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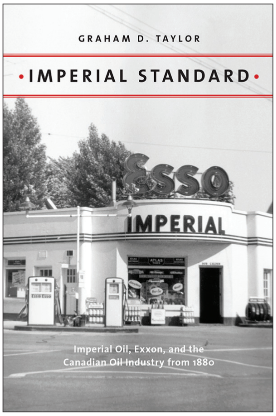

IMPERIAL STANDARD: Imperial Oil, Exxon, and the Canadian Oil Industry from 1880

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NORTHERN VISIONS

During his successful campaign for prime minister in 1957, John Diefenbaker sought a theme that would distinguish his leadership not only from the Liberals but also from the "old guard" Tories he had displaced. He turned to Merrill Menzies, a young economist from Manitoba who persuaded Diefenbaker to embrace a "Northern vision" that would open a "New Frontier" for economic development and exploitation of natural resources in the remote areas of northern Canada, a twentieth century renewal of the National Policy, counterpoised to the "continentalist" orientation of the Liberal regime.[1]

As was often the case in politics, the "Northern Vision" was easier to articulate than to translate into effective policies. Even before its final defeat in 1962, Diefenbaker's Progressive Conservative government was in disarray and none of Menzies's ambitious ideas had come to fruition. But the concept of the "North" as the next frontier for development resonated with the business leaders in Canada's natural resource industries, not least those in the oil and gas field. By the end of the next decade the prospects for new finds in the Arctic region and the possibilities of exploiting the potentially huge reserves in the oil sands of northern Alberta were receiving more than perfunctory attention from the industry. Lack of infrastructure, the limits of technology, and persistently low oil prices were impediments to action through this period. Some of those conditions changed in the 1970s, but resource developers then confronted challenges from First Nations communities and from environmentalists, who had very different versions of the "Northern Vision"—not to mention challenges from a federal government with its own agenda for the region and the industry.

As early as 1963, Imperial Oil was looking ahead to future prospects beyond its maturing fields in southern Alberta. In a report submitted to the company's executive committee, the producing department concluded that "the Southern basin does not appear to have a significant potential as a source of new cheap conventional oil in the 1970s," and it recommended that the company consider alternative sources including "the Athabasca Tar Sands and other heavy hydrocarbon deposits," and "areas of the north including the Arctic Islands, and possibly reserves which might exist on the Atlantic Continental Shelf." Jack Armstrong, then a vice president and the chief executive of Imperial a decade later, asked if the producing department "was in effect 'walking off' the Southern basin." The representatives of the producing department responded that "this was not the case" but reiterated that "the Company was limited to some extent by its current . . . position."[2]

Imperial's parent, Jersey Standard, and other American oil majors were also looking to future sources of supply in this period, even as the country seemed awash in cheap oil and gasoline. In 1956 M. King Hubbert, a geologist with Shell, had presented a paper to the American Petroleum Institute estimating that established fields in North America would reach a production peak between 1965 and 1970, and draw down on diminishing reserves thereafter. Although this warning had little resonance with the industry at the time, and the oil majors could rely on global sources to sustain their operations, by the middle of the 1960s, with growing tensions in overseas regions including the Middle East and Latin America, prudent oil executives were looking at options closer to home. In 1968, two years after the Alaskan coast had been opened by the US Interior Department for oil exploration, the Atlantic Richfield company, backed by Humble Oil of Texas and Jersey Standard (soon to be renamed Exxon), announced a huge discovery at Prudhoe Bay on Alaska's North Slope, with potential reserves exceeding 10 billion barrels. Shortly thereafter, British Petroleum made a strike nearby and a new "oil rush" was on.[3]

This was the context in which Imperial Oil undertook its adventures into the geographic and technological frontiers in the 1970s. In retrospect, the virtual abandonment of development in southern Alberta proved premature, and the company had to buy its way back into the burgeoning Elmworth field later in the decade. Arctic exploration yielded disappointment, and the oil sands and heavy oil investments were both frustrating and a continuing expense. Imperial was not alone in its difficulties with northern initiatives, which ultimately swallowed up some even bolder ventures and roiled Canadian politics into the 1980s.

The Oil Sands

During the summer of 1914, the eminent British geologist Dr. T.O. Bosworth, who would head the Imperial Oil expedition to Fort Norman five years later, traveled to the Athabasca River region at the instance of two Calgary businessmen, to survey the prospects for oil extraction from the "Tar Sand District." Surprisingly, Dr. Bosworth offered the view that the oil-infused bitumen of that area offered a better opportunity for profitable development than did the possible underground deposits in the Turner Valley. "This remarkable series of Bituminous Shales and Limestones . . . is an admirable oil generating formation," he proclaimed. Bosworth went on to recommend that his clients form "a controlling company or syndicate" of all the oil seekers in Alberta to exploit "the oilfields of the north."[4]

The outbreak of the First World War interrupted further developments until 1918, by which time Bosworth appears to have shifted his focus to finding more conventional oil sources in the Northwest Territories. At the time he extolled the merits of oil extraction from the tar sands, no viable commercial process had been developed for this purpose. The oil discovered in the Turner Valley and later at Leduc and other fields in southern Alberta was light and largely free of the sulphurous content that had troubled the Ontario product. By contrast, the oil embedded in the bitumen around Fort McMurray had to be laboriously separated and even then its sulphur-laden content required more refining than the standard product pulled directly from underground sources. Based on exploratory work by American geologists Ralph Arnold and J.L. Tapley in 1917, Imperial Oil took out seventeen leases in the Fort McMurray area, but further investigation indicated that "if there was oil in the Athabasca region, it was not going to yield to traditional methods of drilling."[5]

During the late 1700s Peter Pond and Alexander Mackenzie, fur traders with the North West Company, encountered what Mackenzie described as "bituminous fountains" near the forks of the Athabasca and Clearwater rivers in what is now northeastern Alberta: "A pole of twenty feet long may be inserted without the least resistance" into the bitumen along the river banks.[6] Mackenzie observed that the Cree, the aboriginal people in the region, mixed the bitumen with spruce resin to provide caulking for their canoes. Over the following century other English and Canadian explorers filled in more details of the region and its resources. In the early 1880s Dr. Robert Bell of the Geologic Survey of Canada investigated what he called the "asphaltic sands," which he maintained could contain "abundant" quantities of petroleum.[7]

In 1913, a year before Bosworth's expedition, the engineer Dr. Sidney Ells was commissioned by the federal Department of Mines to look into the commercial potential of the oil-embedded bitumen near the former Hudson's Bay Co. trading post, Fort McMurray. Ells concluded that it could be used as a base for asphalt paving, and was so enthusiastic about the prospects that he formed a company two years later to pave roads and sidewalks in Edmonton. During the mid-1920s, following completion of a railway line to Fort McMurray, Ells joined with an American businessman, Thomas Draper, to form McMurray Oil & Asphaltum Co. It operated for about ten years producing paving materials primarily for the Alberta market. Meanwhile, the Alberta government established a Scientific and Industrial Research Council that employed Dr. Karl Clark, an associate of Ells, to develop a process to separate bitumen from the tarry sands. In 1924 Clark experimented with suspension of bitumen solids in hot water and caustic soda in a rotating drum, producing a liquid that could be converted into synthetic crude oil. Although it did not entirely overcome the problem of impurities in the bitumen, the "hot water extraction process" became the basis for the oil sands industry.[8]

For more than twenty years the oil sands attracted a variety of entrepreneurs, some of them little more than con artists, others with more serious intentions but meeting with limited success. In 1922 Robert Fitzsimmons acquired a federal lease north of Fort McMurray and set up International Bitumen Co., which used a crude variant on the hot water extraction process but relied primarily on the production of asphalt paving and roofing materials and some fuel oils. Although Fitzsimmons improved the hot water process and built a small refinery, the plant at Bitumount had to be shuttered during the Depression. In 1942 Fitzsimmons sold the company to Lloyd Champion, who reorganized it as Oil Sands Ltd. and sought to resurrect it—with help from the Alberta government—as a prototype for Karl Clark's extraction process.

Meanwhile, Sidney Ells, who now saw Clark as a rival, was approached by an entrepreneur from Denver named Max Ball, whose partner James McClave had developed an alternative bitumen extraction process. Shortly before the Canadian government transferred its mineral leasing rights to Alberta in 1930, Ball, with help from Ells, acquired a federal lease near Fort McMurray to set up a "demonstration plant" that would not only extract bitumen from the sands but also refine it into gasoline and fuel oil on a small scale. The company, Abasand Oils Ltd., was set up in 1936 and went into operation several years later—in time to contribute to wartime production—but burned down in 1941. It was taken over by the federal government under the War Measures Act and the plant was rebuilt under direction of Claude Humphreys, a refinery engineer seconded from Imperial Oil; but it was destroyed by fire again in 1945. The Canadian government refused to contribute to another rebuilding effort.[9]

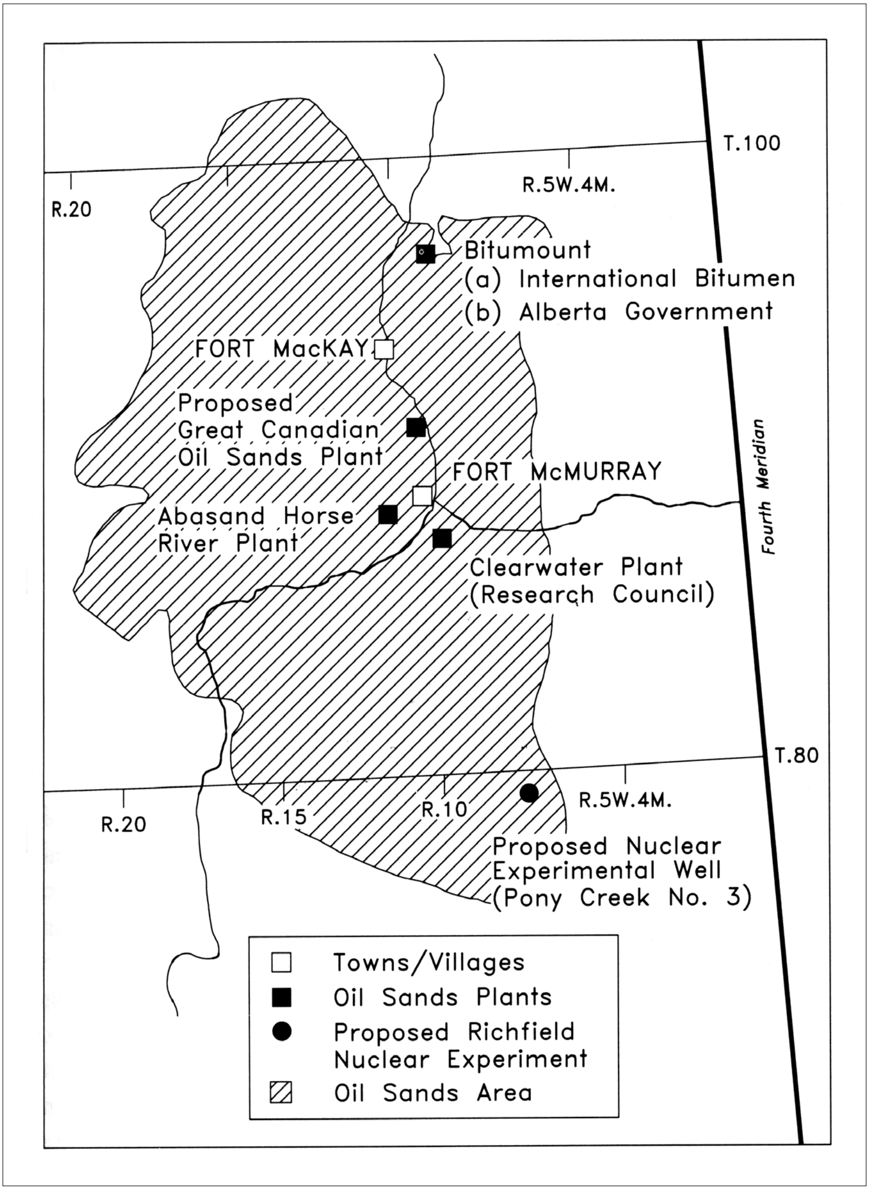
By this time Ernest Manning had become premier of Alberta; with Turner Valley output in decline and no new large conventional oil finds on the horizon, he supported the proposal to rebuild Bitumount as a demonstration plant for Clark's extraction process. The province put up $500,000 (CAD) to back Champion's undertaking. But circumstances changed by 1948. The discovery of Leduc opened the door to a renewed oil industry in southern Alberta. The reconstruction of Bitumount encountered increasing costs of close to $1 million (CAD), and Champion bailed out of the project. Even Karl Clark was frustrated by the disorganization on the ground. Both the Abasand and Bitumount ventures were in limbo.[10]

Up to this point none of the oil majors—or for that matter, medium-level oil companies in North America—had exhibited much interest in the oil sands: the resource was in a remote location, far from any prospective markets, the technology had yet to be tested on a large scale operation, and there was plenty of conventional oil available. Nevertheless, Premier Manning still hoped to stimulate investment in the region: in 1951 Alberta sponsored an "international" conference of oil companies to hear about the potential benefits of the oil sands. Sidney Blair, an associate of Karl Clark and head of Canadian Bechtel, provided an optimistic analysis of projected oil sands production costs and Nathan Tanner promised generous leasing and royalties policies to prospective investors. But many of these participants were put off by the expectation that those seeking leases must undertake development of an operating plant within two to five years.[11]

An exception was J. Howard Pew, chief executive of Sun Oil Co. of Pennsylvania. Sun Oil had entered the Canadian market several years earlier, and was seeking sources of crude oil for its Marcus Hook refinery. But in the context of the Cold War Pew also was committed to the belief that the US, for national security, should rely primarily on North American oil. Pew and Alberta's Premier Manning were both stalwart political and religious conservatives, and they formed a close personal relationship over the next two decades that would have a significant impact on the development of the oil sands. Sun Oil was one of the few companies to take up Alberta's appeals for investment in its northern frontier region.

Lloyd Champion embarked on a new oil sands venture in 1953, cobbling together the remnants of previous ventures at Bitmount and Abasand into Great Canadian Oil Sands Ltd. As with previous forays into the field, this one soon began to founder, but Sun Oil stepped into the breach, taking over 75 per cent of the lease and supporting mining and processing of the oil extracted from bitumen in return for exclusive rights to sell the company's output. Development work commenced at Ruth Lake north of Fort McMurray. The Manning government helpfully arranged in 1955 to exempt oil sands production from Alberta's prorationing process.[12]

Imperial Oil's entry into the field came through a side door and in the wake of one of the more bizarre episodes in the history of the oil sands. In the mid-1950s, as part of President Eisenhower's "Atoms for Peace" concept, the US Atomic Energy Commission initiated "Project Plowshare," a review of proposals to use nuclear weapons for economic development ends. These included ideas such as creating a new interoceanic canal in Nicaragua, vastly enlarging harbours on the Alaskan coast, and blasting through mountains in California to expand highway and railway lines. During the Suez crisis of 1956–57, attention turned to the development of oil resources in North America.



MAP 10.1. Alberta Oil Sands, 1960. David Breen, *The Alberta Petroleum Industry and the Conservation Board*, Edmonton: University of Alberta Press, 1992, p. 441. Courtesy of David Breen.

Manfred Natland, a petroleum geologist employed by Richfield Oil, a medium-sized California company, proposed to address this need. Natland was familiar with the basic problem of the oil sands, the viscous intermixture of bitumen and tarry sand that made the costs of extraction prohibitive even before the residue could be refined. As Karl Clark had noted, recovery of the bitumen from underground would reduce the costs of mining the surface, and also its environmental effects. After witnessing a vivid sunset in Saudi Arabia Natland claimed it occurred to him that using an underground nuclear explosion in the oil sands would "reduce the viscosity" of the bitumen and "permit its recovery by conventional oil field methods."[13]

The Richfield company had limited involvement in the Alberta oil fields, but it entered a partnership with Cities Service, a long-time operator in western Canada that, with Royalite, was engaged in a venture in the Mildred Lake area north of Fort McMurray. Cities Service Athabasca was experimenting with a German-designed bucketwheel dredge to mine the bitumen at Mildred Lake, and a hydrogenation process to extract the oil. Imperial Oil had also been approached as it held leases in the Fort McMurray area, including Pony Creek. Richfield's proposal "to test underground combustion in the oil sands" appeared to be "less costly" than the Cities Service mining venture.[14]

In 1958 Richfield, joined by Cities Service and Imperial Oil, approached the US Atomic Energy Commission with a proposal to test a 9-kiloton nuclear bomb at a depth of 1250 feet at Pony Creek. If successful, the project could be expanded to up to 100 underground explosions, freeing up much of the oil sands for exploitation. At the same time, in June 1958, Richfield presented its proposal to the Atomic Energy Board of Canada, the federal Department of Mines, and the Alberta Conservation Board. The inclusion of Imperial Oil in the proposal may have helped buttress the case presented by the smaller companies, given Imperial's connections with Canadian defence officials. Imperial also took the precaution of having Richfield present the plan to the Jersey Standard executive committee.[15]

In February 1959 the Alberta government hosted a press conference—attended by representatives of the Canadian government and the US Atomic Energy Commission—that outlined the proposal. Its original title—"Operation Cauldron"—had been modified, for public relations purposes, to "Operation Oil Sands." The *Calgary Herald* enthused that the project "will give the Western world a measure of independence from huge Middle East oil deposits," and quoted the federal Department of Mines minister that it would "double the world's petroleum reserves."[16] In outlining Imperial's involvement to the company's executive committee, Vernon Taylor—who now had responsibility for the oil sands as well as conventional production—noted that Richfield hoped to bring in "five or six more companies" to spread the costs of the project, which was now estimated to climb to $10 million (CAD) over a five-year period.[17]

The enthusiasm of government officials for "Operation Oil Sands" was not universally shared. Robert Fitzsimmons, the founder of Bitumount, warned: "if it does not turn the whole deposit into a burning inferno, it is absolutely sure to fuse it into a solid mass of semi-glass or coke." The president of a nuclear engineering company in Utah predicted that an underground blast would lead to "a second hydrogen explosion above ground" and spread radioactive dust for more than 200 square miles.[18] More critical for the project were the shifting views of Canada's prime minister, John Diefenbaker, plus Howard Green, who became Diefenbaker's Minister of Foreign Affairs in April 1959. Green was skeptical of the plans for the placement of US nuclear weapons in Canada. As early as the autumn of 1959 the oil sands bomb test had been "indefinitely postponed." By April 1962, when Green spoke out against all nuclear testing, "Operation Oil Sands" was virtually moribund.[19]

Despite the uncertain status of "Operation Oil Sands," in September 1959 Imperial's executive committee decided to proceed with a partnership with Cities Service Athabasca and Richfield in developing the Mildred Lake mine site, with Imperial assuming a $4 million (CAD) commitment in return for a 30 per cent interest. Royalite, which had acquired Bitumount, was also included with a 10 per cent participation, and the other partners each held 30 per cent. The arrangement was restricted to research and development costs, with a planned 3,000 bbl./day distillation unit in addition to the mining and extraction operations. A Cities Service executive, A.P. Frame, was in charge of the as-yet-unnamed project.[20]

The partnership was not without friction. By 1961 Cities Service, backed by Royalite and Richfield, was anxious to move on to the next stage of development: building a plant capable of processing up to 100,000 bbl./

FIGURE 10.1. Oil sands pilot plant. Mildred Lake, 1960. Glenbow Archive IP-6s-1-1-1, Imperial Oil Collection.

day and filing an application with the Alberta Conservation Board for a commercial operation. Imperial's representatives, including Taylor, Jack Armstrong, and D.S. Simmons were less sanguine. A consulting firm, C.F. Braun, projected the costs of the full-scale plant at $246 million (CAD)—much higher than Cities Service's original estimate—with a potential return of 10 per cent (later adjusted to 13.5 per cent) and a probable time frame of five to six years for completion, which far exceeded the two to three year requirement of the Alberta government.[21]

There were other factors influencing Imperial's hesitation. One concern involved the mining technology. After a visit to Mildred Lake, Vernon Taylor reported "disappointing" progress—in part because the German-designed bucket wheel excavator could not function in the harsh winter conditions of northern Alberta. Eventually the consortium would move toward a process that used scrapers operating on drag lines to remove the overburden, and bucket wheel reclaimers to feed the bitumen onto a conveyor belt—rather than mobile dredgers with giant bucket wheels (which were featured in the operation under development by Great Canadian Oil Sands). In the 1980s Syncrude would replace its draglines and dredgers with gigantic shovels and computerized trucks. But Imperial's engineers remained interested in the concept of some form of underground injection process to loosen the bitumen, which could then be drawn up to the surface. The technology, which would emerge as a steam-driven injection process, would be applied to Imperial's Cold Lake venture.[22]

Another impediment was the shifting perspective of the Alberta Conservation Board. In 1960 the government, under pressure from independent conventional oil producers in the province, had extended the board's reviewing authority to cover oil sands development. By this time, the Cities Service consortium and Great Canadian Oil Sands (GCOS) were actively pursuing large projects, and other big companies, including Shell and Canadian Pacific Oil and Gas, were considering entering the field. Declining market demand for oil in 1958–59 heightened the anxiety of Alberta's conventional producers. Although Premier Manning continued to support GCOS, the conservation board, in reviewing its initial application, was only prepared to consider a project limited to 31,500 bbl./day; and the Alberta government introduced a new royalty scheme that raised the province's take to 20 per cent of production above 900,000 barrels of oil and required advance royalties on the first 8 million barrels. Even though GCOS was willing to proceed under these rigorous terms, the Board delayed reconsideration until 1962. In this context, Imperial's caution was understandable.[23]

The Alberta Conservation Board gave GCOS preliminary approval of its application in October 1962, but the company was now in financial difficulties because of cost overruns in its initial preparations, a common theme in the story of oil sands ventures. Sun Oil, i.e., J. Howard Pew, bailed the company out in exchange for 80 per cent of its shares, and prevailed on the Alberta government to accept a 45,000 bbl./day operation, which would enable GCOS to meet its financial obligations more rapidly—at least in theory. In early 1963 Shell announced plans to enter the oil sands by constructing a 100,000 bbl./day operation at Cold Lake, south of the Athabascan fields. The oil sands market was becoming more crowded.[24]

Despite Imperial's reluctance, the Cities Service consortium proceeded with the 100,000 bbl./day Mildred Lake proposal, which—predictably—was rejected by the conservation board, along with Shell's initiative. Shortly thereafter, the Mildred Lake facility was closed. But the partnership was not dead: in 1964 it was revived, and christened Syncrude Canada Ltd. Once again, Imperial, Cities Service, and Richfield held 30 per cent of the shares, with Royalite receiving the 10 per cent residue. Frank Spragins of Imperial Oil was designated general manager, with Vernon Taylor as the President: Spragins had worked for Carter Oil, Jersey Standard's exploration branch, before joining Imperial in 1949, and was involved in the Mildred Lake project from its outset. For the next decade he would be a key figure in Syncrude; unfortunately, Spragins died shortly after Syncrude opened.[25]

On September 30, 1967, the GCOS plant was officially opened, attended by the usual retinue of politicians, journalists, and business leaders. J. Howard Pew was the featured speaker, emphasizing as usual that "no nation can long be secure in this atomic age unless it be amply supplied with petroleum," and that "oil from the Athabascan area must of necessity play an important role."[26] Behind the congratulatory speeches were some troubling developments. A project initially estimated to cost $59 million (CAD) had exceeded $260 million (CAD) and required several infusions of new financing from Sun Oil. Bad weather delayed the move to full production, and the company had yet to find a satisfactory way of disposing of mine tailings. Sun had to come up with more funding and GCOS ran up losses of more than $90 million (CAD) between 1967 and 1974. Only rising conventional oil prices from $2.55/bbl. to over $10/bbl. in 1973–74 provided GCOS with some respite.[27]

Chastened by the conservation board's rejection of its 1962 application, the Syncrude consortium proceeded more slowly, and benefitted from observing the problems GCOS had encountered: more conventional excavation equipment used in strip mining, for example, replaced the bucket wheel technology, and a fluid coking process developed by Esso Research & Engineering was licensed to Syncrude. In 1966, following a meeting with Premier Manning, the consortium was advised that it could apply for a 50,000 bbl./day plant. A more realistic cost estimate of $350 million (CAD) was projected. The conservation board approved an 80,000 bbl./day operation in 1969, and Syncrude successfully pushed for an amended figure of 125,000 bbl./day in 1971.[28]

But divisions continued within the consortium. In 1968 Imperial expressed concern over the growing cost estimates of the enlarged Syncrude proposal, which had risen to over $800 million (CAD), and also noted the "uncertain market picture" for oil sands crude in light of the Prudhoe Bay discoveries in Alaska. The other consortium members insisted that there should be no further delays in construction plans once the conservation board approval was assured. That approval was forthcoming but the board demanded that production should commence by the beginning of 1977, which increased cost pressures as construction of the plant would have to begin by 1974, at a time when contractors would be in demand for the Alaskan pipeline project and other northern operations—including ventures being undertaken by Imperial itself in the Arctic and the Cold Lake project.[29]

Ironically, it was another member of the consortium that pulled out in order to pursue other opportunities. Richfield had merged with Atlantic Refining in 1966, and under the leadership of Robert Anderson, the company embarked on an aggressive exploration program, playing a lead role in the Prudhoe Bay discovery in 1968 and the development of the Trans Alaska Pipeline in the mid-1970s. In 1974, after the US Export Import Bank turned down a loan application for its Canadian affiliate to cover growing expenditures for Syncrude construction, Atlantic Richfield left the consortium; the Canadian company would be swallowed by Petro Canada two years later.

There were other factors at work. In 1968 Manning retired, and three years later the Social Credit party was defeated by resurgent Conservatives led by Peter Lougheed—grandson of Sir James Lougheed. The new regime was eager to make its mark; ironically, much like the federal government under Pierre Trudeau, Alberta's Conservatives wanted the province to play a more active role in shaping the direction of the oil and gas industry and in particular the future of the oil sands. In the summer of 1973 Lougheed and his Energy minister, Don Getty, met with Syncrude representatives, including Spragins and Jack Armstrong, soon to take over as Imperial's president. Lougheed laid out major new terms: the province wanted a 50 per cent share of the net profits over twenty-five years of Syncrude's operations, a majority share of the pipeline to handle oil shipments from Fort McMurray to Edmonton, plus the option to acquire a 20 per cent ownership of Syncrude once it had become a profitable venture. For two days the talks deadlocked, but an agreement was finally reached when Lougheed accepted Syncrude's demand for a revised royalty formula, which would be based on net rather than gross earnings—the prevailing policy with regard to conventional oil production in the province. As a fillip to the agreement, Syncrude would give hiring preferences to Alberta workers on the project.[30]

This episode took place on the eve of the first major energy crisis of the 1970s and the spike in oil prices, which may have eased the concerns of parties on both sides but also aroused the suspicions of critics of the long-term connections between the oil industry and governments, particularly in Alberta.[31] The outcome may have precipitated Atlantic Richfield's departure from Syncrude. In any case, it gave the Syncrude negotiators more leverage when the parties met again in February 1974 to address the future of the consortium. With inflation, the estimated costs of the project had risen above $2 billion (CAD), and the remaining partners could realistically threaten to close it down. Anxious to retain the gains extracted the previous year, Lougheed and Getty were prepared to deal, joined by the premier of Ontario and the federal energy minister, Donald MacDonald, worried about the escalating price of imported oil for central Canada. Armstrong in particular made the case for refinancing Syncrude, and in the end the federal government accepted a 15 per cent ownership position, with Alberta picking up 10 per cent and Ontario 5 per cent, leaving the private sector partners still in a majority. The government of Alberta also agreed to extend a $200 million (CAD) loan to Cities Service of Gulf Canada to keep them in play. Later the province converted the loan into an additional 20 per cent equity in Syncrude.[32]

The Syncrude plant officially opened on September 15, 1978. After its long period of gestation, the undertaking avoided some of the growing pains that had affected GCOS. With investment from both federal and provincial governments, regulatory issues were less irksome and capital more readily available—which was fortunate, since an explosion and fire in 1984 halted production and legal disputes drove up reconstruction costs. The extended period of low conventional oil prices from the mid-1980s had the paradoxical effect of deterring other companies from embarking on rival projects on the Syncrude scale for more than twenty years. In the late 1970s Shell Canada led a consortium planning an oil sands project to compete with Syncrude, but suspended it as oil prices began to slide, although it did complete a bitumen upgrader and refinery at Stopford near Edmonton. During the 1990s the Alberta government, now under Premier Ralph Klein, sold its stake in Syncrude and reduced its royalty charge to one per cent on gross income and decreased its draw on net profits from 50 per cent to 25 per cent. The company increased capital investment by $10 billion (CAD) between 1996 and 2006. After this second round of expansion, Syncrude was producing over 300,000 bbl./day, running the largest oil mine in the world.[33]

As conventional oil prices began to rise again after 2003, there were new entrants into the oil sands. There was Royal Dutch Shell (which effectively bought out minority shareholders in Shell Canada to secure control of the Albian Sands consortium), and five other companies—including Imperial Oil Resources Ventures Ltd., which held 70 per cent ownership of the Kearl Oil Sands mine, with an estimated 5.5 billion barrel reserve. Exxon Mobil held the remaining 30 per cent. Imperial Oil also maintained a 25 per cent interest in Syncrude. The majority owner (53.7 per cent) of Syncrude is Suncor, the successor company to Sun Oil of Canada, which also took over GCOS in 1979. In 2009 Suncor acquired Petro Canada, the former government-owned corporation, and in 2015 it carried out a hostile takeover of Canadian Oil Sands, making Suncor not only the largest company in the oil and gas industry, but the largest company in Canada, ranked by revenues—a position that Imperial Oil had occupied through most of the twentieth century. It also inherited Imperial's reputation as the most reviled corporate entity in the country—the behemoth of the tar sands.

At the same time that Imperial was joining in the Syncrude venture, it began pursuing a different route toward exploiting the petroleum potential in the oil sands. During the late 1950s the company began assembling leases in the vicinity of Cold Lake, about 160 miles south of the Athabasca region, near the Saskatchewan border. The Alberta Conservation Board reckoned the field could yield up to 164 billion barrels of oil, about a quarter the size of the Athabasca fields. Preliminary work by Imperial indicated that 44 billion barrels were potentially recoverable from Cold Lake, but in contrast to Athabasca the deposits of sediment-laden petroleum was around 1,600 feet underground—the surface mining techniques pursued by GCOS and Syncrude could not be applied here. The efforts to recover oil from these underground sources was referred to as *in situ* production.

There had been efforts since the early 1900s to penetrate this reservoir and separate the bitumen and sand sufficiently to permit the use of conventional drilling techniques. Two approaches were used: one based on underground blasting and the other on the application of steam pressure to reduce the viscosity of the oil and sand mixture. One of the most persistent of the early entrepreneurs in this field was Jacob Owen Absher. In 1926 Absher set up the Bituminous Sand Extraction Company—backed by William Fisher, a Turner Valley oil producer. Absher used both techniques, initially experimenting with steam pumping, but when that proved to be expensive, he tried pouring burning kerosene underground, with disastrous results. Although Absher was undeterred by these setbacks, and his work attracted the attention of both Sidney Ells and Karl Clark, the company failed to produce adequate commercial grade oil and collapsed during the Depression.[34]

Imperial Oil may have been interested in the Richfield idea of using nuclear explosives in part because of possible application to the Cold Lake reservoir, but it was exploring alternatives. Pan American Petroleum, a subsidiary of Standard Oil of Indiana, was experimenting with a process called waterflooding that involved the application of hydraulic pressure to create underground fractures through which steam could be applied directly to the bitumen, pumping it to the surface. At the same time, Imperial's researchers at Sarnia developed a process called cyclic steam stimulation (CSS) and more commonly known as "huff and puff." After drilling down into the viscous bitumen level, steam was pumped through

FIGURE 10.2. Roger Butler. Glenbow Archive IP-26-8b-Butler, R.M., Imperial Oil Collection.

the pipe for several weeks or months. After a period of "soaking," the heated oil was drawn up to the surface. The cycle would then be repeated until the cost of steam pressure exceeded the value of the oil produced, at which point the well would be closed down. The process was developed by Roger Butler, a British-born researcher with Imperial Oil.[35]

In contrast to the friction-filled progress of the Syncrude consortium, at Cold Lake Imperial Oil proceeded at its preferred pace: cautious, methodical, and attentive to costs. In 1964 it drilled four wells and experimented with the cyclic steam process, using a portable generator. Three years later came a more substantive commitment: additional wells were brought in along with a steam plant drawing water from a nearby lake. Meanwhile a bid by Royalite for a share in the Cold Lake venture was deflected, and the Alberta Conservation Board approved a pilot project of 1,500 bbl./day. At this point, Imperial suspended work in order to assess results, in particular relating to the steam process that was now patented.

In 1971 a pilot program got underway with twenty-three wells, an enlarged stem plant linked to an oil separation operation. The processed oil was shipped to Lloydminster in Saskatchewan where Husky Oil had established a heavy oil market for its own production. A larger plant of fifty-six wells went into operation in 1975, with a 5,000 bbl./day output, most of which was used for asphalt in Edmonton. One innovation that opened the way for larger scale production involved setting up platforms that could handle a number of connected wells simultaneously. Between 1964 and 1979 Imperial spent $85 million on the Cold Lake project, a miniscule figure compared to the Syncrude costs.[36]

In 1979, however, this stately procession was accelerated, at least temporarily. In the wake of the second energy crisis of the decade, and the federal government's ambitious National Energy Policy, "megaprojects" were fashionable: massive oil plays in the Beaufort Sea and Shell's giant Alsands venture provided examples. Imperial Oil brought forward a dramatic expansion of Cold Lake, proposing to drill 8,000 wells at a cost of more than $4 billion (CAD) and production targets of 140,000 bbl./day with an enlarged steam plant and a separation upgrader and refinery. The construction project alone would employ 10,000 workers, doubling the local population and creating scenes reminiscent of Fort McMurray.[37]

Sliding international oil prices plus cutbacks in the Alberta government's support for megaprojects brought a halt to these plans in 1981 when Imperial suspended the expansion. Two years later it unveiled a more modest initiative, phasing in further development keyed to shifts in oil prices. The provincial government, now under Premier Don Getty, agreed to scale back royalty payments until the company had recouped its investment costs. By this time, Shell was developing a project at Peace River and a Japanese group (JACOS) initiated a project in 1978, although it did not move forward to production until the 1990s. By 2015 Imperial had the capability to produce 154,000 bbl./day at Cold Lake, awaiting a break in the drought in oil prices.

Meanwhile, Roger Butler, who had pioneered oil sands technology for Imperial, moved to Calgary to join the government-sponsored Alberta

Oil Sands Technology Research Agency. At Sarnia, Butler had developed an improved version of the cyclic steam stimulation process, which he had applied to recovery of potash ore in Saskatchewan. Along with other researchers, including veterans of Imperial, Butler experimented with a process called steam assisted gravity drainage (SAGD) initially developed in the 1960s by Standard Oil of California (Chevron) for deep heavy oil pools in southern California. This process involved drilling two parallel horizontal wells into a reservoir: steam would be pumped into the upper well, and the bitumen mix would be heated in a "steam chamber" in the lower well until it could be drawn up to the surface.

The SAGD process enabled drillers to exploit deeper reservoirs and also to operate on a continuous basis, reducing costs to the point where oil sands wells could compete with more conventional drilling when oil prices rose to $30 (CAD) per barrel. Although Imperial continued to rely on the CSS process in its established Cold Lake site, SAGD was used in most of the newer *in situ* wells, and Imperial held patents to both processes. Roger Butler was named to the Canadian Petroleum Hall of Fame for his achievements.[38]

Arctic Adventures

Imperial Oil was the first major company to undertake exploration of the Northwest Territories and the Yukon, through its affiliate the Northwest Company, beginning with the Bosworth expedition in 1918–19 and the establishment of Norman Wells, 125 miles south of the Arctic Circle, in 1920–21. During the Second World War, Norman Wells was resuscitated and expanded as part of the ill-fated Canol Project. Even as that wartime program was being phased down, Imperial geologists conducted surveys in the Yukon in 1947. With the Leduc discovery, the company's attention shifted to the southern Alberta oil fields.

Not surprisingly, the Arctic region remained largely "undeveloped" by the petroleum industry for more than a decade. Exploration and drilling had to be carried out primarily in the winter months, supplied by airplanes that had to battle through whiteouts, or more primitive transportation: the Imperial survey in 1947 was conducted with dogsleds. Roads and drilling rigs disappeared into the thawed permafrost in the spring, and the Canol experience demonstrated the hazards of building pipelines even in sub-Arctic conditions. There were, however, wildcat drillers willing to take risks in the hopes of getting a foothold in a region that the Canadian government had touted as "the most extensive petroleum field in America, if not the world." In the 1950s John C. "Cam" Sproule, a geologist who had worked for Imperial Oil in Saskatchewan and International Petroleum in Colombia and Peru, set up shop in Calgary as a consultant for those entrepreneurs. By the end of the decade, small-scale drillers were exploring the Mackenzie River north of Norman Wells all the way to the Beaufort Sea.[39]

Although little of substance came out of Prime Minister Diefenbaker's "Northern Vision," the federal government eased leasing regulations for 94 million acres in the Arctic that had been mapped by the Canadian Geological Survey's "Operation Franklin." Permits to explore Crown reserve lands could be converted to leases without payment of a "cash bonus," subject to royalty fees based on production of 5 per cent for the first three years and 10 per cent thereafter. Anticipation of the new regulations led to a flurry of interest among larger oil companies, including British American (Gulf Canada), Texaco, and Shell Canada, accounting for about 15 per cent of the area available for leasing, much of it on the Peel Plateau in northern Yukon and along Canada's Arctic coast.

In 1959 acreage in the Arctic Islands was opened for leasing: here again, some oil majors took an interest, including Texaco, Sun Oil, and Amoco, but a large proportion was taken up by smaller drillers, some associated with Sproule. Two years later, initial drilling in the Arctic Islands began, dubbed "Operation Santa Claus," with a leading role played by Dome Petroleum, an offshoot of the US-owned Dome Mines. Jack Gallagher, who led Dome Petroleum, was another Imperial Oil veteran who left that company in the early 1950s after a confrontation with Tip Moroney. He would figure prominently in the history of oil in the Canadian Arctic for the next two decades.[40]

Drillers in the Arctic Islands discovered some lead and zinc deposits and a small amount of natural gas, but the search for oil proved fruitless. Dome's operations closed down less than a year after its much-touted startup, although Gallagher and Dome would be heard from again. Enthusiasm, particularly among the big companies, noticeably cooled. Imperial Oil kept tracking developments, but adopted its usual cautious course, carrying out seismic surveys to identify potentially valuable acreage, but limiting itself to a “minimum position.” When the production department proposed bidding on a new round of leases in the Arctic region in early 1964, President Twaits warned that “the amount of effort being applied to long term plays”—a reference to the Arctic—must be considered “in relation to the Company’s total exploration program.”[41]

On the other hand, smaller exploration-minded companies were looking at pooling resources to continue their costly ventures. In 1966 Sproule and the heads of some mining and oil companies persuaded the Toronto investment house Nesbitt, Thomson and Co. to underwrite Panarctic Oils Ltd., which would provide a platform for operations by up to seventy-five companies of varying sizes on a “farm-in” basis. Investor interest was boosted by the announcement of the Northern Minerals Exploration Program, funded by the federal government and promising to cover up to 40 per cent of exploration ventures in the Arctic, with generous repayment terms.

Within a year the government stepped in to help the floundering enterprise, taking 45 per cent ownership of Panarctic Oils. Gallagher occupied the chief management position, even though Dome Petroleum held only 5 per cent of the shares—a tribute to his capability as a politically minded entrepreneur and salesman. With government involvement, some larger companies joined up, including Canadian Pacific Oil and Gas and Cominco. Even Imperial took up a “farm-in” position on Immerk Island in the Beaufort Sea, although its preferred exploration area was in the familiar terrain of the Mackenzie River Delta.[42]

The biggest impetus for Canadian exploration in the Arctic, however, came from across the border in Alaska. American oil companies had been aware of the region’s potential for many decades: in 1923 US President Harding had proclaimed a large part of Alaska’s North Slope to be part of the country’s strategic petroleum reserve, for exclusive development by the US Navy. There had been test drilling in the area during the Second World War, and in 1944 Wallace Pratt, geologist and vice president of Jersey Standard’s affiliate Humble Oil, identified the Arctic as “marked by conspicuous seepages of oil . . . the last of our [petroleum] frontiers.”[43] The Navy resumed surveys after the war, but there was little interest on the part of the oil industry in the region until the late 1950s. The renewed

Figure 10.3. Aerial view, Esso Resources Rig #3, Beaufort Sea (1983). Glenbow Archive IP-7f-9, Imperial Oil Collection.

interest was triggered by two developments: the Suez crisis of 1956 and the imposition of mandatory oil import controls by the US government three years later. As Alaska moved toward statehood, the prospect of oil leases outside of the federal reserve proved hard to resist: in 1964 the state opened up areas near Prudhoe Bay for exploration.

The two largest players were Humble and the ubiquitous Richfield Oil Company (which merged with Atlantic Refining Company in 1966), but there were others lurking nearby, including Sinclair Oil and British Petroleum (BP). Early work proved to be as frustrating to the Americans as the Arctic Islands were for the Canadians; BP and Sinclair cut operations in 1967. But a year later, after an investment of $1 billion (USD), Humble and Atlantic Richfield discovered an "elephant," estimated to be larger than the fabled East Texas fields: 16 billion barrels of recoverable oil and 35 trillion cubic feet of natural gas.[44]

In January 1970, after five years of drilling "dry holes," Imperial reported a "discovery well" at Atkinson Point, about 50 miles from Tuktoyaktuk. When drilled to 5700 feet it produced a "medium gravity low sulfur crude." The company continued to work in the Delta, with additional discoveries over the next three years. But President Jack Armstrong observed that "the oil found so far is insufficient to warrant commercial development," although the natural gas finds were "significant," and potential reserves could be 55 trillion cubic feet. Between 1965 and 1975, Imperial spent over $150 million (CAD) in the area, with six discoveries out of forty-six wells drilled—a better record for Imperial than its 133 dry holes before Leduc, as one wag suggested. Armstrong estimated that over the following decade Imperial could spend between $2.5 and $3 billion (CAD) on "exploration and development in the frontier areas," including the Arctic and the offshore Atlantic.[45]

The North Atlantic was another "frontier area" for oil companies in the 1960s–70s. Imperial had begun looking into this opportunity in 1966 when the premier of Newfoundland, Joey Smallwood, began offering permits for exploration. By 1971 the company had accumulated permits for 46 million acres, mostly off of Labrador. Using submersible rigs, Imperial drilled ten wells, but the results were so unpromising that it reduced its interests in the Grand Banks. The company also conducted test drillings off Sable Island in Nova Scotia, but, as in the Arctic islands, it mostly found gas deposits. Although there were large offshore finds on the other side of the Atlantic, in the North Sea during the 1970s, Imperial found the offshore prospects more frustrating than those it encountered in the Arctic.[46]

To accommodate the challenging conditions of drilling in the Mackenzie delta and the Beaufort Sea, Imperial built artificial islands constructed from silt dredged from the river bottom, then packed them with sand bags, rock, and other materials—including clamshells and even anti-submarine torpedo netting—to hold the soil in place, and gave them sloping surfaces to break incoming waves. The islands functioned only during the winter when the ice locked the "island" in place. Imperial constructed twenty of these islands that could operate in depths up to 60 feet. These makeshift rigs were eventually superseded by platforms resting on caisson-retained islands with ice-resistant walls that could operate in greater depths and for longer periods during the drilling season. These rigs could also be reused where their more primitive precursors were abandoned at the end of each winter. Gulf Canada pioneered with this design, which was adopted on a larger or modified scale by Imperial Oil and Dome Petroleum: the *Esso Glomar Beaufort Sea* was one of the largest of these specialized vessels in the 1980s.[47]

As in the case of the oil sands, transportation was a key requirement for the exploitation of Arctic oil and gas. To that end Humble Oil retro-fitted a 115,000 ton supertanker, the SS *Manhattan*, as an icebreaker and launched it from Philadelphia in the summer of 1969 to go through the Northwest Passage to Prudhoe Bay. Although it successfully completed a round trip, the voyage was not without hazards. At one point, the *Manhattan* had to be aided by a Canadian coast guard icebreaker when it was stuck for thirty-four hours. The Canadian government protested that the route followed violated its sovereignty, and also expressed concerns over the potential pollution of Arctic waters by tanker traffic. The *Manhattan* took one more trip in 1970, but then suspended operations.[48]

Meanwhile, oil companies on both sides of the border were organizing consortia to develop plans for pipelines from the Arctic. In Alaska, Humble, Atlantic Richfield, and BP proposed to construct an 800 mile Trans Alaska Pipeline to carry crude oil from Prudhoe Bay to the port of Valdez. On the Canadian side, things were more complicated. In late 1969 Imperial Oil—together with Interprovincial Pipeline, Trans-Mountain Pipeline, and Canadian Bechtel—formed Mackenzie Valley Pipe Line Research Ltd. Eventually the undertaking brought in Hudson Bay Oil and Gas, Texaco Canada, Gulf Canada, and Shell Canada, and developed an alternative to the Trans Alaska consortium that would piggy-back Mackenzie Delta crude onto oil from Prudhoe Bay to Alberta where it could feed into the established pipelines to the United States. Not surprisingly, the Canadian government supported the consortium's argument that it would be environmentally safer than relying on tankers from Valdez to the US west coast. This was not persuasive with the oil majors who wanted to circumvent the US oil import quotas—although the *Exxon Valdez* disaster later demonstrated the merits of the argument.[49]

In 1973, pressured by public fears about rising foreign oil prices, the US Congress passed the Trans Alaska Pipeline Act, and the pipeline was completed in 1977. The amount of oil available in Arctic Canada was insufficient to justify another oil pipeline, but natural gas finds were ample, and the US market was growing. In 1972 Imperial joined another consortium, the Gas-Arctic Northwest Project Study Group, initiated by Trans Canada Pipe Lines with several gas utilities in the American Midwest: the objective was to build a gas pipeline from the Mackenzie Delta to southern Alberta where it would hook up with TCPL's lines, and would supply both the US and central Canada. Ultimately the consortium embraced more than twenty-five companies, including Atlantic Richfield, Standard Oil of Ohio, and Humble Oil, whose participation introduced the prospect of bringing in natural gas production from Prudhoe Bay. The plan that emerged, the Canadian Arctic Gas Pipeline, would run a 48-inch pipe 1600 miles, making it the largest pipeline in North America.

Before long the consortium faced rivals with different pipeline plans. One of the early participants had been Alberta Gas Pipeline Ltd., the trunk line set up in the 1950s by the government of Alberta to handle intraprovincial gas shipments. Bob Blair, who took charge of Alberta Gas Pipeline in 1969, had larger ambitions, including connecting Prudhoe Bay gas to his system. In 1974 he broke ranks with the Trans Canada group, forming an alliance with Frank McMahon's Westcoast Transmission in British Columbia and coming forward with a plan in which an Alberta Gas subsidiary, Foothills, would build a shorter pipeline from the Mackenzie Delta to the northern border. Here it would hook up with Westcoast to run a pipeline to the US border. This morphed into a more elaborate proposal with another partner, Utah-based Northwest Pipeline Corporation, which would build a gas line through Alaska, paralleling the Alaska Highway, hooking up with a Foothills pipeline built through the Yukon rather than along the Mackenzie River. To make things even more complicated, another US company, El Paso Gas, proposed to carry natural gas in tankers from Valdez to Los Angeles, bypassing Canada altogether.[50]

Each of these proposals would have to run the gamut of regulatory approvals in both the US and Canada; but they also faced unfamiliar technical, political, and environmental challenges. On the technical side, the land through which a pipeline would run presented a complex problem. Permafrost conditions characterized the terrain across the Northwest Territories, the Yukon, and northern Alaska, with depths ranging from 40 feet near the Alberta border up to 300 feet at Inuvik on the Mackenzie

Delta. Damage to permafrost would magnify the impact of frost heave and flooding in thaws. The standard practice of burying a pipeline or running it along the surface could result in permafrost destruction due to the heat generated by the passing fuel, which undermined structures and created potential pollution from pipeline breaks.

The builders of the Trans Alaska Pipe Line addressed this problem by running pipe well above the ground surface, although this aroused the ire of Native people, environmentalists, and others because of its effect on caribou migration. The Canadian Arctic Gas Pipe Line designers came up with an alternative approach: "chilling" the gas into packets that would be delivered through a pipeline seated in a trench with berms to offset possible frost heaves. During hearings on the Mackenzie Valley pipeline, critics raised the problems of maintaining the "chilling" through areas of discontinuous permafrost. Arctic Gas developers came up with more elaborate plans for insulating the pipes and maintaining heat probes to monitor the packets. All these plans of course would drive up the construction costs of the line, which were already substantial as the actual building of the line was restricted to winter months.[51]

By 1974 the Canadian Arctic Gas project had cost over $100 million (CAD) in preliminary research and development and Imperial's executive committee reckoned the ultimate cost would exceed $8.6 billion (CAD), which was more than $2 billion (CAD) over the 1972 estimates. Even with cost sharing in the consortium, "many participants were unwilling to sign a financial support agreement . . . in the event of upset conditions." Even the large backers—Exxon, BP, and Sohio—"vowed they would never undertake such a project again." Meanwhile, Blair and the Foothills group had wrapped themselves in the Canadian flag, exploiting the involvement of US majors in the Arctic Gas project, and adding that their plan to run the pipeline through the Yukon would have less potential impact on the permafrost. But the challenges confronting all the would-be pipeline builders extended well beyond technical issues.[52]

As they advanced to the frontiers in the Athabasca region and the Mackenzie River and Beaufort Sea, the oil companies encountered First Nations peoples to a much greater extent than they had before: the Cree in northern Alberta, and the Dene and Inuit in the Northwest Territories and the Yukon. As the numbers of Indigenous employees grew, Imperial

Oil addressed questions relating to both hiring for short-term construction jobs and longer-term commitments. At its peak, the company anticipated needing about 15,000 workers on pipeline construction, which would more than absorb the relatively small population of "employable northerners," estimated at about 2,000 in the Inuvik region. But the report also maintained that "flooding employment pools with requisitions for labourers" could be "a long-term catastrophe for northern residents." For the longer term, the executive committee discussed "educating young people to take 'permanent' jobs in drilling, production, pipeline operation and maintenance" through seasonal hiring and on the job training (in cooperation with the local Indigenous governments) for "students with good potential."[53]

But the issues relating to land use and project development would shape the more immediate relationship between First Nations leaders and the companies. This was a period of uncertainty and growing self-consciousness among the Indigenous people across northern Canada. In Alaska, the Alaska Federation of Natives was able to hold up progress on plans for the Trans Alaska Pipeline until their land claims were settled in 1971. In Canada, tensions were higher: the Cree people were confronting the Quebec government over the province's plans to take over and flood their lands as part of the James Bay Hydro Project. In 1969 the Canadian government of Pierre Trudeau had released a "Statement on Indian Policy" that proposed to eliminate the special status of First Nations.

In the Mackenzie River the Dene had a particular concern: in 1921, after the discovery of oil at Norman Wells, the federal government had imposed treaties that effectively deprived Indigenous people of full land rights although little had happened since then to carry out the implications of the agreements. In 1970 Bob Blair had orchestrated meetings with Indigenous groups in the Mackenzie River and maintained they had no clear understanding of the implications of a pipeline for their traditional hunting and fishing rights.[54]

At the same time, the pipeline advocates faced opposition from another quarter. The 1970s witnessed the dramatic growth of an environmental movement that ultimately challenged basic precepts of industrial development that undergirded the foundations of the oil and gas industry. In contrast to the conservationists of the early 1900s, the new environmentalists opposed not just pollution and waste but the degradation of the natural world by economic growth: in this context the threat to the "pristine" wilderness of the Arctic represented a clear and present danger to the planet, and certainly to Canada. The oil spills offshore Santa Barbara in 1969 and the *Arrow* disaster in Nova Scotia in 1970 dramatized the threats posed particularly by the oil and gas industry. In 1972 the Club of Rome's report, *The Limits to Growth*, magnified this argument, arguing that the uncontrolled exploitation of the world's fossil fuels and other resources would destroy the global economy over the next century.

In the United States there were well-established environmental organizations, including the Sierra Club, which had lobbied against the potential polluting effects of the Trans Alaska Pipe Line. In Canada the opposition to the Mackenzie Valley pipeline projects was more diffuse, featuring a largely intellectual group—the Canadian Arctic Resources Committee (CARC)—who were supported, providentially, by nationalist organizations such as the Council of Canadians. That council opposed the Canadian Arctic Gas consortium because of the role of multinational corporations like Exxon and BP. But the most important player in the unravelling of the Mackenzie Valley pipeline was an outlier, Thomas Berger.

Between 1972 and 1974, the federal Liberals under Pierre Trudeau clung to power through a tacit alliance with the New Democratic Party that led, among other things, to the establishment of Petro Canada during the first energy crisis in 1973. This arrangement fell apart the following year, but in the meantime, the Liberal government established a one-person Royal Commission to address the Mackenzie Valley pipeline issue, even though it would also be subject to review by the National Energy Board. Berger had served as leader of the NDP in British Columbia and as a provincial judge had demonstrated a commitment to aboriginal rights, attributes that led to his appointment as the commissioner. Aware of his proclivities, lawyers for the Canadian Arctic Gas consortium sought in vain to narrow the focus of the commission's investigation. For the next two years Berger conducted a wide-ranging review, meeting with community groups in the Mackenzie Valley as well as holding more formal hearings in Yellowknife where environmental groups like CARC were provided opportunities to testify along with oil industry representatives and technical experts.[55]

Meanwhile the National Energy Board started its own hearings in October 1975, but proceedings were delayed when environmentalists objected to the presence of a former Arctic Gas adviser on the board. Six months later the review resumed, meeting with hundreds of witnesses in Yellowknife, Inuvik, and Whitehorse as well as Ottawa. In the US, the Federal Power Commission undertook its review of the Mackenzie Valley Pipeline in 1976. As the proceedings dragged along, W.G. Charlton of Imperial Oil vented the frustration shared by many oil industry observers. "Interprovincial Pipe Line Limited was incorporated on April 30, 1949. Eighteen months later it began operations," he observed. In contrast, "the Gas Arctic Study Group was formed in mid-1972. At this time—42 months later—the movement of Arctic gas was still being studied by government agencies."[56]

On May 2, 1977, the US Federal Power Commission submitted its recommendations, with the members divided between the Arctic Gas and Foothills proposals. Seven days later, in his report *Northern Frontier, Northern Homeland*, Berger issued his far less equivocal conclusions: the Arctic Gas route was rejected outright because it would intrude on the Arctic Wildlife Range, and all pipeline construction should be suspended for ten years, pending the settlement of First Nations land claims in the region. The National Energy Board report also rejected the Arctic Gas proposal as "environmentally unacceptable" while giving a cautious recommendation for the Foothills project, with revisions.

This was by no means the end of the Mackenzie Valley Pipeline saga. Prime Minister Trudeau gave tentative approval to the Foothills project, and the US and Canada negotiated a Northern Border Pipeline Agreement to coordinate the Alaskan portion of the plan. But in 1979 the National Energy Board reported that Canada's gas supply needs could be satisfied without the Arctic component. By this time the estimated costs had risen to almost $15 billion (CAD) and the huge projects emerging from the National Energy Program absorbed the attention and financial resources of the government and the oil industry. A "pre-build" section covered under the Northern Border Pipeline Agreement was completed in 1982, but the Mackenzie Valley Pipeline was on hold, seemingly indefinitely.[57]

The events of 1977 put an end to the Arctic Gas consortium, but Imperial vowed to continue its exploration program in the north. At the same time, the company was forced to reassess its strategy: the "frontier" investments had yet to produce big payoffs, and Imperial had allowed leases in southern Alberta to expire just before a renewed round of new finds in the West Pembina and Elmworth fields. In 1978 the company reorganized its exploration and production operations into a new entity, Esso Resources Canada Ltd., with a budget of $139 million (CAD) for conventional oil exploration, while sustaining its one-third investment in Syncrude and continuing development of Cold Lake. In that same year, Imperial struck a deal with Canadian Hunter to invest another $150 million (CAD) for a 17.5 per cent share of that company's acreage in the Elmworth field. The timing was good as a new spike in oil and gas prices boosted its earnings, and the company began planning a return to the Mackenzie Valley through a resuscitation of its original foothold there at Norman Wells.[58]

Norman Wells was still producing oil for local needs, at a rate of about 2,000 bbl./day in the 1970s. Based on the tenfold rise in oil prices in 1979, Imperial contemplated an increase to 25,000 bbl./day with gross revenues of $250 million per year. The federal government would retain one-third ownership and 16 per cent of the revenues. Of course expanding production required the resuscitation of the pipeline. In 1981 Imperial and Interprovincial Pipeline [Enbridge] proposed the construction of a 12-inch line to run to Zama Lake on the northern Alberta border, ultimately to be tied into the Enbridge line from Edmonton. The project fit in with the Trudeau government's ambitious plans for northern oil and gas development, but the Dene and Metis organizations objected to the disruptions that would affect local communities and continuing land claims litigation, supported by the public interest group that had fought the Mackenzie Pipeline, the Committee for Justice and Liberty.[59]

In the summer of 1981, with oil prices still at high levels, the federal cabinet came up with a plan that would delay the project for two years to settle outstanding claims and sweetened the deal with an offer of a $10 million (CAD) job training program and an equity position for the Dene in a $9 million (CAD) joint venture with Esso Resources to expand drilling and servicing the Norman Wells fields. The National Energy Board gave conditional approval to the project, and a legal challenge by the Committee for Justice and Liberty was turned back. With the agreement of the First Nations' groups the project moved forward and the pipeline was officially opened in May 1985. By that time oil prices were plunging, but Esso Resources expressed confidence that improvements in drilling and refining technologies would enhance the recovery rate, and planned an expansion of the field by 150 new wells.[60]

Oil prices continued in the doldrums in the 1990s, and in 1996 Imperial, as part of a general retrenchment, closed the refinery at Norman Wells, although it continued to send crude oil through the pipeline until 2016, at a reduced rate of about 11,000 bbl./day by that point. Meanwhile, however, there was renewed interest in a gas pipeline from the Mackenzie Valley, intended for both Canadian and export markets, which were predicted to grow by 17 per cent between 2002–10. By the mid-1990s most of the major First Nations land claims were settled and the Mackenzie Valley highway was completed, easing some of the logistical challenges to earlier pipeline projects. Trans Canada Pipe Line had acquired the right of way permits held by Foothills for the original route. New gas field discoveries in the region had raised estimated supply rates to 800 million cubic feet/day. The major companies involved in developing the fields were Exxon (now Exxon/Mobil) with Imperial, Conoco-Phillips, and Shell Canada. Imperial played a lead role in bringing a new consortium together, the Mackenzie Gas Project, in 2003–04.[61]

There was an additional participant. In 2000 representatives of thirty First Nations communities in the region formed the Aboriginal Pipeline Group (APG) specifically intended to be involved in the project. A key figure in the organization was Fred Carmichael, who began his career as the first aboriginal bush pilot in the Northwest Territories and was president of the Gwich'in Tribal Council as well as the chair of the APG. Through Trans Canada Pipe Line, the APG secured $80 million (CAD) towards financing its participation in the Mackenzie Gas Project, with Imperial holding 34 per cent, Exxon 5 per cent, and the balance by Conoco Phillips and Shell Canada. The estimated cost of the 800-mile gas pipeline was $7.5 billion (CAD). Imperial Oil and Exxon took a 40 per cent share of the project, with Conoco Phillips Canada holding 16 per cent and Shell Canada 11 per cent. The balance, one third of the total, was to go to APG, although the issue of its financing was not clear.

The consortium filed a formal application with the National Energy Board in 2004. But, as in the case of the original Mackenzie Valley Pipeline, the federal government set up a separate panel to review environmental and social issues. Once again, the process got bogged down. Environmental critics, including the Sierra Club of Canada and the Pembina Institute, again raised the issue of damage to the permafrost, and expressed concern over the role of the pipeline in the increasingly controversial development of the oil sands, as the gas could be diverted in part to service the energy needs of those projects. The financing of the APG participation remained a matter of contention: at one point Imperial threatened to pull out of the project. The federal government sought to paper over divisions by pledging $500 million (CAD) to underwrite APG's involvement plus another $40 million (CAD) to support an aboriginal training fund. Although the government declined to take an equity position in the project, it eventually agreed to absorb a "portion of the risk" in return for future royalty sharing. In 2011 when the National Energy Board gave its final approval, tied to over 200 "conditions," the project's cost had swelled to $16 billion (CAD). By this point Exxon had joined with Trans Canada in an even larger Alaska gas pipeline project that could compete with the Mackenzie Valley project.[62]

This was not the end of the tribulations of the Mackenzie Valley Gas Project. When the proposal went to the National Energy Board in 2004, natural gas was priced at over $15/mm BTUs, but by the time the approval had gone through, it had slumped to $4.57/mmBTUs, in part because of the "shale gas revolution" in the United States. Imperial hoped to resuscitate the venture by transforming its focus to developing a liquefied natural gas (LGN) dimension. LGN technology had been around for almost a century but came into more general use in the 1970s–80s. Exxon was a latecomer to this field but became more interested in it after the 1999 merger with Mobil, which had developed LGN operations in Qatar—the Alaska gas pipeline was under consideration for conversion to an LGN operation. If Imperial followed suit, the pipeline from the Mackenzie Valley would be shortened and tied to an LGN terminal to be established in northern British Columbia. In 2015 the Mackenzie Gas Project backers requested an extension of the "sunset clause" for completion of the line from 2018 to 2022. A year later the National Energy Board agreed to the extension, but with gas prices remaining in the doldrums, the project was in limbo.[63]

Meanwhile, in January 2017, Imperial announced that it was suspending operations on its Norman Wells fields for an indefinite period. Enbridge had shut down the pipeline to Zama in the autumn of 2016 because of problems with ground stability around the line. The line had experienced more than seventy reports of spills, leaks, and fires over the preceding decade, some of them leading to contamination of the town's water supply. The federal government had reported a decline in its revenue share from the operation, from $102 million (CAD) in 2010 to $75 million (CAD) in 2014. Imperial estimated the continued life span of the field at ten years, and was seeking a buyer. According to one report, "this development is further proof that the industry's majors are staging a quiet retreat from Canada's Arctic, ending the . . . prospects in the Central Mackenzie Valley."[64] Forty years after Thomas Berger's report, the Mackenzie Valley Pipeline remained on hold, and after almost a century of operations at Norman Wells, Imperial Oil was pulling out of its first venture on Canada's "northern frontier."