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# Environmental Review of Onshore Canadian Oil and Gas Drilling and Production Activities

Canada

Economic and Technical Review
Report EPS 3-EP-83-2

Environmental Protection Programs Directorate
June 1983

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ENVIRONMENTAL REVIEW OF ONSHORE CANADIAN OIL AND GAS DRILLING AND PRODUCTION ACTIVITIES

by

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ZENON Environmental Enterprises, Limited

for the

Environmental Protection Service
Environment Canada

Report No. EPS 3-EP-83-2
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## ABSTRACT

Current and proposed Canadian onshore oil and gas drilling and production activities are reviewed with respect to their potential for environmental effects. Canadian petroleum geology and related hydrogeology are described to provide a framework for discussion of the impact of oil and gas drilling and recovery operations, including tar sands development, and waste disposal practices. Environmental legislation applicable to oil and gas industry activities is also reviewed.

Major environmental concerns identified include the potential for soil and groundwater contamination by drilling fluids, solid wastes, chemical additives, oils and brines, produced sands, and liquid wastes. The potential for contamination depends on handling and disposal practices and the geologic and hydrogeologic characteristics of the drilling and production site. Although fairly comprehensive legislation is in place, its effectiveness in the long-term has not been assessed, and no specific legislation exists for in situ tar sands development.

Areas where knowledge is lacking and research is required have been identified.

## RÉSUMÉ

On examine les travaux et les projets de forage et de production de pétrole et de gaz à terre au Canada, pour ce qui est de leurs effets possibles sur l'environnement. La géologie pétrolière du Canada et son hydrogéologie sont décrites en vue de servir à la discussions des répercussions du forage et de l'extraction, y compris de la volarisation des sables bitumineux et des méthodes d'évacuation des déchets. Le droit de l'environnement applicable à l'activité de l'industrie pétrolière et gazière est aussi examiné.

Les principaux sujets d'inquiétude comprennent la possibilité de contamination des sols et des eaux souterraines par les fluides de forage, les déchets solides, les additifs chimiques, les juiles et les saumures, les sables produits et les déchets liquides. Les possibilités de contamination dépendent des méthodes de manutention et d'élimination ainsi que des caractéristiques géologiques et hydrogéologiques des lieux de forage et de production. Même si des lois assez détaillées existent déjà, leur efficacité à long terme n'a pas été évaluée et aucune loi précise n'existe concernant la volarisation _in situ_ des sables bitumineux.

Les domaines où les connaissances sont fragmentaires et la recherche nécessaire ont été déterminés.

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## SUMMARY


This report reviews current and proposed Canadian oil and gas exploration and production activities, and the environmental effects of associated waste generation (primarily water) and disposal practices. The report also identifies gaps in knowledge and areas that will need to be addressed in the administration and regulation of land-based hydrocarbon resource development in Canada.

The key elements of Canadian petroleum geology and related hydrogeology are described to provide a framework for subsequent discussions concerning the following main areas:

a) Oil and Gas Drilling
b) Conventional Oil and Gas Production
c) Enhanced Oil Recovery
d) In situ Tar Sands Development

The material reviewed in each of the above areas includes:

i) current and future industrial activity and associated water usage,
ii) the nature of the aqueous wastes produced by these activities,
iii) commonly used disposal methods and the associated regulations and water treatment methods, and
iv) the environmental (primarily water-related) impact of the industrial activity.

### Conclusions

The conclusions and environmental concerns identified by this study are summarized in order of importance as follows:

1) It has been proposed that the liquid wastes generated by in situ tar sands recovery projects be disposed of by subsurface injection, as is currently practiced at existing pilot projects. Potential problems are foreseen with injection into the lower McMurray or Methy formations, since wastes injected into the Methy formation are expected to discharge along the edge of the Precambrian Shield in the future; the impact is dependent upon the degree of attenuation of the waste. The geology of northeastern Alberta is not very suitable for subsurface disposal and, therefore, liquid waste should be reduced as much as possible by treatment and reuse of produced water.

2) The main environmental concern associated with enhanced oil recovery (EOR) processes is the disposal of wastewater and, to a lesser extent, the demand for fresh make-up water.

3) In conventional heavy oil production, the main environmental concerns are those associated with the disposal of produced sand, which is coated with a thin film of oil.

4) Considerable uncertainty exists concerning the reliability of the water treatment schemes associated with the recycling of produced water. In case of system breakdowns, surface water pollution may occur nearby. In some cases, it may be appropriate to develop treatment systems for surface discharge to avoid groundwater contamination in certain areas.

5) The environmental impact of any exploration or production activity is related to the geologic and hydrogeologic characteristics of the area. For example, the tar sands occur where discharge from the regional groundwater system is concentrated.

6) In the prairie provinces, all fine-grained sediments are fractured to various degrees and rapid infiltration through the soil zone occurs in several areas (e.g., southern Alberta).

7) Regulatory requirements and current industry practice for abandonment of wells provide very good protection at present from hydrocarbon, groundwater and surface water interaction. However, the long-term integrity of old casings and plugs merit further investigation and/or monitoring related to hydrogeological impacts.

8) Most oil and gas exploration and production activities have the potential for altering surface, subsurface, and aquatic environments. Often the environmental impact of activities such as road and lease preparation is no more negative than that of timber or farming operations, and the effect may be considered positive if, for instance, a recreational potential is created. However, the potential for environmental degradation still exists.

9) The considerable volume of solid and semi-solid waste produced during in situ tar sands recovery will most likely be disposed by a landfill method. Since the sedimentary environment is not impermeable, the location of sites and disposal practices chosen should consider the conditions necessary for biological breakdown of organic compounds, fixation of inorganic compounds, adequate groundwater monitoring procedures, and/or the necessity for impermeable linings and recovery of the pollutant if necessary.

10) Individual drilling fluid additives contain considerable concentrations of several trace metals and toxic organic compounds; however, no analytical results have been published regarding the concentration range or the release to the environment of dissolved metals and trace organics in different drilling fluids.
11) Solid wastes from the drilling operation which remain in the sump after separation from the liquid waste are encapsulated by back-filling the sump pit with the previously excavated sediments. Monitoring is rarely directed toward the long-term environmental effects (particularly on groundwater) of this disposal practice after the material has been encapsulated. This may be of most concern when considering the impacts of cluster drilling for enhanced oil recovery projects.
12) There is a potential for groundwater contamination by drilling muds as a result of lost circulation. Documented case histories are rare, but experts in the field are of the opinion that the occurrence of groundwater contamination is not as rare as published information suggests.
13) Drilling mud contains considerable dissolved ion in its liquid phase. Therefore, contamination of fresh water aquifers due to filtrate loss, which is a function of mud cake quality, will occur, although on a smaller scale than by direct loss of whole drilling fluid.
14) The accumulated effect of small, undetected subsurface leaks of oil and brines from pipelines over time could create environmental problems, especially when there is no surficial evidence or if the leak is detected after the field has been abandoned.
15) The province of Alberta has the most comprehensive legislation regarding environmental aspects of oil and gas drilling and production. The effectiveness of existing legislation can be adequately assessed only after research has been conducted concerning the long-term effects of current disposal practices.

**Research Needs**

In general, there is little, if any, direct evidence that significant environmental problems are created by the industrial activities reviewed here. On the other hand, the potential for environmental damage exists in all activity areas and generally there is insufficient information to ascertain the likelihood of long-term environmental damage.

In particular, further information and research is required in the following areas:

a) the hydrogeology of the northeastern Alberta and adjacent Saskatchewan region (Peace River/Fort McMurray/Lloydminster) in order to assess the possible interactions among water extraction, steam injection, in situ combustion and waste injection within the hydrogeological system;

b) technologically feasible and economically efficient water recycling technology for in situ tar sands/heavy oil developments, in particular, for controlling boiler corrosion and ion exchange fouling.

c) the effect of produced water quality on the functioning of water treatment processes used in water recycling for in situ tar sands and heavy oil development.

d) long-term monitoring needs for waste disposal in the hydrogeological environment;

e) attenuation studies of groundwater contaminants in different hydrogeological environments;

f) the long-term integrity of casings and possible future impacts of existing abandonment procedures;

g) the type and concentrations of toxic components, and the toxicity and effect of organic and inorganic compounds in the aqueous wastes of various oil and gas industrial activities reviewed (particularly in situ recovery methods) and their likelihood of entering the environment;

h) the potential for hydraulic fracturing of the producing zone during in situ operations;

i) the impact of the use of thermal techniques in enhanced oil recovery and in situ recovery schemes;

j) the impact and frequency of occurrence of lost circulation and problems related to well completion; and

k) the movement or fate of the toxic drilling fluid chemicals and metals in the soils near abandoned drilling sumps, particularly in areas of further drilling for enhanced oil recovery.

# 1 INTRODUCTION

Oil and gas production is an important industrial activity in many parts of Canada. Much of this activity has been increasing in areas where the impact on the environment may be significant because:

(i) production zones are often close to the surface and, therefore, the contamination of groundwater is more likely than in the the past,
(ii) chemicals that may be used as additives or that may be created in proposed enhanced oil recovery schemes present a significant threat to both groundwater and surface water quality,
(iii) wastewater produced per barrel of recovered oil has increased significantly and represents a greater disposal problem, and
(iv) solid wastes from proposed enhanced oil recovery schemes have potentially hazardous and/or toxic components.

This review of current and proposed oil drilling and production methods and their associated potential environmental impacts has been undertaken to identify gaps in knowledge and areas that will need to be addressed in the administration and regulation of land-based hydrocarbon resource development in Canada.

Hydrocarbons are found in sedimentary rocks which, in Canada, were deposited in shallow basins on the continent or in deeper basins along the continental margin. Figure 1 shows the sedimentary basins of Canada. The basins containing the thickest sedimentary fill, and therefore having the greatest hydrocarbon potential, are on the continental margins (the Mackenzie-Beaufort Basin; the Sverdrup-Arctic Islands Basin; and the East Coast Offshore Basin). However, these are the least known basins geologically. Consequently, virtually all hydrocarbon production comes from two continental basins (western Canada and Ontario) and almost all of Canada's proven recoverable reserves of oil and gas are land-based. Table 1 gives both current production and total recoverable reserves of oil and gas by province at the end of 1980, as well as the recoverable (proven) reserves and potential (proven and undiscovered) reserves in 1969. (McCrossan, 1973).

Although two-thirds of the ultimate potential conventional oil reserves and three-fourths of the ultimate potential gas reserves were expected to occur offshore in 1969, 98 percent of both production and recoverable reserves still came from the Western Canadian Sedimentary Basin in 1980. The only other significant production has come from

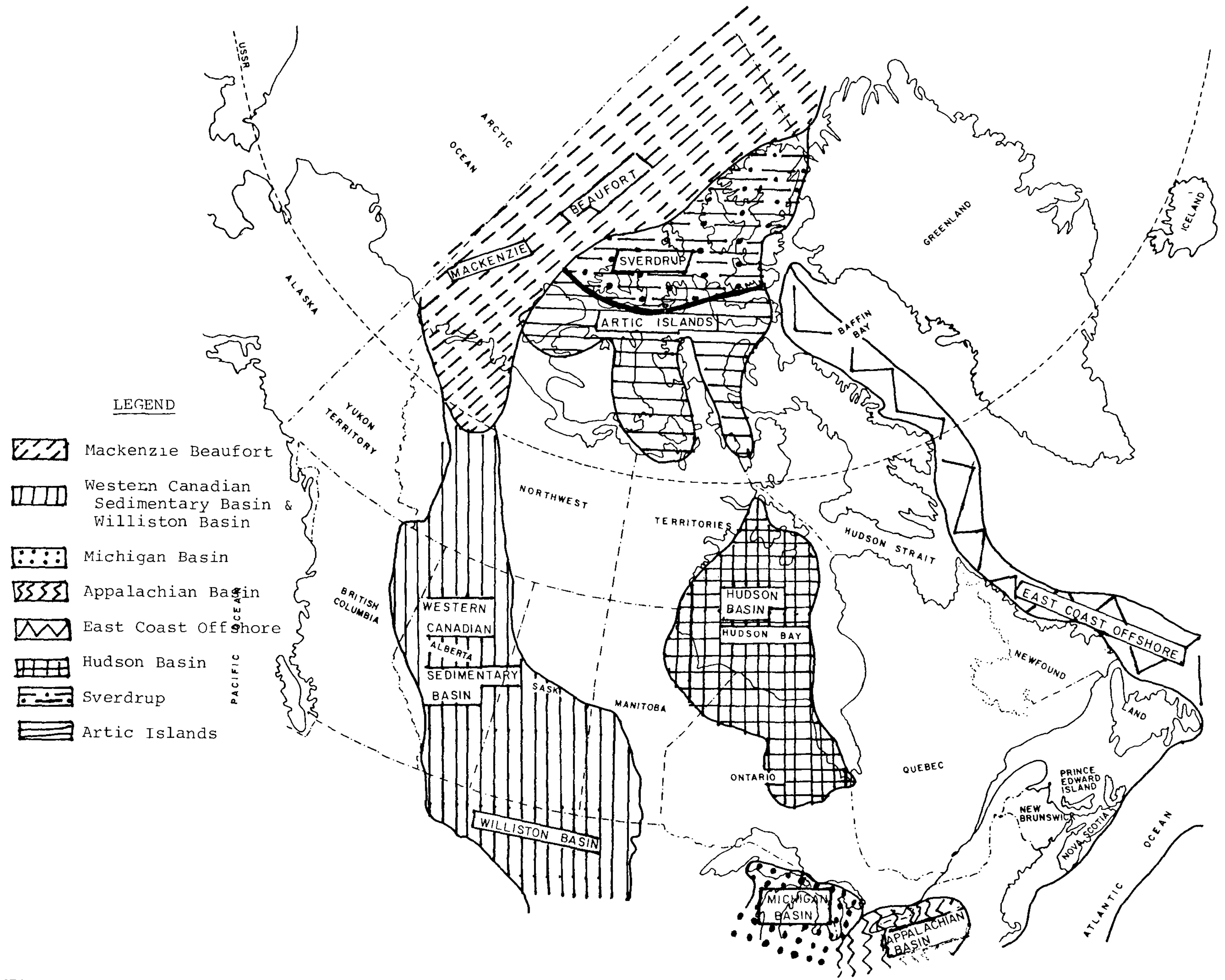



FIGURE 1 SEDIMENTARY BASINS OF CANADA

TABLE 1 OIL AND GAS PRODUCTION AND RESERVE SUMMARIES FOR CANADA

| | 1980* | | | | | 1969 (McCrossan, 1973) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Actual Prod. | Recoverable Reserves | % Total Recoverable Reserves | Remaining Recoverable Reserves | % Total Remaining Recoverable Reserves | Ultimate | Recoverable Reserves | % Total Recoverable Reserves | Ultimate Recoverable Reserves | % Total Ultimate Recoverable Reserves |
| Conventional Crude Oil ($10^6$ $m^3$) | | | | | | | | | | |
| Western Canada | | | | | | | | | | |
| B.C. | 1.9 | 78 | 3.20 | 25.4 | 2.87 | | 78 | 3.57 | 207 | 1.62 |
| Alta. | 62.9 | 1913 | 78.51 | 719.3 | 81.29 | 2600 | 1751 | 80.17 | 2552 | 19.94 |
| Sask. | 9.3 | 379.3 | 15.57 | 104 | 11.75 | | 312 | 14.29 | 409 | 3.20 |
| Man. | 0.6 | 26 | 1.07 | 4.9 | 0.55 | | 23 | 1.05 | 30 | 0.23 |
| Michigan | | | | | | | | | | |
| Ont. | 0.1 | 10.2 | 0.42 | 1.3 | 0.15 | | 10 | 0.46 | 54 | 0.42 |
| Other | | | | | | | | | | |
| Onshore | 0.2 | 30 | 1.23 | 30 | 3.39 | | 10 | 0.46 | 1138 | 8.89 |
| Offshore | 0 | | | 0 | | | | | 8411 | 65.71 |
| Total | 75 | 2436.5 | 100 | 884.9 | 100 | | 2184 | 100 | 12801 | 100 |
| Crude Bitumen | | | | | | | | | | |
| Surface Mining | | | | | | 8000 | | | | |
| In Situ | | | | | | 32000 | | | | |
| Synthetic Crude Oil | | | | | | | | | | |
| Surface Mining | | | | | | 6000 | | | | |
| In Situ | | | | | | 24000 | | | | |
| Gas ($10^9/m^3$) | | | | | | | | | | |
| Western Canada | | | | | | | | | | |
| B.C. | 9.7 | 463.2 | 14.45 | 288.5 | 14.50 | | 301 | 14.40 | 548 | 3.49 |
| Alta. | 63.8 | 2647.1 | 82.56 | 1659.4 | 83.38 | 3800 | 1648 | 78.85 | 2482 | 15.79 |
| Sask. | 1.2 | 66.9 | 2.09 | 38.4 | 1.93 | | 42 | 2.01 | 78 | 0.50 |
| Man. | 0.05 | 1.8 | 0.06 | 0.3 | 0.02 | | 0 | | 0 | |
| Michigan | | | | | | | | | | |
| Ont. | 0.4 | 27.4 | 0.85 | 3.5 | 0.18 | | 28 | 1.34 | 142 | 0.90 |
| Other | | | | | | | | | | |
| Onshore | | NA | 0.00 | NA | 0.00 | | 71 | 3.40 | 850 | 5.41 |
| Offshore | | | | | | | 0 | 0.00 | 11616 | 73.91 |
| Total | 75.15 | 3206.4 | 100 | 1990.1 | 100 | | 2090 | 100 | 15716 | 100 |

* From Alberta Energy Resources Conservation Board and Saskatchewan Department of Mineral Resources.

southwestern Ontario (Michigan and Appalachian Basin). Significant additions to hydrocarbon reserves in the continental basins over the last few years constitute increases in gas reserves only.

Figure 2 shows the distribution of the major producing oil and gas fields of western Canada and southwestern Ontario. To provide a framework for discussion of the potential environmental impact of the land-based exploration and production activities of the oil industry in Canada, the geologic and hydrologic characteristics of the Western Canadian Sedimentary Basin and the Michigan and Appalachian Basins in Ontario have been summarized in Section 2.

Most oil and gas exploration and production activities have the theoretical potential for altering the surface, subsurface, and aquatic environments, and thus have environmental impacts. Some of these activities are necessary to the success of oil and gas production, such as the installation of wells, surface production facilities, pipelines, and service road networks. In many instances, the effect of the activity is no more negative than that of timber operations or farming, such as, for example, the clearing of sites and construction of access roads into remote areas. In fact, the effect of some of these activities may be considered positive if, for instance, they increase the recreational potential of an area. However, even these positive activities have the potential for environmental degradation.

Crude oil is categorized as light (density less than 900 $kg/m^3$, API gravity greater than 25°) or heavy (density greater than 900 $kg/m^3$, API gravity less than 25°). It can also be identified as either conventional oil that is recovered without the addition of chemicals, heat, or miscible fluids or gases (i.e., those that will mix with crude oil), and nonconventional oil that requires enhanced recovery. The recovery processes themselves are categorized as primary, secondary, and tertiary. Primary recovery applies to production of oil and gas that is driven by the natural pressure in the formation resulting from expansion of contained gas or by the hydraulic gradient of the formation fluid aided by mechanical pumping or "pressure maintenance" (the injection of water or natural gas to maintain formation pressures before the natural flow declines below economic levels). Secondary recovery applies to the injection of either water or natural gas or both to repressure a formation and recover additional oil after the depletion of a reservoir by primary production. Tertiary recovery refers to the addition of chemicals, heat, or miscible fluids or gases to a reservoir to enhance recovery. It is often called "enhanced oil recovery" (EOR).

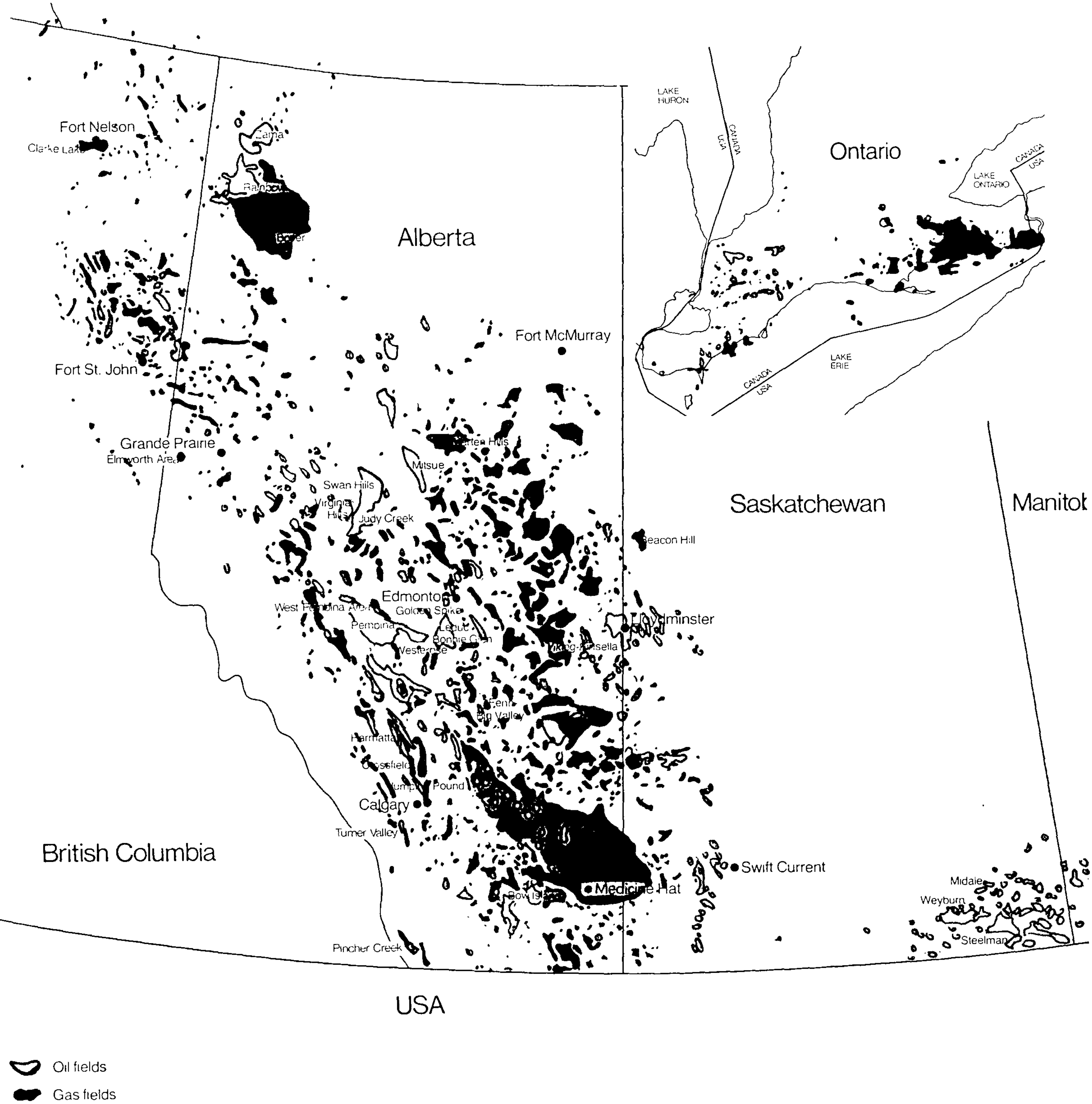



FIGURE 2 MAJOR PRODUCING OIL AND GAS FIELDS

Although enhanced oil recovery methods could be utilized for production of both light and heavy crude oils, at present they are mainly used in pilot project operations for the recovery of heavy oils or oil from tar sands deposits that are too deep for production by surface mining (*in situ* tar sands production).

In this report oil industry activities and the potential environmental impact of these activities are considered under four headings:

i) oil and gas drilling,
ii) conventional oil and gas production (primary and secondary recovery), and
iii) enhanced oil recovery (tertiary recovery of heavy oil), and
iv) *in situ* tar sands development.

These four categories are used because the activities, methods employed, disposal practices, and potential effects are qualitatively different for each category.

Oil and gas production and the procedures used are greatly affected by government regulatory activities. The primary agencies responsible for the implementation and enforcement of regulations relating to onshore oil and gas drilling and production in Canada are the provincial departments or ministries.

The main provincial agencies and relevant acts or regulations containing environmental implications which affect the petroleum industry are summarized in Table 2. The province of Alberta alone drilled approximately 80 percent of Canada's total oil and gas wells in 1980 (Canadian Petroleum Association, 1981) and has the most comprehensive and rigorous legislation. The types of environmental controls enforced by various agencies in Alberta are discussed in detail in this report. Saskatchewan and British Columbia follow Alberta in drilling statistics, and for the sake of brevity these provinces are discussed only in cases where legislation differs significantly from that of Alberta and/or where other environmental aspects are regulated.

The main agencies regulating oil and gas drilling in the province of Alberta are the Energy Resources Conservation Board (ERCB), the Department of the Environment (DE), and the Department of Energy and Natural Resources (DENR). Since all are responsible for some aspects of "environmental protection" or "conservation", their authority overlaps. The main agency responsible for oil and gas drilling and production activities is the ERCB whose function is the "management of energy resources and energy within the province" including appraisal of reserves, capacities, energy requirements and markets, and conservation of resources and the environment in energy-related activities (ERCB, 1972). The Department of the Environment is responsible for coordinating

TABLE 2 REGULATORY AGENCIES AND LEGISLATION

| Province | Agency | Act and/or Regulations |
|---|---|---|
| Alberta | Energy Resources Conservation Board | The Oil and Gas Conservation Act and Regulations. |
| | Department of the Environment | The Clean Water Act and Regulations.<br>The Department of the Environment Act.<br>The Land Surface Conservation and Reclamation Act.<br>Water Resources Act.<br>Ground Water Control Act. |
| | Department of Energy and Natural Resources | The Mines and Minerals Act.<br>The Public Lands Act.<br>The Forests Act, 1971.<br>The Public Highways Development Act (Exploration Regulations). |
| Saskatchewan | Department of Mineral Resources | Oil and Gas Conservation Act (short title).<br>Office consolidation of the Oil and Gas Conservation Regulations. |
| British Columbia | Ministry of Energy Mines and Petroleum Resources, Petroleum Resources Branch. | Petroleum and Natural Gas Act.<br>Drilling and Production Regulations. |

policies, setting and enforcing standards involving the prevention, monitoring and control of pollution, determining the impact of land surface disturbances, managing water resources, and conducting research relating to environmental aspects of all industries including the energy industry. The Department of Energy and Natural Resources has legislation concerning land use, surface rights, surface disturbances and sub-surface exploration. The interdependency of these agencies resulted in the formation of two coordinating councils under the Department of the Environment Act: the Natural Resources Coordinating Council and the Conservation and Utilization Committee. Both include representatives of the ERCB and Department of Energy and Natural Resources, among others, and their purpose is to review policies, make recommendations and conduct studies.

In the province of Saskatchewan, the main agency responsible for the regulation of oil and gas drilling and production activities is the Department of Mineral Resources. The Department administers the Oil and Gas Conservation Act and Regulations, the purpose of which is to prevent waste, to develop, protect and conserve oil and gas resources of the province, and to regulate operations so that the greatest recovery is achieved.

The Ministry of Energy, Mines and Petroleum Resources of the province of British Columbia administers the Petroleum and Natural Gas Act and the associated Drilling and Production Regulations. The Act and Regulations are the main pieces of legislation regarding oil and gas drilling and production activities and include provisions for all aspects of well locating, drilling, casing, completion, abandonment and waste disposal as well as regulating conventional production and enhanced recovery schemes.

A major concern related to oil and gas production is the disposal of liquid wastes by injection into wells in deep formations. This practice has become very attractive in recent years, partly because of the growing public concern about pollution of man's environment, partly because deep well disposal is economically attractive if the formations are sufficiently permeable to accept high injection rates, and partly because deep formations are physically isolated from public view and have the psychological appearance of being environmentally safe.

van Everdingen and Freeze (1971) contend that deep well disposal results in "irreversible pollution" of the host formation and is not necessarily a permanent solution to the waste disposal problem because the waste may well be transported in the subsurface groundwater flow system to reappear elsewhere. van Everdingen and Freeze (1971) also present the best discussion of disposal philosophy in the north American literature. They recognize two classes of liquid waste - "natural" wastes containing only constituents normally found in solution in groundwater, and "foreign" wastes containing any constituents not normally found in solution in groundwater. Saline waters and brines produced by the oil industry are "natural" wastes. They also recognize that some non-waste fluids are injected into the subsurface, primarily water and natural gas for secondary recovery or pressure maintenance schemes in the oil industry and natural gas for temporary underground storage. All other fluids that are injected into the subsurface by the oil industry, either in enhanced oil and _in situ_ tar sands recovery operations or in deep well disposal operations, would be "foreign" fluids.

van Everdingen and Freeze (1971) identify four criteria that must be met by a region before it can be considered to hold potential for safe disposal of liquid wastes. These criteria are:

i) extensive and thick sedimentary rocks (sediments have significant pore space for disposal),
ii) lack of major faulting (faults and fractures in rock provide pathways for rapid waste migration),
iii) lack of seismic activity (seismically active areas are likely to be fractured and injection may trigger seismic events), and
iv) existence of low hydrodynamic gradients (the gradients, whether hydraulic, chemical, or thermal, are a major control on rate and direction of fluid flow and mass transport in the subsurface).

A formation being considered as a waste host must:

i) be sufficiently permeable to accept an injected fluid,
ii) be sufficiently extensive in size that the disposal site can be far from an area of discharge to man's environment,
iii) be rounded by uniformly low permeability units to provide waste confinement,
iv) be hydrologically isolated from aquifers containing potable water,
v) be lithologically compatible with the injected fluid,
vi) contain formation fluids that are chemically compatible with the injected fluid,
vii) contain fluids at low pressure, and
viii) contain hydrodynamic gradients that are very low or are directed vertically downwards.

Most deep well waste disposal in Canada is by industries whose liquid wastes are either natural brines derived from potash mining or "foreign" wastes derived from potash mining or "foreign" wastes derived from chemical production. van Everdingen and Freeze (1971), Vonhof and van Everdingen (1973), and van Everdingen (1974) have provided national reviews of subsurface disposal of liquid industrial wastes. McLean (1968) and Vandenberg, et al (1977) discuss Ontario, and Simpson and Dennison (1975) discuss Saskatchewan.

At least 95 percent of the liquids injected to the subsurface are not wastes but brines injected for pressure maintenance or secondary recovery schemes. These liquids are not a concern. They have minimal potential for environmental impact because they are intended to maintain existing or earlier pressure conditions in the reservoir. In addition, secondary recovery commonly recycles as much water from the original reservoir as possible, thereby minimizing adverse chemical reactions between injected water and the formation water and rock. Even when water is taken from shallow aquifers for injection the long-term effects appear to be minimal (Whitaker, 1980a).

Deep well disposal by the oil industry becomes a potential problem when the liquid waste is sour water or spent caustic from refineries or when exotic chemicals or heat are injected in large quantities or at high pressures. Refinery wastes have tended not to be a problem in western Canada because the refineries are commonly located far from regional groundwater discharge areas and the injection takes place deep in the basin. The subsurface in southwestern Ontario has been extensively polluted by brine injection, hydrocarbon leaks through poorly abandoned wells, and deep disposal. Fortunately high recharge rates from the high annual precipitation in Ontario maintain potable supplies in most of the shallow aquifers in southwestern Ontario.

In western Canada potential problems will be associated with enhanced oil and in situ tar sands recovery operations which involve use of fresh water for steam generation; injection of steam, hot water, or hot caustic with or without in situ combustion; and disposal of the liquid wastes separated from the oil produced. These operations will be concentrated geographically in a triangular area bounded by Peace River, Fort McMurray, and Lloydminster in northeastern Alberta and an adjacent area in Saskatchewan. There is less than 1500 m of sediment above the Precambrian Basement in the area and flow from the regional groundwater system in the Alberta portion of the Western Canadian Sedimentary Basin has concentrated along high permeability zones (faults or fractures) in the Devonian carbonates discharging to the surface in this region. As a region it does not meet three of the four criteria for potential safe disposal listed by van Everdingen and Freeze (1971). The water for injection is commonly drawn from formations above the oil producing units, whereas liquid wastes are disposed of into formations below the oil producing units. In the tar sands area there is hydrologic connection throughout the stratigraphic section. A much more thorough understanding of the hydrogeology of the region than now exists will be required before the interactions that might take place among water extraction, steam injection, and waste injection within this system can be understood, excluding any reference to the tremendous changes that will take place in the formation fluids if in situ combustion is used.

Despite the passage of more than ten years since van Everdingen and Freeze (1971) identified critical research needs, it is still true that "essentially, nothing is known about the behavior of many of these wastes when they come in contact with natural formation rocks, under the conditions of elevated temperature and pressure that prevail in the subsurface." The woefully inadequate monitoring programs associated with existing deep well disposal programs in Canada have produced no meaningful understanding even of the migration of the disposed fluids much less of any increases or decreases in toxicity or hazard to man that may have taken place either by degradation or chemical reaction in the host media.

# 2 GEOLOGIC FRAMEWORK

## 2.1 Western Canadian Sedimentary Basin

**2.1.1 Regional Structure and Stratigraphy.** The Western Canadian Sedimentary Basin is a northwest-southeast oriented trough bounded on the west by the foothills of the Rocky Mountains and on the east by the crystalline rocks of the Canadian Shield. The basin extends from the United States border on the south to the Mackenzie Delta in the Northwest Territories. Figure 3 shows the structure beneath the basin and the location of three cross-sections (Figure 4) that illustrate the gross structural and stratigraphic relationships in the basin.

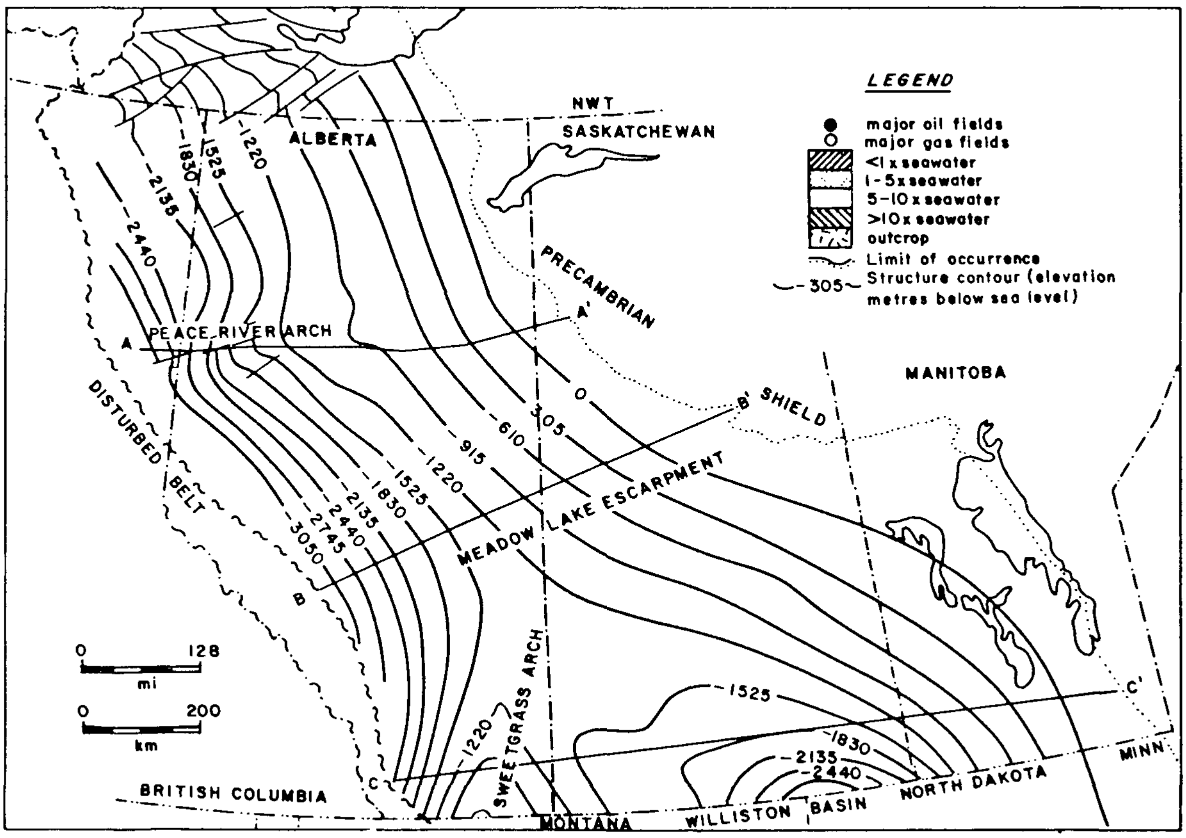



FIGURE 3 STRUCTURE ON PRECAMBRIAN SURFACE BELOW WESTERN CANADIAN SEDIMENTARY BASIN (Hitchon, 1969a)

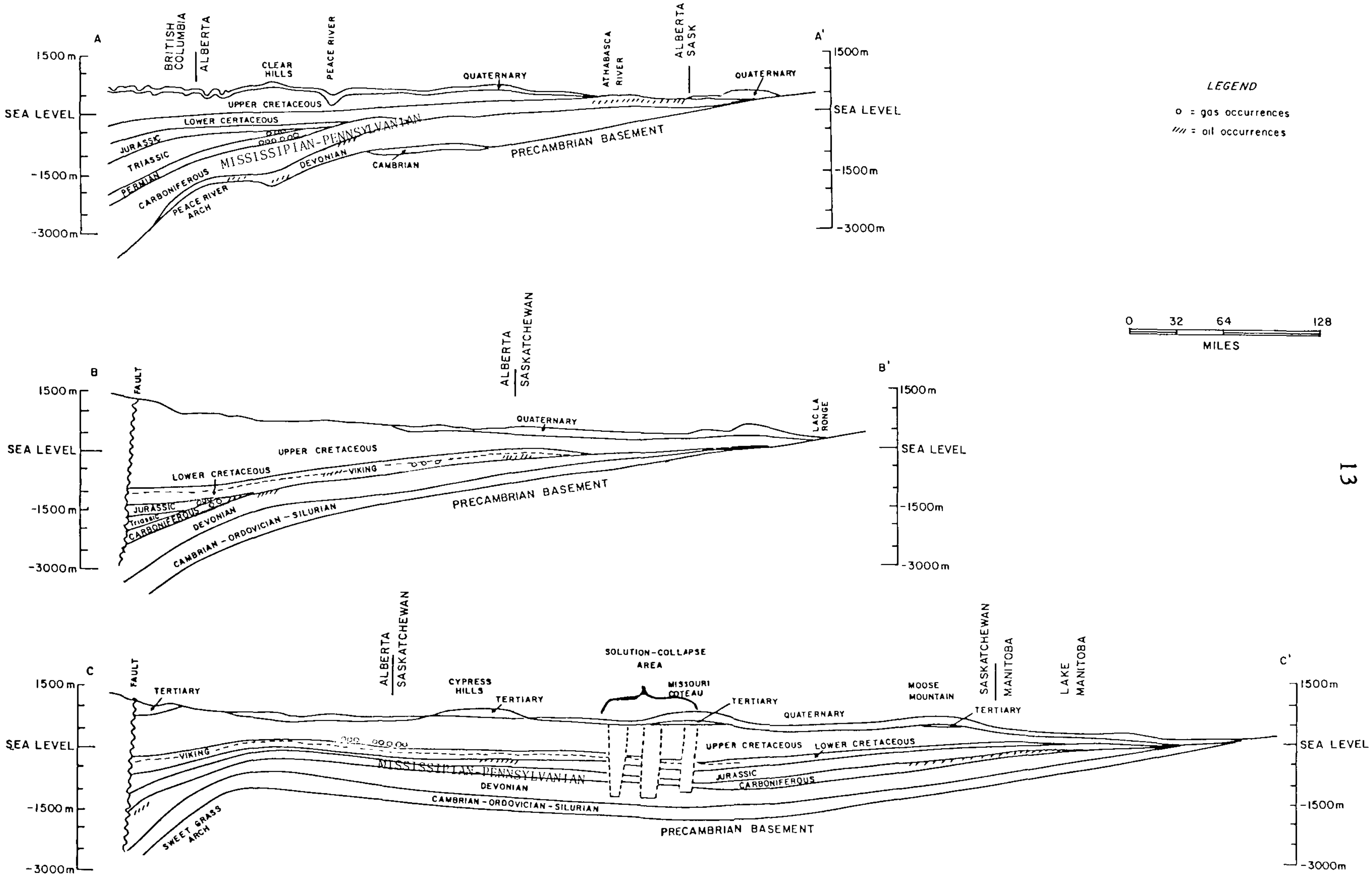



FIGURE 4 STRATIGRAPHIC CROSS-SECTIONS

The geological history of the basin and the geology of hydrocarbon occurrence are well documented in McCrossan et al (1964) and McCrossan (1973). In this report the occurrence and modes of entrapment of hydrocarbons are discussed in a general way in conjunction with figures illustrating formation fluid quality and flow directions based on Hitchon (1964, 1969a and 1969b). Table 3 shows the nomenclature for formations in the basin and Table 4 gives hydrocarbon reserves by major stratigraphic units. It is apparent that most of the hydrocarbons occur in relatively few formations.

Sedimentation began in the basin during Cambrian time when a marine sea advanced over British Columbia and the shoreline moved eastward across Alberta and southern Saskatchewan depositing fine to coarse sand-sized sediments on the Precambrian surface as the weathered crystalline rocks were reworked. Marine shales and carbonates (limestone or dolomite) were deposited as the shallow sea covered the area. During Ordovician and Silurian times the Williston Basin of the Dakotas and southern Saskatchewan began to subside and sedimentation was concentrated within it with some anhydrite (evaporite salts) interbedded with the carbonates. Figures 5, 6 and 7 show the distribution of Cambrian, Ordovician, and Silurian sediments as well as variations in the concentration of chloride in the formation fluids in comparison to seawater (18 980 mg/L). No significant hydrocarbon reserves have been found in these sediments, although a few producing wells have been completed in carbonates in southern Saskatchewan near the northeast corner of Montana in the Upper Ordovician Red River formation. The oil is trapped by overlying anhydrite beds.

A corridor of relatively fresh formation fluid is apparent from southwestern Saskatchewan to the northeast towards the outcrop area on all three maps. Near their eastern limit all three formations show a zone where the formation fluid is fresher than seawater.

Sedimentation took place over most of the basin in mid-Devonian time. Clastics were deposited on the flanks of the Peace River Arch, carbonates were deposited further offshore but in sufficiently shallow water for reefs to develop, and in the basin centre from the Northwest Territories to Dakota evaporites (anhydrite, halite, and sylvite) were deposited interbedded with thin red shale beds. Figure 8 (A and B) shows the distribution of Middle Devonian rock types and Figure 9 shows variations in concentration of chloride in the formation fluids and significant hydrocarbon occurrences. Middle Devonian rocks contain 14.5 percent of remaining recoverable oil reserves and 3.1 percent of remaining recoverable gas reserves. Forty percent of the oil occurs in sands (Gilwood formation) lying directly on the Precambrian on the east flank of the Peace River Arch.

TABLE 3 FORMATION NAMES (ERCB, Alberta, Canada, July, 1978)

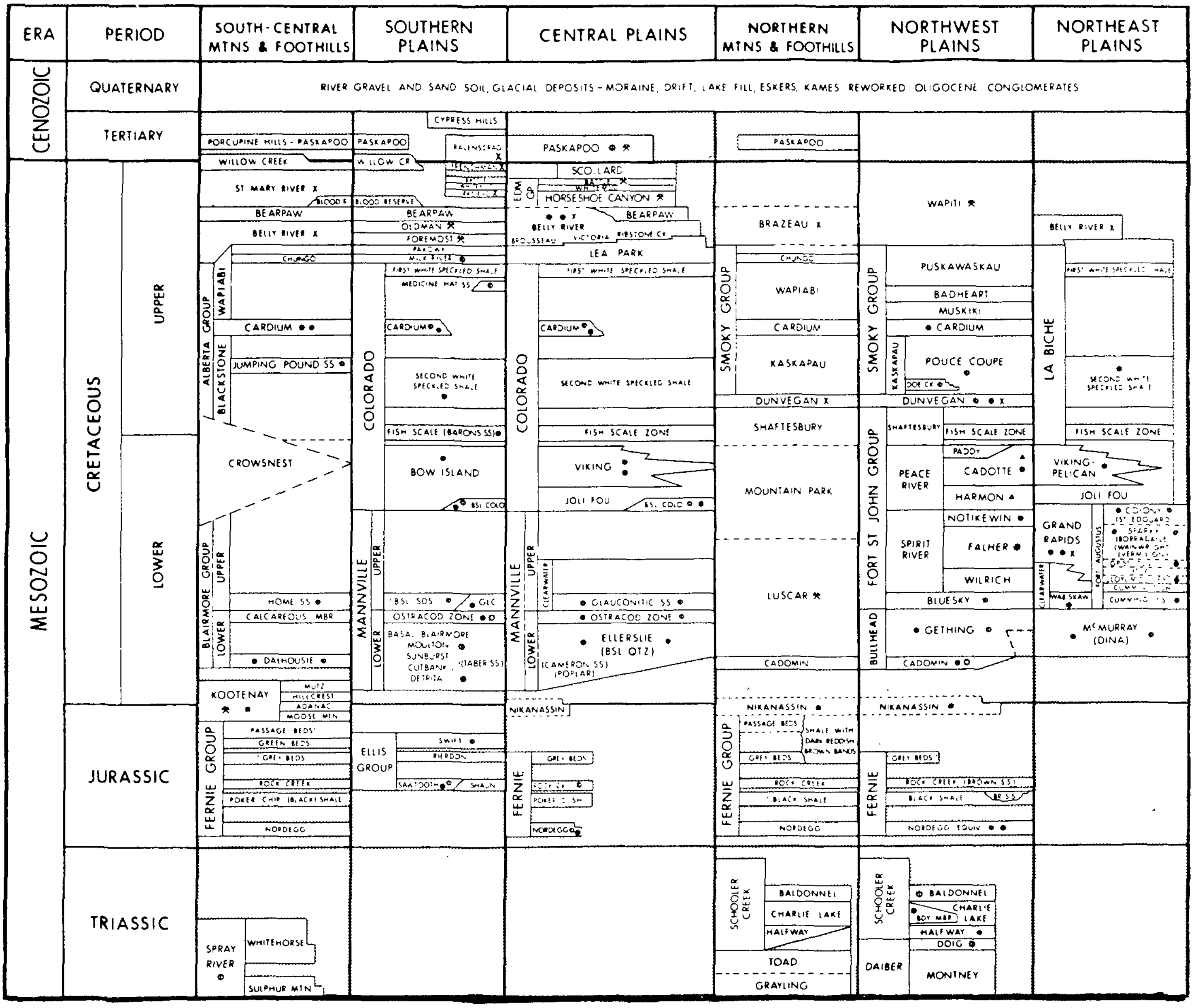
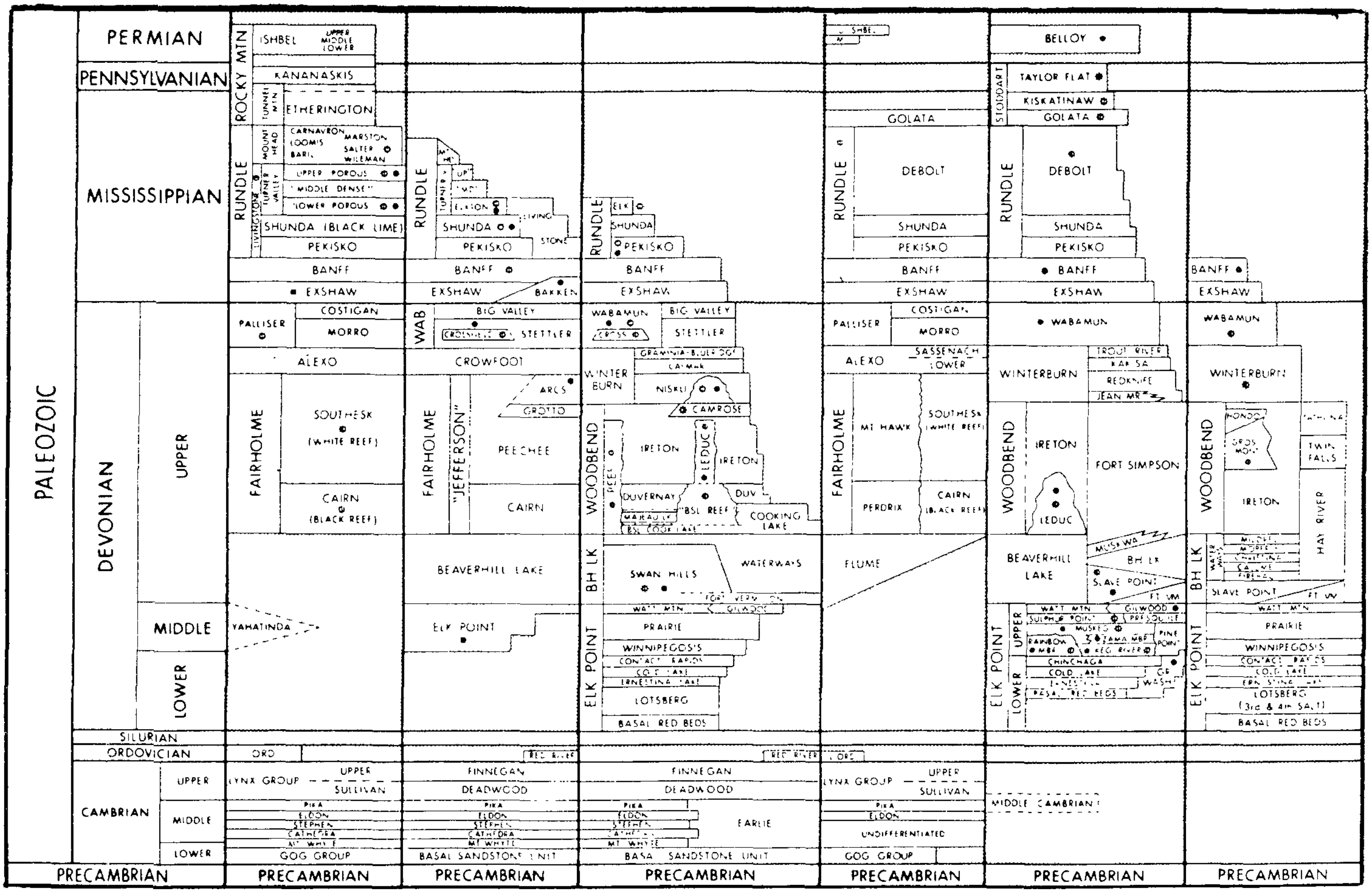


TABLE 3 FORMATION NAMES (ERCB, Canada, July, 1978) (cont'd)




## LEGEND

| | |
|---|---|
| Gas | ✱ |
| Oil | • |
| Coal (coal-bearing, mined) | x, ✱ |
| Correlation Uncertain | ---- |
| Facies Transition | \ or Z |

## NOTES

In the northwest plains column, the Peace River upper Devonian stratigraphy is shown at the left and the Rainbow stratigraphy at the right.

■ age not conclusively established

Δ the faunas suggest that the Cadotte is not the equivalent of the Pelican.

Alternative local names are shown in brackets.

TABLE 4 OIL AND GAS RESERVES BY STRATIGRAPHIC UNIT

| | Oil ($10^6$ $m^3$) | | | | Gas ($10^9$ $m^3$) | | | |
|---|---|---|---|---|---|---|---|---|
| | Total | % | Remain | % | Total | % | Remain | % |
| Upper Cretaceous | | | | | | | | |
| Belly River | 23.1 | 0.95 | 13.1 | 1.47 | 24.4 | 0.78 | 17.8 | 0.91 |
| Medicine Hat | | | | | 280.1 | 8.95 | 212.1 | 10.88 |
| Cardium | 305.3 | 12.52 | 133.1 | 14.95 | 64.6 | 2.07 | 46.5 | 2.39 |
| 2nd Specks | | | | | 42.2 | 1.35 | 34.1 | 1.75 |
| Other | 0.9 | 0.04 | 0.5 | 0.06 | 10.3 | 0.33 | 9.1 | 0.47 |
| TOTAL | 329.3 | 13.51 | 146.7 | 16.47 | 421.6 | 13.48 | 319.6 | 16.40 |
| Lower Cretaceous | | | | | | | | |
| Viking | 56.7 | 2.33 | 14.9 | 1.67 | 275.5 | 8.81 | 159.9 | 8.20 |
| Mannville | 179.3 | 7.35 | 80.4 | 9.03 | 610.8 | 19.53 | 458.6 | 23.53 |
| Other | 3.7 | 0.15 | 1.1 | 0.12 | 104.5 | 3.34 | 54.4 | 2.79 |
| TOTAL | 239.7 | 9.83 | 96.4 | 10.83 | 990.8 | 31.68 | 672.9 | 34.52 |
| Jurassic | | | | | | | | |
| Roseray | 42.3 | 1.74 | 10.9 | 1.22 | 0.7 | 0.02 | 0.2 | 0.01 |
| Shaunavon | 39.8 | 1.63 | 6.6 | 0.74 | 0.4 | 0.01 | 0.1 | 0.01 |
| Other | 13.8 | 0.57 | 7.1 | 0.80 | 37.2 | 1.19 | 26.5 | 1.36 |
| TOTAL | 95.9 | 3.93 | 24.6 | 2.76 | 38.3 | 1.22 | 26.8 | 1.37 |
| Triassic | | | | | | | | |
| Baldonnel | | | | | 107.8 | 3.45 | 69.3 | 3.56 |
| Charlie Lake | 43.9 | 1.80 | 14.3 | 1.61 | 16.8 | 0.54 | 9.8 | 0.50 |
| Halfway | 27.1 | 1.11 | 8.5 | 0.95 | 40.4 | 1.29 | 24.3 | 1.25 |
| Other | 22.6 | 0.93 | 11.7 | 1.31 | 36.1 | 1.15 | 33.5 | 1.72 |
| TOTAL | 93.6 | 3.84 | 34.5 | 3.87 | 201.1 | 6.43 | 136.9 | 7.02 |
| Permian | | | | | 16.6 | 0.53 | 11.1 | 0.57 |
| Mississippian | | | | | | | | |
| Rundle | 71.1 | 2.92 | 20.1 | 2.26 | 590.2 | 18.87 | 330.1 | 16.94 |
| Midale | 133.6 | 5.48 | 26.5 | 2.98 | 2.5 | 0.08 | 0.5 | 0.03 |
| Frob.-Alida | 63.8 | 2.62 | 23.9 | 2.68 | 2.9 | 0.09 | 0.9 | 0.05 |
| Tilston | 33.9 | 1.39 | 6.1 | 0.69 | 2.3 | 0.07 | 0.4 | 0.02 |
| Other | 29.3 | 1.20 | 13.3 | 1.49 | 48.2 | 1.54 | 27.5 | 1.41 |
| TOTAL | 331.7 | 13.61 | 89.9 | 10.10 | 646.1 | 20.66 | 359.4 | 18.44 |
| Upper Devonian | | | | | | | | |
| Wabamun | 1.5 | 0.06 | 0.3 | 0.03 | 91.9 | 2.94 | 55.5 | 2.85 |
| Nisku | 132.1 | 5.42 | 48.3 | 5.42 | 29.8 | 0.95 | 21.2 | 1.09 |
| Leduc | 457.3 | 18.76 | 94.3 | 10.59 | 241.1 | 7.71 | 116.6 | 5.98 |
| Beaverhill L | 422.3 | 17.33 | 182.5 | 20.49 | 126.1 | 4.03 | 93.6 | 4.80 |
| Slave Point | | | | | 154.3 | 4.93 | 93.5 | 4.80 |
| Other | 6.1 | 0.25 | 3.9 | 0.44 | 38.9 | 1.24 | 16.2 | 0.83 |
| TOTAL | 1019.5 | 41.82 | 329.3 | 36.98 | 682.1 | 21.81 | 396.6 | 20.35 |
| Mid Devonian | | | | | | | | |
| Keg River | 162.6 | 6.67 | 79.1 | 8.88 | 13.3 | 0.43 | 11.1 | 0.57 |
| Gilwood | 111.3 | 4.57 | 48.8 | 5.48 | 7.2 | 0.23 | 4.1 | 0.21 |
| Other | 36.9 | 1.51 | 30.7 | 3.45 | 6.1 | 0.20 | 5.7 | 0.29 |
| TOTAL | 310.8 | 12.75 | 158.6 | 17.81 | 26.6 | 0.85 | 20.9 | 1.07 |
| Other | 17.3 | 0.71 | 10.5 | 1.18 | 104.7 | 3.35 | 4.9 | 0.25 |
| GRAND TOTAL | 2437.8 | 100 | 890.5 | 100 | 3127.9 | 100 | 1949.1 | 100 |

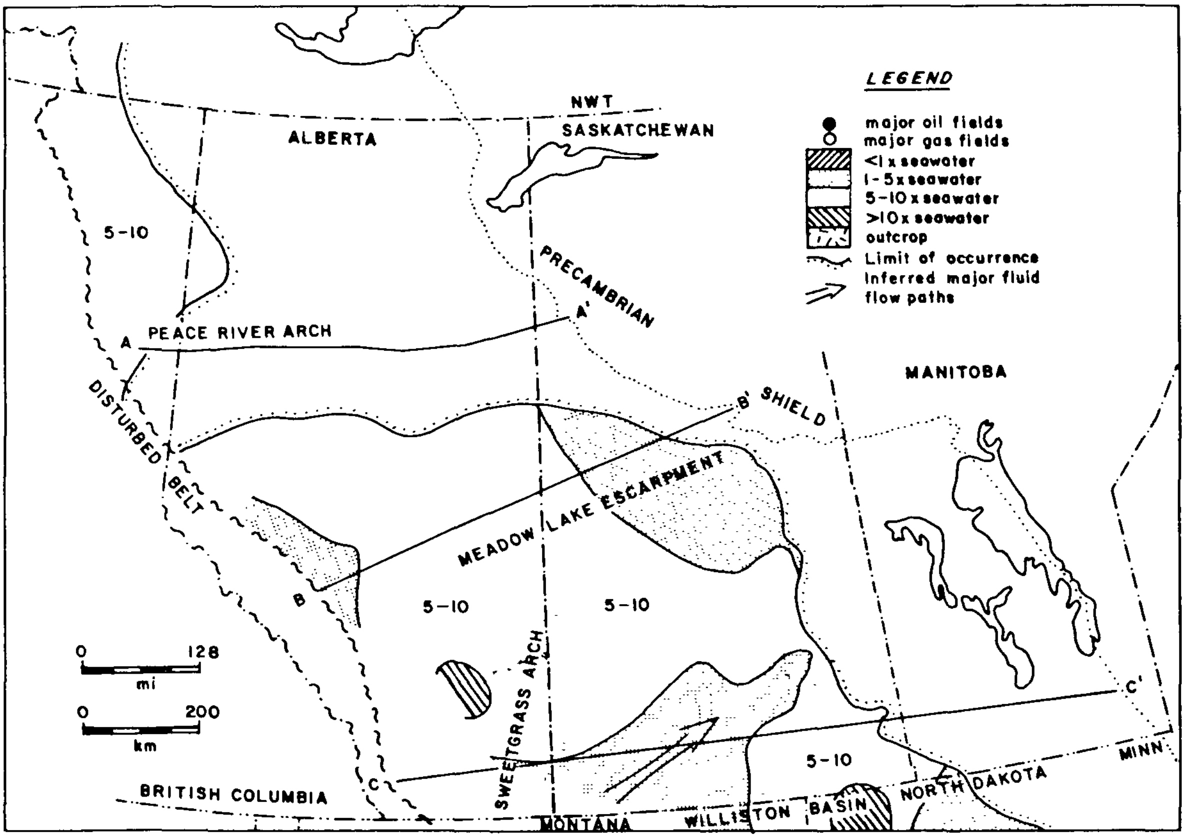



FIGURE 5 DISTRIBUTION OF CAMBRIAN SEDIMENTS AND CHLORIDE CONTENT (modified from Hitchon, 1964)

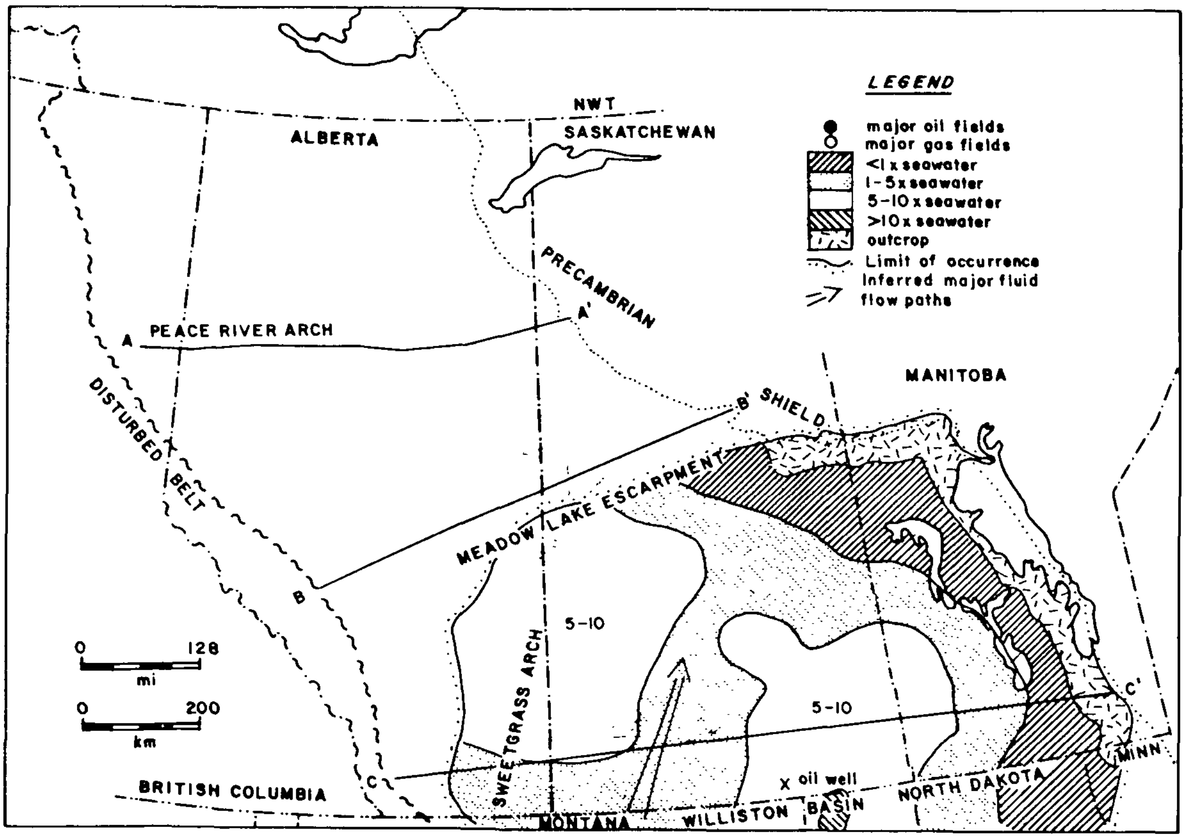



FIGURE 6 DISTRIBUTION OF ORDOVICIAN SEDIMENTS AND CHLORIDE CONTENT (modified from Hitchon, 1964

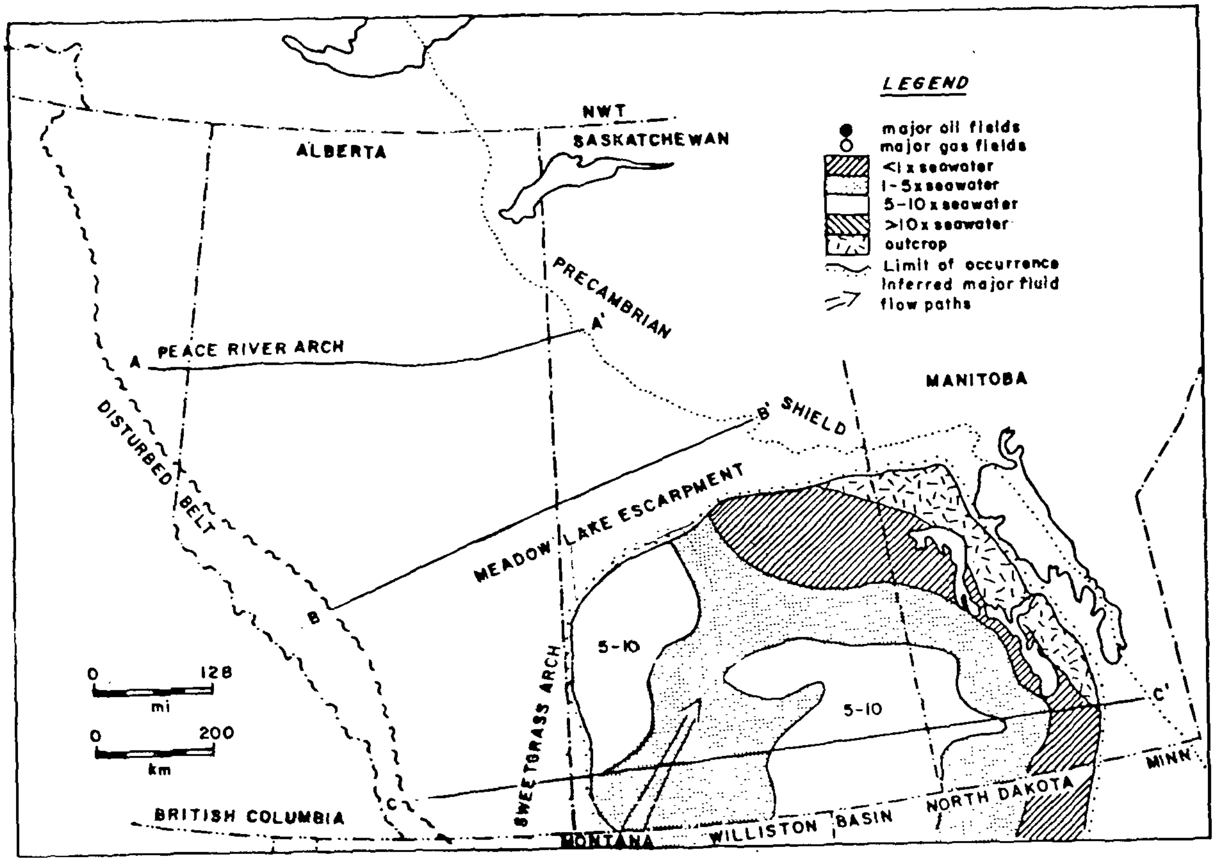



FIGURE 7 DISTRIBUTION OF SILURIAN SEDIMENTS AND CHLORIDE CONTENT (modified from Hitchon, 1964)

The remainder occurs in pinnacle reefs (Keg River formation offshore from the Presqu'ile Barrier Reef in the northwest corner of Alberta). The Rainbow (Keg River) oil field alone accounts for 7.5 percent of remaining oil reserves. The bounding and overlying shales and evaporites act as reservoir seals trapping the oil in the permeable reef carbonates and Gilwood sands. Again there is a fresh corridor in the formation fluids extending northeast from southwestern Saskatchewan, but there is no apparent freshing towards the outcrops along the Clearwater River as there is towards Pine Point and towards the outcrops in Manitoba (Figure 9).

Sedimentation continued with the Upper Devonian Beaverhill Lake formation. Reef development moved further southeast from the Peace River Arch (Swan Hill reefs) but continued along the Presqu'ile trend (Slave Point reefs). Figure 8 shows the distribution of rock types and Figure 10 shows the variations in chloride concentration in the formation fluids and hydraulic head in the formation. The Swan Hills reefs contain 20.5 percent of the remaining reserves of oil and 4.8 percent of the remaining reserves of

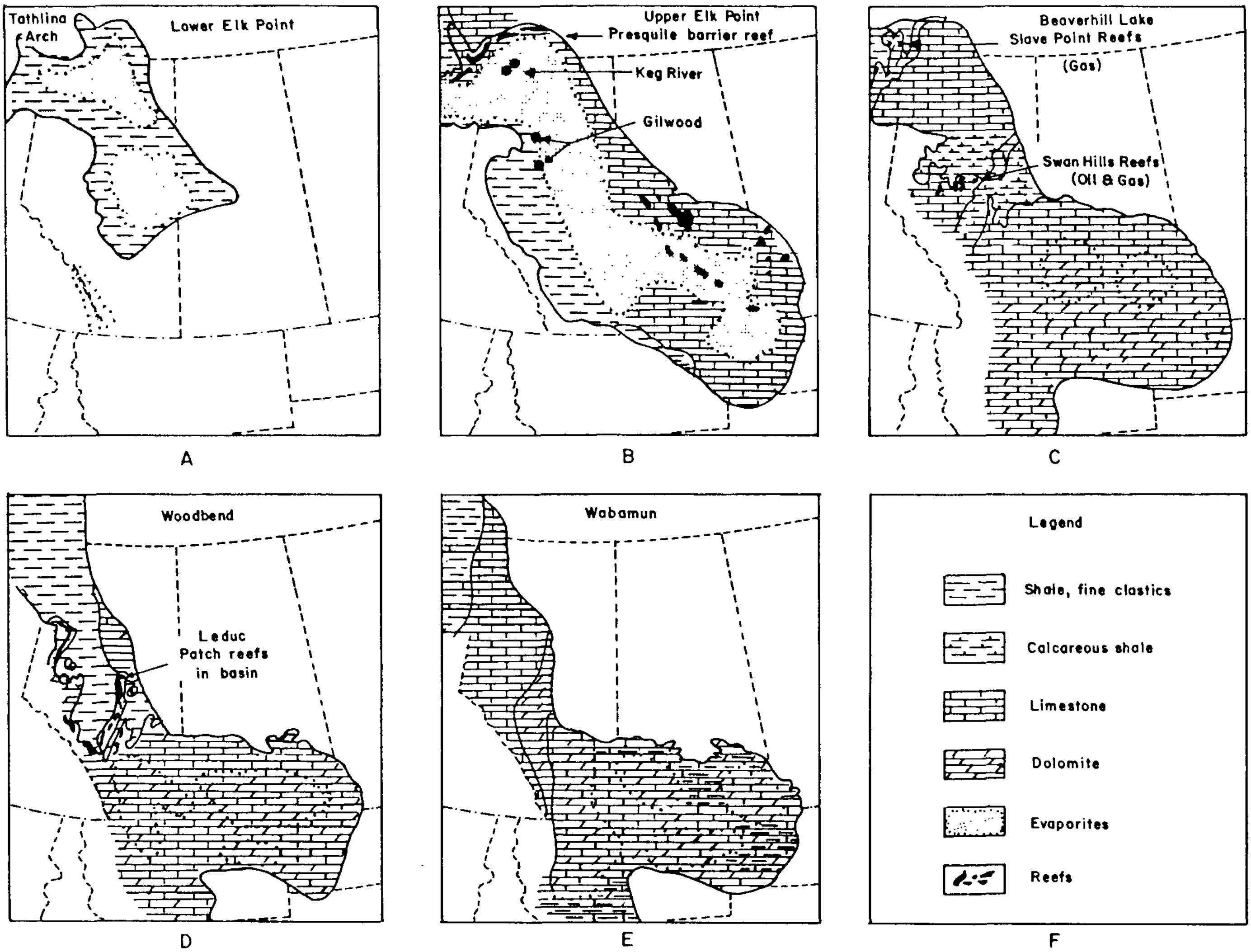



FIGURE 8 DISTRIBUTION OF LITHOLOGIES FOR DEVONIAN ROCKS (modified after Stearn et al, 1979)

gas, while the Slave Point reefs contain an additional 4.8 percent of remaining gas reserves.

Contours of hydraulic head distribution in the Beaverhill Lake formation (Figure 10) show a trough in southern Saskatchewan where the low salinity corridor was located in older sediments. The location of the trough also appears to coincide with the location of the major solution collapse features associated with the removal of the Middle Devonian prairie evaporite formation (Figure 4, C-C'). This suggests that the collapse structures, some of which extend from the bedrock surface to the prairie evaporite, have increased the vertical hydraulic conductivity through the stratigraphic section in this area, creating a groundwater drain.

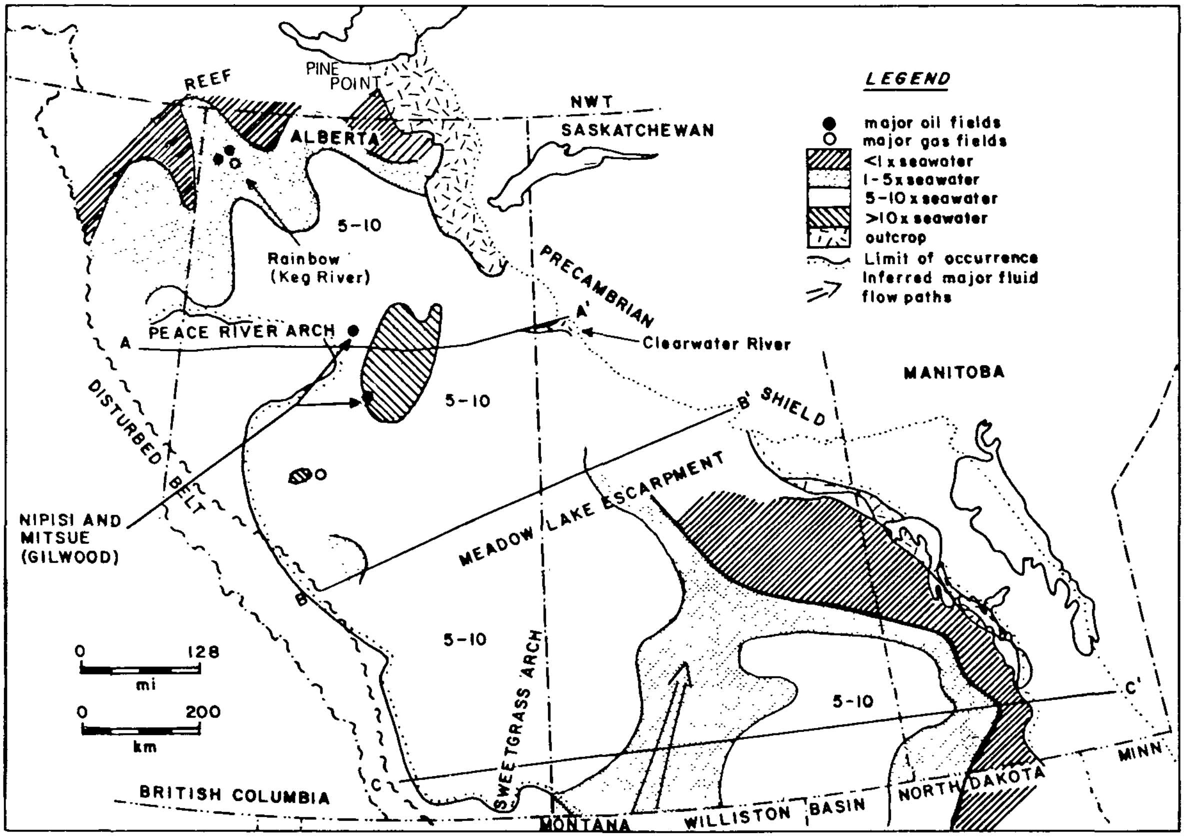



FIGURE 9 CHLORIDE CONCENTRATION IN FORMATION FLUIDS - MIDDLE DEVONIAN (modified after Hitchon, 1964)

Reef development continued to move to the southeast as the Upper Devonian Woodbend group was deposited. The reefs (Leduc formation) are concentrated on a shelf area separating shaley sediments in northern Alberta from carbonates and evaporites in the Williston Basin. Figure 8 shows the distribution of rock types and Figure 11 shows the variations in chloride concentration in the formation fluids and hydraulic head in the group. Virtually all the hydrocarbons are trapped in the carbonate reefs of the Leduc formation, which contain 10.6% of the remaining reserves of oil and 6.0 percent of the remaining reserves of gas.

The salinity and hydraulic head distributions in the Woodbend group indicate that the Leduc reef trend is also associated with a high permeability drain to the north-northeast. Over the sweetgrass Arch formation fluids are being diluted by downward percolating groundwater and in southern Saskatchewan the drain associated with solution collapse features is also apparent.

Towards the close of the Devonian Period, carbonate deposition dominated in the entire basin but no further reef development took place. However, the older Leduc

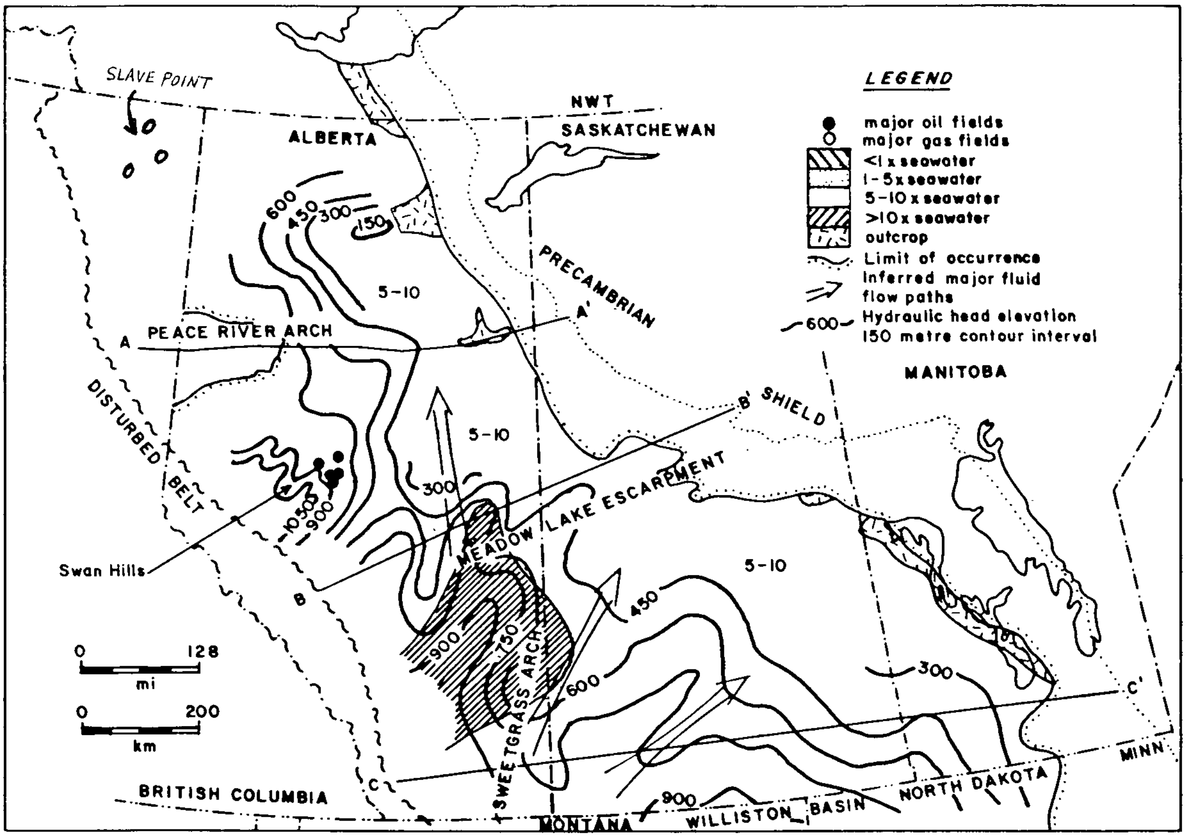



FIGURE 10 HYDRAULIC HEAD DISTRIBUTION - UPPER DEVONIAN BEAVERHILL LAKE FORMATION (modified after Hitchon, 1964)

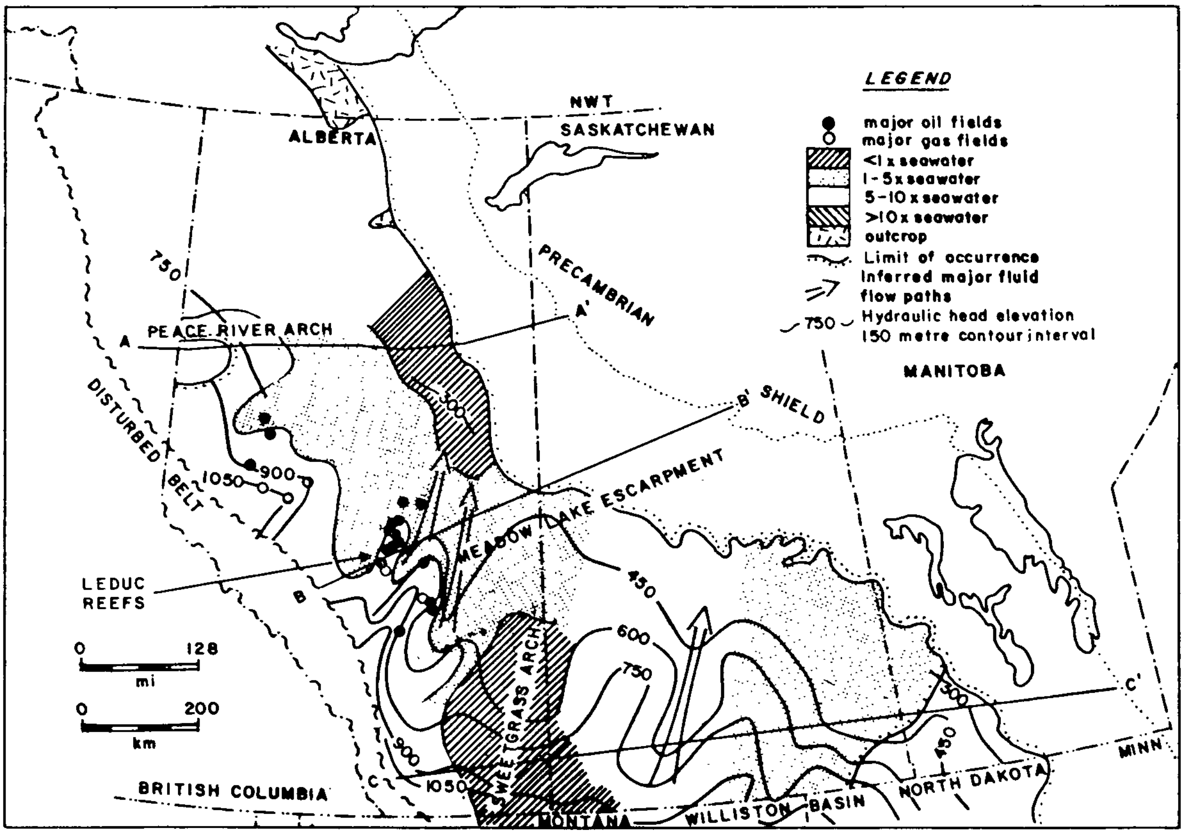



FIGURE 11 HYDRAULIC HEAD DISTRIBUTION - UPPER DEVONIAN WOODBEND GROUP (modified after Hitchon, 1964)

reefs still had an effect on the distribution of porous zones in the carbonates of the overlying Nisku formation. The major oil fields shown in Figure 12 parallel the Leduc reef trend. Major drains are not apparent in the salinity distribution, but dilution over the Sweetgrass Arch and along the subcrop of the Nisku is apparent (Figure 12). The Nisku contains 5.4 percent of remaining oil reserves but only one percent of remaining gas reserves.

The Wabamun formation is the youngest Upper Devonian formation. Figure 8 shows the distribution of rock types in the Wabamun. There is very little oil in the Wabamun but it does contain 2.8 percent of the remaining reserves of gas. Figure 13 shows the distribution of chloride concentration in the formation fluids.

The Mississippian Period (Carboniferous) began with the deposition of shaley rocks. Except for the Bakken formation in southwestern Saskatchewan, this portion of the Mississippian contains virtually no hydrocarbons. Subsequently bioclastic limestones were deposited. The Rundle formation in Alberta and British Columbia contains 2.3 percent of remaining oil and 16.9 percent of remaining gas reserves, whereas the Midale and Frobisher-Alida formations in southeastern Saskatchewan and southwestern Manitoba contain 5.7 percent of the remaining oil reserves. Most of the hydrocarbons are trapped by shaley sediments or anhydrite at the erosional surface on the top of the Mississippian. Figure 14 shows the variation in chloride content in the formation fluids of the Mississippian carbonates. The hydrocarbon occurrences coincide with areas of higher chloride content in the formation fluids. Where low permeability traps do not occur at the top of the Mississippian the rocks have been flushed of hydrocarbons by the groundwater system.

Pennsylvanian (Carboniferous) sediments occur only in the area of the Peace River Arch, which at this time had become a basin. No hydrocarbons are produced from the Pennsylvanian sediments.

Permian sediments are also confined to the area of the Peace River Arch. Sands of the Belloy formation contain less than 1% of the remaining gas reserves.

During the Triassic Period, marine submergence extended farther eastward in the Peace River area and affected the Williston basin south of Saskatchewan. Figure 15 shows the distribution of Triassic rocks. Hydrocarbons occur in sands of the Halfway formation and the overlying carbonates of the Charlie Lake and Baldonnel formations in northeastern British Columbia near Fort St. John. Triassic rocks contain 3.9 percent of remaining oil reserves and 7.0 percent of remaining gas reserves.

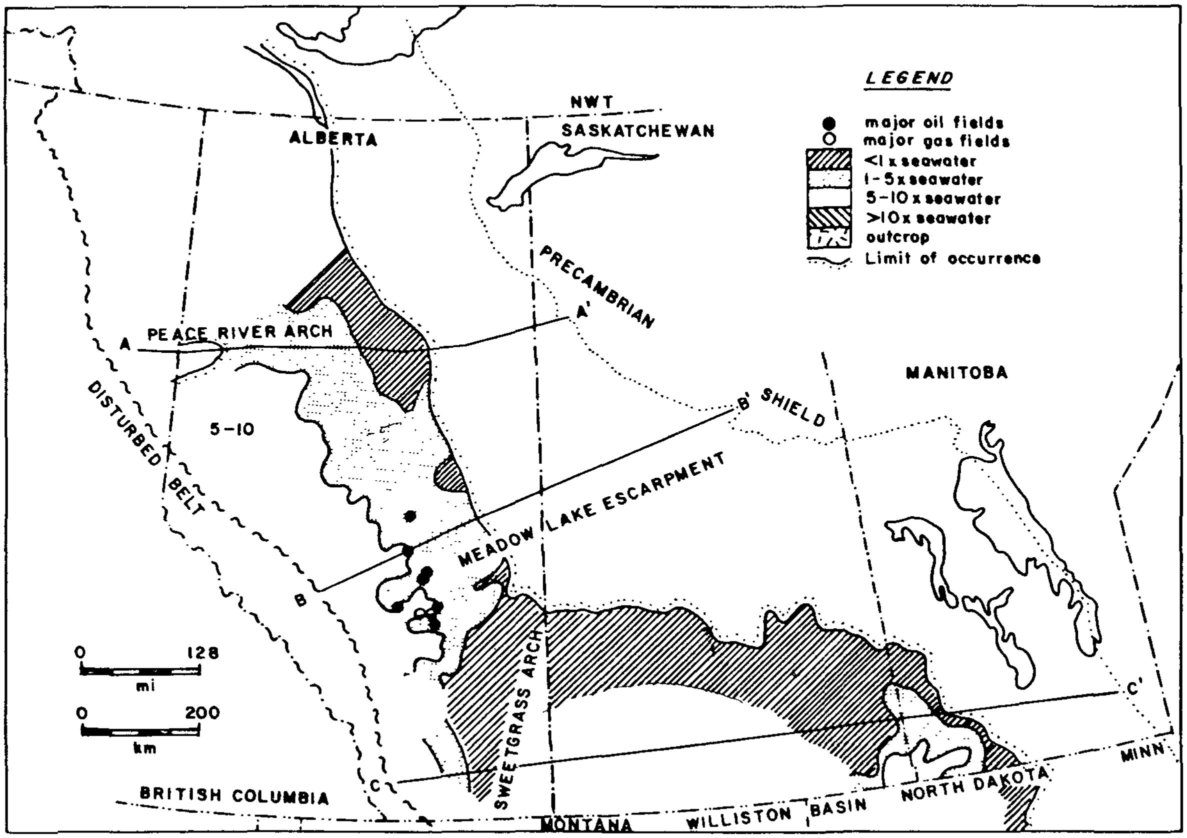



FIGURE 12 CHLORIDE CONCENTRATION IN FORMATION FLUIDS - UPPER DEVONIAN WINTERBURN GROUP (NISKU) (modified after Hitchon, 1964)

The area of submergence continued to expand during the Jurassic Period in southeastern Alberta and into Saskatchewan and Manitoba from the Williston Basin. Hydrocarbons occur only in the basal sand (Nordegg) in Alberta and trapped in channel and beach sands (Shaunavon) or at the erosional surface (Roseray) in Saskatchewan. Figure 16 shows the distribution of Jurassic rocks in the basin. Jurassic rocks contain only 2.8 percent of remaining oil reserves and 1.4 percent of remaining gas reserves.

During the early Cretaceous Period, uplift in the Rocky Mountains began to supply sediment to the basin while marine seas advanced both from the Arctic and the Williston Basin until marine conditions extended all the way from the Arctic Ocean to the Gulf of Mexico. The shoreline of this sea advanced to the west and retreated to the east several times during the Cretaceous Period over the entire Great Plains region of North America. Marine shales were deposited during the advances and wedges of nonmarine deltaic sediments spread eastward from the mountains during the retreats of the sea. In the western Canadian sedimentary basin Lower Cretaceous rocks consist of basal sands

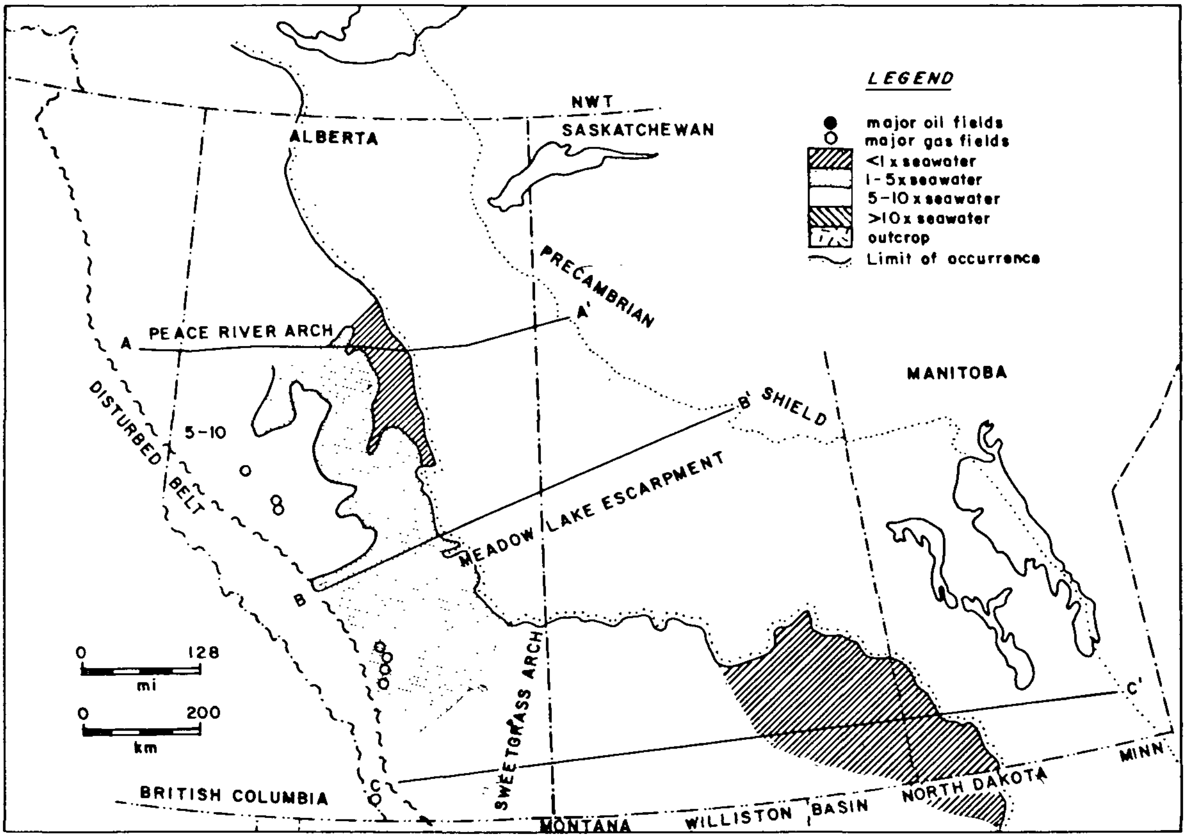



FIGURE 13 CHLORIDE CONCENTRATION IN FORMATION FLUIDS - UPPER DEVONIAN WABAMUN GROUP (modified after Hitchon, 1964)

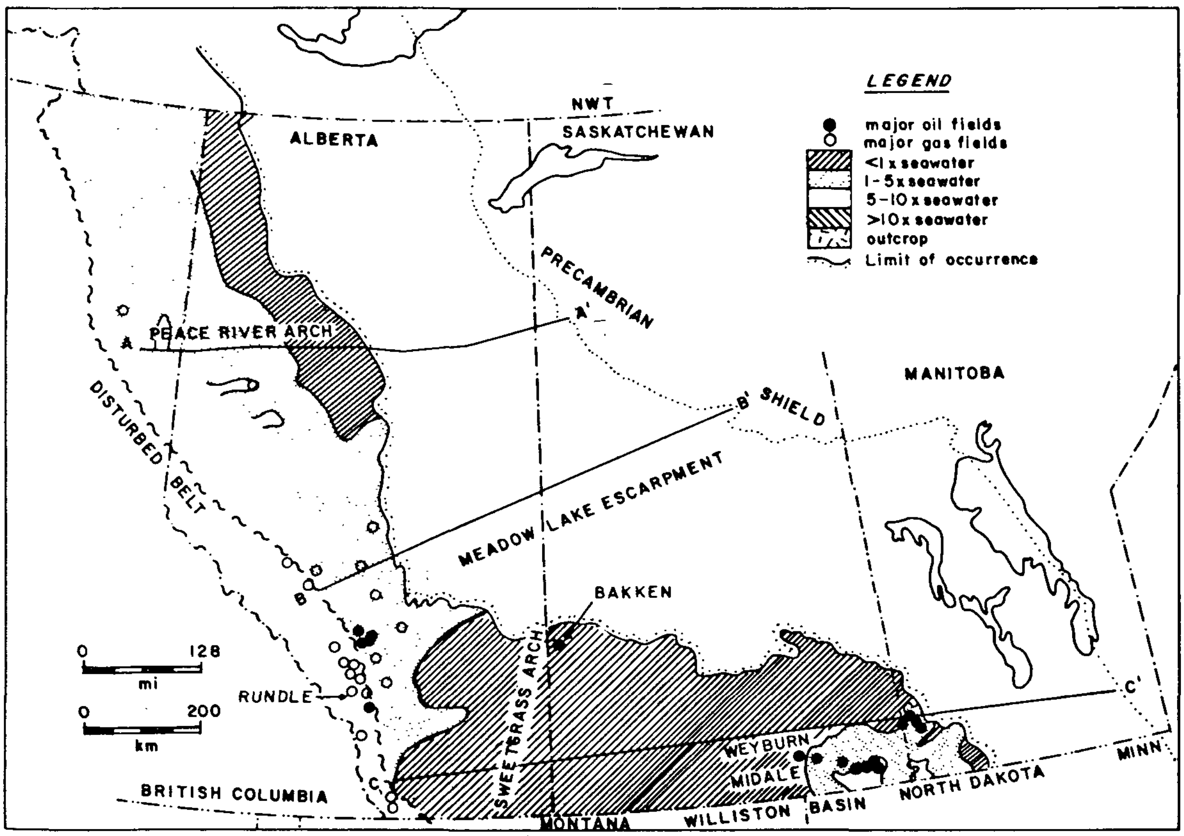



FIGURE 14 CHLORIDE CONCENTRATION IN FORMATION FLUIDS - MISSISSIPPIAN (modified after Hitchon, 1964)

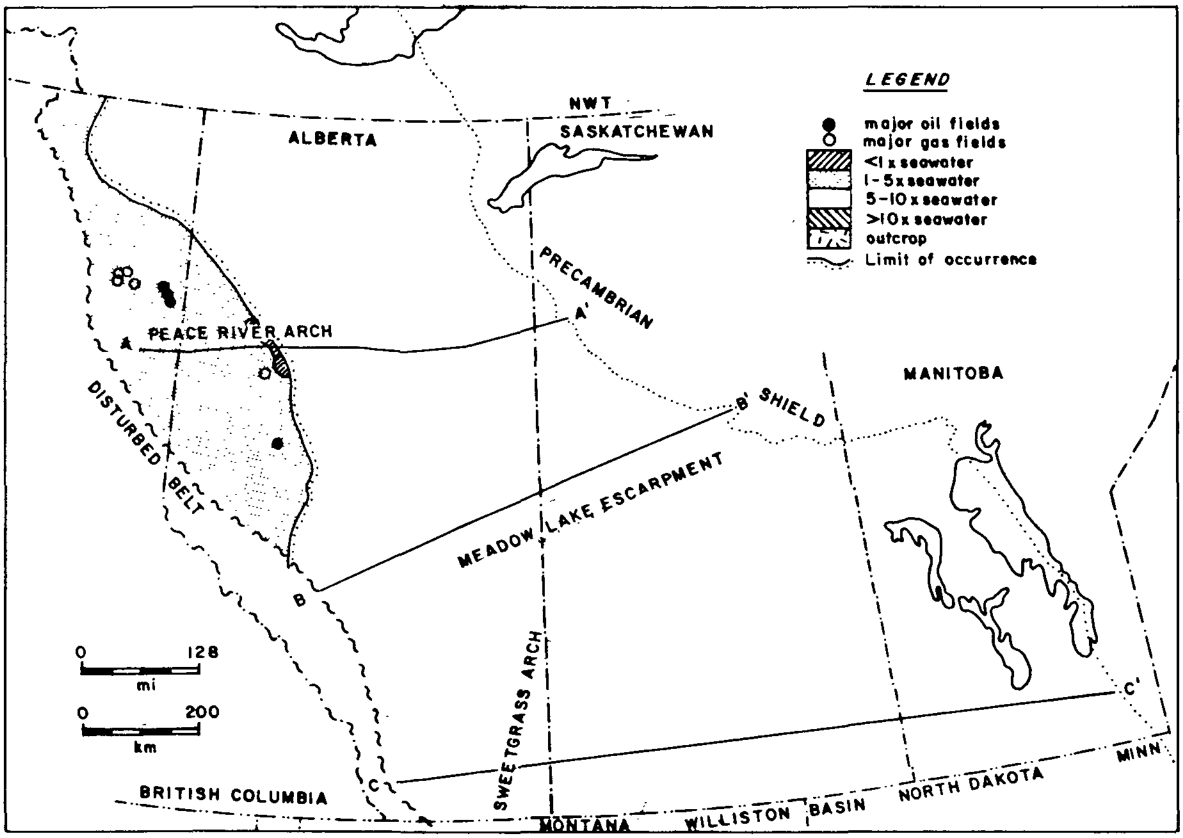



FIGURE 15 DISTRIBUTION OF TRIASSIC SEDIMENTS (modified after Hitchon, 1964)

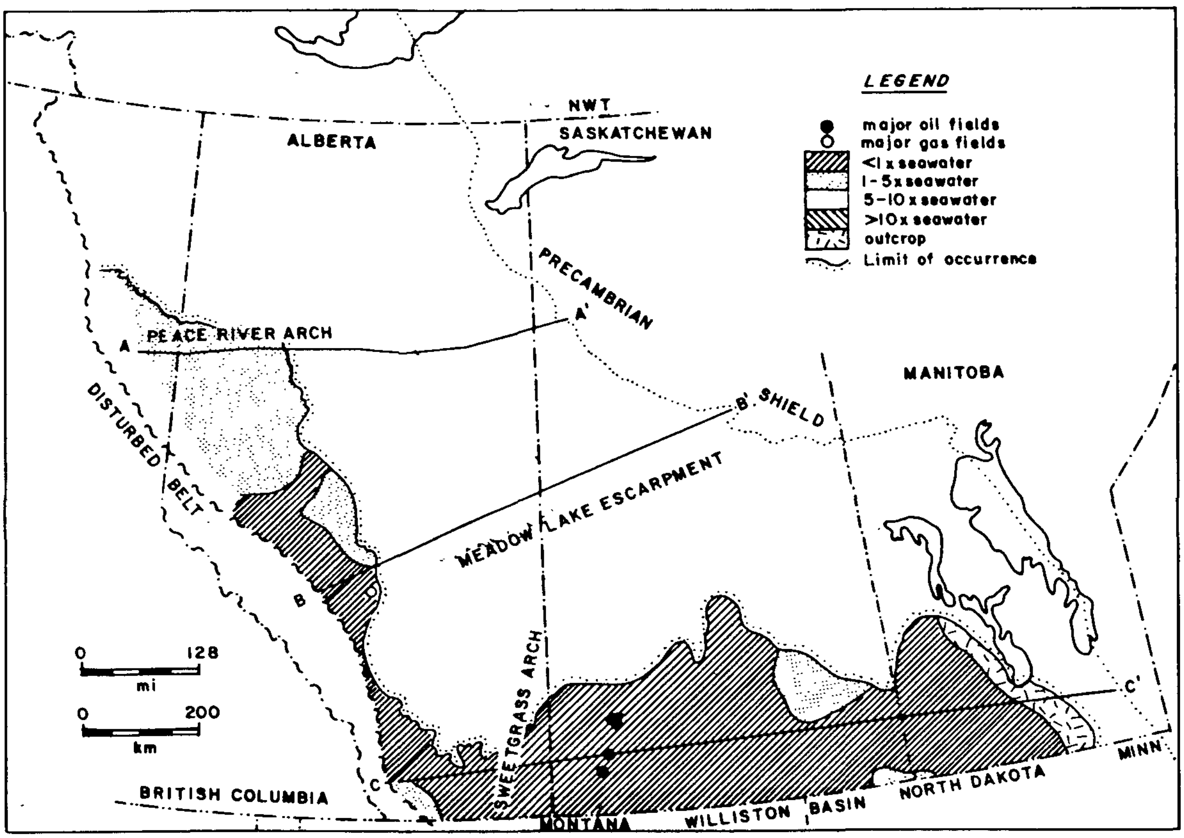



FIGURE 16 DISTRIBUTION OF JURASSIC SEDIMENTS (modified after Hitchon, 1964)

with some interbedded shale tongues representing the first marine advances from the north and the southeast (Mannville group) followed by marine shales (Lower Colorado group) with a sand tongue in the middle (Viking formation).

The Mannville is a tremendous hydrocarbon reservoir, containing not only 9.0% percent of the remaining conventional oil reserves and 23.5 percent of the remaining gas reserves, but also all the crude bitumen deposits (tar sands) of Canada. The tar sands are thought to contain the recoverable synthetic crude oil equivalent of 30 billion cubic metres or 34 times the remaining reserves of conventional oil and 2.3 times the ultimate potential reserves of conventional oil including offshore basins (Table 1). Figure 17 shows the area of occurrence of the Mannville group and the tar sands, as well as the distribution of hydraulic head within the unit.

The head distribution in the Mannville shows that a drain exists over the high permeability area along the Leduc reef trend in the Upper Devonian (Figure 11). The tar sands occur where discharge from the regional groundwater flow system, not only in the Mannville (Christopher, 1980) but also in the underlying Upper Devonian (both the Leduc and the Beaverhill Lake formations), is concentrated. The volatile fractions in the oil have escaped leaving the crude bitumen. Farther from the outcrop area only a portion of the volatiles have escaped, producing the heavy oils of the Cold Lake and Lloydminster districts. Figure 17 shows three separate deposits of tar sand, but there may, in fact, be continuity of tar sand occurrence between the Athabasca and Cold Lake deposits.

Hydrocarbons occur in the Viking formation trapped by the bounding shales as the sand pinches out to the east. It contains 1.7 percent of the remaining oil reserves and 7.9 percent of the remaining gas reserves. Figure 18 shows the area of occurrence of the Viking and the distribution of hydraulic head within it. The head distribution is similar to that in the Mannville group except that there is an even more pronounced closed area of low head (possibly accentuated by chemico-osmotic effects, according to Hitchon, 1969b).

Cyclic sedimentation continued in the Late Cretaceous Period beginning with deposition of the marine shale of the Upper Colorado Group. Two thin sand tongues were deposited within the Upper Colorado group during minor retreats of the sea. Both contain hydrocarbons trapped by the bounding shaley sediments. The Cardium Formation contains 15 percent of the remaining oil reserves and 2.4 percent of the remaining gas reserves (most in the Pembina oilfield) whereas the Medicine Hat sand contains 11 percent of the remaining gas reserves. Figure 19 shows the distribution of the Cardium formation and the area of major development of the Medicine Hat sand.

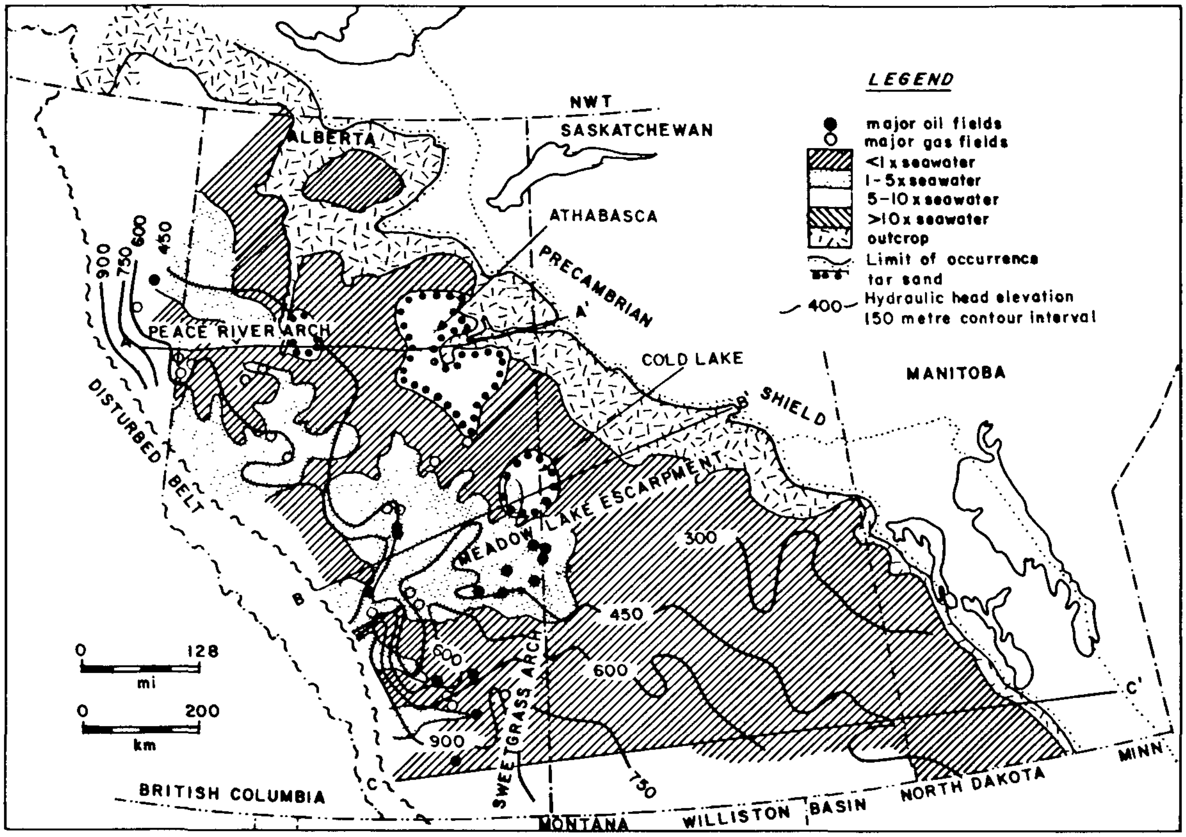



FIGURE 17 HYDRAULIC HEAD DISTRIBUTION - MANNVILLE GROUP (modified after Hitchon, 1964)

**2.1.2 Hydrogeology and Hydrogeochemistry.** The hydraulic head relationships and variations in chloride content of the formation fluids shown in Figures 5 through 19 suggest that the entire Western Canadian Sedimentary Basin comprises an interacting multi-layer regional groundwater flow system with a lower boundary at the top of the Precambrian Basement or at the base of significant fracture permeability in the rocks of the Precambrian Basement. Recharge to the system takes place by infiltration of precipitation (primarily as snowmelt) and discharge from the system takes place along the major river valleys and at the eastern outcrops of the sediments along the Precambrian Shield.

Hubbert (1940) described the classical steady-state regional groundwater flow system. Freeze and Witherspoon (1967) presented many cross-sectional flow diagrams illustrating the effects upon the flow system of different water table configurations and interlaying or intertonguing of beds of different permeability. These theoretical derivations of flow patterns by analytical or numerical methods provide excellent conceptual guidelines for a preliminary understanding of real flow systems. They

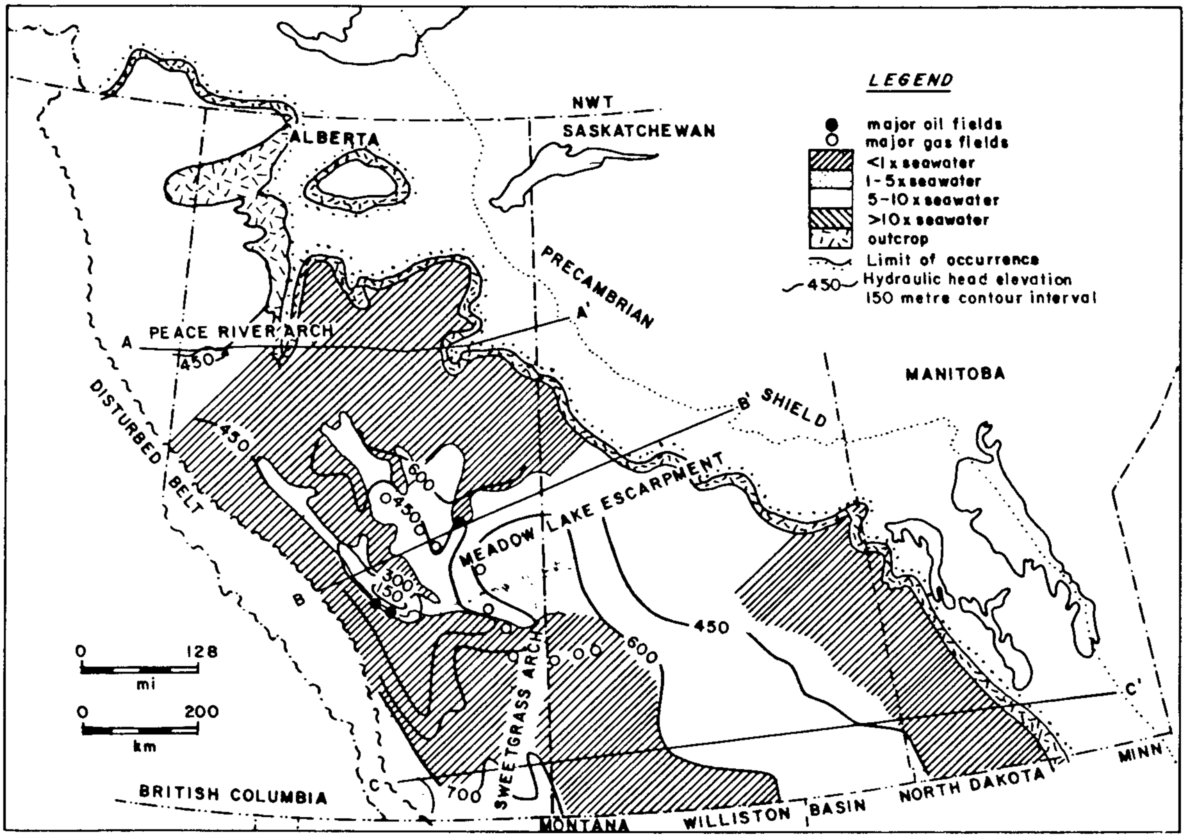



FIGURE 18 HYDRAULIC HEAD DISTRIBUTION - VIKING FORMATION (modified after Hitchon, 1964)

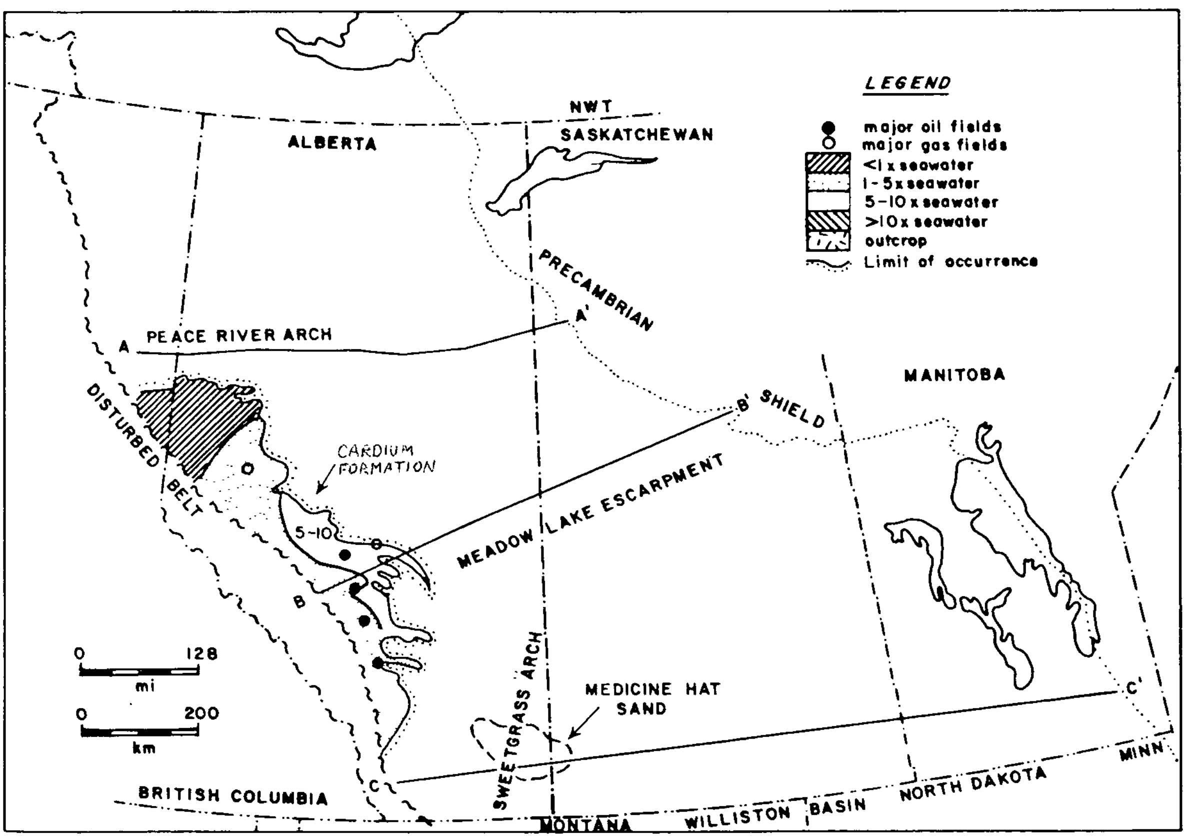



FIGURE 19 DISTRIBUTION OF CARDIUM FORMATION AND MEDICINE HAT SAND (modified after Hitchon, 1964)

demonstrate that discharge areas under topographic conditions similar to those that exist in the Western Canadian Sedimentary Basin are concentrated very close to the valleys or the end of the flow system. This implies that for the deeper flow paths of the basin, discharge takes place only at the outcrops near the Shield or along deeply incised major valleys such as the Peace River and Clearwater River in northern Alberta.

Recharge takes place over most of the basin area, providing a vast input of water to the system annually. Annual recharge to the groundwater system may vary from less than five percent of precipitation in very fine grained sediments to as high as 25 percent in sandy sediments (Whitaker, 1980b). However, recharge to the deep flow system depends upon the bulk field vertical hydraulic conductivities of the beds in the basin, which have not been determined. If it is assumed that 2 cm or approximately 5 percent of annual precipitation recharges over the basin, this represents an annual addition of 26 billion cubic metres to the flow system. Annual groundwater extraction for all uses was estimated at 126 million cubic metres by the Saskatchewan-Nelson Basin Board (1972), which is only about 0.5 percent of the above assumed recharge.

Figure 20 shows the distribution of shallow aquifers (less than 500 m deep) with potable groundwater in the basin. Table 5 shows representative water analyses for many of the shallow aquifers and mean values for the water in formations that produce hydrocarbons. The shallow aquifers have concentrations of total dissolved solids (TDS) less than 4000 mg/L except for the carbonate outcrop area of northeastern Alberta.

As groundwater passes through the sediments in the flow system its chemical character changes. Precipitation that infiltrates on the prairies enters glacial deposits. Aquifers within the glacial drift commonly contain calcium, magnesium bicarbonate (or bicarbonate, sulphate) waters. Additional chemical changes occur when the groundwater enters the bedrock. In regions of Manitoba and Saskatchewan where the bedrock is composed of carbonates little change takes place except where saline deep basin flow discharge adds sodium and chloride ions. In the region of northern Saskatchewan where the bedrock consists of sediments of the Mannville group there may be little change near the Shield, but further to the southwest (up gradient) toward the subcrop, sodium and chloride become dominant and the TDS increases to about 5000 mg/L at the subcrop. The groundwater in the carbonate region of northeastern Alberta (bedrock) is commonly saline due to the concentration of discharge in this area from the Upper Devonian.

Over southeastern Alberta and southern Saskatchewan, the bedrock is commonly Cretaceous shale composed predominantly of sodium montmorillonitic clays. Natural softening takes place as groundwater from the drift passes through the bedrock in

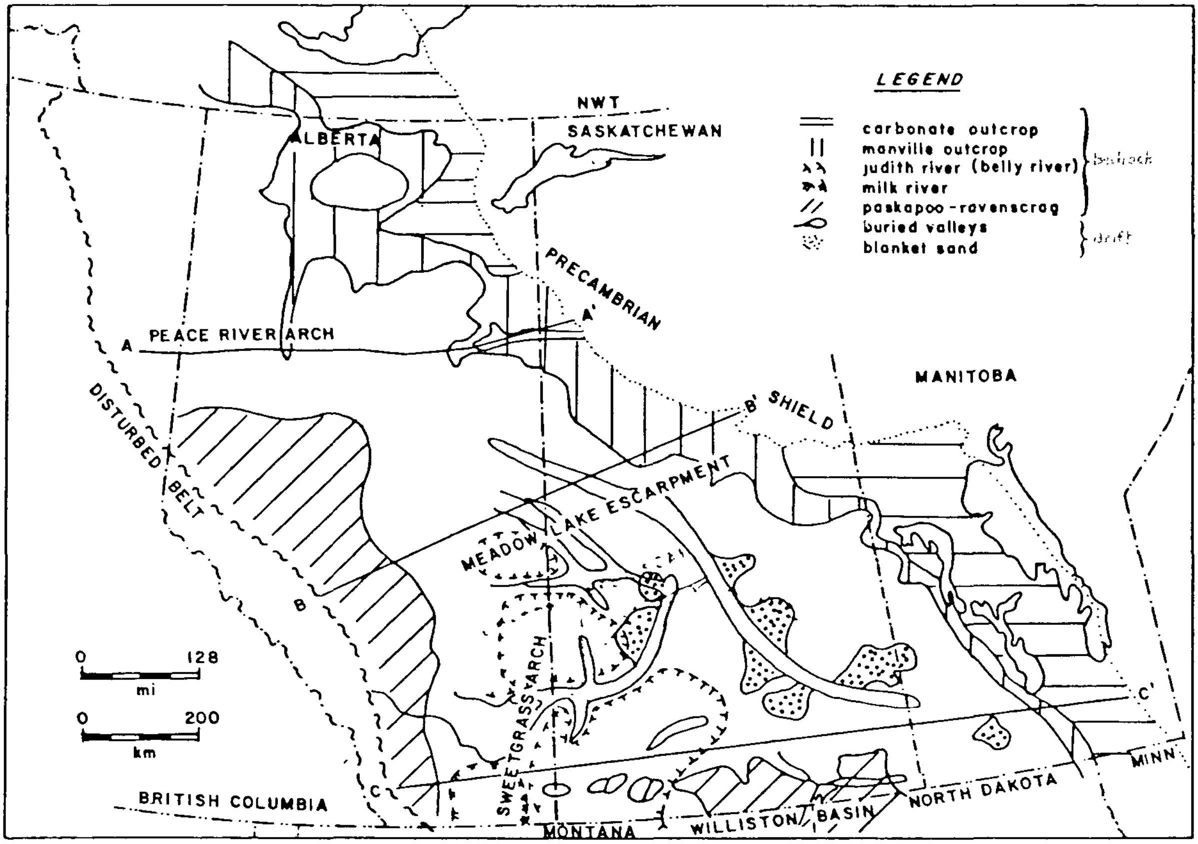



FIGURE 20 SHALLOW AQUIFERS IN THE WESTERN CANADIAN SEDIMENTARY BASIN (<500 m deep)

this region. Sodium replaces calcium and magnesium, bacterial action reduces the sulphate, and chloride is added. The representative analyses given in Table 5 for the Judith River formation in southwestern Saskatchewan illustrate this process.

It is apparent from Table 5 that most ionic concentrations increase as we proceed to older and deeper sediments. However, most of the oil-producing formations contain water with a wide range of concentrations (Hitchon, 1964) and the effect of dilution along major flow paths was apparent all the way to the base of the basin in Figures 5 through 19. In fact, as Meneley (1972) pointed out, there is a systematic decrease in TDS in all the deep aquifers of the basin toward the northeast in the direction of groundwater flow. The decrease in TDS has been accentuated by the reversal of gradients and fresh water backflushing caused by the surcharge placed over the discharge area when ice several kilometres thick was present during the Pleistocene Period. Recharge over the areas of the Mannville and carbonate outcrops tends to dilute and consequently suppress saline discharge from the deep basin.

TABLE 5 GENERAL WATER CHEMISTRY BY FORMATION

| | TDS (mg/L) | Ca+Mg (mg/L) | Na+K (mg/L) | $HCO_3$ (mg/L) | $SO_4$ (mg/L) | Cl (mg/L) |
|---|---|---|---|---|---|---|
| Shallow Aquifers (Saskatchewan-Nelson Basin Board, 1972; Whitaker, 1980a) | | | | | | |
| Blanket Sands | | | | | | |
| Brandon | 500 | 100 | 15 | 320 | 50 | 5 |
| Yorkton | 1150 | 205 | 60 | 550 | 300 | 25 |
| Regina | 1300 | 250 | 80 | 600 | 300 | 5 |
| Buried Valleys | | | | | | |
| Hatfield | 1000-6000 | | | | 800 | 180 |
| Estevan | 1700-2500 | | | | | |
| Paskapoo | 900 | 65 | 200 | 600 | 45 | 25 |
| Judith River (Sask.) | 1200-7500 | | | | | |
| Overlain by drift | | | | | | |
| Top | 2510 | 290 | 440 | 380 | 1520 | 10 |
| Bottom | 2100 | 10 | 730 | 1260 | 40 | 470 |
| Overlain by shale | | | | | | |
| Top | 1500 | 10 | 530 | 530 | 380 | 240 |
| Bottom | 1320 | 5 | 480 | 940 | 20 | 190 |
| Mannville Outcrops | | | | | | |
| Near Shield | < 500 | | | | | |
| Near Subcrop | > 4000 | | | | | |
| Carbonate Outcrops | | | | | | |
| Manitoba | 600 | 120 | 30 | 340 | 50 | 20 |
| Alberta | Highly saline springs, lakes, and flowing wells | | | | | |
| Producing Formations (approximate mean values from Hitchon, 1964) | | | | | | |
| Belly River (Alberta) | 8360 | 660 | 2500 | 450 | 250 | 4500 |
| Cardium | 8620 | 660 | 2500 | 1260 | 200 | 4000 |
| Viking | 20180 | 780 | 6500 | 700 | 200 | 12000 |
| Mannville | 26670 | 1300 | 10000 | 1120 | 250 | 14000 |
| Jurassic | 13400 | 1000 | 4000 | 1400 | 1000 | 6000 |
| Triassic | 44070 | 1650 | 14000 | 1120 | 1300 | 26000 |
| Mississippian | 41540 | 1500 | 14000 | 840 | 1200 | 24000 |
| Wabamun | 61850 | 2650 | 20000 | 700 | 500 | 38000 |
| Witerburn | 100860 | 5300 | 31000 | 560 | 1000 | 63000 |
| Woodbend (Leduc) | 120960 | 7600 | 32000 | 560 | 800 | 80000 |
| Beaverhill Lake | 160800 | 3600 | 48000 | 300 | 900 | 108000 |
| Seawater | 34580 | 1670 | 10550 | 140 | 2650 | 18980 |

It is still commonly thought that the deep formation fluids may be the connate water that was originally deposited with the sediments. However, it is difficult to support this contention for fluids that are active in the flow system. Christopher (1980) is one of the few petroleum geologists who appears to fully recognize the implications of groundwater flow on oil migration in the Western Canadian Sedimentary Basin. For example, the bitumen of the tar sands was derived, at least in part, from several of the upper Devonian formations and had to travel to its present location by fluid flow. It is therefore highly unlikely that the considerably less viscous so-called connate water was left behind. This becomes even more obvious if the groundwater flow is considered on a geological time scale. If it is assumed that the present very low rate of recharge was maintained during the past million years (less than one percent of the total geological time available since deposition commenced in the Western Canadian Sedimentary Basin), the total groundwater flux through the basin exceeds the total volume of the basin. The concept of "connate" water becomes, therefore, even more unrealistic when geological time is considered.

## 2.2 Southwestern Ontario

The sedimentary rocks of southwestern Ontario occur on the Algonquin Arch separating the Michigan Basin on the west from the Appalachian Basin to the southeast. In comparison to the Western Canadian Sedimentary Basin the area is quite small (106 000 $km^2$ vs. 1 296 000 $km^2$), the stratigraphic sequence is thin (maximum 2351 km vs. 8855 km), and the hydrocarbon potential is minimal (0.15% of remaining oil reserves vs. 96.45%). However, the population density in the region and the fact that most of Ontario oil reserves were produced before significant environmental regulations existed makes some discussion of the area worthwhile.

Figure 2 showed the distribution of oil and gas fields in southwestern Ontario. About one-half of the remaining oil reserves occur in Cambrian rocks immediately above the Precambrian Basement in the Appalachian Basin. The sedimentary basins of Ontario are illustrated in Figure 1. The other 50% of the remaining oil reserves are roughly equally divided between Silurian and Devonian carbonates in the Michigan Basin. Virtually all the remaining gas reserves of Ontario occur in Silurian carbonates but equally divided between the Michigan and Appalachian Basins. A geological map of southwestern Ontario is presented in Figure 21. In all cases the hydrocarbons are trapped on the flanks of the Algonquin Arch. Figure 22 illustrates the formations of southwestern Ontario.

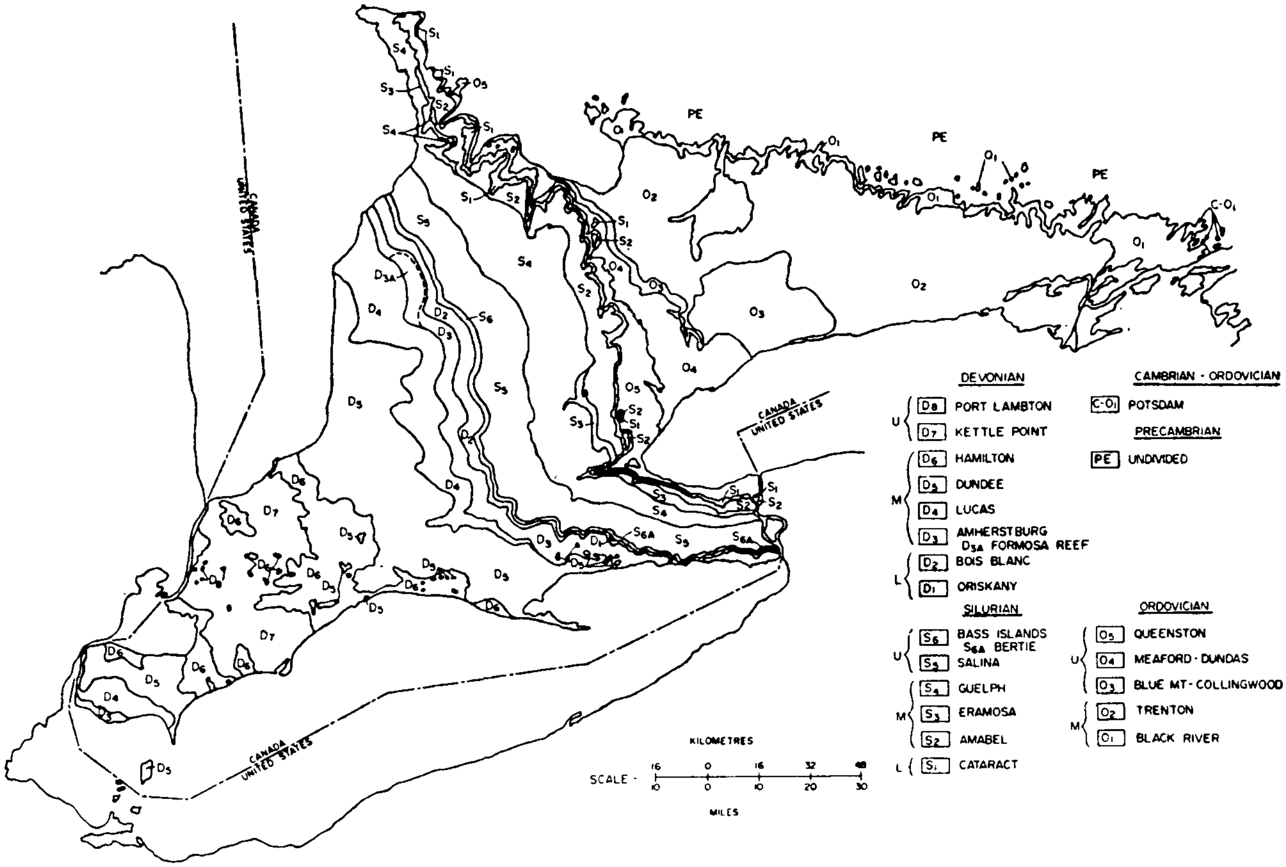



FIGURE 21 GEOLOGICAL MAP OF SOUTHWESTERN ONTARIO
(Winder & Sanford, 1972)

Over 100 000 wells are thought to have been drilled in southwestern Ontario, many before 1900 searching for very shallow Devonian oil. Since this was before any effective environmental regulations existed, abandoned wells from this era provided conduits for cross-formational flow of saline and fresh formation water as well as hydrocarbons. Although a significant proportion of the oil in place could be recovered in principle by enhanced oil recovery processes, the swiss cheese type of environment created by the drilling activity at the end of the last century in many parts of the oil deposits will guarantee failure for any of these methods. Furthermore major environmental hazards would be created by the large number of open lease holes.

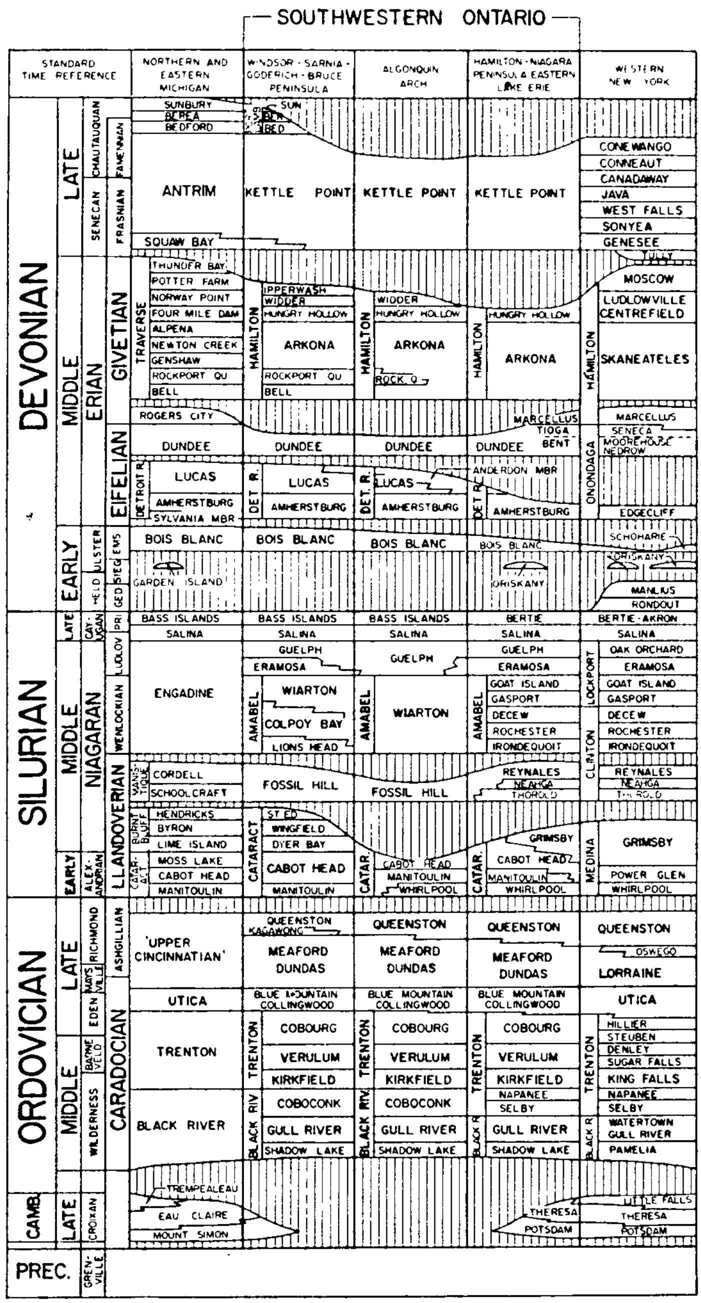


FIGURE 22 GEOLOGICAL FORMATIONS - SOUTHWESTERN ONTARIO (Winder & Sanford, 1972)

# 3 OIL AND GAS DRILLING

## 3.1 Introduction

Until recently drilling activity, as indicated by number of wells and metres drilled, has been constantly increasing in western Canada (Table 6). In 1980, 98 percent of all drilling completions in Canada occurred in the Territories, Arctic Islands and four western provinces. Table 7 presents a summary of drilling completions in Canada.

Several categories of potential degradation of the surface or subsurface environments during drilling activities can be recognized:

i) those resulting from surface site activities;
ii) those resulting from the use and disposal of drilling fluids or their activities used in:
   a) surface hole drilling,
   b) total depth drilling,
   c) completion practices;
iii) those resulting from liquid wastes at drilling (or production) sites;
iv) those resulting from leaching of solid wastes at drilling (or production) sites; and
v) those resulting from problems such as lost circulation and blowouts.

The following section discusses in detail various aspects of the drilling operation to familiarize those not associated with the oil industry with the activities performed to begin and complete a well. Where applicable, disposal practices and the potential environmental impact relating to each activity are also discussed.

## 3.2 Site Selection and Preparation

**3.2.1 Overview.** A number of preliminary activities must be performed before a drilling rig can be moved onto a location for drilling a well. These activities are generally as follows.

A surface access right of entry is obtained. An exact survey of the access road and well site is also required. Depending upon location and well depth, a typical access road allowance is 20 m wide, while the well site usually requires 1.5 ha for the drilling operation. Brush is cleared and burned for road and lease preparation; all timber grade forest is salvaged. Tables 8 and 9 present access road and lease requirements for typical oil and gas well sites. The quality of the roadway prepared depends upon the certainty of production associated with the well. An ungraded trail would be used for access to an exploratory well, while a 10-m wide crown on a graded road with at least pit

TABLE 6 WELLS AND METRES DRILLED IN WESTERN CANADA
(Canadian Petroleum Association, 1981)

| | Exploratory | | Development | | Total | |
|---|---|---|---|---|---|---|
| | Number | Metres | Number | Metres | Number | Metres |
| Cum. to 1947 | 1118 | 900861 | 950 | 1239858 | 2068 | 2140719 |
| 1947 | 129 | 125953 | 202 | 160688 | 331 | 286641 |
| 1948 | 179 | 208307 | 281 | 340034 | 460 | 548341 |
| 1949 | 275 | 352126 | 580 | 669524 | 855 | 1021650 |
| 1950 | 311 | 410170 | 859 | 946081 | 1170 | 1356251 |
| 1951 | 487 | 652801 | 933 | 1135229 | 1420 | 1788030 |
| 1952 | 900 | 1084089 | 1282 | 1571582 | 2182 | 2655671 |
| 1953 | 905 | 1157247 | 1334 | 1628611 | 2239 | 2785858 |
| 1954 | 928 | 1216705 | 1365 | 1575051 | 2293 | 2791756 |
| 1955 | 885 | 1212529 | 2050 | 2663245 | 2935 | 3875774 |
| 1956 | 899 | 1342829 | 2383 | 3379146 | 3282 | 4712975 |
| 1957 | 1058 | 1516179 | 1942 | 2753686 | 3000 | 4269865 |
| 1958 | 849 | 1275048 | 1667 | 2502804 | 2516 | 3777852 |
| 1959 | 939 | 1397939 | 1629 | 2476581 | 2568 | 3874520 |
| 1960 | 818 | 1335657 | 1718 | 2854036 | 2536 | 4189693 |
| 1961 | 769 | 1302665 | 1743 | 2888582 | 2512 | 4191247 |
| 1962 | 869 | 1397234 | 1640 | 2563288 | 2509 | 3960522 |
| 1963 | 1011 | 1579464 | 1850 | 2751836 | 2861 | 4331300 |
| 1964 | 1293 | 1833748 | 2007 | 2910220 | 3300 | 4743968 |
| 1965 | 1470 | 2078430 | 2163 | 2894937 | 3633 | 4973367 |
| 1966 | 1447 | 2050160 | 1605 | 2143615 | 3052 | 4193775 |
| 1967 | 1341 | 1913449 | 1537 | 1959486 | 2878 | 3872935 |
| 1968 | 1495 | 2257325 | 1500 | 1886373 | 2995 | 4143698 |
| 1969 | 1624 | 2149223 | 1553 | 1886851 | 3177 | 4046074 |
| 1970 | 1414 | 1884488 | 1522 | 1610239 | 2936 | 3494727 |
| 1971 | 1445 | 1861534 | 1489 | 1579190 | 2934 | 3449724 |
| 1972 | 1649 | 2176651 | 1936 | 1968887 | 3585 | 4145538 |
| 1973 | 2126 | 2403485 | 2271 | 1465742 | 4397 | 4869227 |
| 1974 | 1648 | 1971296 | 2319 | 2237618 | 3967 | 4208914 |
| 1975 | 1565 | 1715655 | 2467 | 2315283 | 4032 | 4030938 |
| 1976 | 2389 | 2301411 | 3104 | 3021340 | 5493 | 5322751 |
| 1977 | 2739 | 2803393 | 3237 | 3238430 | 5976 | 6041823 |
| 1978 | 3065 | 3529465 | 3913 | 3751819 | 6978 | 7281284 |
| 1979 | 2901 | 4111269 | 4554 | 4463970 | 7455 | 8575239 |
| 1980 | 3744 | 5234229 | 5188 | 5138500 | 8932 | 10372729 |

TABLE 7 1980 DRILLING COMPLETIONS - CANADA (CPA, 1981)

| | Oil | Gas | Abandoned | Suspended* | TOTAL Wells | TOTAL Metres |
|---|---|---|---|---|---|---|
| Territories & Arctic Islands | 4 | 5 | 7 | - | 17 | 37110 |
| British Columbia | 31 | 219 | 129 | 5 | 386 | 694785 |
| Alberta | 1639 | 3968 | 1365 | 23 | 7044 | 8397933 |
| Saskatchewan | 1099 | 49 | 295 | - | 1458 | 1219392 |
| Manitoba | 18 | - | 9 | - | 33 | 29113 |
| Western Canada | 2791 | 4241 | 1805 | 28 | 8938 | 10378333 |
| Ontario | 12 | 91 | 119 | 3 | 238 | 124754 |
| Quebec | - | - | 2 | 1 | 3 | 8253 |
| Eastcoast Offshore | 2 | 1 | 6 | - | 9 | 32644 |
| Eastern Canada | 14 | 92 | 127 | 4 | 250 | 165651 |
| Canada | 2805 | 4333 | 1932 | 32 | 9188 | 10543984 |

* Status undetermined. Mostly indicated gas wells.

run gravel cover would be prepared for a key infill well location. Normally the entire well site is cleared to provide room for manoeuvring equipment about the well site and top soil is saved where feasible.

A sump for disposal of drilling fluids and a flare pit for containment of combustible material during testing are prepared at the time of site construction. Pit size and geometry will depend upon the volume of waste material expected, which in turn is dependent upon size and depth of hole. A pit is usually constructed to allow at least a 1 to 2 m freeboard at the completion of the drilling operation. The Canadian Petroleum Association's environmental operating guidelines discuss and illustrate the possible pit configurations (CPA, 1980).

Typical pit volume requirements range from 1000 to 4000 $m^3$ below the freeboard line. Pit dimensions to accommodate such volume, therefore, would be in the order of 3 to 4 m deep by 10 to 20 m wide and 30 to 50 m long.

**3.2.2 Regulatory Activities.** The Alberta Department of the Environment Act provides broad provisions regarding environmental protection. The Minister has discretionary authority to require an impact assessment depending on the nature or sensitivity

TABLE 8 ACCESS ROAD AND LEASE REQUIREMENTS FOR A TYPICAL OIL WELL

| Oil Field Development | Wellsite (hectares)[a] | Lease Road (kilometres)[b] | Lease Road (hectares) | Total Hectares | Hectares Per Developed Section[c] |
|---|---|---|---|---|---|
| 1) 130 hectares/well - Marginal reservoir spacing | 1.5 | 1.2/50 | 1.4 | 2.9 | 5.8 |
| 2) 65 hectares/well - Most common oil spacing | 1.5 | 0.8/50 | 0.9 | 2.4 | 9.6 |
| 3) 32.5 hectares/well - Usual in fill drill spacing | 1.5 | 0.6/40 | 0.7 | 2.2 | 17.6 |
| 4) 16.25 hectares/well - Conventional heavy oil spacing | 1.0 | 0.4/30 | 0.3 | 1.3 | 20.8 |
| 5) 8.1 hectares/well - Waterflood - Fireflood heavy oil spacing | 0.4 | 0.3/20 | 0.2 | 0.6 | 19.2 |
| 6) 4.0 hectares/well - Fireflood - Steam injection heavy oil spacing | 0.4 | 0.3/20 | 0.02 | 0.6 | 38.4 |

a Wider spacing reflects deeper wells (bigger rig and greater space requirement).

b 1.2/0.5 means 1.2 kilometres total road attributed to the well of which 50 percent will be general trunk road allocation. Lease road width disturbed is 5 metres of crown and 2.5 metres ditch on either side. Trunk road width disturbed is 7.5 metres crown and 3 metres ditch on each side. Heavy oil operations from 4) to 6) inclusive generally utilize a total of only 2.5 metres crown and a 1.0-metre ditch on each side.

c Order of magnitude - preplanning or lack thereof can change the estimate.

TABLE 9 ACCESS ROAD AND LEASE REQUIREMENTS FOR A TYPICAL GAS WELL

| Gas Field Development | Wellsite (hectares) | Lease Road (kilometres)[a] | Lease Road (hectares) | Total Hectares | Hectares Per Developed Section[b] |
|---|---|---|---|---|---|
| 1) 1040 hectares/well - Very wide, good well spacing | 1.5 | 6.5/00 | 6.5 | 8.0 | 2.0 |
| 2) 520 hectares/well - Wide spacing | 1.5 | 4.6/00 | 4.6 | 6.1 | 3.0 |
| 3) 260 hectares/well - Most common gas well spacing | 1.5 | 1.6/10 | 1.6 | 3.1 | 3.1 |
| 4) 130 hectares/well - Future infill also common for shallow gas | 1.5 | 1.2/25 | 1.3 | 2.8 | 5.6 |
| 5) 65 hectares/well - Not common - future infill for shallow gas | 1.5 | 0.8/50 | 0.9 | 2.4 | 9.6 |

a 6.5/00 means 6.5 kilometres total road attributed to the well of which zero percent will be general trunk road allocation. Lease road width disturbed is 5 metres of crown and a 2.5-metre ditch on each side. Trunk road width disturbed is a 7.5-metre crown and a 3-metre ditch on each side.

b Order of magnitude - preplanning or lack thereof can change the estimate.

of an area. Since some of the objectives of the Act are the "prevention and control of pollution" and prevention of any "activities or operations that destroy or alter a natural resource", the Department has authority in all environmental aspects of oil well drilling.

The main regulations pertaining to site selection, design, construction and operation are The Oil and Gas Conservation Act and Regulations and The Mines and Minerals Act, Exploration Regulation (AR 423/78), as administered by the Energy Resources Conservation Board (ERCB) and the Department of Energy and Natural Resources (DENR), respectively (Canadian Petroleum Association, 1981). Formal application to drill a well must be made to the ERCB, and must be accompanied by evidence of surface rights obtained from the landowner. The ERCB issues regulations pertaining to spacing units (Section 4 of the Oil and Gas Conservation Regulations) and proximity to water bodies (Section 2.120). The Board requires that no well be drilled closer than 100 metres (or greater as directed if required) from the normal high water mark of a body of water or stream without written approval of pollution prevention measures from the Board.

The Forests Act (1971) in the Timber Management Regulations, and The Forest and Prairie Protection Regulations administered by the DENR stipulate requirements for clearing land and timber salvage in order to minimize environmental damage and forest removal.

In the province of Saskatchewan, regulations regarding site selection and preparation are basically similar to those of Alberta. In Saskatchewan, under Section 305 of the Oil and Gas Conservation Regulations, wells may not be drilled in a water covered area or within 250 feet (76.2 m) of a shoreline without approval from the minister. Special regulations are issued for drilling in a commercial potash area (Section 306). When drilling below the top of the Prairie Evaporite (a Devonian formation, see Figure 4), a protective casing is required and drilling fluid must be replaced with oil, or a salt-saturated mud used. Wells must be completed such that all communication between zones is prevented; production casing must be cemented in stages involving use of brine-saturated cement and abandoned according to specific plug requirements. In British Columbia, regulations cover the same basic requirements as Alberta, and similarly require approvals from appropriate regulatory bodies.

3.2.3 **Environmental Impact.** Surface site preparation activities cause the greatest environmental impact of all the drilling and production activities. The land modified just for the existing producing wells tabulated in Table 8 amounts to at least 4000 km$^2$. This does not include the land that has been used for abandoned wells, for access to wildcat wells, or for seismic survey lines in remote areas which would more than double the above figure.

On agricultural land, the impact of site work tends to be minimal, except for the actual removal of a portion of the land from agricultural production. Temporary soil removal, sump construction, and site abandonment on cultivated land, providing the existing regulations are followed, seldom increase the potential for wind and/or water erosion. After abandonment of the lease and subsequent site restoration the only negative impact on agricultural land may be a reduction in the productivity of the land over a number of years. In terms of environmental impact, cultivation of agricultural land, which is exceeded in scope only by urban development, open pit mining, and timber harvesting, is orders of magnitude more significant than the activities of the oil industry.

In remote regions, however, where the activity of the oil industry is conducted in forested areas, permafrost regions, or semi-aquatic environments, mere removal of the topsoil can have devastating effects on the landscape. For instance, melting of permafrost creates irreversible changes in the landscape and rates of erosion may be greatly increased, causing not only the development of gullies and loss of fragile soil profiles, but also a corresponding increase of sediments in streams and lakes that may threaten aquatic life in entire drainage basins.

Determining the sensitivity of the landscape to vehicular travel and site clearing before exploration and drilling begins is critical in frontier areas so that remedial measures can be formulated.

## 3.3 Surface Hole Drilling

**3.3.1 Overview.** After site preparation the lease is ready for the rig to move onto except for the establishment of a suitable water supply. A typical drilling operation for a 3000 m deep well requires about 500 to 1000 $m^3$ of water. Of this water, approximately 25 percent is consumed by non-recoverable processes. To allow for possible drilling problems an excess supply of water must be assured.

The water supply for drilling operations is usually taken either from surface sources or from a fresh water well drilled near the rig site. The actual source depends upon the availability of water in the area.

The rig then moves onto the lease and proceeds to "spud" the well. The surface hole is generally jetted rather than drilled and fresh water is used as the drilling fluid. Penetration of the sediments is achieved by the action of high velocity, concentrated streams of mud coming out of the bottom of the bit rather than the by rotary action (intrusion and drag) of the bit. Jetting a hole is similar to hydraulic mining.

Drilling mud recipes are occasionally used for surface holes and are designed to raise the viscosity for more efficient drill cuttings removal and in special cases to increase the weight of the mud to control artesian water flows (Gray et al, 1979). The main purpose of the surface hole and surface casing is to isolate unconsolidated sediment and fresh water aquifers from the wellbore during drilling and to control pressures from zones penetrated at greater depths.

In surface holes less than 200 m deep, lime is often added to develop viscosity, particularly if the source water has a high concentration of sodium. The calcium ions in the lime cause the natural clays to coagulate and develop a viscosity capable of lifting the drill cuttings. Lime is used because it costs less than bentonite, but lime can cause over-coagulation and too high a viscosity, as well as a tendency to show high water loss to formations. Bentonite is used if the surface hole is deeper than 200 m and requires a longer drilling time. The amount of lime required at a given well depends upon the quality of the water used and the composition of the clay materials penetrated, both of which may vary from well to well. Treatment of spud mud tends to be by trial and error in increments of 1 kg per cubic metre of fluid treated.

When bentonite is used, the quantity required will increase with the calcium content in the water supply. To counteract the adverse effect of the calcium content and provide a greater degree of corrosion protection, caustic soda is added in amounts of 0.5 to 1.5 kg/m$^3$ to raise the pH of the system to between 10 or 11. Although a caustic bentonite system is used for virtually every surface hole more than 200 m deep, the quantities used for any particular well are unpredictable because they are so dependent upon the chemical composition of the water used and the clay penetrated. Also the degree of solubility of the caustic, which is a function of well temperature, is unpredictable in a drilling mud system.

Surface hole casing is typically set at the depth where the first competent shale is encountered or at 10 to 15 percent of total depth, whichever is greater. Surface hole diameters are 30 to 50 cm and occasionally larger depending upon expected total depth of the well and production casing design requirements. Surface casing diameter is usually 10 to 15 cm less than the drilled hole diameter to allow for a 5 cm cement sheath to fill the annulus between casing and wellbore. Drilling mud used to drill the surface hole is displaced by cement and dumped to the sump.

**3.3.2 Regulatory Activities.** In Alberta, the ERCB, through the Oil and Gas Conservation Regulations, has requirements pertaining to surface casing depths as a percentage of total depth drilling. The required depth depends on the area being drilled, and the Board may prescribe site-specific provisions (Sections 6.060 to 6.090). Generally, surface casing must be run more than 25 m below unconsolidated sand or gravel or 10 percent of the total depth of the well, or 10 percent of the well when intermediate casing is run, whichever is the lesser. Where surface casing is less than 180 m or 25 m below any aquifer used as a source of potable water within 3 km of the well, the casing string next to the surface casing must be cemented to a depth not less than 180 m, or 25 m below the potable aquifer (Alberta, 1981, Section 6.080, part 4).

Special regulations have been issued for certain areas when required, as was the case for southeastern Alberta. Interim Directive No. ID-OG-76-1 issued in 1976 included two provisions relating to protection of surface and groundwater quality in the area. The minimum surface casing depth in specified zones bordering the two main rivers (South Saskatchewan and Red Deer Rivers) in the area was increased, and this same casing requirement was imposed for any well drilled near a domestic water well to ensure protection of freshwater resources.

The Department of Mineral Resources in Saskatchewan requires that safe and suitable surface casing be used in every well (Oil and Gas Conservation Regulations, Section 602). Surface casing must reach a minimum of 50 feet (15.25 m) below the base of glacial drift to 10 percent of estimated total depth, whichever is greater (or a depth which may be prescribed by the minister). It must be set in or through an impervious formation, and cemented by specified methods.

Division (30) of the Drilling and Production Regulations in British Columbia stipulates that surface casing must "be set to a minimum depth of 15% of the expected total depth or intermediate casing depth but at least 150 m below ground level and 25 m into a competent formation by an approved method" and the annulus must be filled with cement unless otherwise approved. Intermediate and production casing must also usually be cemented through porous zones.

**3.3.3 Environmental Impact.** The main problems encountered during the drilling of a surface hole relate to lost circulation. Lost circulation is the loss of drilling fluids in the borehole to formations penetrated or being penetrated while drilling. For lost circulation to occur, two conditions must exist, i.e., permeable formations have to be exposed in the borehole, and the effective hydrostatic pressure of the fluid column in the borehole opposite the permeable formation has to be greater than the hydrostatic pressure in the formation. Lost circulation can also be caused by induced fracturing, which in turn is caused by hydrostatic pressure imposed on the formation by the drilling mud and associated activities, such as drilling fluid circulation and pipe movement (Moore, 1974).

Lost circulation significantly increases the cost of drilling, and can cause considerable local contamination of potable groundwater resources. Although documented case histories are rare, discussions with the Alberta Department of Environment indicate that the occurrence of groundwater contamination as a result of lost circulation is not as rare as the published information suggests. This has been confirmed by personnel from various oil companies. The contamination of the groundwater in aquifers is generally characterized by any of the following: cloudiness of the water, drilling mud in the water, significant pH increases, reduction in the capacity of the well, presence of dissolved ions peculiar to the mud system in the well water, etc. In most instances the effects appear to be temporary. However, for a well owner whose livelihood depends on a reliable water supply, any interruption in this supply is highly unsettling to say the least, especially in areas where the well yield is low and a constant rate of production is required to maintain volume. If the company involved in the gas or oil well drilling activity recognizes that it may be responsible, the problem can generally be solved amicably, although considerable cost may be incurred by the company. However, if litigation is the only route for recovery of costs by the water well owner, the problem can become very unpleasant and expensive, both in terms of monetary value and of public relations. It may be useful to further evaluate the cause-and-effect relationship of lost circulation.

The two prerequisites for lost circulation, i.e., the presence of permeability and a positive effective hydrostatic pressure in the borehole, theoretically can be controlled during drilling. However, in drilling surface holes, which almost invariably contain that section of the stratigraphic column with fresh water aquifers, it appears that less attention is paid to the control of the above-mentioned conditions than in deeper sections of the borehole. Many of the problems of lost circulation are created by the mud type and drilling method. In most instances, surface holes are drilled with spud mud (see section 3.3.1). This type of mud is inferior to an engineered mud in terms of its rheological and mud cake properties. The mud cake is a sheath or lining of mud deposited on the walls of the hole as a result of water loss to a permeable formation. Furthermore, surface holes are generally jetted rather than drilled.

In unconsolidated and fractured semi-consolidated sediments, jetting can raise havoc with the diameter of the borehole due to washing of cavities and subsequent caving, which is further enhanced by the turbulent flow conditions in the annulus of the drill collar string. Differential hole enlargement causes significant changes in the flow regime of the drilling fluid in the annulus, which will drastically affect cuttings removal by the drilling mud. As a result, cuttings begin to clog and settle in the well bore. This has two immediate effects: reduction in penetration rate, and pressure buildup.

The slowdown in penetration rate exposes the formations being drilled to the drill bit for a longer period and, consequently, increases the risk of washouts.

The pressure buildup causes an increase in the mud density, which in turn increases the pressure differential between the borehole and adjoining formations, increasing the chance of lost circulation. In addition, to overcome the pressure buildup in the borehole, extra mud pump pressure is added to move the cuttings and cavings up-hole. If the formations are competent, the cuttings and cavings can be moved up-hole by the additional pressure. However, in near-surface sediments, which are unconsolidated to semi-consolidated and invariably fractured, the resultant effective fluid pressure will almost certainly exceed the rupture pressure of the formation. Fractures will be created or existing ones further opened. Once a fracture has been created or opened, mud lost to the fracture at a rapid rate will wash out and widen the fracture. Even if the pressure is reduced, coarser material in the mud will act as a propping agent, preventing closure of the fracture, and some loss of circulation will continue.

Once the loss of circulation has been brought under control, fluid loss from the borehole to the surrounding formation will be reduced from whole mud loss to filtrate loss. The magnitude of filtrate loss is a function of mud cake quality, i.e., permeability, and the difference between the effective hydrostatic pressure and the hydrostatic pressure in the formation. Since drilling mud contains considerable dissolved ion in its liquid phase, contamination of fresh water aquifers will continue, albeit on a smaller scale than by direct loss of whole drilling fluids.

## 3.4 Drilling to Total Depth

**3.4.1 Overview.** After the surface hole is completed and surface conductor or casing is cemented in place, the main drilling operation begins (Figure 23). Main hole bit diameter is 2 to 5 cm less than the inside diameter of the surface casing. Figure 24 shows a typical rotary drilling rig configuration.

The surface casing shoe is drilled out and drilling to total depth follows. Depending on the area of operation, the number of hydrocarbon formations expected to be encountered, and the objectives of drilling the well, one or two of several different types of mud may be used.

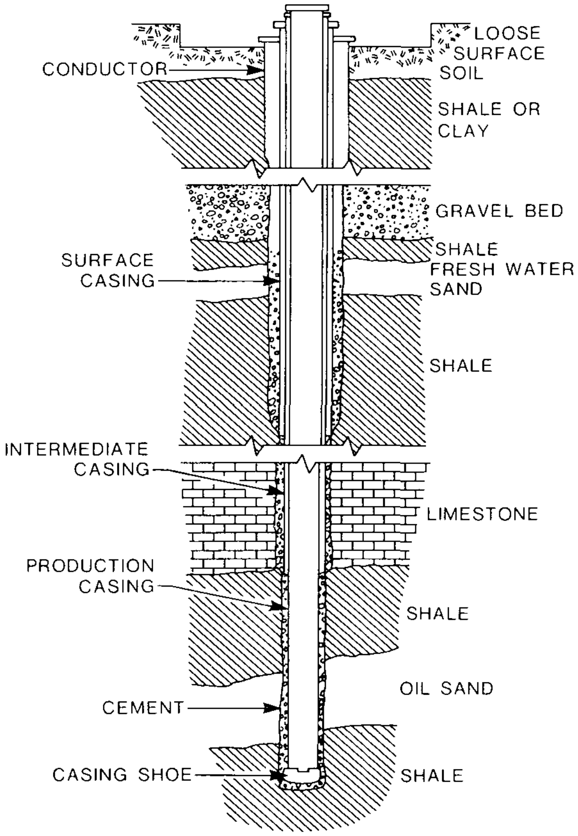



FIGURE 23 CASING STRING AND PIPE USED IN A WELL (adapted from Facts About Oil, American Petroleum Institute)

The drilling fluid system selected depends upon the specific geology of the area. The system can use a range from air to clear water to complex mixtures of clays and chemicals. Regardless of composition, however, the functions of a drilling mud are common to all systems, and are summarized as follows:

i) remove and carry drill cuttings from the bottom of the well to the surface,
ii) suspend cuttings when required and release them at the surface,
iii) control subsurface pressures,
iv) lubricate and cool the bit and drill string,
v) provide borehole stability,
vi) protect productivity of the formation, and
vii) provide maximum information about the formation being penetrated (Moore, 1974; Gray et al, 1979).

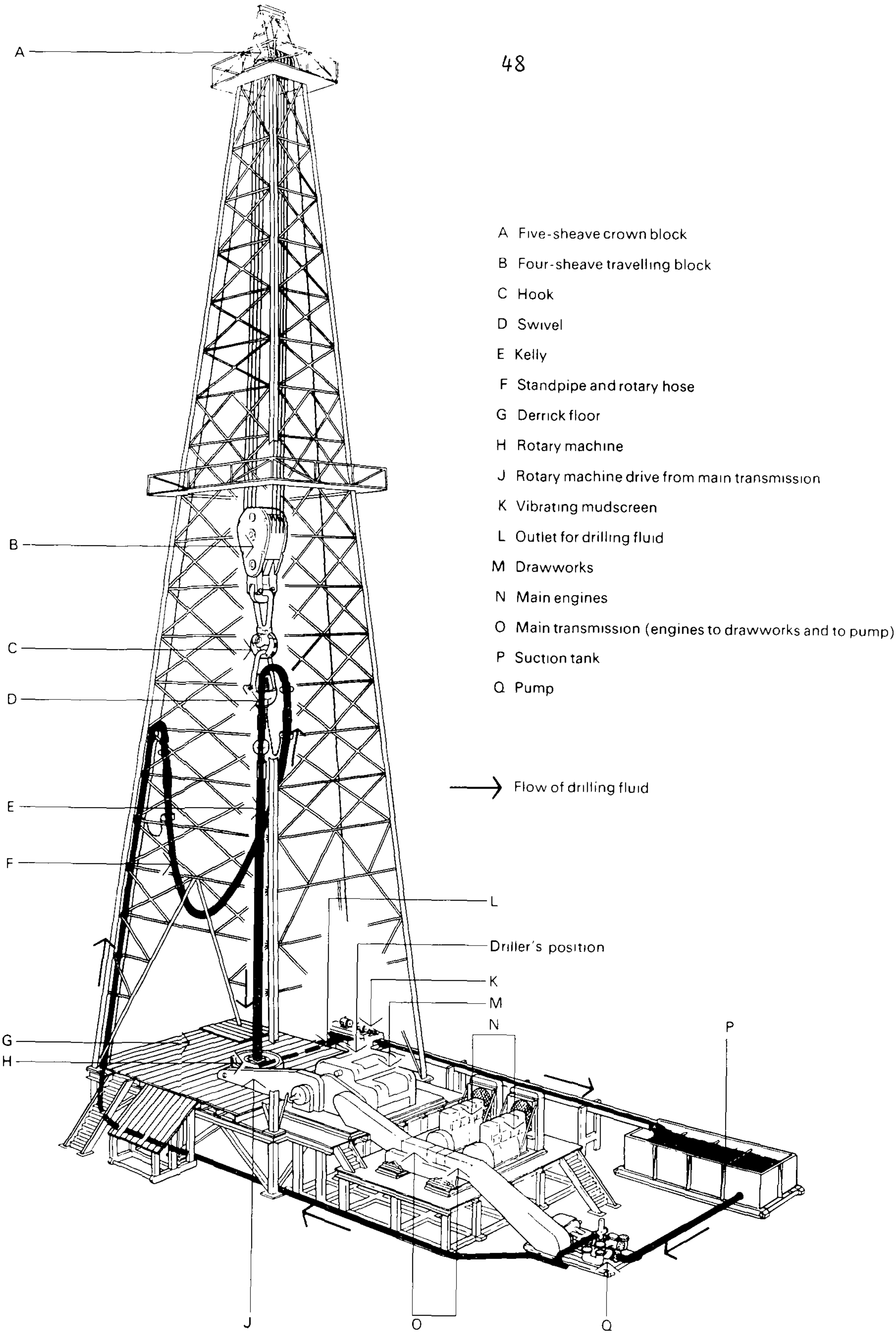



FIGURE 24 DIAGRAMMATIC VIEW OF A ROTARY DRILLING RIG (from The Petroleum Handbook, 5th edition, Shell International Co. Ltd., 1966)

Additives and good drilling practices ensure that the drilling mud achieves these purposes. If the mud is unsuccessful, lost circulation, shale sloughing, and stuck pipes may occur during drilling, or a blowout may occur when a producing zone is encountered.

The different types of mud systems used can be summarized as follows:

i) fresh water,
ii) salt water,
iii) oil base,
iv) polyemulsion, and
v) air and gas.

Selection of mud type depends on the cost of the system, associated drilling expenses, requirements for evaluating well characteristics, and anticipated problems.

The mud volume used at any point in the operation must always be sufficient to fill the hole and allow for 10 to 25 percent surplus. This volume increases proportionally with drilling depth. Once the wellbore is drilled to total depth, if the well is considered economically productive, production casing is run to the bottom. Ordinarily the production casing is only cemented to approximately 300 m above the potential hydrocarbon producing horizons.

The cementing procedure displaces drilling mud from the hole into the surface pits. Potentially productive hydrocarbon zones are isolated by cement. The annulus between the top of the cement and surface, or between staged cement plugs, remains filled with drilling mud at the completion of the drilling operation. Holes are shot through the casing and cement (perforating) into the potentially productive zone to retrieve hydrocarbons.

Wells are abandoned when no hydrocarbon bearing zones capable of production at commercial rates have been penetrated. Cement plugs are placed in the wellbore to seal the potential hydrocarbon bearing zones in the area. Abandoned dry-hole wells have been re-entered occasionally for various purposes and, as early as one year after the initial drilling of the well, considerable hole caving has been encountered. After approximately five years, the extent of hole caving is so significant that it usually eliminates any cost advantage of re-entering an old bore hole. This illustrates the tendency for flow paths into formations created by drilling over-pressure to seal when the pressure is released, but the extent to which this occurs is uncertain.

Areas of unconsolidated surficial material would normally have been cased to prevent fluid penetration from lower formations into fresh water aquifers, but the long-term integrity of this casing is also uncertain. To further prevent the possibility of inflow or cross-formational flow, the abandoned hole is left full of drilling fluid which exerts a hydrostatic head on all exposed zones. If no zones of abnormal pressure are encountered, uncemented zones are either incapable of flow or exert a hydraulic pressure equal to all other zones. Therefore, water bearing zones are not considered of particular concern unless the apparent water zone exhibits abnormal pressure.

The complexity of the drilling mud system is essentially a function of geology, depth expected, horizons encountered, and to a large extent the preference and experience of the engineer. The greater the depth drilled, the greater the temperature encountered and also the greater the variation in texture and chemical composition of rock penetrated. Such variations all have an impact upon the drilling mud recipes used.

Due to the higher temperatures encountered and the resulting reaction of some of the common drilling materials, drilling deep wells requires special techniques. Many of the most commonly used additives for the control of viscosity, filtration and weight are unstable or ineffective when temperatures approach approximately 120°C. In these cases, organic polymers rather than clays (e.g., carboxy methyl cellulose) and modified lignosulfonates are used for control of filtrate loss and viscosity, respectively (Loy, 1975).

The following is a generalization of typical drilling fluids utilized in western Canada.

i) Freshwater Muds
   - spud mud
   - natural muds
   - chemically treated muds

ii) Salt Water Muds
   - seawater mud
   - saturated salt muds

iii) Oil Based Muds
   - invert emulsion muds

iv) Polyemulsion Muds

v) Gaseous Muds
   - air or natural gas
   - foam muds

vi) Clear Water

- chemically treated

Table 10 presents the composition and concentration of the components of typical mud systems. Table 11 summarizes the more commonly used additives on a functional basis.

In western Canada it is estimated that natural freshwater mud is used down to the Colorado shales (an Upper Cretaceous formation) (Figure 4) in over 75 percent of all drilling operations. Chemicals are added when drilling through the Colorado shales to avoid shale sloughing and hole caving as well as in preparation for encountering potentially productive zones.

Oil based muds have been successfully used by the industry for many years. They serve to reduce the adverse effects of water on certain productive formations (such as swelling clays), and aid in maintaining hole stability in formations likely to be water sensitive and which might cave or slough when contacted by water. They also decrease drag and thereby help avoid stuck pipes. Design of the composition of oil muds is discussed by Loy (1975). Usually diesel oil is used as the base, and water is often emulsified into the oil. The amount of water emulsified determines the type of oil muds; oil muds containing more than five percent by volume of water are sometimes called "invert emulsion oil muds". Common additives to oil based muds include emulsifiers, lime, gellants, filtration control additives, oil wetting agents and weight material if needed.

The occasional use of potassium chloride as a shale sloughing control agent deserves some research attention because of its highly toxic nature.

The use of air as a circulating medium was introduced in the 1950's, and research has found that, where there is essentially no water inflow from the formation, air drilling can extend bit life, increase penetration rate and minimize water use, and does not contaminate the environment (Lorenz, 1980). Air is also used to avoid core contamination, particularly in oil sands operations.

Mist drilling, where a mixture of a foaming agent and water is injected into the air stream, is used when water or oil sands are encountered. The water is kept to a minimum and amounts range from 6 to 12 barrels per hour; the quantity and type of water and foamers used depend on the type and amount of fluid produced (Anonymous, 1969).

Aerated muds, where both mud and air are pumped into the well, are used when drilling through water sands with lost circulation where it is impossible to drill effectively with air or water alone.

TABLE 10 COMPOSITION OF TYPICAL DRILLING MUDS

| Component | Concentration ($kg/m^3$ of mud) |
|---|---|
| 1) Fresh Water Mud | |
| 1.1 Water | 500 to 1000 |
| 1.2 Bentonite | 40 to 80 |
| 1.3 Lignite | 3 to 15 |
| 1.4 Lignosulphonate | 6 to 30 |
| 1.5 Caustic | 1.5 to 4.0 |
| 1.6 Barite | 0 to 1500 |
| 2) Salt Water Mud | |
| 2.1 Water | 500 to 1000 |
| 2.2 Salt (NaCl) | 250 to 350 |
| 2.3 Attapulgite | 75 to 100 |
| 2.4 Starch | 7.5 to 15.0 |
| 2.5 Formaldehyde | 0.5 to 1.5 |
| 2.6 Sodium Chromate | 1.5 to 3.0 |
| 3) Oil Based Mud | |
| 3.1 Medium Gravity Oil to Diesel | 400 to 650 |
| 3.2 Water | 100 to 150 |
| 3.3 Calcium Chloride | 40 to 70 |
| 3.4 Emulsifier (Soap, Polyamids) | 15 to 60 |
| 3.5 Amine Lignite | 0 to 30 |
| 3.6 Amine Clay | 6 to 12 |
| 3.7 Barite | 0 to 1500 |
| 4) Gaseous Muds | kg/h Drilled |
| 5.1 Foamer - Soap | 2 to 25 |
| 5.2 Sodium Chromate | 2 to 20 |
| 5.3 Bentonite | 100 to 200 |
| 5.4 Sodium Carboxymethyl Cellulose | 2 to 10 |
| 5) Clear Water Drilling Fluid* | Maximum Solubility ($kg/m^3$ Fluid) |
| 6.1 Sodium Chloride | 1 150 |
| 6.2 Calcium Chloride | 1 400 |
| 6.3 Calcium Bromide | 1 700 |
| 6.4 Zinc Bromide | 2 300 |

* Principle is to eliminate the colloidal suspension materials. Combinations of soluble salts are prepared to produce a liquid of desired specific gravity. Not used for drilling, but used as a completion fluid.

Note: Earth parting gradient is considered to be approximately 230 $g/cm^2 \cdot m$ of depth, (i.e., 2300 $kg/m^3$ fluid).

TABLE 11 COMMON DRILLING MUD ADDITIVES

| Additive* | Amount Added ($kg/m^3$) | Advantage/Function |
|---|---|---|
| 1) Weight Material | | |
| 1.1 Barite | 0 to 1 500 | Does not change viscosity |
| 1.2 Galena | 0 to 1 000 | For conditions of extreme pressure |
| 1.3 Calcium Carbonate | 0 to 600 | Completely soluble, can be removed from production zone |
| 2) Increase Viscosity (Thickeners) | | |
| 2.1 Bentonite | 0 to 100 | Most common |
| 2.2 Carboxymethyl Cellulose | 0.5 to 3 | Air drilling |
| 2.3 Guar Gum | 1.5 to 5 | Salt muds |
| 2.4 Sodium Polyacrylate | 0.5 to 3 | Assists bentonite |
| 2.5 Attapulgite | 75 to 100 | Salt muds |
| 3) Reduce Viscosity (Thinners) | | |
| 3.1 Sodium Tetraphosphate | 0.7 to 1.5 | Soluble in water |
| 3.2 Sodium Acid Pyrophosphate | 0.7 to 1.5 | Soluble in water |
| 3.3 Tannins - Hemlock Tree | 2.5 to 3.0 | Low solubility |
| 3.4 Lignite | 4.0 to 15.0 | Low solubility |
| 3.5 Chrome lignosulphonate | 5.0 to 10.0 | Low cost |
| 3.6 Caustic | 1.5 to 4.0 | Common |
| 3.7 Sodium fero-chrome lignosulphonate | 2.5 to 100 | Treat cement containing muds |
| 4) Lost Circulation and Fluid Loss Control | | |
| 4.1 Bentonite | 0 to 100 | Most Common |
| 4.2 Starch | 5.0 to 15.1 | Need low viscosity |
| 4.3 Para formeldehyde | 1.5 to 3.0 | Preserve starch |
| 4.4 Oil | 0 to 5% of volume | Emulsion block |
| 4.5 Walnut shells | 15 to 150 | Blockage |
| 4.6 Sawdust | 15 to 150 | Blockage |
| 4.7 Cellophane flakes | 15 to 150 | Blockage |
| 4.8 Cement | 15 to 150 | Blockage |
| 4.9 Mica | 15 to 150 | Blockage |
| 5) Corrosion Inhibitors | | |
| 5.1 Sodium Chromate | 1.5 to 30 | Most Common |
| 5.2 Solfite | | |
| 6) Emulsifiers | | |
| 6.1 Soap & Detergents | Trade Names | |
| 6.2 Crude Oil or Diesel Oil | 0 to 50% | |
| 6.3 Quick Lime | 15 to 40% | |
| 6.4 Salt Saturated Water | 0 to 50% | |

* Additional component lists can be found in various trade publications.

In certain formations, the use of foam may be a solution to lost circulation problems. Foam has been successful for drilling where fluid loss, hole enlargement, swelling or sloughing are expected; however, foam is not appropriate for drilling through high pressured zones due to its low hydrostatic head. Since foam is not recycled, its use eliminates mud solids removal equipment (Gould and Maxwell, 1979).

Table 12 provides estimates of mud volumes disposed of at the surface from various typical wellbores. It must be emphasized that the volumes presented in Table 12 represent ideal volumes that may be used to estimate the minimum quantity of mud materials in the surface pit. Table 12, in conjunction with Table 11, can be used to estimate the minimum amount of a specific material in the sump. These estimates do not represent the actual concentrations of various constituents in the total sump fluid. In addition to mud, a significant amount of drill cuttings are generated and must be disposed of after the well is drilled. Table 13 presents volumes and weights of material removed for various depths and diameters. The volume of drilling fluid dumped to the sump as a film coating the drill cuttings is not accounted for in estimates of volume of waste generated. Also drained to the sump are quantities of untreated water from rig washing, lease drainage, etc. The total volume and composition of sump fluid is quite variable and indeterminate except by actual sampling and measurement.

Additional contaminants frequently found in the sumps at a drill site include the following:

i) petroleum liquids, including oils and fuel spilled and drained from the rig operation, and oil or condensate drained or spilled from a production test;
ii) salt water drained from a water-producing production test;
iii) soap products and detergents drained from rig washing and from general housekeeping.

The bulk composition of many of these contaminants is largely unpredictable, but it can be said that overall quantities would increase with rig size and hole depth. It is evident that a large variety of materials and chemicals can be found in the waste products of a drilling operation. Sewage from the site is generally disposed by chemical toilets.

**3.4.2 Disposal Methods and Government Regulations.** Under Section 8.150 of the Alberta Oil and Gas Conservation Regulations the licensee or operator must ensure the containment of liquid waste (including drilling fluids) and must dispose of the waste such that "no air, soil, surface water or underground source of potable water is or could be polluted". If the waste is to be removed from the site, the manner of disposal must be

TABLE 12 TYPICAL DRILLING MUD VOLUMES DISPOSED AT SURFACE

| | Volume Disposed ($m^3$) | | | | |
|---|---|---|---|---|---|
| | Wellbore Diameter (cm) | | | | |
| | 20 | 25 | 30 | 40 | 50 |
| Spud Mud - Surface Hole Depth | | | | | |
| 100 metres | - | - | 10 | 20 | - |
| 250 metres | - | - | - | 50 | 75 |
| 500 metres | - | - | - | 95 | 150 |
| Total Depth Mud System | | | | | |
| 600 metres | 30 | 45 | 65 | - | - |
| 900 metres | 25 | 50 | 70 | - | - |
| 1500 metres | 30 | 65 | 100 | - | - |
| 2000 metres | 50 | 75 | 120 | - | - |
| 2500 metres | 55 | 85 | 140 | - | - |
| 3000 metres | 60 | 100 | 160 | - | - |

NOTES:

a) A surplus drilling fluid volume was assumed to exist at percentages of 50, 35, 30, 25, 20, 20 for depth range 600, 900, 1500 etc., respectively.

b) It was assumed that cement would fill the bottom 500 m of annulus between wellbore and casing, except in the 600 m well which is cemented to the surface.

approved by the Minister of Energy and Natural Resources in cases where the disposal site is on public lands, or by the Board if it is not. Earthen pits used for storage of wastes should be located and dyked so that they will not collect natural runoff water. If surface topography prevents the satisfactory construction of earthen pits, the wastes must be contained in tanks for eventual disposal in an approved area. The actual disposal procedures are not specified, and are at the discretion of the appropriate regulatory body.

Cuttings, after removal of most of the drilling mud, are disposed of in an earthen pit or sump. Drilling fluid, while still part of the active mud system, is generally stored in steel tanks, except in some of the shallow gas drilling operations where it is stored in earthen pits. When the solids content of the mud has reached an acceptable level because of poorly operating solids removal equipment (desanders, desilters), a portion of the drilling fluid is drained and disposed of in the sump. Similarly, when the type of drilling fluid is changed, the old mud is disposed of in the sump. In general, the sump acts as a receptacle for water-based (fresh or salt water type) muds (Table 10). The sump receives all liquid wastes generated around the rig (spent motor oil, diesel fuel, rig

TABLE 13 VOLUME/WEIGHT OF DRILL CUTTINGS REMOVED FROM WELLBORE DURING DRILLING

| | ($m^3$/tonnes) | | | | |
|---|---|---|---|---|---|
| | Wellbore Diameter (cm)* | | | | |
| | 20 | 25 | 30 | 40 | 50 |
| Typical Surface Hole Depth | | | | | |
| 100 metres | - | - | 7.1/9.4 | 12.6/16.7 | - |
| 250 metres | - | - | - | 31.4/41.6 | 49.1/65.1 |
| 500 metres | - | - | - | 62.8/83.2 | 98.2/130.1 |
| Typical Total Depth | | | | | |
| 600 metres | 18.9/25.0 | 29.5/39.1 | 43.1/57.1 | - | - |
| 900 metres | 28.3/37.5 | 44.2/58.6 | 64.7/85.7 | - | - |
| 1500 metres | 47.1/62.4 | 73.6/97.5 | 107.8/142.8 | - | - |
| 2000 metres | 78.5/104.0 | 98.2/130.1 | 143.8/190.5 | - | - |
| 2500 metres | 98.2/130.1 | 122.7/162.6 | 179.7/238.1 | - | - |
| 3000 metres | 117.8/156.1 | 147.3/195.2 | 215.7/285.8 | - | - |

* 20 to 30 cm are typical drilled washed hole diameters for wellbores below surface casing.

30 to 50 cm are typical drilled washed hole diameters for surface hole.

Specific gravity of material removed is assumed to be 2.65.

wash detergents, testing liquids, etc.) because the surface drainage is such that all flow is directed toward the sump.

In environmentally-sensitive areas, liquid waste handling and disposal is much more controlled. The rig area and sumps are lined with impermeable membranes. Where on-site disposal is not permitted the sump generally consists of steel mud tanks. Because of the limited storage capacity of these tanks, the liquid and cuttings are regularly removed, transported, and disposed of in another sump located in a less environmentally-sensitive area.

During normal drilling operations, as the drilling fluid comes to the surface, the undesirable components that have been accumulated are removed and most of the drilling fluid is recycled. Figure 25 illustrates a typical mud treatment circuit. The gas (hydrocarbon) not trapped in the drilling fluid is removed in a mud-gas separator. This device allows the gas to go out the top and the mud out the bottom. The gas is then vented away to a flare pit.

From the mud-gas separator the drilling fluid goes to the screening machine. Screening machines (or shale shakers) come in different sizes and configurations, and use sieves so that the liquid goes into the settling tanks. The solids remain on the screen and are disposed of in the sump.

The drilling mud in the settling tanks is in a near static condition so that large and/or heavy particles with diameters smaller than the screen opening have an opportunity to drop out of the fluid. After the settling tanks the mud is further degassed, desanded and desilted. Degassing is done by a depressuring device, desanding by 6-12 inch (152-305 mm) cyclones and desilting by 4-inch (102-mm) cyclones.

After desilting, the drilling fluid is sometimes centrifuged to remove very small waste solids. The waste or undesired material is sent to holding tanks where chemicals are added to recondition the mud. From these tanks the mud starts its cycle in the hole again.

Once the drilling is completed, the sump fluids and solids must be disposed of. The disposal method depends on the type of mud, i.e., if the liquid phase is water or oil.

The aqueous portion of water-based drilling fluids (freshwater mud, low solids polymer mud, inhibitive muds, gyp mud, lime-treated mud, potassium chloride systems, and salt water muds) in the sump must be separated from the solids and clarified prior to disposal. This is accomplished using organic flocculants (for example polyacrylamides) or inorganics, such as gypsum, depending on the type of water-based mud. Flocculation should be as complete as possible because this results in a denser residual slurry, which in

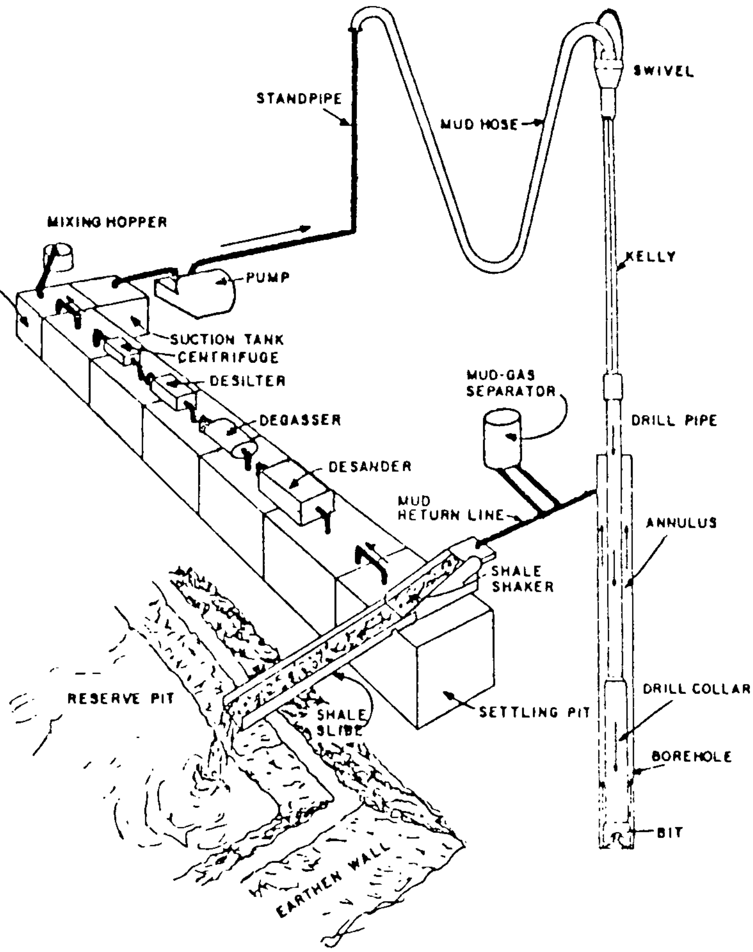



FIGURE 25 TYPICAL WATER-BASED MUD RECIRCULATION SYSTEM (Allred, 1975)

turn decreases the bulk volume of the solids and increases the efficiency of the dewatering process. At this time, disposal of the sump contents involves removal of the liquid phase and encapsulation of the solid waste. The supernatant liquid from the sump is then disposed of by:

i) landspreading on or off the lease area,
ii) deep well injection,
iii) trucking to a hazardous wastewater disposal site,
iv) on-site evaporation, or
v) some combination of the above.

Landspreading is the major method of disposal.

In 1975, Alberta Environment, Alberta Energy and Natural Resources, and the Energy Resources Conservation Board implemented province-wide standards for the disposal of sump fluids in an environmentally satisfactory manner. ERCB Interim Directive No. ID-0G 75-2 outlines the additional requirements for sump fluid disposal on the lease site. Sump contents must be confined to the lease and, when the sump contains more than 6 000 barrels, disposal is regarded as if it were "off-lease" and approval must be obtained from the ERCB or AENR. The lease must be more than 90 m from the normal high water mark of any body of water, stream or potable well, and should be able to accept the contents without runoff. Off-lease disposal requires approval from the appropriate agency and is contingent upon chemical analyses of the untreated fluid meeting given criteria for chloride, sulphate, dissolved solids and pH, and must pass a 96-hour trout survival test.

Figure 26 illustrates environmental controls at a drilling rig, with reference to appropriate sections of the Oil and Gas Conservation Act, as administered by the ERCB.

Further details on the above regulations and recommended sampling and testing procedures are discussed by Shaw (1974) and Environment Canada (1981).

Saskatchewan and British Columbia regulations have provisions for the disposal of drilling fluids and wastes; however, the requirements are not as specific as those in Alberta. Disposal methods in Saskatchewan must be satisfactory to the minister and in a manner which will not "constitute a hazard to public health" or "contaminate fresh water or arable land" (Section 810). British Columbia has similar requirements administered by the Ministry of Energy, Mines and Petroleum Resources (Division 61, Drilling and Production Regulations).

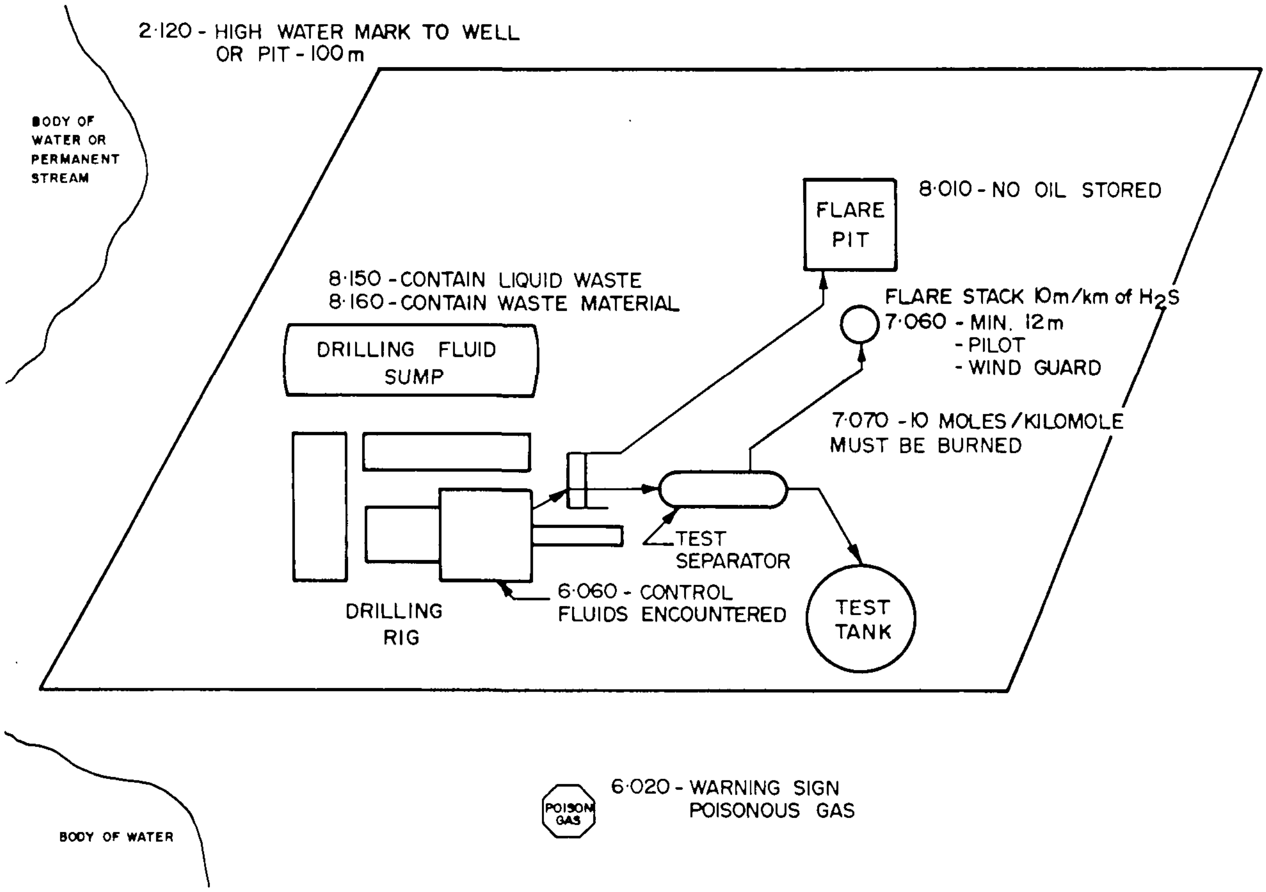



FIGURE 26 ENVIRONMENTAL CONTROLS AT A DRILLING RIG
(From Canadian Petroleum Association, 1980)

Where large volumes of detoxified liquid must be disposed of, irrigation instead of land spreading should be considered. The irrigation potential of the soil will have to be evaluated to determine rates of application and the possible necessity for amendments to the soil. Pesaran (1977) and Miller and Honarrar (1975) studied several different drilling fluids mixed with six different soil types and two commercial agricultural crops and developed the following conclusions:

i) "Excess soluble salts and high exchangeable sodium percentages were the major inhibiting effects of drilling muds to plants and soils."

ii) "Elimination of these effects can be accomplished by the addition of some salt of calcium, magnesium, potassium, or ammonium with subsequent water leaching to move the salts into the deeper less productive soil layers."

iii) "Detrimental effects of diesel oil appear to be less severe and long-lived than the effects of salts and/or exchangeable sodium."

iv) "Most drilling muds caused soil dispersion resulting in surface crusting; however, proper treatment can minimize or eliminate these effects as stated in (ii) above."

v) "Arid regions (less than 20 inches of precipitation annually) have a higher potential for adverse effects than do regions with wetter climates. When employing this method of disposal it is highly desirable to have a final soil:mud ratio of at least 4:1. A higher soil:mud ratio will result in a more efficient disposal process and decreased potential for adverse effects, and care should be taken to ensure an even spreading of the mud/cuttings slurry over the intended landfarming area."

The simple coagulation-flocculation treatment used in the sumps may not render the aqueous layer non-toxic to fish. In such cases, additional treatment may be used. In Canada, however alternative methods of disposal, such as deep well injection or vacuum truck evaporation, are usually preferred.

If the aqueous layer is to be removed by vacuum truck, evaporation or injection, laboratory tests are required by the ERCB. Once the aqueous layer has been discharged the pit can be backfilled.

According to ERCB Interim Directive 81-1, approval for subsurface disposal of drilling fluids will be included as part of the drilling or completion approval. Permission from the board is required, and stipulations regarding disposal zone, depth, formation water resistivity, proximity to hydrocarbon formations and method of disposal are specified to prevent contamination of any subsurface potable water.

The solid waste is encapsulated by backfilling the sump pit with the sediment originally excavated during the construction of the pit. The final levelling of the surface should be such that the area is returned to the original contours and that the topsoil is spread evenly. In non-agricultural areas the surface is subsequently fertilized and seeded to grass. On agricultural lands soil samples are taken to determine the necessary amendments required to restore the area to its original potential. Environmental concern regarding the encapsulated sump material at this stage follows the dictum "out of sight, out of mind". It may be useful to examine this attitude.

Disposal of oil-based muds in the natural environment is not allowed. They must be recovered for re-use. However, not all the drilling fluid is recovered when the cuttings are separated during drilling with an oil-based mud. The cuttings disposed of in the sump are coated with approximately half their volume of drilling fluid (McMordie, 1980). The actual volume of oil-based drilling fluid lost to the sump as films on cuttings depends on the diameter and depth of the hole. Sumps which receive this type of cuttings are invariably lined with impermeable membranes or with bentonite to prevent seepage. Upon completion of the hole, every effort is made to recover as much as possible of the wasted oil-based drilling fluid from the sump. The remaining cuttings and fluid are buried on location or, if environmental considerations do not permit burial, the cuttings are transported to an approved area for disposal or further treatment. The long-term environmental risk in the burial of this type of cuttings is thought to be minimal because of biodegradation by microorganisms (McMordie, 1980).

3.4.3 **Environmental Impact.** Drilling fluids have developed over the years from very simple water-bentonite systems to highly complex inorganic-organic systems. Concurrent with this development a host of chemical compounds have been introduced at the drill site. Tables 10 and 11 listed the basic composition of various types of mud. The complexity of the drilling mud system at a specific site may vary considerably from the basic composition outlined in Table 10, depending on the area where the well is drilled, the rock types encountered, and the temperature of the subsurface environment. In other words, other compounds may be used. A listing of the various drilling additives can be found in Anonymous (1981), Gray et al (1979), and the handbooks of the various mud companies.

The emphasis on the environmental impact of various additives has primarily been directed at single component studies (Land, 1974; U.S. EPA, 1975; Anonymous, 1980). However, only during the storage and the handling of the additives prior to their addition to the mud system can these materials be considered as individual compounds in terms of their environmental impact. Good housekeeping and adherence to the recommendations of the manufacturer on the handling of the material should eliminate the danger of introduction into the natural environment. One aspect of the handling of the drilling fluid additives which requires further attention is the possible effect on human health. The conditions under which the materials are added to the mud system are often less than ideal. Extreme levels of dust in a confined working space and a general lack of knowledge by the people handling the material of the long-term effects of exposure to some of these materials are common.

The hazards of some of the individual drilling fluid components are great and uncontrolled introduction into the environment could have disastrous effects. However, drilling fluids are almost invariably mixtures of several compounds which range from nontoxic to toxic. Complex physico-chemical reactions between the various compounds severely restrict the mobility of individual additives, so that the hazards associated with a drilling fluid during its use and disposal are totally different from those of its individual components (Nesbitt and Sanders, 1981).

The environmental impact of drilling fluids should therefore be considered in terms of the complete fluid. The concerns which have been expressed regarding the encapsulated sump solids discussed in Section 3.4.2 are:

i) the fate of metals,
ii) the fate of organics and the biodegradation of organic compounds, and
iii) the release of metals from organo-metallic compounds.

The potentially toxic metals present in the mud system originate from thinners (chrome lignosulphonates, ferrochrome lignosulphonates), corrosion inhibitors (inorganic chromate salts), and $H_2S$ scavengers (zinc carbonate, iron sponge). If the recommended concentrations of these additives in the mud have been observed, then the concentration of the metals in the mud system would be (Anonymous, 1980):

chromium: 150 - 450 ppm (chrome lignosulphonate)
chromium: 120 - 4900 ppm (sodium dichromate)
zinc: 2500 - 3000 ppm (zinc carbonate)

In addition to the above sources of metals, impurities in barite (primarily sulphides of various metals) can increase the soluble trace metal content in weighted mud systems. The concentration of the trace metals introduced is a function of the amount of barite in the mud system and the concentration of the trace metals within the barite.

Under normal circumstances, liquids containing the above concentrations of trace metals would not be allowed to be disposed of in the natural environment. However, the values are theoretical and do not take into account the various physico-chemical reactions that take place between the additives and the reactive components within the mud system, which may drastically reduce the mobility of the trace metals.

The inorganic chromate salts enter the mud system in the hexavalent state, which is much more toxic than the trivalent compounds. However, once introduced they are chemically reduced to the less toxic and more stable trivalent state by organics, lignosulphonate or lignites, and high temperatures, etc. (Moseley, 1980). Furthermore, a film consisting of a complex chromeoxygen compound is produced which is absorbed on the drill pipe and casing surfaces as well as the mud solids. All these processes result in a lower concentration of chromium reaching the mud pit than was originally added to the drilling mud systems.

The chromium in the chrome lignosulphonates is already in the less toxic trivalent state prior to its addition to the drilling fluids. The chrome lignosulphonate are adsorbed on bentonite particles by cation exchange (Gray et al, 1979), which further immobilizes the chromium.

Zinc carbonate is used as an $H_2S$ scavenger and converts in the presence of $H_2S$ to zinc sulphide, which is insoluble in basic (pH>8) mud systems. Similarly, the sulphides of trace metals added to the mud system as impurities in barite will not materially increase the dissolved metal content of the drilling fluid.

Although individual additives contain considerable concentrations of several trace metals, the complex chemistry of the drilling fluid is thought to prevent their release to the environment. However, no analytical results have been published concerning the concentration range of dissolved metals in different drilling fluids that substantiate this conclusion.

The fate of organic compounds in drilling fluids was assessed in a recent study by Strosher (1980). The investigations focused on fluids derived from three basic drilling mud systems used in the majority of oil and gas well drilling in Alberta, i.e., KCl-water-polymer, flocculated fresh water-gel, and dispersed fresh water-gel. Fourteen different organic parameters were determined on the sump fluids and the fate of these compounds upon terrestrial disposal was assessed. The parameters were: organic carbon, organic polymers, aliphatic hydrocarbons, aromatic hydrocarbons, organic sulphur compounds, organic phosphorus compounds, organic nitrogen-containing compounds, chlorinated hydrocarbons, phenols, organic acids, aldehydes, amines, amides, and sulphonates.

Controlled spills of whole fluids were conducted at four sites, three located in the lower foothills region and the fourth site in a prairie environment. Strosher found that the penetration of the liquid was related to the physical characteristics of the soil (for example moisture content) rather than soil type (all soils were fine-grained). Furthermore, a chromatographic separation of the organics was observed at all four sites. The hydrocarbons penetrated the farthest, followed by polar constituents (organic sulphur), and finally by larger polymeric compounds. The vertical penetration rate after five months varied from 20 to 65 cm in the different soils. Lateral movement was found to be less than one metre. The movement thus far observed appears to be movement in the unsaturated zone only. No information is available on the effect of biological and/or chemical processes within the soil environment on the organic compounds, nor is the contamination potential of the relative amounts of the organic components known or their breakdown products within the soil environment once these compounds are incorporated in the groundwater flow system in the area.

The results of the investigation also showed that the KCl-water-polymer mud system contained, on the average, the highest organic carbon content (see also Younkin and Johnson, 1980) and that the majority of the organic constituents were in fact unaltered additives (organic polymers, hydrocarbons, and lignosulphonates). There were indications that some of the phenols in the mud were derived from the breakdown of lignosulphonates. Similarly, some of the aldehydes and amines (bactericides) observed in the sump fluids could have been generated by breakdown of other organic additives.

The observations of Strosher (1980) strongly suggest that, because the majority of the organics found in the sump fluids were unaltered, the least toxic variety of the organics should be chosen to minimize the environmental impact of disposal. This could indeed reduce the immediate environmental impact of drilling fluid disposal on the terrestrial environment. However, the fact remains that drilling fluid solids and entrapped drilling fluid are presently disposed of in landfills without any monitoring of the fate of the toxic chemicals.

It is possible that biodegradation in time will render the organic components harmless and that the metals released during biodegradation are immediately adsorbed by the clay minerals and immobilized. On the other hand, a host of new organic compounds may be created, which may be harmless or very toxic, and which may have a much greater mobility within the subsurface than their original parent material. In comparison to a landfill site for a medium size city, the sump area for an oil or gas well is negligible; however, a rough estimate of the total bottom sump areas of all wells drilled in the last 15 years in Alberta indicates that this surface area is at least 8 $km^2$. It can be argued that the environmental impact suggested is out of proportion because the area is very fragmented, and the pollution at each source would be diluted and rendered harmless by the environment. Unfortunately, properly documented studies have not been conducted on the long-term environmental impact of this disposal on groundwater resources. Permissible levels of organic pollutants in potable water resources are generally expressed in parts per billion rather than parts per million (i.e., relatively small quantities of toxic organic compounds can contaminate relatively large volumes of potable water). The effect of such small quantities of contaminants has long been recognized in Europe in association with groundwater pollution from refined petroleum products (gasoline, diesel and jet fuel). Concentrations of 1 mg/L have caused an objectionable taste and smell in water

(Zimmerman, 1976). Surface runoff of spills of organic materials such as diesel fuel may affect the taste of surface drinking water supplies.

Groundwater flow and subsequent contaminant movement is only considered in siting criteria for leases where obvious permeable sediments (sands) are present. In these areas sumps are not allowed at all or must be lined. In areas where sumps are constructed in sediments with a very fine-grained matrix (clay, silt, glacial till, etc.) the effect of groundwater flow as a transport mechanism is generally neglected because it is assumed that the sediment is essentially impermeable and no movement occurs, which could indeed be true in some areas. Furthermore, intergranular groundwater flow rates in these sediments are small compared to those in coarser-grained sediments and contaminant movement over the lifetime of a lease would be considered unimportant. However, at least in the prairies, all these fine-grained sediments are fractured to various degrees and fracture flow is the major mechanism for groundwater recharge in these sediments. For instance, in southern Alberta the anticipated development of saline/alkaline soils in fine-grained sediments as a result of irrigation has not occurred because fracture flow has allowed rapid infiltration through the soil zone (Hendry, 1982). Long-term observations in the vicinity of the brine disposal basins near the potash mines in Saskatchewan has shown that over 15 to 20 years brine migration of many tens of metres has occurred in this type of sediment, which was hitherto considered impermeable. It is not known at this time if the relatively rapid contaminant movement in these sediments was caused solely by physical transport along fractures, or if it is the result of the combined effects of fracture flow, osmotic transport, and permeability increases in these sediments due to the effect of potassium-rich brines (20 000-50 000 ppm) on the clays.

The long-term containment of potentially toxic compounds in a buried sump will depend on the transport mechanism. The distribution pattern of contaminants in the shallow subsurface will be determined by the location of the sump within the hydrogeological setting of the area. No studies have been conducted to determine the extent of contaminant movement in different hydrogeological environments.

If the total number of oil and gas wells drilled in Alberta between 1975 and 1981 is considered, and it is assumed that sump fluid was disposed of by land spreading in the majority of the cases, then the total area that has received drilling fluid of various ionic concentrations is conservatively estimated to be in the order of at least 500 $km^2$, based on a minimum disposal area size of 1.51 ha. Whether the disposal of drilling fluids over this area has resulted in any groundwater contamination is not known because baseline data on the concentrations and distribution of the organic drilling fluid components and their breakdown products in groundwater are not available.

The toxicity of the supernatant fluid is measured by the 96-hour trout survival test. This technique allows the overall toxicity of all synergistic and anti-synergistic effects of the various combinations of the dissolved compounds in the fluid to be assessed at the same time. It is, however, only a measure of the toxicity of the fluid to the aquatic environment, which is of relatively minor importance because the fluids are supposed to be contained in the disposal area and introduction into surface water bodies either directly or subsequently by surface runoff is not permitted. It is not known whether toxicity determined by the trout test is related directly to toxicity to other aquatic or terrestrial organisms, or to humans. Present criteria for land disposal were therefore reviewed in terms of groundwater quality standards.

According to Alberta ERCB directive (ID-OG-75-2), the total dissolved solids concentration should not exceed 4000 mg/L. If the TDS concentration exceeds 4000 mg/L, the fluid must be spread at < 400 lbs/acre (448 kg/ha) of chloride ion concentration. A concentration of 4000 mg/L TDS corresponds to a minimum electrical conductivity value for the solution of about 5000 µmhos/cm at 25°C (Richards, 1954). Since land spreading is a form of irrigation, it may be useful to determine the classification of this water. According to Richards (1954), water with an electrical conductivity greater than 2250 µmhos/cm has a very high salinity. Highly saline water is not suitable for irrigation under ordinary conditions, but can be used occasionally under very special circumstances. The soils must be permeable, subsurface drainage must be adequate, and excess irrigation water must be applied to provide considerable leaching (Richards, 1954). Treated drilling fluid applied to this type of soil would infiltrate rapidly and cause groundwater contamination. Areas with this type of soil would be classified as environmentally very sensitive and surface disposal would not be allowed. Spreading fluids with this electrical conductivity on any other soil could result in changes in the physical characteristics which could be detrimental to the productivity of the soil. In most instances leaching will eventually remove the excess salt. However, since the leached salts move downward, the salt load will be added to the groundwater.

The effect of the anions, chloride and sulphate on soils and plant growth cannot be assessed without knowledge of the type and concentration of ionized cations in the fluid.

When the chloride, sulphate, and total dissolved solids concentration criteria are compared to acceptable raw water quality levels for drinking water supplies

(McNealy, et al, 1979), all three are found to exceed the drinking water criteria. Although groundwater that does not meet water quality standards is used for human consumption in many places on the prairies, the concentrations of the chloride and sulphate ions and total dissolved solids content are generally considerably less than the values recommended by the ERCB directive. In areas where the sump fluids reach the groundwater, considerable chemical loading can occur, although this type of loading is only a single event of relatively short duration and the effects are temporary. What may be much more significant than inorganic contamination is the potential for pollution of groundwater resources by organics.

Strosher (1980) showed that some infiltration of various organic compounds in the near-surface sediments does occur after land spreading. He also observed relatively rapid movement, up to 65 cm in five months, which in a normal soil profile would be beyond the zone of significant bacterial action. This means that some of the organics present in the sump fluid could enter the groundwater regime unaltered. In addition, products of biological breakdown of organics introduced to the active soil zone could move down during subsequent recharge events. At this time no data are available on the compounds thus created, their levels of toxicity to various forms of life, their mobility in the hydrogeological regime, or their concentration levels. It should be noted that, since most groundwater recharge and surface runoff occurs during the spring snowmelt, much of the pollution risk could be alleviated if spreading were prohibited during the period between freeze-up and the spring thaw.

The above review shows that serious deficiencies exist in the data base on the fate of the various organic and inorganic compounds in the subsurface environment. Some doubt therefore exists as to whether the present criteria for sump fluid disposal are a realistic measure for the long-term protection of the environment and its ultimate uses.

The environmental impact of lost circulation during the drilling in terms of the potential toxicity of the lost drilling fluid is usually negligible because the formation water is already saline, the volumes lost are generally small, and groundwater flow rates are small. However, under certain specific conditions loss of circulation can cause indirect pollution of the terrestrial environment if lost circulation at total depth results in a blowout of salt water, crude oil, condensate or hydrogen sulphide gas from a shallower formation.

The environmental impact of such an event depends on the total volume blown out of the wellbore, the product and its concentration, the duration of uncontrolled flow, site-specific characteristics such as drainage and vegetation, climatological conditions, season, etc. The environmental effects of blowouts are also geographically dependent. Land-based blowouts in the Arctic are, for example, much more serious than in the more temperate regions of Canada, whereas a blowout in an offshore area would be more serious than one at any land-based location.

In addition to the potential environmental effects of drilling operations and drilling fluid disposal, a long-term potential for impact exists if the integrity of the casings and abandonment plugs in abandoned wells decreases with time. Although it is known that many wells were improperly abandoned before adequate regulations were developed, no thorough study has considered the long-term integrity of wells that have been abandoned according to current regulations.

# 4 CONVENTIONAL OIL AND GAS PRODUCTION

## 4.1 Introduction

According to established terminology, light oil is crude oil having a density of less than 900 $kg/m^3$ (API gravity greater than 25°). Conventional heavy oil is crude oil having a density greater than 900 $kg/m^3$ but with a low enough viscosity to enable a well to produce at a commercial rate by natural forces in the reservoir. Heavy oil, which requires injection of chemicals, heat, or miscible fluids or gases to the reservoir to initiate production, is thought of as non-conventional heavy oil. Production of non-conventional heavy oil is included in the category of "enhanced oil recovery" and is discussed in Chapter 5 in this report. Oil and gas recovery processes are described as primary, secondary, or tertiary operations. Primary and secondary recovery apply to "conventional" oil production, regardless of whether the oil is a light or heavy crude, whereas tertiary recovery applies only to oil production by "enhanced oil recovery" methods. In this chapter only primary and secondary recovery are discussed.

Heavy oil occurs mainly in the Mannville Group (Figure 17), except for some occurrences in Devonian carbonates northeast of the Peace River, and commonly occurs at less than 1200 metres. In the Lloydminster area of Alberta and Saskatchewan the average heavy oil well depth ranges from 450 m to 900 m. In contrast, most light oil production in western Canada is derived from depths exceeding 1200 m.

## 4.2 Primary Recovery

**4.2.1 Overview.** The natural force moving oil and gas to wells in response to a pressure differential is attributable to the expansion of gases within a reservoir or to hydraulic gradients related to local or regional fluid flow systems. Production processes using this natural force are referred to as "primary recovery". Figure 27 illustrates the displacement of petroleum to wells by natural energy. Oil itself is only slightly compressible and therefore expands very little with a decrease in pressure. Water tends to be even less compressible than oil. If it were necessary to rely only on expansion of the reservoir oil itself, only about one percent of the oil-in-place would be recovered. Gas, in contrast to oil, is very compressible and will consistently show a primary recovery of over 50 percent of the gas-in-place. The principal sources of energy that push crude oil into a well are natural (dissolved) gas drive, gas cap, and natural water-drive.

To achieve maximum economic recovery, most reservoirs are subjected to secondary recovery processes involving water or gas injection and, where water is used,

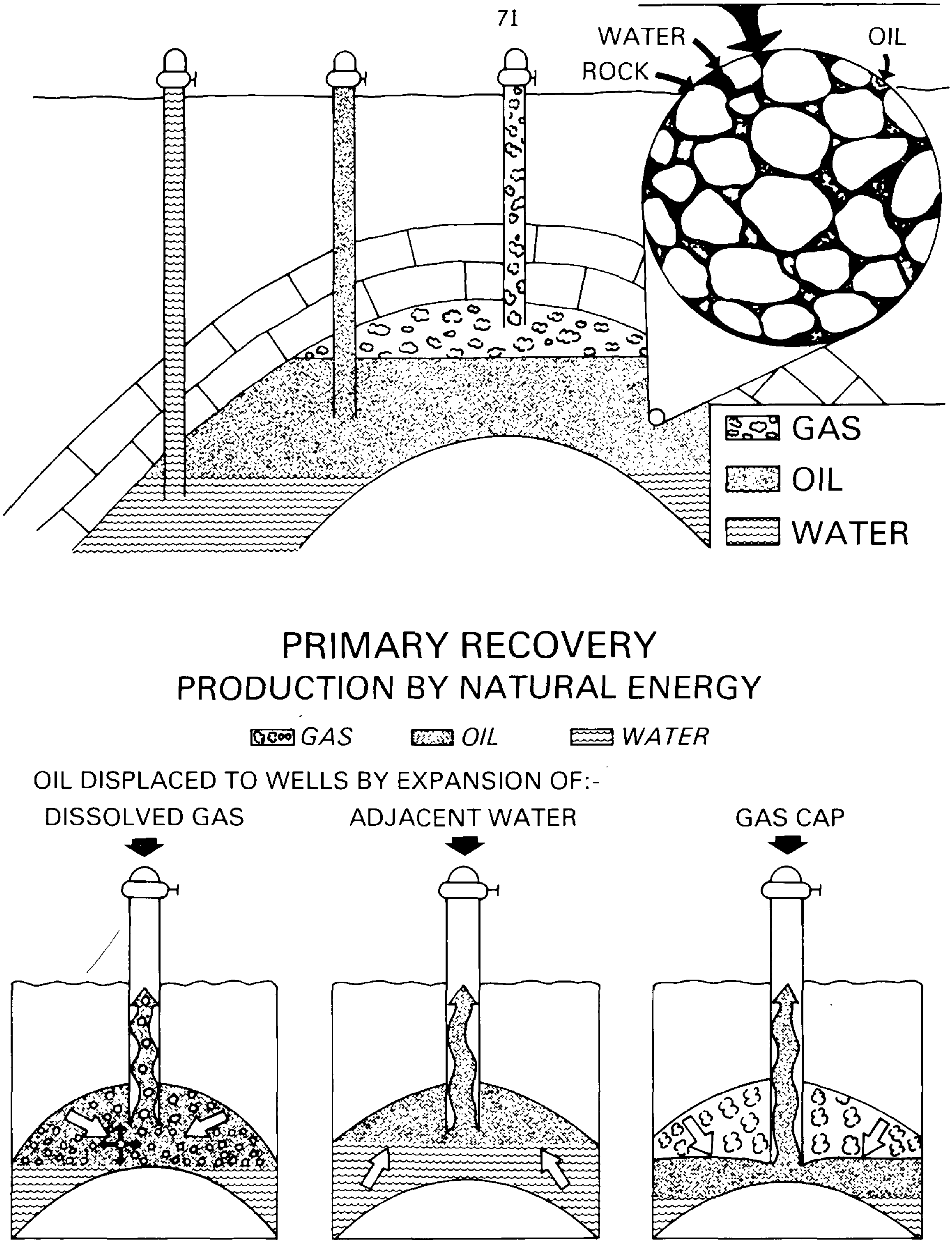



FIGURE 27 OCCURRENCE OF PETROLEUM AND PRIMARY RECOVERY BY NATURAL ENERGY

consequent water production. Typical production and injection volumes for several light and heavy fields in western Canada are presented in Tables 14 and 15.

**4.2.2 Dissolved Gas Drive.** Dissolved gases in the reservoir oil increase recovery by providing natural drive energy in addition to that of pure expansion. Figure 28 illustrates dissolved gas drive and the attributable oil recovery. When pressure is released at a producing wellbore the oil flows to the wellbore because of the pressure gradient created. As oil is produced and pressure in the reservoir decreases, the gases come out of solution and expand to occupy space voided by the oil. The released gas occupies more and more of the pore space until this free gas also begins to flow and is produced at the wellbore. Eventually the supply of energy generating gas is depleted and the reservoir pressure begins to decline rapidly until the oil production rate decreases to an uneconomic rate.

The fraction of oil recoverable by dissolved or solution gas drive depends on the reservoir rock properties, type of oil and amount of gas in solution. Typical dissolved gas drive recovery ranges from 3 to 15 percent of oil-in-place, averaging about 10 percent.

Recovery of heavy oil by primary depletion amounts to only 3 to 5 percent of oil-in-place because of its viscosity. The production rate for this type of oil is inversely proportional to the viscosity of the reservoir oil. Light oils typically range from 5 to 50 Pa/s in viscosity. Heavy oil viscosity may range from 500 Pa/s to more than 1 000 000 Pa/s at Fort McMurray. If all other parameters were equal a conventional oil well would show a production rate 100 times greater than a heavy oil well in the low viscosity range. Since the production rate tends to be lower for heavy oil wells the limit for economic recovery is also reached at much lower rates.

Waterflooding is also used to increase heavy oil recovery but is quite inefficient because of the high viscosity ratio between the oil and the water. The portion of the reservoir contacted, or sweep efficiency, is also low. Gas caps and natural water drives are relatively ineffective for increasing heavy oil recovery. "Inactive" bottom water is also common in many heavy oil reservoirs and production tends to be characterized by relatively high water-oil ratios even when there is relatively little water injection. This is clearly illustrated by the water-to-oil ratios in Tables 14 and 15.

**4.2.3 Gas Cap Drive.** Assistance for the expansion and gas-in-solution energy sources for primary recovery of lighter oils is occasionally derived from a natural gas cap. The gas cap may be made up of free gas initially present, or released solution gas which moves to the top of the oil zone, as illustrated in Figure 29. To displace the oil the gas

TABLE 14 TYPICAL WESTERN CANADA LIGHT OIL PRODUCTION AND INJECTION RATES

| | Production | | | Injection | | | Production Ratios ($m^3/m^3$) | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Water ($m^3/d$) | | | |
| Field & Pool | Oil ($m^3/d$) | Gas ($10^3/m^3/d$) | Water $m^3/d$ | Gas ($10^3$ $m^3/d$) | Produced | Make-up | Gas/Oil Ratio | Water/Oil Ratio |
| Alberta Light | | | | | | | | |
| Acheson D-3A | 1975 | 171 | 240 | 0 | 203 | 109 | 87 | 0.1 |
| Ante Creek BHL | 232 | 125 | 0 | 40 | 0 | 523 | 539 | 0.0 |
| Bonnie Glen D-3A | 12860 | 5528 | 140 | 3519 | 399 | 0 | 430 | 0.0 |
| Brazeau Riv Niskua | 728 | 124 | 0 | 561 | 0 | 0 | 170 | 0.0 |
| Fenn Big Val D-2A | 8825 | 660 | 2045 | 0 | 1016 | 0 | 75 | 0.2 |
| Golden Spike D-3A | 717 | 2106 | 27 | 0 | 0 | 0 | 2937 | 0.0 |
| Harmatton E Runol | 2338 | 5574 | 1520 | 1341 | 0 | 2055 | 2334 | 0.6 |
| Judy Creek BHL | 3660 | 557 | 16733 | 0 | 0 | 24950 | 152 | 4.6 |
| Judy Creek BHLC | 1474 | 750 | 4579 | 0 | 0 | 7488 | 509 | 3.1 |
| Kaybob BHL B | 1256 | 312 | 1714 | 0 | 0 | 5147 | 248 | 1.4 |
| Kaybob SO BHL A | 1381 | 254 | 465 | 8571 | 2570 | 316 | 184 | 0.3 |
| Leduc Woodben D-3A | 1036 | 829 | 5166 | 0 | 0 | 3043 | 800 | 5.0 |
| Mitsue Gilwood A | 5463 | 612 | 308 | 0 | 0 | 9092 | 112 | 0.1 |
| Nipsi Gilwood A | 5255 | 371 | 5128 | 0 | 0 | 11028 | 71 | 1.0 |
| Pembina Cardium A | 10511 | 3676 | 20255 | 46 | 38 | 30463 | 350 | 1.9 |
| Provost Vik Cak&Man | 1013 | 1829 | 552 | 0 | 55 | 2586 | 1806 | 0.5 |
| Rainbow Keg Riv A | 1006 | 497 | 13 | 632 | 0 | 0 | 494 | 0.0 |
| Rainbow Keg Riv B | 1380 | 125 | 808 | 0 | 0 | 3378 | 91 | 0.6 |
| Rainbow Keg Riv F | 2261 | 405 | 243 | 0 | 0 | 2250 | 179 | 0.1 |
| Rainbow Keg Riv AA | 871 | 270 | 206 | 326 | 0 | 552 | 310 | 0.2 |
| Redwater D-3 | 7839 | 304 | 134645 | 0 | 137066 | 8579 | 39 | 17.2 |
| Simonette D-3 | 3000 | 1733 | 1530 | 0 | 0 | 3439 | 578 | 0.5 |
| Sturgeon Lake D-3 | 1592 | 267 | 850 | 0 | 975 | 0 | 168 | 0.5 |
| Swan Hills BHL C | 5723 | 6669 | 1813 | 0 | 0 | 2601 | 1165 | 0.3 |
| Swan Hills BHL A&B | 6312 | 729 | 10247 | 0 | 0 | 20381 | 115 | 1.6 |
| Swan South | 6312 | 2056 | 23277 | 986 | 0 | 32312 | 326 | 3.7 |
| Westerose D-3 | 2706 | 318 | 0 | 0 | 0 | 0 | 118 | 0.0 |
| Willesden GR Card | 1726 | 937 | 213 | 910 | 0 | 2479 | 543 | 0.1 |
| Wizard Lake D-38 | 7702 | 937 | 0 | 2289 | 0 | 3844 | 122 | 0.0 |
| Other Alberta | 43973 | 1500 | 36649 | 8881 | 0 | 61590 | 34 | 0.8 |
| Saskatchewan Light | | | | | | | | |
| Area 2 Light | 1367 | 90 | 881 | 0 | 0 | 1600 | 66 | 0.6 |
| Area 4 Medium | 4630 | 186 | 16650 | 0 | 0 | 22000 | 40 | 3.6 |
| Area 4 Light | 4149 | 439 | 20367 | 0 | 0 | 25000 | 106 | 4.9 |
| British Columbia | | | | | | | | |
| Boundary LK A | 2054 | 232 | 1822 | 0 | 0 | 5925 | 113 | 0.9 |
| Eagle Belloy | 1192 | 143 | 14 | 0 | 0 | 1518 | 120 | 0.0 |
| Other B.C. | 2250 | 260 | 5211 | 90 | 0 | 5460 | 116 | 2.3 |
| GRAND TOTAL | 166819 | 41575 | 314311 | 28192 | 142322 | 299708 | 249 | 1.9 |

Source: Alberta Energy Resources Conservation Board Monthly Production Statement

TABLE 15 TYPICAL WESTERN CANADA HEAVY OIL PRODUCTION AND INJECTION RATES

| Field & Pool | Production | | | Injection | | | Production Ratios ($m^3/m^3$) | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Water ($m^3/d$) | | | |
| | Oil ($m^3/d$) | Gas ($10^3/m^3/d$) | Water $m^3/d$ | Gas ($10^3$ $m^3/d$) | Produced | Make-up | Gas/Oil Ratio | Water/Oil Ratio |
| Alberta Medium & Heavy | | | | | | | | |
| Bantry Manville A | 540 | 58 | 2286 | 0 | 1078 | 1296 | 107 | 4.2 |
| Bantry Manville D | 116 | 12 | 398 | 0 | 353 | 0 | 103 | 3.4 |
| Cessford Manville C | 411 | 207 | 279 | 0 | 77 | 0 | 504 | 0.7 |
| Chauvin SO Sparky H | 101 | 2 | 173 | 0 | 0 | 281 | 20 | 1.7 |
| Chauvin SO Spky A&B | 162 | 13 | 518 | 0 | 0 | 992 | 00 | 3.2 |
| Chin Coulee Bas Mana | 140 | 3 | 412 | 0 | 0 | 566 | 21 | 2.9 |
| Countess Up Man B | 147 | 8 | 631 | 0 | 0 | 1038 | 54 | 4.3 |
| Countess Up Man D | 995 | 50 | 3469 | 0 | 0 | 3980 | 50 | 3.5 |
| Countess Up Man H | 242 | 11 | 858 | 0 | 0 | 1116 | 45 | 3.5 |
| Countess Up Man O | 172 | 19 | 832 | 0 | 0 | 706 | 110 | 4.8 |
| Glenevis Banff | 105 | 7 | 227 | 0 | 223 | 0 | 67 | 2.2 |
| Grand Forks UPMANB | 329 | 8 | 278 | 0 | 0 | 901 | 24 | 0.8 |
| Grand Forks LOMANA | 157 | 6 | 879 | 0 | 0 | 904 | 38 | 5.6 |
| Grand Forks LOMAND | 1247 | 19 | 1437 | 0 | 0 | 2823 | 15 | 1.2 |
| Grand Forks LOMANE | 318 | 19 | 986 | 0 | 0 | 952 | 60 | 3.1 |
| Grand Forks LOMANG | 157 | 1 | 148 | 0 | 0 | 144 | 6 | 0.9 |
| Grand Forks LOMANK | 558 | 12 | 463 | 0 | 0 | 1513 | 22 | 0.8 |
| Hays Manville A | 163 | 8 | 1336 | 0 | 0 | 1699 | 49 | 8.2 |
| Horsefly Lake Man | 152 | 2 | 246 | 0 | 0 | 419 | 13 | 1.6 |
| Lloyd Sparky B | 137 | 3 | 47 | 0 | 0 | 21 | 22 | 0.3 |
| Lloyd Sparky G | 186 | 17 | 170 | 0 | 0 | 0 | 91 | 0.9 |
| Lloyd Spky C Genpet | 114 | 12 | 343 | 0 | 0 | 482 | 105 | 3.0 |
| Lloyd Spky Y Genpet | 285 | 45 | 634 | 0 | 288 | 462 | 158 | 2.2 |
| Provost Up Man B | 101 | 4 | 102 | 0 | 0 | 0 | 40 | 1.0 |
| Taber Man D | 220 | 3 | 497 | 0 | 0 | 604 | 14 | 2.3 |
| Taber So Man A | 105 | 1 | 574 | 0 | 0 | 658 | 10 | 5.5 |
| Taber So Man B | 140 | 3 | 1253 | 0 | 0 | 1385 | 21 | 9.0 |
| Viking Kin Wain B | 1043 | 32 | 3239 | 0 | 0 | 4461 | 31 | 3.1 |
| Wainwright Spky H | 1048 | 38 | 4359 | 0 | 0 | 5602 | 36 | 4.2 |
| Wildmere Lloyd A | 313 | 53 | 394 | 0 | 0 | 831 | 169 | 1.3 |
| Saskatchewan Heavy & Medium | | | | | | | 0 | 0.0 |
| Area 1 Heavy | 5473 | 0 | 9525 | 0 | 0 | 12000 | 0 | 1.7 |
| Area 2 Heavy | 1402 | 32 | 3872 | 0 | 0 | 5000 | 23 | 2.8 |
| Area 3 Medium | 3570 | 166 | 21171 | 0 | 0 | 26000 | 46 | 5.9 |
| GRAND TOTAL | 20349 | 874 | 62036 | 0 | 2019 | 76836 | 42 | 3.0 |

Source: Alberta Energy Resources Conservation Board Monthly Production Statement

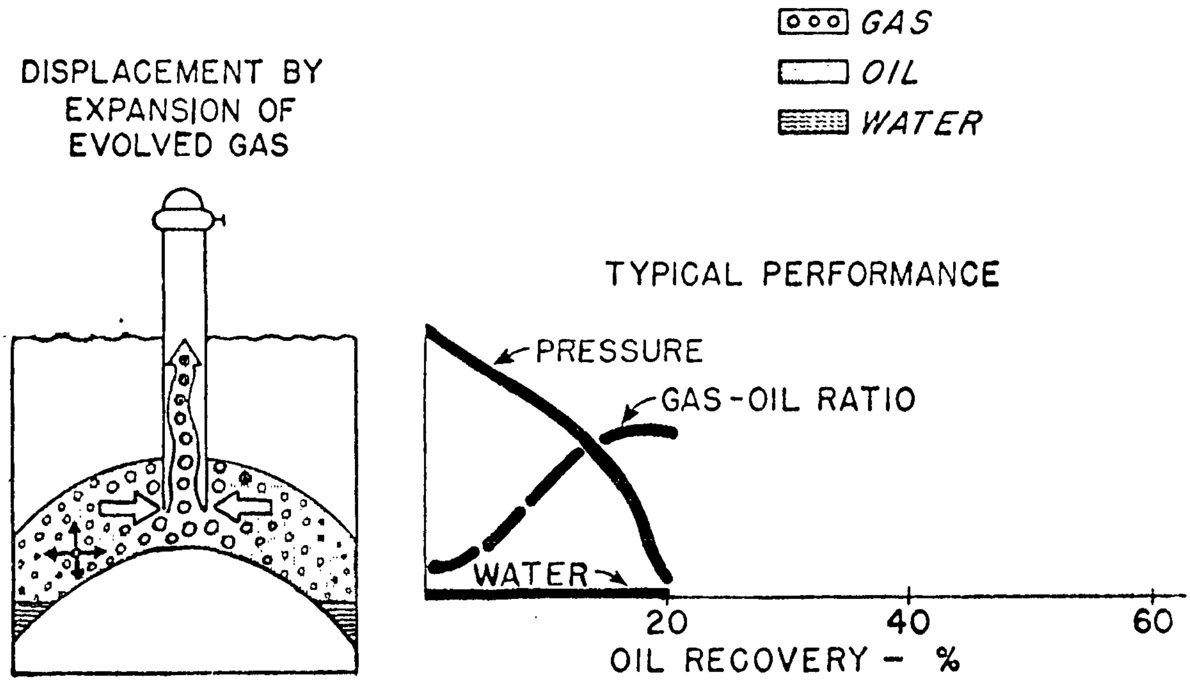
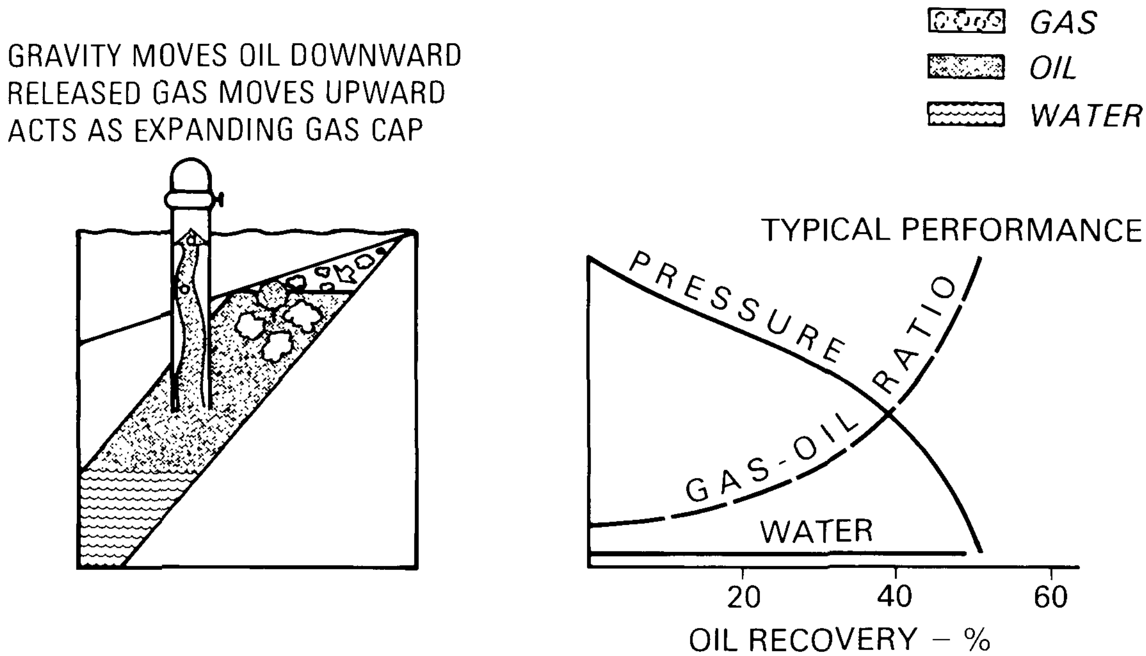



FIGURE 28 DISPLACEMENT OF PETROLEUM BY DISSOLVED GAS DRIVE

cap expands downward into the oil zone. This expansion occurs as the pressure in the oil zone decreases in response to production. However, instead of cleanly displacing the oil, the invading gas, being more mobile than the oil, often tends to flow along with the oil. Eventually the gas may also break through to the producing well, which depletes the reservoir of the energy source.

Oil recovery from a reservoir with gas cap drive assistance is also dependent upon reservoir rock properties and fluid conditions. Recovery from gas cap drive reservoirs typically ranges between 15-45 percent and averages about 25 percent of the oil-in-place.

4.2.4 **Natural Water Drive.** Oil and/or gas recovery is sometimes accomplished with energy derived from water in aquifers adjacent to the oil and/or gas reservoirs. Figure 30 illustrates the principles of water drive and the related oil recovery. A water drive may be active or inactive. Water from the aquifer will move in response to the existing natural hydraulic gradients in the flow system or in response to the gradients induced by production from the well and will invade the oil and/or gas zone which is being pressure




## GRAVITY DRAINAGE

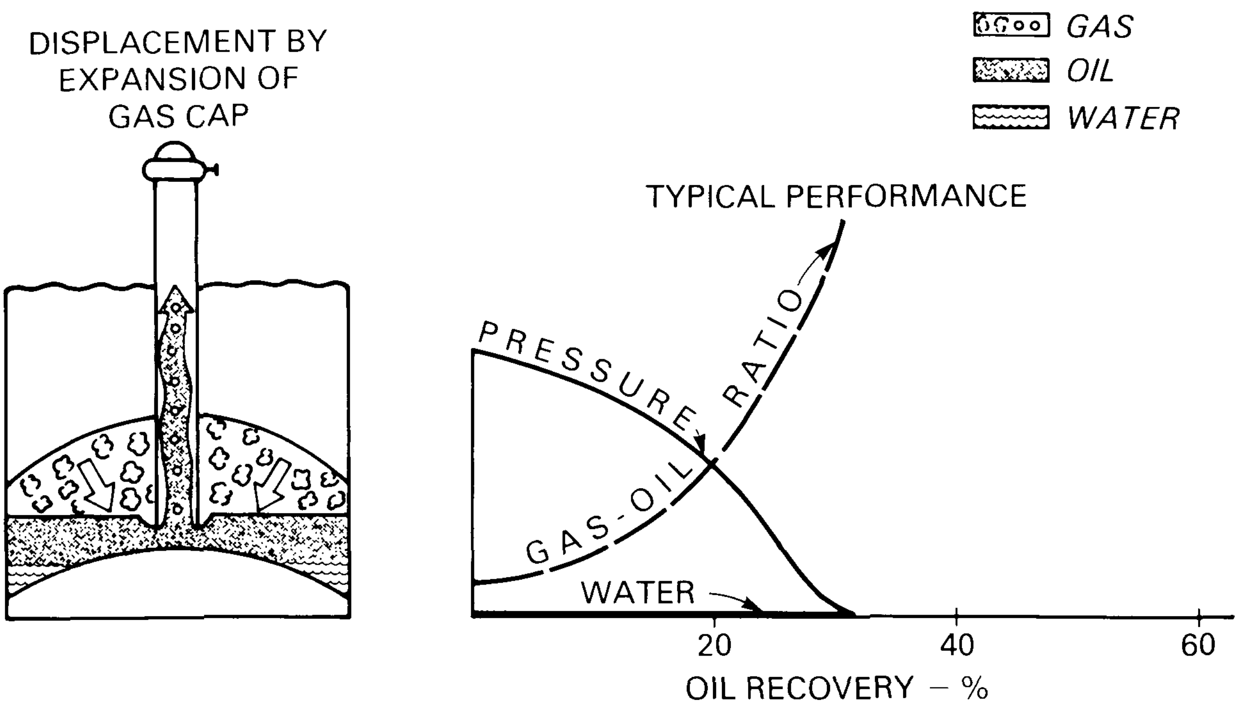



FIGURE 29 GAS CAP DRIVE AND GRAVITY DRAINAGE

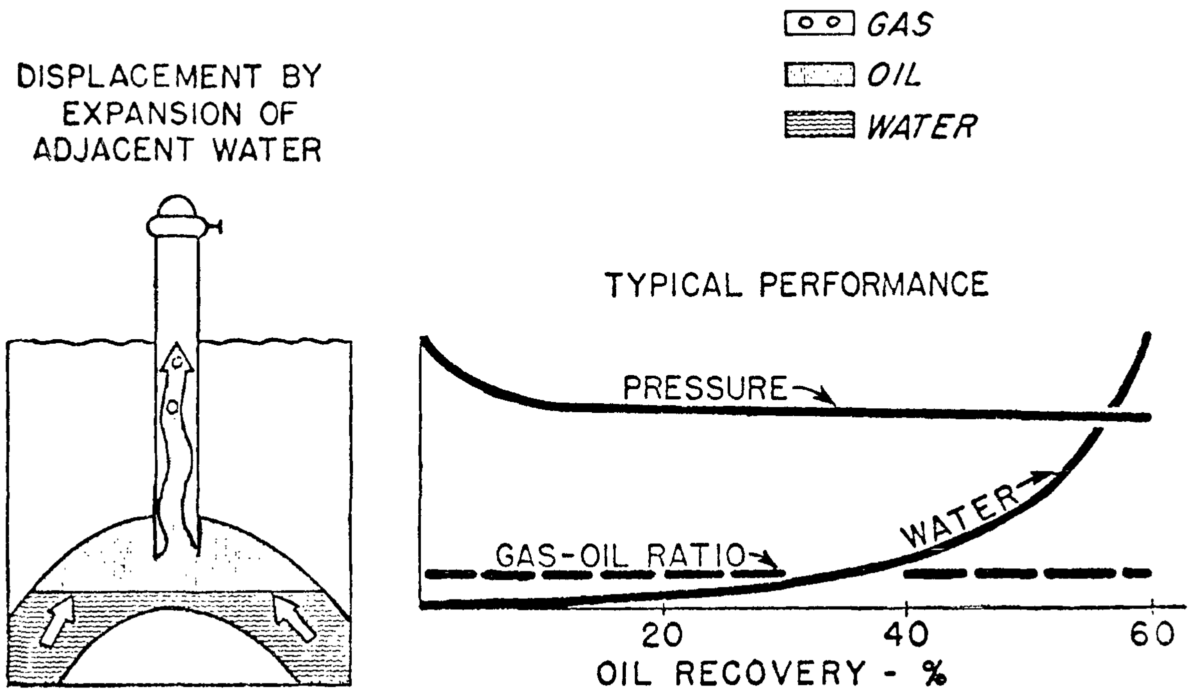



FIGURE 30 DISPLACEMENT BY WATER DRIVE

depleted in response to production at the well. If the aquifer is not hydraulically connected to an active flow system, pressure may decline rapidly in response to gas or oil production and the water drive will cease (an "inactive" water drive). If, however, the aquifer is well connected hydraulically to the regional flow system or even a local flow system with high gradients, very little, if any, pressure decline will occur in response to oil or gas production. Such reservoir is considered to have an active water drive.

Eventually the aquifer water encroaches upon the producing wellbore and floods out the oil and/or gas production. Typical oil recovery from a natural water drive reservoir ranges from 25-80 percent of the oil-in-place and averages about 60 percent. A gas reservoir subject to natural water drive usually has a longer production life, but not necessarily a higher ultimate recovery, than a gas reservoir where production is by expansion. Gas reservoir recoveries from natural water drive typically range from 50 to 80 percent of the gas-in-place.

Water breakthrough at a producing well occurs long before the production operation is uneconomic. Substantial amounts of water are usually co-produced with oil during the productive life of a natural water drive reservoir. Produced water typically shows a salinity of at least 10 000 and often over 200 000 mg/L. The water is not considered potable or usable for any purpose except in relatively small quantities within the oil industry itself, e.g., for oil well servicing. Water production is relatively uncommon with the other primary recovery mechanisms and, when evident, the volume is insignificant. Most of the reservoirs in Canada show only partially active water drive.

## 4.3 Secondary Recovery

**4.3.1 Overview.** Most oil fields show relatively low production by primary recovery either because there is little or no water drive or the water drive is inactive. Declining reservoir pressure can be reversed by reinjecting the produced water and/or gas, and adding additional water and/or new gas to the reservoir to maintain or increase the hydraulic head in the reservoir. Additional recovery attributable to such injection is referred to as secondary recovery. If injection begins after a reservoir has been depleted by primary recovery the additional oil production is usually considered secondary recovery, whereas injection begun before significant primary recovery has been accomplished is considered a pressure maintenance operation.

Secondary recovery projects usually involve either water or gas injection or both. Operators attempt to balance the amount of water and/or gas that is injected and the volume of oil and gas produced. During the early stages of an injection operation, excess fluid is often injected to compensate for previous loss of pressure. Eventually, late in the life of the project, injection is terminated while production continues. Good engineering practice usually calls for volume replacement on a cumulative basis to at least equal total produced fluid volume.

**4.3.2 Gas Injection in Gas Reservoirs.** Secondary recovery by water injection is seldom if ever implemented to increase recovery from gas fields. The compressibility of gas is high while the viscosity is relatively low, so primary recovery cannot usually be economically improved by water injection. Gas injection cycling operations are sometimes implemented in gas reservoirs to improve recovery of propane and heavier, or "propane plus", components. Propane plus components tend to condense and liquify, remaining in the reservoir as pressure is lost in response to production because they are more volatile at higher pressures and temperatures. Injecting a lean gas that is low in propane plus composition tends to maintain pressure and revaporize liquids in the reservoir. Overall heat value recovery can be substantially increased by gas cycling. Water injection, because the water tends to collect in the bottom of the reservoir and prevent flow to the wells, tends to trap reservoir gas permanently rather than increase recovery. The configurations of wells for two gas injection schemes are illustrated in Figure 31.

In general, gas field operations produce very little water because there is usually very little water in the reservoir and also because, if present, water flows less readily to the well than gas. If a water drive aquifer is present, resulting in free water flow to the well, the water is usually disposed of by re-injection to the reservoir of origin. Relative flow characteristics of water and/or gas are such that if much water is present in the vicinity of the well, instability arises either in the reservoir or up the wellbore and gas flow from the well ceases at relatively low water production rates. Table 16 illustrates gas and water production rates for typical non-associated gas fields in Alberta and British Columbia.

Water vapour is present in almost all gas reservoirs to some degree and can amount to a maximum of about 25 $m^3$ of water per million cubic metres of gas in deep, saturated, high temperature reservoirs. Average water vapour content for Alberta and British Columbia reservoirs is about 10 $m^3$ of water per million cubic metres of gas. Shallow gas reservoirs, which are of lower pressure and low temperature, contain about 5 $m^3$ of water per million cubic metres of gas. Compared to water production in secondary recovery oil projects, the water vapour produced with gas is insignificant. Gas wells cannot maintain extended economic production at aquifer water production rates exceeding 500 to 1000 $m^3$ water per million cubic metres gas.

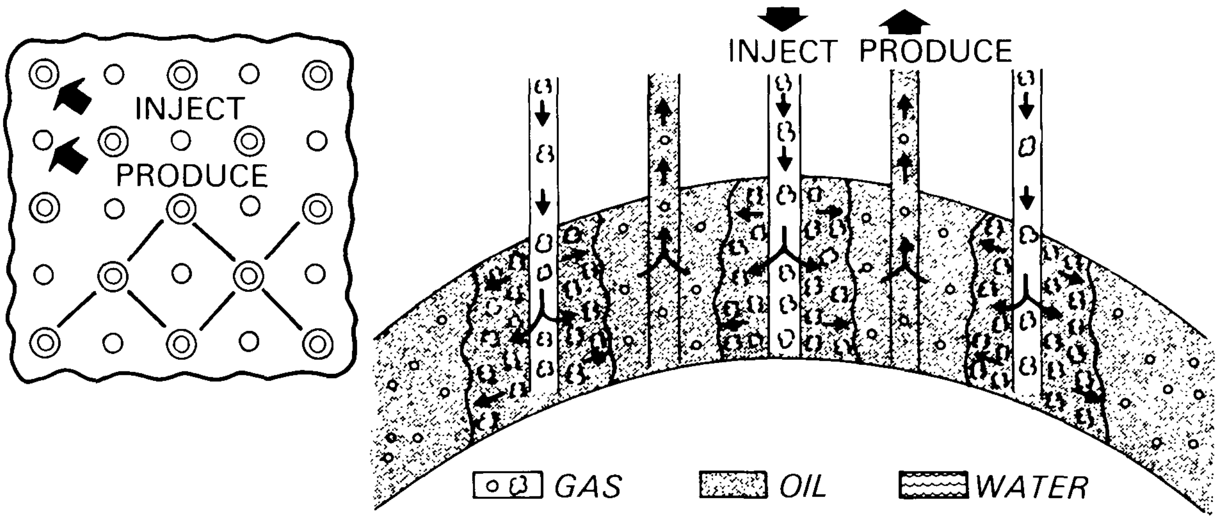
**4.3.3 Water and Gas Injection in Oil Reservoirs.** Water and/or gas injection can be applied to virtually all reservoirs producing oil under primary recovery schemes, including gas cap and water drive reservoirs. In the case of a gas cap drive, gas is injected to the cap to supplement the pressure drive provided by the compressed gas. Water is injected down dip and/or at bottom even if that requires injecting into the water aquifer to supplement the natural water drive energy (more efficient production would be achieved by injecting up gradient of the oil regardless of the dip but the hydraulic gradients in the groundwater flow systems are often not known by the operators). When the reservoir has neither a gas cap nor a water drive, and a waterflood is suitable, water injection wells are spotted in a regular pattern among the oil wells at ratios of injectors to producers ranging from 1:1 to 1:3. Two configurations are illustrated in Figure 32.

TYPICAL RECOVERY:

PRIMARY (DISSOLVED GAS DRIVE) 21%

SECONDARY (DISPERSED GAS INJECTION) + 6% = 27% TOTAL

INCREASE OVER PRIMARY = 30%




## GAS CAP INJECTION

TYPICAL RECOVERY:

PRIMARY (GAS CAP) 30%

SECONDARY + 10% = 40% TOTAL

INCREASE OVER PRIMARY = 33%

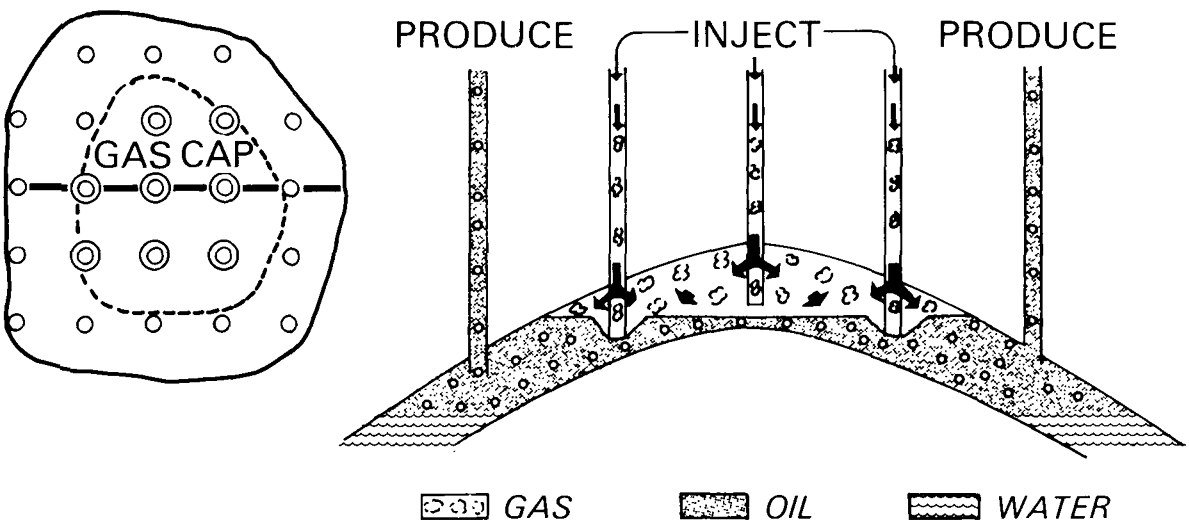



FIGURE 31 RECOVERY BY GAS INJECTION

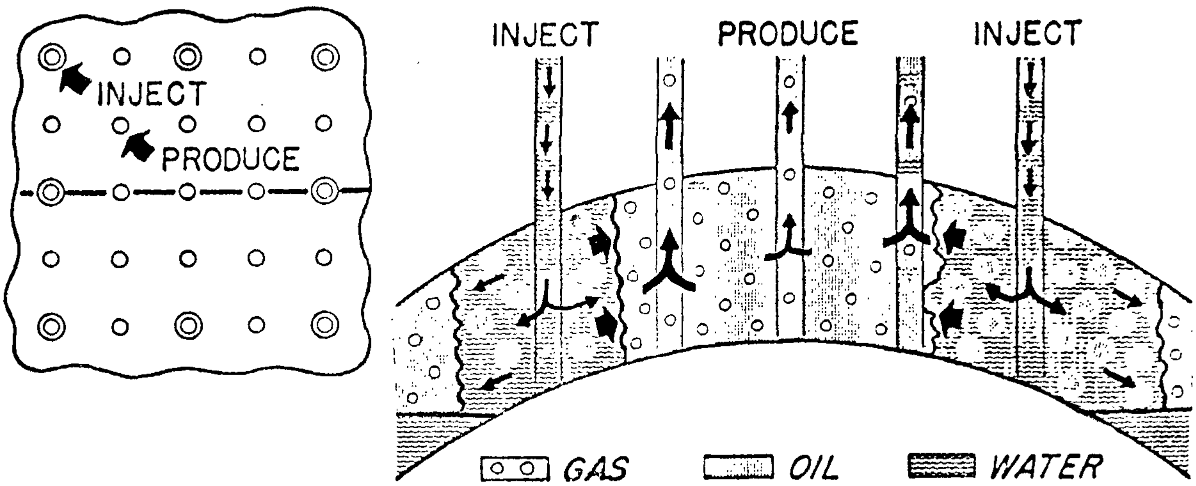
TABLE 16 TYPICAL GAS FIELD PRODUCTION - KEY FIELDS IN ALBERTA AND BRITISH COLUMBIA

| Field | | Daily Gas Rate ($10^6$ $m^3$) | Daily Water Rate ($m^3$) | Water/Gas Ratio ($m^3/10^6$ $m^3$) |
|---|---|---|---|---|
| Alberta | | | | |
| 1) | Berland River | 0.730 | 8 | 11 |
| 2) | Big Bend | 0.650 | 10 | 15 |
| 3) | Boyer | 1.030 | 24 | 23 |
| 4) | Bruce | 1.110 | 37 | 33 |
| 5) | Burnt Timber | 2.480 | 18 | 7 |
| 6) | Cache | 0.820 | 5 | 6 |
| 7) | Carson Creek | 1.020 | 2 | 2 |
| 8) | Carstairs | 2.050 | 16 | 8 |
| 9) | Craigend | 0.750 | 6 | 8 |
| 10) | Dunvegor | 3.750 | 39 | 10 |
| 11) | Elmworth | 7.000 | 20 | 3 |
| 12) | Fir | 0.780 | 3 | 4 |
| 13) | Hairy Hill | 0.620 | 37 | 60 |
| 14) | Homeglin Rimbey | 1.670 | 22 | 13 |
| 15) | Hotchkiss | 1.100 | 17 | 15 |
| 16) | Jumping Pound | 0.800 | 2 | 3 |
| 17) | Jumping Pound West | 3.750 | 8 | 2 |
| 18) | Timestone | 1.570 | 1 | 1 |
| 19) | Tong Coulee | 0.830 | 1 | 1 |
| 20) | Medicine Hat | 8.750 | 116 | 13 |
| 21) | Sinclair | 1.800 | 3 | 2 |
| 22) | Strachan | 2.780 | 63 | 23 |
| 23) | Tweedie | 0.760 | 1 | 1 |
| 24) | Wainwright | 1.590 | 30 | 19 |
| 25) | Warwich | 0.640 | 95 | 148 |
| 26) | Westirose | 3.410 | 11 | 3 |
| 27) | Westlock | 1.400 | 21 | 15 |
| 28) | Waterton | 6.000 | 8 | 1 |
| Total | | 59.740 | 624 | 10 |
| British Columbia | | | | |
| 1) | Clark Lake | 1.690 | 1370 | 810 |
| 2) | Dahl | 0.520 | 5 | 10 |
| 3) | Helmet | 0.920 | 8 | 9 |
| 4) | Laprise Creek | 1.420 | 21 | 15 |
| 5) | Monias | 0.680 | 1 | 1 |
| 6) | Roger | 0.600 | 15 | 25 |
| 7) | Sierra | 2.660 | 24 | 9 |
| 8) | Stoddart | 0.560 | 1 | 2 |
| 9) | Yoyo | 2.640 | 58 | 22 |
| Total | | 11.690 | 1503 | 128 |
| Alberta and B.C. (Total all Fields) | | 71.430 | 2127 | 30 |
| Alberta and B.C. (Less Clark Lake) | | 69.740 | 757 | 11 |
| Clark Lake Life Total Average | | | | 31 |

Sources: Alberta Energy Resources Conservation Board, Monthly Production Statement. British Columbia Department of Energy Mines, and Petroleum Resources, Monthly Production Statement.

## LINE (PERIPHERAL) WATER FLOOD

TYPICAL RECOVERY:
PRIMARY (DISSOLVED GAS DRIVE) 21%
SECONDARY (PERIPHERAL FLOOD) + 21% = 42% TOTAL
INCREASE OVER PRIMARY = 100%




## PATTERN (FIVE SPOT) WATER FLOOD

TYPICAL RECOVERY:
PRIMARY (DISSOLVED GAS DRIVE) 21%
SECONDARY (PATTERN FLOOD) + 21% = 42% TOTAL
INCREASE OVER PRIMARY = 100%

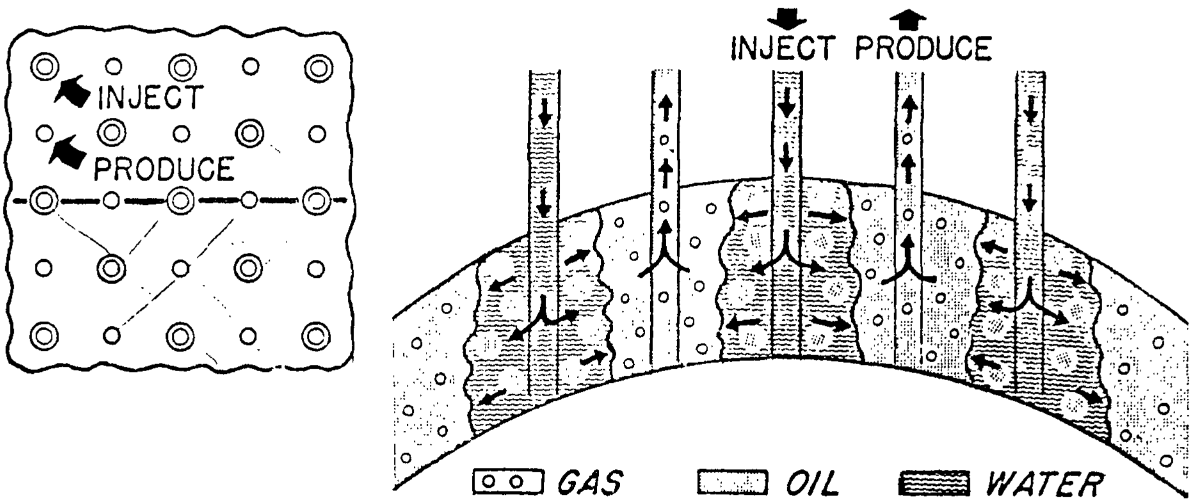



FIGURE 32 WATERFLOOD CONFIGURATIONS

In western Canada the majority of secondary recovery projects were implemented early in the life of the fields, before significant primary depletion had occurred. Total estimated production and injection balances are shown in Table 17. Analysis of the net injection, shown as part 4 of Table 17, confirms that the effect and intent of injection is to replace the oil and solution gas volume withdrawn from the reservoir.

Oil production from the various primary and secondary processes can be summarized as follows:

i) primary recovery is typically 3 to 15 percent of the oil-in-place, averaging about 10 percent;

ii) secondary recovery typically increases the ultimate total oil production to approximately twice that attainable by primary recovery.

Various secondary and tertiary processes can be applied to almost any type of primary recovery system, such as reservoirs with gas cap or water drive systems, but many techniques work best in particular types of reservoirs. Engineering design and performance predictions increase in complexity with the complexity of the reservoir system.

It must be emphasized that some reservoirs are suitable only for waterflood operations. Also waterflooding may be a necessary preliminary step prior to a tertiary recovery scheme.

4.3.4 **Abandonment.** If no hydrocarbon-bearing zones capable of production at commercial rates are penetrated during the drilling process, abandonment involves placing cement plugs in the wellbore to seal potential hydrocarbon-bearing zones. Different procedures are used, however, to abandon a well that has been producing for a period of time, since production casing has been set in addition to surface casing.

Typically, an attempt is made to set cement opposite the perforated and producing zone as though no casing were present. The pipe is cut off from the surface to a depth of 2 m or so below ground to prevent any agricultural or other surface activity from contacting the remaining casing string. The top portion of casing (15 m or so) is filled with cement before a steel plate is welded on to cap the open-ended pipe. The specific procedure utilized is subject to approval according to applicable legislation and depends upon the zones penetrated, the depth of the well, and other factors that may affect the potential for environmental damage.

In some cases, an attempt may be made to recover a portion of the production casing. This is often successful if the well was drilled recently or is located in an area

TABLE 17 PRODUCTION RATE AND RESERVE DATA

1) Conventional Oil

| | Daily Rate 1981 ($m^3/d$) | Cumulative Production to 1981/7/1 ($10^6$ $m^3$) | Remaining Recoverable as at 1981/7/1 ($10^6$ $m^3$) | % of Total Remaining Recoverable[a] |
|---|---|---|---|---|
| British Columbia | 5 500 | 53.592 | 24.441 | 2.9 |
| Alberta | 165 000 | 1230.661 | 682.498 | 81.0 |
| Saskatchewan | 20 000 | 279.022 | 100.247 | 11.9 |
| Manitoba | 1 550 | 21.400 | 4.603 | 0.5 |
| Ontario | 240 | 8.896 | 1.320 | 0.2 |
| Other | 450 | - | 30.000 | 3.5 |
| Total Canada | 192 840 | 1593.571 | 843.109 | 100.0 |

2) Raw Gas, Net After Injection

| | Daily Rate 1981 ($10^6$ $m^3/d$) | Cumulative to 1981/7/1 ($10^9$ $m^3$) | Remaining Recoverable 1981/7/1 ($10^9$ $m^3$) | % of Total Remaining Recoverable[a] |
|---|---|---|---|---|
| British Columbia | 26.989 | 179.495 | 283.741 | 10.9 |
| Alberta | 217.432 | 1219.347 | 2289.933 | 87.6 |
| Saskatchewan | 3.905 | 29.050 | 37.823 | 1.4 |
| Manitoba | 0.100 | 1.500 | 0.300 | 0.0 |
| Ontario | 1.100 | 24.040 | 3.326 | 0.1 |
| Other | - | - | - | - |
| Total Canada | 249.526 | 1453.432 | 2615.123 | 100.0 |

3) Water Production W/Oil

| | Daily Rate 1981 ($m^3/d$) | Cumulative to 1981/7/1 ($10^6$ $m^3$) | Water to Oil Ratios | |
|---|---|---|---|---|
| | | | Current | Cumulative |
| British Columbia | 7 047 | 29.566 | 1.3 | 0.1 |
| Alberta | 300 260 | 585.850 | 2.0 | 0.5 |
| Saskatchewan | 72 467 | 313.521[b] | 3.6 | 1.1 |
| Manitoba | - | - | - | - |
| Ontario | - | - | - | - |
| Other | - | - | - | - |
| Total Canada | 379 774 | 928.937 | | |

4) Water Injection - Includes Produced and Fresh Water

| | Daily Rate 1981 ($m^3/d$) | Cumulative Injection ($10^6$ $m^3$) | |
|---|---|---|---|
| | | Actual to 1981/7/1[c] | Net to 1981/7/1[d] |
| British Columbia | 12 440 | 92.514 | 63.350 |
| Alberta | 470 060 | 1738.730 | 1152.880 |
| Saskatchewan | 100 000[b] | 603.704 | 290.183 |
| Manitoba | - | - | - |
| Ontario | - | - | - |
| Total Canada | 582 500 | 2434.948 | 1506.413 |

a % of total refers to the provincial share of total remaining recoverable reservoirs.

b Saskatchewan daily water injection rate and cumulative water production are estimated.

c Actual Injection means including produced water.

d Net Injection means total injection less cumulative water produced.

where geologic conditions are suitable for retrieval. In many areas, such as Lloydminster, regulations require that all production casing be cemented full depth. In such cases casing cannot be recovered.

If some casing is recovered, the open hole portion is abandoned as a "dry hole" while the remaining cased portion is abandoned as described above. Where the cased and open hole sections meet, a cement plug (approximately 15 m in and 15 m out) is set.

Cased holes are protected from cross-formational flow by casing and plugs set during abandonment. This practice is satisfactory for the short-term but casing inevitably corrodes or collapses due to earth pressures after 20 to 30 years or more. If the casing corrodes, the subsequent natural processes would ultimately be similar to those of open hole abandonment and the drilling mud or cement left in the hole would exert a hydrostatic pressure considered sufficient to restrict any flow into the wellbore.

Zones containing corrosive hydrogen sulphide are encountered occasionally in a wellbore. During abandonment, an attempt is made to plug the portion of the hole opposite the zone potentially containing hydrogen sulphide with cement. Even if the cement plug should corrode and deteriorate, the mass itself will remain permanently to fill and clog the hole.

The combination of drilling fluid to prevent flow, and cemented surface casing to protect fresh water will reduce cross-formational flow compared to an open hole but the occurrence and frequency of problems in the long-term is uncertain.

4.3.5 **Future Exploration Potential and Water Requirements.** During 1980 public hearings were held by the Energy Resources Conservation Board of Alberta and the National Energy Board to investigate the expected supply of oil and petroleum products from 1980 to the year 2000. These hearings investigated both the potential production from established reserves and additions from exploration activity.

The productivity forecasts of the ERCB and NEB are given in Tables 18 and 19. The ERCB forecast for light crude oil for Alberta in Table 18 is greater than the NEB total forecast for Canada from 1984 to 1991. Although NEB and ERCB total forecasts are very close, the NEB assumed that only 81 percent of production would come from Alberta. These discrepancies are not as large as they might seem when considered on a percentage basis and reflect the difficulty in preparing such forecasts with any degree of accuracy, given that changes in technology and economics can have major impacts on productive capacity.

TABLE 18 FORECAST OIL PRODUCTION CAPACITIES FOR ESTABLISHED RESERVES

| Year | NEB Total Canada Modified Base Case | ERCB Alberta Total |
| --- | --- | --- |
| Light Crude Oil ($10^3$ $m^3$/d) | | |
| 1981 | 165.6 | 159 |
| 1982 | 149.1 | 143 |
| 1983 | 130.0 | 130 |
| 1984 | 113.3 | 115 |
| 1985 | 99.7 | 103 |
| 1986 | 88.3 | 91 |
| 1987 | 78.1 | 81 |
| 1988 | 69.4 | 71 |
| 1989 | 61.9 | 63 |
| 1990 | 55.4 | 56 |
| 1991 | 49.9 | 50 |
| 1992 | 45.1 | 45 |
| 1993 | 40.4 | 40 |
| 1994 | 36.9 | 36 |
| 1995 | 33.6 | 32 |
| 1996 | 30.7 | 29 |
| 1997 | 28.1 | 26 |
| 1998 | 25.7 | 23 |
| 1999 | 23.6 | 21 |
| 2000 | 21.7 | 20 |
| Total | 1347.0 | 1332 |
| NEB Estimated Distribution: | British Columbia | 2.9% |
| | Alberta | 81.0% |
| | Saskatchewan | 11.9% |
| | Manitoba | 0.5% |
| | Ontario | 0.2% |
| | Other | 3.5% |
| Conventional Heavy Crude Oil ($10^3$ $m^3$/d) | | |
| 1981 | 31.2 | 12 |
| 1982 | 28.4 | 10 |
| 1983 | 25.6 | 9 |
| 1984 | 23.0 | 8 |
| 1985 | 20.7 | 7 |
| 1986 | 18.7 | 6 |
| 1987 | 16.8 | 5 |
| 1988 | 15.2 | 5 |
| 1989 | 13.7 | 4 |
| 1990 | 12.5 | 4 |
| 1991 | 11.3 | 3 |
| 1992 | 10.2 | 3 |
| 1993 | 9.3 | 2 |
| 1994 | 8.4 | 2 |
| 1995 | 7.6 | 2 |
| 1996 | 6.9 | 1 |
| 1997 | 6.2 | 1 |
| 1998 | 5.5 | 1 |
| 1999 | 4.8 | 1 |
| 2000 | 4.3 | 1 |
| Total | 208.3 | 81 |
| Alberta & Saskatchewan - 100% | | |

Sources: Canadian Energy Supply and Demand 1980 - 2000, National Energy Board, June 1981.

Alberta Energy Resources Conservation Board Proceedings, 800065, Productive Capacity and Ultimate Potential of Crude Oil.

TABLE 19 FORECAST OIL PRODUCTION FROM NEW DISCOVERIES, ADDITIONS AND ENHANCED RECOVERY

| Year | NEB Total Canada On-shore Non-frontier | ERCB Alberta Total |
|---|---|---|
| New Discoveries and Additions - Light Crude Oil ($10^3$ $m^3$/d) | | |
| 1981 | 2.7 | 4 |
| 1982 | 6.3 | 6 |
| 1983 | 10.5 | 9 |
| 1984 | 14.8 | 11 |
| 1985 | 18.8 | 14 |
| 1986 | 25.9 | 16 |
| 1987 | 30.1 | 19 |
| 1988 | 33.6 | 19 |
| 1989 | 36.4 | 21 |
| 1990 | 38.3 | 22 |
| 1991 | 39.8 | 23 |
| 1992 | 40.4 | 23 |
| 1993 | 41.0 | 24 |
| 1994 | 41.3 | 24 |
| 1995 | 41.4 | 24 |
| 1996 | 41.3 | 24 |
| 1997 | 41.0 | 24 |
| 1998 | 40.7 | 24 |
| 1999 | 40.3 | 24 |
| 2000 | 39.8 | 24 |
| Total | 624.4 | 379 |
| NEB Estimated Distribution: | British Columbia | 2.9% |
| | Alberta | 81.0% |
| | Saskatchewan | 11.9% |
| | Manitoba | 0.5% |
| | Ontario | 0.2% |
| | Other | 3.5% |
| New Discoveries and Enhanced Recovery - Heavy Crude Oil ($10^3$ $m^3$/d) | | |
| 1981 | 0.9 | - |
| 1982 | 2.5 | - |
| 1983 | 4.8 | 0.8 |
| 1984 | 7.6 | 1 |
| 1985 | 10.3 | 3 |
| 1986 | 13.2 | 5 |
| 1987 | 15.9 | 7 |
| 1988 | 18.3 | 9 |
| 1989 | 20.3 | 12 |
| 1990 | 22.3 | 13 |
| 1991 | 24.1 | 14 |
| 1992 | 26.0 | 15 |
| 1993 | 27.4 | 17 |
| 1994 | 28.5 | 17 |
| 1995 | 29.4 | 19 |
| 1996 | 30.0 | 20 |
| 1997 | 30.5 | 22 |
| 1998 | 30.7 | 23 |
| 1999 | 30.5 | 24 |
| 2000 | 30.2 | 25 |
| Total | 403.4 | 246.8 |
| Alberta & Saskatchewan - 100% | | |

Sources: Canadian Energy Supply and Demand 1980 - 2000, National Energy Board, June 1981.

Alberta Energy Resources Conservation Board Proceedings, 800065, Productive Capacity and Ultimate Potential of Crude Oil.

Table 19 presents the views of the two boards regarding new production capacity, additions attributable to primary recovery and waterflooding of new pool discoveries for conventional light oil, and enhanced recovery of heavy oil. Previous discussion has indicated that net water requirements are based on the reservoir volume of oil and solution gas withdrawn from the reservoir. In special cases of gas injection, a small part of the space to be occupied by water may be filled by a trapped gas pocket. As a rule of thumb, the future water requirements for light oil recovery schemes may be estimated as equal to the volume of oil withdrawn. Current water supplies are obtained from surface drainage systems, groundwater sources and sub-surface non-potable reservoirs. The water supply for oil production operations in British Columbia is obtained mainly from surface drainage systems, including the Peace River. Saskatchewan water supply is obtained mainly from subsurface reservoirs, particularly the Blairmore Water Sand. Injection water supplies in Alberta are obtained from the North and South Saskatchewan Rivers, Peace River, the Paskapoo and Belly River formations, and from various lakes. All water requirements and consumption in Alberta are licensed with the Water Branch of the Department of Natural Resources in the region involved.

Table 20 presents water use forecasts for conventional light and heavy oil production operations. Forecasts of water requirements can be made in several ways. For the purpose of this study, an approach often used which sets total liquid production as constant was modified and used for the light oil water requirements.

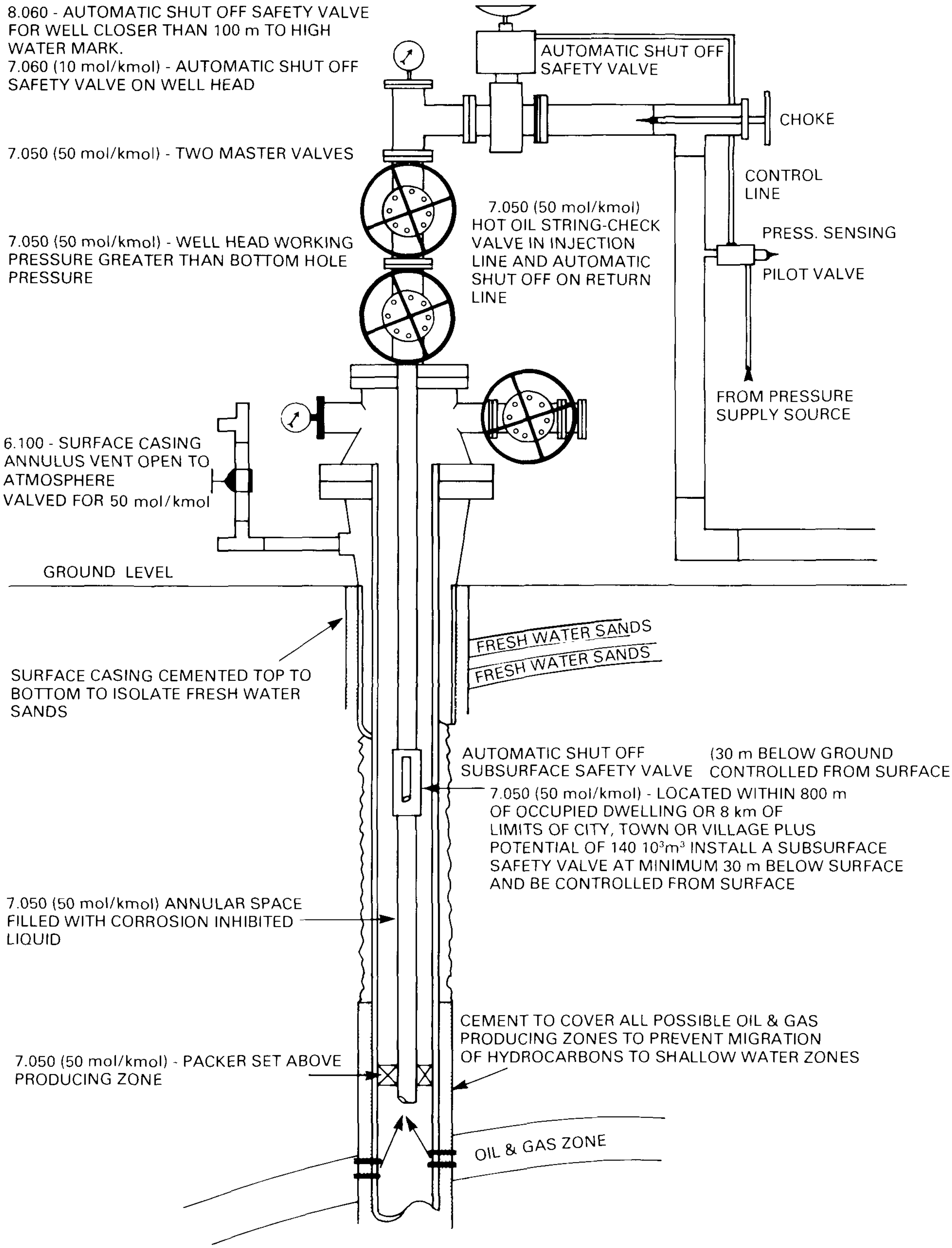
4.3.6 **Regulatory Activities.** The main agency responsible for oil and gas production regulations in Alberta is the ERCB. The site selection, construction, and operation of an oil production battery or field gas plant is controlled through the Oil and Gas Conservation Act and Regulations. Formal written application must be made to the ERCB for the approval of any such facility. Alberta Environment and the Department of Energy and Natural Resources may both play a role depending on the facility to be constructed. Figures 33 through 35 illustrate required government approvals and environmental controls at a well, an oil production battery, and a gas well installation.

Water pollution control requirements are also specified through the Oil and Gas Conservation Act regarding product storage, spill control, liquid waste disposal, operation, maintenance, and measurement of production and injection rates. The regulations under sections 8.010 to 8.031 state that oil cannot be stored in pits, and a permit is required for storage of crude bitumen or hydrocarbon derivatives. Any tank containing oil or any fluid other than water must be surrounded by a dyke or firewall, the capacity and locations of which are at the discretion of the board.

TABLE 20 FORECAST WATER USE FOR ESTABLISHED LIGHT OIL AND CONVENTIONAL HEAVY OIL RECOVERY OPERATIONS

| | ESTABLISHED LIGHT OIL RECOVERY* | | | | | | CONVENTIONAL HEAVY OIL RECOVERY | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Alberta | | Saskatchewan | | British Columbia | | Associated with Established Reserves | Associated with New Reserves ($10^3$ $m^3/d$) | | |
| Year | Rate ($10^3$ $m^3/d$) | Water to Oil Ratio ($m^3/m^3$) | Rate ($10^3$ $m^3/d$) | Water to Oil Ratio ($m^3/m^3$) | Rate ($10^3$ $m^3/d$) | Water to Oil Ratio ($m^3/m^3$) | ($10^3$ $m^3/d$) | Water Flood** | Thermal Recovery*** | Total ($10^3$ $m^3/d$) |
| 1981 | 262 | 1.8 | 39.9 | 3.9 | 7.2 | 1.3 | 86.1 | 0.5 | 1.5 | 88.1 |
| 1982 | 270 | 1.9 | 40.6 | 4.3 | 7.8 | 1.7 | 91.0 | 1.4 | 4.4 | 96.8 |
| 1983 | 278 | 2.1 | 41.7 | 5.0 | 8.5 | 2.1 | 95.9 | 2.8 | 8.4 | 107.1 |
| 1984 | 288 | 2.5 | 42.6 | 5.7 | 9.1 | 2.7 | 100.7 | 4.6 | 13.4 | 118.7 |
| 1985 | 294 | 2.9 | 43.3 | 6.5 | 9.6 | 3.3 | 105.4 | 6.6 | 18.2 | 130.2 |
| 1986 | 300 | 3.3 | 43.9 | 7.3 | 9.9 | 3.9 | 109.9 | 9.1 | 23.3 | 142.3 |
| 1987 | 305 | 3.8 | 44.5 | 8.2 | 10.2 | 4.5 | 114.5 | 11.9 | 28.1 | 154.5 |
| 1988 | 310 | 4.4 | 45.0 | 8.1 | 10.5 | 5.2 | 118.9 | 14.7 | 32.3 | 165.9 |
| 1989 | 312 | 5.0 | 45.5 | 10.1 | 10.7 | 5.9 | 123.3 | 17.5 | 35.9 | 177.6 |
| 1990 | 314 | 5.6 | 46.0 | 11.4 | 10.9 | 6.8 | 127.5 | 20.3 | 39.4 | 187.2 |
| 1991 | 314 | 6.3 | 46.3 | 12.5 | 11.0 | 7.6 | 131.9 | 23.3 | 42.6 | 197.8 |
| 1992 | 315 | 7.0 | 46.6 | 13.6 | 11.2 | 8.5 | 135.4 | 26.6 | 46.0 | 208.0 |
| 1993 | 315 | 7.8 | 46.8 | 14.8 | 11.3 | 9.5 | 123.5 | 30.3 | 48.5 | 202.3 |
| 1994 | 315 | 8.7 | 47.1 | 16.2 | 11.4 | 10.6 | 111.6 | 33.8 | 50.4 | 195.8 |
| 1995 | 315 | 9.7 | 47.3 | 17.6 | 11.5 | 11.8 | 101.2 | 37.3 | 52.0 | 190.5 |
| 1996 | 315 | 10.6 | 47.5 | 19.0 | 11.6 | 13.0 | 92.2 | 40.5 | 53.1 | 185.8 |
| 1997 | 315 | 11.7 | 47.7 | 20.4 | 11.7 | 14.3 | 81.8 | 43.7 | 53.9 | 179.4 |
| 1998 | 315 | 13.1 | 47.8 | 22.0 | 11.8 | 15.7 | 72.9 | 47.4 | 54.3 | 174.6 |
| 1999 | 315 | 14.2 | 48.0 | 23.7 | 11.8 | 17.2 | 64.0 | 50.4 | 53.9 | 168.3 |
| 2000 | 315 | 15.0 | 48.1 | 25.4 | 11.9 | 18.8 | 56.5 | 53.2 | 53.4 | 163.1 |

* Calculated based on oil production forecasts in Table 18.
** Water-to-oil ratio increases at rate of 5%/year from 2 to 6.9.
*** Considers a steam stimulation operation (discussed in Chapter 5) at four barrels water injected as steam per barrel oil produced.




ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA

FIGURE 33 ENVIRONMENTAL CONTROL AT A WELL (Alberta ERCB)

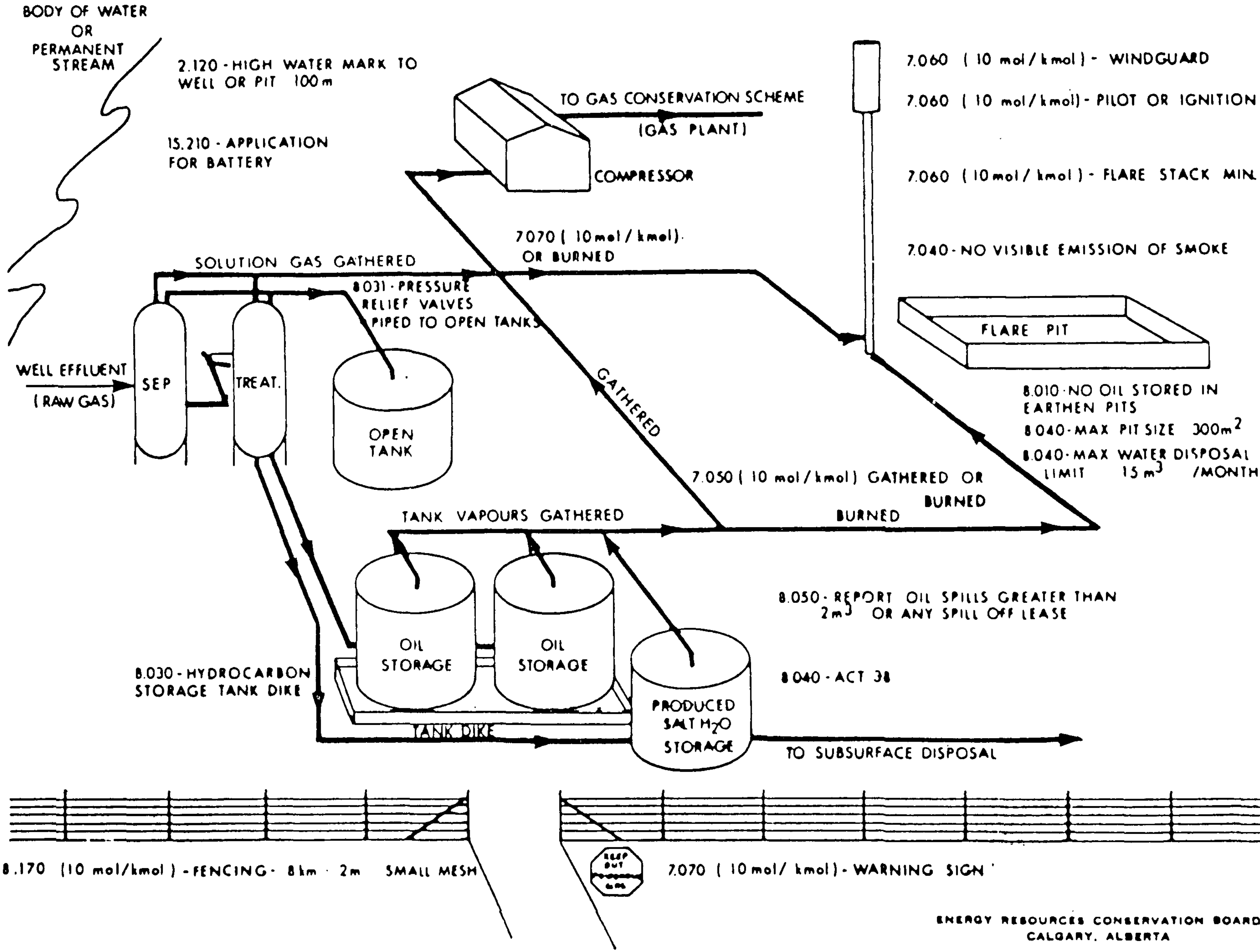



FIGURE 34 ENVIRONMENTAL CONTROL AT AN OIL PRODUCTION BATTERY (Alberta ERCB)

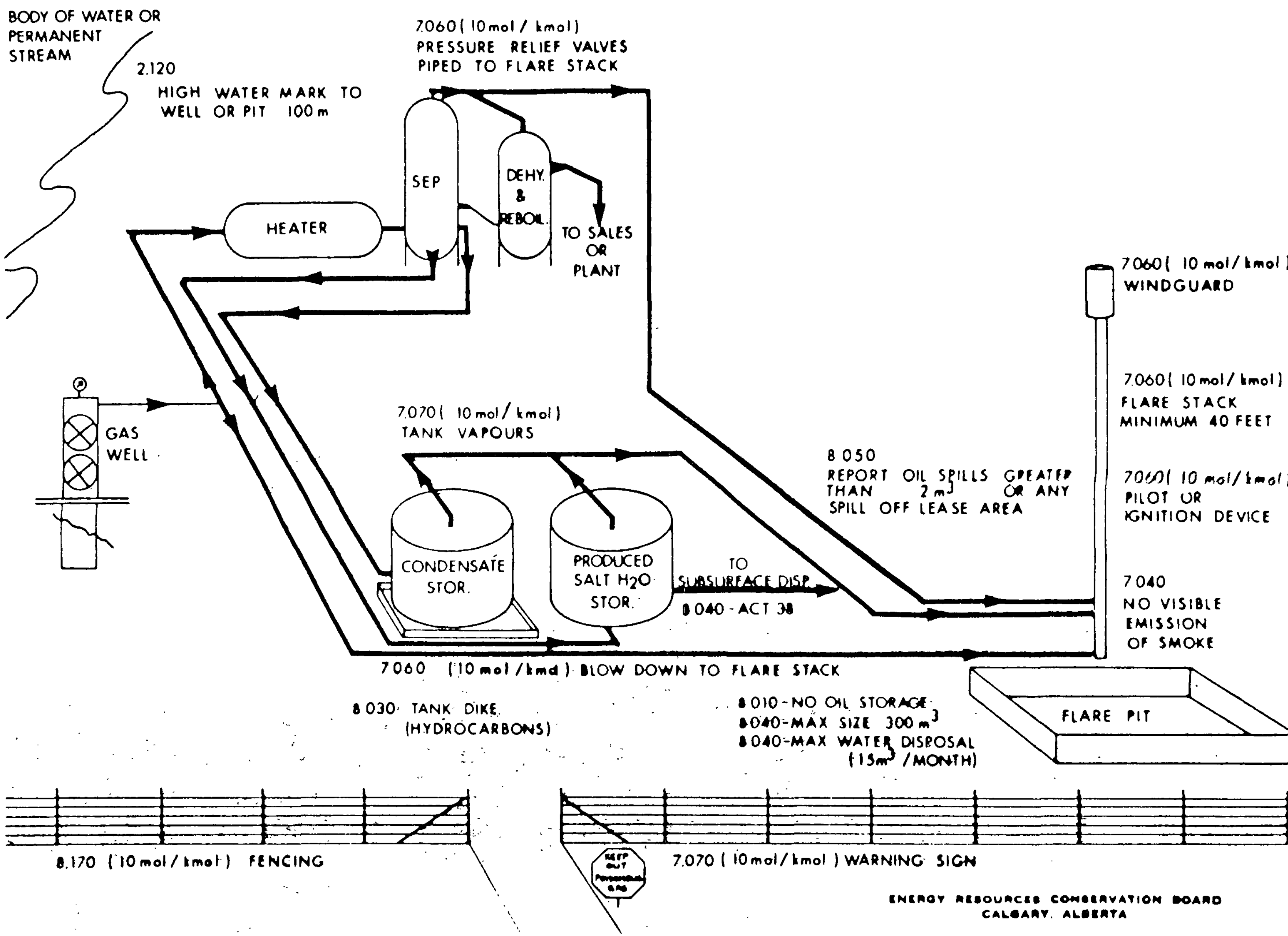



FIGURE 35 ENVIRONMENTAL CONTROL AT A GAS PRODUCTION BATTERY (Alberta ERCB)

If oil or salt water is spilled due to a break or leak in equipment, the licensee or operator is responsible for containment and retrieval and, if the spill is not confined to the site and/or is in excess of 2 $m^3$, immediate notification of the board (section 8.050) is required. Where a well or battery is within 100 m of the high water mark of a waterbody or stream, and the ERCB is of the opinion that a leak could reach the water, special precautions are required, such as automatic shut-off valves, special trenches or dykes, and preparation of a plan of recovery in the event of a spill (section 8.060).

More recently, oil spill contingency plans were set through the combined efforts of the Alberta ERCB, Alberta Department of Environment, and Alberta Department of Energy and Natural Resources which require that all operators prepare effective containment, recovery, and cleanup procedures (ERCB-ID-0G-75-2).

Under section 38 of the Oil and Gas Conservation Act, any scheme for the gathering, storage, and disposal of water produced in conjunction with oil or gas, or the storage or disposal of any fluid in an underground formation must be applied for and approved by the ERCB. The application requires description of the geographic and geologic details, type of fluid used in the annulus, etc., and will also be reviewed by the Department of the Environment which may impose conditions prior to approval.

Under section 8.040 of the regulations, all produced water must be disposed of in a manner satisfactory to the ERCB. Generally, disposal is to subsurface formations, which, as discussed earlier, assists in maintaining pressure. Only small quantities are permitted to be disposed of in surface pits, a method that is discouraged and will most likely be even further reduced with time (Wolff, 1978).

No more than one pit may be used for storage or disposal of water per facility at a given time (section 8.040). Construction of earthen pits requires use of clay or other impermeable material, and the surface area must be no larger than 300 $m^2$. Walls are required to guard against spills and to prevent collection of natural runoff water. A maximum of 15 $m^3$ of produced water per month may be disposed of or stored in the pit but, depending on factors such as water salinity, soil characteristics and others, the ERCB or the Department of the Environment may prescribe special requirements.

It is the responsibility of the licensee or operator to ensure that all liquid waste products from a well or battery are contained at all times and disposed of in such a way that no air, soil, surface water or underground water is or could be polluted. Upon completion, suspension or abandonment, all excavations must be filled and liquid wastes disposed of according to AERCB regulations.

If air, gas, water or any other substance is injected through a well to an underground formation, it must be continuously measured in a manner satisfactory to the ERCB (section 14.200). The licensee must keep daily records of oil, gas, water and other substances produced, details of operations, and types, volumes, source, and pretreatment of substances injected (section 12.030). The construction details of a typical injection well are shown in Figure 36.

Disposal of oil or gas treatment plant wastewater or surface runoff water must be approved by the Department of the Environment if charged to a surface water body or disposal pond. Disposal to an underground formation must be approved by both the ERCB and the Department of the Environment.

Provisions for saltwater disposal in Saskatchewan are indicated in Section 810 of the Oil and Gas Conservation regulations. Produced formation water must be disposed of in a method satisfactory to the minister, and in a manner such as not to constitute a health hazard or contaminate fresh water or arable land. Disposal by subsurface injection must be approved and application accompanied with the consent of affected mineral owners.

British Columbia regulations also require approval before disposal to subsurface formations (Division 9.5 of Drilling and Production Regulations). Lined pits may be used for emergencies, and the maximum surface area is 600 $m^2$ (Division 91), compared to 300 $m^2$ in Alberta.

## 4.4 Disposal Practices and the Associated Wastewater Treatment Methods

Figure 34 illustrates the process schematics along with the relevant ERCB regulations for an oil production facility. As shown in this figure, oil and gas are first separated in a gravity separator. Oil and water are then usually drawn off together and separated in a treater (such as the heated treater illustrated in Figure 37). The water is then pumped to a produced water tank. The contents of this tank, with or without some further treatment, are then usually reinjected in the original formation for pressure maintenance. In some cases, evaporation pits are used to eliminate excess water. The waste generated during gas production consists of minor volumes of formation water. In comparison to the volume of water handled during conventional oil production, it is insignificant.

The wastes generated during conventional oil production consist of: formation water, emulsions of oil and water, and sludges, for example those generated during the treatment of produced water prior to injection.

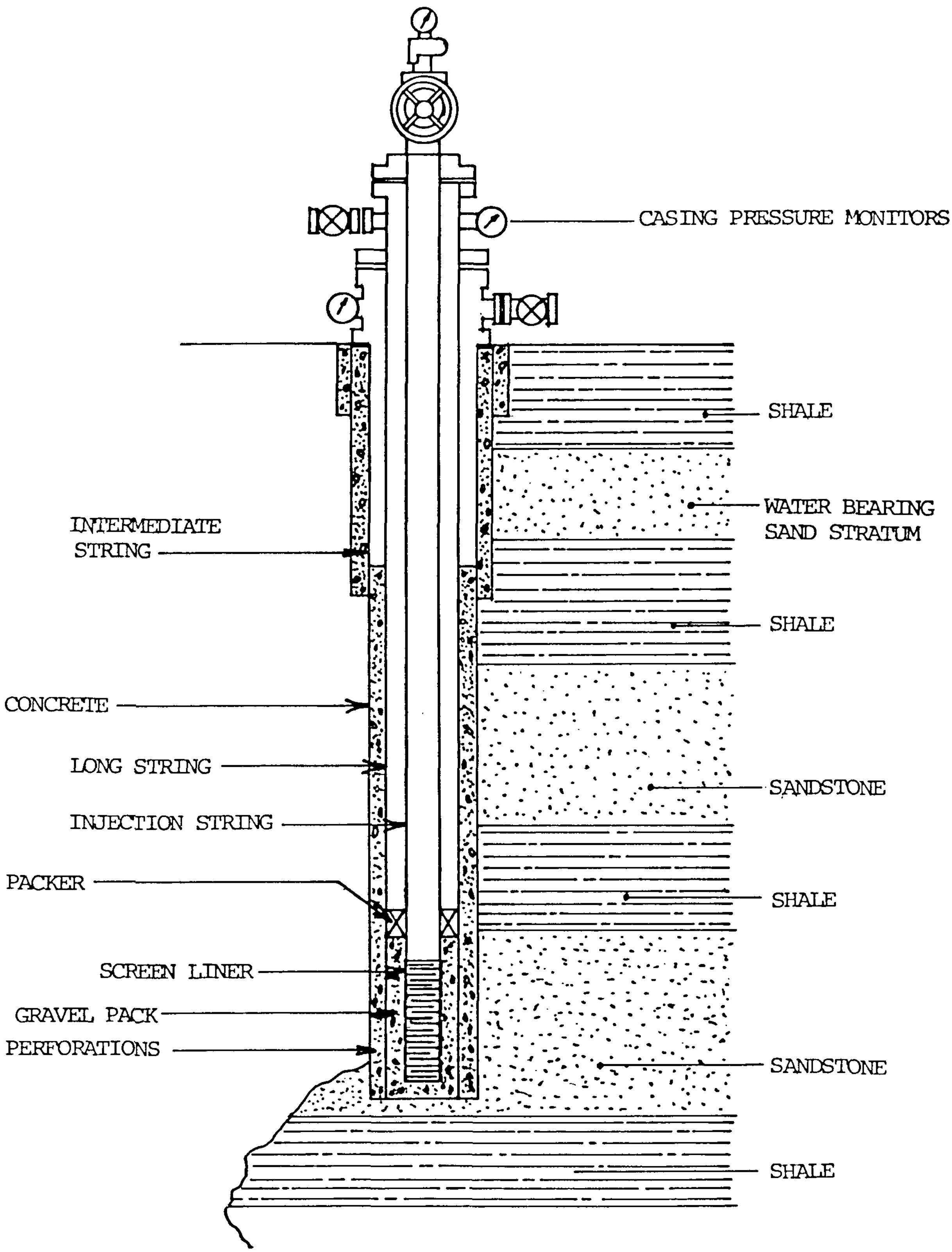



FIGURE 36 A TYPICAL INJECTION WELL (Canadian Petroleum Association, 1980)

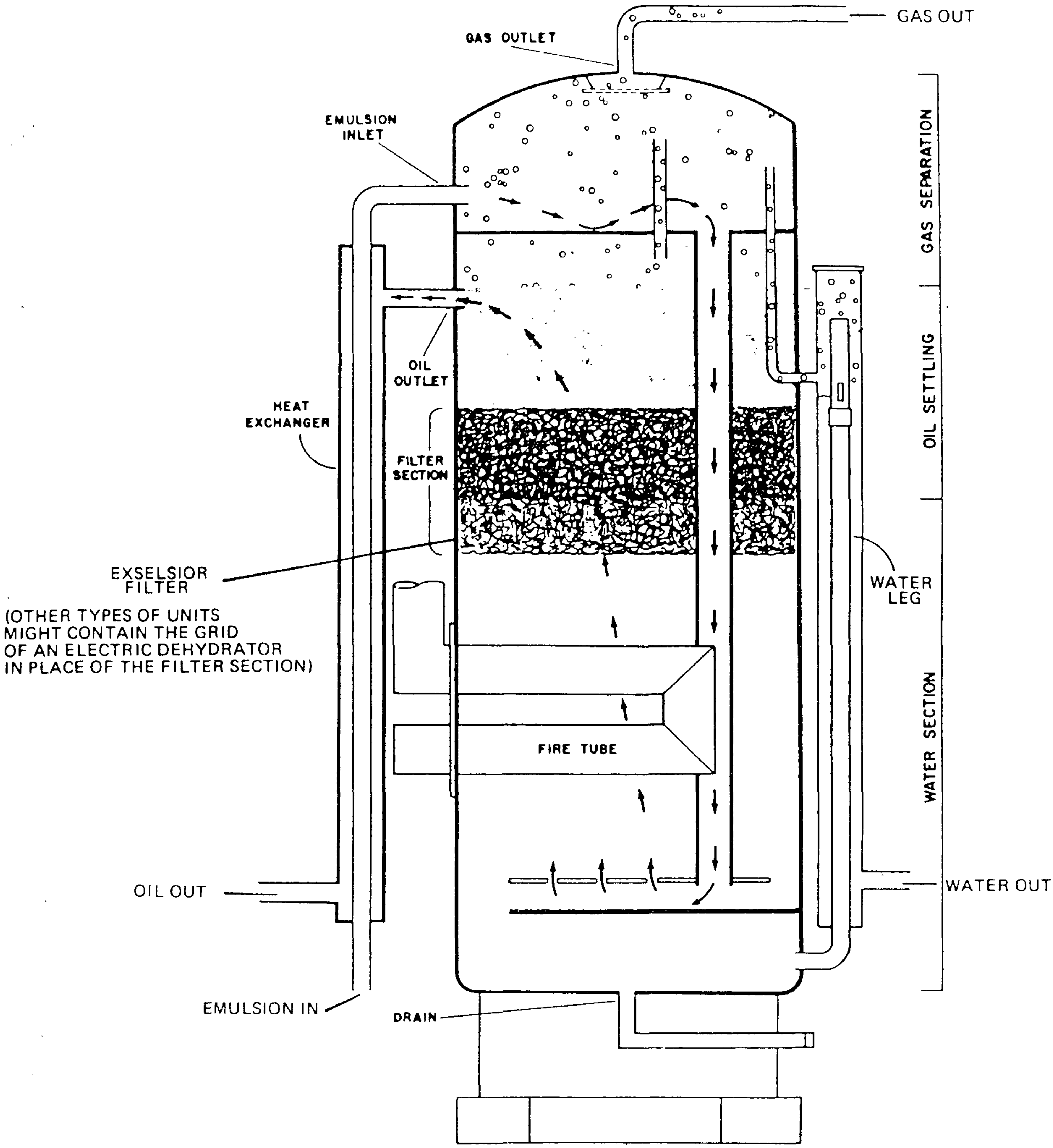



FIGURE 37 CROSS SECTION OF A VERTICAL HEATED OIL/WATER TREATER
(U.S. Environmental Protection Agency, 1976)

The concentrations of some inorganic components in the produced waters are listed in Tables 21 and 22. The total dissolved solids content of produced water, while variable, can be quite high. The organic content of produced water can be also quite high; however, no information regarding organic composition equivalent to the chemical data shown in Tables 21 and 22 was available at the time of writing.

The oil and, therefore, to some extent the organic content of produced water, depends on the degree of treatment achieved by the oil/water separator. Prior to subsurface injection, brines are often treated (as shown in Figure 38) to maintain the water quality necessary for effective waterflood and tertiary recovery programmes, and to avoid the following problems:

i) formation plugging,
ii) equipment corrosion,
iii) microbial growth, and
iv) clay swelling in the formation.

Table 23 summarizes the desired water properties to overcome the above problems. In terms of treatment to prevent formation plugging, operators are usually concerned with:

i) high suspended solids level in the brine relative to the porosity and permeability of the target formation, and
ii) precipitation reactions resulting from the presence of oxygen or the addition of incompatible water to the reservoir water.

The desirable levels of suspended solids (oil, clay, iron oxides, sand, etc.) are those concentrations which can be obtained by either flotation or sedimentation, usually with the aid of coagulants (such as alum) or flocculants (e.g., polyacrylamides). If the target zone permeability is low, sedimentation or flotation is usually followed by filtration.

Precipitation reactions can occur upon exposure of the brine to air and the consequent dissolution of oxygen in the brine. The oxygen in turn can oxidize $Fe^{++}$, where present, to $Fe^{+++}$ which will then precipitate. The resulting precipitate can form scales in the wellbore or plug the formation into which the brine is injected, possibly resulting in the need for a higher injection pressure which could rupture the disposal system (Collins, 1971).

Iron precipitation may also occur when fresh water containing oxygen is added to the formation water. In such cases, other mineral precipitates such as gypsum, calcite

TABLE 21 TYPICAL PRODUCED WATER ANALYSES

| Field | Pool | TDS (mg/L) | Cl (mg/L) | $Ca^{++}$ (mg/L) | $Mg^{++}$ (mg/L) |
|---|---|---|---|---|---|
| Alberta | | | | | |
| Tabor | MAN D | 10008 | 3135 | 51 | 20 |
| Tabor South | MAN B | 7943 | 2834 | 19 | 17 |
| Judy Creek | BIIL A | 194384 | 118121 | 6375 | 1127 |
| Judy Creek | BIIL B | 186993 | 112926 | 4693 | 607 |
| Swan Hills | BIIL A&B | 207473 | 125400 | 11692 | 1118 |
| Swan Hills | BIIL C | 182079 | 111825 | 12680 | 2090 |
| Swan Hills S | BIIL A&B | 184585 | 111718 | 4930 | 573 |
| Lloydminster | SP.C&GPA | 30550 | 55092 | 3528 | 1372 |
| Lloydminster | SP&GPC | 90856 | 56411 | 4990 | 2359 |
| Acheson | D-3A | 212540 | 131366 | 22857 | 3203 |
| Redwater | D-3 | 106252 | 64288 | 4156 | 1898 |
| Kaybob | BIILA | 181310 | 111757 | 7259 | 2956 |
| Kaybob South | TRIASSIC A | 144722 | 87600 | 2066 | 391 |
| Pembina | CARD | 11581 | 6807 | 162 | 0 |
| Pembina | KBR B | 22003 | 12806 | 476 | 57 |
| Rainbow | KR A | 240317 | 146600 | 15219 | 388 |
| Rainbow | B | 213294 | 130000 | 14010 | 1455 |
| Rainbow | F | 205590 | 125800 | 14218 | 1940 |
| Rainbow | KR AA | 159647 | 96900 | 9505 | 1720 |
| Zama | TOTAL | 174167 | 107043 | 6889 | 3710 |
| Bonnie Glen | D-3A | 235378 | 148144 | 39311 | 5070 |
| Saskatchewan | | | | | |
| Aberfeldy | SPARKY | 113100 | 63800 | 3188 | 1502 |
| South Aberdelfy | SPARKY | - | - | - | - |
| Dulwich | SPARKY | 96900 | 50000 | 2888 | 1386 |
| Golden Lake North | WASECA | - | - | - | - |
| Golden Lake South | SPARKY | - | - | - | - |
| North Hoosier | BASAL BLAIRMORE | - | 11169 | 481 | 294 |
| Gull Lake N | U/SHAUNOVAN | 6900 | 3775 | 44 | 44 |
| Main Success | ROSERAY | 6492 | 2550 | 17 | 21 |
| Midale | C/MIDALE/U | 128739 | 75416 | 2090 | 440 |
| Midale | C/MIDALE N/U | - | - | - | - |
| Weyburn | MIDALE | 90958 | 48990 | 1640 | 464 |
| British Columbia | | | | | |
| Aitken Creek | GETHING | 8771 | 3707 | 52 | 11 |
| Blueberry | DEBOIT | 75064 | 44816 | 1565 | 342 |
| Inga | INGA | 122479 | 71643 | 2884 | 826 |
| Deatton River | HALFWAY | 114331 | 68000 | 1208 | 559 |
| Beatton R. W. | BLUESKY/GETHING | 28875 | 117000 | 701 | 182 |
| Crush | HALFWAY | 10858 | 1950 | 529 | 141 |
| Currant | HALFWAY | 19556 | 4345 | 605 | 63 |
| Milligan Creek | HALFWAY | 94669 | 56000 | 1530 | 1060 |
| Peejay | HALFWAY | 138011 | 82586 | 3873 | 1369 |
| Weasel | HALFWAY | 132449 | 78657 | 6408 | 1798 |
| Wildmint | HALFWAY | - | - | - | - |
| Boundary Lake | TAYLOR | 102254 | 62166 | 4599 | 1450 |

TABLE 22 TYPICAL FORMATION WATER ANALYSIS, BASAL BLAIRMORE HEAVY OIL ZONES

Basal Blairmore Heavy Oil Zones: 750 metre depth

| Component Ion | Average (mg/L) |
|---|---|
| Na | 25000 |
| K | 250 |
| Ca | 2000 |
| Mg | 750 |
| Cl | 45000 |
| $HCO_3$ | 700 |
| $SO_4$ | 3 |
| Total Solids | 73703 |
| pH | 7.5 |
| Resistivity | 0.21 ohm metres at 21.7°C |

Near Surface Groundwater Sand: 90 metre depth

| Component Ion | Average (mg/L) |
|---|---|
| Na | 140 |
| Fe | 4 |
| Ca | 150 |
| Mg | 60 |
| Cl | 5 |
| $HCO_3$ | 780 |
| $SO_4$ | 255 |
| Total Solids | 1394 |
| pH | 7.4 |
| Resistivity | 6.45 ohm metres at 25°C |

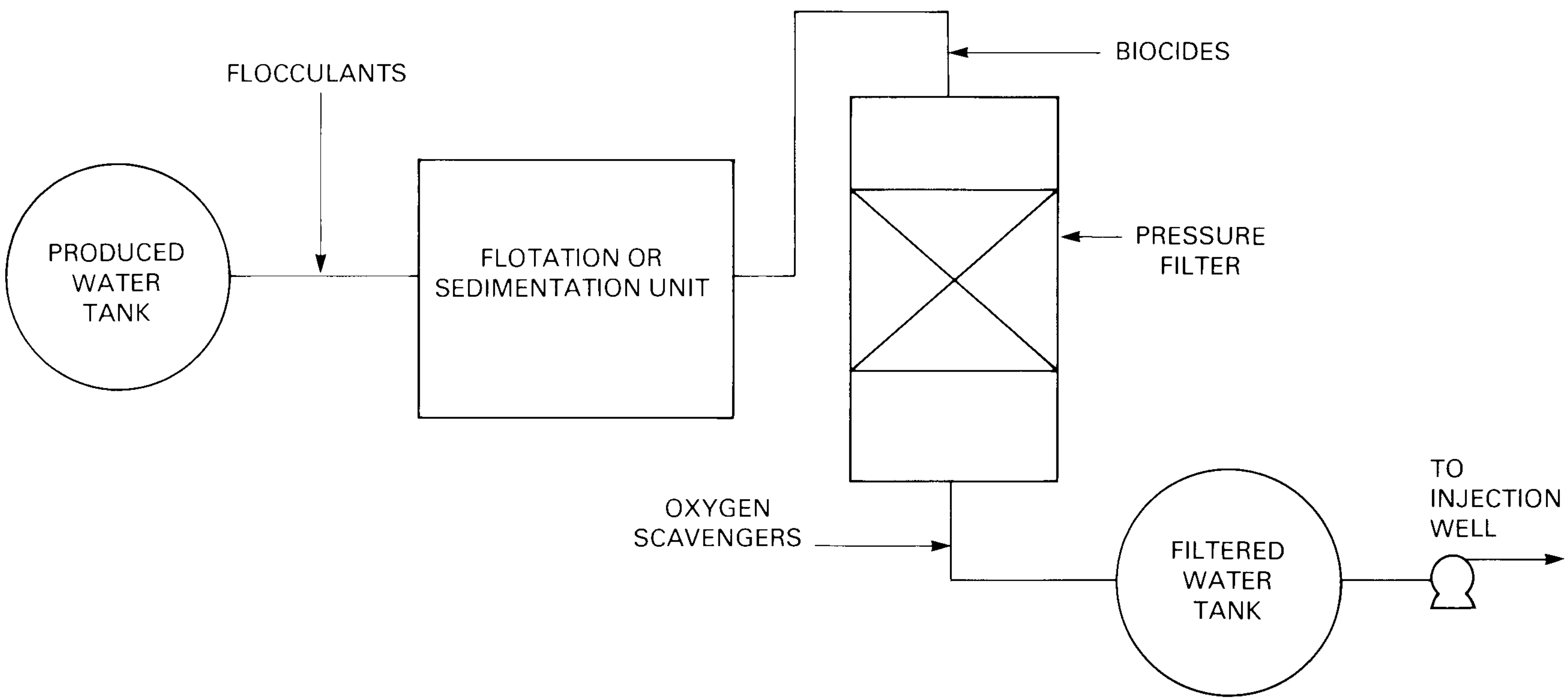



FIGURE 38 TYPICAL PRODUCED WATER TREATMENT SCHEMATIC

TABLE 23 WATER QUALITY SPECIFICATION CHART FOR INJECTION WELLS (Hensel et al, 1981)

| Parameter | Maximum limit | Detrimental effects | Design considerations or corrective action |
|---|---|---|---|
| Corrosion rate | 1 mil penetration per year | Equipment failures, increased solids. | Internal coating and lining of tubular goods and equipment. Effective corrosion control program which includes monitoring. |
| Oxygen | <0.05 mg/L | Equipment failures, increased chemical costs, iron hydroxides, plugging material. | Maintain closed system to eliminate oxygen entry -- deaeration, oxygen scavenging. |
| Suspended solids* | 5 mg/L | Formation plugging, increased horsepower for injection. | Filtration, chemical treatment for solids separation. Scale and corrosion control. |
| Bacteria | Colonies/mL | Corrosion, formation plugging, increased chemical costs. | Isolate source, chemical control and monitoring. |
| (1) Sulphate reducers | 10 to 100 | | |
| (2) Slime formers | 10 | | |
| Hydrocarbon (oil carryover) | 225 mg/L | Formation plugging. | Improve efficiency of oil removal equipment. Review demulsifier program, if used. |
| Compatibility | | | |
| (1) Scaling tendencies | Controlled/Eliminated | Scale buildup, formation and equipment. Plugging damage. | Chemical treatment, isolate incompatible waters. |
| (2) Formation clays | Controlled/Eliminated | Clay swelling, increased injection pressures, formation damage. | Seek alternate source of makeup waters. |

* Suspended solids limits may vary according to the permeability of the formation into which the water is injected. Suggest looking at available core data for individual field evaluation.

and barite may form as well (Schumaker, 1978). Iron precipitate formation can be prevented by minimizing exposure of the produced water to air and by chemicals that scavenge the dissolved oxygen (e.g., sodium sulphite, hydrazine). Frequently, it is best, however, to allow the iron precipitate to form and then remove it by sedimentation and filtration or by lowering the pH. Other types of scale can be prevented by the addition of sequestering agents such as sodium polyphosphates, and the sodium salts of ethylene diamine tetraacetic acid (EDTA). Iron can also be sequestered by chemicals such as sodium glycoheptonate or citric acid (Schumaker, 1978).

Occasionally, the removal of an anion to prevent scale formation is preferred. This can be done by precipitation (e.g., $BaCl_2$ for $SO_4$ removal) followed by sedimentation and filtration if necessary.

Equipment corrosion is usually caused by acidic gases (such as hydrogen sulphide or carbon dioxide) and/or oxygen. Acidic gases can be eliminated through aeration at low pH while oxygen can be either reacted with sodium sulphite, or the ferrous or manganous ion. The precipitate resulting from the ferrous or manganous ion addition can be removed by sedimentation and filtration as noted before (Schumaker, 1978).

Microbial growth can be prevented by the minimization of oxygen (as outlined above) and/or the addition of algicides (e.g., copper sulphate or quaternary ammonium salts) and bacterial disinfectants (e.g., chlorine) (Schumaker, 1978). High salt levels (more than 100 000 mg/L TDS) will also inhibit microbial activity.

Finally, clay swelling in the formation (due to sodium exchange) can also lead to formation plugging or permeability reduction and, therefore, calcium and magnesium are desirable (to reexchange with the sodium in the clay) in the injection water. Their presence, ideally, should exceed 10 percent of the TDS (Case, 1977). Several textbooks provide detailed information on oil field water treatment (e.g., Patton, 1977; Ostroff, 1979).

Waterflood operations require more water than is normally produced with the oil and a nearby water source is usually utilized. Figure 39 illustrates the process used at the Scurry-Rainbow West Eagle waterflood operation, where Uronlie Lake water is used to supplement the produced water. Treatment of the additional surface water used at this site follows conventional methods. In addition, both the produced water and the additional surface water are treated using cartridge filters (a type of filtration becoming more common in oil field water treatment with advances in cartridge materials).

Occasionally, some oil field excess water may have to be discharged to surface waters, in which case organic pollutants may have to be removed. With this in mind,

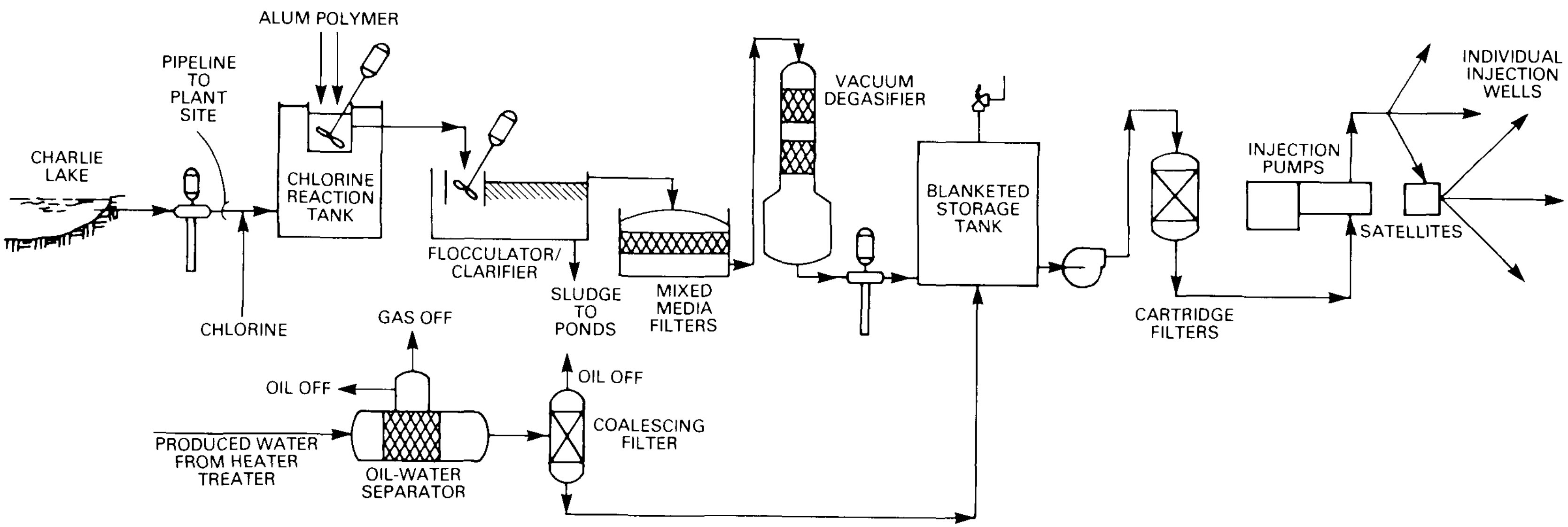



FIGURE 39 SCURRY-RAINBOW WEST EAGLE WATERFLOOD PROCESS SCHEMATIC (Kus, 1981)

Beyer et al (1979) studied the treatment of oil field water by aerated lagoons. Figure 40 illustrates the recommended flow schematic for the use of such lagoons and Table 24 summarizes treatment results for the system. As shown in Table 24, the wide variety of organics observed in the feed are well removed by the aerated lagoon system. Although Figure 40 illustrates a system used for ocean discharge, the processes used are similar to those which may be applied for discharge into freshwater. However, seasonal problems with the reduced activity of biological methods in a cold climate might require design or operation considerations for Canadian locations.

## 4.5 Environmental Impact

The production of oil and gas is subject to government regulations and as a result is under constant supervision. Production sites are visited regularly, transmission lines are inspected, and volumes of gas, oil, and water are constantly monitored and measured. In comparison, supervision of the drilling phase, ends with the disposal of the wastes produced irrespective of the long-term fate of the various pollutants in the environment.

The main environmental impact of oil and gas production is a change in land use for the lifetime of the oil and/or gas field. This impact can be lessened if good housekeeping practices, based on the existing regulations, are followed. Many of the problems experienced in some existing oil and gas fields, for example, soil erosion due to land clearing, cannot entirely be blamed on the oil companies because regulations were inadequate at the time the fields were developed. Furthermore, environmental awareness was still in its infancy when exploration and initial production activity took place in these fields.

Aside from changes in the use of the land surface, spills, subsurface disposal, and past surface disposal practices are major factors in the environmental impact of oil and gas fields.

Even with the best engineering and housekeeping practices accidental spills occur. The magnitude of these spills is generally limited because of constant supervision and monitoring. The most common spills are oil and brine spills due to pipeline breaks, minor spills at the production well during well workovers, and occasional well blowouts during a workover. Depending on the size of the pipeline, the automatic or manual monitoring techniques, and the time that passes before the break is detected, a considerable volume of liquid occasionally escapes. Experience has shown (Cook et al, 1973) that, although the effect of crude oil can be devastating on existing vegetation,

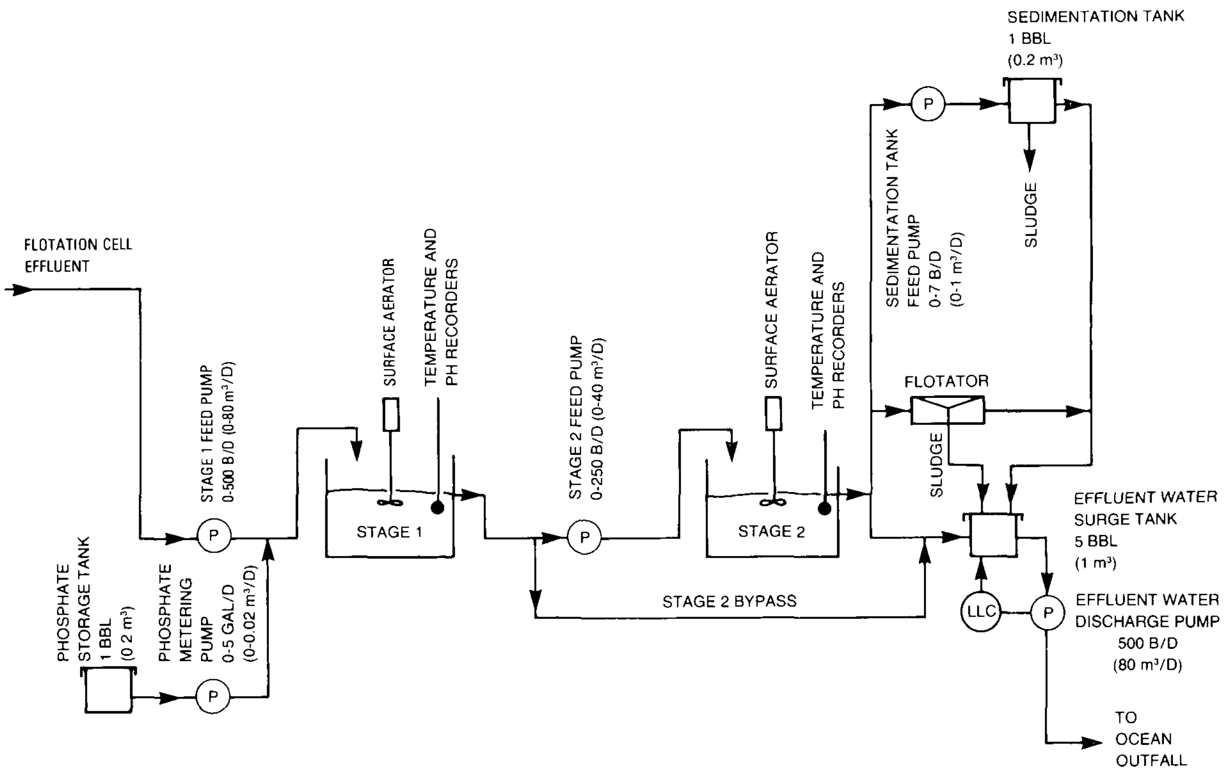



FIGURE 40 AERATED LAGOON PILOT PLANT, AT CARPINTERIA, CA (Beyer et al, 1979)

TABLE 24 AERATED LAGOON TREATMENT PERFORMANCE (BEYER et al, 1979)

| Parameter ($g/m^3$ or as shown)* | Number of Data Points | Feed: 50** Percentile | Feed: Upper 10† Percentile | Stage 1 Effluent: 50 Percentile | Stage 1 Effluent: Upper 10 Percentile | Stage 2 Effluent: 50 Percentile | Stage 2 Effluent: Upper 10 Percentile | 1972 California Ocean Plan Limits Not to Be Exceeded More than: 50% of Time | 1972 California Ocean Plan Limits Not to Be Exceeded More than: 10% of Time |
|---|---|---|---|---|---|---|---|---|---|
| Oil and grease | 14 | 17 | 45 | 7 | 13 | 7 | 15 | 10 | 15 |
| Biochemical oxygen demand ($BOD_5$) | | | | | | | | | |
| Settled samples | 14 | 232 | 314 | 43 | 96 | 39 | 93 | -- | -- |
| Filtered samples | 13 | 201 | 288 | 37 | 90 | 36 | 89 | -- | -- |
| Chemical oxygen demand (COD) | | | | | | | | | |
| Settled samples | 13 | 595 | 641 | 342 | 421 | 352 | 408 | -- | -- |
| Total organic carbon (TOC) | | | | | | | | | |
| Filtered samples | 1 | 115 | -- | 40 | -- | 43 | -- | -- | -- |
| Organic acids | 4 | 70 | 82 | -- | -- | 8 | 10 | -- | -- |
| Phenols, as $C_6H_5OH$ | 12 | 1.9 | 2.5 | < 0.05 | < 0.05 | < 0.05 | < 0.05 | 0.5 | 1.0 |
| Identifiable chlorinated hydrocarbons | 1 | -- | -- | -- | -- | < 0.002 | -- | 0.002 | 0.004 |
| Ammonia, as N | 15 | 41 | 44 | 20 | 34 | 1.4 | 4.0 | 40 | 60 |
| Nitrites and nitrates, as N | 14 | < 0.01 | < 0.01 | 35 | 74 | 88 | 109 | -- | -- |
| Total suspended solids (TSS) | 12 | 98 | 167 | 146 | 172 | 140 | 166 | 50 | 75 |
| Volatile suspended solids (VSS) | 12 | 45 | 77 | 96 | 121 | 88 | 110 | -- | -- |
| Toxicity, toxicity units†† | | | | | | | | | |
| Killifish | 2 | 4.4 | -- | 1.9 | 2.8 | 0.6 | 0.6 | 1.5 | 2.0 |
| Brine shrimp | 2 | 2.3 | 3.6 | 0.9 | 1.6 | 0.4 | 0.7 | 1.5 | 2.0 |
| Cyanide | 4 | -- | -- | -- | -- | < 0.1 | < 0.1 | 0.1 | 0.2 |
| pH | 13 | 7.5 to 7.9 | | 8.3 to 8.6 | | 8.3 to 8.8 | | 6.0 to 9.0 at all times | |
| Temperature, °F (K) | 13 | 105 to 115 (315 to 320) | | 70 to 80 (295 to 300) | | 60 to 65 (290) | | -- | -- |

* Information on analytical methods is available from the authors.
** The arithmetic mean ($\bar{x}$) of the experimental data.
† Determined by $x + 1.28\sigma$, where $\sigma$ is the standard deviation of the experimental data (normal distribution).
†† When Y (the percent survival of the bioassay test organisms in undiluted produced water) $\leq 50\%$:

$$\text{Toxicity units} = \frac{100}{TL_{50} - X}$$

where $TL_{50}$, X is the volume percent of produced water in a blend of produced water and clean water, in which half of the organisms survive for X hours.

When Y > 50%:

$$\text{Toxicity units} = \frac{\log(100 - n)}{1.7}$$

proper soil management can generally restore the site after a number of years without apparent lasting effects. The brine carried with the crude oil or from a brine disposal line presents a greater problem because of its mobility in the soil and underlying sediment. Furthermore, brine will kill the existing vegetation and induce physical changes in the soil, which will reduce the productivity of the soil and hamper rehabilitation. Depending on the size of the spill and the type and use of the soil, it may be necessary to amend the soil and in serious cases to require installation of subsurface drains to rehabilitate the area. According to Brushett (1979) 650 spills occurred in Alberta during 1978, of which approximately 420 were oil only, 100 were salt water only, and 130 were oil/salt water emulsion spills. Most of these spills were caused by pipeline breaks.

Small leaks are much more insidious than large and obvious surface spills. Flow measuring equipment is generally not accurate enough to detect small leaks of a few litres per day. However, the accumulated effect over time can create environmental problems of considerable magnitude, especially where no surficial evidence is apparent. A small leak can be a major problem if it is detected after the field has been abandoned.

The brine that is separated from the oil (and gas) is disposed of by injection in deep wells. These wells are almost invariably completed in the same reservoir from which the oil was extracted. The volume of the separated oil field brines is in many areas augmented with water obtained from other sources (surface or subsurface) to maintain proper pressure control in the reservoir for optimum recovery of the oil. Since the additional water in some areas is obtained from fresh water aquifers in the shallow subsurface, extraction of large amounts of water could lower the hydraulic head in the aquifer. This in turn would affect the production capacity of other wells completed in the aquifer and could result in changes in the hydrochemistry of the water because of altered groundwater flow patterns.

The total volume of the produced brine given in Table 14 for all of western Canada is 314 311 $m^3/d$. This is a considerable volume and surface disposal of any of this liquid is not allowed. Furthermore, strict regulations govern handling and ultimate deep well disposal. If an average chloride concentration of 100 000 mg/L in the brine is assumed and if all chloride is assumed to be sodium chloride, then the total annual production of sodium chloride in oil and gas field brines is approximately 17 500 000 tonnes. This is equivalent to the solid sodium chloride waste produced by the potash industry in Saskatchewan. However, the potash industry is allowed to dispose of this highly soluble material at surface, albeit in diked areas, while no surface disposal is allowed for the oil industry. It may be appropriate to develop treatment methods which would allow surface discharge of some injected liquid wastes to avoid groundwater contamination in certain areas.

Another major source of sodium chloride in the environment is highway salting during the winter. According to the various district offices of the Alberta Department of Highways, road salt use over the winter season is in the order of 1.5 to 6 tonnes per lane kilometre. In terms of the oil field brine discussed above this is equivalent to 38 700 to 193 600 litres per kilometre of two-lane highway. Disposal of this quantity of brine on the land surface by the oil industry would be considered environmental heresy, even if it could be proven that annual spring runoff would remove most of the salt.

The surface disposal practices of the past are now presenting considerable problems in several areas. Inadequate regulatory control in the past resulted in disposal practices with little or no regard for the environmental implications. Pit disposal of brine was widely practiced and the location of the pit was based on convenience rather than on its position within the hydrogeological regime. As a result, large quantities of brine have infiltrated into the subsurface in several areas. This in turn has resulted in groundwater pollution and the development of saline and saline/alkaline soils in the groundwater discharge areas. According to White and de Jong (1975), 160 of 164 oil field disposal pits in Saskatchewan showed contamination. The cost of cleanup and rehabilitation of these areas is generally high and may run into hundreds of thousands of dollars. Fortunately, under the present regulations and as a result of the environmental awareness of the oil industry, this problem seldom occurs anymore.

The environmental impact of the land disposal of the various sludges depends on the composition of the sludge, the toxicity of the components, the relative mobility of these components in the subsurface environment, and the setting of the disposal site within the hydrogeologic regime of the area.

# 5 ENHANCED RECOVERY OF CONVENTIONAL OIL AND GAS

## 5.1 Introduction

Recently, the term "tertiary recovery" has come to refer to the recovery of oil by new injection processes implemented after secondary pressure maintenance operations have been used. The term "tertiary" has been broadened to include sophisticated recovery processes that involve the generation of heat in the reservoir by injecting air, steam or other hot gases, or those that increase recovery by injection of various chemicals or miscible fluids.

The objectives of every tertiary recovery process are as follows:

i) to increase the ultimate recoverable oil by the largest possible amount over that achievable by current operations at maximum profit to the capital input, and
ii) to increase and/or maintain the highest possible production rate to recover the additional increment of oil attributable to the tertiary recovery process during as few years as possible to maximize the time value of profit.

Ultimate recovery in broad terms is a function of the following factors:

i) injected fluid viscosity,
ii) reservoir fluid viscosity,
iii) reservoir rock properties, and
iv) displacement efficiency of the injected fluid.

In a given reservoir the reservoir fluid viscosity and rock properties are fixed. The reservoir permeability and variations within the reservoir determine the portion of reservoir contacted and rate of production and injection. Injection fluid viscosity and displacement efficiency are specific characteristics of the injection fluid.

Ultimate recovery by any injection process is determined by the portion of the reservoir contacted (areal and vertical sweep efficiency) and the displacement efficiency in that portion contacted. Typical waterflood (immiscible displacement) areal sweep efficiency is 70 percent of the total floodable area while vertical sweep efficiency is 70 percent of vertical pay thickness (Anonymous, 1973). Therefore, approximately 50 percent of the reservoir pore volume is contacted. If an immiscible fluid such as water is injected the displacement efficiency in the swept portion (50 percent) of the reservoir is 50 percent. It follows that the ultimate recovery is 25 percent of the oil-in-place.

Tertiary processes in light oil operations are directed towards increasing the efficiency of oil displacement in the portion of the reservoir contacted. If all of the oil could be recovered from the swept portion of the reservoir the typical tertiary recovery process would show an ultimate total recovery of 50 percent of the oil-in-place.

Conventional oil production, including water flooding, typically recovers only one-third of the original oil-in-place (OOIP). Canada has approximately 8 782 241 000 $m^3$ in place (Canadian Petroleum Association, 1980), part of which will initially be recovered by primary and secondary methods. At current rates of consumption (287 921 $m^3/d$), a one percent increase in ultimate oil recovery through enhanced oil recovery (EOR) will extend the life of Canadian conventional crude oil supplies by almost a year.

Chapter 4 described the various primary and secondary (pressure maintenance) techniques for oil and gas production. This chapter discusses tertiary or enhanced oil recovery methods for the production of conventional light and heavy oils, but does not discuss _in situ_ production of oil from the tar sands. The three main tertiary or enhanced oil recovery processes are:

i) Chemical Flooding
- polymer flooding
- surfactant (micellar) flooding
- caustic flooding

ii) Thermal Flooding
- hot water injection
- steam injection
- _in situ_ combustion

iii) Miscible Flooding
- hydrocarbon fluids
- carbon dioxide
- other gases (e.g., $H_2S$, $SO_2$, $N_2$)

No significant large-scale chemical flood projects are operating in Canada at this time. Conceptually, chemical processes appear capable of considerable potential for tertiary oil recovery. However, chemical flood technology remains relatively untested and has serious weaknesses, which are discussed in Section 5.2.

Thermal flooding is being tested in relatively large-scale pilot projects. The significance of this technique is that Canada possesses very large reserves which at this time are only recoverable by thermal flooding.

Miscible flooding is the most proven technology in Canada and there are several miscible flood operations in Alberta and British Columbia. The South Swan Hills miscible flood is the most advanced true tertiary recovery operation. Ultimate incremental potential recovery attributable to miscible flooding in Canada has been estimated to range between 1.5 to 3.0 billion barrels. All miscible flood operations in Canada use liquid hydrocarbon gases as the miscible fluid and as the injection slug, though nitrogen is also being used in some cases.

Future miscible flood operations are expected to use carbon dioxide as the miscible fluid. The cost of hydrocarbon materials is expected to prohibit their use for miscible floods in the future. Pusher material to drive the miscible slug will be either water, recycled carbon dioxide, nitrogen or some other low cost gas.

Table 25 presents the NEB (1981) estimated production capacity attributable to tertiary recovery processes to the year 2000.

## 5.2 Chemical Flood Processes

In chemical flood processes, an increase in the viscosity of injected fluid is generally required; however, the permeability of most reservoirs in Canada is too low to maintain an adequate injection of chemically-treated water to all layers of the reservoir. This single factor severely restricts the application of chemical processes in Canada. The low permeability also tends to destroy polymers due to the high shear rates required for injection, which creates further technological problems.

In polymer flooding an activator compound is often injected with polymers (polyacrylamides, xanthans, cellulosics, polysaccharides). The activator functions as a cross-linking agent which thickens the polymer in areas where porosity and permeability are greatest. The effect of the polymer is to lower the permeability of the high permeability zones of the reservoir so that the injected fluid is forced through lower permeability areas not previously contacted.

Surfactant flooding is also referred to as micellar or microemulsion flooding. Surfactants are molecules which are active at the oil-water interface. Normally they are molecules with a hydrophilic head and a hydrophobic tail (directly analogous to household detergents). They form micelles or droplets of oil stabilized in water as an emulsion.

Surfactants increase displacement efficiency by reducing the surface tension between the oil and injected waters and are most likely to be used in reservoirs where miscible processes do not function, such as medium to heavy gravity oil reservoirs. An injected surfactant slug ranging from 10 to 30 percent of the oil-in-place can, under ideal

TABLE 25 ESTIMATED CANADIAN OIL PRODUCTION CAPACITY ATTRIBUTABLE TO TERTIARY RECOVERY PROCESSES

| | Production Capacity ($10^3$ $m^3/d$) | | |
|---|---|---|---|
| Year | Light Crude | Lloydminster Heavy | Cold Lake Heavy |
| 1981 | 1.0 | 0.5 | 2.0 |
| 1982 | 2.0 | 1.9 | 3.0 |
| 1983 | 3.0 | 3.7 | 4.0 |
| 1984 | 4.4 | 6.1 | 4.0 |
| 1985 | 5.9 | 9.6 | 5.0 |
| 1986 | 7.7 | 13.0 | 12.0 |
| 1987 | 9.8 | 16.4 | 12.0 |
| 1988 | 12.6 | 19.4 | 12.0 |
| 1989 | 15.4 | 21.8 | 19.0 |
| 1990 | 18.7 | 22.8 | 19.0 |
| 1991 | 21.9 | 23.2 | 19.0 |
| 1992 | 25.0 | 22.5 | 19.0 |
| 1993 | 27.4 | 21.6 | 19.0 |
| 1994 | 29.1 | 20.5 | 19.0 |
| 1995 | 30.1 | 19.2 | 19.0 |
| 1996 | 30.5 | 17.7 | 19.0 |
| 1997 | 30.6 | 16.2 | 19.0 |
| 1998 | 30.0 | 14.6 | 19.0 |
| 1999 | 28.9 | 13.3 | 19.0 |
| 2000 | 27.5 | 11.9 | 19.0 |
| Total | 361.5 | 295.9 | 282.0 |

Source: Canadian Energy Supply and Demand 1980 - 2000, published June 1981 by National Energy Board.

conditions, achieve a displacement efficiency of between 75 to 100 percent of the oil from the portion of the reservoir contacted. This slug is often then displaced by polymerized water injection. The increased viscosity of the polymerized water reduces the oil-to-water viscosity ratio and, consequently, results in a larger portion of reservoir being contacted.

Unfortunately, surfactants are precipitated by hardness and are less effective in saline reservoir brines. Since many reservoirs contain saline brines with a Na:Ca:Mg ratio of 20:2:1, the typical surfactant flood requires a fresh water preflush to reduce the harmful influence of these brine constituents.

Caustic floods are based on the reaction of the reagents with organic acids or bases in the crude oil to form surface active products. Four principal effects of this reaction have been proposed (Johnson, 1975): emulsification and entrainment, wettability reversal (oil wet to water wet and vice versa), emulsification, and entrapment. The net result of these effects is the reduction of water mobility and improvement of relative oil/water mobility, lowering of the oil/water surface tension, and consequent improved waterflood sweep efficiency.

Caustic reacts readily with multivalent cations such as calcium, magnesium, and iron, and the presence of significant amounts of such cations in the reservoir water or rock may render the caustic inoperative or uneconomic. Salinity is beneficial to the caustic action in that it can improve the wetability of the rock and lower the caustic concentration required to achieve minimum surface tension (Johnson, 1975). In Canada, caustic will probably be used mainly in combination with thermal processes as a hot caustic injection flood because a reduction in viscosity of the bulk of the crude is usually also required. Considering the problems associated with chemical processes and the necessity for precise design and operating conditions, it seems improbable that chemical flooding will become a significant recovery technique in western Canada (with the possible exception of thermal caustic methods). The majority of the reservoirs suitable for chemical flooding are equally or more suitable for thermal methods or conventional miscible flooding. Also a large majority of western Canadian reservoirs are in carbonate rocks which usually have a high level of dissolved divalent cations. This results in a high loss of surfactant by precipitation, while the high formation water salinities lead to dispersion of the micellar solutions.

### 5.3 Thermal Recovery Processes

Thermal flooding, or heating a reservoir to increase oil recovery, can be accomplished either by injection of a heated fluid or gas or by initiating combustion (fireflood) in the reservoir. Heat transporting fluids could be any gas or liquid but are usually steam or hot water because of the low cost. Similarly, heat generation is accomplished by the injection of air after combustion has been started. Wet and/or dry combustion simply refer to water injection, or lack thereof, along with the air injection. Figures 41 and 42 schematically illustrate steam and fireflood operations.

Oil production rate is inversely proportional to the viscosity of oil (which is inversely proportional to temperature). Therefore, the higher the temperature, the higher the oil production rate, regardless of whether the high temperature is naturally or mechanically generated. Figure 43 illustrates the variation in production rate with respect to viscosity for a typical Lloydminster area heavy oil reservoir. Figure 44 illustrates viscosity versus temperature variations for various crude oils.

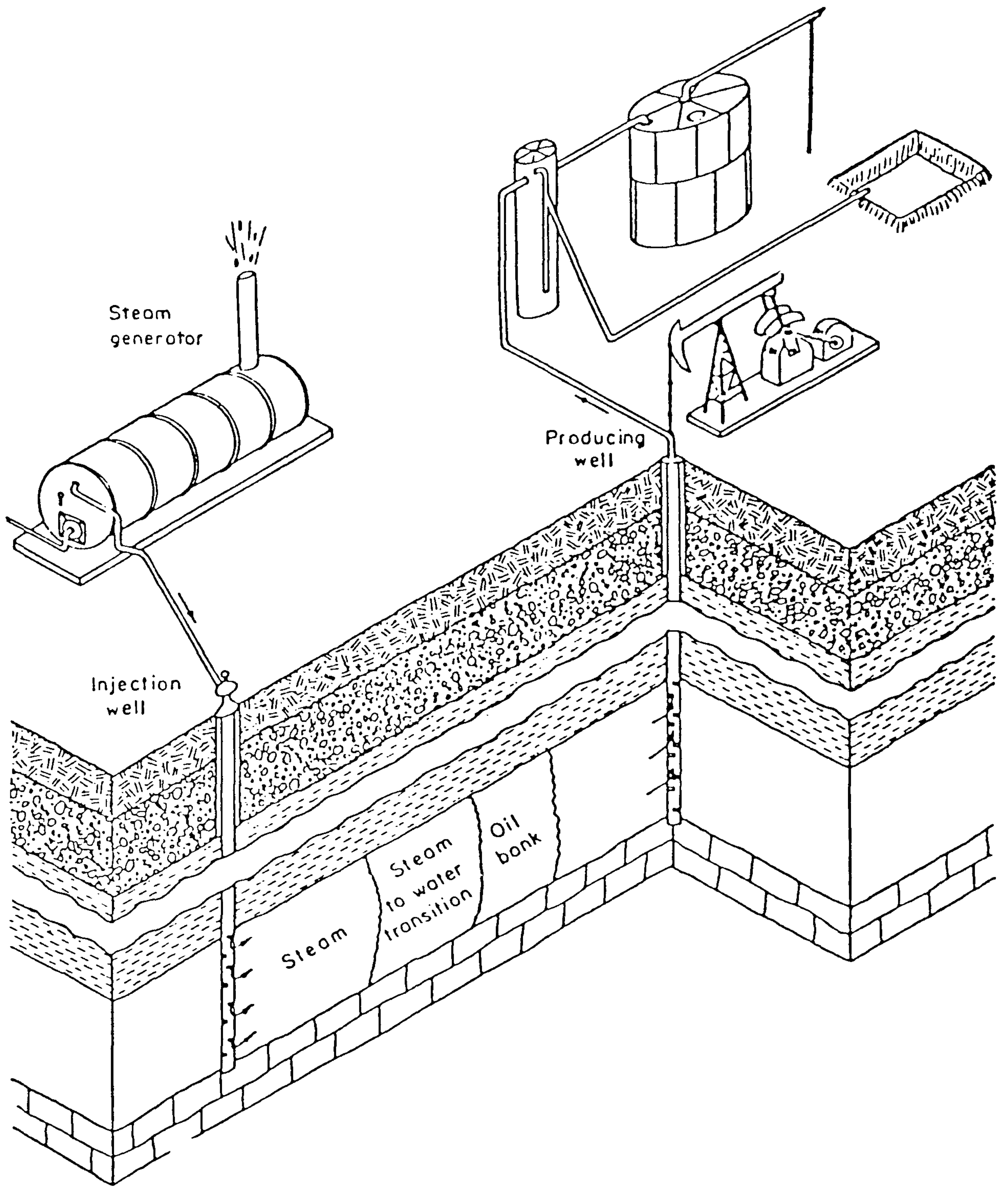



FIGURE 41 SCHEMATIC ILLUSTRATION OF STEAM FLOOD OPERATION

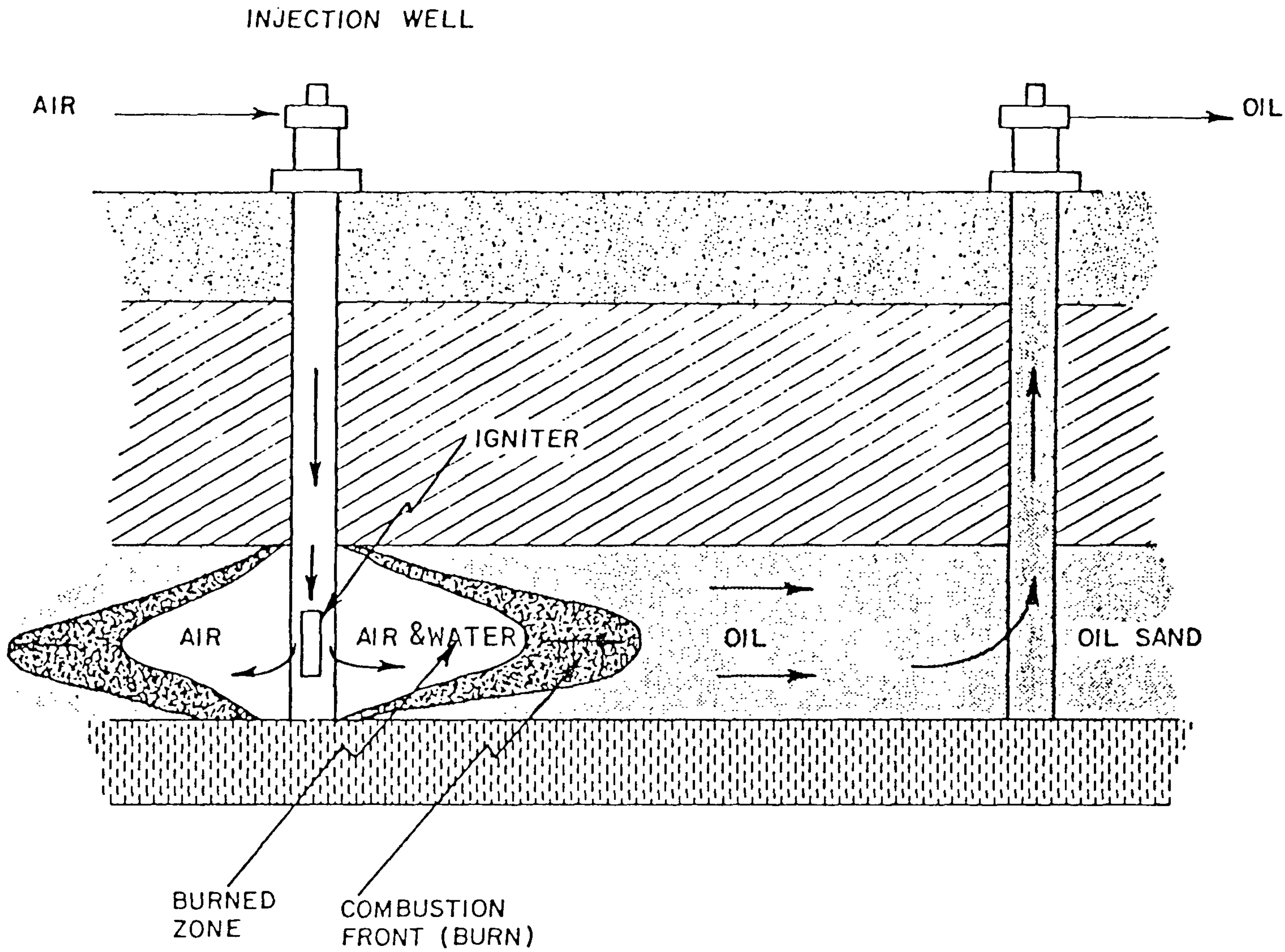



FIGURE 42 SCHEMATIC ILLUSTRATION OF FIREFLOODING BY AIR INJECTION

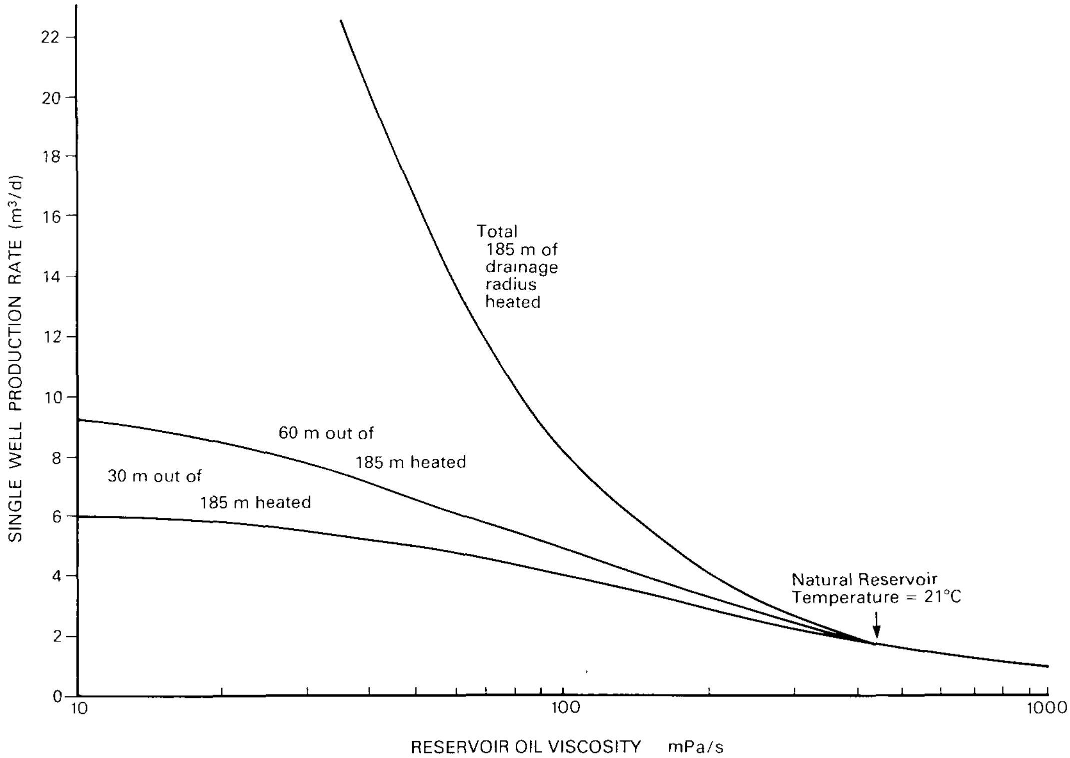



FIGURE 43 TYPICAL LLOYDMINSTER WELL PRODUCTION RATE VERSUS RESERVOIR OIL VISCOSITY

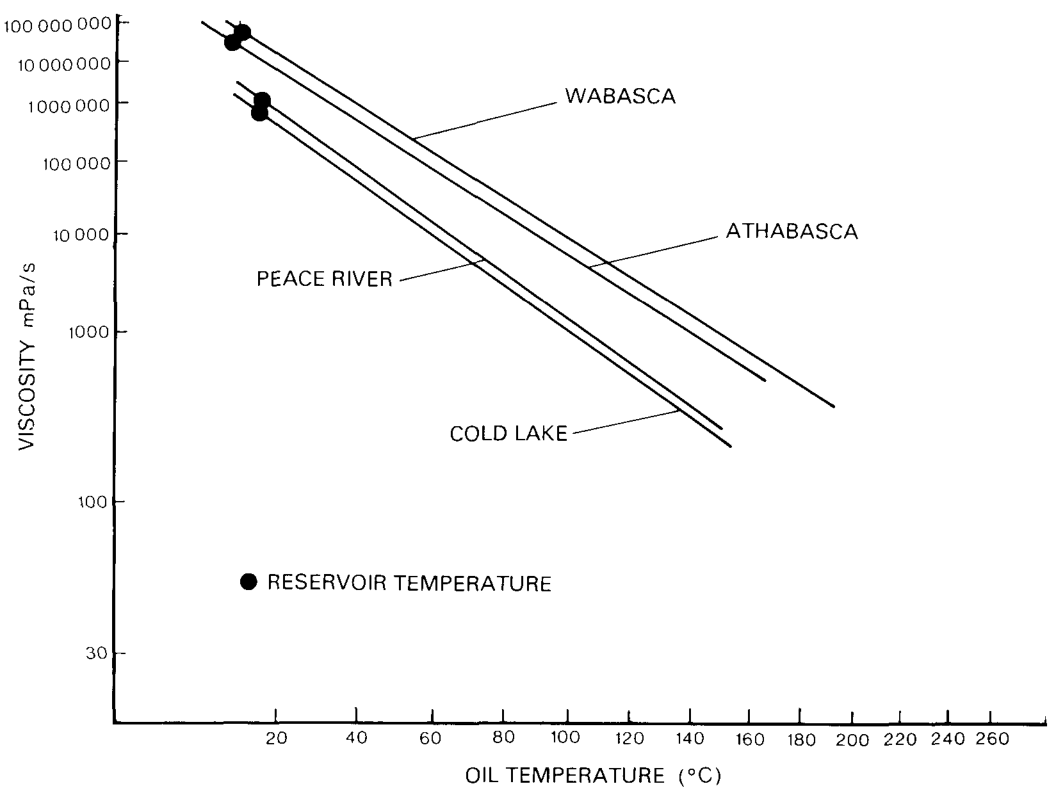



FIGURE 44 WESTERN CANADA HEAVY OIL VISCOSITY VERSUS TEMPERATURE

Substantial increases in production rate can be achieved if heavy oil can be heated. Typical steamflood operations generate temperatures between 150°C and 200°C, while fireflooding can generate temperatures higher than 350°C. The difficulty with thermal flooding is achieving heat dispersion in the reservoir. Heat transfer by conduction and diffusion alone is insignificant for all practical purposes. To implement and operate a thermal flood, the heat injected must move through the reservoir. Beyond the injection front the reservoir fluid is unheated and, therefore, cold fluid flow must take place (Craft and Hawkin, 1959; Pirson, 1958).

Thermal flooding of conventional oil reservoirs in Canada is expected to include a number of wet combustion firefloods. Dry combustion is inefficient because vaporized oil and water move ahead of the dry combustion front and the greatest heat transfer to the reservoir is behind the firefront where hydrocarbons are burned out. In wet combustion, water is injected following the firefront. The generated steam transfers heat to oil zones and, as the burned-out zone cools, the water injected acts as a hot-water drive. Tables 26 and 27 present water production forecasts for steamflood and fireflood operations.

## 5.4 Miscible Flooding

The term "miscible flooding" refers to the use of a solvent which can dissolve the reservoir oil essentially completely and achieve virtually 100 percent displacement of the oil from the portion of the reservoir contacted. Such displacement can be achieved when there is no phase boundary between the displaced and displacing fluids. Gas displaces other gas miscibly, and most reservoir oil is miscible with other reservoir oil. The key is to achieve miscible displacement with a low cost material so that all the valuable fluids are recovered and the process shows an economic return for each barrel injected. A schematic illustration of a miscible displacement process is presented in Figure 45.

The most common miscible processes involve injecting a miscible fluid to the reservoir in amounts of between 10 and 30 percent of the oil-in-place. This "slug" accounts for the largest single cost of the project. Slug design to maximize recovery for the least cost is a science and the subject of many technical articles (D&S Petroleum Consultants, 1974). The slug itself is driven and displaced by hydrocarbon gas, followed by an inert gas (such as nitrogen), and/or water. Care must be exercised to avoid piercing the slug with the immiscible pusher gas or water, thereby destroying the miscibility between the reservoir oil and the driving fluids.

TABLE 26 WATER PRODUCTION FORECAST FOR FUTURE STEAMFLOOD AND FIREFLOOD OPERATIONS (Cold Lake, Peace River and Wabasca)

| | Steam Huff & Puff* | | Steamflood** | | Fireflood** | |
|---|---|---|---|---|---|---|
| Year | Steam-to-Oil Ratio | Water ($10^3$ $m^3/d$) | Water-to Oil Ratio | Water ($10^3$ $m^3/d$) | Water-to Oil Ratio | Water ($10^3$ $m^3/d$) |
| 1981 | 4 | 8.0 | - | - | - | - |
| 1982 | 4 | 12.0 | - | - | - | - |
| 1983 | 4 | 16.0 | - | - | - | - |
| 1984 | 4 | 16.0 | 4 | 4 | - | - |
| 1985 | 4 | 16.0 | 4 | 16 | 4 | 16 |
| 1986 | 5 | 20.0 | 4 | 16 | 3 | 12 |
| 1987 | 5 | 20.0 | 4 | 16 | 2 | 12 |
| 1988 | 5 | 20.0 | 4 | 30 | 2 | 15 |
| 1989 | 5 | 20.0 | 4 | 30 | 2 | 15 |
| 1990 | 5 | 20.0 | 5 | 37.5 | 2 | 15 |
| 1991 | 6 | 24.0 | 5 | 37.5 | 2 | 15 |
| 1992 | 6 | 24.0 | 5 | 37.5 | 2 | 15 |
| 1993 | 6 | 24.0 | 5 | 37.5 | 3 | 22.5 |
| 1994 | 6 | 24.0 | 5 | 37.5 | 3 | 22.5 |
| 1995 | 6 | 24.0 | 5 | 37.5 | 3 | 22.5 |
| 1996 | 6 | 24.0 | 6 | 45.0 | 3 | 22.5 |
| 1997 | 6 | 24.0 | 6 | 45.0 | 3 | 22.5 |
| 1998 | 6 | 24.0 | 6 | 45.0 | 3 | 22.5 |
| 1999 | 6 | 24.0 | 6 | 45.0 | 4 | 30.0 |
| 2000 | 6 | 24.0 | 6 | 45.0 | 4 | 30.0 |

* Steam huff & puff contributes a maximum of 4 x $10^3$ $m^3/d$ oil production.

** Steam-to-oil and water-to-oil ratios and trends based on arbitrary estimate and experience.

Miscible processes usually involve a low viscosity displacing fluid and a reservoir oil of a viscosity of at least ten times greater. To increase the portion of the reservoir swept, it is common practice to inject water along with other drive agents, a so-called "water-alternating-gas" (WAG) process. After the miscible slug is injected the relative quantity of water injected is limited by the reservoir capacity and miscible slug volume. Water tends to trap and consume the miscible slug in the reservoir. The slug and water injection volumes must be considered before injection commences.

Although a number of miscible floods using liquified petroleum gas (LPG) have been operating in Alberta for a considerable time, future miscible flood operations are likely to use carbon dioxide where technically feasible, as the miscible agent itself has

TABLE 27 WATER PRODUCTION FORECAST FOR LLOYDMINSTER AREA FIREFLOOD OPERATIONS

| Year | Water-to-Oil Ratio | Water $10^3$ $m^3/d$ |
|---|---|---|
| 1981 | 3 | 1.5 |
| 1982 | 3 | 5.7 |
| 1983 | 3 | 11.1 |
| 1984 | 3 | 18.3 |
| 1985 | 3 | 28.8 |
| 1986 | 3 | 39.0 |
| 1987 | 3 | 49.2 |
| 1988 | 3 | 65.4 |
| 1989 | 4 | 91.2 |
| 1990 | 4 | 92.8 |
| 1991 | 4 | 90.0 |
| 1992 | 4 | 86.4 |
| 1993 | 4 | 82.0 |
| 1994 | 4 | 76.8 |
| 1995 | 4 | 70.8 |
| 1996 | 5 | 81.0 |
| 1997 | 5 | 73.0 |
| 1998 | 5 | 66.5 |
| 1999 | 5 | 59.5 |
| 2000 | 5 | 50.0 |

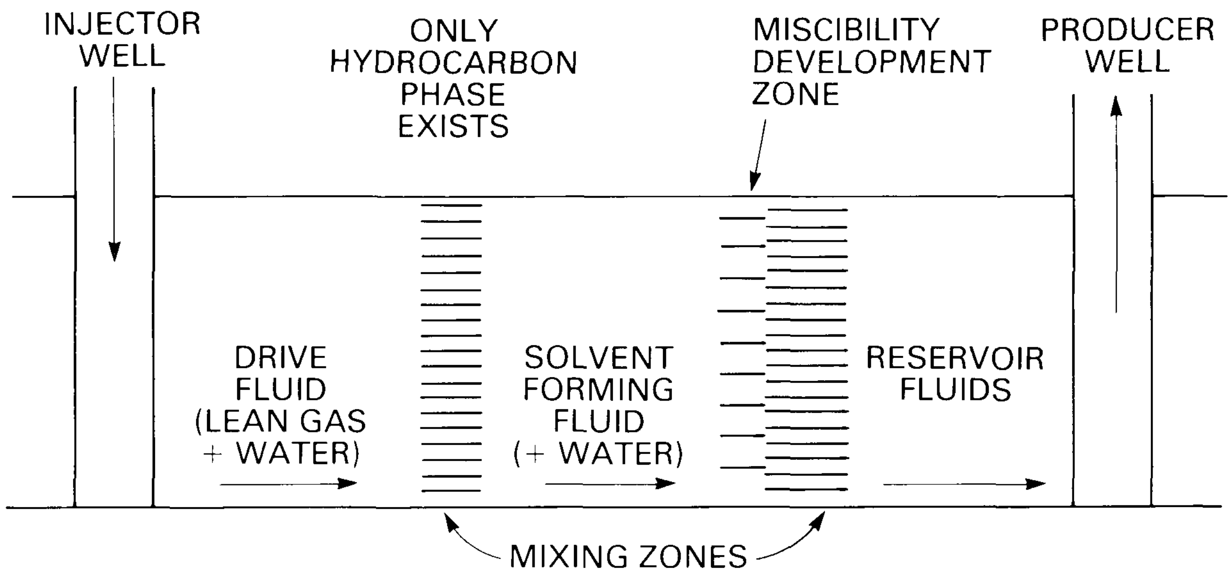
little or no alternative use, and should be cheaper than liquified petroleum gas. However, Canada has relatively few high $CO_2$ content reservoirs such as those which are the source of large amounts of economical $CO_2$ in many U.S. projects.

Tables 28 and 29 present the estimated potential resource base for miscible recovery processes, and water production forecasts, respectively.

## 5.5 Regulatory Activities and Waste Disposal Methods

The ERCB is the central agency providing approval for enhanced recovery schemes in Alberta. As with all other aspects of oil and gas drilling and production which may be of environmental concern, the Department of the Environment, through the Department of the Environment Act and Clean Water Act, can be involved in approving applications.

Under Section 38 of the Oil and Gas Conservation Act, any scheme for enhanced recovery must be first approved by the ERCB. The application requires detailed information which includes reservoir pore volume and permeability, predicted recovery,




SOLVENT FLUIDS

LIQUIFIED PETROLEUM GAS ———— DIRECTLY MISCIBLE WITH OIL
GASEOUS ———— DEVELOPS MISCIBILITY WITH OIL

FIGURE 45 SCHEMATIC ILLUSTRATION OF MISCIBLE FLOOD CONCEPTS

injection rates, corrosion prevention measures and evidence of the compatibility of the injection fluid with the formation rock and water (Section 15.040). Following approval, the ERCB requires the operator to submit reports specifying production and injection details on a biannual basis for the first two operating years (Section 12.130).

Saskatchewan and British Columbia do not have regulations significantly different from Alberta. Both provinces require similar approvals and adequate monitoring.

In general, there has been very little experience with EOR in Canada and there is very little knowledge of waste disposal methods associated with such systems. Only chemical waste disposal is discussed in this section as the wastes from miscible EOR operations are expected to be minimal and the wastes from thermal systems are similar to those emanating from <u>in situ</u> tar sands recovery which are discussed in the next chapter.

Among chemical flooding systems, the wastes from alkali flooding are expected to be handled in a manner similar to the methods described for production wastes in Chapter 4. The other chemicals, such as surfactants, polymers and co-

TABLE 28 WESTERN CANADA POTENTIAL LIGHT OIL RECOVERY THROUGH MISCIBLE FLOODING

| Province | Original Oil-in-Place million $m^3$ | Established Recoverable | | Incremental Tertiary | |
|---|---|---|---|---|---|
| | | Million Barrels | % Oil-in-Place | $10^6$ $m^3$ | % Oil-in-Place |
| B.C. | 225 | 78.033 | 34.7 | 17.514 | 7.8 |
| Alberta | 5563 | 1913.159 | 34.4 | 463.493 | 8.3 |
| Sask. | 1245 | 379.269 | 30.5 | 99.571 | 8.0 |
| Manitoba | 100 | 26.033 | 26.0 | 8.789 | 8.8 |
| Total | 7133 | 2396.464 | 33.6 (average) | 589.368 | 8.3 (average) |

Source: Dome Petroleum Ltd. Submission to National Energy Board, September 1980, Order No. EHR-1-80, Volume II, Supply and Demand For Crude Oil In Canada, Supplemental Information. The above data represent the technically achievable recovery independent of economics.

surfactants, may be highly toxic and their disposal in deep wells or in surface ponds may be of concern. A list of the chemicals used in EOR and their toxicity is presented in Table 30.

### 5.6 Environmental Impact

Although a number of different EOR processes have been developed, the only process used in western Canada on a large scale is miscible flooding. All other processes are in various stages of pilot testing with steam injection and/or wet combustion as the most prominent ones.

Liquified petroleum gas (LPG) is used primarily in miscible flood operations. The wastes produced during these operations are similar to those generated during conventional oil production, with the same potential environmental impact as was discussed in the previous chapter.

Very little information is currently available on the composition of the waste products (liquid, semi-solids, and solids) generated during the pilot testing of the other EOR processes in Canada. Comments with respect to the environmental impact of these processes are therefore primarily based upon a review of U.S. operations. Table 31 shows

TABLE 29 WATER PRODUCTION FORECAST* FOR WESTERN CANADA LIGHT CRUDE MISCIBLE FLOOD PROJECTS

| | Water Production Forecast | |
|---|---|---|
| Year | Water-to-Oil Ratio | $10^3$ $m^3/d$ |
| 1981 | 2 | 2.0 |
| 1982 | 2 | 4.0 |
| 1983 | 3 | 9.0 |
| 1984 | 3 | 13.2 |
| 1985 | 4 | 23.7 |
| 1986 | 4 | 30.8 |
| 1987 | 3 | 29.4 |
| 1988 | 3 | 37.8 |
| 1989 | 3 | 46.2 |
| 1990 | 2 | 37.4 |
| 1991 | 2 | 43.8 |
| 1992 | 2 | 50.0 |
| 1993 | 2 | 54.8 |
| 1994 | 1.5 | 43.7 |
| 1995 | 1.5 | 45.2 |
| 1996 | 1.5 | 45.8 |
| 1997 | 1.5 | 45.9 |
| 1998 | 1.5 | 45.0 |
| 1999 | 1.5 | 43.4 |
| 2000 | 1.5 | 41.3 |

* Calculated as per discussion on page 88. Based on oil production forecasts as shown in Table ~~28~~.
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a general overview of the potential problems associated with wastes generated by the various EOR processes in the U.S. (Wilson and Kendall, 1980). The main concern is the disposal of wastewater and, to a lesser extent, the demand for fresh make-up water. Of particular concern in the disposal of the wastewater by deep well injection is the potential for corrosion of the well casing by the low pH water. This could lead to contamination of fresh water aquifers; however, Canadian regulations are more stringent, i.e., injection wells are equipped with injection tubing and the annulus between the well casing and the tubing is filled with a non-corrosive liquid. Furthermore, the pressure in the annulus is monitored. Any leaks in the injection tubing can be detected immediately and remedial measures can be taken to replace the injection tubing before any serious damage to the well casing has taken place.

TABLE 30 GENERAL TOXICITY DATA FOR CHEMICALS PROPOSED FOR USE IN ENHANCED OIL RECOVERY (Wilson & Kendall, 1980)

| Compound | Toxicity Data | Carcinogen/ Response | Route of Exposure* | Major Use |
|---|---|---|---|---|
| Acrylamidediacetone | | | | Surfactant additive |
| Acrylmethylpropyl sulphonic acid | | | | Surfactant |
| Acrylonitrile | TLV 20 ppm | neoplastigen | ihl[1] | Surfactant additive/ contaminant |
| Aluminum citrate | | | | Fraction micellar slug |
| Alkyltoluene sulphonate | $LD_{50}$ 2480 mg/kg | | orl | Surfactant |
| Aniline | TLV 5 ppm | positive | skin | Combustion, biocide |
| Ammonium hydroxide | rec'd std. 50 ppm | | eye-irritant | Alkaline flooding |
| Acrolein | TLV 0.1 ppm | | ihl-irritant | Bactericide |
| Alkyl dimethyl benzyl ammonium chloride | $LD_{LO}$ 50 mg/kg | | | Bactericide |
| Alkyl dichlorophenol (2,4) | $TD_{LO}$ 312 ($\mu$g/kg) | positive | skin | Bactericide; fraction micellar |
| Ammonium chromate | | | | Cosurfactant |
| Alkyl phenoxypolyether | $LD_{50}$ 2140 mg/kg | | orl, skin (rat) | Surfactant |
| Alkyl benzene sulphonates: | | | | |
| p-n alkyl | $LD_{50}$ 1850 mg/kg | | orl (rat) | Surfactant |
| linear alkyl | $LD_{50}$ 650 mg/kg | | orl (rat) | |
| Alkyl ortho xylene sulphonate | $LD_{LO}$ 500 mg/kg | | ipr (mus) | Surfactant |
| Acrylamide copolymer | TLV 0.3 $mg/m^3$ | | skin | Mobility control agent |
| Acrylamide homopolymer | | | | Mobility control agent |
| Acrylic acid | DOT label: Corrosive | | | Surfactant additive |
| Alkyl aryl naphthenic sulphonate | | | | Surfactant |
| Alpha olefin sulphonate | | | | Surfactant |
| Alkylene oxide (see Ethylene oxide, Methylene oxide) | | | | Surfactant |
| Benzene | TLV 25 ppm | neoplastigen | ihl-bld | Fraction micellar slug |
| n-Butanol | TLV 150 ppm | | ihl | Cosurfactant |
| Benzyl alcohol | $LD_{LO}$ 500 mg/kg | | orl | |
| | $LC_{50}$ 1000 ppm/8 h | | ihl (rat) | Cosurfactant |
| Cresol (hydroxytoluene) | TLV 5 ppm | neoplastigen | skin | Cosurfactant |

TABLE 30 GENERAL TOXICITY DATA FOR CHEMICALS PROPOSED FOR USE IN ENHANCED OIL RECOVERY (Wilson & Kendall, 1980) (cont'd)

| Compound | Toxicity Data | Carcinogen/ Response | Route of Exposure* | Major Use |
|---|---|---|---|---|
| Cyclohexanol | TLV 50 ppm |  | ihl-irritant | Cosurfactant |
|  | $TC_{LO}$ 75 ppm |  |  |  |
| Calcium sulphate | TLV 10 $mg/m^3$ |  | ihl | Bactericide |
|  | $TD_{LO}$ 194 $g/m^3$/10 years |  |  |  |
| Cadmium | TLV 0.05 $mg/m^3$ | positive | ihl | Bactericide |
| Carboxymethylcellulose | (nontoxic) 2700 mg/kg |  | orl (rat) | Mobility control agent |
| Carboxypolymethylene (Carboxyvinyl polymer) | (nontoxic) 2700 mg/kg |  | orl (rat) | Mobility control agent |
| Calcium chloride | TLV 10 $mg/m^3$ |  | orl, ihl | Alkaline flooding |
| Cyclohexanone | TLV 50 ppm |  | ihl-irr | Fraction micellar slug |
| Citric acid | $LD_{50}$ 11700 mg/kg |  | orl (rat) | Fraction micellar slug |
| Cyclohexane | TLV 300 ppm |  | orl | Fraction micellar slug |
| p-Chloroaniline sulphate laurate |  | positive |  | Surfactant |
| Cocodimethylbenzyl ammonium chloride |  |  |  | Bactericide |
| Decane |  |  |  | Fraction micellar slug |
| Dodecane |  |  |  | Fraction micellar slug |
| Alkyl dimethyl quaternary ammonium chlorides |  |  |  | Surfactant |
| Ditetradecyl dimethyl ammonium chloride |  |  |  | Surfactant |
| Dodecyl trimethyl ammonium chloride |  |  |  | Surfactant |
| Decyl benzyl sulphonic acid | $LD_{50}$ 2000 mg/kg |  | orl (mus) | Surfactant |
| Dihexyl sodium succinate |  |  | ? | Surfactant additive |
| Diethyleneglycol sulphate | $LD_{50}$ 1000 mg/kg |  | orl (rat) | Surfactant |
| n-Dodecyl-diethyleneglycol sulphate | $LD_{50}$ 1000 mg/kg |  | orl (rat) | Surfactant |
| Dodecyl benzene sulphonate | $TLm_{96}$ 100-10 ppm |  |  | Surfactant |
| Diphenol picrylhydrazine |  | positive |  | Combustion |
| Dimethyl hydrazine | TLV 0.5 ppm | neoplastigen | skin | Combustion |
| Diethylenetriamine | TLV 1 ppm<br>$LD_{LO}$ 500 mg/kg |  | skin | Combustion; bactericide |
| Decanol (nonyl carbinol) | 75 mg/3D-I | neoplastigen | skin | Cosurfactant |

TABLE 30 GENERAL TOXICITY DATA FOR CHEMICALS PROPOSED FOR USE IN ENHANCED OIL RECOVERY (Wilson & Kendall, 1980) (cont'd)

| Compound | Toxicity Data | Carcinogen/ Response | Route of Exposure* | Major Use |
|---|---|---|---|---|
| Diisobutylphenoxyethoxyethyl dimethyl benzyl ammonium chloride | $LD_{LO}$ 50 mg/kg | neoplastigen | orl, eye | Surfactant |
| Dextrans | (nontoxic) | | | Mobility buffer |
| Deoxyribonucleic acid | (nontoxic) | | | Mobility buffer |
| Ethanol | TLV 1000 ppm | teratogen tests in progress | ihl | Cosurfactant |
| Ethylene oxide | $LC_{LO}$ 4000 ppm | possible | ink | Demulsification |
| Ethanolamines | TLV 3 ppm; DOT: corrosive | | | Demulsification |
| Ethylenediamine | $TC_{LO}$ 200 ppm, TLV 10 ppm | | ihl-irr | $CO_2$ removal |
| EDTA | 2000 mg/kg 7-14 d | teratogen | orl (rat) | Preflushing agent |
| Glycerol | $LD_{50}$ 1260 mg/kg | | orl | Mobility control agent; fraction micellar slug |
| Glyoxal (40%) | $LD_{50}$ 7070 mg/kg | | orl, skin | Surfactant |
| Guar Gum | $LD_{50}$ 9400 mg/kg | | orl (rat) | Mobility buffer |
| Glycerol disulphoacetate monomyristate | (low) | | | Surfactant |
| Glutaraldehyde | TLV 2 ppm | | skin | Bactericide; cosurfactant |
| Furfuryl alcohol | TLV 5 ppm | | skin | Cosurfactant |
| Fusel oil | 12500 mg/kg 5 d | mutagen | orl,scu (mus) | Cosurfactant |
| Formaldehyde | TLV 2 ppm | neoplastigen | ihl-irr | Bactericide; cosurfactant |
| Fluoride solutions | DOT: Poison & Oxidizers | | | Preflushing agent |
| 1-hexanol | $LD_{LO}$ 500 mg/kg | | orl, rat | Cosurfactant |
| 2-hexanol | | | | Cosurfactant |
| Heptanol | $LD_{50}$ 3250 mg/kg | | orl, rat | Cosurfactant |
| Hydroxyethylcellulose | | subcutaneous implant tumors | | Mobility control agent |
| Hydrazine | TLV 1 ppm | positive | skin | $O_2$ scavenger; combustion |
| Hydrogen peroxide | TLV 1 ppm; DOT: oxidizer | | ihl | Alkaline flooding; combustion |
| Hexadecyltrimethyl ammonium chloride | | | | Surfactant |
| Hexadecylnaphthalene sulphonate | $LD_{50}$ 2320 mg/kg | | orl, rat | Surfactant |
| Hydroxyalkylsulphonate | | | | Surfactant |
| Heptane | | | | Fraction micellar slug |
| Isobutyl methacrylate | 420 mg/kg | teratogen | ipr (rat) | Surfactant |
| Isoquinoline | 350 mg/kg | | orl, skin | Alkaline flooding |
| Isobutanol | 500 mg/kg | positive | orl, skin | Cosurfactant |

TABLE 30 GENERAL TOXICITY DATA FOR CHEMICALS PROPOSED FOR USE IN ENHANCED OIL RECOVERY (Wilson & Kendall, 1980) (cont'd)

| Compound | Toxicity Data | Carcinogen/ Response | Route of Exposure* | Major Use |
|---|---|---|---|---|
| Isopentanol | TLV 100 ppm | positive | ihl-irr | Cosurfactant |
| Isopropanol | TLV 400 ppm | | ihl-irr; skin | Cosurfactant |
| Lauryl polyethoxy sulphate | (low) | | | Surfactant |
| Lithium hydroxide | | | | Steam flooding |
| Magnesium | | | | Bactericide |
| Manganese | | | | Bactericide |
| Monosaccharide | | | | Mobility control agent |
| n-Methyltaurine oleamide | | | | Surfactant |
| Monobutylphenyl phenol sodium sulphate | | | | Surfactant |
| Morpholine stearate | | | | Surfactant |
| Methyl methylacrylate | TLV 100 ppm | | ihl-CNS, irritant | Surfactant |
| Methyl acrylate | 75 ppm | | ihl-irritant | Surfactant |
| p-Nonyl phenol | $LD_{50}$ 1620 mg/kg | | orl (rat) | Cosurfactant |
| Nitrilotriacetic acid | $LD_{50}$ 1470 mg/kg | neoplastigen | orl (mus) | Fraction of micellar slug |
| Nitric Acid | TLV 2 ppm; DOT: Oxidizer and Corrosive | | | Combustion |
| Nitrogen oxide | TLV 25 ppm; DOT: Anesthetic gas | teratogen | ihl (rat) | Combustion |
| Octadectoluene sulphonate | | | | Surfactant |
| Octane | | | | Fraction of micellar slug |
| Methyl nonyl ketone | $LD_{50}$ 5000 mg/kg | | | |
| Methyl ethyl ketone | $LD_{50}$ 5000 mg/kg | | | Fraction of micellar slug |
| Oxyethyl cellulose | | | | Mobility buffer |
| 1-octanol | $LD_{50}$ 790 mg/kg | | orl, skin | Cosurfactant |
| 2-pentanol (amyl alcohol) | 500 mg/24 h | | skin, eye, orl; moderate to severe effects (rodents) | Cosurfactant |
| Phenol | TLV 5 ppm | positive | skin | Cosurfactant, biocide |
| Pentadecyl phenol | | | | Cosurfactant |
| Pentane | TWA 1000 ppm | | ihl-CNS | Fraction of micellar slug |
| Propane | TLVA 1000 ppm | | ihl | Fraction of micellar slug |
| Potassium permanganate | $TD_{LO}$ 2400 g/kg/d | | | Fraction of micellar slug |
| Potassium chromate | TLV 100 g | possible | orl, ihl | Fraction of micellar slug |

TABLE 30 GENERAL TOXICITY DATA FOR CHEMICALS PROPOSED FOR USE IN ENHANCED OIL RECOVERY (Wilson & Kendall, 1980) (cont'd)

| Compound | Toxicity Data | Carcinogen/ Response | Route of Exposure* | Major Use |
|---|---|---|---|---|
| Polyoxyethylene | $LD_{50}$ 7460 mg/kg | | orl (rat) | Fraction of micellar slug; Cosurfactant; Mobility - control agent; Demulsification |
| Polyglycerol monolaurate | (nontoxic) | | | Surfactant |
| Phenyl ethanol | $LD_{LO}$ 500 mg/kg<br>$LD_{50}$ 1790 mg/kg | | | Cosurfactant |
| Polyoxyethylene aryl phenol | | | | Surfactant |
| Pentaerythritol monostearate | TLV 10 mg/kg | | | Surfactant |
| Polyethoxyalkylthiol | | | | Surfactant |
| Polybutenesulphonate | | | | Surfactant |
| Polyethylene glycol | $LD_{LO}$ 5000 mg/kg | | orl | Mobility control agent |
| Polyacrylamide | (low toxicity) | | | Mobility control agent |
| Polyacrylaride | (low toxicity) | | | Mobility control agent |
| Phenoxypolyethoxy ethanol | $LD_{50}$ 2140 mg/kg | | orl (rat) | Mobility control agent |
| Paraformaldehyde | $LD_{LO}$ 50 mg/kg | | skin-severe | Bactericide |
| Pentachlorophenol | TLV 500 μg/m | neoplastigen | skin | Bactericide |
| Polyisobutylene in benzene | (high) | possible | | Mobility control agent |
| Quinoline | 10 mg/24 h | neoplastigen | skin-mild<br>eye-severe<br>orl-carcinogen | Alkaline and thermal floods; biocide |
| Sodium lauryl sulphonate | | | | Surfactant |
| Sodium sulphate oleylethanilide (tallow amine) | (Low) | | | Surfactant |
| Sodium glyceryl monolaurate sulphate | | | | Surfactant |
| Sulfur trioxide | DOT: Corrosive | | | Surfactant additive |
| Styrene copolymer | $LC_{50}$ 120 mg/m$^3$/10M | neoplastigen | ihl (mus) | Surfactant |
| Sodium hydrosulphite | $LD_{LO}$ 500 mg/kg | | ihl-irritant | $O_2$ scavenger; surfactant additive |
| Sodium hypochlorite | DOT: Corrosive | | | Bactericide |
| Sodium sulphate | $LD_{50}$ 5989 mg/kg | | orl (rodent) | Fraction micellar slug |
| Sodium chloride | $LD_{LO}$ 500 12357 mg/kg 23D | | orl-ipr | Fraction micellar slug |

TABLE 30 GENERAL TOXICITY DATA FOR CHEMICALS PROPOSED FOR USE IN ENHANCED OIL RECOVERY (Wilson & Kendall, 1980) (cont'd)

| Compound | Toxicity Data | Carcinogen/ Response | Route of Exposure* | Major Use |
|---|---|---|---|---|
| Sodium nitrate | $LD_{LO}$ 500 mg/kg | | orl | Electrolyte |
| Sodium silicate (orthosilicate) | $LD_{50}$ 1600 mg/kg | | orl (rodents) | Alkaline flooding |
| Sodium carbonate | $LD_{LO}$ 4000 mg/kg | | orl (rat) | Alkaline flooding |
| Sodium borate | $LD_{LO}$ 500-709 mg/kg | | orl-mild toxic effects | Alkaline flooding |
| sec-Butanol | TLV 150 ppm | | ihl | Cosurfactant |
| Sorbitan fatty ester | $TD_{LO}$ 49 g/kg/40M-I | | scu | Cosurfactant |
| Sodium bisulphite | $LD_{LO}$ 500 mg/kg | | orl | Alkaline flooding; $O_2$ Scavenger |
| Sodium hydroxide | TLV 2 mg/m$^3$/15 min | | ihl | Alkaline flood; preflushing agent; bactericide; electrolyte; thermal floods |
| Sodium dichlorophenol | | | | Bactericide |
| Sodium pentachlorophenol | $LD_{50}$ 210 mg/kg | | orl (rat) | Bactericide |
| Triethyl borane | $LD_{50}$ 235 mg/kg<br>$LC_{50}$ 2800 mg/m3 | | orl<br>ihl | Bactericide<br>Combustion |
| Triethyl aluminum | | | | Combustion |
| Toluene sulphonic acid | | | | Surfactant |
| Tridecylbenzyl sulphonate | | | | Surfactant |
| Triethanolamine laurate | 5000 mg/kg | | orl | Surfactant |
| Triethanolamine myristate | | | | Surfactant |
| Triethanolamine oleate | 5000 mg/kg | | orl | Surfactant |
| p-Toluidine sulphate laurate | | | | Surfactant |
| Toluene | TLV 100 ppm | CNS | skin | Fraction of micellar slug |
| Tallow amines | $LD_{50}$ 1850 mg/kg | | orl (rat) | Surfactant |
| Xylidine | TLV 5 ppm<br>$LD_{50}$ 50 mg/kg | | skin | Combustion |
| Xylene | 100-ppm/10 min | | ihl, irr | Surfactant |
| Xylene sulphonate | | | | Surfactant |
| Xanthan gum | (low) | | | Mobility control agent |

* Unless otherwise noted in "Route of Exposure" column, data is human health data.

TLV = threshold limit value
$LD_{50}$ = lethal dose for 50% mortality
$LD_{LO}$ = lowest reported concentration causing death
$TD_{LO}$ = lowest reported concentration for a specific toxic effect

TABLE 31 PRIMARY ENVIRONMENTAL CONCERNS ASSOCIATED WITH EOR (BY PROCESS)*
(Wilson and Kendall, 1980)

| Waste Component | Steam Injection | *In Situ* Combustion | Micellar-Polymer | $CO_2$ Injection |
|---|---|---|---|---|
| Air | $SO_2$, $NO_x$, AND TSP EMISSIONS FROM STEAM GENERATORS<br><br>Wellhead emissions of HC | HC and CO emissions from wells<br><br>$SO_2$, $NO_x$, TSP emissions from air compressors | Fugitive emissions from on-site manufacture of chemicals | Leaks of $CO_2$ in process use or transport<br><br>$H_2S$ emissions from wells |
| Water Use | SIGNIFICANT WATER DEMAND | Moderate water demand in wet combustion process | SIGNIFICANT WATER DEMAND | SIGNIFICANT WATER DEMAND |
| Water Effluents | DISPOSAL OF PRODUCED WATER | DISPOSAL OF PRODUCED WATER<br><br>Aquifers contamination from low pH water with trace metals resulting from corrosion of well casings | AQUIFER CONTAMINATION FROM INJECTED CHEMICALS<br><br>DISPOSAL OF PRODUCED WATER<br><br>Spills/leaks of chemicals to surface waters | DISPOSAL OF PRODUCED WATER<br><br>Aquifer contamination from low pH water and corrosion of well casings |
| Solid Waste | Disposal of scrubber sludges<br><br>Disposal of water treatment wastes | Disposal of wastes from wellhead gas cleaning<br><br>Disposal of water treatment wastes | Disposal of wastes from on-site chemical manufacture<br><br>Disposal of water treatment wastes | Disposal of water treatment wastes |

* Capital letters indicate major environmental issues according to Wilson and Kendall.

The environmental hazards associated with the subsurface disposal of the liquid waste will depend largely on the position of the disposal formation within the total hydrogeological regime, the modifications to the regime caused by the injection pressures, the volume of the waste, toxicity, attenuation of waste products, etc. Without comprehensive knowledge of all the site-specific parameters of a deep well wastewater disposal operation it is difficult to assess what the long-term environmental impact, if any, will be.

In terms of the terrestrial environment, acid rain, resulting from various different types of emissions (wellheads, compressors, boilers, processing facilities, etc.), but primarily from EOR combustion processes, could become a problem. The technology to minimize atmospheric contamination is available and stack scrubbers and precipitators will have to be used extensively. Also, some authorities claim that the use of oxygen instead of air can minimize the formation of hydrogen sulphide and sulphur dioxide from combustion processes for high-sulphur heavy crudes. During the processing of the recovered oil, semi-solid and solid wastes will be generated at various points within the process. EOR-related solid wastes undoubtedly will contain hazardous and/or toxic substances which would present problems for their disposal in the terrestrial environment (Riedel et al, 1981).

Several of the chemicals used during EOR processes are hazardous and/or toxic (Schumacher, 1978; Silvestro, 1980). Direct release of those chemicals into the environment could have significant effect and great care should be taken to prevent this from happening. Contingency procedures for handling spills of these chemicals under all climatic conditions should be part of the operating practices.

Very little information has been published on the mass balance of the chemicals used in the various processes nor on their possible alteration during their process path. Environmental impact therefore cannot be accurately assessed.

One area which warrants further discussion with respect to enhanced oil recovery processes is the Lloydminster heavy oil field area of Alberta and Saskatchewan. Although the future development of this field does not follow the standard format for enhanced oil recovery (i.e., tertiary recovery preceded by secondary and primary), the processes that will be used (steam stimulation and/or wet combustion) are classified as enhanced recovery processes. For these processes to operate properly a densely spaced network of production wells and steam injection wells will be necessary. The exact pattern of production wells and steam injection wells would be determined by pilot studies and the distribution of the heavy oil in the sediments of the Manville group.

A typical steam injection heavy oil field would comprise a central processing facility, steam generators, storage tanks, waste disposal areas, and an interconnecting network of roads and pipelines. One of the major impacts of current heavy oil development methods will therefore be the impact on the terrestrial environment. The combination of closely spaced wells (a few hectares per production well with a central steam injection well for each group of production wells) and an integrated network of roads with pipeline rights-of-way will severely limit other land use, especially if development takes place on agricultural land. Grain farming of the small areas between the roads and the different leases would be highly inefficient. It may, however, be possible to use it for cattle by seeding the grain land to pasture and fencing large tracts of the field. If this is not possible, then the land will have to be taken out of production for the life of the development. The magnitude of the land use changes could be reduced by clustering or aligning well heads and directionally drilling to the subsurface target(s) so that as much agricultural land could be returned to productivity as possible.

North and west of Lloydminster the land is generally wooded. Development of heavy oil production in these areas would result in deforestation to various degrees. It may be possible, by careful layout of the well field, to provide sufficient cover to minimize the disturbances to the wildlife community. Clearing in forested areas will also increase surface runoff which, depending on the surface drainage characteristics of the area, could cause siltation of lakes and sloughs, and/or increase the sediment load in the streams. A positive aspect of the clearing (partial or complete) would be that, once production has ceased and the field is abandoned the area can be used for cattle grazing.

The efficient extraction of heavy oil requires that a large number of wells be drilled. Each site will require sump solids and drilling fluid disposal. Land spreading of drilling fluid could become a problem because of the proximity of the wells, especially if the drilling fluid contains appreciable amounts of dissolved salts. Drilling fluid volume is estimated at between 40 and 75 $m^3$ per site depending on hole diameter (Table 12), and cutting volume per hole, depending on hole diameter (Table 13), is estimated at 20 to 35 $m^3$. Because of the potential for long-term pollution of groundwater associated with a large number of point sources (buried sumps), and the total surface area required for safe land disposal of the liquid wastes in combination with the proximity of the individual wells, it may be advisable to consider central disposal of the cuttings in an appropriate hydrogeological environment and re-use of the mud after proper cleaning and conditioning. This would minimize the possible environmental impact of sump disposal and land spreading at each well site. Mud volumes for heavy oil wells are such that it should be possible to design a self-contained system with no disposal at any one site. Depending on the type of mud system used and the content and type of soluble salts, the use of cuttings as fill in the roads should be investigated as an alternative cutting disposal method. More extensive use of air and foam drilling could reduce the impact of mud disposal and further research should be encouraged in this area.

Deep well injection appears to be the safest method for ultimate disposal of produced wastes. The disposal formation should be well below the producing beds. In terms of containment this formation should be below the Prairie Evaporite formation of the Middle Devonian age. There is, however, some question about the integrity of the Prairie Evaporite formation as a confining layer because of its removal by salt dissolution in places and subsequent collapse of the overlying beds in the cavities (Christiansen and Whitaker, 1974). The collapse has undoubtedly resulted in the creation of areas with a considerable number of vertical fractures along which upward migration could occur if the hydraulic head distribution is altered significantly by the injection of wastewaters. Disposal volumes and injection pressures should therefore be kept to a minimum. In addition, any other toxic liquid waste generated during the processing of the heavy oil (water treatment residue, acids, spent chemicals, etc.) should be considered for deep well injection.

The sand produced from wells perforated opposite the hydrocarbon-bearing sands is invariably coated with a thin film of oil. Disposal of this sand into the terrestrial environment through methods such as road surfacing will mean direct introduction of hydrocarbons. Although the hydrocarbons are essentially immobile at the time of introduction, bacterial action will eventually break them down. Depending on the composition of the hydrocarbons and the diversity of the decomposing organisms, the breakdown will be complete or only partial. Release of partially decomposed hydrocarbons from the sand grains to the environment could present a serious problem. Trace metals contained in the hydrocarbons could also be released. Decomposition of the hydrocarbons by micro-organisms is environment specific, i.e., dependent on the presence of other organics, nutrients, etc., and time dependent. Similarly, the migration pattern and rate of migration in the shallow subsurface is a function of the hydrogeological environment and regime. This means that a specific disposal practice can be used for a long time before any pollutant transport becomes evident. Proper placement of the waste material in the hydrogeological environment to minimize migration becomes very important. The waste disposal site should be adequately monitored to provide for the earliest detection of contaminant movement. Given the volume of waste generated, attention should be given to research towards a central collection and disposal facility for treatment of produced sand waste.

Because of the instability of the sand in the disposal area, eolian transport could be significant. Adjacent lands could be affected to various degrees, depending on wind pattern and present use.

The presence of the sand in the oil will increase the operating costs and especially the maintenance cost of the facility. Abrasion rates on equipment and piping will be significant, which could, for example, increase the number of breaks in transmission lines and consequently the spills. Furthermore, the sand production in the well will alter the hydraulic characteristics in the area of the well bore, which undoubtedly will reduce the production efficiency of the well.

The large quantities of sand removed from the producing horizon could present another problem, namely subsidence. Under normal operating conditions in an oil field a replacement of crude oil by water and/or gas takes place in the pore spaces. In heavy oil production, in addition to the removal of the oil, part of the matrix is also removed. In other words, partial mining of sediment and heavy oil takes place in the producing beds. Depending on the spatial distribution of sediment removal in the subsurface, differential settlement of various degrees of the overlying beds may occur, which will alter the confining nature of these beds and result in drastic changes in the hydrological regime of the subsurface. If significant amounts of sediment are removed in the immediate vicinity of the wellbore, subsidence could affect the integrity of the wellbore cement, which could result in cross-formational flow. In areas where differential settlement in the subsurface is transmitted to the surface, a larger number of pipeline failures could occur because of the additional stress in combination with the abrasive character of the oil-sand mixture and normal thermal and climatic expansion and contraction.

At the present time sand production from the Lloydminster heavy oil fields varies from 0.5 to 10 percent of oil production, creating approximately 40 000 $m^3$/annum of oily sands for disposal (personal communication, Husky Oil). A small research programme is being run by Husky with other operators to develop improved waste oils and sands handling in the area.

It is apparent from the foregoing that sand production from wells should be minimized. This means that consideration should be given to the development and use of completion techniques that could reduce the inflow of sand. Greater effort should also be expended to develop appropriate methods of dealing with sand disposal in the Lloydminster heavy oil area.

The natural gas produced with the heavy oil may contain a small percentage of sulphur compounds. Regardless of the end use of the gas (flaring or used for steam production) the sulphur must be removed according to government regulations. The sulphur is generally stored and exposed to the atmosphere until it is shipped. It is therefore conceivable that some minor drifting of fine sulphur particles could occur onto adjacent land. Oxidation of the sulphur by bacteria would form sulphuric acid, which could cause soil acidification. The rate of this process depends largely on the buffering capacity of the soil.

The large number of wells and the vast network of pipelines in a relatively small area at Lloydminster increases the potential for oil and salt water spills compared to conventional oil fields. The seriousness of any of these spills will depend on the volume, composition, surface drainage characteristics and hydrogeological environment at the site of the spill. Proper monitoring and surveillance should limit the environmental impact.

# 6 IN SITU TAR SANDS PRODUCTION

## 6.1 Introduction

Hydrocarbons occur in the tar sands as bitumen that is immobile at normal reservoir temperatures. Therefore primary and secondary recovery from the tar sands is not feasible. Where the bitumen occurs at a very shallow depth, production is by surface mining followed by separation of the hydrocarbons from the reservoir sediment. Where the bitumen occurs below surface mining depths, production must be by processes that will be effective in situ. The in situ production processes that have been proposed are similar to the thermal enhanced oil recovery methods used for conventional heavy oil.

The total Canadian reserves of heavy oil and oil sands amount to 469 billion $m^3$ (Meyer and Dietzman, 1979), well in excess of conventional light and heavy oil reserves. This is clearly illustrated in Figure 46 where the amounts of reserves in conventional light and heavy oil are compared to the different heavy oil (bitumen) regions in Alberta. Figure 47 illustrates the approximate areas of light, medium, and heavy oil fields, as well as tar sands, in western Canada. This report only considers the potential impacts of in situ tar sand recovery projects. The impact of recovery by surface mining of tar sand is not discussed.

All in situ recovery schemes involve heating the bitumen to initiate flow. The main process is the so-called "huff and puff" method in which steam is injected to stimulate the reservoir. Then injection is stopped for a period while heat transfer continues in the reservoir. The cycle is completed by pumping from the wells until production declines to a certain level. This process is repeated until production is no longer economic. All in situ tar sands recovery methods require very dense well spacings because of the small radius around the individual wells that can be affected in a bitumen deposit.

In addition to "huff and puff", small pilot projects are evaluating other processes such as steam flood using continuous steam injection and oil production from separate wells (Figure 48), "combination of forward combustion and water flood" (COFCAW) methods, and combined steam and fireflood methods. Conceptual designs for recovery methods that involve initiating fracturing in the reservoir for better heat transfer or drilling horizontal injection and production wells from underground shafts or tunnels are also being evaluated but insufficient information is available to consider potential effects. Until more research is conducted it will not be known if the present

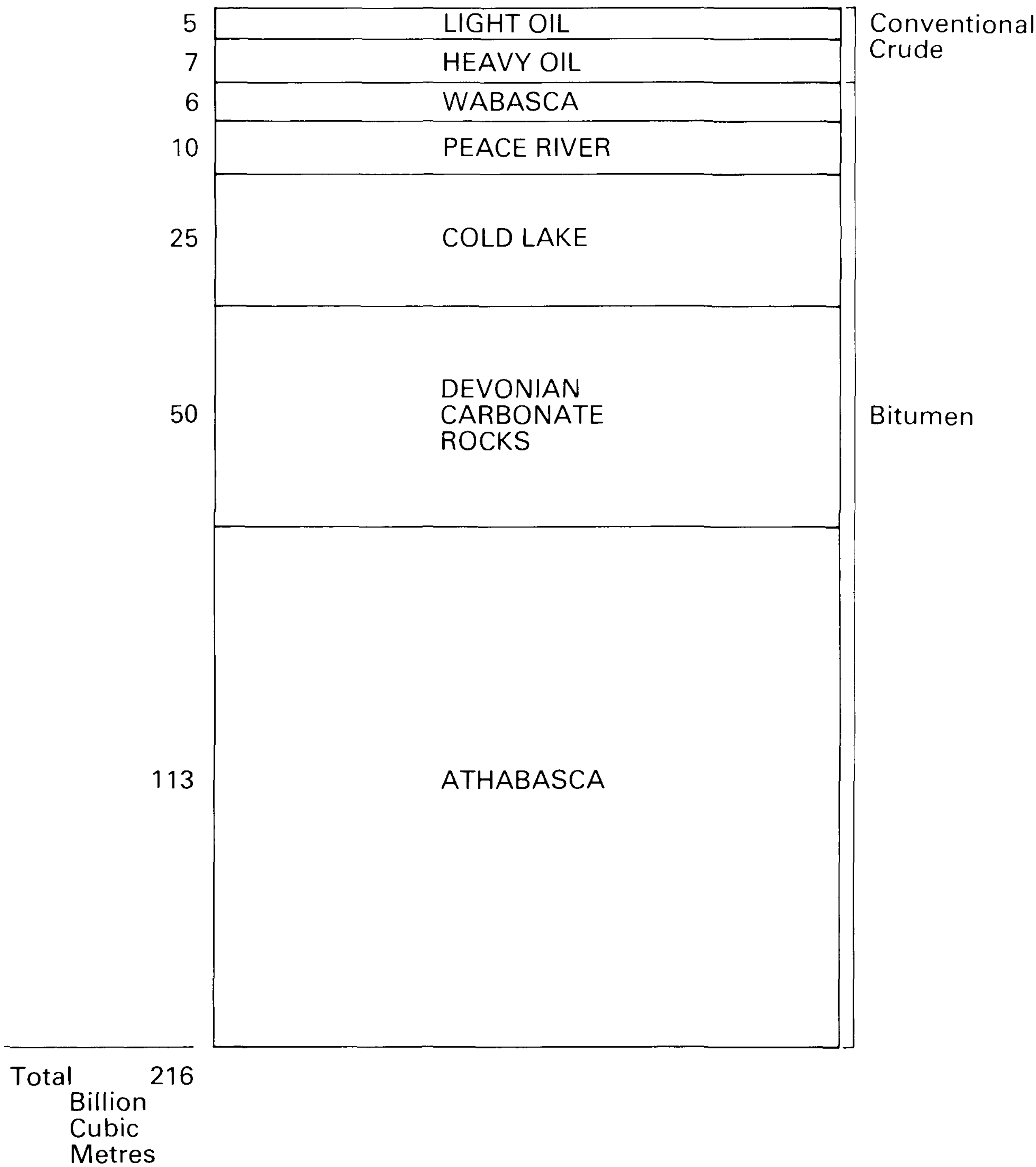


FIGURE 46 ALBERTA'S OIL RESERVES (Dugdale and Bartman, 1981)

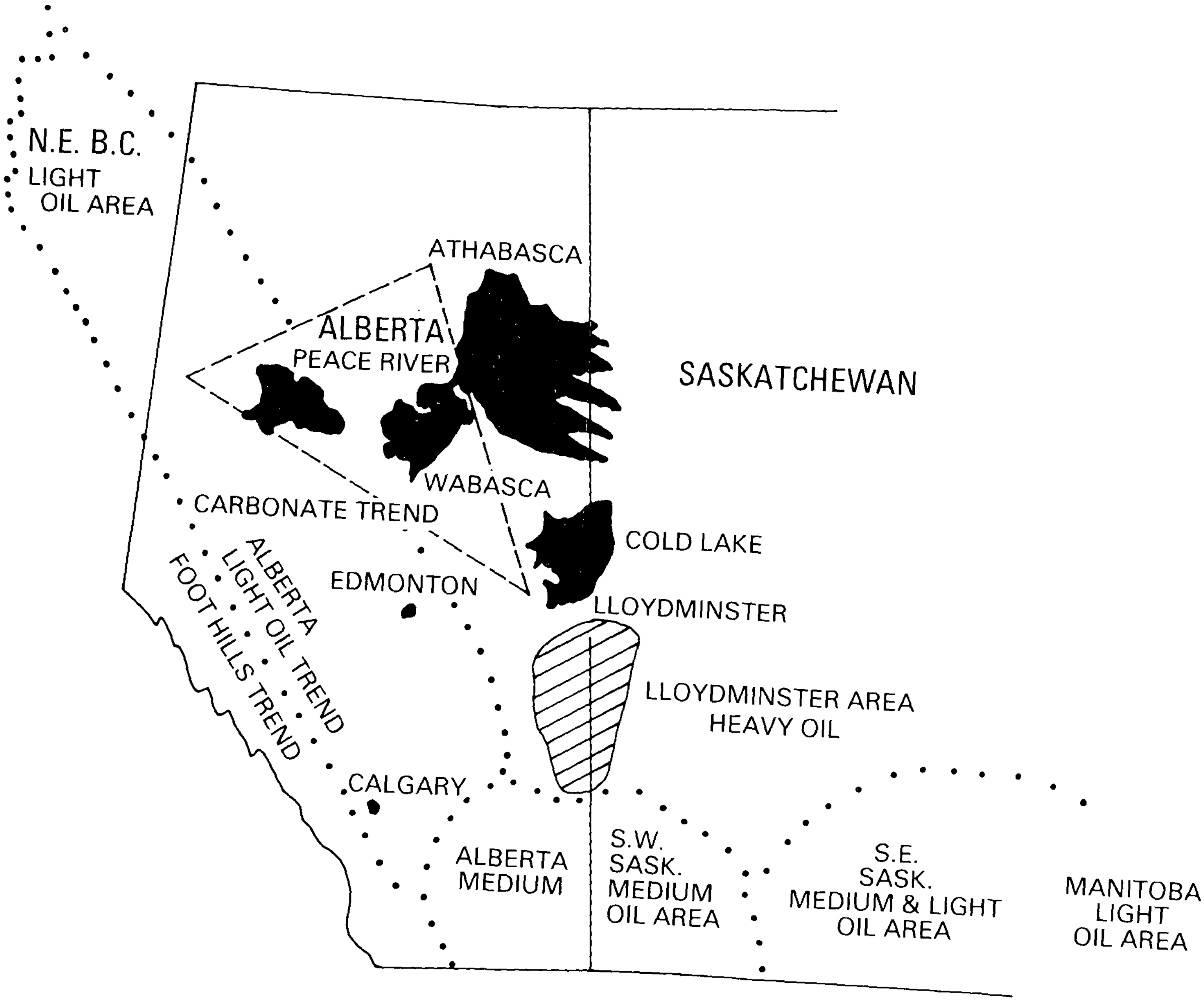


FIGURE 47 LOCATION OF VARIOUS TYPES OF OIL RESERVOIRS IN WESTERN CANADA

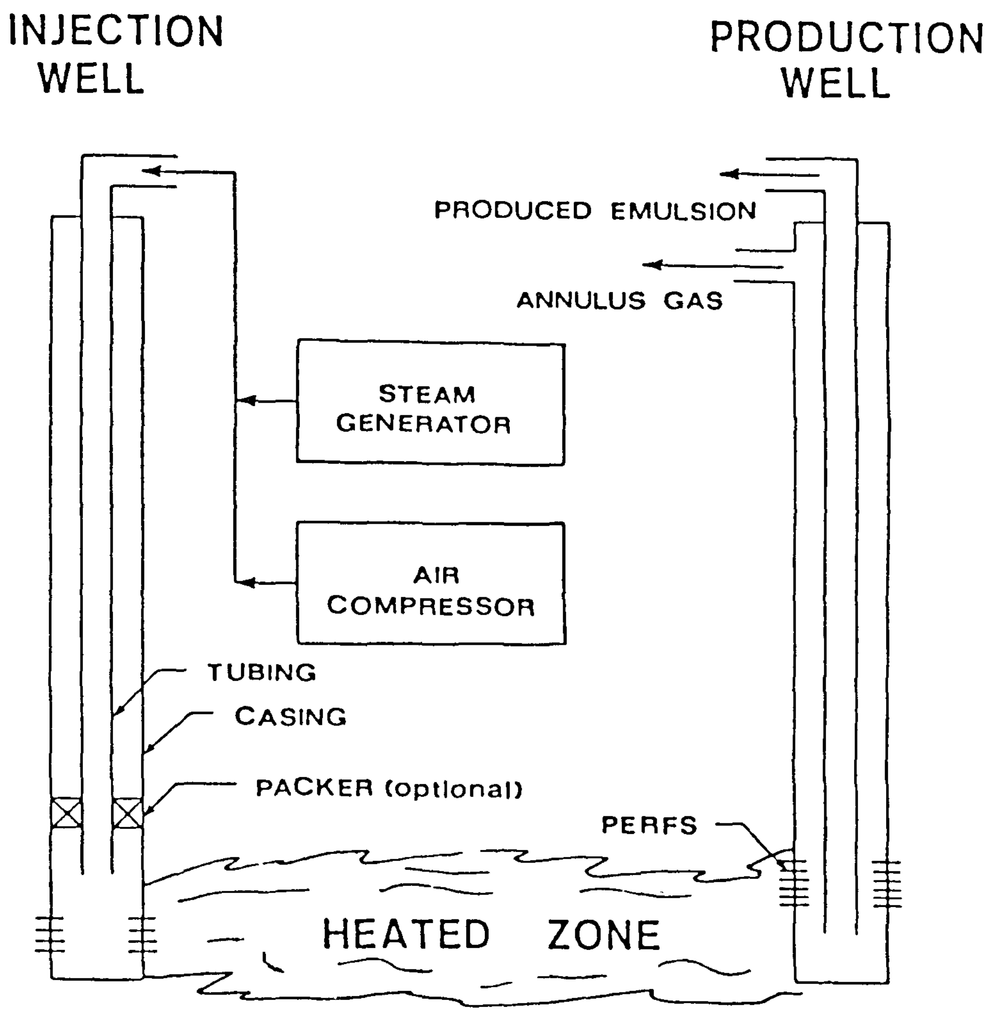


FIGURE 48 TYPICAL IN SITU RECOVERY PILOT
(Dugdale and Bartman, 1981)

estimates of water consumption and waste generation associated with any of the proposed recovery methods are appropriate.

Table 32 lists some of the pilot projects undertaken by industry with the support of the Alberta Oil Sands Technology and Research Authority (AOSTRA). Unfortunately, there is very little information in the literature on the water-related effects.

TABLE 32 AOSTRA IN SITU RECOVERY PILOT PROJECTS, ALBERTA (Dugdale and Bartman, 1981)

| Location | Process | Operator |
|---|---|---|
| Oil Sands | | |
| Athabasca | COFCAW (combustion-waterflood) | Amoco |
| Peace River | Steamflood | Shell |
| Cold Lake | Steam Stimulation Fireflood | BP |
| Carbonates | | |
| Buffalo Creek | Steam Stimulation Fireflood | Union |
| Heavy Oil | | |
| Viking Kinsella | Steamflood and Fireflood | Petro-Canada |
| Suffield | Fireflood | AEC |

In this report the potential impact of the "huff and puff" recovery scheme proposed for the Cold Lake project is discussed because it appears to be one of the more likely recovery schemes to be used and estimates of water use for steam generation and quantities of wastes requiring treatment and disposal are available. Although other in situ projects may differ from Cold Lake with respect to production techniques, water requirements and waste treatment, no information and data are widely available at present.

No specific provisions have been made in the provincial legislation or regulations for oil sands in situ recovery projects. Like all other "improved" or "enhanced" recovery schemes, in situ projects must be approved by the appropriate regulatory bodies.

## 6.2 Water-Related Aspects of In Situ Tar Sands Production

**6.2.1 Water Properties.** The chemical composition of produced water from several different pilot studies are reported in Tables 33 to 35.

Table 33 summarizes the characteristics of a wide variety of produced waters from heavy oil steam stimulation projects. The water produced at Cold Lake has relatively high oil concentrations; however, on the whole it appears to be similar to other produced waters. This table does not specify the dissolved organic concentrations in Cold Lake water, although several publications (Whalley and Wilson, 1979; Imperial Oil, 1978) have given the TOC as >30 mg/L. Tables 34 and 35 show that, at least in the case of fireflooding or combustion waters, the TOC can be near 10 000 mg/L.

Barbour and Guffey (1979) attempted to determine the nature of the TOC. In their work they identified a very wide range of organic molecules; examples of the more abundant of these molecules are as follows:

$C_6$ ketones
Dimethylpyridine
P - Cresol
Xylenol
Quinoline
1 - Propanol
Phenol
M-Cresol

It is worthwhile to note that, not unexpectedly, oxygenated and hydroxylated molecules are quite prominent in the above list.

Produced water from steam simulation studies at Esso's Leming Cold Lake Area pilot project was tested for fish toxicity by Tsui and McCort (1979). The analyses of water samples obtained by these researchers were similar to the values shown for Cold Lake in Table 33 except for the level of oil and grease (which was lower at 4.5 to 7 mg/L). In addition, Tsui and McCort obtained $NH_3$ and phenol analyses in the ranges of 10 to 22 mg/L and 11 to 38 mg/L, respectively. Tsui and McCort found that, in general, produced water was more toxic to fish than petroleum refinery wastewater or mine depressurization groundwater from the Fort McMurray tar sands area. Further research needs to be conducted with respect to the sources of this toxicity. Specifically, the type and effects

TABLE 33 A SURVEY OF MAJOR COMPONENTS IN PRODUCED WATER FROM STEAM STIMULATION PROJECTS ($CH_2M$ - Hill, 1981)

| Parameter | Esso Cold Lake Alberta | Suncor Ft. Kent Alberta | BP Marguerite Lake Alberta | Shell Peace River Alberta Cold Prod. | Shell Peace River Alberta Hot Prod. | Getty Oil Kern. River California | Texaco San Ardo California | Mobil S. Belridge California | Oil McKittrick California | Cat Canyon Field California |
|---|---|---|---|---|---|---|---|---|---|---|
| Ca (mg/L) | 48 | 290 | 100 | 48 | 156 | - | - | 188 | 109 | - |
| Mg (mg/L) | 5 | 40 | 30 | 143 | | - | - | 27 | 56 | - |
| Na (mg/L) | 1743 | 4 500 | 2500 | 11 007 | 2 252 | 215 | 2105 | 3 300 | 2500 | 1600 |
| Total Hardness (mg/L $CaCO_3$) | 141 | 890 | 374 | 709 | - | 132 | 162 | 580 | 503 | 41 |
| $CO_3$ (mg/L) | 15 | 0 | 0 | 300 | 0 | 15 | 0 | - | 45 | 0 |
| $HCO_3$ (mg/L) | 304 | 410 | 275 | 6 468 | 1 558 | 292 | 255 | - | 883 | 1281 |
| $SO_4$ (mg/L) | 111 | 525 | 175 | 22 | 379 | 53 | 410 | - | 180 | 150 |
| Cl (mg/L) | 3094 | 7 253 | 3850 | 13 348 | 2 569 | 199 | 2980 | 4 800 | 3517 | 788 |
| S (mg/L) | 40 | 0.01 | - | - | - | 0 | 10 | - | 0 | - |
| $NO_3$ (mg/L) | - | 0.34 | - | - | - | 0 | - | - | - | - |
| B (mg/L) | 10 | - | - | - | - | 1 | - | - | 15 | - |
| $SiO_2$ (mg/L) | 250 | 236 | - | 8 | 98 | 125 | 130 | 380 | 121 | 178 |
| Fe (mg/L) | 0.8 | 0.1 | - | 0.3 | < 0.1 | 0.1 | 1.0 | - | - | 0.3 |
| TDS (mg/L) | 6015 | 13 300 | 7300 | 31 349 | 7 009 | 844 | 6115 | 13 000 | 7 000 | 3 132 |
| pH | 8.0 | 8.1 | 7.0 | 8.6 | 7.1 | 8.3 | 6.8 | 7.2 | - | 8.2 |
| Conductivity (μ mhos/cm) | - | 17 000 | - | 50 000 | 11 100 | 1190 | - | 17 000 | 8360 | 4317 |
| Suspended Solids (mg/L) | 68 | 447 | - | - | | - | 69 | - | - | 130 |
| Oil (mg/L) (Insoluble or suspended oil) | 400-2000 | 220 | - | - | | 200 | 96 | 140 | - | - |

TABLE 34 AVERAGE WATER ANALYSIS FROM A FIREFLOOD EXPERIMENT ON ATHABASCA BITUMEN (Bennion et al, 1978)

The lowest concentrations usually correspond to the beginning of the burn.

| Parameter | Range in mg/L | | |
|---|---|---|---|
| pH | 1.1 | to | 7.1 |
| Sodium | 10 | to | 690 |
| Potassium | 20 | to | 270 |
| Calcium | 20 | to | 340 |
| Magnesium | 18 | to | 94 |
| Iron | 180 | to | 1200 |
| Chloride | 15 | to | 4700 |
| Sulphate | 270 | to | 12300 |
| Total Organic Carbon | 110 | to | 8700 |
| Total Dissolved Solids | 5800 | to | 30100 |

TABLE 35 WATER QUALITY ANALYSIS AFTER RESERVE COMBUSTION (Barbour and Guffey, 1979)

| Parameter | Range | | |
|---|---|---|---|
| Calcium | 0.2 | - | 12 |
| Magnesium | 0.0 | - | 1.7 |
| Sodium | 0.0 | - | 1.2 |
| Potassium | 0.0 | - | 1.6 |
| Carbonate | | -- | |
| Bicarbonate | | -- | |
| Sulphate | | - | 140.0 |
| Chloride | 8.8 | - | 170.0 |
| Fluoride | 2.1 | - | 11.0 |
| Ammonium | 41.0 | - | 790.0 |
| Total Nitrogen | 43.0 | - | 820.0 |
| pH | 2.5 | - | 4.0 |
| Chemical Oxygen Demand | 29000 | - | 42000 |
| Total Organic Carbon | 7970 | - | 12150 |

of organics in the produced water, and the effect and interactions of inorganic components should be examined.

**6.2.2 Water Handling.** The process flowsheet for the proposed Imperial Oil Cold Lake plant is shown in Figure 49. As shown in this figure, much of the produced water is to be recycled. The more polluted streams from the upgrading, as well as produced water recycling (utilities area), are to be injected into deep wells while some of the less polluted wastewaters are expected to be stored in surface ponds.

Table 36 shows the water balance for the whole project and identifies the specific volumes discharged to deep well or surface ponds. It is interesting to note that approximately 30 percent of total water used is to be obtained by recycle.

The process developed for water recycling is shown schematically in Figure 50. The key elements of this process are deoiling (by induced gas flotation), softening (by hot lime softeners) and deionization by ion exchange. The details of the technology developed for each of these steps have not been published by Imperial Oil or Esso Resources. Some personnel who worked on this project, however, have published papers which relate to some aspects of the processing steps. Konak and Grisard (1980) published a paper that shows significant improvements in deoiling by acidification (to pH 4.5). Similarly, Hawkins (1979) discussed the instrumentation of the water reuse pilot plant, and Whalley and Wilson (1979) presented a discussion of different recycle schematics.

In all water reuse schemes, the type of boiler chosen ultimately determines the cost and complexity of the water treatment scheme. Thus, if conventional high pressure boilers are used, a nearly complete deionization step is required prior to the boiler. On the other hand, if the thermo sludge boiler is used, water treatment chemicals are added directly to the boiler and very little pretreatment is required. At the present, most <u>in situ</u> systems are likely to use once-through 80 percent quality steam boilers which require only partial deionization (primary or partial divalent cation removal).

In general, there is little information published regarding the effectiveness or efficiency of water recycling processes presently in use. Problems may be encountered in the following treatment stages:

(i) Oil/water separation, especially in the case of emulsions.
(ii) lime softening (in particular when there is a high silica content) and lime sludge disposal.
(iii) ion exchange fouling due to organic content.
(iv) Boiler corrosion and associated piping.

Very high demands are placed upon the technology for recycling <u>in situ</u> water and, therefore, the likelihood of problems relating to the above areas may be high during the initial start-up phases.

If any treatment stage should fail, recycling would not be possible, and emergency treatment would be required prior to disposal to surface waters. Alternative

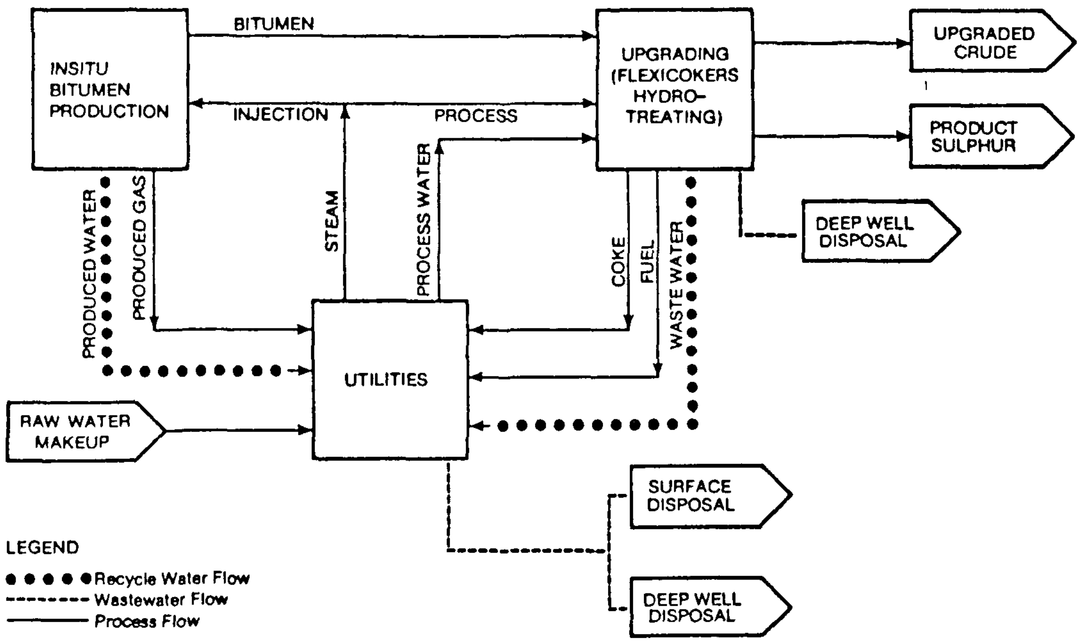


FIGURE 49 WATER FLOWSHEET AT THE PROPOSED COLD LAKE PLANT (Hrudey and Scott, 1981)

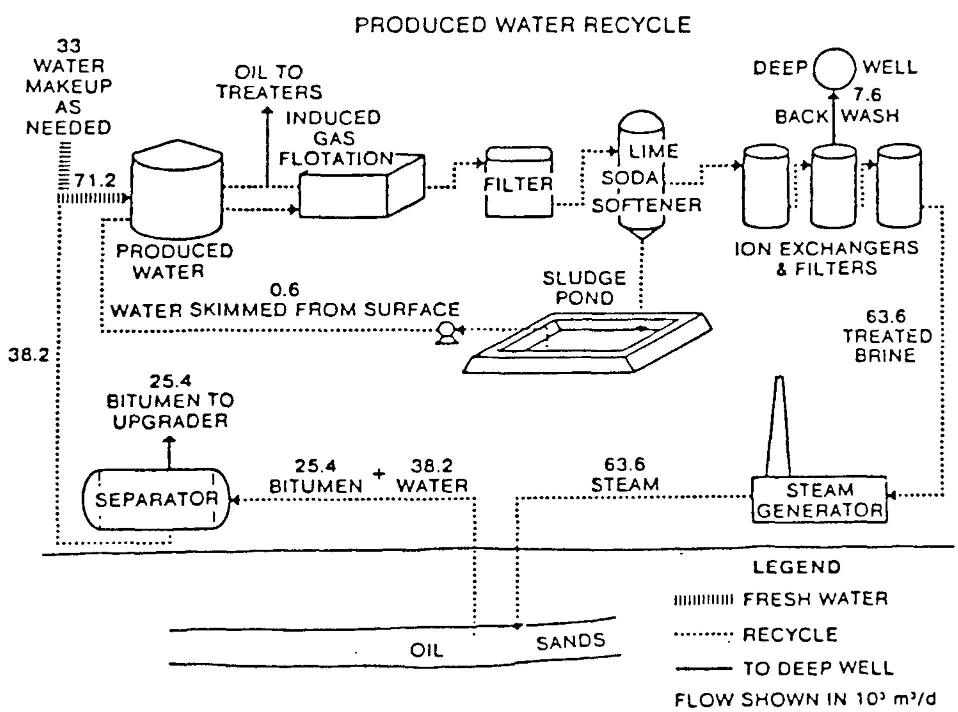


FIGURE 50 PROCESS SCHEMATIC FOR RECYCLE OF PRODUCED WATER FROM CYCLIC STEAM STIMULATION BITUMEN RECOVERY AT COLD LAKE (Imperial Oil, 1978)

TABLE 36 WATER BALANCE AT COLD LAKE (Imperial Oil, 1978)

| Water Requirements | $10^3$ $m^3/d$ |
|---|---|
| Injection Steam | 63.6 |
| Process Water and Steam | 19.7 |
| Cooling Tower | 25.8 |
| Water Treatment Backwash | 17.6 |
| Utility Water | 12.7 |
| Potable Water | 3.8 |
| Total | 143.2 |
| Consumed in Operations | |
| Displacing Bitumen | 25.4 |
| Cooling Tower Evaporation | 20.0 |
| Hydrogen Synthesis | 2.4 |
| Coke Gasification | 5.1 |
| Subtotal | 52.9 |
| Waste Disposal | |
| Deep Wells - | |
| Water Treatment Backwash | 7.6 |
| Sour Water | 2.4 |
| Desalter Brine | 2.4 |
| Chemical Wastes | 0.8 |
| Subtotal | 13.2 |
| Surface - | |
| Water Treatment Backwash | 10.0 |
| Cooling Tower Blowdown | 3.3 |
| Boiler Blowdown | 2.7 |
| Utility Water Waste | 10.7 |
| Subtotal | 26.7 |
| Recycled | |
| Produced Water | 38.2 |
| Sour Water | 4.4 |
| Sanitary Wastes | 3.8 |
| Oily Wastes | 4.0 |
| Subtotal | 50.4 |
| Total | 143.2 |
| Water Supply | |
| Recycled Water | 50.4 |
| Fresh Water Make-up | 92.8 |
| Total | 143.2 |

water disposal locations in the area may be insufficient. Research directed towards the development of recycling technology that is both technologically feasible and economically affordable is necessary. Also, the effect of produced water quality on the functioning of water treatment processes used in water recycling for in situ tar sands and heavy oil development should be further studied.

## 6.3 Environmental Impact

The environmental impact of an in situ bitumen recovery process can be divided into two broad areas:

i) physical recovery of bitumen, and
ii) processing of recovered bitumen and associated wastes

The environmental impact will be discussed primarily with respect to the Esso Cold Lake Project because, as previously mentioned, this is the only project with sufficient published information.

**6.3.1 Physical recovery of bitumen.** The areas where in situ recovery of the bitumen is presently planned are forested. The immediate impact on the environment will, therefore, be the clearing of the land for access roads, transmission lines, oil gathering pipelines, steam distribution pipelines, drilling pads, upgrading facilities, steam generating facilities, etc. Some of these disturbances will be permanent for the life of the project, such as the upgrading facility and main access roads, whereas other disturbances will be temporary and depend on the rate of recovery of bitumen at the site of extraction. For example, steam injection/production wells and associated infrastructures are temporary disturbances, because the area will be reclaimed and restored subsequent to abandonment.

The disturbance of the natural environment will undoubtedly have an effect on the wildlife and will change the species distribution pattern in the area. Whether this represents a serious environmental impact depends largely on the set of values, emotional versus economic, against which the disturbance is measured.

The "temporary" clearing for road and pipeline access to drill pads and subsequent production facilities appears to be the major source of surface impact because it will likely disrupt surface drainage to a certain extent and could result in flooding of bordering areas. Furthermore, the removal of surface vegetation will result in increased erosion until vegetation is established by re-seeding. The erosion, depending on the surface drainage characteristics of an area, could result in siltation of existing wet land areas, and/or increase the sediment load in existing drainage paths. Good housekeeping practices and environmental awareness during site selection and drilling should minimize this type of problem.

The extraction of the crude bitumen will require a dense network of wells. The environmental impact associated with this type of drilling is similar to heavy oil production.

According to Jackson (1979), the bitumen-bearing sands will be fractured during the steam stimulation at Cold Lake. Hydraulic fracturing of a formation, although it considerably improves the hydraulic conductivity of the formation, carries the inherent risk of causing damage to overlying and/or underlying beds (in other words, the integrity of confining beds may be seriously damaged). It is questionable whether fracture orientation can be controlled. Once a fracture has been initiated in the formation in the well bore, the hydraulic fracture will follow the path of least resistance which, based on theoretical considerations under the assumption of homogeneity, isotropy, and elasticity, will be perpendicular to the least compressive in situ principal stress (Grace et al, 1980). In areas where the stress imparted by the overburden is the greatest and, consequently, the stress in the horizontal plane is smaller, fractures induced by hydraulic fracturing tend to be vertical. However, in areas where differential compaction of the sediments has taken place, for example in the Cretaceous sediments in this area, the compaction frequently imparts principal stresses to rocks along various inclined or horizontal directions. Prediction of the orientation of hydraulically-induced fractures in these rocks is next to impossible, because the fracture orientation is dictated by the natural formation properties. There is little hope of forcing fracture initiation in any direction other than that dictated by the formation (Grace et al, 1980). The significance of the induced fractures will be explained further during the discussion of waste disposal practices.

It is not known if any sand will be produced with the crude bitumen during production. If the quantities are similar to those produced in the heavy oil production in the Lloydminster area, differential settlement can be expected, which will have an impact similar to that discussed in the section on enhanced oil recovery.

Breaks, accidental or as a result of mechanical failure, will undoubtedly occur. Their frequency could be considerably higher than in a conventional oil field because of the extensive network of pipelines necessary for in situ recovery. The environmental impact of a pipeline break will depend on the product carried by the pipeline, the volume spilled, and the environmental setting. Contingency planning should limit the environmental impact of a spill.

The injection of steam or any liquid at pressures exceeding the rupture pressure of the formation can cause low magnitude earthquakes or fracture movement in some areas. If a high incidence of this activity were to occur during the recovery of bitumen, fracturing of the confining beds could result. Similarly, the integrity of cement seals around casings could be affected. This would invite cross-formational flow, especially if the steam injection pressures are considered.

According to Jackson (1979), the water used during recovery and subsequent upgrading at Cold Lake will be surface rather than groundwater. The groundwater resources are considered insufficient, and would also require considerable treatment for use as boiler feed water. The total water requirements are in the order of 125 000 $m^3/d$.

**6.3.2 Processing of crude bitumen and wastes.** The liquid wastes generated during the recovery of the crude bitumen and its subsequent conversion to artificial crude are: production waters, oily wastewater, scrubber water, chemical wastewater, ash disposal water, blowdown water, water treatment wastewater, and sanitary wastes.

The solid and semi-solid wastes generated are: reactor sludges, chemical sludges, oily sludges, water treatment sludges, sand (possibly), fly ash, coke, catalysts, particulates from flue gas treatment, municipal waste, and other forms of semi-solid and solid wastes.

Little or no information is available on the anticipated composition and concentration of constituents in each group of waste, the bulk volume of each waste group, and the disposal methods (containment, monitoring, etc.). Discussion of the environmental impact of the waste disposal practices must, therefore, be restricted to those wastes for which some published information is available.

The liquid wastes generated, except sewage, will be disposed of by deep well injection. The waste stream will contain formation fluids, various dissolved hydrocarbons, trace metals, phenols and other organic compounds, cyanides, sulphites, water treatment chemicals, etc. (Jackson, 1979; Whalley and Wilson, 1979; Konak and Grisard, 1980). In other words, contaminated wastes which cannot be disposed of in the surface environment will be injected into a subsurface formation. According to Jackson (1979), about 80 000 barrels per day (13 100 $m^3$) of liquid waste from the Cold Lake Project will be injected. The disposal formation is the Lower McMurray formation. The McMurray formation immediately underlies the Clearwater formation which is the main bitumen-bearing formation (both are included in the Mannville group of the Lower Cretaceous Age;, see Figure 4). The disposal formation will be hydraulically fractured if the permeability is too low to accept the projected waste volume. A number of potential problems are associated with the deep well injection presently visualized:

i) Both the producing zone and the disposal horizon will be hydraulically fractured. Since no control can be exercised over the orientation of the fractures in either formation, cross-formation flow is a real possibility, which could result in contamination of shallow fresh formation water by waste liquids.

ii) The Cold Lake area is near the northern edge of the Prairie Evaporite formation (Simpson and Dennison, 1975). This edge is a subsurface erosional contact. East and north of this edge the salt beds have been removed by dissolution and the overlying beds have collapsed in the solution cavities. Extensive fracturing of the overlying beds has in all likelihood occurred, seriously jeopardizing the containment characteristics of confining beds.

iii) The injection pressures of 6 900 kPa (well head) are approximately twice the maximum recorded in Canada for waste injection (Vonhoff and van Everdingen, 1973). The high injection pressures in combination with the presence of fractures, natural or induced, could result in upward migration of waste products. Upward migration could also occur around improperly cemented disposal wells and/or exploration boreholes.

iv) The waste, once injected, could migrate in a northeasterly direction toward Saskatchewan because this is the regional groundwater flow direction. The rate of movement and the configuration of the waste plume would depend on the changes induced by the injection pressures on the existing groundwater flow regime. Detailed information on the hydrogeological environment will be required to provide the necessary answers on the long-term downstream effect of the waste injection.

v) No information is available on possible attenuation of the disposed waste. Studies on this aspect of the waste disposal should be conducted, because the groundwater flow is inter-provincial.

If the liquid waste is injected into a deeper formation, for example the Devonian Methy formation, many of the points raised above will apply. (Note: the Methy formation immediately underlies the Prairie Evaporite formation and is considered a good aquifer in this area.) As was described in Chapter 1, the major regional low fluid potential drain is situated within the Devonian carbonate sediments in this general area.

This drain discharges at the edge of the Pre-Cambrian shield in Saskatchewan. Numerous salt springs and seeps are present in that area. Liquid wastes injected into the Methy formation will in the future undoubtedly discharge along the edge of the Pre-Cambrian shield. The impact of the liquid waste will depend on its attenuation.

The foregoing discussion shows that the northeastern part of Alberta is not really suited for deep well disposal, because the disposal would be finite in this hydrogeological environment. Liquid waste generation should be reduced as much as possible by the maximum treatment and reuse of the produced water.

No major, high-volume rivers are present in the Cold Lake area. As discussed in Section 6.2 large volumes of slightly contaminated water will be stored in surface ponds. In the case of accidents, leaks or continual treatment equipment malfunctioning, a considerable volume of highly toxic wastewater could be intercepted by the integrated surface drainage of the plant site.

It appears that a considerable volume of solid and semi-solid waste will have to be disposed of over the life of the plant. The disposal most likely to be used is a landfill method, although incineration may be used as well. Siting of the actual landfills is going to be extremely important, because no sedimentary environment is impermeable over time. Emphasis should be placed on bacterial breakdown of the organic compounds and fixation by natural materials of the inorganic compounds. To provide the necessary biocommunity for complete breakdown, different types of wastes may have to be mixed, for example municipal and oily wastes, and nutrients added if necessary. If impermeable linings are used, drainage pipes should be installed below the linings for monitoring purposes and, if breakthrough of pollutants is observed, for the recovery of the pollutant.

The major air pollutants generated will be sulphur dioxide and hydrogen sulphide, contributors to acid rain. In addition, minor amounts of hydrocarbons and nitric oxides will be released by the plant. The immediate effect will be stress symptoms in the plant communities. Long-term effects of the major pollutants will be an increase in acidity of soils and standing water bodies. The impact of the acid rain will depend on the buffering capacity of the environment.

The greatest problem in assessing the impact of in situ crude bitumen recovery and subsequent processing of the recovered bitumen is the incomplete data base. Because of the uniqueness of the environment, the characteristics of the waste, and the long-term containment requirements, the design of the waste disposal method should be based on an evaluation of worst parameters only.

# 7 INFORMATION GAPS AND RESEARCH REQUIREMENTS

The potential environmental impact of oil and gas exploration activities and conventional oil and gas production activities are not only relatively well-known (if not always well understood) but also covered by comprehensive regulations that are well enforced by an established and experienced regulatory bureaucracy. Gaps in knowledge in these areas involve primarily the actual fate of some of the new complex chemical components in drilling additives following disposal of drilling fluids or abandonment of reclaimed sumps. In addition, the potential environmental damages from lost circulation and problems related to well completion are inadequately established.

Enhanced oil recovery and in situ tar sands recovery technologies have the potential for significant environmental impact, because the most feasible methods have a thermal component and produce considerable amounts of contaminated water. Furthermore, due to insufficient previous experience, regulations to prevent environmental damage from potential accidents have not yet been developed. These operations are concentrated in the heavy oil and tar sands areas of northeastern Alberta. The hydrocarbons occur at depths shallower than 1200 m and the entire sedimentary thickness is generally less than 1500 m. Furthermore, there is a complex intertonguing of saline and fresh water with the Mannville group (the major heavy oil producer). This groundwater, which may ultimately become a source of drinking water, could become contaminated during production.

In heavy oil production, the main environmental concerns are directed towards disposal of produced sand which is coated with a thin film of oil. In this regard research should address methods of reducing volumes of produced sand and the development of a central collection and disposal facility for the handling and treatment of the produced sand waste.

Thermal recovery processes require large volumes of fresh water for steam generation at a commercial scale, but if the water is obtained from aquifers, the pumping will have a major effect on hydraulic gradients, not only in the fresh water aquifers, but also in the producing formations. The processes are also estimated to generate large volumes of liquid wastes. If these wastes are injected to formations below the producing formations by deep well disposal, again there will likely be a major effect on hydraulic gradients in all formations in the region.

At present the regional hydrogeological framework is not well enough known to predict the interaction of the effects of production and disposal either with each other or with the existing gradients in the oil and bitumen bearing zones.

Laboratory experiments (Bennion et al, 1978) suggest that in situ combustion processes will likely produce formation fluids with very concentrated sulphuric acid and high organic content. The fate of these fluids in the flow system could be critical not only because they are potential pollutants of fresh water aquifers or surface waters but also because of their effects within the producing horizons.

In situ tar sands development will also require the recycling of a large quantity of produced water. The technology for recycling this water is not well known and serious technological problems are likely to be encountered, which in turn may lead to serious water consumption and environmental waste disposal problems. Research should be directed towards the development of water recycling technology that is both technically feasible and economically affordable. The effect of produced water quality on the functioning of water recycling treatment processes should be investigated. In addition, emergency treatment techniques should be developed to ensure adequate water quality control if spills or long term equipment failures were to develop.

The characteristics of wastewaters produced during all facets of oil and gas production, especially with regard to dissolved organics and associated toxicity, are poorly established and research should be undertaken to establish baseline data.

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