There were also people within the two companies who questioned whether more money should be spent at all on the North Slope given the long string of dry holes that had been drilled.

Prudhoe won out partly because the logistics were cheaper, according to the story. The companies planned to take the rig off the Slope by barge and had to move it to the coast. On the way to the coast the drillers were authorized to make one last try at Prudhoe Bay.

Photos: Top, helicopter drops off a geologist during 1960s summer field work on the North Slope; Middle, a geologists' camp in the northern Brooks Range; Bottom, tractors similar to those used in early North Slope exploration.

In *Crude Dreams*, Roderick wrote that ARCO chairman Robert O. Anderson acknowledged to him that there was debate within the company about whether to drill the Prudhoe well. “If the Prudhoe well had been dry, we were going home. It was our last shot.”

One problem the companies faced at Prudhoe, however, was that there was unleased acreage near where they wanted to drill, and the companies wanted the State to conduct another lease sale so that the prospect area would be fully leased. The companies were worried that having unleased acreage in the immediate area of the well would give ammunition to those within their organizations who wanted the money spent elsewhere.

The State Department of Natural Resources staff, which then included the Oil and Gas Conservation Committee, supported having another lease sale at Prudhoe Bay. Pedro Denton, chief of the Division of Lands minerals section at the time, spent a lot of time working to persuade Governor Egan. Egan, however, was reluctant to offer the acreage because the Inuit Eskimo people in the region were protesting the state’s leasing of lands to the industry, and were hoping to see their Native land claims resolved (this finally happened in 1971).

However, Egan lost his 1966 bid for reelection and Walter Hickel was elected governor. Denton briefed Hickel on the situation and found him more supportive of an additional Prudhoe lease sale to offer the adjacent lands. The sale was held in 1967.

What happened next, of course, is history. The newly merged ARCO, the operator of the discovery well, began drilling in spring, 1967, suspended the well for the summer and resumed work in November. That winter the well came in as a big gas find. But there was oil, too, and a second well was planned 7 miles to the Southeast. It

was when the second well, the Sag River No. 1, hit 400 feet of oil-saturated sandstone that the companies knew they had a big discovery.

The new find sent BP rushing to line up a rig, because the rig it had previously used had been taken by ARCO and Humble to drill the second Prudhoe well. In 1969 BP drilled on its Prudhoe Bay leases, and found more oil.

Marshall wasn’t surprised oil had been found along the North Slope coast, but he was flabbergasted by the size of the discovery, and particularly the rocks it had been found in.

Marshall and other geologists had thought the North Slope’s big oil find would be in the Lisburne limestone rock formation that underlies the coastal plain. It was the slightly-shallower Sadlerochit sandstone, however,

that contained the huge Prudhoe reservoir, a big surprise.

The Lisburne did contain some oil, but nothing like what was in the Sadlerochit. Marshall did-

n’t think the Sadlerochit had potential because where it outcrops to the east in what is now the Arctic National Wildlife Refuge, the formation did not appear to be good reservoir rock.

On September 10, 1969, the state held its last and biggest Prudhoe Bay-area lease sale. It was after the discovery had been announced and interest in the industry had climbed to a fever pitch. The acreage offered, however, was out on the fringes of the oil-filled underground reservoir, although most of the bidders did not know that. The bids were sky-high for those days. Nine hundred million dollars were paid in bonus bids to the State treasury, an amount that electrified Alaskans. It is an irony that most of the acreage sold in the 1969 sale ultimately turned up dry.

**“If the Prudhoe well had been dry,
we were going home. It was our last shot.”**

*Former ARCO chairman Robert O. Anderson,
from “Crude Dreams” by Jack Roderick.*

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Jody Colombie
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STAFF



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Howard Okland
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Steve McMains
Statistical Technician



Bob Fleckenstein
Statistical Technician



Linda Laasch
Administrative Assistant



Christine Shartzler
Natural Resources Technician



Chasity Smith
Administrative Clerk

INSPECTORS



Lou Grimaldi
Inspector



Chuck Scheve
Inspector



Jeff Jones
Inspector



Bob Noble
Inspector



John Crisp
Inspector



APPENDICES

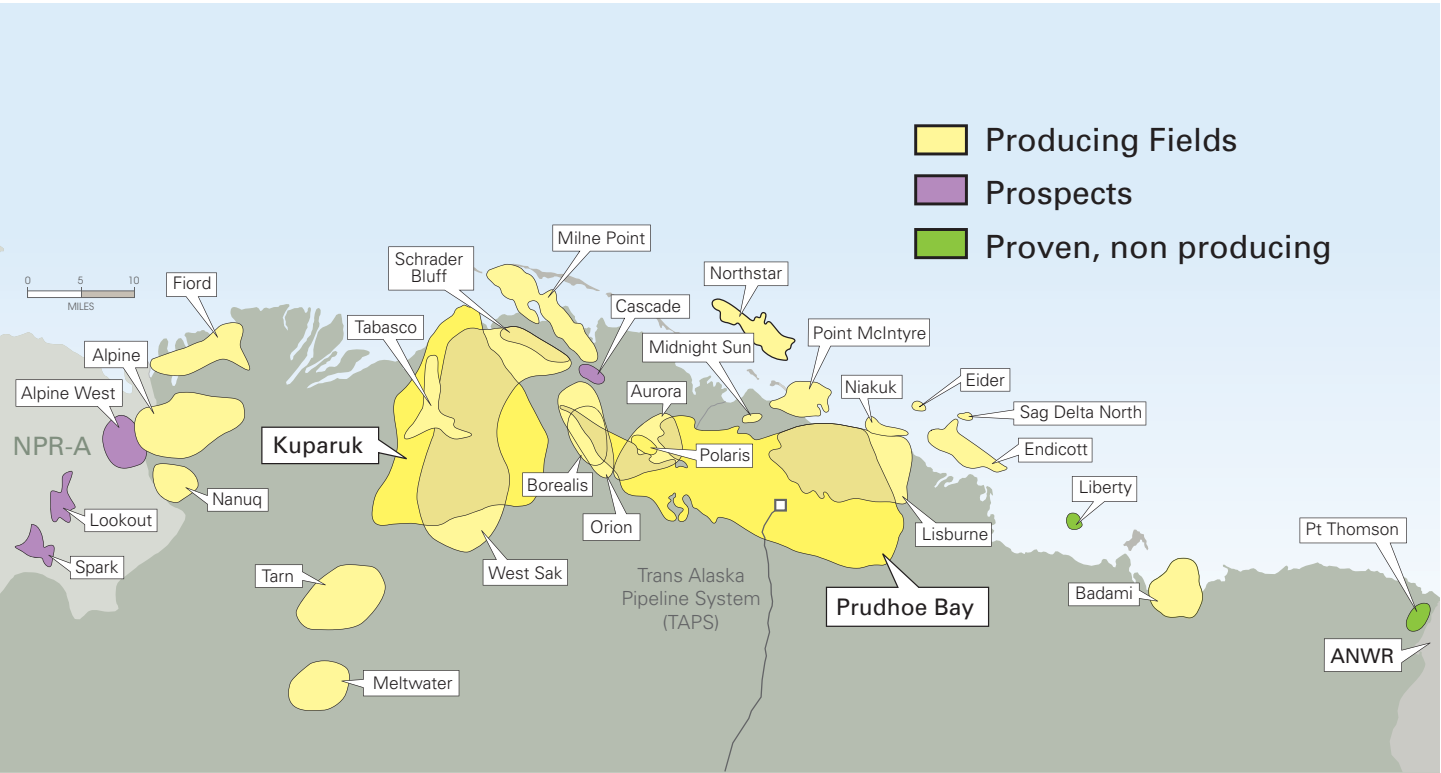
- A** Map of Alaska's Sedimentary Basins
- B** North Slope Map
- C** Cook Inlet Basin Map
- D** Major Oil and Gas Fields
- E** Oil and Gas Well Statistics
- F** Alaska Oil and Gas Production
- G** Average ANS Price of Oil By Year
- H** AOGCC Commissioners
- I** AOGCC Professional Staff
- J** Significant Commission Orders and Decisions
- K** Additional Sources of Information
- L** Alaska's Governors

APPENDIX A - Alaska's Sedimentary Basins



Source: State of Alaska, Division of Oil & Gas

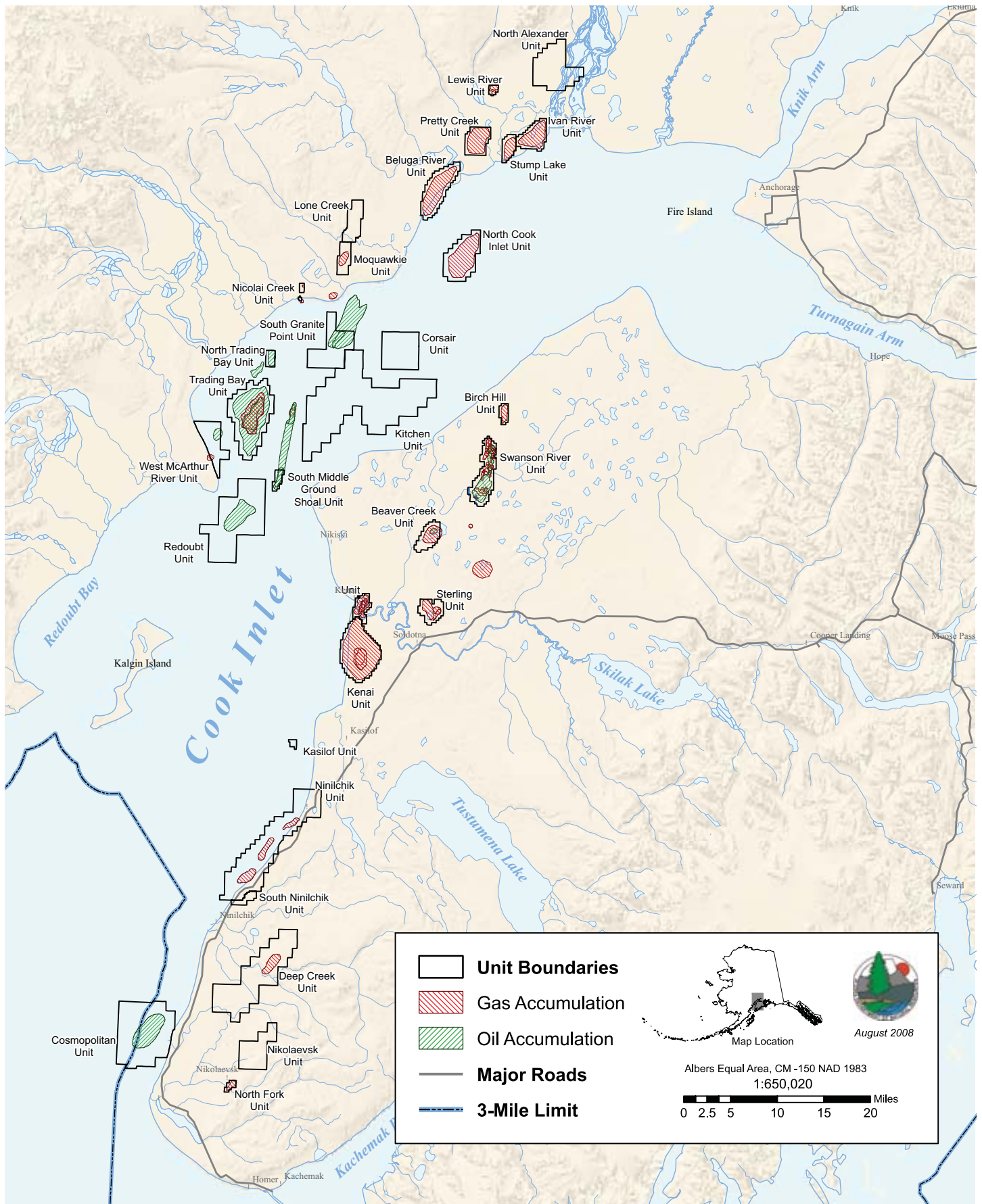
APPENDIX B - North Slope Fields Map



Source: State of Alaska, Division of Oil & Gas



APPENDIX C - Cook Inlet Basin Map



APPENDIX D - Major Oil and Gas Fields (developed or in development)

Unit or Field	Type	Location	Year Discovered	Cumulative Production through 6/08		Remaining Reserves ¹	
				Oil ² MMB	Net Gas ³ BCF	Oil ² MMB	Gas BCF
Barrow	Gas	North Slope	1949	-	49	-	32
Swanson River	Oil/ Gas	Cook Inlet	1957	230	280	1	6
Cannery Loop	Gas	Cook Inlet	1959	-	163	-	26
Kenai	Gas	Cook Inlet	1959	-	2,346	-	112
West Fork	Gas	Cook Inlet	1960	-	6	-	0
Ninilchik	Gas	Cook Inlet	1961	-	34	-	109
Sterling	Gas	Cook Inlet	1961	-	11	-	4
Ivan River, Lewis River, Pretty Creek, Stump Lake ⁴	Gas	Cook Inlet	1961 (Stump Lake)	-	106	-	4
Beluga River	Gas	Cook Inlet	1962	-	1,086	-	461
Middle Ground Shoal	Oil/ Gas	Cook Inlet	1962	196	110	17	5
North Cook Inlet	Gas	Cook Inlet	1962	-	1,802	-	269
West Foreland	Gas	Cook Inlet	1962	-	10	-	4
Granite Point	Oil/ Gas	Cook Inlet	1965	146	131	19	10
McArthur River	Oil/ Gas	Cook Inlet	1965	637	1,344	19	103
Trading Bay	Oil/ Gas	Cook Inlet	1965	103	78	4	2
Nicolai Creek	Gas	Cook Inlet	1966	-	2	-	7
Albert Kaloa	Gas	Cook Inlet	1968	-	3	-	1
Lone Creek, Moquawkie ⁴	Gas	Cook Inlet	1968	-	10	-	1
Prudhoe Bay	Oil	North Slope	1968	12,362	5,254	2,776	24,500
Redoubt Shoal	Oil/ Gas	Cook Inlet	1968	2	1	4	1
Kuparuk River	Oil	North Slope	1969	2,286	538	1,171	1,150
Milne Point	Oil	North Slope	1969	268	54	312	13
Beaver Creek	Oil/ Gas	Cook Inlet	1972	6	199	1	18
Endicott	Oil	North Slope	1978	456	271	114	843
Northstar	Oil	North Slope	1984	78	450	206	450
Badami	Oil	North Slope	1990	5	0	2	8
W McArthur River	Oil/ Gas	Cook Inlet	1991	12	5	4	0
Colville River	Oil	North Slope	1994	295	43	389	400
Wolf Lake	Gas	Cook Inlet	1998	-	1	-	0
Deep Creek	Gas	Cook Inlet	2003	-	11	-	6
Hansen	Oil/ Gas	Cook Inlet	2003	6	0	-	-
Kustatan	Gas	Cook Inlet	2003	-	0	-	0
Oooguruk	Oil	North Slope	2003	0	0	49-110 ⁵	-
Kasilof	Gas	Cook Inlet	2004	-	3	-	21
Three Mile Creek	Gas	Cook Inlet	2005	-	2	-	1

(1) Except as otherwise noted, remaining reserves based upon DOG 2006 Annual Report, adjusted for sales in 2007 and 2008.

(2) Includes NGLs

(3) Net Gas = Produced-Injected. Includes sales, fuel, flare

(4) Fields combined

(5) AOGCC Conservation Orders 596 and 597

Source: AOGCC Database
June 2008

APPENDIX E - Alaska Oil and Gas Statistics

- **First well drilled in Alaska:**
Katalla, Alaska, 1898
- **Average daily oil production per well in Alaska as of December 31, 2007:**
408 bbls/day.
- **Number of stripper wells in Alaska producing less than ten bbls/day:**
Zero
- **Most prolific well in Alaska:**
Prudhoe Bay Unit J-06. Cumulative production April 1, 1988 to October 1, 2008 was 56,701,272 bbls of oil.
- **Deepest onshore well drilled in Alaska (true vertical depth):**
Tunalik#1 Well, SW NPR-A, 20, 211'TVD.
- **Deepest offshore well drilled in Alaska (true vertical depth):**
Cook Inlet N. Foreland St. No. 1 Well, 17,756'TVD.
- **First multilateral well completed in Alaska:**
A33-IILS, completed March, 1994.
- **Greatest lateral deviation (departure) in a well:**
Colville River Unit CD4-07: 21,052' horizontal offset between surface and bottom hole location.
- **Well with greatest measured depth:**
The Colville River Unit CD4-07: 25,040'.
- **Total number of Alaska wells drilled since 1955*:**
6,813
- **Years that Alaska has been the nation's No. 2 oil-producing state:** 29
- **Portion of the nation's domestic oil production that comes from Alaska:** 15%
- **Portion of Alaska's oil production that comes from fields other than Prudhoe Bay:** 53%
- **Number of the country's 100 largest oil fields that are in Alaska:** 14

* Includes multi-lateral well-bores.

Source: AOGCC and historical records and Anchorage Daily News of 8/15/2008

APPENDIX F - Alaska Oil and Gas Production*

Year	Daily Total BOE	Annual Total BOE
1959	584	213,077
1960	1,665	609,556
1961	18,100	6,606,570
1962	29,703	10,841,491
1963	31,499	11,497,141
1964	33,159	12,136,164
1965	34,013	12,414,679
1966	45,239	16,512,143
1967	90,687	33,100,906
1968	199,881	73,156,586
1969	240,859	87,913,571
1970	297,601	108,624,436
1971	289,569	105,692,645
1972	270,887	99,144,666
1973	266,149	97,144,448
1974	266,672	97,335,230
1975	271,641	99,148,925
1976	257,680	94,310,732
1977	558,267	203,767,455
1978	1,327,786	484,641,918
1979	1,507,088	550,087,132
1980	1,723,672	630,863,999
1981	1,724,734	629,528,071
1982	1,817,990	663,566,286
1983	1,845,062	673,447,633
1984	1,861,304	681,237,249
1985	1,979,120	722,378,939
1986	2,015,541	735,672,302
1987	2,170,936	792,391,478
1988	2,258,211	826,505,223
1989	2,111,871	770,832,985
1990	2,012,031	734,391,393
1991	2,065,618	753,950,735
1992	1,992,118	729,115,298
1993	1,865,113	680,766,417
1994	1,843,922	673,031,628
1995	1,788,973	652,975,191
1996	1,709,693	625,747,757
1997	1,611,050	588,033,304
1998	1,486,483	542,566,269
1999	1,351,163	493,174,503
2000	1,276,044	467,032,081
2001	1,272,723	464,543,923
2002	1,280,140	467,251,192
2003	1,265,452	461,890,138
2004	1,202,993	440,295,621
2005	1,155,499	421,757,274
2006	1,005,905	367,155,464
2007	985,474	359,697,996
2008	911,335	221,454,460 (ytd)
Total		19,476,154,274

* BOE is Barrels of Oil Equivalent and includes natural gas converted to BOE at 6,000 cubic feet gas = 1 BBL oil.

Source: AOGCC Production Database through August 31, 2008

APPENDIX G - Average ANS Price of Oil by Year

Historical ANS Spot Price \$ per barrel

FY	Nominal	Real 2008\$
• 1981	\$34.92	\$87.74
• 1982	\$32.04	\$73.48
• 1983	\$30.31	\$64.93
• 1984	\$29.26	\$61.10
• 1985	\$27.89	\$55.88
• 1986	\$22.03	\$42.54
• 1987	\$17.28	\$32.79
• 1988	\$16.12	\$29.48
• 1989	\$14.61	\$25.73
• 1990	\$17.22	\$28.84
• 1991	\$21.57	\$34.50
• 1992	\$16.64	\$25.42
• 1993	\$17.83	\$26.42
• 1994	\$14.05	\$20.22
• 1995	\$16.76	\$23.54
• 1996	\$17.74	\$24.18
• 1997	\$20.90	\$27.71
• 1998	\$15.86	\$20.56
• 1999	\$12.64	\$16.11
• 2000	\$23.27	\$29.09
• 2001	\$27.86	\$33.57
• 2002	\$21.78	\$25.43
• 2003	\$28.16	\$32.52
• 2004	\$31.74	\$35.90
• 2005	\$43.44	\$47.58
• 2006	\$60.80	\$64.95
• 2007	\$61.67	\$63.15
• 2008*	\$94.40	\$94.40

27-year ANS West Coast Average

\$28.17 \$40.99

Key Assumptions: January 1981- April 1987 are ANS Gulf Coast; May 1987- April 1996 are a weighted average of ANS Gulf and ANS West Coast; May 1996-present are ANS West Coast.

**2008 is estimated based on current annual CPI inflation rate from the Bureau of Labor Statistics (May 2007-May 2008)*

Source: Tax division SOA, DOR. 555 W. 7th Ave, Suite 500, Anchorage

APPENDIX H - List of AOGCC Commissioners*

Petroleum Engineering Commissioners

• Richard V. Murphy	1959 – 1962
• K. Davison	1962 – 1963
• Karl VonderAhe	1963 – 1968
• O.K. "Easy" Gilbreth, Jr.	1968 – 1978
• Hoyle H. Hamilton	1977 – 1981
• C.V. "Chat" Chatterton	1982 – 1990
• Russell A. Douglass	1990 – 1995
• J. David Norton	1995 – 1996
• Robert Christenson	1997 – 2000
• Julie Heusser	2000 – 2002
• Mike Bill	2002 – 2003
• Randy Ruedrich	2003 – 2003
• Cathy Foerster	2005 - Present

Geologist Commissioners

• Donald D. Bruce	1959 – 1962
• Thomas R. Marshall, Jr.	1962 – 1978
• Harry W. Kugler	1979 – 1986
• William W. Barnwell	1986 – 1988
• David W. Johnston	1989 – 2000
• Daniel T. Seamount, Jr.	2000 – Present

Public Members

• Phil R. Holdsworth	1955 – 1963
• James A. Williams	1959 – 1969
• Charles F. Herbert	1964 – 1967, 1970 – 1973
• Dale Wallington	1967 – 1969
• Homer L. Burrell	1969 – 1973
• Lonnie C. Smith	1979 – 1992
• Leigh Griffin	1992 – 1993
• Tuckerman Babcock	1993 – 1996
• Mary Marshburn	1997 – 1997
• Camille Oechsli Taylor	1997 – 2003
• Sarah Palin	2003 – 2004
• John K. Norman	2004 – Present

** Between 1959 and 1979 the "Commission" was called the "Committee"*

APPENDIX I - AOGCC Professional Staff

Petroleum Engineers

• O.K. "Easy" Gilbreth, Jr.	1966 - 1968
• Lonnie C. Smith	1969 - 1978
• John C. Miller	1970 - 1978
• Blair Wondzell	1974 - 2001
• Russell Douglass	1976 - 1990
• Joesph Green	1977 - 1979
• James K. Trimble	1979 - 1985
• Harold Hedlund	1982 - 1987
• Michael Minder	1982 - 1993
• John D. Hartz	1990 - 2005
• Tom Maunder	1999 - Present
• Winton Aubert	2001 - 2006
• Jane Williamson	2001 - Present
• Jim Regg	2002 - Present
• David Roby	2005 - Present

Geologists

• Harry Kugler	1967 - 1978
• John Levorsen	1970 - 1986
• William Van Alen	1978 - 1987
• Robert Crandall	1988 - 2006
• Steve Davies	1999 - Present
• Art Saltmarsh	2006 - Present

AOGCC Legal Counsel (Department of Law)

• Joseph Rudd, Esq.	1960 - 1961
• Richard Bradley, Esq.	1961 - 1963
• Ralph G. Crews, Esq.	1965 - 1967
• Robert L. Hartig, Esq.	1967 - 1970
• John K. Norman, Esq.	1970 - 1971
• John Reeder, Esq.	1972 - 1974
• Jeff B. Lowenfels, Esq.	1974 - 1978
• Michael Arruda, Esq.	1979 - 1982
• Ann Prezyna, Esq.	1981 - 1986
• Mark Worcester, Esq.	1986 - 1990
• Robert E. Mintz, Esq.	1990 - 2005
• Cammy Oechsli Taylor, Esq.	2006 - 2007
• Alan Birnbaum, Esq.	2007 - Present

Blowouts on wells in Alaska, 1949-2008:

North Slope:

- Simpson Core Test No. 16 in 1949 at Cape Simpson: occurred while drilling an exploration well (gas to surface);
- Simpson Core Test No. 26 in 1950 at Cape Simpson: occurred while drilling an exploration well (oil to surface);
- Gubik No. 2 in 1951 near Umiat: occurred while drilling an exploration well (gas to surface);
- Kavik No. 1 in 1969, near the Canning River on the eastern North Slope: occurred while drilling an exploration well (gas to surface);
- NGI-7 in 1976, Prudhoe Bay: occurred while working over a development well (gas to surface);
- CPF1-23 in 1979, Kuparuk River: occurred while drilling a disposal well (gas to surface);
- F-20 in 1986, Prudhoe Bay: occurred while drilling a development well (gas to surface);
- J-23 in 1987, Prudhoe Bay: occurred while completing a development well (gas to surface);
- Cirque No. 1 in 1992, central North Slope: occurred while drilling an exploration well (gas to surface); and
- I-53/Q-20 in 1994, Endicott: occurred while drilling a development well (gas to surface).

Cook Inlet:

- Beluga River 212-35 in 1962, onshore west side of Cook Inlet, development well (gas to surface);
- MGS State 17595 No. 1 in 1962 at Middle Ground Shoal in Cook Inlet, exploration well (gas to surface);
- Cook Inlet State No. 1 in 1962 in Cook Inlet, exploration well (gas to surface);
- Mobil Moquawkie No. 1 in 1965 onshore west side of Cook Inlet, exploration well (gas to surface);
- Beaver Creek unit 1-A in 1967 on the Kenai Peninsula, development well (gas to surface);
- Trading Bay unit G-10RD in 1985 on the Grayling platform in Cook Inlet, development well (gas to surface);
- Trading Bay unit M-26 in 1987 on the Steelhead platform in Cook Inlet, development well (gas to surface); and
- Moquawkie No. 4 in 2008 onshore west side of Cook Inlet, development gas well (gas to surface).

*Source: Compiled from records of
Alaska Oil and Gas Conservation Commission
Courtesy: Petroleum News*

APPENDIX J - Significant Orders and Decisions

Description	Type	Order Number	Effective Date	Affected Pools	Affected Fields
AOGCC is organized pursuant to the Conservation Act- Adoption of Regulations.	CO ¹	1	10/1/58	ALL Pools	N/A
First Decision on producing fields in Alaska- Spacing exception, Well - Kenai Unit #14-6. After a public hearing and an emergency order.	CO	2	4/30/59	*No Pool*	KENAI CANNERY LOOP UNIT
Original Spacing exception, spacing rules, and gas injection rules for Swanson River Field, FIRST OIL FIELD IN ALASKA RESULTS IN STATEHOOD.	CO	4, 5, & 9	4/4/1960 5/11/1962	HEMLOCK OIL	SWANSON RIVER
First oil well decision in offshore Cook Inlet- Spacing exception, Well - Granite Pt State 17587 #3.	CO	36	3/10/67	*No Pool*	GRANITE PT
Defines Pool and spacing rules for Trading Bay Field, Pool rules for MGS Oil Pools A, B, C, D, E, F & G Field Rules and Fluid Injection for Granite Point Field.	CO	41, 44, 57, 59, & 60	6/5/1967 to 2/23/1968	VARIOUS	OFFSHORE COOK INLET
First offshore Cook Inlet gas field, major discussion prior to CO 391- Cluster spacing. Tertiary System Gas Pool	CO	40	6/8/67	*No Pool*	NORTH COOK INLET
Pool rules for McArthur River Middle Kenai Gas Pool, McArthur Riv Middle Kenai "G", Hemlock & West Forelands Oil Pools.	CO	80	9/30/69	VARIOUS POOLS	MCARTHUR RIVER
First Prudhoe Bay pool rules, largest oil field in the U.S.	CO	83	1/12/70	PRUDHOE OIL	PRUDHOE BAY
Orders halted wasteful flaring of gas in Offshore Cook Inlet Oil Fields	CO	102, 103, 104, & 105	6/30/71	ALL OIL POOLS	OFFSHORE COOK INLET OIL FIELDS
First Cook Inlet offshore EOR- Water injection authorized in Trading Bay "G" NE & Hemlock NE Oil Pools for the purpose of pressure maintenance.	CO	108	11/18/71	G-NE/HEMLOCK-NE OIL	TRADING BAY
Pool rules revised for Prudhoe Oil Pool, Prudhoe Bay Kuparuk River Oil Pool, and Prudhoe Bay Lisburne Oil Pool. Amends rules 3 and 4 of COs 098A, 098B, 083C.	CO	137	1/9/76	PRUDHOE OIL	PRUDHOE BAY
Pool rules (new) & amending existing rules for Prudhoe Oil Pool. Portions of CO 98B and 137 are made part of this order. Established 2.7 BCFD offtake rate (Rule 9).	CO	145	6/1/77	PRUDHOE OIL	PRUDHOE BAY
Denial of Burglin petitions for compulsory unitization in Ivan River and Beluga Units. (Subsequent order 12/16/85 after remand and remand of 10/14/92 decision).	CO	149 & 150	6/12/80	*No Pool*	IVAN RIVER FIELD
Pool Rules for the development of the Kuparuk River Field, 2nd biggest oil field in the U.S., Kuparuk Riv Oil Pool and the Prudhoe Bay Field, Kuparuk Riv Oil Pool.	CO	173	5/6/81	KUPARUK RIVER OIL	KUPARUK & PRUDHOE BAY FIELDS
Approval of Prudhoe Bay Miscible Gas Project as a Qualified Tertiary Recovery Project for Crude Oil Windfall Profit Tax of 1980.	CO	195	3/5/84	PRUDHOE OIL	PRUDHOE BAY
Approve full-field waterflood project for Kuparuk River Oil Pool.	CO	198	6/14/84	KUPARUK RIVER OIL	KUPARUK RIVER
Pool rules for the Endicott Oil Pool.	CO	202	9/20/84	ENDICOTT OIL	ENDICOTT
Approves waterflood project for MPU Kuparuk River Oil Pool & Field.	CO	205	10/9/84	KUPARUK RIVER OIL	MILNE POINT
First AIO's in Alaska after gaining primacy over Class II wells from the U.S. Environmental Protection Agency in 1986- authorizations of underground injection for enhanced recovery and for disposal of oil field wastes for Endicott, Kuparuk River, Prudhoe Bay, & Milne Point Oil fields.	AIO ²	1, 2, 3, & 10	5/30/1986 through 9/18/1986	ENDICOTT, KUPARUK RIVER, PRUDHOE, and SCHRADER BLUFF OIL POOLS	ENDICOTT, KUPARUK RIVER, PRUDHOE and MILNE POINT
First authorizations in Cook Inlet of underground injection of fluids for enhanced recovery and disposal for McArthur River Field, Granite Point Field, the Northern and southern portions of MGS Field developed by Baker and Dillon Platforms, and Trading Bay Field, developed by the Monopad Platform.	AIO	5, 6, 7, 8, 9, 11, & 12	9/4/1986 to 11/29/1986	VARIOUS POOLS	COOK INLET OFFSHORE
Approves immiscible Water Alternating Gas Injection ops at DS 2F, 2G, 2U.	CO	198	10/10/86	KUPARUK RIVER OIL	KUPARUK RIVER
First Disposal Injection Order in Alaska after gaining primacy over Class II wells from the U.S. Environmental Protection Agency in 1986 - Authorizes underground injection for disposal of non-hazardous oil field wastes in Kenai Unit WD-1.	DIO ³	1	2/18/87	*No Pool*	KENAI CANNERY LOOP UNIT
Authorizes underground injection for purposes of enhanced recovery and disposal of fluids in Swanson River Field.	AIO	13	3/16/87	*No Pool*	SWANSON RIVER
Approval of enriched Gas EOR project.	CO	198	6/3/87	KUPARUK RIVER OIL POOL	KUPARUK RIVER
Historical Kick Well (ANWR) Litigation Arctic Slope Regional Corporation et al. vs. SOA, et al 3AN-88-4357 CI.	OTH ⁴	23	7/13/92	*No Pool*	N/A

Description	Type	Order Number	Effective Date	Affected Pools	Affected Fields
Pool rules established for Point McIntyre & Stump Island Oil Pools.	CO	317	7/2/93	PM STUMP ISLAND OIL	PRUDHOE BAY
Consolidation of numerous individual conservation orders affecting the Prudhoe Bay Field, Prudhoe Oil Pool into one order.	CO	341	11/2/94	PRUDHOE OIL	PRUDHOE BAY
Permit commingling of production from Middle Kenai "G" Hemlock/W Foreland/undefined Jurassic Oil Pools, in TBU M-32 wellbore.	CO	350	12/23/94	*No Pool*	MCARTHUR RIVER
First attempted Coal Bed Methane development in Alaska- Establishes pool rules for the development of the Houston Coalbed Gas Pool.	CO	358	7/6/95	COAL BED METHANE GAS	HOUSTON
Pool defined and pool rules for development of the West Sak Oil Pool in the Kuparuk River Field.	CO	406	10/16/97	WEST SAK OIL	KUPARUK RIVER
Defines the Alpine Oil Pool and establishes rules for development.	CO	443	3/15/99	ALPINE OIL	COLVILLE RIVER
Redoubt Field Plan.	OTHR ⁴	9	1/6/00	*No Pool*	REDOUBT SHOAL
Authorizes underground injection for an enhanced oil recovery project on an area basis in the Alpine Oil Pool, Colville River field.	AIO	18	1/24/00	ALPINE OIL	COLVILLE RIVER
Amend AIO 4 to initiate a Miscible Gas Enhanced Oil Recovery Project in the Point McIntyre Oil Pool and a Water and Gas Injection Enhanced Oil Project in the West Beach Oil Pool.	AIO	4	4/19/00	PRUDHOE OIL	PRUDHOE BAY
Order establishing fiscal year 2001 regulatory cost charges after buget crisis of 1999.	OTHR	3	10/19/00	*No Pool*	N/A
Order denying Rehearing. Petition of Greenpeace Permit to Drill 200-211 Northstar Unit.	OTHR	12	5/9/01	*No Pool*	N/A
Authorizes underground injection of fluids for enhanced recovery in Northstar Oil Pool	AIO	23	10/9/01	NORTHSTAR OIL POOL	NORTHSTAR
Pool Rules for development of Northstar Oil Pool.	CO	458	10/9/01	NORTHSTAR OIL POOL	NORTHSTAR
Enforcement Order. GRI and ICNA are liable to pay AOGCC the penal sum of \$200,000 under surety bond no K05880877 to plug four Mat-Su valley dry coal bed methane test holes.	OTHR	15	3/8/02	*No Pool*	N/A
After major oil well explosion, AOGCC on its own motion, adopted rules regulating sustained casing pressures in development wells in all pools within the Prudhoe Bay, Endicott, Kuparuk River, Northstar, Point McIntyre, Beluga River, North Cook Inlet, Kenai., etc.	CO	483, 492, 494, 501, 502, 503, 506, 507, 523, 524, & 525	1/16/2003 to 7/20/2004	VARIOUS POOLS	NORTH SLOPE AND COOK INLET OIL AND GAS FIELDS
Authorizes a pilot water flood project designed to test the potential for enhanced oil recovery in the Hemlock Formation, Redoubt Unit, Cook Inlet.	ERIO ⁵	2	8/26/04	UNDEFINED OIL POOL	REDOUBT SHOAL
Enforcement Action Prudhoe Bay Field A-22 explosion.	OTHR	29	11/5/04	*No Pool*	N/A
Adoption of rules regulating the use of multiphase meters for well testing and allocation of production.	CO	402, 547, 548, 549, 550, 551, 552, & 559	2/11/2005 AND 11/14/2006	LISBURNE, BADAMI, ENDICOTT, MELT-WATER, SCHRADER BLUFF, NORTH-STAR, ALPINE & PUT RIVER OIL	NORTH SLOPE OIL FIELDS
First Gas Storage Injection Order in Alaska- Order authorizing the underground storage of hydrocarbons in the Beluga and Sterling Formations in the Pretty Creek Unit Well #4.	SIO ⁶	4	9/12/05	UNDEFINED GAS POOL	PRETTY CREEK
AOGCC's report on Commission inquiry into potential revision of 2.7 BCFD gas offtake limit (CO 145) for the Prudhoe Bay Oil Pool, Prudhoe Bay Field. Amended Report distributed 7/10/07.	OTHR	40	12/5/05	PRUDHOE OIL	PRUDHOE BAY
Enforcement Action. Trading Bay Unit, Steelhead Platform, Automatic Shut-in Equipment.	OTHR	39	4/6/06	*No Pool*	TRADING BAY
Most costly deliberations in AOGCC history- Petition to integrate interest & unitization of the tracts in the existing North Cook Inlet Unit w/state oil & gas leases ADL 369100 & ADL 369101. Decision on Remand concerning Danco's application for an order granting intregation of interests and unitization of tracts in existing North Cook Inlet Unit with ADL 369100 and ADL 369101. AOGCC won lawsuit in the Alaska Supreme Court.	CO	391	3/7/1997 to 7/21/2006	*No Pool*	NORTH COOK INLET
Administrative Approval to establish an allowable gas off take rate to permit shipping gas from CRU to the Village of Nuiqsut.	CO	443	2/13/07	ALPINE OIL	COLVILLE RIVER
Disposal of Class II oil field wastes by underground injection in the Beluga Formation in the Aspen No. 1 Well.	DIO	32	2/7/08	*No Pool*	*EXPLORATORY
Order authorizing underground injection of fluids for enhanced oil recovery in Oooguruk Field, the first North Slope oil field operated by an independant.	AIO	33 & 34	4/11/08	KUPARUK and NUIQSUT UNDEFINED OIL POOLS	OOGURUK

APPENDIX K - **Additional Sources of Information**

- Alaska Department of Administration: www.state.ak.us/local/akpages/ADMIN/home.htm
- Alaska Department of Environmental Conservation: www.dec.state.ak.us
- Alaska Department of Natural Resources: www.dnr.state.ak.us
- Alaska Department of Revenue, Tax Division: www.tax.state.ak.us
- Alaska Natural Gas Development Authority: www.angda.state.ak.us
- Alaska Journal of Commerce (publishing The Alaska Oil & Gas Reporter): www.alaskajournal.com
- Alaska Oil and Gas Association: www.aoga.org
- Alaska Oil and Gas Conservation Commission: www.aogcc.alaska.gov
- Alaska Oil Field Production: www.tax.state.ak.us/programs/oil/production.aspx
- Alaska Oil/Income Production Forecast: www.tax.state.ak.us/sourcesbook/index.asp
- Anchorage Chamber of Commerce: www.anchoragechamber.org
- Anchorage, Municipality of: www.muni.org
- BLM - Bureau of Land Management: www.blm.gov/ak/st/en.html
- Coastal Zone Management: www.coastalmanagement.noaa.gov/about/czma.html#section307
- Alaska Coastal Management Program: www.alaskacoast.state.ak.us
- Cook Inlet Regional Citizens Advisory Council: www.circac.org
- DEC Air Quality: www.dec.state.ak.us/air/index.htm
- DEC Environmental Health: www.dec.state.ak.us/eh/index.htm
- DEC Spill Prevention and Response: www.dec.state.ak.us/spar/index.htm
- DEC Water Quality: www.dec.state.ak.us/water/index.htm
- DNR Division of Geological and Geophysical Surveys: www.dggs.dnr.state.ak.us
- DNR Land Administration System: www.dnr.state.ak.us/las/lasmenu.cfm
- DNR Land Records Info: www.plats.landrecords.info
- DNR Division of Mining, Land, and Water Management: www.dnr.state.ak.us/mlw/index.htm
- DNR Division of Oil and Gas: www.dog.dnr.state.ak.us/oil
- DNR Office of Habitat Management and Permitting: www.habitat.adfg.alaska.gov
- DNR Office of Project Management and Permitting: www.dnr.state.ak.us/opmp
- DOE Fossil Energy: www.fossil.energy.gov
- ENSTAR Natural Gas Company: www.enstarnaturalgas.com
- EPA's UIC Program: www.epa.gov/safewater/uic/index.html
- Glossary of Oil Field Terms (courtesy of Schlumberger): www.glossary.oilfield.slb.com
- GWPC – Ground Water Protection Council: www.gwpc.org
- IOGCC – Interstate Oil and Gas Compact Commission: www.iogcc.state.ok.us
- Kenai Peninsula Borough: www.borough.kenai.ak.us
- Matanuska-Susitna Borough: ww1.matsugov.us
- MMS – Minerals Management Service: www.mms.gov/alaska
- National Energy Technology Laboratory: www.netl.doe.gov/technologies/oil-gas/index.html
- North Slope Borough: www.co.north-slope.ak.us
- Petroleum News: www.PetroleumNews.com
- Regulatory Commission of Alaska: www.rca.alaska.gov
- State of Alaska: www.state.ak.us
- State Pipeline Coordinator's Office - Joint Pipeline Office: www.jpo.doi.gov

A one volume publication, "Alaska Oil and Gas Laws and Regulations Annotated," with CD-Rom, may be ordered by calling the publisher, Matthew Bender & Co., Inc, toll-free at (800) 562-1197 or by ordering on-line at www.lexisnexis.com/bookstore.

APPENDIX L - **Alaska's Governors**



1959-1966
William A. Egan



1966-1969
Walter J. Hickel



1969-1970
Keith H. Miller



1970-1974
William A. Egan



1974-1982
Jay S. Hammond



1982-1986
William J. "Bill" Sheffield



1986-1990
Steve C. Cowper ¹



1990-1994
Walter J. Hickel



1994-2002
Tony Knowles ²



2002-2006
Frank H. Murkowski ³



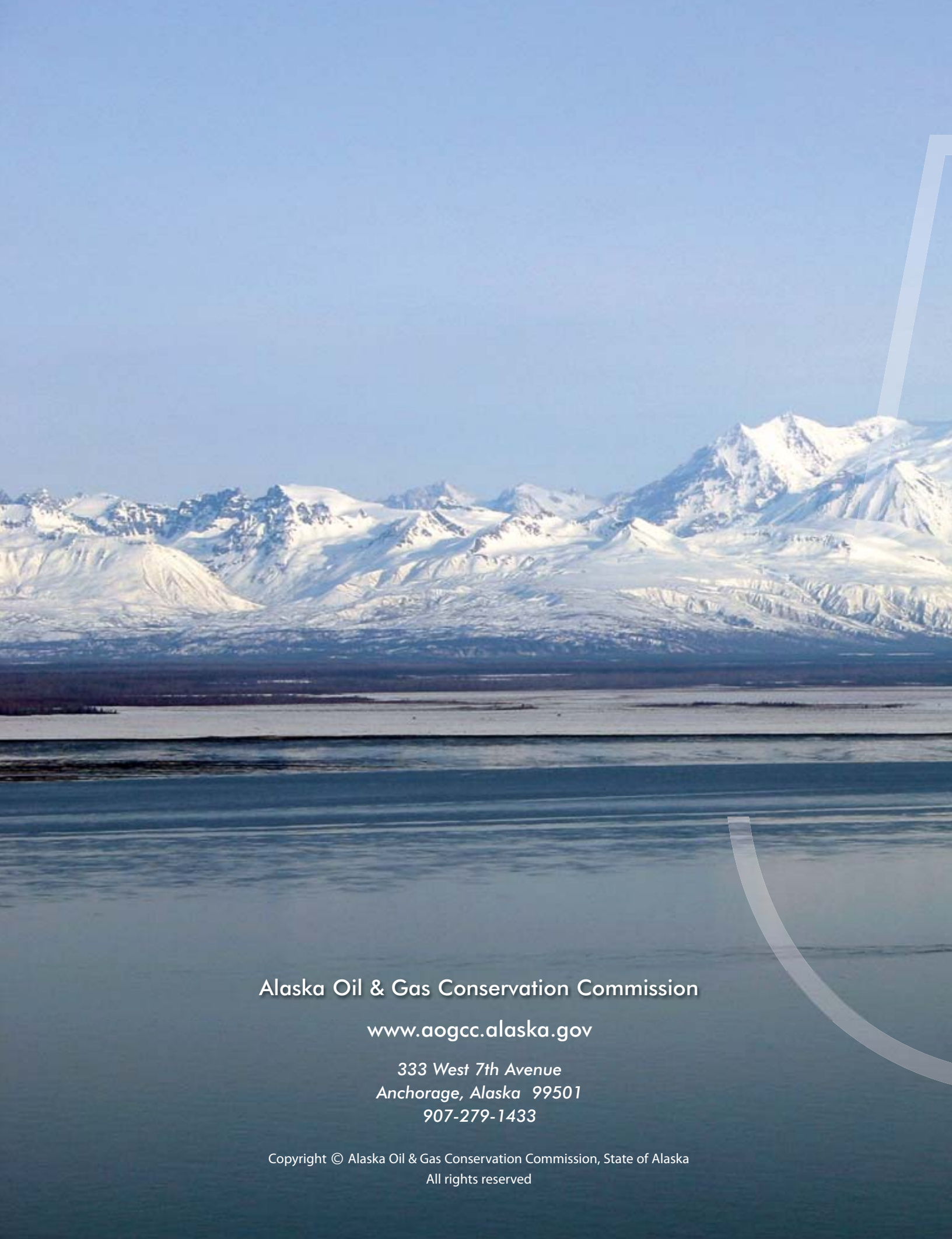
2006-Present
Sarah Palin ⁴

¹ Interstate Oil & Gas Compact Commission, Chair, 1989

² Interstate Oil & Gas Compact Commission, Chair, 2000 and 2001

³ Interstate Oil & Gas Compact Commission, Chair, 2005

⁴ Interstate Oil & Gas Compact Commission, Chair, 2008



Alaska Oil & Gas Conservation Commission

www.aogcc.alaska.gov

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