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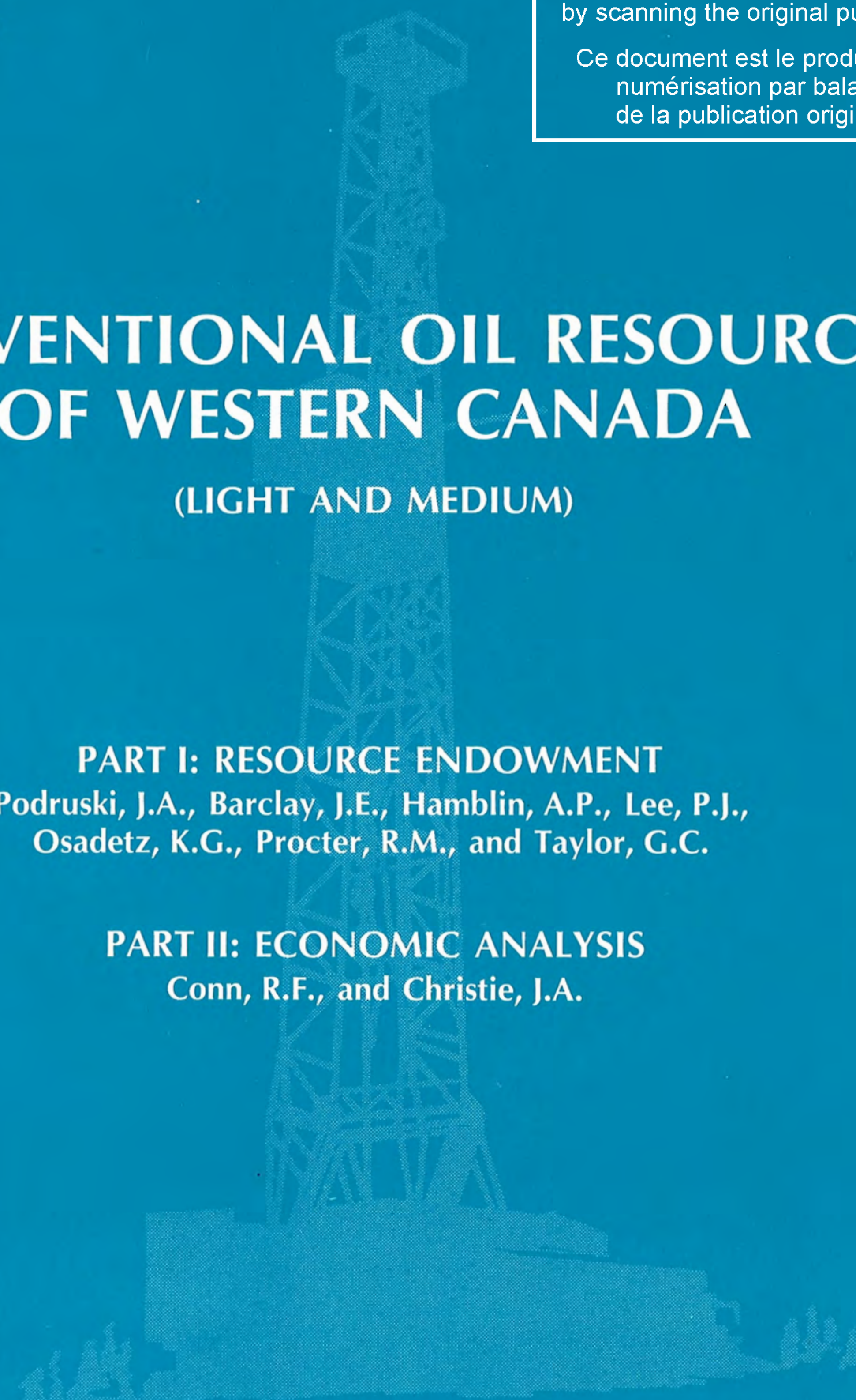

CONVENTIONAL OIL RESOURCES OF WESTERN CANADA

(LIGHT AND MEDIUM)

PART I: RESOURCE ENDOWMENT

Podruski, J.A., Barclay, J.E., Hamblin, A.P., Lee, P.J., Osadetz, K.G., Procter, R.M., and Taylor, G.C.

PART II: ECONOMIC ANALYSIS

Conn, R.F., and Christie, J.A.

Canada

1988

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PREFACE

The major oil discovery at Leduc in 1947 led to the development of a vital Canadian petroleum industry. Conventional oil from the Western Canada Sedimentary Basin has been the mainstay of the nation's oil supply ever since. However, conventional oil reserves are being depleted and there is a need to systematically estimate both the amount of undiscovered oil likely to remain in the basin and the economic conditions under which it may be found and developed.

Part I of this paper presents estimates of remaining conventional light and medium oil potential prepared in 1986 by the Geological Survey of Canada. It is a comprehensive analysis of the resource endowment of the region based upon extensive geological, technical and statistical analysis of both present production areas and regions still to be fully explored. This information is used to develop an estimate of future resources expressed in terms of probability.

Part II is an economic analysis coordinated by the Energy Commodities Sector of the Department of Energy, Mines and Resources Canada. It takes the information from Part I and determines the relationship between the wellhead price of oil and the long-term profitability of the undiscovered resources under a set of technical, cost and fiscal assumptions.

Assessments of the oil and gas resources of each of the major sedimentary basins of Canada are prepared on a regular basis by the Department of Energy, Mines and Resources Canada. These assessments provide timely objective analyses of Canada's oil and gas resources and form a basis for future supply planning. It is hoped that the information provided in this study will not only identify opportunities for exploration and development in western Canada conventional resources, but also contribute to the complex science of resource appraisal. The report will be of special interest to anyone who wants an overview of the geological basis for the exploration plays and a synopsis of their resources.

OTTAWA, July 1987

R.A. Price
Assistant Deputy Minister
Geological Survey of Canada

R.G. Skinner
Assistant Deputy Minister
Energy Commodities Sector

PRÉFACE

La découverte majeure de pétrole faite à Leduc en 1947 a mené à l'essor d'une industrie pétrolière Canadienne très prospère. Le pétrole conventionnel du bassin sédimentaire de l'Ouest canadien a toujours constitué depuis la principale source des approvisionnements en pétrole du pays. Toutefois, les réserves de pétrole conventionnel s'épuisent et il est nécessaire d'estimer de manière systématique les quantités de pétrole non découvert que renferme vraisemblablement encore le bassin ainsi que les conditions économiques dans lesquelles ce pétrole peut être découvert et exploité.

La partie I de la présente étude fournit l'estimation des ressources non découvertes de pétrole conventionnel léger et moyen, telle que préparée en 1986 par la Commission géologique du Canada. Il s'agit d'une analyse exhaustive des ressources de la région basée sur une analyse géologique, technique et statistique des zones actuelles de production ainsi que des régions non encore parfaitement explorées. Ces renseignements sont utilisés pour établir une estimation des ressources futures, exprimée en termes de probabilités.

La partie II est une analyse économique supervisée par le Secteur des ressources énergétiques du ministere de l'Énergie, des Mines et des Ressources du Canada. À partir des renseignements fournis dans la partie I, cette analyse établit la relation entre le prix du pétrole en tête de puits et la rentabilité à long terme des ressources non découvertes en fonction d'un ensemble d'hypothèses sur les méthodes, les coûts et la fiscalité.

L'évaluation des ressources pétrolières et gazières de chacun des principaux bassins sédimentaires du Canada est préparée sur une base régulière par le ministère de l'Énergie, des Mines et des Ressources du Canada. Ces évaluations fournissent des analyses opportunes et objectives des ressources pétrolières et gazières du Canada et constituent le fondement de la planification des approvisionnements futurs. Il est à espérer que les renseignements fournis dans la présente étude permettront non seulement de reconnaître les possibilités d'exploration et de mise en valeur des ressources conventionnelles de l'Ouest canadien, mais qu'ils contribueront de plus au perfectionnement de la science complexe de l'évaluation des ressources. Ce rapport présentera un intérêt particulier pour quiconque désire obtenir une vue d'ensemble de la géologie des zones pétrolières et un résumé de leurs ressources.

OTTAWA, juillet 1987

R.A. Price
Sous-ministre adjoint
Commission géologique du Canada

R.G. Skinner
Sous-ministre adjoint
Secteur des ressources énergétiques

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CONVENTIONAL OIL RESOURCES OF WESTERN CANADA

ABSTRACT

An examination of 78 established petroleum exploration plays and 49 conceptual plays of the Western Canada Sedimentary Basin formed the basis for new estimates of the remaining conventional light and medium oil potential (Part I). It is estimated that the established plays, in which about 2360 x 10^6 m^3 of recoverable oil have already been discovered, have an additional 509 x 10^6 m^3 (median value) of recoverable oil still to be discovered. An additional 61 x 10^6 m^3 (median value) are estimated to occur in conceptual plays that have not yet been successfully tested. The remaining potential is predicted to be dispersed in more than 4000 separate accumulations, most of which would be small relative to existing discoveries. These estimates were prepared without any economic constraints; Part II of this report attempts to identify the proportion of the potential that might be economically exploitable.

Estimates are presented of the long-term relationship between oil prices and western Canadian light-medium oil potential. The economic analysis deals only with long-term profitability, hence short-term economic conditions are not addressed. The marginal full-cycle case estimates profitability at the time an exploratory drilling decision is made. The half-cycle case does not consider any discovery costs. The study shows that 70% of the undiscovered light and medium oil resources may be profitable over the long-term at prices ranging from $CAN 94 to 142/$m^3$ ($CAN 15 to 22.50/bbl). The relationship of price and economic potential is relatively inelastic in this price range.

RÉSUMÉ

L'étude des 78 zones pétrolières prouvées et des 49 zones pétrolières possibles du bassin sédimentaire de l'Ouest canadien a servi de base aux nouvelles estimations des ressources non découvertes de pétrole conventionnel léger et moyen (partie I). On estime qu'il reste encore à découvrir 509 x 10^6 m^3 (valeur médiane) de pétrole récupérable dans les zones prouvées où on a déjà découvert environ 2360 x 10^6 m^3 de pétrole récupérable. De plus, les zones pétrolières possibles qui n'ont pas encore été explorées avec succès en renfermeraient 61 x 10^6 m^3 (valeur médiane). Il est prévu que les ressources non découvertes seront dispersées dans plus de 4000 accumulations distinctes, dont la plupart seront de petite taille comparativement aux découvertes existantes. Ces estimations ont été preparées en ne tenant compte d'aucune contrainte économique; dans la partie II du présent rapport, on tente de déterminer la proportion du potentiel qui pourrait être exploitée de manière rentable.

On présente des estimations de la relation à long terme entre le prix du pétrole et le potentiel de l'Ouest canadien en pétrole léger et moyen. L'analyse économique traite exclusivement de la rentabilité à long terme et par conséquent, les conditions économiques à court terme n'y sont pas abordées. L'analyse du cycle complet marginal est une estimation de la rentabilité au moment de la décision de forer un puits d'exploration. L'analyse du demi-cycle ne prend en considération aucun coût de découverte. L'étude montre que 70% des ressources non découvertes en pétrole léger et moyen pourraient constituer à long terme des investissements rentables à des prix variant de 94 à 142 $ can. le m^3 (15 à 22,50 $ can. le baril). À l'intérieur de cette plage de prix, la relation entre prix et potentiel économique est relativement inélastique.

SUMMARY

The conventional oil resources (light and medium) of the Western Canada Sedimentary Basin are described in two sections. In Part I the regional resource endowment is assessed in a geological context. The oil resource endowment is the total quantity of oil estimated to exist in the region. It includes both what has already been found (reserves) and an undiscovered component (potential) that can be inferred to exist based on current understanding of the geology of the region or basin. Data and information concerning reserves is readily available from provincial agencies and the National Energy Board. Estimates of undiscovered potential are prepared by the Geological Survey of Canada and are the main focus of Part I of the paper. The systematic approach used by the Geological Survey results in estimates of the total quantity of pooled oil that remains regardless of whether components of this potential will ever be discovered, or, if discovered, be economically exploitable. Part II of the paper contains an attempt to determine how much of the estimated potential may be economically exploited under a variety of price, cost, tax and royalty options. The economic analysis contained in Part II was done by staff of the Energy Commodities Sector of the Department of Energy, Mines and Resources.

The assessment of petroleum resources was made using both statistical and subjective probability methods applied at the exploration play level. Exploration plays are families of prospects and discovered pools that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration. Each play forms a natural geological population and is limited areally and stratigraphically. Exploration plays were identified and defined by an analysis of the geological history of major depositional sequences represented in the basin. In total 78 established plays (those that have demonstrated reserves) and 49 conceptual plays (those within which no discoveries have yet been made, or that have never been the focus of exploration) were assessed. The plays were assessed using either of two methods dependent on the level of data available. For those plays that had a significant record of discovery (about 8 or more pools) the discovery process model was used. This methodological approach assumes that the discovery record (size of pools in terms of oil in place or OIP) represents a biased sample of the total play population. Statistical methods that reflect an understanding of how exploration bias has influenced the sample were used to predict the total pool size distribution. This method was used to assess 57 of the 78 established plays. For each of them the play definition, a summary of the petroleum geology, reservoir characteristics, exploration history and reserves are provided along with a list of the largest pools in the play. The estimated potential is also described and illustrated as an array of pools, from largest to smallest, appropriate for the play. In that illustration, those predicted pools that have already been discovered are identified. The undiscovered pools are shown along with a measure of their probable range of size. The "matching" of existing discoveries with predicted pool sizes was an important component of the discovery process model analysis.

SOMMAIRE

Les ressources en pétrole conventionnel léger et moyen du bassin sédimentaire de l'Ouest canadien sont décrites en deux étapes. La partie I aborde à l'échelle régionale les réserves et le potentiel dans un contexte géologique. Les réserves et le potentiel constituent la quantité totale de pétrole estimé dans la région. Cette quantité totale englobe ce qui a déjà été découvert (les réserves) et ce qui reste à découvrir (le potentiel), dont on peut déduire l'existence d'après les connaissances actuelles de la géologie de la région ou du bassin. Les données et renseignements concernant les réserves sont faciles à obtenir auprès des organismes provinciaux et de l'Office national de l'énergie. Les estimations du potentiel sont préparées par la Commission géologique du Canada et constituent le principal sujet de la partie I de la présente étude. La démarche systématique utilisée par la Commission géologique conduit à des estimations de la quantité totale de pétrole non découvert dans les gisements, qu'il y ait éventuellement découverte ou non de composantes de ce potentiel ou, s'il y a découverte, que l'exploitation soit rentable ou non. Dans la partie II de l'étude, on tente de déterminer la proportion du potentiel estimé qui pourrait être exploitée de manière rentable selon diverses options quant aux prix, aux coûts, aux impôts et aux redevances. L'analyse économique présentée à la partie II a été effectuée par le personnel du Secteur des ressources énergétiques du ministère de l'Énergie, des Mines et des Ressources.

L'évaluation des ressources pétrolières a été faite selon des méthodes de probabilités statistiques et subjectives, appliquées à l'échelle des zones pétrolières. Les zones pétrolières sont des concentrations de sites d'intérêt et de gisements découverts partageant des caractéristiques communes quant à la genèse et la migration des hydrocarbures, la formation des réservoirs et la configuration des pièges. Chaque zone constitue une population géologique naturelle et est délimitée en surface et selon la stratigraphie. Les zones pétrolières ont été identifiées et définies par une analyse de l'histoire géologique des principales séquences sédimentaires représentées dans le bassin. Au total, 78 zones pétrolières prouvées (dont l'existence des réserves a été démontrée) et 49 zones pétrolières possibles (à l'intérieur desquelles aucune découverte n'a été faite jusqu'ici, ou qui n'ont pas encore fait l'objet de travaux d'exploration) ont été évaluées. Les zones ont été évaluées à l'aide de l'une ou l'autre des deux méthodes, selon la quantité de données disponibles. En ce qui concerne les zones présentant un nombre important de découvertes (de l'ordre de 8 gisements ou plus) on a utilisé le modèle du processus de découverte. Par cette methode, on suppose que le dossier des découvertes (dimension des gisements en termes de pétrole en place, PEP) constitue un échantillon biaisé de la population totale de la zone. Des méthodes statistiques reflétant une connaissance de la manière dont le biais d'exploration a influencé l'échantillon ont été utilisées pour prédire la nature de la distribution totale des dimensions des gisements. Cette méthode a été utilisée pour évaluer 57 des 78 zones pétrolières prouvées. Pour chacune d'entre elles, l'étude présente une définition, un résumé de la géologie pétrolière, les caractéristiques des roches réservoirs, un historique de l'exploration, les réserves ainsi qu'une liste des plus grands gisements de la zone. Le potentiel estimé est également décrit et illustré sous la forme d'une série de gisements, appropriée à chaque zone, allant du plus grand au plus petit. Dans le cadre de cette illustration, les gisements prévus qui ont déjà été découverts sont identifiés. Les gisements non découverts sont accompagnés de données sur l'étendue probable de leur dimension. La "correspondance" établie entre découvertes existantes et dimensions prévues des gisements constituait une composante importante de l'analyse effectuée au moyen du modèle du processus de découverte.

For those plays with an inadequate history of discovery, and for the conceptual plays, a subjective probability method was used. In this approach, subjective opinion, combined with such data from discovery as exists, was used to estimate the size and number of prospects by constructing frequency distributions of the variables involved. This approach also required the subjective estimation of exploration risk. The distributions were combined to produce pool size distributions and estimates of the number of pools expected to exist. These two components were then used to produce estimates of potential and sizes of individual pools. Both methods that were used produced individual pool size data that were subsequently used in the economic analysis component of the study (Part II), but only the established plays were included in that part of the analysis.

The Western Canada Sedimentary Basin occupies an area of 1.4 x 10^6 km^2 extending across southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia, and the extreme southwestern corner of the District of Mackenzie. Its extensions into the United States are not included in this report. Within the Western Canada Sedimentary Basin, the Sweetgrass Arch separates the Alberta Basin, a westward-dipping monocline, from the southward-dipping Williston Basin. Two major sedimentary wedges, of approximately equal volume, were deposited in the basin. The lower wedge consists of Cambrian to Middle Jurassic marine rocks, deposited on the relatively stable craton, that grade westward into similar rocks deposited in a miogeocline over a passive continental margin. The lower wedge is overlain by Late Jurassic to Tertiary shallow marine and continental rocks deposited in a foreland basin, east of tectonic highlands created by the collision and accretion of micro-continents to the western margin of ancient North America.

For the analysis of the petroleum resource endowment the basin was divided into five stratigraphic intervals, each of which is characterized by specific families of petroleum occurrences. Four of these intervals are in the lower sedimentary wedge, the fifth represents the entire upper wedge.

The oldest interval consists of Cambrian, Ordovician, and Silurian marine shelf carbonate and siliciclastic rocks. The only petroleum discoveries in these systems in Western Canada have been small pools in structurally-controlled traps in the Ordovician rocks of southeastern Saskatchewan. In the more intensively explored United States portion of the basin, however, there are a large number of producing fields in equivalent rocks. There appear to be no geological reasons not to expect similar accumulations in Canada. Several conceptual plays have been formulated for this deepest part of the basin section. The combination of sparse deep well penetrations and the large areas underlain by these rocks allows the perception of this as the last frontier exploration area in western Canada.

The Devonian is by far the most important oil-producing interval of the Western Canada Sedimentary Basin, with 55% of recoverable reserves and 55% of recoverable potential in 28 established plays. The Devonian is characterized by reef and shelf carbonate reservoirs, commonly encased within carbonate-clastic and carbonate-evaporite basin-fill, seal and source rocks.

Dans le cas des zones pétrolières possibles et des zones présentant un historique de découvertes inadéquat, on a utilisé une méthode de probabilités subjectives. Par cette méthode, un jugement subjectif est combiné aux données disponibles liées aux découvertes pour estimer la dimension et le nombre de sites d'intérêt en établissant des distributions de fréquences des variables en cause. Cette méthode exige également l'estimation subjective du risque d'exploration. Les distributions sont combinées pour obtenir des distributions de dimensions des gisements et des estimations du nombre de gisements prévus. Ces deux composantes sont ensuite utilisées pour produire des estimations du potentiel et de la dimension de gisements individuels. Les deux méthodes utilisées fournissent des données sur la dimension de gisements individuels ultérieurement utilisées dans l'analyse économique de l'étude (partie II), pour laquelle toutefois il n'a été tenu compte que des zones pétrolières prouvées.

Le bassin sédimentaire de l'Ouest canadien, d'une superficie de 1,4 x 10^6 km^2, occupe le sud-ouest du Manitoba, le sud de la Saskatchewan, l'Alberta, le nord-est de la Colombie-Britannique et l'extrême sud-ouest du district de Mackenzie. Ses prolongements aux États-Unis ne sont pas abordés dans le cadre du présent rapport. À l'intérieur du bassin sédimentaire de l'Ouest canadien, l'arche de Sweetgrass sépare le bassin de l'Alberta, monoclinal plongeant vers l'ouest, du bassin de Williston, incliné vers le sud. Deux biseaux sédimentaires importants, de volume approximativement égal, ont été déposés dans le bassin. Le biseau inférieur se compose de roches marines datant du Cambrien au Jurassique moyen, déposées sur le craton relativement stable, qui passent progressivement vers l'ouest à des roches analogues déposées dans un miogéoclinal sur une marge continentale passive. Le biseau inférieur est recouvert par des roches de milieu marin peu profond et des roches continentales datant du Jurassique supérieur au Tertiaire qui ont été déposées dans un bassin d'avant-pays, à l'est de hautes-terres tectoniques produites par la collision et l'accrétion de micro-continents à la bordure occidentale de l'ancienne Amérique du Nord.

Aux fins de l'analyse des ressources pétrolières, le bassin a été divisé en cinq intervalles stratigraphiques caractérisés par des familles distinctes d'occurrences pétrolières. De ces intervalles, quatre se trouvent dans le biseau sédimentaire inférieur, le cinquième constituant l'ensemble du biseau supérieur.

L'intervalle le plus ancien consiste en roches marines siliciclastiques et en roches carbonates de plate-forme qui datent du Cambrien, de l'Ordovicien et du Silurien. Dans l'Ouest canadien, les seules découvertes de pétrole dans ces systems sont des gisements de petite taille à l'intérieur de pièges contrôles par la structure dans les roches de l'Ordovicien du sud-est de la Saskatchewan. Toutefois, il existe aux États-Unis, dans les parties du bassin explorées de manière plus intensive, un grand nombre de champs productifs dans des roches équivalentes. Sur le plan géologique, il semble n'exister aucune raison pour laquelle on ne trouverait pas d'accumulations analogues au Canada. L'existence de plusieurs zones pétrolières possibles a été proposée dans cette zone qui constitue la partie la plus profonde du bassin. Les puits profonds dispersés à l'intérieur de cette partie du bassin et les grandes étendues sus-jacentes à ces roches permettent de considérer cet intervalle comme la dernière région pionnière de l'Ouest canadien.

L'intervalle dévonien est de loin le plus important quant à la production pétrolière du bassin sédimentaire de l'Ouest canadien; il recèle 55% des réserves récupérables et 55% du potentiel récupérable dans 28 zones pétrolières prouvées. Cet intervalle est caractérisé par des roches réservoirs carbonatées récifales et de plate-forme, généralement contenues dans des roches de remplissage de bassin, des roches-couvertures et des roches mères carbonatées clastiques et évaporitiques.

In the Northern Alberta District, most production is from Keg River reefs that developed in Middle Devonian evaporite basins. Ten percent of the Devonian reserves occurs in a large number of relatively small pools (less than 0.5 x 10^6 m^3 recoverable oil). The Peace River Arch District, of north-central Alberta, contains 13% of Devonian recoverable reserves, dominantly in structural and structural-stratigraphic traps in Keg River, Slave Point, Leduc, and Wabamun reef and shelf carbonate, and Gilwood, Keg River, and Granite Wash clastic reservoirs. The Central Alberta District, with 77% of Devonian recoverable reserves, is the single most important oil producing region of Canada. Oil occurs in stratigraphic traps in Beaverhill Lake, Leduc, and Nisku reef reservoirs and in drape traps in Nisku shelf carbonate reservoirs. Major pools in this district are the Beaverhill Lake Swan Hills A and B (103 x 10^6 m^3 recoverable oil) and the Leduc Redwater (128 x 10^6 m^3 recoverable oil). Most of the Devonian potential is expected to occur in the mature to developing plays of Alberta. Several undiscovered pools are expected to be in the 10 x 10^6 to 20 x 10^6 m^3 OIP range.

In contrast, the Williston Basin District has less than 1% of the Devonian reserves and only moderate potential. The relatively sparse geological and statistical data base in this district results in greater uncertainty for the estimates of potential. In addition to the established plays, a significant proportion of the potential in conceptual plays is probably contained in Devonian rocks.

The Carboniferous and Permian rocks of the basin contain 15% of the recoverable reserves and 11% of the recoverable potential, distributed in 17 established plays. Most of the oil is trapped at the updip termination of Carboniferous shelf carbonate reservoir rocks beneath Mesozoic unconformities in central Alberta and southeastern Saskatchewan. Lesser amounts of oil occur in stratigraphic and structural traps in northeastern British Columbia and in the Foothills of Alberta. Most established plays are considered very mature with the remaining potential expected in pools of less than 1 x 10^6 m^3 OIP. Greater uncertainty is associated with the prediction of larger pools in the few immature and conceptual plays in the Carboniferous and Permian, as there has been little exploration in parts of the section downdip from the erosional edges.

The Triassic and Jurassic interval has the most limited distribution within the Western Canada Basin. Shallow marine clastic and carbonate reservoirs contain 7% of the recoverable reserves and 8% of the recoverable potential, in stratigraphic, structural, and unconformity traps. Most of the potential is expected to occur in the Triassic of the Peace River District. The Triassic section is the richest part of the Western Canada Sedimentary Basin in terms of volume of oil per volume of rock. Some relatively large pools, in the 5 x 10^6 to 20 x 10^6 m^3 OIP range, are predicted, though most of the potential is expected to be dispersed in pools less than 1 x 10^6 m^3 OIP in 18 established plays.

The Late Jurassic, Cretaceous, and Tertiary interval consists dominantly of Cretaceous rocks, which extend across the entire basin. They are second only to the Devonian in economic importance. They contain 19% of the

Dans la région du nord de l'Alberta, la plus grande partie de la production provient des récifs de Keg River qui se sont formés dans les bassins d'évaporites du Dévonien moyen. Dix pour cent des réserves de l'intervalle dévonien se trouvent dans un grand nombre de gisements de taille relativement restreinte (moins de 0,5 x 10^6 m^3 de pétrole récupérable). La région de l'arche de Peace River, dans le centre nord de l'Alberta, renferme 13% des réserves récupérables de l'intervalle dévonien, principalement dans des pièges structuraux et structuro-stratigraphiques dans les roches carbonatées récifales et de plate-forme de Keg River, de Slave Point, de Leduc et de Wabamun ainsi que dans les roches réservoirs clastiques de Gilwood, de Keg River et de Granite Wash. La région du centre de l'Alberta, où se trouvent 77% des réserves récupérables de l'intervalle dévonien, est la région productrice de pétrole la plus importante au Canada. Le pétrole se trouve dans des pièges stratigraphiques dans les roches réservoirs récifales de Beaverhill Lake, de Leduc et de Nisku ainsi que dans des pièges de plissement moulant dans les roches réservoirs carbonatées de plate-forme de Nisku. Les principaux gisements de cette région sont le gisement Beaverhill Lake Swan Hills A et B (103 x 10^6 m^3 de pétrole récupérable) et celui de Leduc Redwater (128 x 10^6 m^3 de pétrole récupérable). On prévoit trouver la plus grande partie du potentiel de l'intervalle dévonien dans les zones pétrolières de l'Alberta ayant fait l'objet d'une exploration intensive ou progressive. Plusieurs gisements non découverts seraient de l'ordre de 10 x 10^6 à 20 x 10^6 m^3 PEP.

À l'opposé, la région du bassin de Williston renferme moins de 1% des réserves de l'intervalle dévonien et ne présente qu'un potentiel modéré. En raison de la rareté relative des données géologiques et statistiques disponibles au sujet de cette région, une plus grande incertitude est liée aux estimations du potentiel. En plus du pétrole des zones pétrolières prouvées, une proportion importante du potentiel des zones pétrolières possibles se trouve probablement dans les roches dévoniennes.

Les roches carbonifères et permiennes du bassin renferment 15% des réserves récupérables et 11% du potentiel récupérable dans 17 zones prouvées. La plus grande partie du pétrole est piégé a la terminaison amont-pendage des roches réservoirs carbonatées de plate-forme du Carbonifère, sous des discordances mésozoïques du centre de l'Alberta et du sud-est de la Saskatchewan. Il existe des quantités moindres de pétrole dans des pièges stratigraphiques et structuraux du nord-est de la Colombie-Britannique et dans les contreforts de l'Alberta. On estime que la plupart des zones pétrolières prouvées ont fait l'objet d'une exploration tres intensive, les ressources non découvertes étant prévues dans des gisements de moins de 1 x 10^6 m^3 PEP. Une plus grande incertitude est associée à la prévision des gisements plus importants dans les quelques zones pétrolières possibles ayant fait l'objet d'une exploration relativement préliminaire dans les roches du Carbonifère et du Permien, puisqu'il n'y a encore eu que peu d'exploration dans les parties du bassin en aval-pendage des limites d'érosion.

L'intervalle du Trias et du Jurassique présente la répartition la plus restreinte à l'intérieur du bassin de l'Ouest canadien. Des roches réservoirs marines clastiques et carbonatées formées en milieu peu profond renferment 7% des réserves récupérables et 8% du potentiel récupérable dans des pièges stratigraphiques, structuraux et des discordances. On prévoit que la plus grande partie du potentiel se situera dans les roches du Trias de la région de Peace River. L'intervalle triasique constitue la partie la plus riche du bassin sédimentaire de l'Ouest canadien en termes de volume de pétrole par volume de roches. L'existence de certains gisements relativement importants, de l'ordre de 5 x 10^6 à 20 x 10^6 m^3 PEP, est prévue, mais on estime que la majorité du potentiel serait dispersée dans des gisements de moins de 1 x 10^6 m^3 PEP dans 18 zones pétrolières prouvées.

L'intervalle du Jurassique supérieur, du Crétacé et du Tertiaire consiste principalement en roches du Crétacé qui s'étendent sur l'ensemble du recoverable reserves of conventional oil and 17% of the potential in 13 established plays. In addition they host major deposits of heavy oils and bitumens not considered in this assessment. Oil is stratigraphically trapped in shallow marine, marginal marine, and continental coarse clastic rocks where they change depositional facies updip into fine clastic rocks. The principal reservoirs are in the Mannville Group and in the Viking, Cardium, and Belly River formations. The largest conventional oil accumulation in western Canada is the Upper Cretaceous Cardium pool at Pembina (240 x 10^6 m^3 recoverable oil).

The approach adopted in this analysis of the Cretaceous required the definition of several composite plays. The bias introduced by this approach when large pool populations are involved, and play concepts are generalized, commonly results in estimates of potential that are conservative. For most plays the largest predicted pools are in the 5 x 10^6 to 15 x 10^6 m^3 OIP range. Exploration opportunities should still exist even in the relatively mature Cretaceous plays as the stratigraphic traps formed by the complex depositional facies changes are subtle and difficult to locate.

The analysis of 78 established exploration plays that had initial established reserves of about 2360 x 10^6 m^3 of recoverable oil indicates that an additional 509 x 10^6 m^3 of recoverable oil may exist as future potential. Although a portion of this potential will not be economic, it is important to note that the remaining potential from existing plays, currently being explored for and developed, is similar to the remaining established reserves (684 x 10^6 m^3 of recoverable oil as of January 1984).

The additional estimated 61 x 10^6 m^3 (median value) of oil associated with conceptual plays, most of which are not currently the target of exploration, will probably become the focus of activity in future decades.

Total potential from established and conceptual plays, which is estimated to have a median value of 570 x 10^6 m^3 of technically recoverable oil, is expected to be dispersed in more than 4000 individual pools. This number is modestly larger than the 3300 pools that currently exist. Given that future pools are expected to be more difficult to locate (lower success rate of wildcat wells), the implication is that it will require as many exploratory wells to locate the last 20% of the resource as it took to find the first 80%.

The geological distribution of oil resources is not likely to change significantly as a result of future discovery. Devonian reservoirs, with their superior characteristics, will continue to be dominant, with almost 60% of the resource base.

In summary, most of the oil potential of the Western Canada Sedimentary Basin is expected to occur in the currently productive horizons, in proportions similar to the reserve base. Most of the resource occurs in stratigraphic or unconformity traps, at the updip terminations of reservoir rocks in the gently-dipping monoclines of the Alberta and Williston Basins. Though several predicted pools are in the 5 x 10^6 to 20 x 10^6 m^3 OIP range, the bulk of the potential will be dispersed in a large number of smaller pools.

bassin. Pour ce qui est de l'importance économique, elles se classent au deuxième rang, derrière les roches dévoniennes. Elles renferment 19% des réserves récupérables de pétrole conventionnel et 17% du potentiel dans 13 zones prouvées. Elles renferment de plus d'importants gisements de pétrole lourd et de bitume dont ne tient pas compte la présente évaluation. Le pétrole se trouve dans des pièges stratigraphiques dans des roches clastiques grossièrement grenues, marines, formées en milieu peu profond et marginal, et continentales, à l'endroit où leur faciès de dépôt change et où elles deviennent en amont-pendage des roches clastiques finement grenues. Les principales roches réservoirs se trouvent dans le Groupe de Mannville et dans les Formations de Viking, de Cardium et de Belly River. L'accumulation de pétrole conventionnel la plus importante de l'Ouest canadien est le gisement de Cardium, dans les roches du Crétacé supérieur, à Pembina (240 x 10^6 m^3 de pétrole récupérable).

La méthode adoptée pour la présente analyse du Crétacé exige la définition de plusieurs zones composites. Le biais introduit par cette méthode, lorsque sont en cause de grandes populations de gisements, et lorsque les concepts de zones pétrolières sont généralisés, produit couramment des estimations prudentes du potentiel. Dans la plupart des zones, les plus grands gisements prévus sont de l'ordre de 5 à 15 x 10^6 m^3 PEP. Il devrait encore subsister des possibilités d'exploration, même dans les zones pétrolières crétacées ayant fait l'objet d'une exploration relativement intensive, bien que les pièges stratigraphiques formés par de complexes modifications de faciès de dépôt soient imprécis et difficiles à localiser.

L'analyse des 78 zones pétrolières prouvées, dont les réserves avaient initialement été établies à environ 2360 x 10^6 m^3 de pétrole récupérable, indique qu'elles pourraient renfermer 509 x 10^6 m^3 de pétrole récupérable de plus. Bien qu'une partie de ce potentiel ne puisse être rentable, il est important de noter que les ressources non découvertes des zones existantes, actuellement explorées et mises en valeur, correspondent au reste des réserves prouvées (684 x 10^6 m de pétrole récupérable en janvier 1984).

La quantité additionnelle de pétrole estimée (61 x 10^6 m^3, valeur médiane) associée aux zones pétrolières possibles, dont la plupart ne sont pas actuellement des cibles d'exploration, deviendra probablement le foyer de l'activité au cours des décennies futures.

Le potentiel total de pétrole techniquement récupérable des zones pétrolières prouvées et possibles, dont on estimé la valeur médiane à 570 x 10^6 m^3, serait dispersé dans plus de 4000 gisements individuels. Ce nombre est légèrement plus élevé que celui des 3300 gisements existants. Puisqu'il est prévu que les gisements futurs seront plus difficiles à localiser (taux de succès réduit des puits de reconnaissance), il en résulte qu'il faudra forer autant de puits d'exploration pour localiser le 20% additionnel de ressources non découvertes qu'il a été nécessaire d'en forer pour le 80% découvert jusqu'à maintenant.

La répartition géologique des ressources pétrolières ne changera vraisemblablement pas de manière importante à la suite des découvertes futures. Les roches réservoirs dévoniennes, qui présentent de meilleures caractéristiques, resteront dominantes et renfermeront près de 60% des ressources.

En résumé, il est prévu que la plus grande partie du potentiel pétrolier du bassin sédimentaire de l'Ouest canadien se trouvera dans les horizons actuellement productifs, en proportions analogues à celles des réserves. La plus grande partie des ressources se trouve dans des pièges stratigraphiques ou des discordances aux terminaisons amont-pendage de roches réservoirs dans les monoclinaux à faible pendage des bassins de l'Alberta et de Williston. Bien que plusieurs gisements prévus soient de l'ordre de 5 à 20 x 10^6 m^3 PEP, le potentiel sera en majeure partie dispersé dans un grand nombre de gisements de plus petite taille.

Resource endowment estimates of western Canadian conventional light and medium oil were prepared unconstrained by economic factors. As a complementary study, Part II presents an economic analysis of the resource endowment which was estimated at a median level of probability. The objective of the work was to estimate what portion of undiscovered potential may, in the long-term, become part of future supply. The analysis was done on 61 established plays based on geological and reservoir data available from Part I. This was used with engineering and cost data to identify the smallest pool within each play that would be marginally profitable.

A number of cases were considered in order to identify marginally profitable pools. Profitability is estimated at two points in the investment cycle. **Marginal full-cycle** profitability is estimated at the time an exploratory drilling decision is made. Pre-drilling expenditures are not part of this decision process but all such costs are assumed to be recovered through the discovery of larger, more profitable pools. **Half-cycle** profitability is estimated at the time a development decision is made. For each of these cases both private and public perspectives are provided. **Commercial (private) viability** takes into consideration net fiscal burdens associated with taxes and royalties. **Economic (public) viability** considers only resource costs.

The estimated relationships show that, for western Canada as a whole, a high proportion of remaining undiscovered resources constitute profitable long-term investments in the price range of $CDN 94 to 142/m^3 ($15 to 22.50/bbl). This provides an encouraging view of long-term industry fundamentals and suggests that an additional 350 x 10^6 m^3 recoverable (2.2 billion barrels) may be profitably found at near current oil prices.

It is important to realize that these resources are undiscovered. The economic analysis does not address possible short-term conditions associated with cash flow, financing, debt, demand, or expected short-term fiscal measures. Equally important, industry must have an expectation of finding pools larger than marginal pools to allow recovery of pre-drilling costs and a competitive return on all invested capital.

L'estimation des ressources en pétrole conventionnel léger et moyen de l'Ouest canadien a été préparée sans tenir compte des contraintes exercées par les facteurs économiques. À titre de complément de l'étude, la partie II présente une analyse économique des ressources qui ont été estimées à un niveau médian de probabilité. L'objectif des travaux consistait à estimer la partie du potentiel non découvert qui pourrait, à long terme, être intégrée aux approvisionnements futurs. L'analyse a porté sur 61 zones pétrolières prouvées, d'après les données sur la géologie et les roches réservoirs fournies dans la partie I. Ces données ont été combinées aux données d'ingénierie et de coûts afin d'identifier dans chaque zone le plus petit gisement de rentabilité marginale.

Un certain nombre de cas ont été pris en considération pour identifier les gisements de rentabilité marginale. La rentabilité est estimée à deux moments du cycle d'investissement. La rentabilité **marginale du cycle complet** est estimée au moment de la décision d'effectuer des forages d'exploration. Les dépenses antérieures aux forages ne font pas partie de ce processus de prise de décision, mais on suppose que tous les coûts de ce genre seront compensés par la découverte de gisements plus étendus et plus rentables. La rentabilité **du demi-cycle** est estimée au moment de la décision quant à la mise en valeur. Pour chacun de ces cas, on fournit la perspective du secteur privé et du secteur public. **La viabilité commerciale (secteur privé)** tient compte des charges fiscales nettes associées aux taxes et redevances. **La viabilité économique (secteur public)** ne tient compte que du coût des ressources.

Les relations estimées indiquent que, dans l'ensemble de l'Ouest canadien, une proportion élevée de ressources non découvertes constitue un investissement rentable à long terme à des prix de l'ordre de 94 à 142 $ can. le m^3 (15 à 22,50 $ can. le baril). Cela est encourageant pour l'avenir à long terme de l'industrie et laisse supposer que 350 x 10^6 m^3 additionnels de pétrole récupérable (2,2 milliards de barils) pourraient être découverts de manière rentable à des prix semblables au prix actuel du pétrole.

Il est important de souligner que ces ressources ne sont pas encore découvertes. L'analyse économique ne traite pas des conditions possibles à court terme associées au flux de liquidité, au financement, à la dette, à la demande ou aux mesures fiscales prévues à court terme. Il est également important que l'industrie prévoie trouver des gisements plus importants que les gisements marginaux pour récupérer les coûts antérieurs aux forages et pour obtenir un rendement concurrentiel de tout le capital investi.

PART I: RESOURCE ENDOWMENT

INTRODUCTION

The report that follows summarizes a comprehensive analysis of the light and medium conventional oil resources that are estimated to remain in the Western Canada Sedimentary Basin. The primary objective of this analysis was to determine the resource endowment of the region; that is, to quantify the total amount of pooled oil that might exist, regardless of whether elements of the resource would eventually be discovered, or, if discovered, be economically exploitable. A secondary objective was to undertake the analysis using methods that would enable others to evaluate the likelihood of discovery of individual pools, and also permit analysis of economic viability in order to estimate how much of the remaining resource endowment might become a part of future supply.

Estimates of regional resource endowment are prepared periodically by the Geological Survey of Canada using a systematic approach to both the geoscience components and the resource evaluation methods. To support this activity, a comprehensive computer-based petroleum resource evaluation system has been developed within the Geological Survey of Canada (Lee and Wang, 1983, 1984, 1985, 1986). The methods used include subjective probability and statistics-based techniques, both applied at the exploration play level. The evaluation process depends on two types of activity performed by the Basin Analysis Group and the Geological Potential Committee respectively.

Basin Analysis Group: Every analysis of regional resource endowment begins with the formation of a basin analysis group consisting of a variety of geoscientists. The group's objective is to develop the best understanding of basin evolution, geometry, sedimentation, geochemistry, structural history and hydrocarbon occurrence that time and resources permit. Within this geological framework, petroleum geologists create conceptual models of oil accumulations grouped by plays. The prospective hydrocarbon content of these models can then be evaluated systematically.

Geological Potential Committee: Each analysis of regional resource endowment is supported by a geological potential committee selected for the specific region. The committee consists of a core of full time evaluation specialists (Petroleum Resource Appraisal Secretariat) plus a number of other geoscientists with independent but relevant experience to ensure that different regions are equitably treated. The responsibilities of the committee are: to review critically the work of the basin analysis group, with their help to develop the play definitions that will control the quantitative analysis, to participate in the evaluation procedures, and, to be responsible for the final estimates. The committee is required to review and provide feedback for each of the individual play estimates.

Terminology: The terms reserves, resources and potential have been variously defined in the literature. In the petroleum resource evaluation activities and publications of the Geological Survey of Canada their usage is as follows: the word **resource** is used as a synonym for resource endowment, and includes all oil and gas accumulations known or inferred to exist; **reserves** are that portion of the resource that has been discovered; the word **potential** describes that portion of the resource inferred to exist but not yet discovered. The terms **potential** and **undiscovered resources** are thus synonymous and can be used interchangeably.

The expression **established reserve** is used to describe those reserves which, under given economic conditions and within a specified time frame, are **recoverable** with a high degree of confidence from known reservoirs. The expression **oil in place (OIP)** is used to represent the total volume of oil (at surface conditions) in a reservoir without consideration of what portion may be recoverable.

The terms **field, play, pool,** and **prospect** are often used interchangably, without clear definitions. Within this study, a **field** is used to designate an area that produces oil, without stratigraphic interval restrictions. A **pool** is a discovered accumulation of oil, typically within a single stratigraphic interval, that is hydraulically separate from any other oil accumulation. Any number of pools can exist within a field. A **prospect** is an untested exploration target, usually within a single stratigraphic interval, that may contain oil. A **play** consists of a family of pools and/or prospects that share a common history of hydrocarbon generation and migration, reservoir development, and trap configuration.

Scope of Study: The analysis of remaining conventional oil resources of the Western Canada Sedimentary Basin involved the systematic examination of more than a hundred exploration plays. Exploration plays were divided into two categories for the study: **established plays** (those that are demonstrated to exist by virtue of discovered pools with established reserves) and **conceptual plays** (those that do not yet have discoveries or reserves but which geological analysis indicates may exist). In the analysis of oil potential of western Canada there were 78 established plays and 49 conceptual plays. For purposes of this report, the established play category is further split into plays with sufficient maturity and data to justify a full quantitative statement, and plays with very limited discoveries to date. Although quantitative estimates are provided for this latter group, the documentation is abbreviated. Quantitative estimates for individual conceptual plays are not given, but aggregate estimates for the group are included in the summary.

Only the conventional light and medium oil pools are considered in this report. This encompasses most oil pools in Western Canada, including some of the Alberta Carboniferous and Jurassic heavy oil pools, but excluding the Cretaceous heavy oil pools of eastern Alberta and western Saskatchewan.

Although most of this study is based upon the 1983 data sets of various provincial agencies (Alberta Energy Resources Conservation Board, 1984; Manitoba Energy and Mines, 1983; Province of British Columbia, 1983; Saskatchewan Energy and Mines, 1983), some plays with significant recent discovery records have been re-evaluated with the 1985 data sets (Alberta Energy Resources Conservation Board, 1986; Manitoba Energy and Mines, 1985; Province of British Columbia, 1985; Saskatchewan Energy and Mines, 1985).
Several field names referred to in the text do not appear on any illustrations in this report. The locations of these fields can be obtained from Wallace-Dudley (1982).

Acknowledgments

The authors have freely drawn on the work of many geologists, including several employed in the petroleum industry and co-workers at the Institute of Sedimentary and Petroleum Geology; they have also drawn heavily from the published literature. Special acknowledgement is made to C. Gemeroy and R. Serafini (National Energy Board), W. Young (British Columbia Ministry of Energy Mines and Petroleum Resources), M.J. Vrskovy (Alberta Energy Resources Conservation Board), W.J. Ward (Canadian Oil and Gas Lands Administration), J.P. Hea (EMR-Energy Commodities Sector), and J.A. Wade (GSC-Atlantic Geoscience Centre) all of whom assisted on the Geological Potential Committee.

Completion of the report would not have been possible without the active participation of L. Mac Lachlan as production editor, and his staff of draftsmen, particularly W.P. Vermette and B.H. Ortman. Special thanks go to A. Foo who was responsible for the word processing, and to P. Greener and H. King for compugraphics processing.

RESOURCE ASSESSMENT PROCEDURE

There are numerous methods of estimating the quantities of oil and gas that may exist in a play, region, or basin, depending on the nature and amount of data available for the process. Each is different in the type of information generated. White and Gehman (1979) and Rice (1986) describe several approaches that are currently in use. The Geological Survey of Canada uses two methods, both of which operate at the exploration play level, selected because they are capable of estimating the size and reservoir characteristics of individual pools as well as estimating the total play potential. The two approaches, both of which were used in the analysis of oil resources of the Western Canada Sedimentary Basin are called the **discovery process model** and the **subjective probability** methods. The discovery process model is a statistically based method developed by Lee and Wang (1984, 1985, 1986). For established plays, with as few as eight discoveries, this method has been found to be the more powerful of the analytic approaches. The underlying theory is that discoveries made in the course of exploration represent a biased sample of a population, the sum of which is equal to the resources in a play. If the discovery process can be understood and modelled, then methods can be developed to estimate the characteristics of the population. The discovery process model of Lee and Wang uses the sizes of discoveries that have already been made and their sequence of discovery to produce estimates of both play potential and individual pool sizes. This method, using two of the most reliable sets of input data, deals equally well with stratigraphic and structural plays, a feature that not all methods have.

The subjective probability method is used mainly for conceptual and very immature plays. For these plays, subjective opinion, combined with such data from exploration as exist, is used to estimate the size and number of prospects by constructing frequency distributions of the variables involved. The method also requires the subjective estimation of either the exploration risk or the total number of pools. This method initially used the Monte Carlo simulation technique as the means of combining distributions (Roy *et al.*, 1975). This methodology was subsequently extended, making use, amongst other features, of an alternate technique in which lognormal approximations to the distributions are combined by summation to obtain pool size distributions. The enhanced subjective probability method is also incorporated in the evaluation software system that includes and supports the discovery process model method.

Although there are several steps in the process of making an estimate of the resources in a play, and several types of output, two elements, the pool size distribution and the estimate of the number of pools, are essential to the process. The way in which these elements were derived and then used in the evaluation of the Western Canadian Sedimentary Basin oil resources is shown by describing the several steps in the process and using appropriate examples from one of the plays from the region. The play used is the Cardium Marine Scour play. The steps followed in the play assessment include:

- Play definition

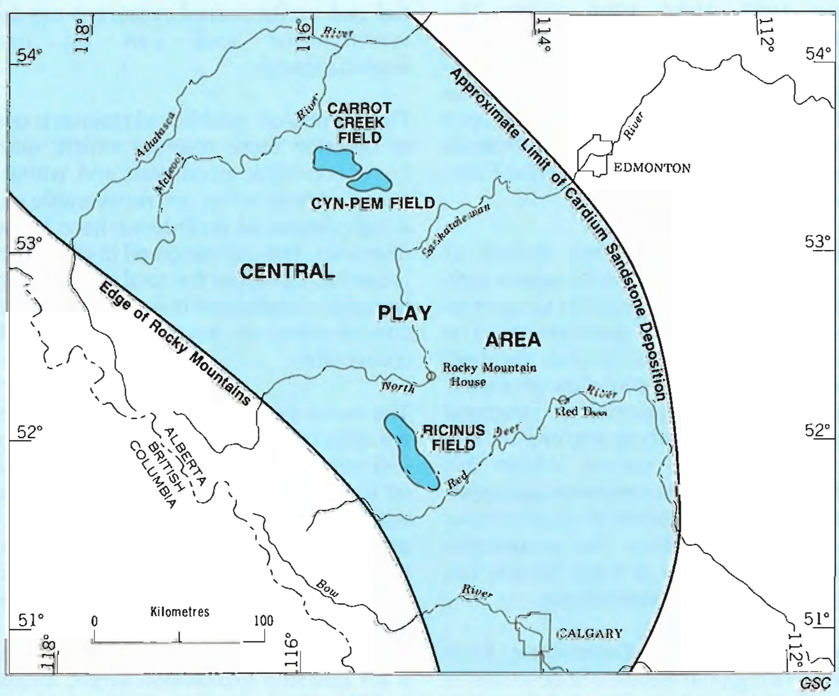


Figure 1. Cardium Scour Play Map.

- Compilation of relevant data or subjective opinion
- Estimation of the pool size distribution
- Estimation of the number of pools
- Estimation of individual pool sizes by rank
- Use of feedback processes to test predicted pool sizes and number: by examing the distribution in the light of geological judgement and recent discovery history; and by matching existing discoveries to the pool sizes by rank
- Conditioning of the individual pool sizes to discovery data
- Estimation of the play potential distribution
- Compilation of the play report and generation of reservoir data for economic analysis

Play Definition

An exploration play consists of a family of prospects and/or discovered pools that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration. As such, the prospects and pools form a natural geological population that is limited to a specified area.

Play definition is one of the primary objectives of the basin analysis studies that precede resource evaluation. The petroleum geologist in the study group attempts to recognize within each "package" of geology what opportunities exist for the generation and entrapment of hydrocarbons. These opportunities take the form of sedimentological and structural models that are then translated into play definitions. Play definitions may be very broad or quite restricted. If, for example, the definition were to apply to reefs in a world-wide context, then the resulting estimate would have a world-wide predictive application. The same type of definition restricted to a specific type of reef, of a specific age, and limited geographic distribution, would produce estimates more applicable to the area of interest. Usually, as geological understanding increases as a result of exploration, plays tend to be subdivided into better defined elements, permitting more specific and more reliable estimates. The Upper Cretaceous Cardium sandstone provides an example (Fig. 1). Cardium pools that produce from stratigraphic traps involving thick sandstone and conglomerate lenses that formed within relatively narrow but long linear trends were originally included in a play with Cardium sheet sandstones. Modern interpretation based on sedimentological models divides the Cardium into two plays. Deposition of shallow marine

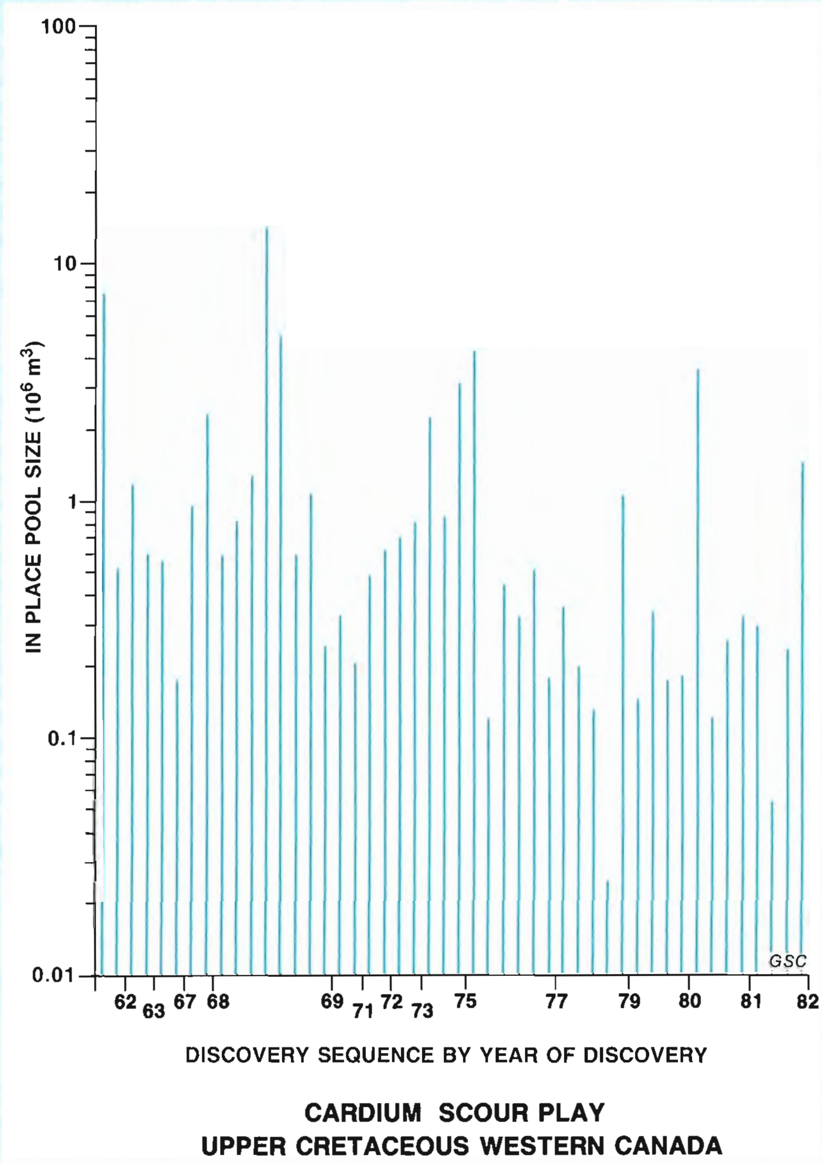


Figure 2.

medium- to coarse-grained sandstone, and pebble to granule conglomerate occurred within broad shallow scours in the Ricinus, Cyn Pem, and Carrot Creek fields. These scours were several kilometres wide and several tens of metres deep, and were eroded in underlying Cardium marine sandstone or shale. They were apparently oriented perpendicular to the ancient shoreline and located on the marine shelf. The details of the play concept and its predictability are only now beginning to emerge (Walker, 1985). The play concept definition used in the current study was:

CARDIUM SCOUR
Play Definition: This oil play was defined to include all oil pools and prospects that are stratigraphically trapped in sandstones and conglomerates formed in marine scours of the Cardium Formation.

Compilation of Exploration Play Data

Once a play has been formally defined, the next step is to identify all the discovered pools in that play and transfer selected data elements to the petroleum resource appraisal software system. Data items include pool name, in-place volume, date of discovery, pool area, net pay, recovery factor, water saturation, porosity, depth, and reservoir temperature. Most of this data is derived from computer tapes containing pool data compiled by provincial agencies and is then transferred, play by play, directly into the evaluation software system. Information related to the play, such as geological structure, isopach and facies maps, cross-sections, oil pool distribution maps, penetration maps and similar items, are also compiled and summarized for the permanent record of the play evaluation.

Pool Size Distribution

The pool size distribution, describing the size range of pools in the play and their frequency of occurrence, is probably the most important element of the resource appraisal process. This element influences the economic analysis more than any other single factor. Combined with an estimate of the number of pools it allows the analyst to estimate the sizes of individual pools.

The pool size distribution is a function of the play model. It describes the population of pools that would result from the repeated application of the play model. Each particular application of the model will differ from others due to subtle differences in the size and location of the play area, the quality of source rocks, migration paths, density of structures, etc. Thus, a particular application can be treated as a random sample from this greater population (a statistical concept called the superpopulation) with a finite number of pools.

Both the discovery process model and subjective probability methods provide ways of determining the pool size distribution. For the discovery process model, the discoveries in a play are recognized as a sample taken from the pool population as a result of exploration. The standard statistical procedure for computing the mean and variance for the population from the sample set are valid only if the sample set is assumed to be a random sample from the population, or if the sample set can be assumed large enough to represent the population. In fact, neither of these assumptions is usually valid. In the process of exploration, large pools are normally discovered at an early stage because the best available prospects tend to be identified and drilled first. As a result, the undrilled targets will include a disproportionate number of small pools. Therefore the mean of the sample would be an overestimate and the variance of the sample set would be an understatement of the population parameters.

The sample set of discovered pools that results from the exploration process is clearly biased rather than random. This is apparent in Figure 2 which is a plot of the size of discoveries in the Cardium Scour play, arranged in order of discovery. Although there are several "waves" or "cycles" in the sequence, a definite tendency towards early discovery of larger pools is apparent. In a simplistic sense, the degree to which this bias is present is a measure of exploration efficiency (although there may be several contributing factors). The discovery process model incorporates mathematical computations that are based on the assumptions that sampling in exploration is proportional to pool size and that the sampling of the population is without replacement.

The method estimates the mean and variance of the lognormal pool size distribution, a measure of the "exploration efficiency" and some indication of the total number of pools in the play. The method does not incorporate the factors that bias the sample other than proportionality to size and sampling without replacement, and for that reason the estimated pool size distribution probably underestimates the mean and overestimates the variance of the population. The relationship between the pool size distribution for the Cardium Scour play based on the sample being assumed random and that derived from the discovery process model are shown in Figure 3. The distribution of the true population probably lies between the two distributions shown. The method then, provides estimation intervals for the parameters (mean and variance) and subsequently derives a final estimate of the pool size distribution.

The pool size distribution can also be calculated using the subjective probability method. It relies on describing each of the variables in a pool size equation (net pay, pool area, porosity, hydrocarbon saturation, and formation volume factor) by a probability distribution that describes the range of possible values of the variable for all the prospects or pools in the play. The probability distributions of each variable incorporate as much objective data as is available, modified by subjective opinion or analog data where necessary. These are combined to form a pool size distribution for the play.

Number of Pools Estimation

The total number of pools in the play is an essential element in the estimation process. The discovery process model provides an estimate of this value in the process of estimating the parameters of the pool size distribution. The method also provides the analyst with the option of testing a range of values of the number of pools and observing the impact this has on individual pool sizes.

In the subjective probability method the number of pools must be estimated directly as a single value or as a probability distribution. Alternatively the number of prospects can be estimated, usually as a distribution, and subsequently discounted to a number of pools distribution using exploration risk. Risk is estimated by considering both the chance that the play is not valid (no eventual discoveries) and the chance that a proportion of the prospects will lack closure, effective reservoir, hydrocarbon charge or trap integrity.

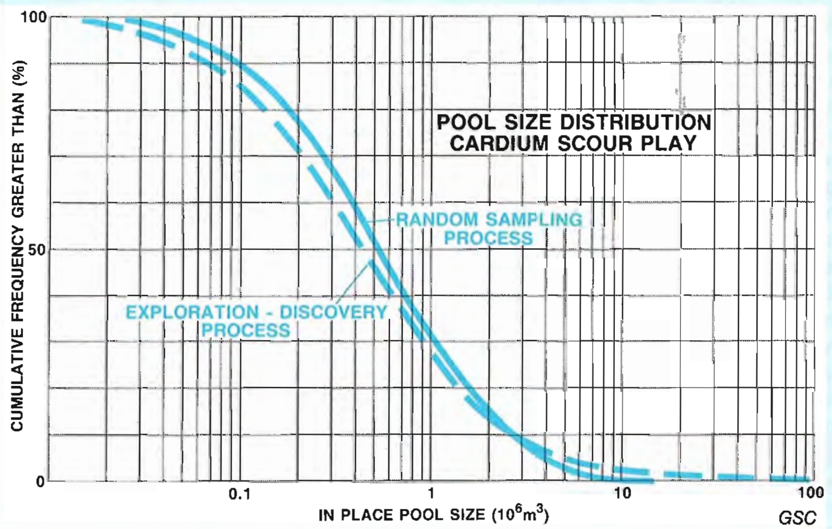


Figure 3. Pool Size Distribution, Cardium Scour Play.

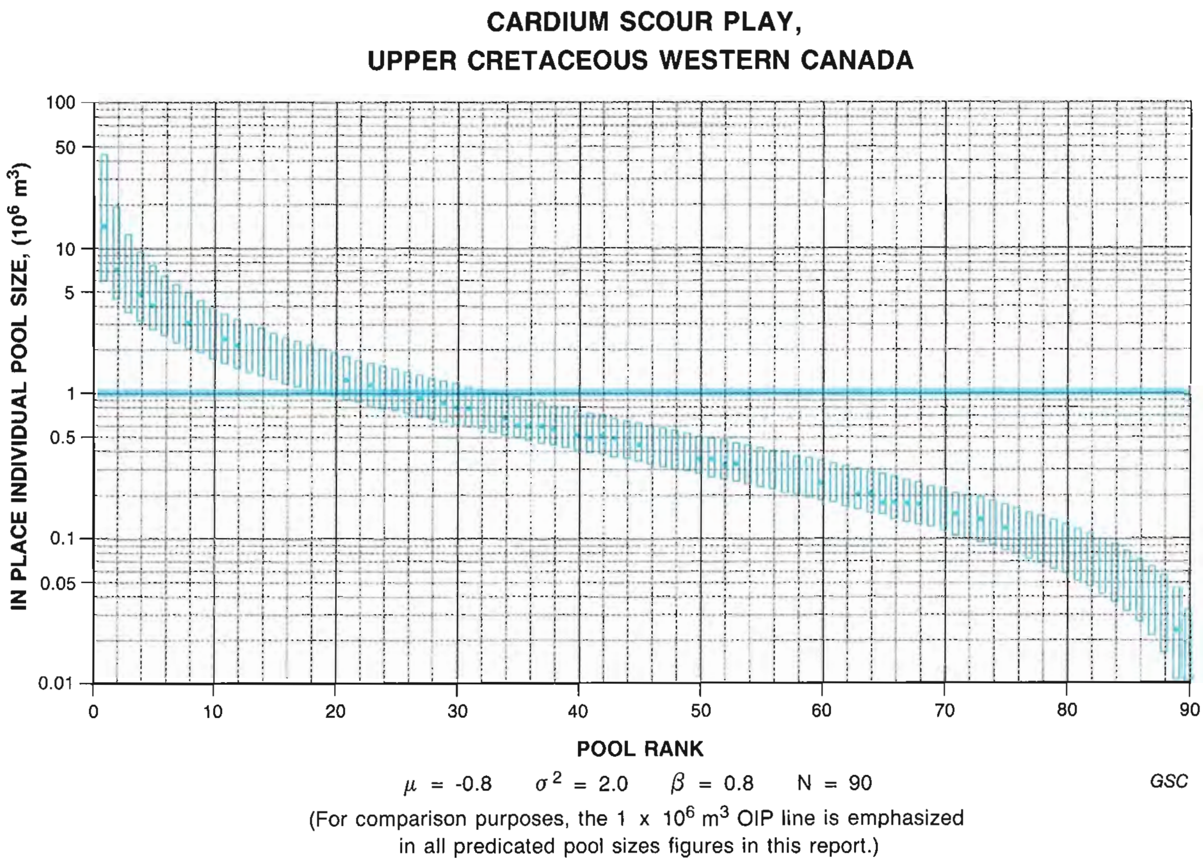


Figure 4. Predicted Pool Sizes (5^{th} to 95^{th} precentile), Cardium Scour Play.

Individual Pool Sizes by Rank

In resource evaluations, one of the most useful products is the prediction of individual pool sizes by rank, i.e. sizes of the largest pool, the second largest pool, and so on.

The necessary and sufficient inputs required for the computation are the pool size distribution and the number of pools in the play, derived by the methods described above. The individual pools are represented by boxes indicating the range of probable sizes (either by 25^{th} and 75^{th}, or 5^{th} and 95^{th} percentiles). In the first case there is a 50% chance that the pool size falls into this interval; in the second case, a 90% chance. The boxes are simply arranged from largest to smallest pool size. In Figure 4 the pool sizes are displayed in the predicted array using the 5^{th} to 95^{th} per cent option.

In the case where there is a very large number of pools, then the estimates of pool sizes are expressed in terms of numbers in pool-size classes.

Feedback Processes and Discovery Matching

The ability to estimate the sizes of individual pools in a play provides a range of feedback opportunities. At this stage the analyst can test any presumptions in terms of size and frequency against the predicted set of pools. Do the discovered pools fit into the set in a reasonable way? Do the parameters of the predicted pool size distribution compare with similar plays in a logical manner? Can the play area as defined accommodate the number of predicted pools? Does the size of the largest pool seem consistent with the discovery record to date? These and similar questions lead the analyst to adjust the parameters so that the play population computed from them is more consistent with available information and judgement related to the play. The petroleum resource appraisal software has a component called a matching process that assists the analyst. This component allows the assessor to input a stepped range of values of the mean and variance of the pool size distribution as well as a stepped range of values of N, the total number of pools. The component also uses the sizes of individual discovered pools that are already in the evaluation system. Each of the many combinations that result from the input ranges is ranked to identify the best matches according to various criteria. The assessor can examine the group of "good matches" and select one as a final choice according to his judgement of the best fit of prediction versus observed discoveries. This matching process with feedback consideration is one way of arriving at an acceptable value of N, the total number of pools.

The feedback process and the matching program can also be used as a test. For example, if a play has 15 or more discoveries, then the sample set is divided into two sets according to their discovery sequence. The first set is then used to predict the second set. This exercise allows the validation of the pool size distribution and the number of pools that were derived in the assessment. In the example used for discussion, the first forty discoveries, made prior to 1980, were used to make the assessment.

If that exercise could not predict the sizes of the eight discoveries made subsequently, then the assessment would be considered flawed and would have to be reevaluated. The outcome was that all eight new pools were predicted. For example, the pool discovered in April 1981 could be matched to the 7th ranked pool (Fig. 5) that was indicated to be undiscovered in the initial prediction.

Individual Pool Sizes by Rank Conditional to Discovery Data

After each of the discovered pools was matched to the predicted pools to the satisfaction of the analyst, the ranges of size of the undiscovered pools were recalculated. For example, pool number 3 (Figs. 4 and 5) is the largest remaining undiscovered pool in the play. The accepted match stipulates that both the 2nd and 4th ranked pools have been discovered, and the predicted size ranges of these pools illustrated in Figure 4 have been replaced by single values in Figure 5. These single values then limit the acceptable range in predicted size for pool number 3 (Fig. 5) given that the match (pool 2 and 4 discovered) is correct. This reduction in the predicted range in size of the undiscovered pools is termed "conditioning on the match". The impact of the conditioning process is evident from the comparison of Figure 4 and Figure 5 in that the size ranges of the undiscovered pools in Figure 5 are substantially modified after the discovered pools are represented by a single value. The undiscovered pools are represented by boxes, whereas discovered pools are indicated by dots.

The following observations can be made from consideration of Figure 5:

1. The total number of pools in the play is 90
2. There is a 90% probability that the size of the largest undiscovered pool ranges from 5 x 10^6 to 7 x 10^6 m^3 OIP
3. Each of the 13 largest remaining undiscovered pools exceeds 1 x 10^6 m^3 in size.

Play Potential Distributions

The pool size distribution and the number of pools can also be used to compute a probability distribution of the total resource in the play. The distribution of oil resource for the Cardium Scour play suggests that the in-place volume ranges from 90 x 10^6 to 125 x 10^6 m^3 with 50% probability. Of this total resource, 62 x 10^6 m^3 has already been discovered, the remainder being the undiscovered potential. The distribution of the remaining potential of a play can be obtained by appropriately summing the distributions of the individual undiscovered pools. This distribution of remaining potential ranges (at 90% probability) from 35 x 10^6 to 40 x 10^6 m^3 OIP with the median value of 37 x 10^6 m^3 OIP (7.18 x 10^6 m^3 recoverable potential). In this report the median value of the play potential distribution is reported and the estimation interval has also been reported for certain plays that have a wide range in their estimates.

Preparation of Data for Economic Analysis

After completing each play estimate the resource evaluation software system uses a

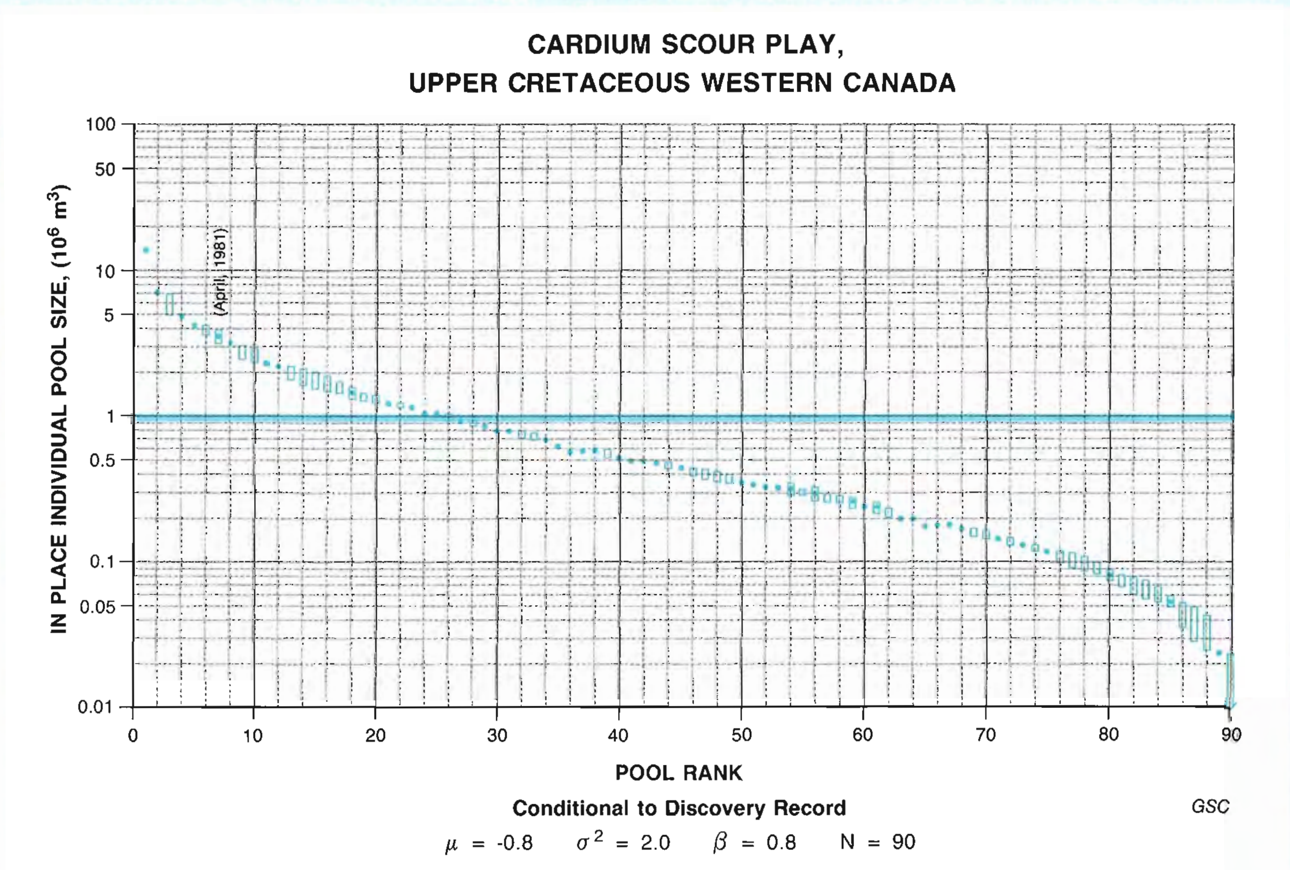


Figure 5. Conditioned Pool Array (5th to 95th precentile), Cardium Scour Play.

report writer to compile material generated in the analysis for the economics group. The data provided includes:

- a summary of the estimates
- listing of pool data used
- all outputs from different evaluation components
- graphic displays of probability distributions and estimates
- cross plots of various reservoir parameters such as in-place pool volume plotted against pool area, etc.

The estimates for the individual pool sizes by rank are the principal inputs for the economic analyses. Unfortunately only the median value for each individual pool size distribution could be entered into the economic model. The use of single values instead of the entire distribution for the economic evaluation does not incorporate the uncertainty associated with the estimate and may lead to misinterpretations during the downstream analyses.

Assumption of Lognormality

Pool sizes within an exploration play are commonly observed to be approximately lognormally distributed. In the evaluation of oil resources of the Western Canada Sedimentary Basin, most of the mature established plays were analyzed using the assumption that their pool size distributions could be approximated by a family of lognormal distributions. For each play the sizes of the discovered pools were plotted on lognormal probability paper in order to detect any evidence that would invalidate this assumption. Figure 6 is the log-probability plot for the Cardium Scour play used as an example. The relatively straight line formed by the discovered pools is an indication that the assumption is valid for this play.

Limitations in the Estimation Process

There are many ways in which error can be introduced into the resource evaluation process. Poor definition or mixing of plays may distort statistical analysis; errors may exist in the input data; failure to match largest pools correctly or to recognise the possibility of a larger "largest pool" can seriously affect the estimates; and incomplete or incorrect understanding of the basic geological controls of a play can lead to poor judgement in the selection of the number of pools. Each methodology is subject to improvement as research reveals new functional relationships. This is a continuing process and the methods that have been used in the current study are simply the best that were available to the analysts at the time.

Play Potential

Play potentials are calculated as a distribution on which all points are valid. Plays in a basin may be summed and expressed in a similar fashion (Fig. 7) including the discovered portion of the resource. For convenience, only the median values for the potential are quoted in this report. It should be noted that in PART II: ECONOMIC ANALYSIS, only these median values were used.

In the descriptions of individual plays in the following parts of this report only the first 30 pools are illustrated in the rank plot. The mean (μ) and the variance (σ^2) of the lognormal distribution are also given, as are the values of the total number of pools in the play (N), and a value beta (β) that describes the "exploration efficiency" factor that is reflected in the discovery sequence plots (Fig. 2). Beta values are commonly between zero and one, and are a measure of the proportionality of the pool sizes to discovery. A low β value suggests that the discovery process is nearly a random sampling process. This randomness could be due to the effect of nearly uniform pool sizes, or any of the factors previously mentioned. The higher the value, the more the impact of pool sizes has on the order of discovery.

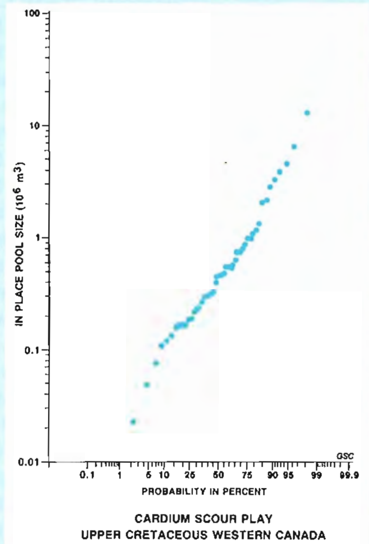


Figure 6. Log Probability Plot, Cardium Scour Play.

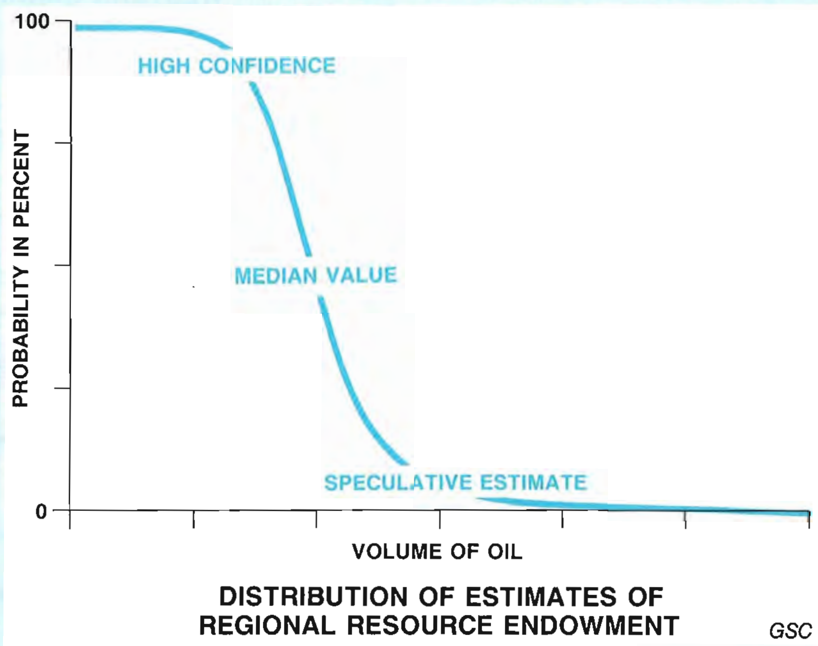


Figure 7. Cumulative Frequency Plot of Resource Endowment.

GEOLOGICAL FRAMEWORK

The Western Canada Sedimentary Basin occupies an area of 1.4 x 10^6 km^2 of southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia, and the southwestern corner of the Northwest Territories. The extension of the basin in the United States has an additional area of 0.26 x 10^6 km^2. The basin is bounded on the north by the Tathlina Arch; on the east by the erosional edge at the Canadian Shield; and on the south by the Transcontinental, Sioux and Central Montana Arches. To the west the basin is limited by the structural front of the Rocky Mountains. During much of its history, the basin did not possess well-defined limits, and was directly linked to other depocentres in western North America. The boundaries chosen in this report do, however, have some geologic significance in addition to being approximately coincident with the political boundaries of the Prairie Provinces of Canada. In general, the sediments of the basin form a prism which thickens from the erosional edge at the Canadian Shield towards the southwest. The Western Canada Sedimentary Basin is subdivided into the Alberta and Williston Basins by the Sweetgrass Arch (Fig. 8).

Two major westward-thickening sedimentary wedges constitute the fill of the Western Canada Sedimentary Basin. Each wedge contains about the same volume of sediment, but they were the product of very different tectonic settings. The deeper wedge contains dominantly marine sediments of Late Proterozoic to Middle Jurassic age. These easterly-sourced units were deposited on the stable passive continental margin and adjacent craton of ancient North America during a series of episodic transgressive events. The second major wedge contains shallow marine and non-marine clastic sediments of Late Jurassic to Tertiary age. These sediments were deposited in a migrating foredeep created by the loading of the craton by the overriding tectonic mass of thrust sheets resulting from the collisional accretion of micro-continents to the western margin of ancient North America. The rising thrust sheets provided both the detritus to fill the foredeep and the tectonic load to tilt the earlier sediments towards the continental margin. This gentle westward tilt created the burial conditions for hydrocarbon generation and the gravitational potential for the updip eastward migration towards traps within the system.

BASIN DEVELOPMENT

The episodic nature of both the epeirogenic and orogenic movements through time resulted in periodic major changes in sources of sediment and sudden lateral shifts in facies belts. Recognition of these large-scale events within the stratigraphic succession has permitted the identification of two Precambrian and six Phanerozoic major unconformity-bounded sequences. Within the Phanerozoic, four sequences occur in the first wedge of stratigraphy, and two within the second (Fig. 9). Similar unconformity-bounded sequences established by Sloss (1963) for the mid-continent region of North America provide a convenient framework within which to describe the geological history of the Western Canada Sedimentary Basin. Although there is a reasonable degree of coincidence between the classical Sloss sequences and the historical record of the Western Canada Sedimentary Basin, not all his boundaries correspond precisely to the major tectonic events that have influenced the basin at the local level. Nevertheless the concept is useful and has served as a guide in the treatment of individual chapters.

Only a summary overview of the geological history of the Western Canada Sedimentary Basin has been attempted in this chapter as greater detail is to be found in the main body of the report dealing with the specific geological periods and their oil prospectivity. Also included in those chapters are references to the significant publications that form the basis of the following geological summary.

Precambrian

The initial phase of basin development occurred during the Helikian, when rifting of the entire western margin of North America resulted in the deposition of syn-rift and post-rift passive margin sedimentary terrace wedges. The Belt-Purcell Supergroup (1600-1350 Ma B.P.) of southwestern British Columbia and northwestern Montana contains up to 15 km of deep water clastic, to shallow water clastic and carbonate rocks (sequence 1). The rifting event was probably followed by transformation from a passive to an active margin and later uplift and partial erosion of the sediments of sequence 1.

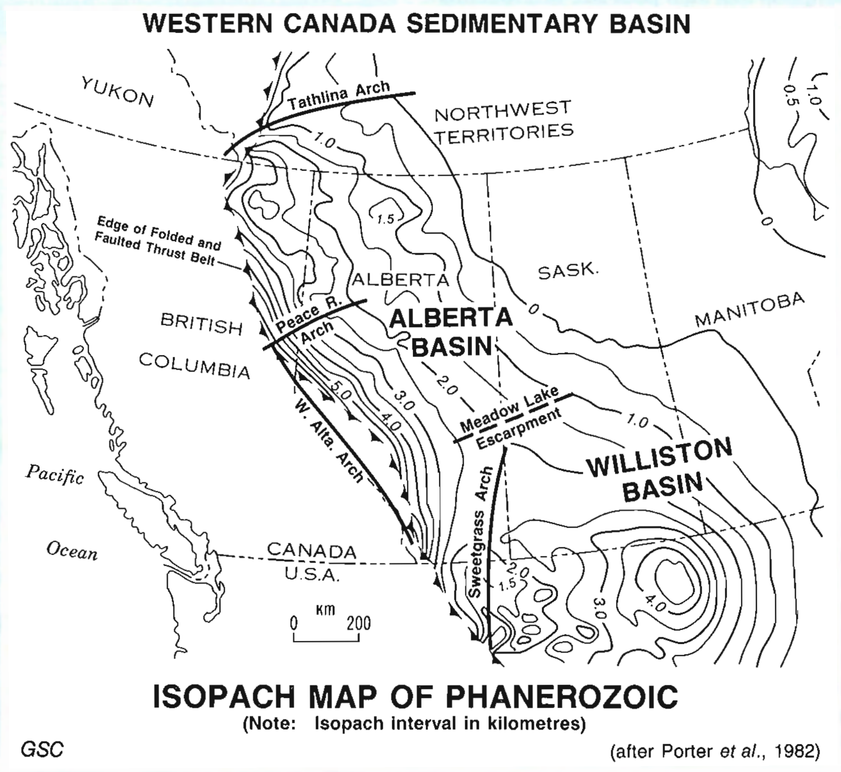


Figure 8. Basin Fill Map, Western Canada Sedimentary Basin.

A second rifting event during the Hadrynian re-opened the western continental shelf to marine influence. The sediments deposited at this time (sequence 2) comprise the Windermere Supergroup (850-600 Ma B.P.). This sequence is a westward thickening wedge of immature, dominantly coarse clastic rocks more than 9 km thick. The sequence unconformably underlies Cambrian rocks in the eastern regions but may be conformable in its western, more distal development.

Virtually all of the Precambrian rocks were deposited in the miogeocline west of the relatively stable craton. The narrow "Southern Alberta Rift" (Kanasewich *et al.*, 1969) may be the only Precambrian depocentre in the Western Canada Sedimentary Basin. Precambrian sedimentary rocks are not included in this assessment of oil potential.

Cambrian to Lower Ordovician

The third sedimentary sequence (Sauk) contains the record of the first extensive transgression of the seas onto the interior of the North American continent. In western Canada these deposits comprise a westward thickening wedge of sediments deposited in response to the formation of a passive continental margin similar to the present Atlantic margin of North America. The deposits of this sequence are dominated by shallow marine carbonates and clastics. The seas transgressed from the west so that the facies belts are aligned approximately along north-northwest trends. The continental surface on which the sediments were deposited was relatively flat so that minor fluctuations of sea level resulted in abrupt lateral shifts of the facies belts. Ancient North America at that time was located in the equatorial latitudes that favoured the deposition of carbonates in warm, shallow oxygenated water relatively free from the influx of clastic sediments.

Middle Ordovician to Silurian

The record of the Tippecanoe sequence is fragmentary in much of the Western Canada Basin. Tectonic loading as a result of the Taconic Orogeny in eastern North America depressed the eastern part of the continental crust in Middle Ordovician time. Epeiric seas transgressed the Transcontinental Arch and deposited sediments in Manitoba and southern Saskatchewan that onlapped from the southeast. In the west a slow rate of subsidence resulted in the deposition of widespread shallow marine sediments. The depositional environments were similar to those of the Sauk sequence. However, the Late Ordovician phase of transgression that covered most of North America left little

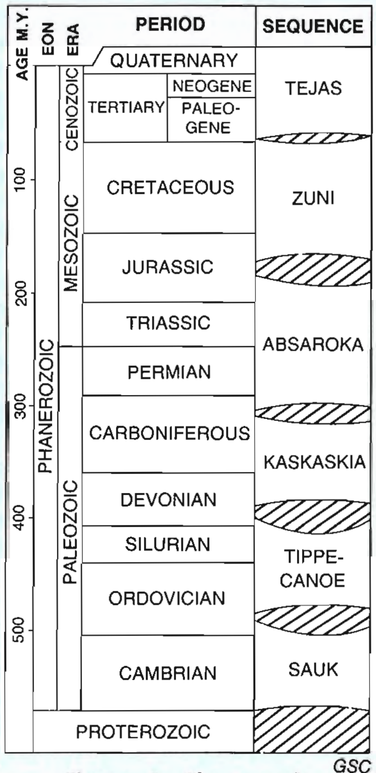


Figure 9. Phanerozoic Time Scale.

source area available for the production of clastic detritus; as a result, the characteristic facies belts lose their definition. The relatively broad development of the carbonate facies limited the opportunity for the development of stratigraphic traps. During Late Silurian and earliest Devonian time the seas withdrew from the centre of the continent and the subsequent period of erosion resulted in the removal of much of the stratigraphic record from the Alberta Basin.

Devonian to Lower Carboniferous

Strata assigned to the Kaskaskia sequence record the history of a number of transgressive-regressive cycles. Because the major portion of the conventional light and medium oil resources of western Canada are hosted in rocks of this sequence, Moore (in press) gave names to the Devonian cycles to provide an adequate framework within which to discuss their geological history. In the Devonian chapter of this report Moore's sequences are used as the basis for analysis.

During the period of erosion and assumed tectonism that preceded deposition of rocks assigned to the Kaskaskia sequence the Alberta Basin was divided by arches into basins that controlled the depositional patterns of Devonian sediments. The coverage of the arches was not complete until late in the Devonian. The arches created a number of partially protected basins in which extensive reef tracts grew. Coarse clastics shed from the arches fringed the basins, particularly around the Peace River Arch. Anoxic conditions developed in the deeper parts of the partially enclosed basins permitting the accumulation of organic-rich sediments. These would become the prolific source rocks that ultimately charged the reef traps and marginal clastics with hydrocarbons.

With the arches buried, early Carboniferous depositional patterns became more like those of the earlier Paleozoic. The Peace River Arch ceased to exist as a positive element by this time and instead became a major depocentre for late Paleozoic sedimentation.

Upper Carboniferous to Middle Jurassic

The Absaroka sequence, spanning the time between Late Carboniferous and Middle Jurassic, is characterized by a general instability of the continental margin. The stratigraphic record is interrupted by a series of minor unconformities. The unconformity surfaces merge eastward into a zone where most of the stratigraphic record is missing. Except in the limited areas of mild tectonic activity described below, sea level fluctuation was the dominant control on sedimentation. However at no time during deposition of this sequence is there evidence of prolonged or extensive transgression of the seas over the interior of the craton. The offlapping pattern characteristic of the immediately underlying Carboniferous continued, with the bulk of the clastic components being derived from the craton. A gradual transition from dominantly carbonate deposition to clastic sedimentation is evident. This was largely in response to the gradual northward drift of the North American continent towards higher latitudes, unfavourable for carbonate sedimentation.

Subtle tectonic features and structures in the continental crust were accentuated during this period of minor continental instability. In particular, uplift of the Sweetgrass Arch and subsidence in the Peace River and Williston Basin regions influenced the depositional framework. Williston Basin was characterized by terrestrial and shallow marine deposits whereas north of Sweetgrass Arch sedimentation occurred under the influence of open marine conditions. However, much of the Upper Carboniferous stratigraphic record is missing because of several internal unconformities.

The Mesozoic portion of the Absaroka sequence continued to be dominated by clastic sedimentation except for a brief interval during the Late Triassic. Rocks of this age are limited to the northwestern and western parts of the Alberta Basin where a partial stratigraphic record is preserved. There the marginal marine deposits, where preserved, indicate frequent though not excessive fluctuations of sea level. Shallow marine Lower and Middle Jurassic strata are distributed across most of the Williston Basin, the Sweetgrass Arch, and the western part of the Alberta Basin.

Late Jurassic to Paleocene

A major change in the depositional regimes of the Western Canada Sedimentary Basin occurred early in the Zuni sequence. This was caused by the arrival off the west coast of ancient North America of exotic terranes or subcontinents riding with oceanic plates and their accretion to the North American plate. The accreting terranes compressed and detached the sediments that formed the westward extension of the cratonic margin and translated these up and over each other to form the orogenic belt that bounds the basin to the west. The tectonic loading caused by these telescoping thrust sheets flexed the crust to create the migrating foredeep that developed in front of the advancing thrusts. The eastward expanding orogenic welt of the Cordillera became the source of the clastic sediments deposited in the Foreland Basin. Several clastic sequences reflect the major orogenic developments. Late Jurassic to earliest Cretaceous, and Early Cretaceous to late Early Cretaceous sequences were deposited during and following the Columbian Orogeny. During the early Late Albian a major transgression from the south and east established an extensive intracontinental seaway. Within this sea, major transgressions occurred during the early Late Albian, Turonian and Santonian. From Campanian to Maastrichtian time major regressive sandstones prograded into the intracontinental seaway. This represents the early stages of the Laramide Orogeny which continued into the Paleocene and was accompanied by molasse sedimentation. Sedimentation in the Foreland Basin ceased by Eocene time following which the region was subjected to uplift and erosion.

Eocene to Pliocene

The Western Canada Sedimentary Basin was episodically uplifted and eroded from the Eocene to the Pliocene. The only deposits representing the Tejas Sequence (Sloss, 1963) are continental coarse clastic rocks, with extremely limited distribution and no oil potential.

CAMBRIAN, ORDOVICIAN, AND SILURIAN SYSTEMS

Two sequences (Sloss, 1963) are represented by the Cambrian, Ordovician, and Silurian systems in the subsurface of the Western Canada Sedimentary Basin: the Sauk sequence contains Middle Cambrian to Lower Ordovician rocks, and the Tippecanoe sequence contains Middle Ordovician to Silurian rocks. Major unconformities separate the two sequences from each other, from underlying Precambrian crystalline basement, and from overlying Devonian or younger sedimentary rocks. The maximum preserved thickness of the Sauk sequence is 600 m, in eastern Alberta; that of the Tippecanoe sequence is 500 m in southeastern Saskatchewan.

The division of the Alberta and Williston basins in these sequences follows the approximate trend of the Sweetgrass Arch northward into the Meadow Lake Escarpment (Fig. 8). Stratigraphy differs between the basins, because of Middle Cambrian depositional limits eastward and Ordovician and Silurian preservational limits westward (Table 1).

Most of the wells in western Canada have been drilled for Devonian or younger targets; nevertheless, the small number (less than 1000) of wells that have penetrated pre-Devonian Phanerozoic rocks are enough to provide an outline of the depositional history and approximate distribution of these rocks. Many additional details of the geological history have been obtained from the study of the well exposed stratigraphic sections of the eastern Rocky Mountains and the eastern outcrop belt in Manitoba and Saskatchewan. Pre-Devonian rocks in the Williston Basin have been the focus of a great deal more exploration activity in the United States portion of the basin than in Canada. These additional subsurface data have also contributed to the understanding of Lower Paleozoic depositional history in Canada.

DEPOSITIONAL STYLE

The surface over which the seas of the initial Sauk transgression advanced was one of low relief with few identifiable (or as yet identified) elevated areas. Locally however in southeastern Alberta and western Saskatchewan small hills or monadnocks of crystalline basement with as much as 100 m of local relief existed during Cambrian sedimentation. Other Precambrian structural or geomorphological features have been postulated, such as a precursor of the Peace River Arch inferred by Pugh (1973) from the configuration of the Middle and Upper Cambrian strata.

Facies development in rocks of the Sauk sequence was primarily controlled by fluctuations in sea level. The combination of low relief and the location of the ancient North American craton very close to the paleoequator favoured carbonate deposition within the warm, shallow epeiric seas. The nearly flat crystalline basement surface was mantled by deeply altered clastic debris that the advancing Saukian seas reworked into diachronous basal sandstone deposits. Typically, the overlying sediments occur in three distinctive facies belts. Shallow water limestones of the "middle carbonate" belt separated the "outer detrital" deep water fine grained sediments from the fine- to coarse-grained sediments of the "inner detrital" facies (Aitken, 1966). Only the "inner detrital" and the "middle carbonate" facies occur in the subsurface of the Western Canada Basin. Evaporitic sediments commonly were deposited as tongues between the "inner detrital" and "middle carbonate" facies. Because carbonate deposition kept pace with the slow rise of sea level, and also because the low relief of the craton limited clastic influx from the margins, the facies belts were relatively stable. In contrast, during the rare occasions when rapid sea level fluctuations occurred, abrupt lateral shifts of the facies belts resulted.

Following the period of erosion that separates the Sauk and Tippecanoe sequences, broad uplifts (Fig. 12) were initiated that began to define the Williston Basin as a discrete entity. Basal marine sandstone and shale of the Winnipeg Formation derived from the emerging uplifts record the marine transgression into the Williston Basin from the southeast. The sandstone covers much of the basin, varying in thickness from its depositional edge in the west and its erosional edge in the east, to 60 m in the basin centre. Succeeding

EPOCH	SLOSS SEQ.	ALBERTA BASIN		WILLISTON BASIN	
EARLY DEVONIAN					
LATE SILURIAN	TIPPECANOE SEQUENCE			INTERLAKE GROUP	
EARLY SILURIAN	TIPPECANOE SEQUENCE			INTERLAKE GROUP	
LATE ORDOVICIAN	TIPPECANOE SEQUENCE			BIGHORN GROUP	STONEWALL
				BIGHORN GROUP	STONY MOUNTAIN
				BIGHORN GROUP	HERALD / YEOMAN; RED RIVER
MIDDLE ORDOVICIAN	TIPPECANOE SEQUENCE			WINNIPEG	
EARLY ORDOVICIAN					
LATE CAMBRIAN	SAUK SEQUENCE	LYNX GROUP	DEADWOOD	DEADWOOD	
MIDDLE CAMBRIAN	SAUK SEQUENCE	PIKA	EARLIE		
		ELDON	EARLIE		
		STEPHEN	EARLIE		
		CATHEDRAL	EARLIE		
		MT. WHYTE			
		Basal Sandstone Unit			
EARLY CAMBRIAN					
PRECAMBRIAN (APHEBIAN)		Crystalline Basement		Crystalline Basement	

GSC

Table 1. Table of Formations, Cambrian to Silurian, subsurface of Western Canada Sedimentary Basin.

sediments of the Bighorn and Interlake groups are dominantly shallow water, low energy, shelf carbonates (Kendall, 1976). Deposition was typically cyclical, with subtidal carbonate or argillaceous carbonate forming the base of each cycle. This facies passes upward into shallow subtidal and semi-restricted carbonate. The cycles are commonly capped by evaporite beds deposited in either supratidal environments or shallow restricted basins. Both early (syndepositional) and late (post-compaction) diagenetic alteration to dolomite took place. Diagenesis was responsible for porosity creation in the otherwise impermeable lime mudstones and wackestones of the Bighorn and Interlake groups. The maximum preserved thickness of the Ordovician-Silurian carbonate beds is 500 m, in southeastern Saskatchewan.

DISTRIBUTION

The present distribution of rocks of the Sauk sequence is the result of a combination of several episodes of erosion (Fig. 10). Within the Alberta Basin only small preserved remnants lie north of the Peace River Arch, and much of the section is missing from the West Alberta Arch. South and east of these arches, in the subsurface of southern Alberta and eastern Saskatchewan, the rocks have been bevelled normal to their depositional strike, indicating that the Williston Basin did not become established until later (Porter *et al.*, 1982). The eastern limit of Middle Cambrian strata is the only depositional edge in this sequence.

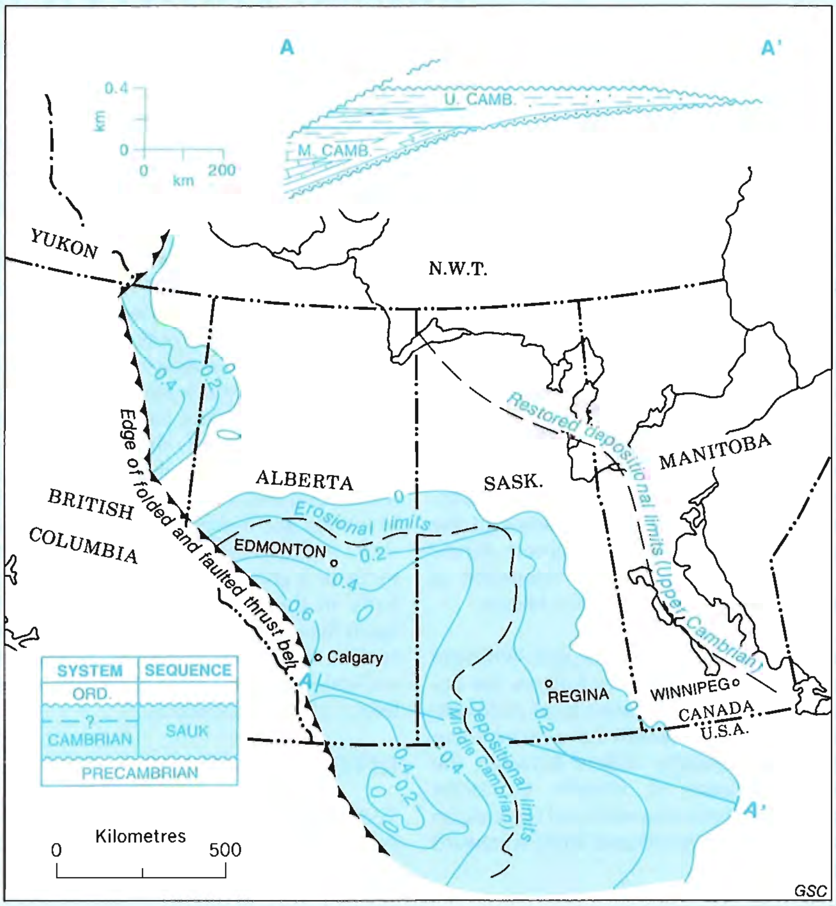


Figure 10. Distribution of Sauk Sequence, Western Canada Sedimentary Basin (after Porter *et al.*, 1982).

The Ordovician transgressions over the North American craton were the most extensive of the geologic record. Deposition of Ordovician (and possibly Silurian) carbonates probably occurred over most of western Canada, but they are now only preserved in the Rocky Mountains and in the Williston Basin. The stratigraphic record is, however, nearly complete in the central portion of the Williston Basin. The northwest subsurface erosional limit is defined by the Meadow Lake Escarpment, a cuesta-like feature developed prior to the deposition of Devonian rocks (Figs. 11 and 12).

PETROLEUM GEOLOGY

Little oil has been discovered in the pre-Devonian rocks of the Western Canada Sedimentary Basin. Shows and discoveries have been mostly confined to the Red River Formation of the Williston Basin. Nevertheless numerous pools have been discovered in these and older rocks within the United States portion of the basin where there has been considerably more exploration effort. It can be assumed that at least moderate success would result from a comparable exploration effort in Canada.

Middle Cambrian reservoir rocks of the Alberta Basin (Table 1) include: the basal sandstone unit and Mt. Whyte Formation sandstones; and the carbonate beds of the Cathedral, Eldon, and Pika Formations. The carbonates are typically impermeable lime mudstone and wackestone. They require diagenetic alteration to dolomite to form reservoir rock. This has occurred by movement of reactive fluids: from adjacent shale beds at abrupt shale to limestone facies transitions; up fault and fracture planes in structurally-deformed areas; and downward from subaerially exposed unconformity surfaces. Sandstones equivalent to the Cathedral, Eldon, and Pika formations that surround the southern part of Peace River Arch, and Earlie Formation sandstones of the "inner detrital" belt, are also potential reservoir rocks. Upper Cambrian reservoirs are Lynx Group carbonates, which are commonly dolomitized beneath the Devonian unconformity in central Alberta; and Deadwood Formation sandstones and limestones.

Clastic reservoir rocks of the Williston Basin (Table 1) include the Upper Cambrian Deadwood Formation sandstones and Middle Ordovician Winnipeg sandstone. The Red River (Yeoman and Herald equivalent), Stony Mountain, and Stonewall formations of the Bighorn Group and the Interlake Group all contain carbonate beds that are potential reservoir rocks, providing that porosity was developed by either early or late diagenesis in the normally low permeability, fine grained lime mudstone beds.

Type II organic matter has been identified in source rocks (Williams, 1974; Dow, 1974; Osadetz and Snowdon, 1986) within the Ordovician of the Williston Basin. The richest source rocks are the Icebox shale of the Winnipeg Formation, and kerogenite layers within the Red River (Yeoman) Formation. The source rocks necessary to establish the prospectivity of Cambrian plays in the Alberta Basin have not been identified. The depositional model developed for the Cambrian rocks does not exclude the possibility of source rocks, but it does not favour them.

Although the bulk of the production of oil from pre-Devonian pools in the United States portion of the Williston Basin comes from structural traps, such as those along the Nesson Anticline, there appear to be no similar structures in the Canadian portion of the basin. Most of the traps envisaged for Canada are stratigraphic.

EXPLORATION PLAYS

Eighteen exploration plays have been defined for the purpose of the report in the pre-Devonian rocks of the Western Canada Sedimentary Basin. Only one of these plays (Red River) has been confirmed by discoveries, and these are so few in number that no in-depth analysis has been attempted.

Conceptual Plays

Two classes of conceptual plays were analyzed and each should occur in both the Alberta and Williston Basins. Stratigraphic traps may occur because of facies change in both clastic and carbonate successions and beneath regional unconformities; structural traps may occur over local uplifts or in drapes over pre-existing basement topography, and in porosity developed either because of fractures or dolomitization associated with faulting.

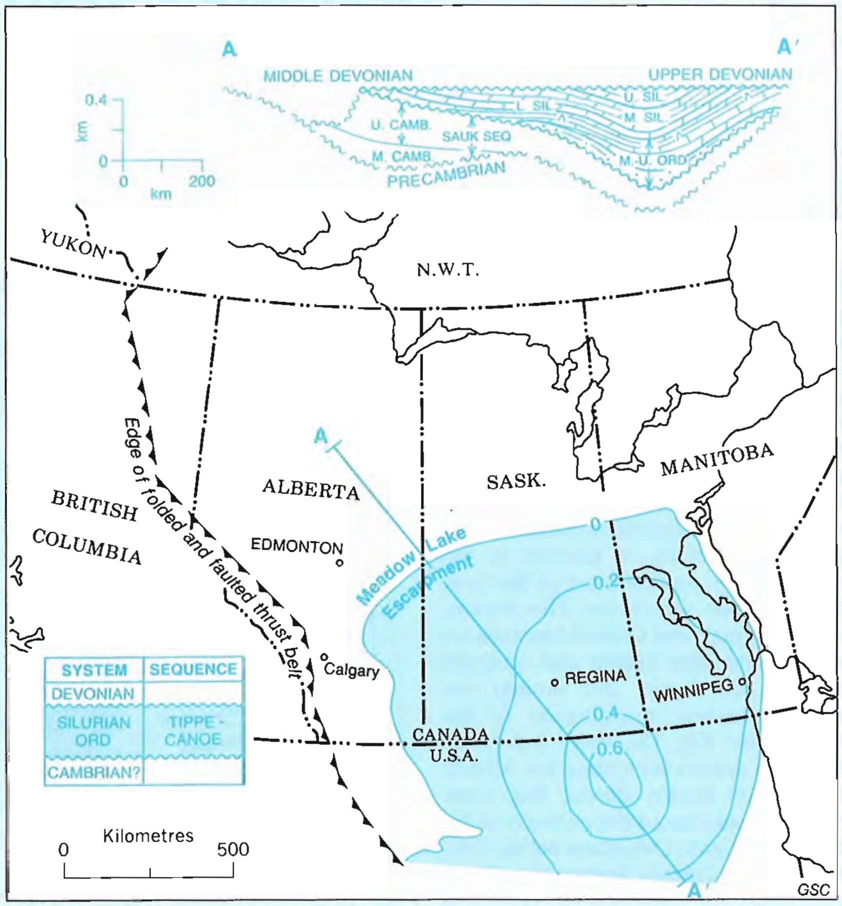


Figure 11. Distribution of Tippecanoe Sequence, Western Canada Sedimentary Basin (after Porter *et al.*, 1982).

The **Lynx unconformity play** is related to dolomitization associated with the immediately overlying pre-Devonian unconformity. Other stratigraphic traps in carbonate reservoirs should exist as the result of facies change in the **Cathedral, Eldon, Pika** and **Lynx** formations at the updip transformation from the "middle carbonate" to "inner detrital" facies within the Alberta Basin. There are only minor shows and porosity developments within these five stratigraphic carbonate plays of the Alberta Basin.

Stratigraphic traps resulting from the updip pinchout of porous clastic reservoir probably occur in the **Earlie Formation** (and equivalent Cathedral, Eldon, and Pika sandstones immediately south of the Peace River Arch), and in the ubiquitous **basal sandstone unit**. Other traps can be expected where porous clastics onlap the paleotopography of the crystalline basement.

Within the Canadian portion of Williston Basin stratigraphic traps may occur in **Deadwood** and **Winnipeg** sandstones and in the **Bighorn** and **Interlake** group carbonates. The trapping seal in the carbonate plays is expected to be up-dip porosity occlusion by evaporite minerals; in the clastic plays it is expected to be an updip facies change to shale. The four plays have been found to contain oil staining or 'dead' oil.

There is also an unconformity play in the **Red River**, along its northwest erosional edge that follows the Meadow Lake Escarpment and the Sweetgrass Arch.

The **Alberta Cambrian Structure** play includes structural trap development where Cambrian clastic and carbonate reservoirs are either draped over pre-existing topography or occur in larger post-Cambrian structures. Inert gas is produced from the basal sandstone unit along local structures on the Sweetgrass Arch in southern Alberta. There is no hydrocarbon production in this play.

Similar trap situations are envisaged for the **Deadwood Structure** and **Winnipeg Structure** plays in the Williston Basin. Both of these formations have minor oil production in the United States, and the Deadwood produces inert gas in local structures in southeastern Saskatchewan.

The **Stony Mountain-Stonewall Structure** and the **Interlake Structure** plays have significant production in the United States portion of the Williston Basin, where both structural culmination and late diagenesis play a role in trap development. There is no production in Canada from these two carbonate structure plays.

Established Plays

The **Red River Structure** play has small oil pools at Lake Alma, Hummingbird, Beaubier, West Oungre, and Tablelands in southeastern Saskatchewan. The reservoir is porous shelf carbonate, and the source may be indigenous kerogenite layers. Traps are created by small local structures. Solution movement along fault planes in these areas probably enhanced reservoir properties. This play contains most of the pre-Devonian oil reserves in the United States portion of the Williston Basin.

DEVONIAN SYSTEM

For purposes of this report the Kaskaskia sequence (Sloss, 1963) has been divided into Devonian and Mississippian sections based upon economic importance and differences in basin configuration, depositional style and hydrocarbon trap mechanisms. Deposition of Lower, Middle and Upper Devonian sediments was preceded or accompanied by Late Silurian to Early Devonian epeirogenic movements which had a profound effect upon sedimentation patterns. The development of the Tathlina, Peace River, and West Alberta arches in the north and west parts of the basin caused abrupt local facies variations manifested by reef rimmed shelves, in contrast to the ramp-dominated environment of the Sauk and Tippecanoe sequences. The Severn, Transcontinental, and Central Montana arches controlled the eastern and southern margin of the basin and limited the southeast directed transgression of the Devonian seas (Fig. 12). There was no effective arch system separating the Alberta and Williston basins during this time. Periodically, continuous deposition over the Tathlina and Central Montana arches linked the Western Canada Sedimentary Basin to the Mackenzie Basin and the Wyoming Shelf. The western margin of the basin occurs over a broad hinge zone where the relatively stable craton grades into the miogeocline. The eastern limit of the basin is the erosional edge of Devonian rocks, which formed during several Paleozoic, Mesozoic, and Cenozoic erosional events. Deposition occurred upon eroded Ordovician and Silurian rocks in the Williston Basin, and upon eroded Precambrian and Cambrian rocks in the Alberta Basin (Fig. 12).

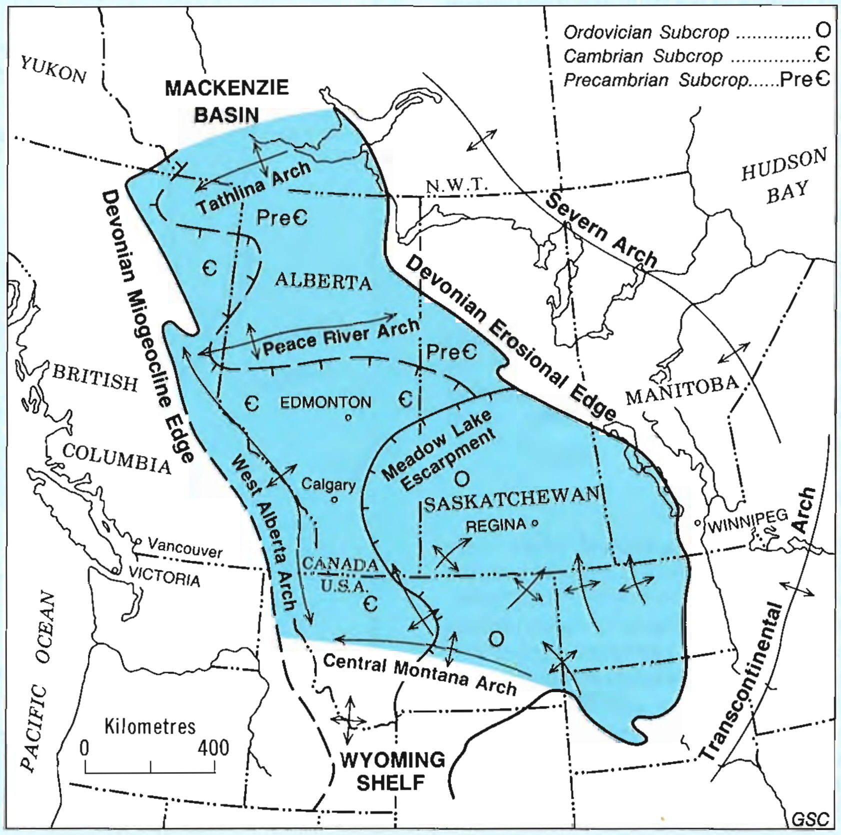


Figure 12. Principal Devonian and pre-Devonian tectonic elements, Western Canada Sedimentary Basin. The basin limits are the miogeocline edge to the west, the Tathlina Arch to the north, the erosional edge to the east, and the Central Montana Arch to the south.

Five major Devonian transgressive-regressive cycles by have been identified by Moore (in press). In order of decreasing age, these are: Delorme (Gedinnian-Siegenian), Bear Rock (Emsian-Eifelian), Hume-Dawson (Eifelian-Givetian), Beaverhill-Saskatchewan (Givetian-Frasnian), and Palliser (Famennian) sequences. They correspond approximately to the Lotsberg Formation; the remainder of the Lower Elk Point Group; the Upper Elk Point Group; the Beaverhill Lake, Woodbend and Winterburn groups; and the Wabamun Formation of the Alberta Basin respectively (Table 2). The Beaverhill-Saskatchewan sequence is divided into two subsequences in which the basin architecture is different but which are not separated by an unconformity. These sequences are of a lower order than the Sloss sequences; but they represent events that deposited internally conformable units separated by minor unconformities. They correspond to third order events of Vail *et al.* (1977). The extent of deposition, or the magnitude of sea level rise, basin subsidence, or both, increased progressively to a maximum during the Frasnian, then waned during Famennian time.

DEPOSITIONAL STYLE

Western Canada was situated in equatorial latitudes throughout the Devonian and thus became a dominantly carbonate-evaporite sedimentation province. A single depositional model can be applied to the five sequences with only minor modifications. Figure 13 illustrates the relatively thick epeiric sea deposits that lie between thin clastic-evaporite, fluvio-deltaic and shallow marine sediments adjacent to the continental landmass and deep marine clastic-carbonate sediments of the miogeocline or open continental shelf west of the craton. This figure does not illustrate the thickness changes that occur within a sequence toward the shoreline or over local topographic highs. The complex facies distribution of the epeiric sea deposits which included simultaneous deposition of excellent hydrocarbon source beds in proximity to potential reservoir rocks was what created the vast hydrocarbon resource of the Devonian of Western Canada.

An interpretation of the depositional settings is best introduced by the definition of the terms used in this chapter (Fig. 13).

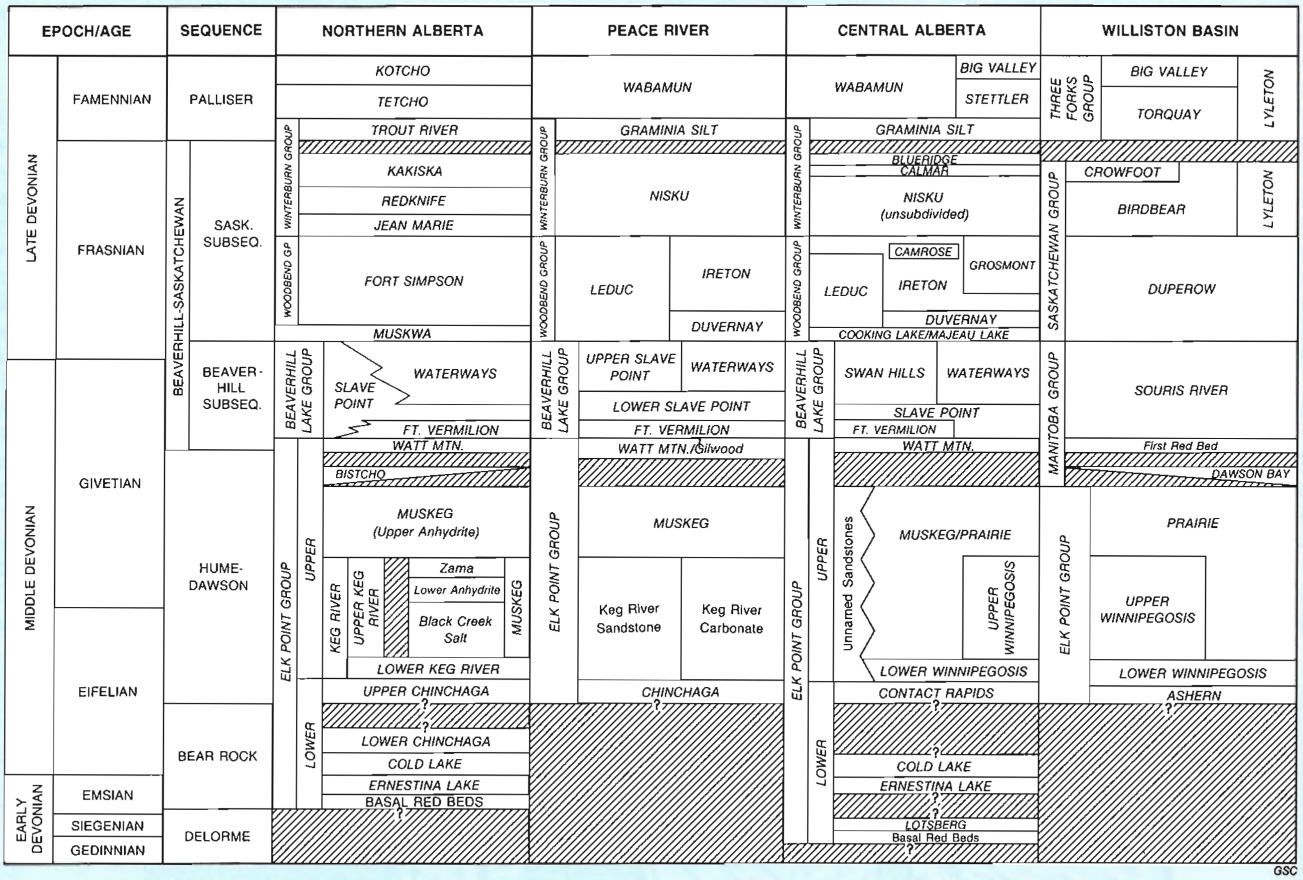


Table 2. Table of Formations, Devonian, subsurface of Western Canada Sedimentary Basin.

The **Transgressive Phase** refers to deposition during rapidly rising sea level in which carbonate production could be maintained only in discrete basinal areas and on barrier-protected shelves. Equivalent basinal sediments were thin relative to carbonate units. It should be noted that in this report **Transgressive** is a term used loosely to indicate deposition during deepening conditions, regardless of the direction of migration of the shorelines which, in many cases, lay outside the area of study.

Regressive Phase beds were formed by deposition during slowly rising sea level, stillstand, or falling sea level, when carbonate production developed thin, widespread beds, equivalent to thick basin-fill units. In this report the term **Regressive** is used loosely to indicate shelf progradation or deposition under shallowing conditions regardless of the direction of migration of the shorelines which, for the most part, lay outside the area of study.

A **Reef** is a massive marine carbonate unit that formed by progressive buildup of organic framework constituents and their local sediment derivatives and had topographic relief above the sea floor at the time of deposition.

Carbonate Units — Reservoirs

A **Barrier Reef** is a chain of transgressive phase reefs that separated seaward deep water clastic and carbonate deposition from landward carbonate shelf, evaporite-carbonate intra-shelf basin, and clastic-evaporite sedimentation. Open marine circulation was restricted at times behind the barrier reefs.

A **Reef Complex** is an areally extensive transgressive phase reef, commonly with a lagoonal interior and complex sedimentary facies distribution, that was surrounded by deeper-water clastic-carbonate or evaporite-carbonate units.

A **Pinnacle Reef** is a transgressive phase reef, less than a half square kilometre in area, that is thicker than its diameter and possesses relatively simple facies distribution. It was surrounded by basinal sediments.

A **Patch Reef** is less than three square kilometres in area, is thinner than its diameter, commonly possesses internal facies complications, and was surrounded by basinal or lagoonal sediments. Its diameter will normally increase upward during regressive phase and decrease upward or remain constant during transgressive phase growth.

A **Platform Carbonate** is a thin, extensive, bedded carbonate deposit formed during the initial stages of marine transgression, upon which transgressive phase reefs were rooted. Massive reef facies developed at the seaward margins and within the interior associated with overlying reef complexes. It possesses an overall deepening-upward sedimentation pattern, though shallowing-upward cycles are common toward the continental limits of deposition. A platform commonly overlies a shallowing upward regressive phase shelf carbonate that may have controlled its distribution, and is laterally equivalent to thin clastic-carbonate basin deposits. Shelf and platform units are typically included within a single geologic formation because of similarities in lithology and spatial distribution.

A **Shelf Carbonate** contains thin, cyclic, bedded carbonate and evaporite sediments deposited in shallow marine environments during either the transgressive or regressive phase. Shelves consist of both laterally extensive and local shoaling upward cycles that were dominated by normal marine sediments in transgressive phase deposits, or by intertidal-supratidal sediments in the regressive phase. These sediments intertongue laterally with clastic-evaporite units adjacent to exposed land areas and with shelf margin or barrier reefs or clastic-carbonate basin-fill units in a seaward direction.

Shelf Margin Reefs are formed at the maximum basinward extent of regressive phase carbonate shelves where higher energy marine conditions and local sea-bottom topography stimulated framework organic growth. They are analogous to barrier reefs, but are much thinner and were less effective barriers to water circulation. Their distribution was controlled by topography of the basin-fill deposited during the earlier part of the regressive phase.

Shelf Interior Reefs are regressive phase patch reefs that are surrounded by shelf carbonate and evaporite units. Local pre-shelf topography probably influenced the location and formation of shelf interior reefs.

Basin Units — Source and Seal Rocks

Transgressive Phase Carbonate - Clastic Basin Deposits are typically thin, laterally extensive, interbedded oxic and anoxic carbonate and shale beds that contain reef debris beds adjacent to transgressive phase reefs. Basin geometry was controlled by pre-sequence topography and local current directions in the epeiric sea. The basinal anoxic beds formed good potential source rocks.

Transgressive Phase Evaporite - Carbonate Basin Deposits are thick accumulations of evaporitic carbonate, sulphate, halite, and occasionally potash salts deposited in an intra-shelf basin behind a barrier complex. Basin geometry was controlled by pre-sequence topography.

Regressive Phase Clastic - Carbonate Basin Fill units formed sheet-like deposits over transgressive phase reefs and were deposited in large clinoforms in basinal areas. The geometric distribution and composition of the beds was controlled by proximity to carbonate shelves and clastic sources of sediment, as well as by previous basin-fill topography. Basin infilling typically occurred from the south and east toward the north and west: the coarseness of the clastic component tends to increase upward in the section in each depositional unit. The basin fill interfingers laterally with carbonate shelves, but must have had clastic detrital input across parts of these shelves.

Regressive Phase Evaporite - Carbonate Basin Fill occurred in isolated basins surrounded by carbonate shelves that limited

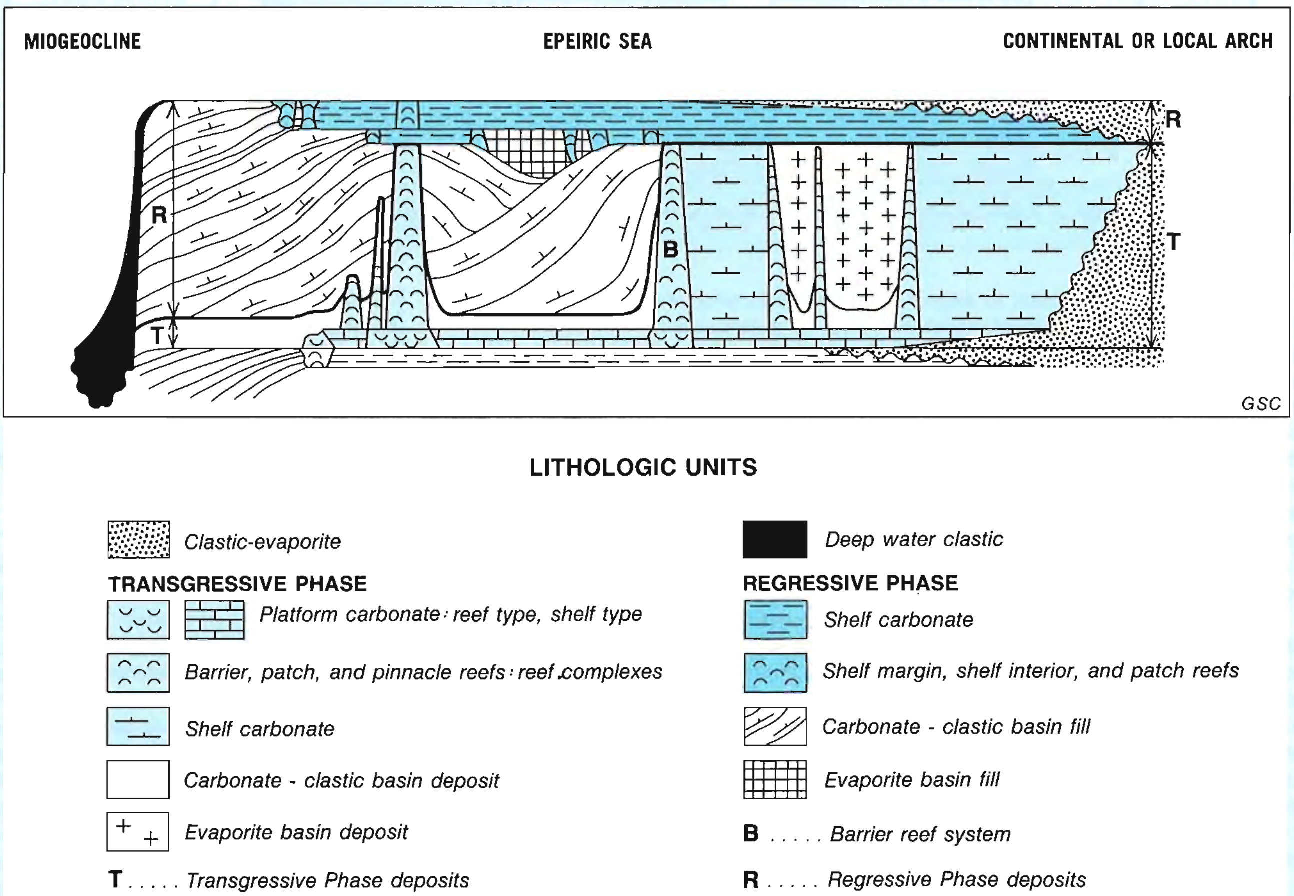


Figure 13. Depositional model, reef-rimmed shelf, Devonian, Western Canada Sedimentary Basin. Section does not exhibit pre-sequence topography or thickness changes of individual lithologic units. Coloured units contain carbonate reservoir rocks. Wavy lines indicate facies changes.

marine circulation and clastic sediment supply. The formation of these isolated basins was dependent upon previous regressive phase basin-fill patterns, and not by pre-sequence topography or structure. Sediments consist of either shallow- or deep-water evaporitic carbonate, sulphate, and salt.

Figure 13 is an illustration with large vertical exaggeration of the Devonian depositional style during a major eustatic sea level rise and fall event. Initial deposits of the transgression were shallow water platform carbonates on shoal areas that were controlled by pre-Devonian topography, Devonian epeirogenic movement, or pre-sequence carbonate shelf deposition. Landward equivalents of the platform were shallow water carbonate, evaporite, and clastic beds: seaward equivalents were thin calcareous shales and argillaceous lime mudstones. The deepening-upward platform sediments grade into overlying thick reefs and thin basinal deposits in basin regions, and reefs and carbonate shelves landward of a barrier reef system. Basinal regions received little sediment since water depths were too great to sustain carbonate sediment accumulation and the barrier-shelf system inhibited clastic sediment supply. Conditions were commonly anoxic, resulting in good preservation of organic matter. The shelf regions formed either massive reef sediments or shallowing-upward carbonate evaporite cycles, depending on sedimentation rates, circulation patterns, and water depths. The shelf carbonates grade into clastic-evaporite units landward. At the end of and during the transgressive phase, shallow intra-shelf basins were infilled with evaporite since the barrier reef system restricted marine circulation. The evaporites covered normal marine basinal sediments, carbonate platforms, and patch and pinnacle reefs.

Regressive phase deposits completed the infilling of the basin in each depositional sequence. They are represented by thick clastic-carbonate basin-fill clinothems and thin carbonate-evaporite shelf deposits which overstepped the barrier reef system and earlier regressive basin rocks. Clastic-evaporite deposits are landward equivalents of the carbonate shelves. Shelf interior and shelf margin reefs are associated with the bedded carbonates. Basin-fill and shelf rocks generally become younger in a northwest direction (direction of regression) or with distance from local arch systems. Where basin fill was complete and significant marine regression occurred, depositional sequences have been eroded.

The depositional model shown in Figure 13 serves as a general guide to the depositional setting and the geometry of Devonian source, reservoir, and seal rocks, but is not applicable to each of the Devonian sequences in Western Canada. Five reasons for modification of the model within any sequence are:

1. Transgression was not extensive enough to permit the deposition of the entire spectrum of facies in Western Canada (e.g. only continental clastic-evaporite and shelf facies occur);

2. Deposition occurred in ramp conditions, rather than on a rimmed shelf, so that shelf carbonates intertongue with basinal carbonate and shale. Ramps and reef-rimmed shelves, may have existed in different parts of the basin within a single sequence;

3. Differential subsidence occurred during deposition, so that a single unit or formation may possess both regressive and transgressive characteristics;

4. Carbonate sedimentation was inhibited by large amounts of clastic detritus being shed into the basin. As a result, shallow water clastic units may grade into evaporites or deep water facies without intervening carbonate shelf facies;

5. Erosion between sequences removed sediments from certain areas. In addition, post-Devonian erosion has removed much of the sedimentary record of Western Canada.

DISTRIBUTION

The Delorme and Bear Rock sequences are limited to the northwest parts of the basin where they consist of shallow marine clastic, evaporite, and carbonate sediments on the plains and shelf carbonates in the disturbed belt of northeast British Columbia. Rocks of these sequences are absent over most of the Tathlina, Peace River, and West Alberta arches owing to non-deposition or to intra-Devonian erosion. These rocks represent the initial Devonian deposits in a basin with significant topography that resulted in coarse clastic sediments inhibiting carbonate production. Extensive marine facies development occurs north of the Tathlina Arch.

The Hume-Dawson sequence records increased transgression relative to previous Devonian events as evidenced by: a thicker section with greater areal extent and onlap onto arches; limited clastic-evaporite facies distribution; and a major southeast advance across the Meadow Lake Escarpment. There are two stages of carbonate sedimentation: the Winnipegosis-Lower Keg River-Hume platform and the Winnipegosis-Upper Keg River barrier reef and carbonate shelves. The platform extends to the miogeoclinal edge of the Delorme — Bear Rock sequence although the Keg River barrier was built up southeast of this margin. Small tectonically controlled intra-shelf evaporite basins in northern Alberta and the large Prairie evaporite basin between Winnipegosis shelves in Saskatchewan contain patch and pinnacle reefs.

The Beaverhill-Saskatchewan sequence is divided into two subsequences at a boundary where a second major marine transgression occurs without previous major regression. This transgression resulted in a lateral shift in facies unaccompanied by erosion or deposition of an intervening clastic wedge. The Beaverhill subsequence contains two stages of carbonate production. The Slave Point developed a barrier reef complex along the Keg River barrier trend, northwest of a platform carbonate in northern Alberta. South of the Peace River Arch, the overlying Swan Hills carbonates formed a reef-rimmed shelf on the West Alberta Arch complex, but were deposited in a ramp setting at the shelf-basin boundary of southeastern Alberta. The Beaverhill Lake basin in Alberta probably had open marine connections through the Slave Point barrier in the north and through low areas in the West Alberta Arch. This permitted the development of large Swan Hills reef complexes and younger Waterways clastic-carbonate basin fill. The early drowning of the Slave Point shelf north of the Peace River Arch and the withdrawal of shoaling conditions to the southeast where the Souris River ramp-edged shelf was established indicates increased transgression during Beaverhill time.

The most extensive Devonian transgression occurred in the Frasnian. It resulted in deposition of rocks of the Saskatchewan subsequence, which includes the Leduc barrier reef and reef complexes, and Duperow carbonate shelf sediments deposited on Cooking Lake and equivalent platform carbonates. Minor tectonically induced topographic shoal areas on the platform controlled Leduc reef growth and rapid transgression maintained the location of the Leduc reefs in these specific areas. During regressive phase deposition, Ireton and Fort Simpson shale and limestone progressively infilled the basin from east to west. Carbonate shelves of the Birdbear, Grosmont, Camrose, Lower Nisku, Upper Nisku and Blueridge formations spread over the basin-fill deposits. It should be noted that these sediments were deposited under shallowing conditions, although at a time when Devonian transgression was continuing its invasion of the craton.

The base of the succeeding Palliser sequence consists of shallow marine and continental clastic-evaporite units of the Graminia and Sassenach formations that pass upward into Wabamun and Palliser shelf carbonates. The carbonates were deposited in ramp conditions during relatively uniform basin-wide subsidence. The only anomalous subsidence area is the Peace River Arch, which is downwarped at this time. The Wabamun-Palliser shelf carbonates pass laterally into clastic-evaporite units of the Williston Basin and into clastic-carbonate rocks of the miogeocline in northeastern British Columbia.

PETROLEUM OCCURRENCE

Approximately 90% of the Devonian oil reserves of Western Canada (or 45% of the total recoverable reserves of the basin) occur in transgressive phase reef complexes, patch, and pinnacle reefs of the Leduc, Swan Hills, and Keg River formations of the Beaverhill-Saskatchewan, and Hume-Dawson sequences. These reefs formed in open marine clastic-carbonate or intra-shelf evaporite basins, and are thus surrounded by basinal sediments that have compaction histories and velocity profiles that contrast with those of the reefs. This makes seismic identification of reefs relatively simple, except in the case of the large Swan Hills complexes where the velocity contrast is insufficient. Thus most reserves were discovered soon after the initial discovery within a play.

The reason that the transgressive phase reefs are charged with oil is that they are interbedded with and adjacent to excellent basinal source rocks, facilitating local migration, and are covered by regressive phase basinal seal rocks. Typically, platform carbonates underneath the source rocks serve as pipelines for long distance oil migration into reef traps (Fig. 14).

Most of the other reserves occur in clastic rocks surrounding the Peace River Arch and in drape traps over Leduc reefs in the Nisku shelf, as illustrated diagrammatically in Figure 15. The Nisku Formation commonly has good reservoir characteristics over Leduc reefs and is an obvious exploration target when drilling a Leduc seismic feature. Oil leakage from the Leduc presumably filled these Nisku traps. Relatively minor amounts of oil have been found in Hume-Dawson regressive phase deposits and in the Wabamun Formation of the Palliser sequence. No oil has been found in the Delorme and Bear Rock sequences probably owing to limited exploration and to geologic factors such as the thin section, limited distribution, poor source potential, and rare occurrence of traps.

Past petroleum exploration in the Devonian of Western Canada has been focused on very few of the trap types exhibited in Figures 14, 15, and 16. The updip termination of reef complexes (Fig. 14) and the drape trap of shelves (Fig. 15) have been adequately explored along established trends. A discovery on a new trend or in a previously unproductive basin is still possible in these play types.

Present exploration, using refined seismic data gathering and processing techniques, is finding oil in channels in reef complexes, pinnacle reefs (Fig. 14), shelf margin and patch reefs at shelf edges (Fig. 15) and in the structural and structure-enhanced reservoir plays in areas such as the Peace River Arch (Fig. 16). The remainder of the trap types in Figures 14 and 15 are potential future exploration targets.

PETROLEUM EXPLORATION DISTRICTS

There are four petroleum exploration districts in the Devonian of the Western Canada Basin that are defined by unique geography, oil source and migration paths, trap mechanisms, and trap stratigraphy (Fig. 17). The Northern Alberta, Peace River Arch, and Central Alberta districts underwent two major pulses of exploration activity: one followed the initial discovery in each region, and the second occurred in the period 1980 to 1985 when abundant leases with deep rights became available and when interest was renewed in Devonian oil relative to other targets. Devonian rocks in the Canadian portion of the Williston Basin, the large fourth district, have received little recent attention after early exploration failures.

Exploration limits for oil within the Western Canada Sedimentary Basin are defined in the east by the Devonian erosional edge, produced by several Paleozoic, Mesozoic, and Cenozoic events, and in the west by the Devonian "hot line". The "hot line" is

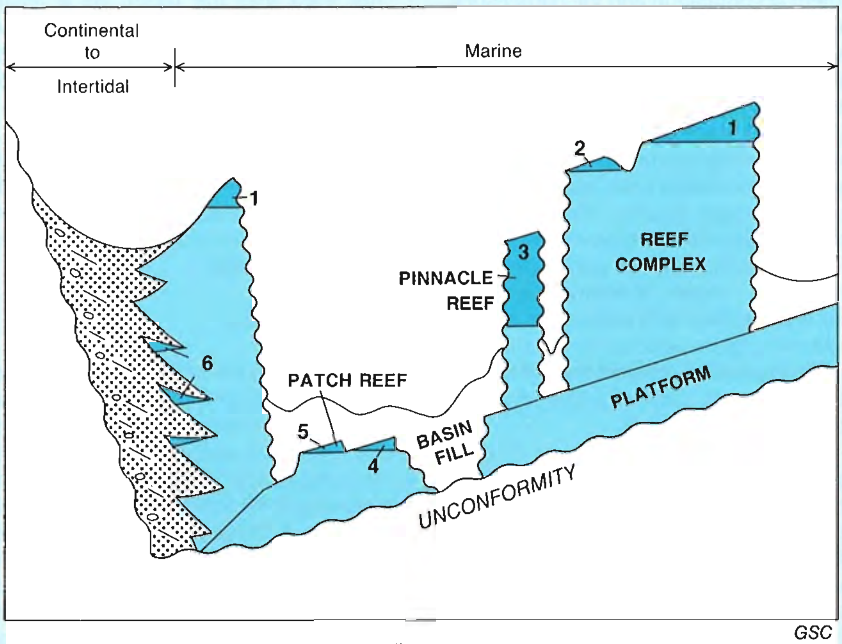


Figure 14. Trap Styles, Devonian transgressive phases.

a geochemical boundary, southwest of which thermal metamorphism of the sedimentary rocks and their contained fluids has precluded the existence of reservoired oil. Thermally derived gas, which is commonly sour, occurs downdip of this line (Bailey *et al.*, 1974).

The northern and southern limits of the Western Canada Sedimentary Basin are the Tathlina and Central Montana arches respectively though deposition was continuous across those features through much of the Devonian. The international boundary between Canada and the United States is the southern limit of this assessment.

NORTHERN ALBERTA DISTRICT

The Northern Alberta District is bounded by the Tathlina Arch to the north, the Peace River Arch to the south, the Devonian erosional edge and outcrop belt in the east, and the Devonian "hot line" in the west (Fig. 17). The exploration focus has been on stratigraphic traps in Keg River reefs developed within back-barrier evaporite basins and on drape traps in overlying regressive phase carbonate shelves. These basins are typically less than 20 townships in area, but are prolific oil producers as they contain large numbers of small reefs adjacent to excellent source rocks. As a result, oil exploration has been concentrated in relatively small, discrete areas of this district.

DEPOSITIONAL AND TECTONIC HISTORY

The Delorme sequence is not present in this district, probably owing to either very limited deposition or post-Delorme erosion. Shelf carbonates occur in the Rocky Mountains of northeast British Columbia, and continental clastic-evaporite units occupy a sub-basin in east-central Alberta, bounded by the Meadow Lake Escarpment and the Peace River Arch. The earliest Devonian rocks present, belonging to the Bear Rock sequence, were deposited on eroded Precambrian, Cambrian, or Ordovician strata, and include, in ascending order: Ernestina Lake redbeds, limestone and anhydrite; Cold Lake salt; and Lower Chinchaga anhydrite. These units represent the continental clastic-evaporite facies deposited southeast of normal marine carbonate shelves. This sequence is a poor exploration target because of the absence of: discovery to date, documented potential source beds, thick and widespread reservoir units, or good trap configurations.

The first major marine transgression deposited the Hume-Dawson sequence, consisting in ascending order of: Upper Chinchaga clastic-evaporite sediments, Lower Keg River platform carbonate, Upper Keg River reef and shelf carbonates, basinal and shelf Muskeg evaporites and carbonates, and Bistcho shelf carbonates

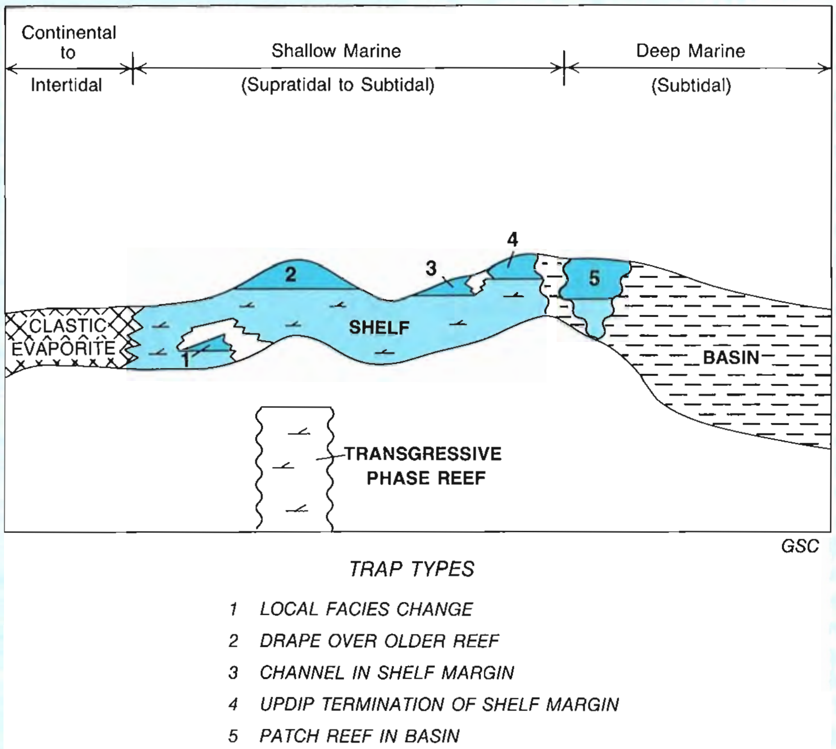


Figure 15. Trap Styles, Devonian regressive phases.

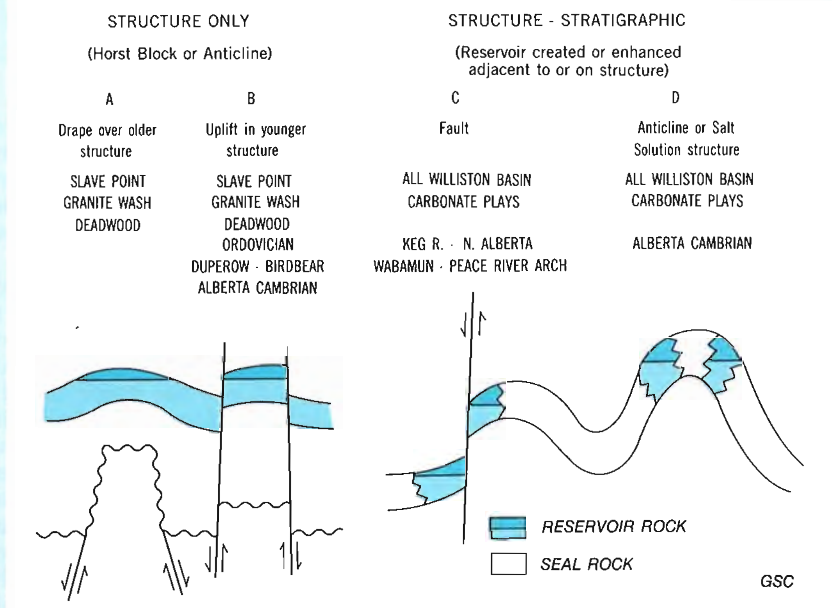


Figure 16. Structural and structural-stratigraphic traps, Devonian.

(Table 2). Upper Chinchaga redbeds and evaporites were deposited over the entire region during the initial stages of transgression. They form the base of a deepening-upward hemicycle of coarse to fine clastics and evaporites followed by the development of the Keg River platform and reefs. The Lower Keg River is a ubiquitous low energy normal marine carbonate, locally deposited on shoals that served as loci for Upper Keg River reef growth. The most prominent depositional element is the Keg River barrier reef system, which extends from the Tathlina Arch on Great Slave Lake to the Peace River Arch in northeastern British Columbia (Fig. 18). It separates open marine clastic-carbonate rocks to the northwest from a carbonate-evaporite shelf with intra-shelf evaporite basins to the southeast. The carbonate shelf passes laterally into an evaporite-dominated shallow basin in central Alberta and Saskatchewan and into clastic-evaporite units adjacent to the Peace River Arch. Patch and pinnacle reefs developed within small, deep evaporite basins at Rainbow, Zama, and Shekilie, immediately behind the barrier reef system (Fig. 18). Keg River deep water evaporitic laminites, Black Creek salts, and Muskeg anhydrite and carbonate constitute the fill encasing the reefs within these basins. Shallow water regressive phase shelf evaporites and carbonates of the Muskeg and Bistcho ("Sulphur Point") formations blanket the entire area, except for parts of the barrier complex.

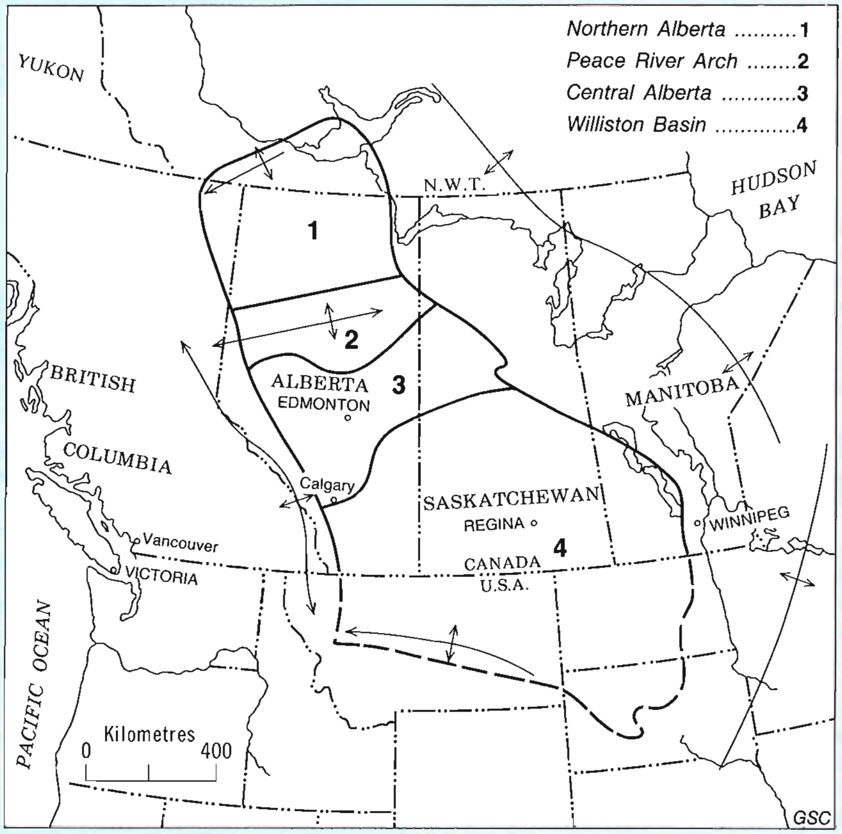


Figure 17. Devonian Exploration Districts, Western Canada Sedimentary Basin. Downdip or southwest exploration limit is defined by approximate Devonian hot line (Bailey *et al.*, 1974); updip or northeast exploration limit is Devonian erosional edge.

The Beaverhill-Saskatchewan sequence was deposited following a period of marine regression and partial erosion of the Hume-Dawson rocks. Initial clastic deposits of the Watt Mountain Formation were overlain by the extensive Slave Point carbonate shelf and barrier reef complex. The Slave Point barrier is approximately in the same position as the underlying Keg River barrier, but shelf sedimentation differed in that carbonates spread over the previous evaporite basins. Fort Vermilion evaporites in the southeastern part of the district are equivalent to the lower part of the Slave Point carbonates. Basinal shale and carbonates of the Waterways Formation cap the Slave Point shelf and mark the close of Beaverhill Lake Group sedimentation. This was followed by widespread transgression and the deposition of starved-basin Muskwa shale and carbonates. Carbonate-clastic rocks of the Fort Simpson Formation filled the remainder of the basin in the form of large clinothems directed to the northwest. Winterburn Group clastic and carbonate units cap the sequence as the final Frasnian deposits of the Devonian transgression.

Final Devonian deposition is represented by the basal clastic rocks of the Trout River, succeeded by ramp carbonates and shales of the Kotcho and Tetcho formations of the Palliser sequence. All Upper - and some Middle - Devonian rocks pass laterally into the basinal Besa River shale to the west.

There are minor epeirogenic events which have influenced the accumulation of hydrocarbons within the Northern Alberta District. The earliest is the pre-Kaskaskia uplift and faulting that established the Tathlina and Peace River Arch systems with the associated development of relief. This topography controlled, in part, the position of the Keg River barrier complex. The second event is an apparent Middle Devonian reactivation along the previously defined arch systems and along extensions of the East Arm Fault of the Canadian Shield beneath the plains. These movements probably controlled location of the barrier trend and may have initiated development of the Keg River intra-shelf basins. Related movement during Muskeg and Bistcho time enhanced solution of the Black Creek salt. A Late Devonian to Carboniferous multistage diagenetic event led to the formation of "Presquile" dolomite, secondary evaporite, and low temperature hydrothermal sulphide and gangue minerals, presumably along active fault systems (Krebs and Macqueen 1984). Evidence suggests that some of the hydrocarbons in the Keg River reservoirs were generated during the elevated geothermal gradient that existed at that time (Aulstead and Spencer, 1985), though presumably most hydrocarbon generation occurred in the Cretaceous (Deroo *et al.*, 1977).

PETROLEUM GEOLOGY

Virtually all of the oil reserves in the Northern Alberta District occur within carbonate reef- and shelf- rocks of the Hume-Dawson sequence. Stratigraphic traps in Keg River reef complexes and pinnacle and patch reefs in the Rainbow, Zama, and Shekilie evaporite basins account for most of the reserves. Drape traps in the carbonate shelf rocks of the Muskeg (including Zama Member) and Bistcho ("Sulphur Point") formations, which are commonly in hydraulic communication with underlying Keg River reefs, contain subordinate amounts of oil. Drape traps also occur over Black Creek Salt remnants. The Slave Point platform carbonates of the next sequence typically contain gas, though one Slave Point pool at Rainbow contains oil.

The potential source rocks for the oil are the bituminous carbonates of the Lower Keg River, bituminous inter-reef carbonates, or Muskeg laminites (Schmidt *et al.*, 1985). Both local migration directly into the reefs and longer distance movement through the Keg River platform may have charged the reservoirs. Faulting may also have played a role in migration, particularly into the overlying shelf units where they are separated from reefs by evaporites.

The Keg River reefs are sealed laterally and vertically by Muskeg anhydrite or carbonate. Reservoir facies were developed in some beds of the Muskeg Formation, particularly the Zama Member, in shoal areas above reefs. These traps are filled with hydrocarbons, and are sealed laterally by facies changes.

Past and present exploration has concentrated on the seismically definable Keg River reefs, which must be distinguished from Black Creek salt remnants, multi-stage salt solution effects, and pure structural anomalies. Future targets will include stratigraphic traps in the following: the carbonate shelves and the Slave Point platform over basinal areas; the Keg River shelf surrounding evaporite basins; and reefs in poorly explored basins such as Meander. Other targets will be found in subtle structural or multi-stage salt solution drape traps.

EXPLORATION PLAYS

A total of 5 established plays (those with discoveries) and several conceptual plays (those that on the basis of geological understanding should exist but have not yet been successfully explored) have been assessed for the Devonian System in the Northern Alberta District. Both types of plays are described in the following section, but quantitative treatment of estimates is limited to the established plays.

Conceptual Plays

Several conceptual plays may be the future focus for exploration in the Northern Alberta District. Assessment of these plays is difficult without knowing whether adequate local source rocks exist or whether there were the necessary migration paths from more distant source areas needed to charge the reservoirs.

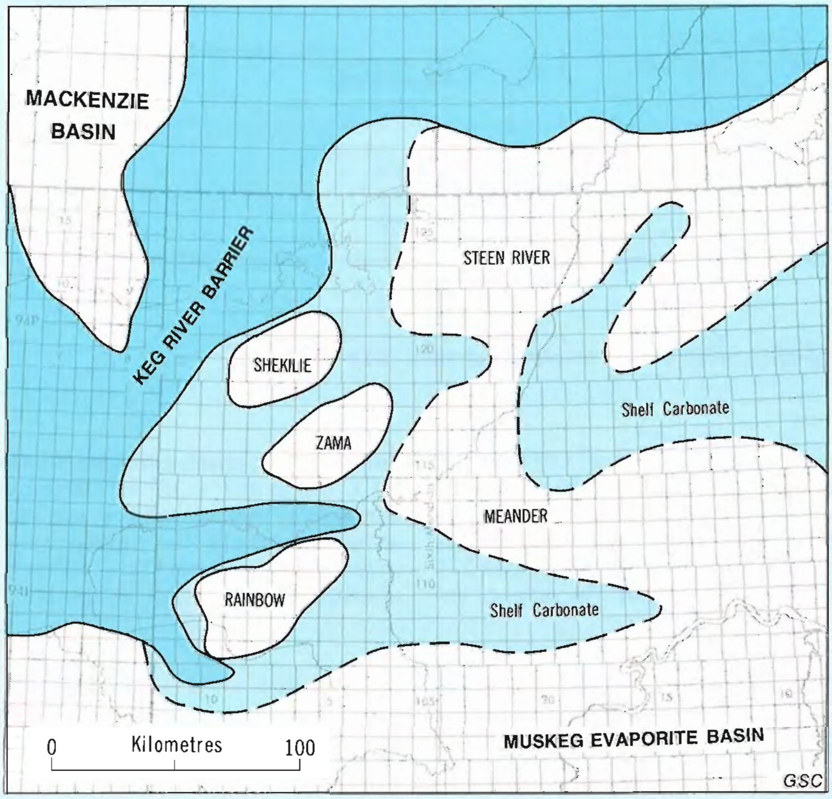


Figure 18. Northern Alberta Devonian Play Map. Established plays are within the Rainbow, Zama, and Shekilie basins.

The oldest potential oil reservoirs occur in the **Upper Chinchaga**, probably as stratigraphic-structural and structural traps, particularly in the vicinity of the Tathlina Arch.

The **Keg River Formation** conceptual play includes: patch and pinnacle reefs formed in presently non-productive basins such as Meander or Steen River (Fig. 18); patch reefs, channels, or subtle facies changes developed within the carbonate shelf or the barrier complex; shelf edge reefs which surround the deep evaporite basin; barrier margin and associated patch reefs north of that margin (Fig. 18); and post-Keg River structures within the shelf or barrier system, possibly related to the Tathlina Arch, the western extension of the East Arm fault system, or meteorite impact features.

The **Zama, Muskeg**, and **Bistcho** plays of the deep evaporite basins may be repeated in similar basins such as Meander, provided that drape traps over Keg River reefs and Black Creek salt remnants are present. Post-Bistcho structures may form traps over the entire region.

The **Slave Point** is the youngest good quality Devonian reservoir rock in this region. It is typically gas-bearing but has not been adequately explored in several areas. Plays include: stratigraphic intra-shelf traps in and around the Rainbow, Zama and Shekilie basins; structural traps throughout the district; barrier edge and associated patch reef traps at the northern shelf margin; and shelf-interior reef traps throughout most of northern Alberta.

The Upper Devonian **Jean Marie** shelf carbonate is a poor quality gas reservoir in northeastern British Columbia. Although it usually has poor permeability, it may have enhanced porosity and permeability due to local depositional or diagenetic facies changes that could create traps for oil.

Established Plays

Exploration to date has concentrated on the seismically definable Keg River reefs in the deep evaporite basins at Rainbow, Zama, and Shekilie. Plays targeting these reefs and the overlying Zama, Muskeg, and Bistcho carbonate shelves have discoveries and are discussed individually.

The **Slave Point** drape traps within the Rainbow, Zama, and Shekilie Basins typically contain gas, except in a single pool at Rainbow. The play is too immature to warrant a detailed assessment, and is considered a poor oil exploration target.

KEG RIVER

Play Definition: This oil play was defined to comprise all pools and prospects in patch and pinnacle reefs, and reef complexes, of Keg River age that occur within the Rainbow, Zama, and Shekilie basins in northwestern Alberta (Fig. 18).

Geology: The Keg River reefs developed on a regional lower Keg River platform carbonate, and are typically less than one section in area. They grew in small, deep basins surrounded by carbonate shelves. The basins were eventually filled with Muskeg evaporites that form the seal rock for the traps. (Barss *et al.*, 1970; Langton and Chin, 1968). Dark bituminous limestone of the platform and Muskeg laminites are the most likely oil sources in these small, but prolific basins.

The upper Keg River consists of between 50 and 200 m of reefal dolomite with a complex diagenetic history and excellent reservoir properties, that has recovery factors from 10 to 60%. Most reefs form single well pools, owing to their small areas, and have recovery factors at the lower end of this range.

Exploration History: One of the most significant discoveries in the Alberta Basin occurred in 1965 at Rainbow. This discovery demonstrated that reefs could develop and oil could be generated and trapped in the evaporite basins of northern Alberta. The early intensive exploration effort was followed by relatively continuous drilling to the present. In the 1980s a resurgence of intense activity resulted in several new discoveries.

There are 340 x 10^6 m^3 OIP in 439 Keg River pools in the fields at Rainbow, Rainbow South, Sousa, Black, Fire, Tehze, Larne, Virgo, Zama, Shekilie, and Amber. Pool sizes range from less than 0.1, in small pinnacle reefs in Shekilie, to 44 x 10^6 m^3 OIP in reef complexes at Rainbow (Table 3).

TABLE 3

KEG RIVER PLAY

Class Interval (10^6 m^3)	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
>4			
	Rainbow B	43.80	1965
	Rainbow F	31.80	1966
	Rainbow AA	15.90	1967
	Rainbow A	14.30	1965
	Rainbow South E	7.15	1966
	Rainbow South B	6.52	1966
	Rainbow O	6.21	1966
	Rainbow I	6.13	1966
	Rainbow South A	5.72	1965
	Rainbow South N	5.00	1978

0 to 4 pools undiscovered in this class

•Total Expected Pools : 846
•Number of Discovered Pools : 439

TABLE 4

POOL SIZE ANALYSIS — KEG RIVER PLAY

Class Interval In-Place Pool Size (10^6 m^3)	Number of Pools Discovered	Undiscovered
< 0. - 0.5	324	213-365
0.5 - 4	105	19-38
> 4	10	0-4
	439	233-407

Median value of undiscovered potential 151 x 10^6 m^3

Play Potential: Because of the large number of pools, this play was assessed using the discovery process methodology option that produces results in pool class sizes rather than as a continuous pool array. These results (Table 4) show that in the pool class-size greater than 4 x 10^6 m^3 OIP ten pools have been discovered and from zero to four are estimated to be undiscovered. The smallest class, on the other hand, consists of 324 discovered pools with between 213 and 365 yet to be found. The range of undiscovered potential is estimated to be from 50 x 10^6 to 265 x 10^6 m^3 OIP for high confidence and speculative confidence levels respectively. The median value of potential is estimated at 151 x 10^6 m^3 OIP distributed in more than 300 pools.

ZAMA

Play Definition: This oil play was defined to include all pools and prospects in drape traps of the Zama Member where they have developed over Keg River reefs or salt remnants within the Rainbow, Zama, and Shekilie basins in northwestern Alberta (Fig. 18).

Geology: The Zama Member consists of partially restricted shelf carbonates deposited during a marine incursion into the dominantly evaporitic deposition of the Muskeg Formation. Thickness varies from 8 m at Shekilie to 50 m at Rainbow. Although ubiquitous within the basins, the Zama Member is most porous over the Keg River reefs where high energy depositional conditions and later diagenesis resulted in the deposition of a biostrome that developed good reservoir qualities (McCamis and Griffith, 1967). This biostrome facies, composed of dolomite grainstone and mudstone, merges with and is difficult to separate from the Keg River at Rainbow, lies directly above it in the Zama basin, and is separated from it by anhydrite at Shekilie. Traps are created both by drape over the reefs and by lateral facies change to seal rock within the Zama Member. The Muskeg anhydrite forms the top seal. Oil probably migrated through the Keg River into the Zama reservoirs, as the units are commonly in direct contact or in hydraulic communication.

Reservoirs generally have from 5 to 15% porosity, good permeability, water saturations under 20%, and recovery factors from 10 to 30%. Pool areas average and are usually close to a quarter section, and net pay varies from 5 to 50 m.

Exploration History: Exploration for this play has been a by-product of the relatively continuous exploration since 1965 for Keg River reefs at Rainbow, Rainbow South, Virgo, Tehze, Zama, Larne, Black, Amber, and Shekilie (Table 5). There are currently 71 pools with total reserves of 23 x 10^6 m^3 OIP. Pools typically contain less than 0.5 x 10^6 m^3. The Zama Member is usually considered a secondary exploration target.

TABLE 5

ZAMA PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Rainbow Muskeg F	3.18	1965
4	Rainbow Muskeg I	1.43	1967
6	Rainbow South Muskeg G	1.22	1978
10	Rainbow Muskeg K	1.06	1977
17	Rainbow Muskeg C	0.80	1967
20	Tehze Muskeg A	0.72	1967
21	Black Muskeg C	0.70	1967
24	Rainbow Muskeg A	0.64	1966
25	Rainbow South Muskeg H	0.63	1967
26	Zama Muskeg PP	0.59	1983

- **Total Discoveries : 71**
- **Discoveries in the Top 30 Pools : 10**
- **Total Pool Population : 160**

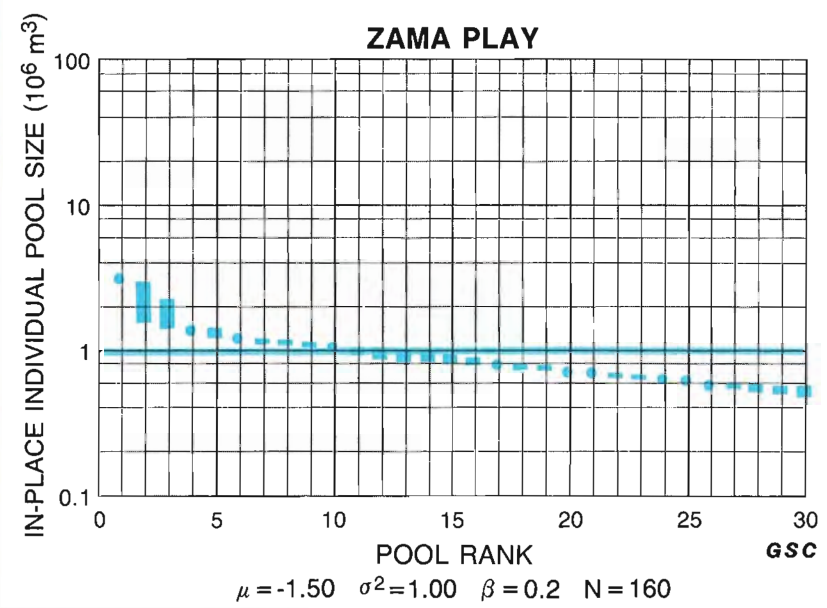


Figure 19

Play Potential: Estimates of undiscovered potential for this play yield a median expectation value of 33 x 10^6 m^3 OIP. This estimate assumes a total population of 160 pools, of which 89 remain undiscovered. The pool array diagram (Fig. 19) indicates by its relatively low slope that the play is highly dispersed. The play is also relatively immature, with more than half of the resource yet to be found, and with several of the larger pools (notably the 2^{nd}, 3^{rd}, and 5^{th} ranked pools) in the undiscovered category. Several of those pools, in the 0.5 to 1 x 10^6 m^3 range, would be very attractive exploration targets. They may exist over undiscovered Keg River reefs and in subtle stratigraphic traps within the Zama Member.

MUSKEG

Play Definition: This oil play was defined to include all pools and prospects in thin dolomite beds of the Muskeg Formation formed where they drape over remnants of the Black Creek Salt or Keg River reefs within the Rainbow, Zama, and Shekilie basins of northwestern Alberta (Fig. 18).

Geology: The Muskeg Formation is an evaporite and carbonate basin-fill unit in northern Alberta that normally forms a seal rock surrounding Keg River reefs. Some of the dolomite beds, however, are porous and contain oil in drape traps over underlying remnants of the Black Creek Salt. In these reservoirs, permeability is generally fair, porosity is from 5 to 10%, water saturation is under 20%, pool areas are less than one section, total net pay is less than 20 m, and recovery factors are less than 20%. Evaporite interbeds form seals and may also have been a local source rock for the oil.

Exploration History: Only four pools containing reserves of 5 x 10^6 m^3 OIP have been discovered within the Muskeg in the Rainbow basin (Table 6). This is a currently active play, despite the high drilling density in the region, because the Muskeg was a secondary or tertiary drilling objective, and may not have been adequately assessed in wells completed in deeper horizons.

Play Potential: Median play potential is 32 x 10^6 m^3 OIP in 38 remaining pools, most of which are less than 1 x 10^6 m^3 in size (Fig. 20). The pool array diagram indicates by its relatively low slope that the resource is highly dispersed in this play. It should be noted that Figure 20 differs from most predicted pool size figures in that it has not been conditioned on a match of discovered pools to specific pool ranks. The uncertainty associated with the data in this play precludes the conditioning process.

The play is also relatively immature, with more than 80% of the resource yet to be found, and with several of the larger pools (in the 1 to 10 x 10^6 m^3 OIP range) in the undiscovered category. Future exploration may focus on this play, provided that a significant discovery, such as the largest remaining pool of 6 x 10^6 m^3, is made.

TABLE 6

MUSKEG PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
2	Rainbow O	2.82	1983
9	Tehze B	1.79	1968
28	Rainbow P	0.14	1965

- **Total Discoveries : 4**
- **Discoveries in the Top 30 Pools : 3**
- **Total Pool Population : 42**

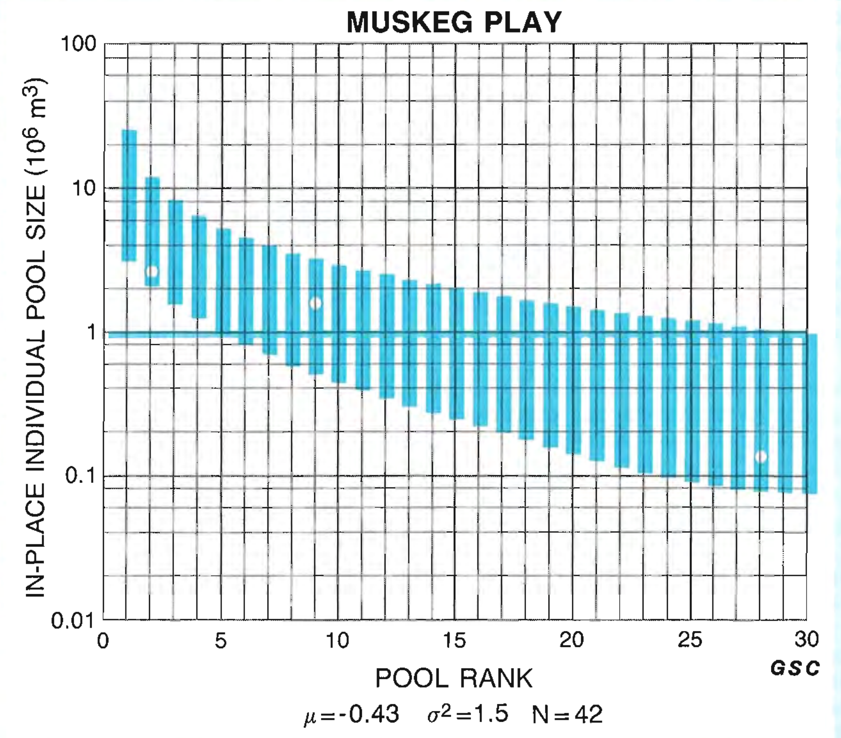


Figure 20

BISTCHO

Play Definition: This oil play was defined to include all pools and prospects in drape traps in the Bistcho ("Sulphur Point") carbonate shelf over Keg River reefs or Black Creek Salt remnants within the Rainbow, Zama, and Shekilie basins of northwestern Alberta (Fig. 18).

Geology: The Bistcho Member consists of a shelf carbonate 10 to 80 m thick which disconformably overlies the Muskeg evaporites and is unconformably overlain by the Watt Mountain shale. It consists of interbedded partially restricted limestone, wackestone and dolomite mudstone, with low porosity (5 to 10%) and low permeability. Traps occur where this shelf is draped over Keg River reefs. Seal rocks include impermeable carbonates in the Bistcho and the Watt Mountain shale. Oil appears to have accumulated in the Bistcho by vertical migration from Keg River reefs. Pools are generally less than one section in area, net pay varies from 2 to 25 m, and recovery factors vary from 1 to 15%.

Exploration History: Most of the Bistcho pools were discovered by chance between 1966 and 1976 during exploration for Keg River reefs. Total reserves currently are 5.5 x 10^6 m^3 OIP distributed in 15 pools, which fall in the size range from 0.1 to 1.0 x 10^6 m^3 (Table 7).

Play Potential: The undiscovered potential for this play is estimated to have a median value of 11 x 10^6 m^3 OIP in 55 remaining pools (Fig. 21). The slope of the pool array implies a fairly dispersed pool size distribution. The large number of undiscovered pools, including several in the top 30, indicate that this is a relatively immature play. The remaining potential is expected to exist in drape traps over undiscovered Keg River reefs, in drape traps over Black Creek salt remnants, and in subtle stratigraphic traps within the Bistcho shelf itself.

TABLE 7

BISTCHO PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
3	Zama F	0.95	1967
4	Rainbow F	0.86	1970
6	Tehze A	0.60	1967
12	Rainbow C	0.40	1965
13	Rainbow B	0.38	1965
14	Zama B	0.35	1967
15	Sousa A	0.32	1968
16	Zama D	0.32	1967
17	Rainbow I	0.29	1975
20	Zama C	0.25	1967
21	Virgo A	0.25	1969
25	Zama A	0.20	1967

- **Total Discoveries : 15**
- **Discoveries in the Top 30 Pools : 12**
- **Total Pool Population : 70**

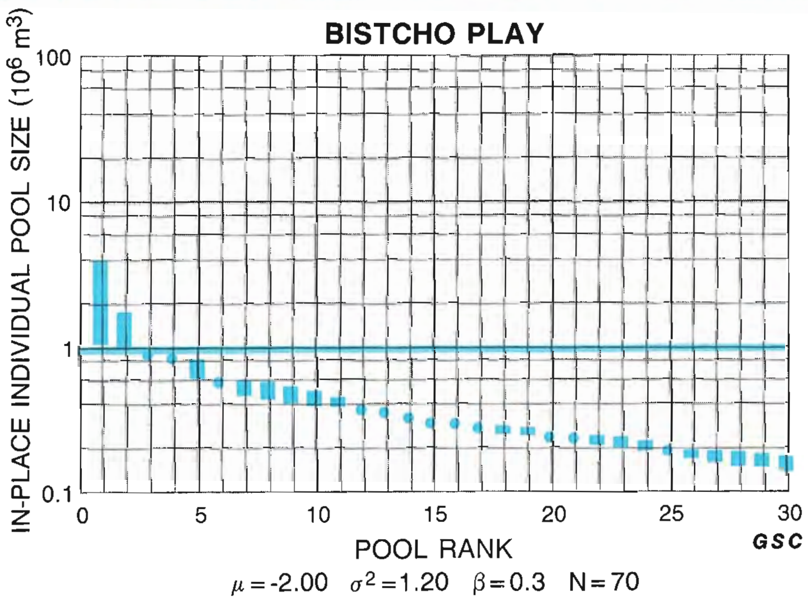


Figure 21

PEACE RIVER ARCH DISTRICT

This district includes the area of the Peace River Arch system between the Devonian hot line and the erosional edge (Fig. 17). It is the most complex exploration region because of the variety of trap types and ages and is characterized by the occurrence of structural and structural-stratigraphic traps in transgressive phase basal clastic and succeeding carbonate reef rocks.

DEPOSITIONAL AND TECTONIC HISTORY

The Peace River Arch, the principal tectonic element of the district, probably originated as a zone of weakness during the Precambrian. The late Precambrian and early Paleozoic stratigraphic record, if developed, was removed by pronounced pre-Kaskaskia sequence uplift accompanied by marine regression, during which the arch was eroded to Precambrian crystalline basement. Fragmentary stratigraphic evidence from adjacent areas suggests the existence of the arch as a positive feature as early as Middle Cambrian (Pugh, 1973). Block faulting produced a series of horsts and grabens trending both parallel (SW-NE) and perpendicular (NW-SE) to the axis of the arch. Devonian faulting did occur, but was relatively minor. During the Devonian there was a progressive movement of the shoreline and a translation of deeper water facies toward the crest of the arch with time (Figs. 22 and 23). Famennian (Palliser sequence) subsidence of the arch relative to the surrounding Alberta Basin resulted in almost complete immersion of the arch. Epeirogenic downwarp and block faulting continued in the Carboniferous, Permian, and Mesozoic, creating an embayment over the old arch system.

Devonian deposition began with continental and brackish water clastic and evaporite rocks of the Delorme and Bear Rock sequences on the eastern or lowest part of the arch. Clastic units fringed the land mass and passed basinward into evaporites. Erosion during regressive phases that occurred between sequences locally removed the depositional record of these units.

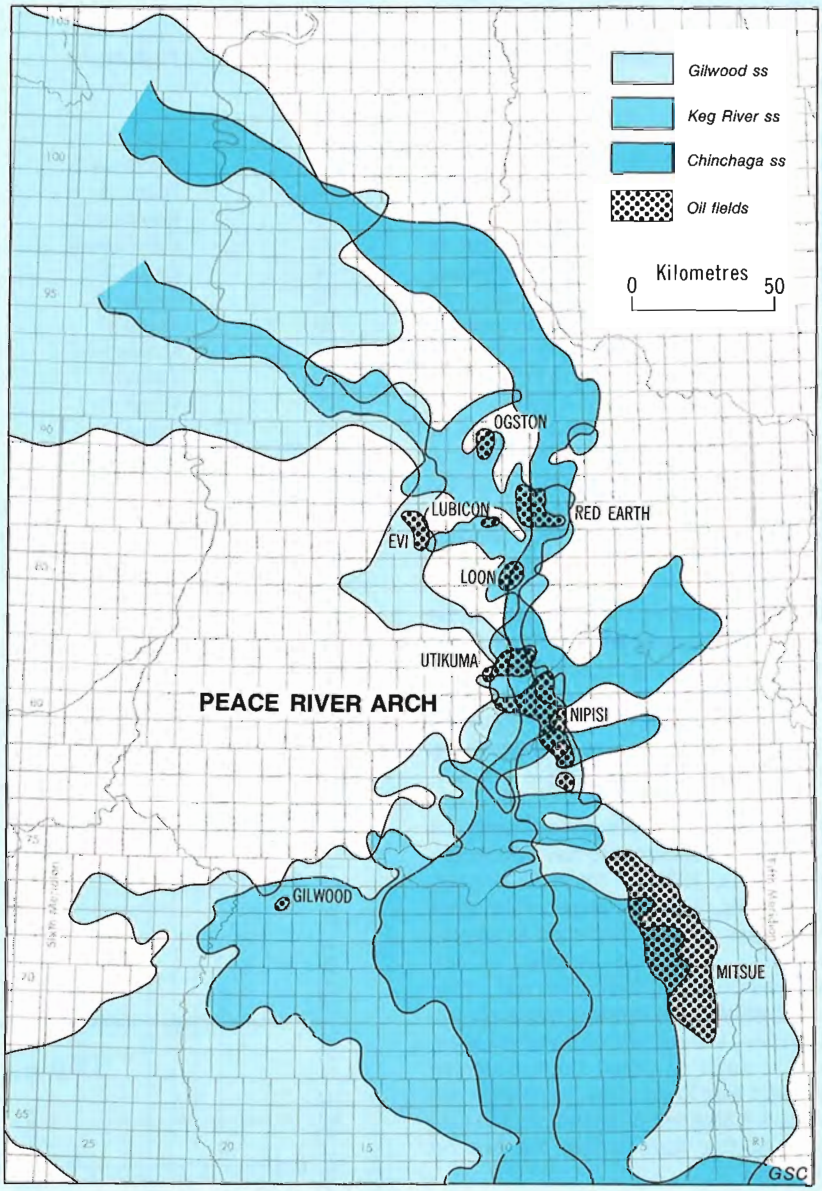


Figure 22. Middle Devonian Clastic Play Map, Peace River Arch District. The large Gilwood pools at Mitsue and Nipisi are in the Gilwood-Mitsue Play. Exploration limits are the outer (eastern) depositional edges and the inner (western) depositional edges of the Chinchaga, Keg River, and Gilwood sandstones.

The first major transgression onto the arch is recorded in basal Chinchaga sandstone and shale overlain by lower Keg River carbonate platform of the Hume-Dawson sequence. The platform was part of the relatively continuous lower Keg River — lower Winnipegosis carbonate that was deposited over most of Western Canada. Thin upper Keg River patch reefs developed on the platform offshore along the east side of the arch (Fig. 23). The carbonates are interbedded with, and intertongue with clastic rocks adjacent to the arch. The Hume-Dawson sequence ended with the deposition of the Muskeg evaporites.

Marine regression and minor erosion preceded deposition of the Beaverhill-Saskatchewan sequence. Initial clastic deposits, the Watt Mountain Formation, include widespread alluvial, deltaic, and shallow marine Gilwood Sandstone and brackish water to marine shales. They are the basal deposits of a deepening upward cycle, and are succeeded by Slave Point carbonate, or Fort Vermilion evaporites, followed by Waterways basinal carbonate and shale. Around the Peace River Arch reef facies developed at various stages of sea-level as it rose (Fig. 23). The lower two stages are both called "Slave Point" by industry, although only the lowest one is of the same age as the widespread Givetian Slave Point Formation. To distinguish the stages around the arch for the purposes of this assessment, they have been referred to as "lower" and "upper" Slave Point; this is not a formal designation. The reefs do not form continuous reef-rimmed shelves because of the irregular basement topography. Deeper water carbonates developed basinward of the reefs: landward the reefs grade into lagoonal carbonates and coarse clastic rocks.

The overlying Woodbend Group exhibits facies relationships like those of the Beaverhill Lake Group. Ireton shale and carbonate were deposited basinwards of a Leduc age barrier reef that fringed the arch (Fig. 23). The reef is interbedded with, and grades landward into, lagoonal shelf carbonate and clastic sediments. The overlying lower Nisku did not develop a broad carbonate shelf but maintained a basinal character adjacent to much of the arch. It formed a narrow shelf over parts of the Leduc barrier complex. The upper Nisku

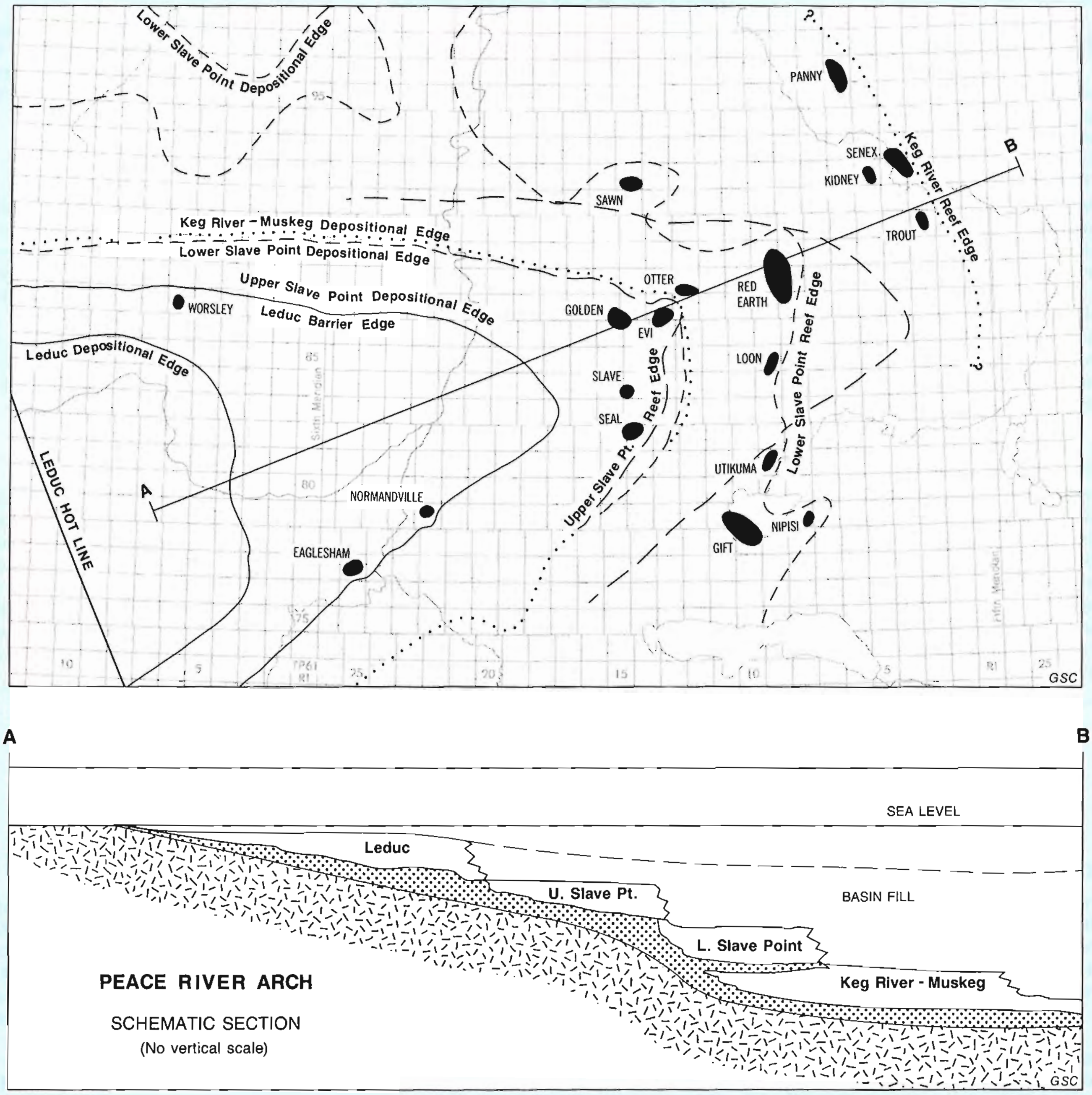


Figure 23. Devonian transgressive phase reef plays, Peace River Arch District. Areas for each of the Keg River, Lower Slave Point, Upper Slave Point, and Leduc plays lie between the outer edge of patch or barrier reef development and the inner depositional limit.

(Meekwap) and the Blueridge are carbonate shelves with a large clastic content that also intertongue with clastic rocks adjacent to the arch.

The Wabamun Formation covered the entire arch and consists of shelf limestone with rare patch reefs. It has been dolomitized and fractured along fault zones in the southwestern portion of the arch. It thins and grades into clastic rocks on local topographic high areas on the crest of the arch.

PETROLEUM GEOLOGY

This district contains only 13% of the Devonian in-place oil reserves in western Canada, and most of this is in the large Gilwood stratigraphic sand pinch-out traps at Mitsue and Nipisi. Apart from these pools, it is a district typified by a large number of small pools in structural and structural-stratigraphic traps, in both sandstone and carbonate reservoirs. The number of recent discoveries made in all horizons within the past two years has been the most significant aspect of exploration. The increase in number of pools and reserves is directly related to the increase in exploration activity during this time.

An important and obvious feature of this district is that virtually all of the oil discovered is located south and east of the arch. Only minor gas shows have been identified in the north sector. Whether this is the natural distribution or simply a product of exploration activity across the region is unresolved. If it is natural, then it suggests that the oil might have been sourced in the south and has migrated updip (north-northeast) onto, but not across, the arch, and that there may be no mature oil source beds in the north. This thesis is also supported by the fact that over large areas several formations appear to belong to one hydraulic system, and that many oils have similar properties. The very permeable basal clastic section may have aided long distance migration and equilibrated fluid potentials in the region. Vertical migration was facilitated by the fault structures. Potential oil source rocks are the Duvernay and Lobstick basinal shales and carbonate and parts of the Muskeg evaporite section.

The carbonate reservoirs include: the Keg River, lower Slave Point, upper Slave Point (Swan Hills equivalent), and Wabamun patch reefs; Leduc barrier reefs; and Wabamun dolomite developed along fault zones. The Keg River, upper Slave Point, and Leduc reefs have been dolomitized. Lower Slave Point reefs are limestone or dolomitic limestone. The dolomitized rock typically forms superior reservoirs with higher recovery factors than does the limestone. The fine- to very coarse-grained sandstones of the Keg River, Granite Wash, and Gilwood commonly have good porosity and excellent permeability.

With the exception of the Mitsue and Nipisi fields, the traps that have been discovered are all related to block faulted structures. Smaller stratigraphic traps in the sandstone and carbonate units probably exist, but are not as attractive an exploration target as the seismically defined structures. A single seismic feature may contain pay in multiple traps including both carbonate and clastic reservoirs, enhancing its economic attractiveness. Topography associated with pre-Devonian faulting localized the growth of reefs over which compaction draping in younger cover may have resulted in stacked traps. Additionally, the basal clastic section, if not present on top of a horst block, may have oil trapped at depositional edges along the flanks of the structures. Post-Devonian faulting both created simple structural traps and allowed dolomitizing fluids to enhance or create porosity in the carbonate section.

EXPLORATION PLAYS

A total of 8 established plays and one conceptual play have been examined for the Devonian of the Peace River Arch District. Quantitative treatment is limited to the established plays.

Conceptual Plays

The only identified conceptual play occurs in the **Meekwap** shelf surrounding parts of the arch (Fig. 31). It may have oil in structural traps and in shelf and reef traps similar to those in the Meekwap and West Pembina plays of central Alberta. There are reservoir and potential source rocks in the section, but structure is probably required to create a trap, as there is no seal rock in the direction of the crest of the arch.

Established Plays

Virtually all of the potential of this region is assessed in the 8 established plays. Future exploration will expand along the presently explored trends, concentrating on subtle structural traps. If a significant oil discovery is made on the north side of the Peace River Arch, then a vast underexplored area will be considered prospective for oil in all the arch related plays.

GILWOOD — MITSUE

Play Definition: This oil play was defined to include oil in stratigraphic traps in the Gilwood sandstone pools at Mitsue and Nipisi on the southeast flank of the Peace River Arch in central Alberta (Fig. 22).

Geology: The Gilwood coarse clastic wedge was deposited around the Peace River Arch landmass in continental to shallow marine environments (Kramers and Lerbekmo, 1967). At its distal depositional edge it changes facies into Watt Mountain shale and siltstone, which forms the seal for the traps at Mitsue and Nipisi. On the southeast flank of the arch, this facies change is aligned parallel to regional strike, and forms an ideal situation for the formation of large oil pools that would have collected all of the oil that migrated through the very permeable clastic wedge from the southwest.

The reservoir quality is good, with average porosities varying between 10 and 15%, water saturations between 30 and 40%, and recovery factors, including secondary and tertiary schemes, between 40 and 65%.

Exploration History: There are only three pools in this play discovered in the 1960s at Mitsue and Nipisi. The Mitsue "Gilwood A" and Nipisi "Gilwood A" pools, with 123 and 115 x 10^6 m^3 OIP respectively, are among the largest oil pools in Western Canada.

Play Potential: This play is considered to have no remaining potential, as the play area includes the small, well explored corridor immediately downdip of the Gilwood sandstone edge between and including the Nipisi and Mitsue fields.

MIDDLE DEVONIAN CLASTICS

Play Definition: This oil play was defined to include all pools and prospects in structural and stratigraphic-structural traps in Middle Devonian sandstone reservoirs that mantle the flanks of the Peace River Arch in north-central Alberta (Fig. 22).

Geology: The Chinchaga, Keg River, Granite Wash, and Gilwood sandstone reservoirs are parts of shallow marine clastic wedges that surround the Devonian Peace River Arch landmass. They pass laterally into, and are overlain by, shallow marine shale, evaporite, and carbonate seal rocks (Jansa and Fischbuch, 1974; Shawa, 1969). As the entire Middle Devonian sequence thins onto the arch and the intervening identifiable carbonate-evaporite units disappear, the clastic rocks are termed "Granite Wash". Away from the arch the thickness of sand also decreases to a distal depositional limit (Fig. 22) where most of the hydrocarbons are trapped. Trap controls are: stratigraphic at the updip (northeast) sandstone depositional limit; stratigraphic-structural, where local pre-Middle Devonian structures influence sand thickness and depositional patterns; and structural, where younger structures pool oil in relatively continuous sand sheets.

Excellent quality reservoirs are composed of fine- to coarse-grained, in part conglomeratic, arkosic sandstone, that decreases in maturity toward the arch (Kramers and Lerbekmo, 1967; Rottenfusser and Oliver, 1977). Permeability is normally excellent, porosities range from 10 to 30%, recovery factors from 10 to 30%. Pool areas are from less than a quarter section to 16 sections.

Exploration History: The initial discovery in 1954 was a small structural-stratigraphic pool at Gilwood, but the significant discoveries at Utikuma and Red Earth occurred in the mid-1960s. Recent exploration utilizing modern seismic techniques has found several pools on small structures in the established productive areas. Total oil discovered to 1984 amounts to 80 x 10^6 m^3 OIP found in 106 pools. Utikuma and Red Earth fields contain the two largest pools with 17 and 15 x 10^6 m^3 OIP respectively. The remainder of the pools range from 0.05 to 3 x 10^6 m^3 OIP (Table 8).

TABLE 8

MIDDLE DEVONIAN CLASTICS PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Utikuma Lake Keg River A	17.00	1963
2	Red Earth Granite Wash A	14.40	1958
7	Red Earth Granite Wash E	4.00	1959
11	Utikuma Lake Keg River N	2.90	1976
12	Red Earth Granite Wash C	2.64	1956
13	Otter Granite Wash A	2.50	1982
14	Utikuma Lake Keg River U	2.35	1980
15	Nipisi Keg River E	2.05	1977
16	Red Earth Granite Wash D	1.99	1957
17	Nipisi Keg River A	1.97	1966
25	Ogston Keg River A	1.41	1975

•Total Discoveries : 106
•Discoveries in the Top 30 Pools : 11
•Total Pool Population : 280

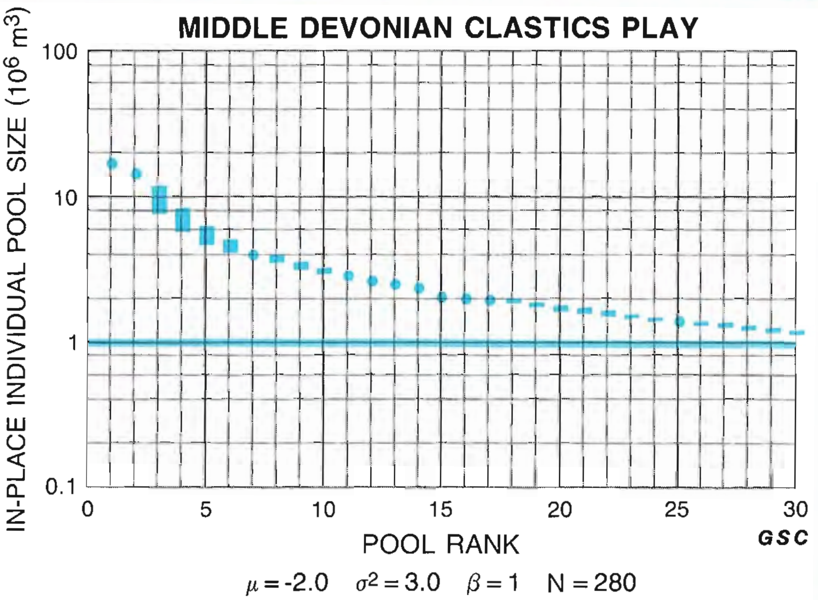


Figure 24

Play Potential: Estimates of undiscovered potential for this play yield a median expectation value of 81 x 10^6 m^3 of OIP. This estimate assumes a total population of 280 pools of which 174 remain undiscovered. The pool array (Fig. 24) indicates that a significant number of the larger pools in this play are undiscovered. Some of these may be located in the relatively unexplored sand units north of the arch, assuming there is a reasonable source for hydrocarbons.

KEG RIVER — SENEX

Play Definition: This oil play was defined to include all pools and prospects in Keg River patch reefs on local and regional structural culminations in a 50-km wide arcuate trend on the east flank of the Peace River Arch in north-central Alberta (Fig. 23).

Geology: There are two types of reservoir rocks in the region. The Senex A pool, which lies at the east edge of the trend, is a relatively deep water, low energy carbonate mudstone with low porosity, permeability, and a recovery factor of less than 3%. The remaining pools are superior reservoirs with recovery factors in the 15 to 50% range, owing to the reefal depositional facies and tectonic-diagenetic enhancement of porosity and permeability. The reefs are commonly developed over eroded Precambrian basement highs, presumably formed by pre- Keg River block faulting.

The oil source is unknown, but fluid migration paths, whether local or regional, could be extremely complex owing to the structure.

Exploration History: The initial discovery assigned to this play was the Senex A pool found during 1969. The generally poor quality of the reservoir discouraged further exploration until the 1983 discovery at Panny, where superior reservoir characteristics exist along a higher energy carbonate depositional trend. Total reserves discovered to the end of 1985 are 10 x 10^6 m^3 OIP in 14 pools, most of which are less than 1 x 10^6 m^3 (Table 9). As most pools have been discovered since 1983, this play has been reassessed using discovery data as recent as 1985.

Play Potential: Estimates of remaining potential in this play have a median expectation value of 33 x 10^6 m^3 OIP. This estimate assumes a total population of 50 pools of which 36 remain undiscovered. The analysis suggests that the three largest pools are yet to be discovered (Fig. 25), the largest of which is predicted to contain between 4 and 18 x 10^6 m^3 OIP.

TABLE 9

KEG RIVER — SENEX PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
4	Panny D	2.60	1984
7	Trout A	1.68	1984
8	Senex A	1.57	1969
11	Panny C	1.22	1984
15	Kidney A	0.91	1985
24	Panny A	0.48	1983
26	Senex C	0.44	1985
30	Panny G	0.35	1985

- **Total Discoveries : 14**
- **Discoveries in the Top 30 Pools : 8**
- **Total Pool Population : 50**

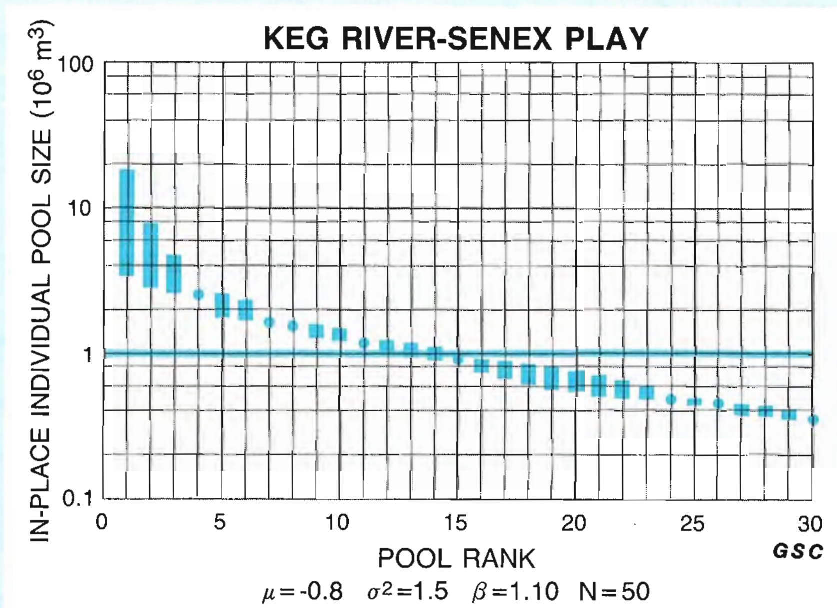


Figure 25

SLAVE POINT — SAWN

Play Definition: This oil play was defined to include all pools and prospects in structural, stratigraphic, and composite traps in lower Slave Point reefs and reef complexes in an arcuate trend around the east end of the Peace River Arch in north-central Alberta (Fig. 23).

Geology: The Slave Point includes several minor depositional cycles that contain small reefs. The reefs did not form a continuous barrier system, but rather developed in an arcuate trend in front of the Peace River Arch on isolated topographic highs related to pre-Middle Devonian structural events. The reefs average 30 m in thickness and occur between the Slave Point platform of the Central Alberta Region and an extensive platform carbonate in northern Alberta.

Hydrocarbons are trapped in post-Slave Point structures and in drapes formed by differential compaction over pre-Slave Point structures. Localized reef growth adds a stratigraphic component to some traps. Reefs without structural control may exist but are difficult to identify as prospects because of low seismic contrast with the non-porous shelf rock. Lateral and upper seal rocks are Waterways carbonate and shale. The source for the oil is unknown.

The reservoirs typically consist of lime wackestone, with low porosity (5 to 10%) and permeability, and variable recovery factors (5 to 25%). Pool areas are extremely variable, ranging from less than a quarter section to 15 sections at Red Earth.

Exploration History: The largest pool at Red Earth was the initial discovery in this play. Since its discovery in 1958 relatively continuous exploration has found 49 x 10^6 m^3 OIP in 37 pools to the end of 1985 (Table 10). Several recent discoveries have been made during the intense exploration effort of the 1980s, using modern seismic techniques to locate structures. Most of the new pools are of less than 0.5 x 10^6 m^3 OIP, with the exception of Gift A, and Sawn J.

Play Potential: Estimates of undiscovered potential for this play yield a median expectation value of 23 x 10^6 m^3 OIP. This estimate assumes a total population of 80 pools of which 43 remain undiscovered. The pool array (Fig. 26) indicates that this is a moderately dispersed resource. The play is relatively mature with two-thirds of the resource already discovered. The largest remaining pool should contain 2 to 3 x 10^6 m^3 OIP. The northern part of the play area has no discoveries, is relatively under-explored, and may be a significant exploration area in the future.

TABLE 10

SLAVE POINT — SAWN PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Red Earth A	8.22	1958
2	Gift A	8.00	1983
3	Red Earth E	6.79	1966
4	Sawn J	5.86	1984
5	Loon A	5.43	1966
6	Otter A	3.00	1981
7	Gift C	2.79	1980
9	Sawn A	1.95	1983
16	Red Earth I	1.06	1978
30	Gift E	0.47	1984

- Total Discoveries : 37
- Discoveries in the Top 30 Pools : 10
- Total Pool Population : 80

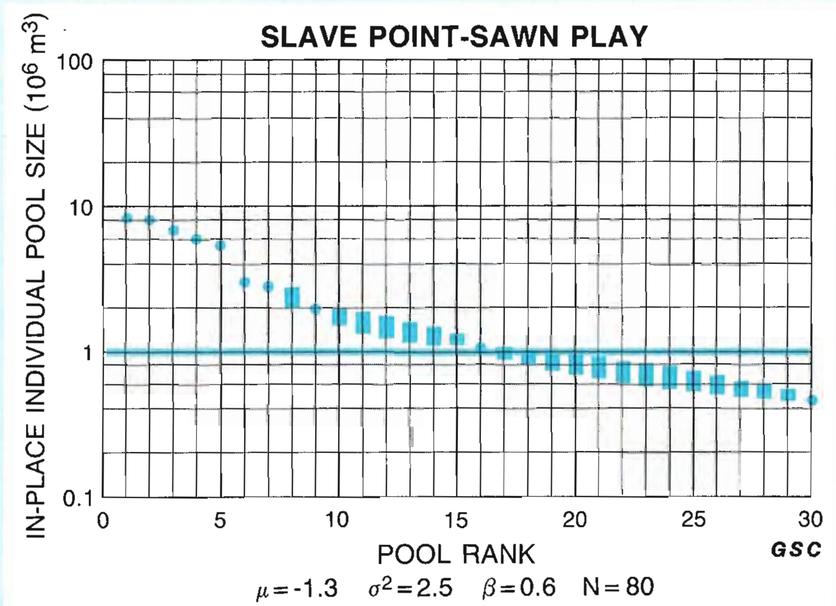


Figure 26

SLAVE POINT — GOLDEN

Play Definition: This oil play was defined to include all pools and prospects in structural, stratigraphic, and composite traps in the upper Slave Point reefs and reef complexes that developed in a narrow arcuate trend along the east flank of the Peace River Arch in north-central Alberta (Fig. 23).

Geology: The upper Slave Point reefs of this play are 5 to 40 m thick reef complexes and patch reefs, that developed on and around Precambrian basement highs on the Peace River Arch (Dunham *et al.*, 1983). The reefs range in area from less than a quarter section to seven sections. They formed at a stratigraphic level equivalent to the Swan Hills of the central Alberta region, but are conventionally termed Slave Point in the Peace River Arch District. Basinal Waterways Formation forms lateral and vertical seals around the reefs. Post-Slave Point structural reactivation is believed to have influenced the migration and entrapment of the oil. Oil source rock and migration paths are unknown at present.

The structurally influenced paleotopography on the arch that initiated Slave Point reef growth also limited deposition of the underlying Muskeg and Fort Vermilion evaporites. The upper Slave Point section is dolomitized, possibly as a result of fluid movement from these evaporites upwards into the carbonates. The dolomitization enhanced permeability and porosity, resulting in the high recovery factors of 20 to 40%.

Exploration History: The initial major discovery was at Golden in 1970. The play continues to develop, using seismic to detect structures. This has resulted in discoveries at Slave, Seal, and Evi. There were twelve pools with a total reserve of 14 x 10^6 m^3 OIP as of 1983 (Table 11).

Play Potential: Estimates of undiscovered potential for this play yield a median expectation value of 8 x 10^6 m^3 OIP. This estimate assumes a total population of 40 pools, of which 28 remain to be discovered. The pool array (Fig. 27) suggests that the 2nd largest pool in the play remains to be discovered.

TABLE 11

SLAVE POINT — GOLDEN PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Golden A	6.88	1970
3	Slave G	1.96	1980
4	Seal	1.40	1974
5	Evi B	1.21	1979
6	Evi A	0.88	1979
14	Evi C	0.28	1981
16	Evi D	0.22	1982
17	Evi L	0.19	1982
18	Evi J	0.18	1982
19	Evi I	0.15	1982
21	Evi F	0.12	1982
27	Evi E	0.07	1982

- Total Discoveries : 12
- Discoveries in the Top 30 Pools : 12
- Total Pool Population : 40

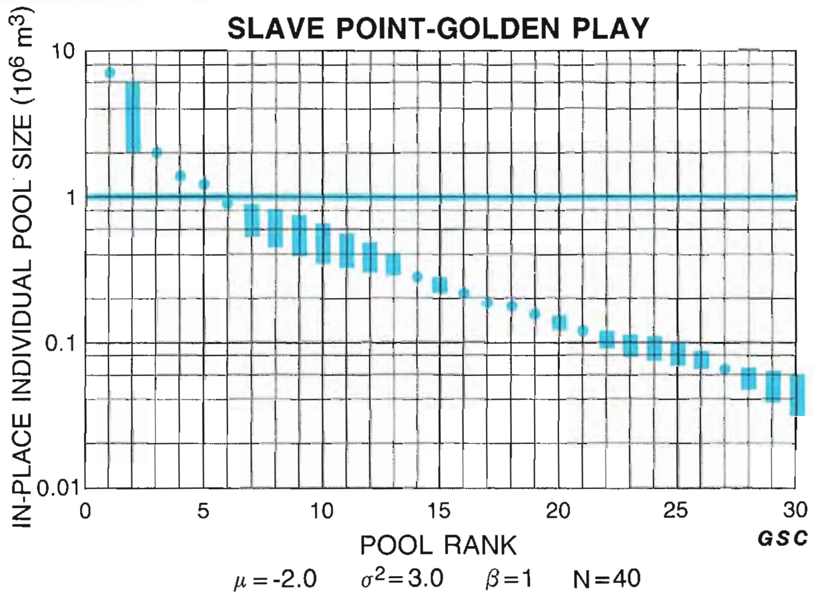


Figure 27

LEDUC — PEACE RIVER

Play Definition: This oil play was defined to include all pools and prospects in the Leduc reefs that fringe the Peace River Arch in northwestern Alberta. The play area includes that region of the arch updip from the Leduc hot line to the limit of Leduc fringing reef growth (Figs. 23 and 30).

Geology: The reservoirs are an intensely altered dolomite with vuggy, intercrystalline, and fracture porosity on the south side of the arch. Those on the north flank consist of interbedded dolomite and sandstone. The 200 to 250 m thick barrier reefs were built on a thin veneer of clastic rocks over Precambrian basement. Pools are typically one section or less in area, with pay thickness varying between 5 and 30 m. Porosity is between 3 and 10%, water saturation is less than 30% in carbonates, and up to 60% in sandstones, although permeabilities are generally excellent. The wide range of recovery factors, from 5 to 40%, is in part due to variations in reservoir size and gas content.

Top and lateral seal rocks are argillaceous limestone of the Winterburn Group. Oil was probably sourced from basinal Woodbend and Winterburn sediments.

Traps usually occur where post-Devonian faulting has placed basinal Winterburn Group sediments adjacent to, and laterally updip of the Leduc reefs.

TABLE 12

LEDUC — PEACE RIVER PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
2	Eaglesham	0.73	1959
3	Normandville B	0.56	1958
4	Normandville A	0.41	1949
7	Worsley F	0.19	1961

- **Total Discoveries : 4**
- **Discoveries in the Top 10 Pools : 4**
- **Total Pool Population : 10**

Exploration History: Only four pools, with total reserves of 1.9 x 10^6 m^3 OIP, have been discovered along this trend (Table 12). The pools are Normandville (1949, 1958), Eaglesham (1959), and Worsley F (1961), all discovered during the post-Leduc exploration phase in Alberta. There has been little direct activity focused on this play in the 1980s, despite the interest in all other Devonian plays.

Play Potential: The median play potential is 2 x 10^6 m^3 OIP expected in 6 additional pools, approximately equal to what has been discovered to date. This low potential is the result of a perceived lack of adequate seal rocks in the Woodbend and Winterburn over the Peace River Arch. The coarse clastic mantle should serve as a conduit for fluid migration toward the arch crest that even the complex fault pattern cannot interrupt. There has been moderate level of exploratory drilling on the barrier rim during the last 30 years, with no success outside of the three fields.

WABAMUN — PEACE RIVER

Play Definition: This oil play was defined to include all prospects and pools that occur where porosity was developed along fault-fracture zones in the Wabamun carbonate shelf on the Peace River Arch in northwestern Alberta. The play area is within the Peace River Arch structural region, bounded by the occurrence of gas within similar reservoirs to the southwest and by the Banff erosional edge to the northeast (Fig. 32).

Geology: There are two reservoir types in this play. The principal reservoir is a fractured dolomite, formed by upward movement of fluids along fault fracture zones, such as at Tangent. This is sealed above and laterally by impermeable Wabamun shelf limestone which was unaffected by this diagenetic event. The second reservoir, only producing at Normandville, consists of a fractured, partially dolomitized limestone patch reef that developed on a paleotopographic high over a Leduc reef. Post-Wabamun block faulting added a structural component to this trap. Upper, lower, and lateral seals are impermeable shelf limestone. Hydrocarbons probably migrated into the traps vertically from the Leduc reefs through fracture systems. The source may be the basinal Woodbend and Winterburn sections on the flanks of the arch or the overlying Exshaw shale.

A single pool at Simonette is included in this play, despite being geographically in the Central Alberta region, as it has many of the characteristics of the pools on the Peace River Arch.

Reservoirs are areally limited, but yield high initial production rates because of the fracture permeability. Porosity is less than 5%, water saturation is high for a carbonate (20 to 40%), and recovery factors are typically in the 15 to 35% range. All pools have been assigned areas of a quarter section, except Normandville which is one and a half sections in area.

Exploration History: The initial discoveries at Normandville (1956) and Simonette (1963) were made by chance during exploration for Leduc prospects. A flurry of exploration activity from 1979 to the present has discovered the other pools of this developing play (Table 13). To the end of 1985 total discovered reserves are 16 x 10^6 m^3 OIP in 29 pools. The discovered pools are all of similar size, ranging from 0.08 to 1.5 x 10^6 m^3 OIP.

TABLE 13

WABAMUN — PEACE RIVER PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
3	Simonette C	1.53	1963
4	Tangent E	1.35	1983
5	Tangent V	1.19	1985
7	Tangent A	0.97	1981
8	Normandville B	0.81	1984
9	Tangent P	0.75	1984
10	Tangent K	0.74	1984
11	Tangent U	0.70	1985
12	Tangent T	0.69	1985
13	Tangent M	0.67	1984
14	Tangent R	0.64	1984
15	Tangent H	0.64	1983
16	Tangent F	0.59	1983
18	Normandville A	0.53	1956
19	Eaglesham B	0.50	1981
21	Cindy A	0.48	1985
24	Tangent I	0.43	1983
27	Tangent G	0.38	1983
29	Tangent O	0.35	1984

- •Total Discoveries : 29
- •Discoveries in the Top 30 Pools : 19
- •Total Pool Population : 80

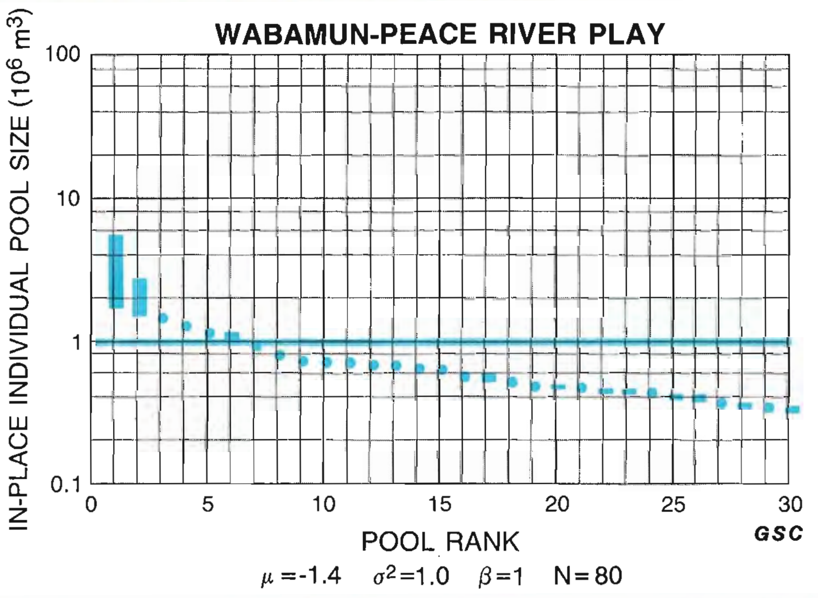


Figure 28

Play Potential: Estimates of the undiscovered potential for this play yield a median expectation value of 15 x 10^6 m^3 OIP. The estimate assumes a pool population of 80 pools of which 51 remain undiscovered. The predicted pool array (Fig. 28) indicates the dispersed nature of the resource and the analysis suggests that the largest two pools in the play remain undiscovered.

Because so many pools have been found in only a small parts of the play area it is possible that the potential has been underestimated. A new discovery, distanced from the Tangent-Cindy-Normandville region, might spark activity that would significantly increase the play reserves.

CENTRAL ALBERTA DISTRICT

Most of the Devonian oil reserves in this district occur within stratigraphic traps in transgressive phase reefs of the Swan Hills and Leduc Formations. The district is bounded by the Devonian hot line and erosional edges, the Peace River Arch, and the Leduc barrier reef system.

DEPOSITIONAL AND TECTONIC HISTORY

The earliest Devonian rocks in this District are the Delorme and Bear Rock sequences deposited north of the Meadow Lake Escarpment (Fig. 12). They consist of continental and shallow marine clastic, evaporite and carbonate rocks of the basal red beds (informal), Lotsberg, Ernestina Lake, and Cold Lake formations (Table 2).

Rocks of the Hume-Dawson sequence are present over most of the district, with successively younger units having greater areal distribution due to progressive onlap of the West Alberta and Peace River arches. Basal sandstone and shale (Ashern, Contact Rapids, Assineau, Grizzly) pass upward into the Winnipegosis-Keg River platform carbonate. Muskeg or Prairie evaporite deposition followed platform development. The Muskeg evaporites are interbedded with clastic rocks where they directly overlie pre-Devonian rocks in west-central Alberta (Grayston *et al.*, 1964). A minor erosional unconformity separates these rocks from those of the overlying Beaverhill-Saskatchewan sequence.

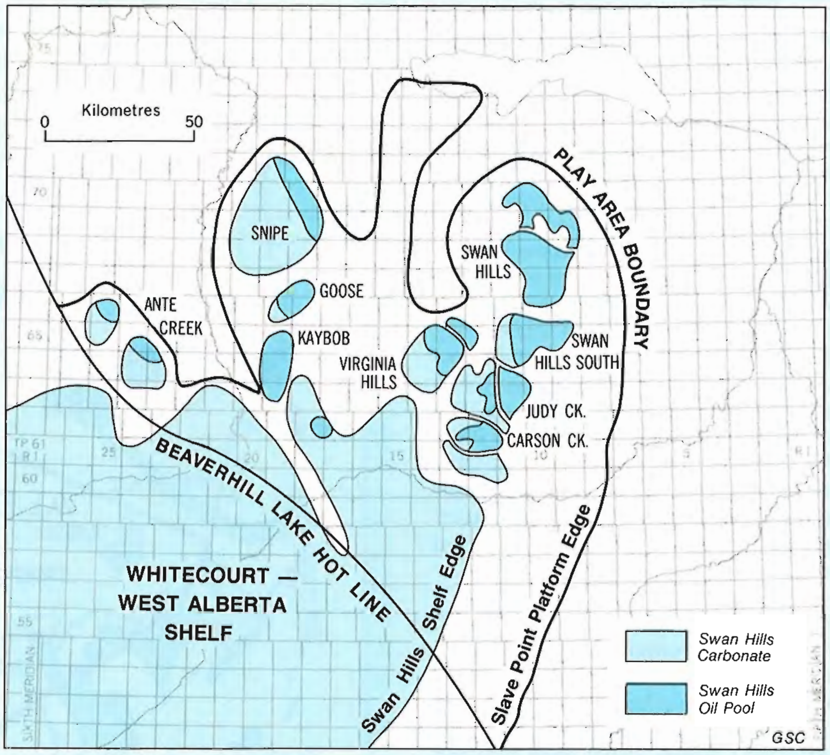


Figure 29. Beaverhill Lake Play Map. Play lies within area enclosed by Slave Point platform edge, updip of Beaverhill Lake hot line.

Sediments of the Beaverhill-Saskatchewan sequence were deposited in a partially enclosed marine basin surrounded by the shelf carbonates of the Souris River, Duperow, and Grosmont formations, and the West Alberta — Peace River Arch complex. Channels in the west and a large opening to the north allowed normal marine conditions to exist during deposition of most of this sequence. Initial deposits consisted of the shallow marine or lacustrine Watt Mountain shale and Gilwood sandstone. These units grade upwards into Ft. Vermilion evaporites, Slave Point platform carbonates, or Waterways shale-carbonate basin-fill. The Slave Point rims the West Alberta Arch in the south and spreads over much of the northwestern part of this district. It serves as the platform for Swan Hills reef complexes of Central Alberta (Fig. 29). Waterways carbonate and shale basin-fill clinothems surround the Swan Hills reefs. Thin, regressive phase Cooking Lake carbonate caps the depositional cycle of the Beaverhill Lake Group.

A subsequent major sea level rise without intervening regression deposited rocks of the Woodbend and Winterburn groups. Basal Cooking Lake platform carbonate spread over the southern part of the area. It passes upward into either basinal carbonate and shale of the Duvernay Formation or thick transgressive phase Leduc reefs (Fig. 30). In the northwestern part of the district the "Low Leduc" carbonate is deposited directly on a Swan Hills shelf, where it may be the equivalent of the Cooking Lake Formation, as it serves as a platform for thicker Leduc reef buildups. Water depth may have been as great as 300 m prior to deposition of regressive phase basin-fill clinothems of the Ireton Formation. These deep-water deposits are succeeded by carbonate shelves of the Grosmont, Lower Nisku, Upper Nisku or Meekwap, and Blueridge formations. Part of the Ireton is time equivalent with each of the carbonate shelves except the Blueridge. Nisku-equivalent basin-fill units are the Lobstick, Bigoray, and Cynthia Members of the Nisku Formation (Exploration Staff, Chevron Standard Limited, 1979). Infill of the basin occurred from southeast to northwest with the deepest and youngest portion located adjacent to the Peace River Arch. Basin fill was essentially complete by Blueridge time, with only small, isolated evaporitic basins left in the western portion of the district.

The final phase of Devonian sedimentation followed minor regression and erosion and consists of basal fine and coarse clastic rocks of the Graminia Formation (silt member) succeeded by the thick Wabamun Formation carbonate shelf.

There is no direct evidence of Devonian tectonism within the Central Alberta District, but the pronounced linearity of some depositional facies fronts implies that minor fault movement did occur. Such faulting influenced topography which, in turn, partially controlled facies distribution of features such as the Leduc Rimbey-Meadowbrook reef trend.

PETROLEUM GEOLOGY

The Central Alberta District has been the most important oil producing region in Canada as it contains 77% of the recoverable Devonian oil and 41% of the total recoverable reserves of Western Canada. Most of this oil is trapped in the Leduc and Swan Hills reefs, with subordinate amounts in regressive phase carbonate shelves of the Nisku and Wabamun formations. Four types of trapping mechanism occur in these shelves: drape over Leduc reefs, shelf interior reef to evaporite facies changes, basinal patch reefs, and post-Devonian unconformity traps. The large Gilwood oil pool at Mitsue, though geographically within this district, is included in the Peace River Arch District because it is associated with depositional facies and play types related to the arch. The Slave Point carbonates of the Peace River Arch District are continuous with the platform carbonates of Central Alberta, but are treated separately because of the structural influence on hydrocarbon trapping in that district.

The only documented source rock for oil is the Duvernay Formation, which is contemporaneous with the Leduc and was deposited in anoxic bottom conditions in the partially silled Woodbend Basin (Stoakes and Creaney, 1984). Both local and long distance migration of oil from the Duvernay to the Leduc occurred, through the Cooking Lake and Swan Hills platforms. The Duvernay may also have been the source for the oil in Swan Hills traps, through updip, but down section migration. Nisku and Wabamun petroleum may have leaked up section out of Leduc reefs. Oil in Nisku traps at West Pembina and Meekwap was probably derived from the time-equivalent Cynthia shale. The Exshaw may also be a local source for pooled Wabamun oil.

Petroleum generation and migration occurred in the Cretaceous to early Tertiary interval during loading of molasse wedges in the western part of the basin. Southwest tilting occurred at this time, causing hydrocarbon migration into the northeast terminations of traps. Reservoirs in every Devonian horizon exhibit evidence of thermal cracking of oil to gas down dip of "hot lines"; the evidence points to more than one stage of loading, heating, and hydrocarbon generation.

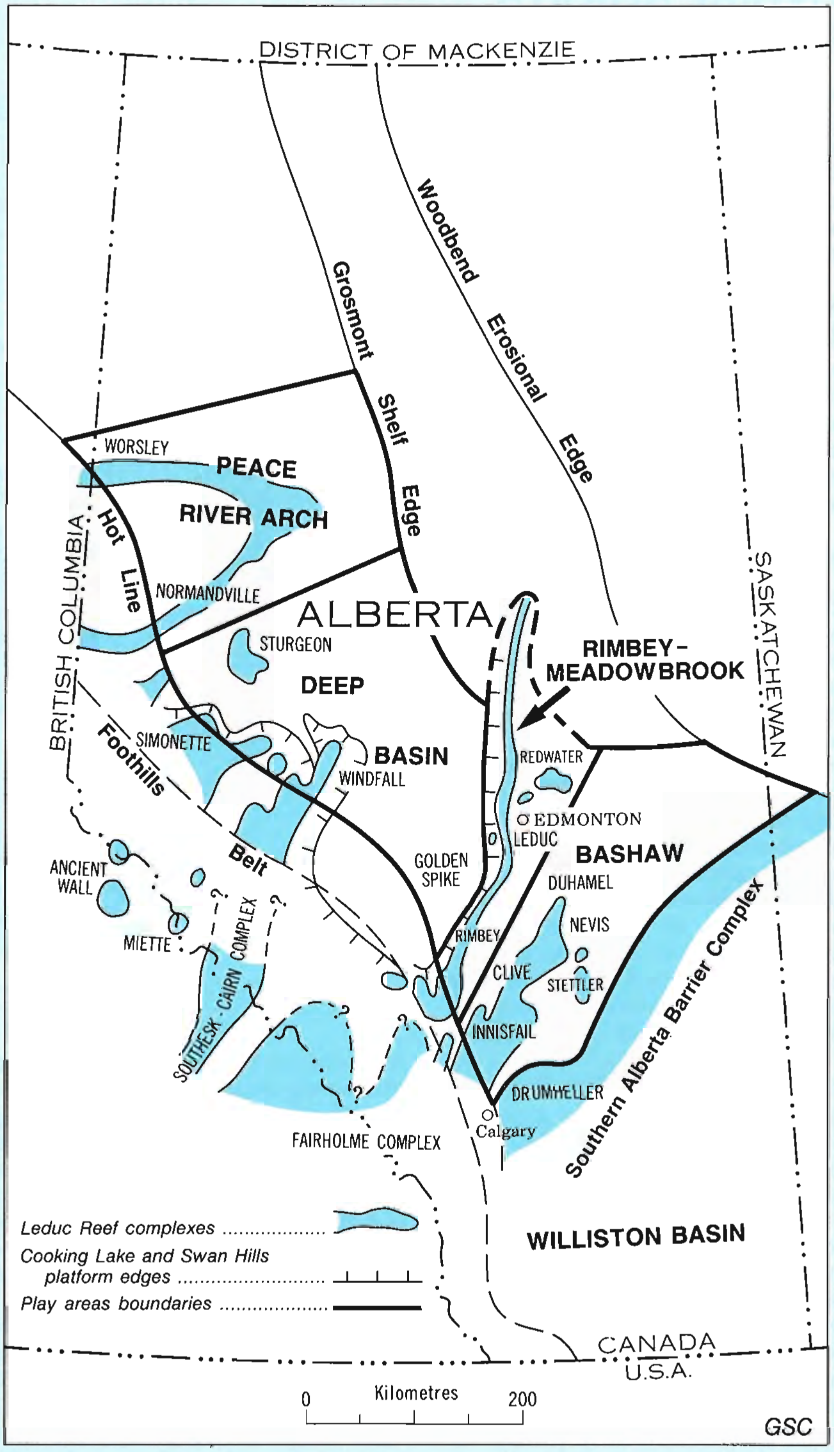


Figure 30. Leduc Play Areas, Alberta.

Most of the Wabamun, Nisku, and Leduc reservoirs are dolomite, formed by several stages of early and deep burial diagenesis demonstrated by matrix and allochem alteration, porosity formation, and porosity plugging (Belyea, 1964; Eliuk, 1984; Machel, 1984). Subordinate minerals are calcite and anhydrite. The Golden Spike and Redwater Leduc and all of the Swan Hills reservoirs are mainly limestone, also altered during several stages of diagenesis (Fischbuch, 1975; Klovan, 1964; Viau and Oldershaw, 1984; Walls, 1983).

Upper and lateral seals to the transgressive-phase reef complexes and the regressive-phase patch reefs are basin-fill limestones and shales. Shelf interior oil is sealed by either evaporites or impermeable limestone.

EXPLORATION PLAYS

There are twelve established plays in the Central Alberta District, nine of which are sufficiently mature to be assessed using the discovery process model. This is the most prolific producing region of the entire Western Canada Basin as it possesses excellent conditions for oil generation, migration, and entrapment. It is expected that several of the conceptual plays that have mature play analogues will contribute to the future reserve base of this district, providing that similar conditions exist. An example of a relatively modern conceptual play, without productive analogues, that rapidly became a mature established play, is the Nisku at West Pembina.

Conceptual Plays

The Hume-Dawson, Bear Rock, and Delorme sequences are as yet unproductive and are under-explored within this district. The **basal sandstones** and the **Winnipegosis** platform are potential reservoir rocks, and the associated evaporite deposits may contain source beds. Local structural reversals or updip stratigraphic seals would be required to effect trapping. Possibly owing to the low drilling density, neither traps nor mature source beds have yet been identified in these plays.

Regressive phase **shelf edges** have also been under-explored in central Alberta, with the exception of the Meekwap (Upper Nisku) trend. Plays similar to West Pembina and Meekwap (Fig. 31), with basinal patch and shelf margin reef development, could exist at the edges of the Camrose, Grosmont, Lower Nisku, and Blueridge shelves.

The **erosional edges** of the Beaverhill-Saskatchewan sequence regressive phase shelves may trap oil, by analogy with the Wabamun edge play, provided that Mesozoic rocks form adequate seals. There is little potential for conventional oil in this play, as these erosional edges are in the heavy oil district of eastern Alberta.

The **Wabamun** Formation may contain oil in subtle stratigraphic traps west of its eroded edge and south of the Peace River Arch (Fig. 32) where depositional or diagenetic activity has formed reservoir facies in this normally impermeable limestone shelf. It presently produces gas from such traps.

Established Plays

Two of the four immature established plays, involving the **Slave Point** and **Cooking Lake** platform units of the Beaverhill-Saskatchewan sequence, are discussed in conjunction with their corresponding transgressive phase reef plays. They are, however, under-explored and may have platform margin and patch reefs developed in them. Since petroleum migrated through the platforms, any stratigraphic or structural trap within them should pool hydrocarbons. The only discoveries to date are the Slave Point pools at Swan Hills and Virginia Hills, and the Cooking Lake pool at Skaro. The inability of seismic to detect thin reef developments makes exploration difficult.

The third immature play is the **Blueridge** shelf, which contains small stratigraphically trapped oil pools and oil shows in the shelf interior, shelf margin and lagoonal rocks of west-central Alberta. Oil also occurs in drape traps over Leduc reefs at Sturgeon South.

A fourth play that contains a small reserve base is in the **Crossfield Member** of the Wabamun Formation. This is a relatively mature sour gas play in south-central Alberta that contains one significant oil pool at Olds and a small pool at Okotoks (Fig. 32). The trap is stratigraphic, where the subtidal to intertidal shelf carbonate of the Crossfield changes facies updip (east) into intertidal to supratidal Stettler evaporites. Total reserves are approximately 7 x 10^6 m^3 OIP, and remaining potential is considered to be limited due to the relatively high drilling density along this sour gas exploration trend.

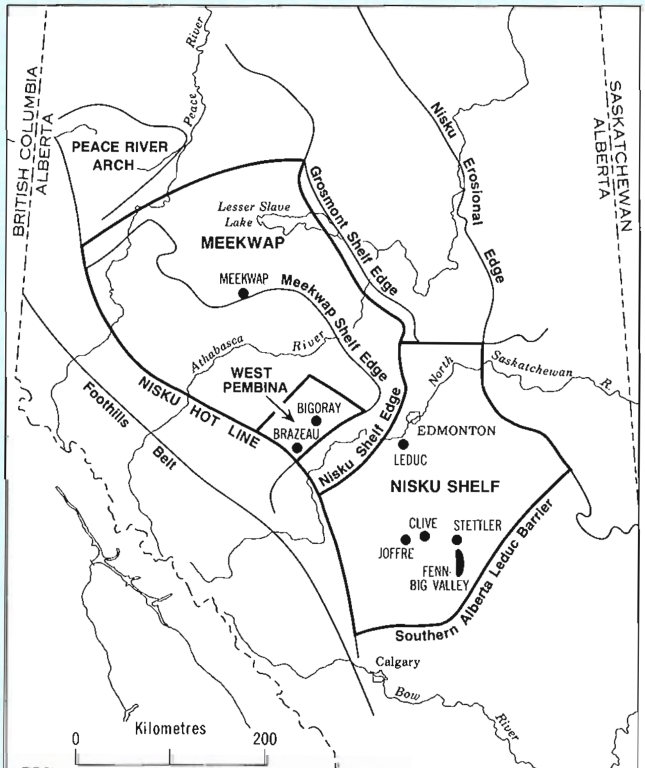


Figure 31. Nisku Play Areas, Central Alberta District.

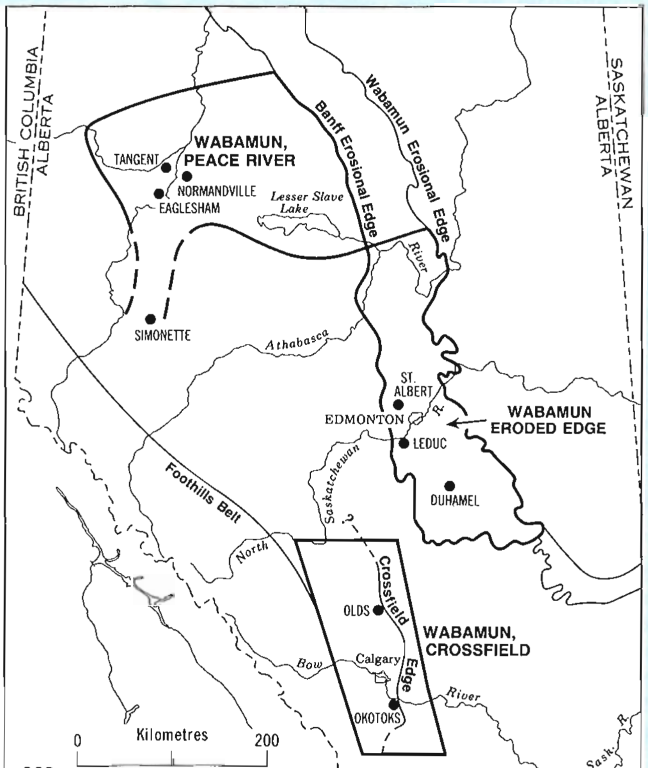


Figure 32. Wabamun Play Areas, Alberta.

BEAVERHILL LAKE

Play Definition: This oil play was defined to include all pools and prospects in Beaverhill Lake age reefs and reef complexes that grew on the Slave Point platform in west central Alberta. The play area is bounded to the southwest by the Beaverhill Lake "hot line", to the north by the southern limit of Peace River Arch, and to the east and south by the edge of the Slave Point platform (Fig. 29).

Geology: The Swan Hills reef complexes, which developed on a 40 m thick Slave Point platform, are from one half to four townships in area and are approximately 60 m thick. The reefs are limestone, with complicated internal stratigraphy and facies distribution (Fischbuch, 1968; Jansa and Fischbuch, 1974; Viau, 1983; Wendte and Stoakes, 1982), and excellent reservoir rock properties. Most pools are on secondary or tertiary recovery schemes that recover between 20 and 60% of the reserves. Oil is also produced from the Slave Point platform extending beyond the depositional margin of the Swan Hills Formation in the Swan Hills and Virginia Hills fields, but this reservoir is generally less porous and permeable than the reef complexes. These reservoirs are not conceptually within the play definition, but are included in this play for convenience.

The reef reservoirs are encased in Waterways carbonate and shales, which were deposited as regressive phase basin-fill sediment (Sheasby, 1971). The source and migration history of these oils is unknown, though the overlying Duvernay Formation appears to be the most likely source rock.

Exploration History: The initial discovery at Virginia Hills in 1956 was followed by Kaybob and the major Swan Hills find in 1957. Twenty one pools in this mature play were found by 1976. The total reserves of 967 x 10^6 m^3 OIP are found primarily in the large pools at Swan Hills, Swan Hills South and Judy Creek (Table 14). Lack of velocity contrast and similarity of compaction history of reef and basin sediments makes conventional seismic methods ineffective for this play.

Play Potential: Estimates of undiscovered potential for this play have a median expectation value of 60 x 10^6 m^3 OIP. This potential is expected to occur in an additional 39 pools about half of which will be in the range of 1 to 10 x 10^6 m^3 OIP (Fig. 33). Undiscovered pools may exist either in new reef complexes; downdip of subtle channels in discovered reef complexes; or in patch reefs formed on the platform. Refined seismic data gathering and processing techniques may be required for future Swan Hills exploration.

TABLE 14

BEAVERHILL LAKE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Swan Hills A & B	303.00	1957
2	Swan Hills South A	144.00	1959
3	Judy Creek A	130.00	1959
4	Swan Hills C	98.70	1958
5	Virginia Hills	75.40	1956
6	Kaybob A	47.70	1957
7	Carson Creek North B	42.50	1957
8	Judy Creek B	41.30	1959
9	Snipe Lake	31.00	1962
10	Goose River A	23.10	1963
11	Carson Creek North	15.10	1958
14	Ante Creek A	5.93	1962
24	Ante Creek B	1.56	1966
25	Judy Creek South C	1.50	1962
26	Fox Creek A	1.50	1976
30	Ethel A	1.29	1964

- •Total Discoveries : 21
- •Discoveries in the Top 30 Pools : 16
- •Total Pool Population : 60

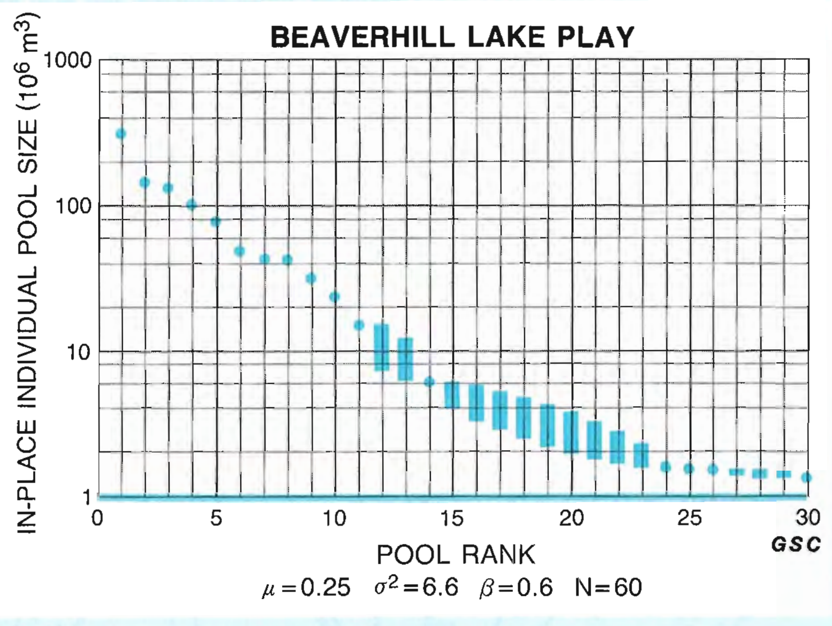


Figure 33

LEDUC — DEEP BASIN

Play Definition: This oil play was defined to include all pools and prospects in Leduc age reef complexes that grew on Swan Hills platforms in west-central Alberta. The play area is defined by the Rimbey-Meadowbrook Cooking Lake platform edge to the southeast, the Grosmont Shelf edge to the northeast, the southern limit of the Peace River Arch to the north, and the Leduc hot line to the southwest (Fig. 30).

Geology: Included in this play are Leduc reefs that may exist within the little explored parts of the basin. Growth of the Leduc reef complexes occurred in two stages on the Swan Hills platform: typically a 90 m thick lower Leduc reef section succeeded by 180 m thick but areally less extensive upper Leduc reef. Areas underlain by the reef complexes can be as large as several townships, whereas areas of the associated patch reefs can be as small as a half section.

Reef reservoirs are intensely altered to dolomite with vuggy, intercrystalline, and fracture porosities varying between 6 and 15%. Vugs were formed by solution of reef-building fossil remains and are partially filled with secondary anhydrite, dolomite, calcite, sulphur, and pyrobitumen. Permeability is typically good because of fracture systems. Water saturation is less than 20%, oil pay thickness varies from 10 to 30 m, and gas oil ratios are high (150 to 600 m^3/m^3). Recovery factors vary from 10 to 55% in patch reefs and from 22 to 55% in reef complexes. All pools have had gas caps and an active water drive. The depth of oil occurrence ranges from 1500 m down to 3500 m at Simonette, the deepest oil pool in Alberta.

Lateral and top seal rocks include the Ireton, Lobstick, Cynthia-Wolf Lake, and Calmar argillaceous limestones and calcareous shales. The most probable source rock is the Duvernay limestone and shale which underlies the Ireton and is interbedded with Leduc reef margins. The widespread Swan Hills and lower Leduc platforms may have served as conduits for long distance updip hydrocarbon migration.

TABLE 15

LEDUC — DEEP BASIN PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Sturgeon Lake South	45.30	1953
2	Simonette	18.00	1958
3	Windfall A	13.40	1957
5	Sturgeon Lake	7.06	1952
15	Windfall B	1.31	1972
16	Sturgeon Lake South B	1.21	1964
18	Windfall	0.81	1983
19	Windfall C	0.80	1979
22	Simonette B	0.53	1982
23	Sturgeon Lake South D	0.40	1984

- **Total Discoveries : 10**
- **Discoveries in the Top 30 Pools : 10**
- **Total Pool Population : 40**

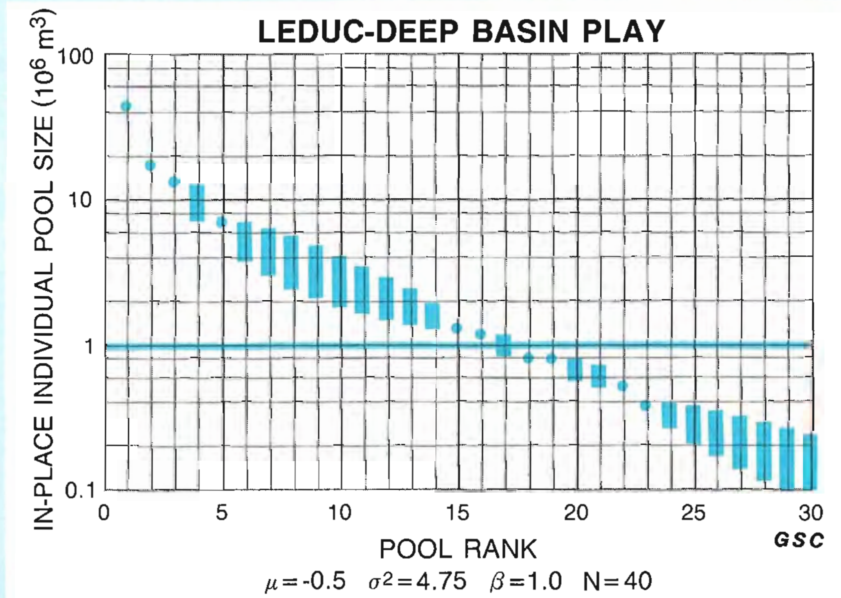


Figure 34

Exploration History: Approximately 90 x 10^6 m^3 OIP was discovered in ten pools during the period 1952 to 1983 (Table 15). Pool sizes range from 0.5 to 45 x 10^6 m^3 OIP. The early discoveries were at the updip terminations of reef complexes identified by classic Leduc drape and velocity pull-up effects on 100% seismic sections; subsequent exploration using more advanced seismic data-gathering and processing techniques has been able to define Leduc patch reefs associated with these complexes. Several recent oil and gas discoveries have been made in this relatively mature play, in the vicinity of the three large reef complexes.

Play Potential: Estimates of the undiscovered resource potential of this play indicate a median value of 42 x 10^6 m^3 OIP. The estimate assumes a total pool population of 40 pools, 30 of which remain to be discovered and should contain almost half of the total play resource (Fig. 34). The estimated 30 remaining pools may exist as pinnacle and patch reefs on both lower Leduc and Swan Hills platforms, or adjacent to channels and subtle stratigraphic facies changes within complexes, or in as yet unidentified Leduc reefs that may occur in relatively under-explored parts of the basin, such as beneath the Cretaceous Pembina oil field.

LEDUC — RIMBEY-MEADOWBROOK

Play Definition: This oil play was defined to include all pools and prospects in Leduc reef complexes and patch reefs that grew on the Cooking Lake platform in a linear north-northeast trend across central Alberta. It is bounded by the "hot line" to the southwest, and the limit of Leduc reef development to the north (Fig. 30).

Geology: Traps in this play are of the transgressive phase reef stratigraphic type, with regressive phase Ireton basin-fill forming lateral and top seals. The Duvernay has been identified as the source rock, and both long distance and local migration through the Cooking Lake platform carbonate into Leduc reservoirs has occurred (Stoakes and Creaney, 1984).

There are two stages of Leduc reef growth that may contain oil. The first consists of a lower biostromal development that is relatively thin and serves as a platform for the thick upper Leduc buildups of the second phase.

The Golden Spike and Redwater reefs which are located off the principal reef chain are mainly limestone, but all other reefs are dolomite (Andrichuk, 1958a, b; Klovan, 1964, 1974; Mountjoy, 1980; and Walls, 1983). In spite of internal morphological and diagenetic complexities, both rock types make excellent reservoirs, with excellent permeability, porosities between 5 and 15%, and recovery factors close to 50%. In addition to the oil, there is also a wide range of associated and solution gas.

Exploration History: The most important discovery in the history of exploration in the Western Canada Basin occurred at Leduc in 1947. By demonstrating the existence of oil in the Devonian of the basin, it initiated an intensive search for other Devonian reefs that is still continuing. As a result, more than half of the oil production from Western Canada has been from Devonian reservoirs. Total reserves are 576 x 10^6 m^3 OIP distributed in 23 pools, in this relatively mature play. (Table 16).

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 49 x 10^6 m^3 OIP. This potential is estimated to occur in 17 additional pools, five of which are expected to be of a size greater than 5 x 10^6 m^3 OIP and are speculated to occur close to the edges of the Cooking Lake platform.

The pool array shown in Figure 35 indicates that this play has one of the most concentrated pool size distributions in Western Canada. The very high slope of the pool array (σ^2 = 5.75) implies that most of the play resource is concentrated in a small number of pools.

TABLE 16

LEDUC — RIMBEY-MEADOWBROOK PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Redwater	207.00	1948
2	Bonnie Glen A	125.00	1951
3	Wizard Lake A	62.00	1951
4	Leduc-Woodbend A	61.20	1947
5	Golden Spike A Total	49.60	1949
6	Westerose	31.00	1952
7	Acheson A	27.60	1950
8	Homeglen-Rimbey	14.90	1953
14	Glen Park A	4.66	1951
15	St. Albert-Big Lake	3.70	1956
16	Fairydell-Bon Accord A	2.77	1952
17	Morinville B	2.59	1960
18	Leduc-Woodbend B	2.38	1951
20	St. Albert-Big Lake B	1.75	1952
21	Yekau Lake A	1.52	1952
23	Leduc-Woodbend F	1.03	1953
24	Golden Spike B	0.88	1950
27	Morinville C	0.62	1963
29	Golden Spike C	0.43	1951

- •Total Discoveries : 23
- •Discoveries in the Top 30 Pools : 19
- •Total Pool Population : 40

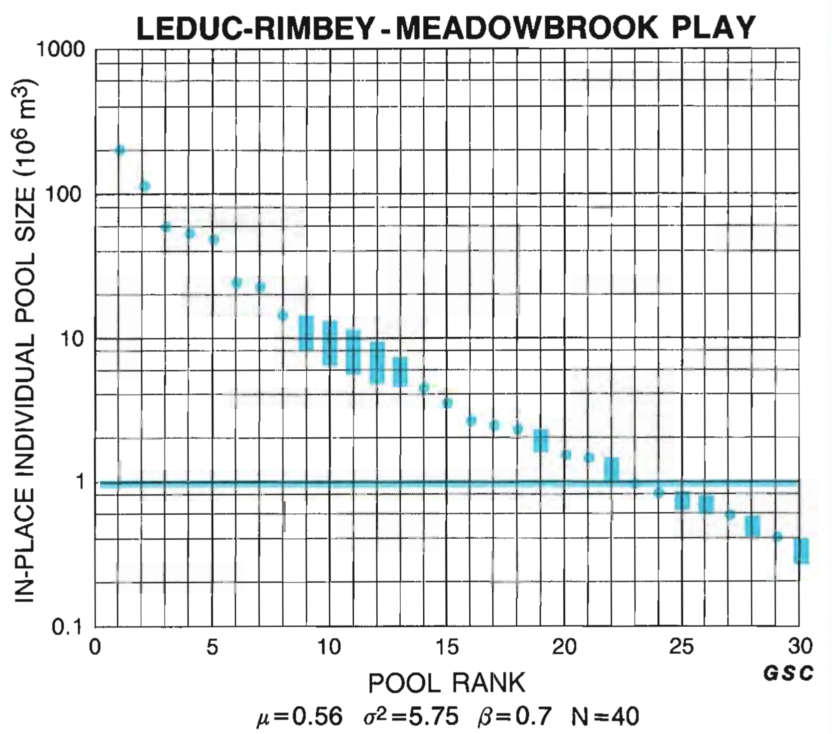


Figure 35

LEDUC — BASHAW

Play Definition: This oil play was defined to include all pools and prospects in Leduc reef complexes and associated patch and pinnacle reefs that grew on the Cooking Lake platform between the Rimbey-Meadowbrook and Southern Alberta barrier reef trends. The play area is defined by the Leduc erosional edge to the northeast, the edge of thick Cooking Lake platform to the northwest, and the edge of the Southern Alberta barrier reef complex in the south and southeast (Fig. 30).

Geology: Porous Leduc reefs from 250 to 300 m thick developed on the Cooking Lake platform of southern Alberta (Andrichuk, 1958a, b) and are surrounded and overlain by Ireton basin-fill rock (Stoakes, 1980). Traps occur at updip terminations of large reef complexes (Bashaw), downdip of channels forming low trends in the top of reef complexes (Clive), in small reef complexes (Duhamel, Erskine), in channeled rim features (Stettler), in patch reefs (Nevis), and in pinnacle reefs (Rumsey) (Alberta Society of Petroleum Geologists, 1960). The reefs are dolomite, with a complex diagenetic history. They form good reservoirs with high permeability, good porosity (5 to 15%), low water saturation (less than 20%), and high recovery factors particularly in the large pools (25 to 65%). The reef complexes typically have thin oil columns spread over a large area whereas the patch and pinnacle reefs have thick pay intervals over small areas. This empirical relationship may be due to a lack of adequate oil supply to the reservoir during migration or to the lack of adequate sealing capacity of the relatively thin Ireton shale over the large complexes.

Source rocks for oil are probably the basinal Duvernay shale and carbonate. The reefs were charged with oil by either local or long distance migration through the Cooking Lake platform.

Exploration History: All of the pools in this play were discovered during relatively continuous exploration from 1949 to 1970, following the initial find at Stettler. Several new pools, including the Rumsey pinnacle, were found during high exploration activity levels in the 1980s and have been included in this assessment. Total discoveries amount to 97 x 10^6 m^3 in 51 pools, with wide range of pool sizes from less than 0.1 x 10^6 to 20 x 10^6 m^3 OIP (Table 17).

TABLE 17

LEDUC — BASHAW PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Innisfail D-3	19.70	1957
2	Wimborne D-3A	15.00	1956
3	Clive D-3A	13.10	1952
4	Erskine D-3	6.39	1952
5	Rich D-3A	6.19	1985
6	Stettler D-3A	6.15	1949
10	Fenn-Big Valley D-3F	3.00	1954
11	Lone Pine Creek D-3A	2.35	1962
12	Duhamel D-3B	2.24	1950
13	Fenn West D-3C	2.13	1982
14	Fenn West D-3E	1.99	1983
15	Haynes D-2 and D-3	1.67	1969
16	Malmo D-3A	1.60	1951
17	Bashaw D-3A	1.60	1951
19	Buffalo Lake D-3	1.41	1960
21	Nevis D-3E	1.27	1970
28	Buffalo Lake D-3B	0.78	1959
29	Chigwell D-3B	0.77	1950

- Total Discoveries : 51
- Discoveries in the Top 30 Pools : 18
- Total Pool Population : 80

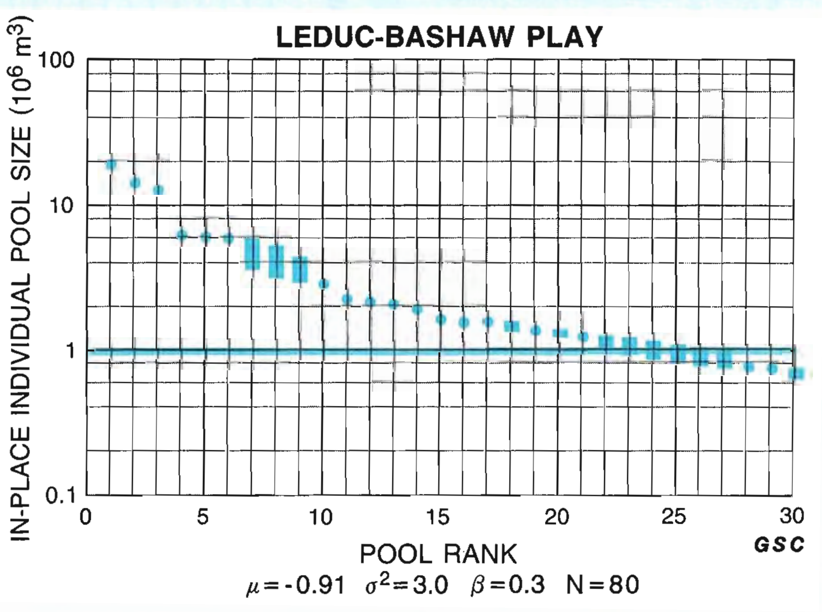


Figure 36

Play Potential: The estimate of undiscovered potential has a median expectation value of 24 x 10^6 m^3 OIP. This potential is expected to occur in 29 pools, with several pools in the 1 to 10 x 10^6 m^3 OIP size range (Fig. 36). Recent exploration has focused on pinnacle reefs and channels and variations in the thickness of the reef complexes, which are located with detailed seismic grid patterns. A continuation of this activity is expected to lead to further discoveries in these trap types.

NISKU — MEEKWAP

Play Definition: This oil play was defined to include all pools and prospects in reef reservoirs developed at or near the regressive phase Upper Nisku or Meekwap shelf edge in west-central Alberta. The play extends along an arcuate, approximately 20 km wide, corridor centred on the shelf edge (Fig. 31), from Morinville to Swan Hills, Sturgeon, and Eaglesham.

Geology: Reservoirs for this play include shelf margin reefs isolated by channels, and patch reefs developed landward within lagoonal shelf sediments. Basinal patch reefs similar to those at West Pembina have not been discovered to date. Reservoir rocks include both fossiliferous limestone and dolomite, with vuggy, intercrystalline, and fracture porosity. Dolomitization has enhanced the reservoir properties (Cheshire and Keith, 1977). Pool areas vary from one quarter to 8 sections. The reefs are about 30 m thick with 5 to 15 m of net pay. Recovery factors range from 10% in small pools to 50% in the large Meekwap A pool (currently on water flood). Water saturations are less than 30% and solution gas-oil ratios are low.

Lateral seal rocks consist of low energy channel-fill shelf limestones and the upper seal is formed by basinal argillaceous limestones of the Calmar Formation. Downdip basinal sediments of the Winterburn and Woodbend groups are the probable oil source rocks.

Exploration History: Exploration in the mid-1960s for Leduc and Swan Hills reef complexes resulted in the Nisku discoveries at Meekwap, Goose, and Kaybob (Table 18). Subsequent exploration and development drilling in the 1980s has found the remainder of the pools in the Meekwap field. Meekwap A, with 9.7 x 10^6 m^3 OIP is the only significant pool in the play. All other pools contain small reserves (less than 1 x 10^6 m^3) with areas of less than one section. Total reserves equal 12 x 10^6 m^3 OIP in seven pools.

TABLE 18

NISKU — MEEKWAP PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Meekwap A	9.70	1966
9	Kaybob Nisku C	1.10	1978
18	Meekwap D	0.33	1971
19	Goose River A	0.30	1965
22	Meekwap E	0.18	1973
23	Meekwap B	0.18	1971
27	Meekwap C	0.10	1980

- **Total Discoveries : 7**
- **Discoveries in the Top 30 Pools : 7**
- **Total Pool Population : 30**

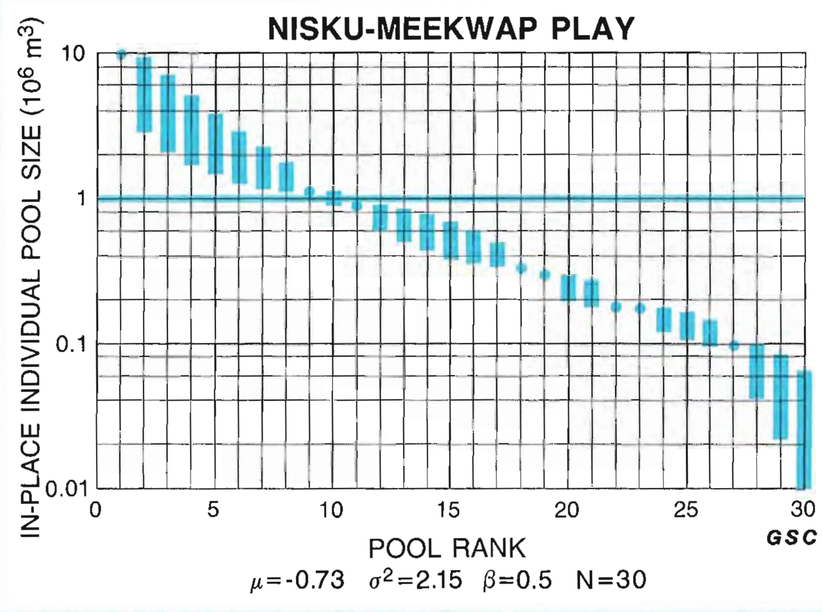


Figure 37

Play Potential: The undiscovered potential of this play is estimated to have a median expectation value of 25 x 10^6 m^3 OIP, which is approximately twice the discovered resource. Five undiscovered pools within the top thirty are estimated to be larger than 1 x 10^6 m^3 OIP and would be lucrative exploration targets (Fig. 37). The remaining resource could be found anywhere along the play trend, but exploration will be difficult owing to the small pool areas, poor well control outside of the established Devonian fields, and the inability of the seismic reflection tool to differentiate reservoir and seal rock on the carbonate shelf.

NISKU — WEST PEMBINA

Play Definition: This oil play was defined to include all pools and prospects in regressive phase patch reefs developed basinward of the Upper Nisku or Meekwap shelf edge in west-central Alberta. The play area is bounded by the Nisku hot line to the southwest, by a lack of porous reefs to the northeast, by the shelf edge to the southeast, and by a region of relatively deeper basin without reef development to the northwest (Fig. 31).

Geology: The patch reefs are less than one section in area, with from 10 to 60 m of oil pay. They consist of fossiliferous dolomite and limestone with a complicated internal morphology and diagenetic history (Exploration staff, Chevron, 1979). Diagenetic complexity, dolomite content, and gas content all increase towards the southwest (Machel, 1985).

The Cynthia Member basinal shale and limestone forms the lateral seal surrounding the reefs and is also a possible hydrocarbon source rock. The argillaceous limestone of the Calmar Formation forms the upper seal.

Exploration History: Most of the 45 oil pools at Brazeau, Bigoray, Pembina, and West Pembina were discovered within the four year period following the initial 1977 Pembina find (Table 19). This rapid industry response, using 1200% CDP seismic surveys, turned this from a conceptual play in 1976 to a mature play in this short time. The total in place reserve of 82 x 10^6 m^3 is distributed in pools ranging from 1 to 5 x 10^6 m^3. Most pools were placed on water or gas flood recovery schemes early in their production life, and have recovery factors in the order of 50%.

There has been little recent activity in this play, despite the industry interest in most other Devonian exploration trends.

Play Potential: The undiscovered potential estimated to exist in this play has a median expectation value of 9 x 10^6 m^3 OIP. This potential is expected to occur in five pools, two of which are greater than 2 x 10^6 m^3 OIP in size. This limited potential is based on the relatively small play area and extensive modern seismic coverage, that should have identified most of the reef anomalies. New pools may be found in the less explored northeast and northwest margins of the region, and in reefs with poor seismic definition.

TABLE 19

NISKU — WEST PEMBINA PLAY

Field Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
Brazeau River A	5.30	1977
Pembina D	4.80	1978
Pembina P	4.25	1979
Pembina Q	4.23	1980
Pembina L	4.20	1978
Westpem C	4.00	1979
Pembina G	3.00	1978
Pembina M	2.85	1978
Pembina A	2.80	1977
Brazeau River D	2.70	1978
Westpem A	2.65	1977
Bigoray F	2.50	1978
Pembina K	2.43	1978
Brazeau River E	2.30	1977
Brazeau River B	2.30	1978
Bigoray H	2.20	1978
Bigoray D	2.20	1978
Westpem D	2.20	1978
Pembina F	2.10	1978
Bigoray E	2.00	1978
Pembina O	1.70	1979
Pembina N	1.60	1979
Bigoray B	1.50	1978
Pembina C	1.43	1977
Pembina J	1.20	1978
Brazeau River I	1.06	1979
Brazeau River F	1.00	1978

- **Total Discoveries : 45**
- **Discoveries in the Top 30 Pools : 27**
- **Total Pool Population : 50**

NISKU — SHELF

Play Definition: This oil play was defined to include all pools and prospects in the porous regressive phase Nisku shelf carbonate that occur principally in drape structures over Leduc reef complexes. The region is bounded by the edge of the Southern Alberta Leduc barrier reef complex to the south and southeast, the Nisku erosional edge to the northeast, the Nisku shelf edge to the northwest, and the hot line to the southwest (Fig. 31).

Geology: All of the pools except Joffre occur where the Nisku shelf is draped over Leduc reefs. There is also a stratigraphic component to several of the traps, since a change of depositional facies occurs more or less coincident with the Leduc to Ireton transition in the underlying strata. Joffre, which is a purely stratigraphic trap formed by a facies change in the shelf (Alberta Society of Petroleum Geologists, 1960), may not be conceptually consistent with the play definition but has been included in this play for convenience.

Reservoirs in this play have pool areas that vary from a quarter section to a township, with pay intervals usually less than 20 m thick, porosity between 3 and 10%, water saturation usually less than 25%, and recovery factors between 20 and 50%. The reservoir rock is dolomite, with vuggy, intercrystalline, and fracture porosity.

The oil was probably sourced originally from the Duvernay Formation and migrated from Leduc complexes through fractures in the Ireton into the Nisku shelf. The top and lateral seals are formed by the Calmar and Graminia silty dolomite. Impermeable beds within the Nisku also form partial lateral seals.

Exploration History: The initial play discovery was at Leduc in 1947 and was followed by discoveries related to the intense Devonian exploration effort in the 1950s. Reserves of 210 x 10^6 m^3 OIP are distributed in 65 pools and form 70% of the Nisku and 30% of the total Alberta conventional oil reserves. Recent exploration has found a number of small pools (<1 x 10^6 m^3), along the established exploration trends. Four large pools that form a significant part of the reserve base are at Fenn-Big Valley, Leduc, Joffre, and Stettler (Table 20).

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 68 x 10^6 m^3 OIP. The potential is expected to occur in an additional 83 pools, several of which are greater than 1 x 10^6 m^3 OIP (Fig. 38). Much of the potential, particularly the larger pools, would be in stratigraphic traps similar to Joffre. Recent Nisku successes suggest that there is still room to explore for small pools over established Leduc trends.

TABLE 20

NISKU — SHELF PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Fenn-Big Valley A	75.20	1950
2	Leduc-Woodbend A	32.70	1947
3	Joffre	26.90	1956
5	Leduc-Woodbend B	11.60	1950
6	Stettler A	9.37	1949
7	Clive A	7.41	1951
9	Excelsior	6.20	1949
18	Malmo A	2.57	1952
19	Fenn West A	2.54	1961
21	Golden Spike A	2.18	1952
22	New Norway	2.15	1951
23	Duhamel A	2.00	1950
25	Haynes A	1.67	1968
26	Alix	1.62	1956
27	Stettler South	1.60	1951
28	Ewing Lake D	1.50	1953

- Total Discoveries : 65
- Discoveries in the Top 30 Pools : 16
- Total Pool Population : 150

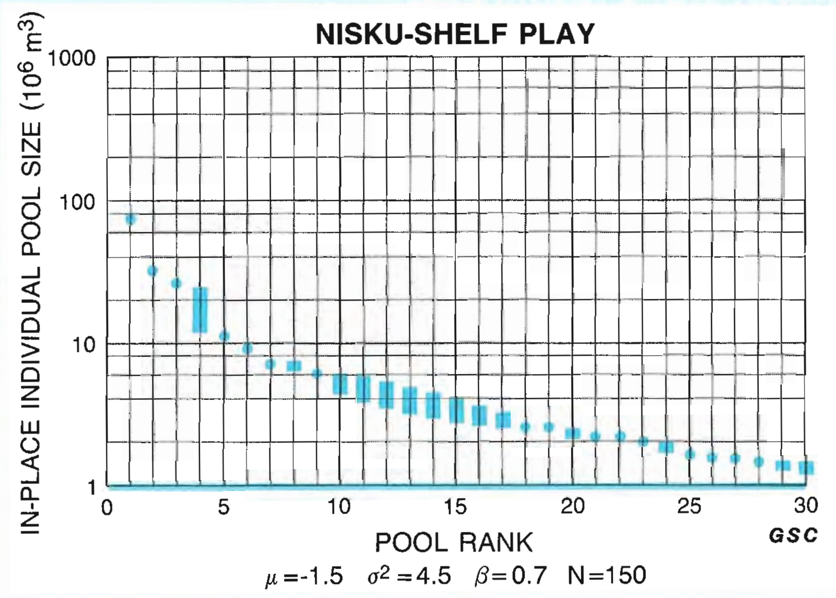


Figure 38

WABAMUN — ERODED EDGE

Play Definition: This oil play was defined to include all pools and prospects in traps developed against the unconformity where the Wabamun shelf carbonates subcrop beneath Cretaceous rocks. The play is bounded to the south by the facies change from Wabamun carbonate to Stettler evaporites. The northern boundary is ill-defined, but has been arbitrarily set at the southern limit of the Peace River Arch District (Fig. 32).

Geology: The trap mechanism is a combination of Cretaceous shales above the unconformity forming an updip seal and structural drape over Leduc reefs localizing oil accumulation.

Reservoir rock is dolomite, probably formed by diagenetic alteration related to the Mesozoic erosion events. Reservoirs in this play have pool areas less than one section, net pay from 1 to 30 m, porosity between 3 and 12%, and recovery factors less than 20%.

Seal rocks are Lower Cretaceous shales that fill erosional topography and encase the Wabamun carbonate. Some impermeable Wabamun limestone may also act as the upper seal. Oil source is not known with certainty but the oils do exhibit an affinity to the underlying Leduc oil (Deroo *et al.*, 1977), and thus may be oils from a Duvernay source that migrated up section and updip into the Wabamun.

Exploration History: Most of the pools were discovered in the 1950 to 1965 period by wells drilled with the Leduc as target, at fields such as St. Albert, Leduc, and Duhamel. The low total reserve base of 5 x 10^6 m^3 OIP, the small individual pool size range of from 0.05 to 3 x 10^6 m^3 OIP, and the unpredictable nature of the porosity distribution have discouraged recent exploration (Table 21).

Play Potential: The estimate of remaining potential for this play has a median expectation value of 6 x 10^6 m^3 OIP. This potential is expected to occur in 31 additional pools, the largest of which is estimated to contain between 1 and 3 x 10^6 m^3 OIP (Fig. 39).

TABLE 21

WABAMUN — ERODED EDGE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	St. Albert-Big Lake D	2.88	1953
3	Acheson Wabamun A	0.92	1980
5	Alexander Wabamun B	0.51	1965
11	St. Albert-Big Lake A	0.25	1956
16	Leduc Woodbend A	0.16	1963
17	Joarcam Wabamun	0.15	1980
27	Morinville A	0.06	1953
28	Leduc-Woodbend B	0.06	1963
29	Duhamel Wabamun A	0.05	1952

- Total Discoveries : 9
- Discoveries in the Top 30 Pools : 9
- Total Pool Population : 40

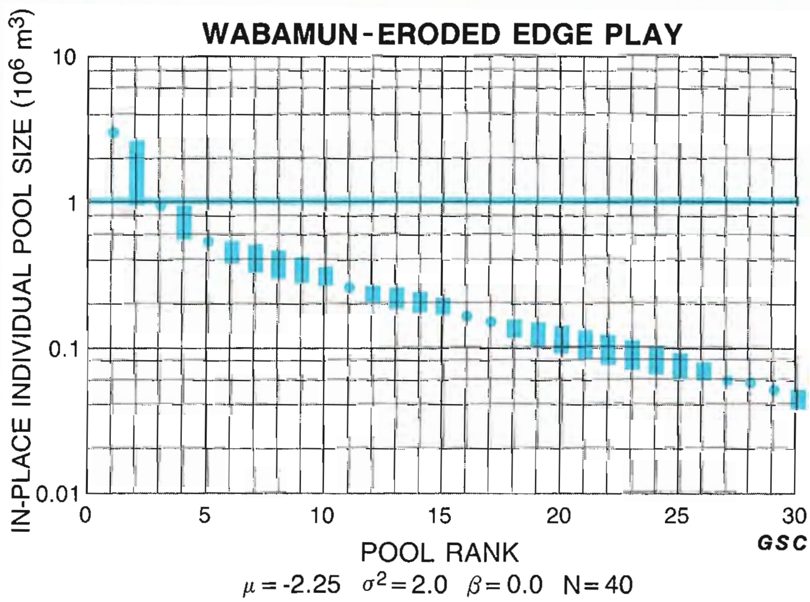


Figure 39

WILLISTON BASIN DISTRICT

This district includes a vast area of carbonate shelf, intra-shelf evaporite basin, and shallow water clastic-evaporite deposits. The southern boundary is political rather than geologic, which distorts the assessment of resource potential. The geologic boundaries of the Devonian Williston Basin are defined by the Meadow Lake Escarpment in the north, the Devonian eroded outcrop belt in the northeast, the subcrop belt in the southeast, the Central Montana Arch (Fig. 12) and the Laramide thrust belt in the southwest (Fig. 8). The northwest boundary is difficult to define as there was no significant arch system present during the Devonian to separate the Alberta and Williston basins. It is arbitrarily placed at the edge of the Southern Alberta Leduc barrier reef complex (Fig. 30), which also approximately coincides with the Beaverhill Lake to Souris River transition and the pre-Devonian erosional edge of the Ordovician as it extends south from the Meadow Lake Escarpment (Fig. 40).

DEPOSITIONAL AND TECTONIC HISTORY

Pre-Devonian epeirogenic uplift along the Transcontinental, Central Montana and West Alberta arches and possibly along the Meadow Lake Escarpment is responsible for the physical definition of the basin. Movements also occurred on a number of intra-basin features such as the Nesson and Cedar Creek anticlines. Development of several evaporite basins and subsequent Devonian halite solution were probably accompanied by minor tectonism, though this has not been documented. Most positive areas became negative from early Mississippian to the Permian, probably along reactivated fault zones. There were also vertical movements associated with Tertiary intrusion of alkalic hypabyssal rocks and with meteorite impacts throughout the Phanerozoic.

The Devonian of the Williston Basin is characterized by two facies belts: a shelf carbonate, with local or regional shallowing-upward carbonate to evaporite hemicycles and intra-shelf shallow-($\simeq$10 m) or deep-($\simeq$100 m) water evaporite basins; and shallow marine or continental clastic-evaporite units that form the base and landward equivalent of the shelves (Fig. 13). The Hume-Dawson sequence was deposited on Silurian or Ordovician rocks and consists of two major depositional cycles separated by a minor unconformity. The Ashern redbeds, Lower Winnipegosis platform, Upper Winnipegosis shelf and reefs, and Prairie evaporite constitute the first package; and the Second Red Bed, Dawson Bay carbonate, and Hubbard evaporite the second. All of these units intertongue with thin clastic equivalents surrounding the arch systems.

The initial deposits of the Beaverhill-Saskatchewan sequence were clastics of the First Red Bed, that is included within the Dawson Bay Formation, despite recognition that an unconformity separates it from underlying Dawson Bay carbonates (Dunn, 1982). They were followed by deposition of the Souris River, Duperow, and Nisku-Birdbear carbonate shelves, that extended across the entire basin and onlapped parts of the surrounding arch systems. The Nisku shelf of Central Alberta District appears to be correlative with the upper part of the Birdbear Formation. The Lower Birdbear passes laterally into shales in the western part of the basin, but redeveloped as a carbonate shelf in southern Alberta termed the Camrose Member of the Ireton Formation. Local evaporite basins recognized within the carbonate shelf include the Davidson (Souris River Formation) and the Youngstown, Wymark, and Flat Lake (Duperow Formation).

Rocks assigned to the Palliser sequence unconformably overlie the Beaverhill-Saskatchewan deposits. Stratigraphic units include the Stettler evaporites and the Big Valley shales in the west, Torquay evaporites and Big Valley in the central, and Lyleton red beds in the eastern regions of the District.

PETROLEUM GEOLOGY

The Canadian segment of the Williston Basin is a lightly explored region with few discoveries and accounts for less than 1% of the Western Canada Devonian reserves. Most of the pools occur within a single play along the Southern Alberta Leduc barrier reef trend, that is in many aspects genetically related to Leduc and Nisku plays of the Central Alberta District.

Most of the Devonian production is in the U.S.A. portion of the Williston Basin from pools in the Winnipegosis, Souris River, Duperow, and Birdbear shelf carbonates, with dominant structural and subordinate stratigraphic trap components. A direct comparison to the Canadian portion of the basin is difficult to make, since structures decrease in number and amplitude in the northern part of the basin. The potential does exist, however, for large stratigraphic and numerous small structural traps to have been formed throughout the Devonian section in Canada.

Stratigraphic traps within the shelves may have been formed by subtle depositional or diagenetic facies changes within the carbonates or by carbonate to evaporite facies transitions. The development of reefs within and surrounding evaporite basins should present further stratigraphic trap opportunities. Unconformity and hydrodynamic traps may also occur within this region.

The more important uncertainties affecting the assessment of the Williston Basin Devonian section were the adequacy of source rock and the nature and efficiency of migration pathways required to charge traps, should source rocks exist.

EXPLORATION PLAYS

For the purpose of this assessment, ten plays were defined to analyze the potential of the Devonian rocks of the Williston Basin (Fig. 40). Some of these plays may be considered composite plays that would have been subdivided had a more exhaustive analysis been undertaken. There are two conceptual and eight established plays, only one of which has sufficient discovery record to warrant assessment by the discovery model technique.

Most exploration for Devonian and older targets occurred prior to 1970, with limited success. Recent discoveries in southern Alberta and southern Saskatchewan may stimulate exploration activity in this district.

Conceptual Plays

Only two plays without discoveries in either Canada or the United States were considered in this report. One involves a **hydrodynamic** component to trapping in structures or facies change traps in southwestern Saskatchewan. This is a region where fresh water recharge from Montana flows northeast through the basin. This may have created potential minima for oil at locations displaced from conventional trapping sites. Prospective reservoirs in this play are the Winnipegosis, Dawson Bay, Souris River, Duperow, and Birdbear carbonate shelves.

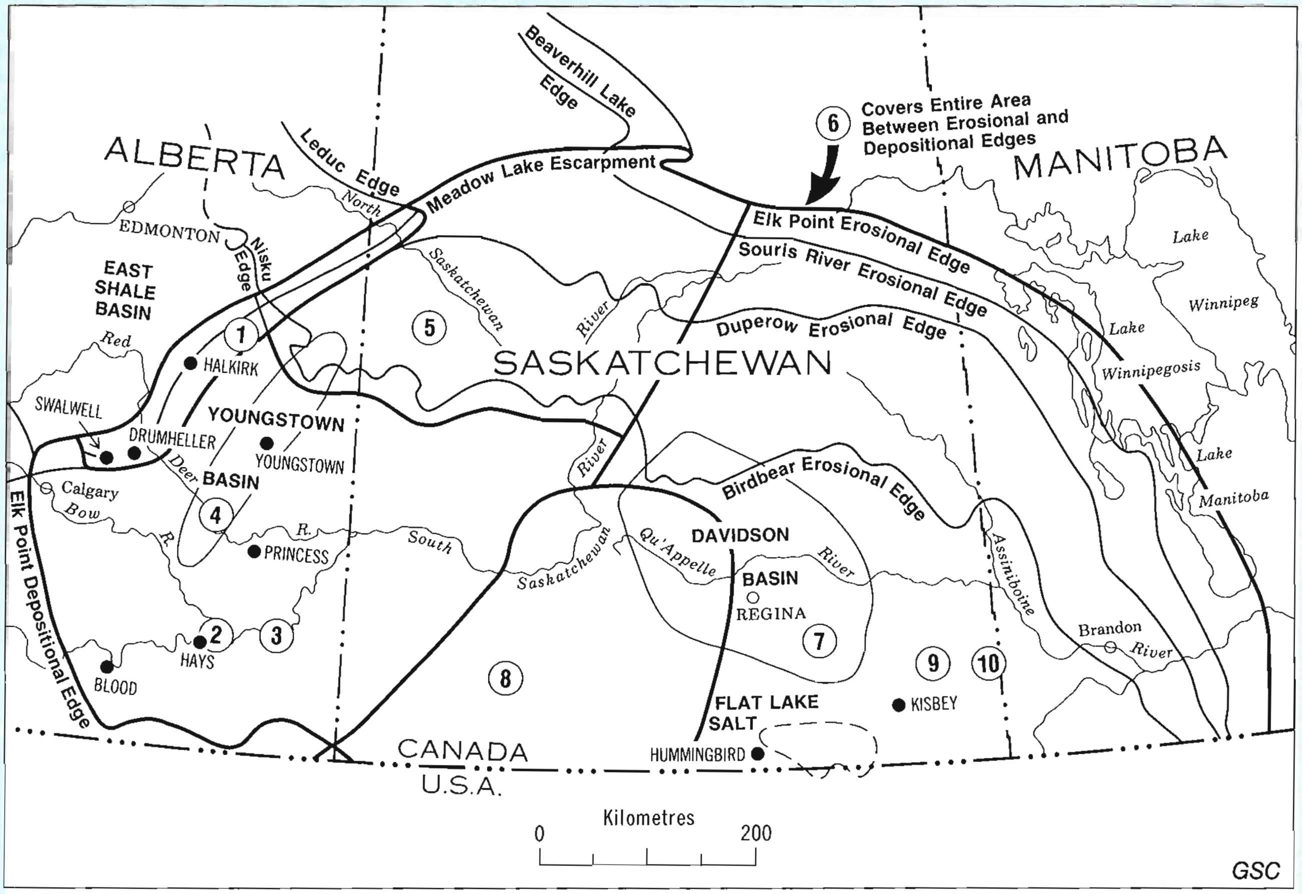
The second play would include stratigraphic traps in the Souris River Formation in the **Davidson Basin** of central Saskatchewan (Lane, 1964; Meijer Drees, 1986). The basin is a large, deep evaporite basin that may have shelf-margin and pinnacle reefs associated with it, similar to the Keg River evaporite basins of northwestern Alberta. Potential source rocks could exist in the platform and evaporite facies, and evaporites surrounding the reefs would form the seal. Subordinate multi-stage salt solution traps may also occur in the overlying Duperow and Birdbear shelves. Major difficulties with the play could be the quality and maturity of source rock and the effect of salt plugging the Souris River reservoirs.

Established Plays

Seven of the eight established plays are immature, and, of those, only five have discoveries in Canada. The two plays without discoveries are defined to include **stratigraphic** traps in all of the carbonate shelves in **southern Alberta** and in **southeast Saskatchewan - Manitoba,** on either side of the Devonian fresh water recharge region (Fig. 40). Stratigraphic traps are difficult to identify, but do occur in some of the shelf units in the United States (Longman, 1981, Weinzapfel and Neese, 1986). The shelves are built up of several shallowing-upward carbonate to evaporite cycles. Local diagenetic or stratigraphic facies change within a single cycle could produce trap configurations. Prospects will be difficult to locate in these two plays, because of the inability of seismic to detect subtle facies change. Age, quality, and maturity of potential source rocks are unknown, though it seems that an indigenous source would be required.

The five remaining immature plays are discussed in geographical order, from west to east (Fig. 40).

The **Southern Alberta Structure** play comprises all structural and salt-related drape traps that pool oil in the Souris River, Duperow, Birdbear, and Big Valley carbonate shelves of southern Alberta (Fig. 40). The principal structures are folds and faults of Laramide age. The structures strike parallel to the disturbed belt in the west and gradually change to a north and northeast orientation in eastern Alberta, where they are associated with the Sweetgrass Arch. Reservoir enhancement seem to have occurred within the structures. Production has been from the Big Valley Formation on the



1. Leduc-Nisku, Southern Alberta Play.
2. Southern Alberta Structure Play.
3. Southern Alberta Stratigraphic Play.
4. Youngstown Basin Play.
5. Devonian Erosional Edge Play.
6. Winnipegosis Play.
7. Davidson Basin Play.
8. Hydrodynamic Play.
9. Southeast Saskatchewan-Manitoba, Structure Play.
10. Southeast Saskatchewan-Manitoba, Stratigraphic Play.

Figure 40. Williston Basin Devonian Play Areas.

Blood Reserve, and the Birdbear (Nisku) at Princess and in the Hays-Enchant region. Several Birdbear pools occur in Montana, immediately south of the border, on the Kevin-Sunburst Dome.

The **Youngstown Basin** play includes all stratigraphic Duperow reef and salt-related Duperow and Birdbear drape traps in and immediately surrounding the Duperow Youngstown Basin (Fig. 40). This deep evaporite basin is analagous to the Keg River basins of northern Alberta and may have enormous potential providing that adequate, mature source rocks are found within it and that salt plugging has not adversely affected reservoir quality. The only discovered pool is the Youngstown "Arcs" (Birdbear) pool that is in a drape trap over a salt remnant. The oil in this pool appears to be more typical of Cretaceous oils (Deroo *et al.*, 1977).

The **Devonian Erosional Edge** play includes all unconformity traps in the Souris River, Duperow, and Birdbear carbonate shelves, where they lie beneath the Mesozoic erosion surface (Fig. 40). Diagenetic enhancement of reservoir properties due to unconformity-related processes probably occurred. Oils could be sourced either from Devonian or Cretaceous rocks. There are several recent discoveries in the Birdbear (Nisku) in the Wainwright-Edgerton region of eastern Alberta. The Duperow and Souris River erosional edges have yet to be successfully tested.

The **Winnipegosis** play includes all prospects and pools in the lower Winnipegosis platform and the upper Winnipegosis reefs. In the Williston Basin they occur between the Elk Point depositional edge to the west, and the erosional edge to the east (Fig. 40). The reefs are the principal exploration target, and are probably best developed on the thicker platform areas of southern and central Saskatchewan (Gendzwill, 1978; Wardlaw and Reinson, 1971; and Wilson, 1984). The Ratner Member that lies directly above the platform is a potential source rock, and the Prairie evaporite that overlies the Winnipegosis would be the seal. There has been only one recent Winnipegosis discovery in Canada, at Tableland near Estevan, Saskatchewan, but several pools have been found in the United States. Major concerns in evaluating this play were the maturity of the potential source rocks, the effects of salt plugging on reservoir quality, and the effect of fresh water recharge and Prairie salt solution on trap integrity.

The **Southeast Saskatchewan-Manitoba Structure** play is defined to include all pools and prospects in the Dawson Bay, Souris River, Duperow, and Birdbear carbonate shelves in structural traps. The play occurs in southern Saskatchewan and southwestern Manitoba, in the area between the fresh water recharge zone and the erosional edge of the basin. Three types of structure occur in the region: tectonic, related to one or several stages of epeirogenic movement; salt solution,formed during multi-stage collapse of the Prairie Evaporite (De Mille *et al.*, 1964; Smith and Pullen, 1967); and meteorite impact structures (Sawatzky, 1975). There are two Birdbear pools in southeastern Saskatchewan: Hummingbird with $1.17 \times 10^6 m^3$ and Kisbey with $1.56 \times 10^6 m^3$ OIP. Most Devonian production in the United States portion of the Williston Basin occurs in large structures such as the Nesson anticline. There may be indigenous Devonian oil source rocks, but recent work suggests that the Hummingbird oil is derived from the Bakken Formation or a combination of Bakken and Ordovician sources (Brooks *et al.*, 1987). This play is perceived as having more potential than other Williston Basin District plays.

LEDUC-NISKU — SOUTHERN ALBERTA

Play Definition: This oil play was defined to include all pools and prospects in thick reef carbonates along the Leduc Formation barrier reef, and those in the Camrose Member and Nisku carbonate shelves where they are draped over Leduc features with positive morphological relief. The play is within a 30-km wide corridor along the Leduc barrier complex from Swalwell to Drumheller, extending north to Halkirk and bounded by the Leduc erosional edge in western Saskatchewan (Fig. 40).

Geology: Approximately 250 m of Leduc barrier reef is developed above the Cooking Lake platform. Variations in thickness, possibly due to inter-reef channels and isolated buildups immediately basinward of the barrier edge, create stratigraphic trapping situations. Generally less than 10 m of Ireton shale overlie the Leduc reefs, and are in turn overlain by the Camrose and Nisku regressive phase shelf carbonates. Drape traps occur in these units over Leduc buildups. The thin Ireton interposed between the reservoir units was a poor seal that allowed vertical oil migration. The Stettler and Winterburn evaporites form the upper seal of the system. Oil was probably sourced from Duvernay shales and migrated through the barrier reef system.

All pay zones consist of reefal dolomite having vuggy, intercrystalline, and fracture porosity, good permeability, and low water saturations. Pay zones are generally less than 10 m thick. Pools vary from a quarter to two sections. Oil recovery factors range from 10 to 65% with the better recovery factors characteristic of the larger pools.

Exploration History: 20 x 10^6 m^3 OIP has been discovered in eleven pools. Pool sizes vary from 0.1 x 10^6 to 7.2 x 10^6 m^3 OIP. The Drumheller and West Drumheller fields were discovered early in the 1950s, Swalwell in 1969, and Halkirk in 1983 (Table 22). Little exploratory drilling has been focused on this play and the overall play area is still under-explored in comparison to other Leduc trends.

TABLE 22

LEDUC-NISKU — SOUTHERN ALBERTA PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	West Drumheller D-2A	7.17	1952
2	Drumheller D-2B	5.75	1962
5	Drumheller D-2A	2.51	1951
8	Swalwell D-2A	1.73	1969
10	West Drumheller D-3A	1.25	1954
25	West Drumheller Ireton A	0.33	1967
26	Halkirk Camrose B	0.30	1984

- Total Discoveries : 11
- Discoveries in the Top 30 Pools : 7
- Total Pool Population : 60

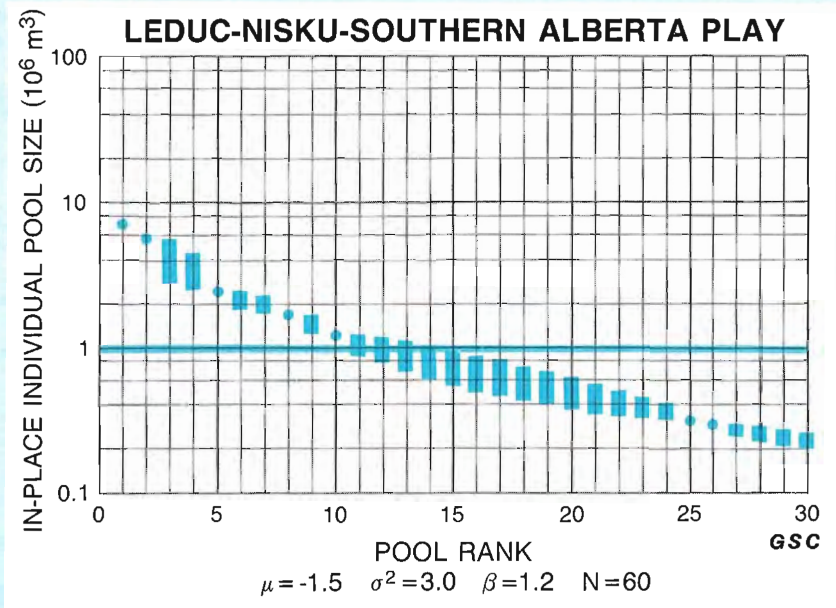


Figure 41

Play Potential: Estimates of the undiscovered potential of this play yield a median expectation value of 25 x 10^6 m^3 OIP. The estimate assumes a pool population of 60 pools of which 49 remain to be discovered (Fig. 41).

CARBONIFEROUS AND PERMIAN SYSTEMS

The Carboniferous and Permian successions form part of the upper Kaskaskia and lower Absaroka sequences of Sloss (1963), which were deposited on the western margin of the North American craton. These units are separated from underlying Famennian strata by either widespread (minor) unconformities or hiatal surfaces. A well developed regional unconformity is probably not present.

Upper Famennian elements of mainly Carboniferous formations like the Exshaw and Bakken formations, that overlie the Wabamun, Big Valley, or Torquay formations are included in this chapter because they are relatively thin, lithologically indistinguishable from overlying Carboniferous strata, and are separated from underlying Famennian strata by either disconformities or hiatal surfaces.

In most of the Western Canada Sedimentary Basin, Mesozoic strata unconformably overlie the Carboniferous successions. However in most of the Rocky Mountains, the northern Foothills, much of the interior plains of northeast British Columbia, and the Peace River region of northern Alberta, Permian strata unconformably overlie the Carboniferous deposits. Where Permian rocks are preserved they are commonly unconformably overlain by Triassic units, although in northern British Columbia rocks as young as Cretaceous may directly overlie the Permian.

The eastern and northern subsurface limits of Carboniferous and Permian rocks were defined by erosion during several Mesozoic events. The western margin in the Rocky Mountains is outside the oil exploration limits considered in this report. The southern limit of the study area is the International Boundary even though sedimentation was continuous into the Williston Basin of the west central United States (Fig. 42).

DEPOSITIONAL STYLE

The subsurface Western Canada Sedimentary Basin contains two depocentres of Carboniferous rocks. The two — the Peace River Embayment and the Williston Basin — are separated by the Alberta Shelf (Fig. 42). Permian rocks are widespread in the Peace River Embayment, but have not been found in the Canadian portion of the Williston Basin (Fig. 44). These depocentres merge westward with the Prophet Trough (Carboniferous) and Ishbel Trough (Permian) (Henderson *et al.*, in press; Richards *et al.*, in press) and into the Alberta Shelf. Both depocentres progressively shrank in size during the Carboniferous with accompanying expansion of adjacent shelf areas. These shelves contain shallow-water deposits that were interrupted by episodic erosional events.

The initial development and subsequent restriction of the basinal regions was achieved through regional downwarp and local block faulting during several discrete events from the Late Devonian to the Permian. Superposition of several marine transgressions on this evolving basin geometry during carbonate and clastic sedimentation resulted in a great diversity in facies pattern. Four principal facies assemblages are recognized, and they provide the basis of the paleoenvironmental interpretation of the Carboniferous sediments of the Western Canada Sedimentary Basin.

The units of the first facies assemblage were deposited in a quiet basinal environment. Deep water anaerobic, organic-rich shales (black shale unit of Exshaw, lower Bakken) grade upward into either aerobic normal marine siltstone and sandstone (upper Exshaw, middle Bakken) or into thin-bedded argillaceous, bituminous (basal Banff, upper Bakken), and cherty (spiculitic) limestone, lime mudstone, mudstone and wackestone (Banff, Lodgepole) (Richards *et al.*, in press).

The second facies assemblage consists of marine carbonate and clastic slope, and carbonate shelf deposits. The basinal deposits grade upward, and eastward to northward,

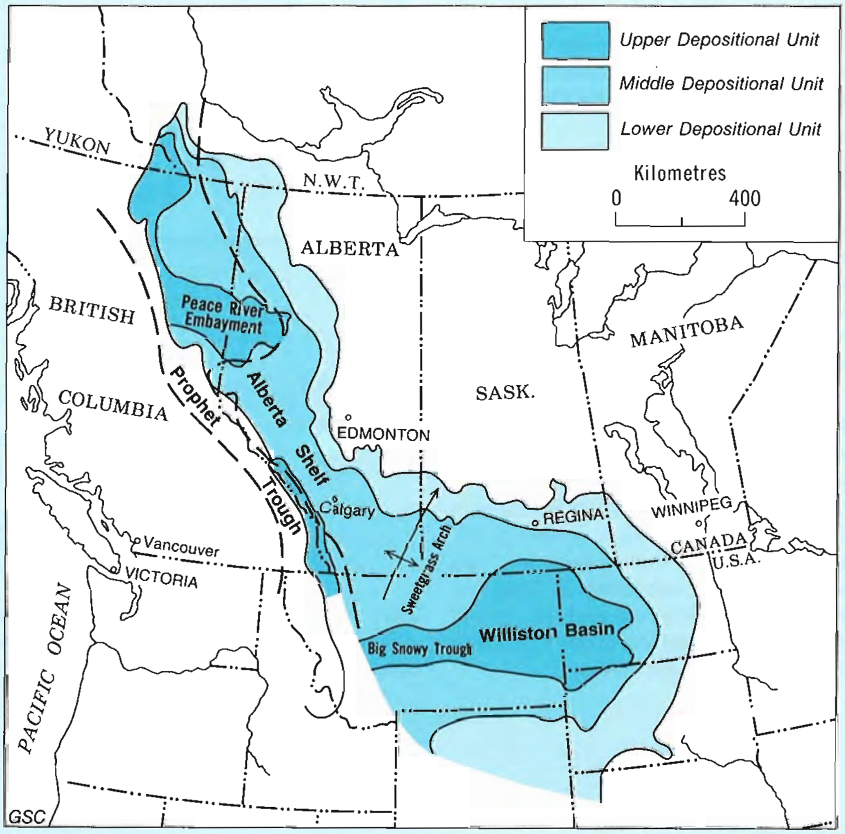


Figure 42. Distribution of Carboniferous Rocks, Western Canada Sedimentary Basin. Dashed line shows approximate and assumed position of the Prophet Trough and Peace River Embayment in the Upper Tournaisian (after Richards *et al.*, in press).

into slope facies, which pass upward into high energy carbonates deposited on platforms and ramps. In contrast to the Devonian, shelf-margin reefs are absent. Instead, oolitic or bioclastic grainstone composed primarily of echinoderm and bryozoan fragments dominated the shelf margins of the platforms. Waulsortian mounds developed locally on the carbonate slopes. The high-energy deposits are overlain by, and grade landward into, restricted-marine subtidal to supratidal carbonates and evaporites. The Carboniferous shelf carbonates are cyclic to hemicyclic because of numerous transgressions and regressions.

The third facies assemblage was deposited in clastic deltaic and nearshore environments (Kiskatinaw Formation, Mattson Formation). This facies consists of prodelta shales; delta front siltstone and sandstone; distributary channel and splay sandstone, siltstone, and shale; and marsh or lagoon deposits. Marine dolomite and limestone are commonly intercalated with the terrigenous deltaic facies.

The fourth facies assemblage consists of widely developed interbedded marine sandstone and carbonate deposited in slope to shallow neritic and supratidal environments (Taylor Flat, Kibbey, Etherington, Mattson, and Belloy formations). Deeper water equivalents are shale and siltstones (Besa River, Golata formations).

DEPOSITIONAL HISTORY

The Carboniferous succession, from southwestern Manitoba to southwestern District of Mackenzie (Northwest Territories) has been divided on the basis of lithology and depositional history into the lower, middle, and upper depositional units (Table 23) by Richards *et al.*, (in press). From east-central British Columbia to southwestern District of Mackenzie the three units overlie and pass basinwards into a fourth depositional unit, the Besa River Formation. The Permian succession has been divided into a lower depositional unit of Asselian to Artinskian age and an upper unit of Artinskian to Kazanian age (Henderson *et al.*, in press). The upper unit is not shown on Table 23 because it is restricted to the mountain outcrops.

The lower depositional unit of the Carboniferous overlies Devonian (Famennian) basin and shelf sediments. In most areas a hiatal surface (probably not a subaerial erosion surface) separates underlying Devonian deposits from those of the lower depositional unit. In much of the central Rocky Mountains (about 52°30′N to 54°30′N), however, a major erosional unconformity separates the lower depositional unit from underlying Devonian shales. The Exshaw has been removed from most of that region by pre-Banff erosion. The lower depositional unit consists of two shallowing-upward cycles, separated by a minor disconformity, that represent two transgressive-regressive events. The lower cycle is within the Exshaw and lower and middle Bakken formations, and consists of black, organic-rich shale overlain by siltstone and sandstone. The upper cycle also has a basal black shale unit (upper Bakken, or basal Banff formations). It grades upward into Banff and Lodgepole clastic and carbonate shelf and basin deposits. In general, on the Alberta shelf, shale, spiculite, and lime mudstone and wackestone form the lower part of this cycle. They are commonly overlain by high-energy upper slope to shelf lime grainstone. The latter grade upward and toward the paleoshoreline into low energy subtidal to supratidal carbonates, sandstones and shale constituting the upper part of this cycle (Richards *et al.*, in press). The unstable craton of southern Alberta was a northern continuation of the unstable craton of central and western Montana. Southern Alberta was a seaway connecting the Williston Basin to the Prophet Trough. In southern Alberta facies belts trend east and progressively deeper water, basinal rocks were deposited southward.

During deposition of the middle unit of the Carboniferous (Middle Tournaisian to Upper Visean), continuous minor uplift in the general region of the Sweetgrass Arch in southern Alberta progressively restricted the Williston Basin. The lower contact of the depositional unit is conformable in Williston Basin and most of the Prophet Trough, but on much of the Alberta Shelf it is a minor disconformity. This unit consists of an overall shallowing-upward succession of carbonate shelf, slope, and basin units, deposited during multiple transgressive-regressive cycles. In the shelf deposits many cycles begin with high energy bioclastic or oolitic grainstones. These basal deposits generally grade upward into lagoonal to supratidal carbonates, shale, and evaporite. In Williston Basin the shelf deposits prograde over and intertongue with slope deposits of the Lodgepole

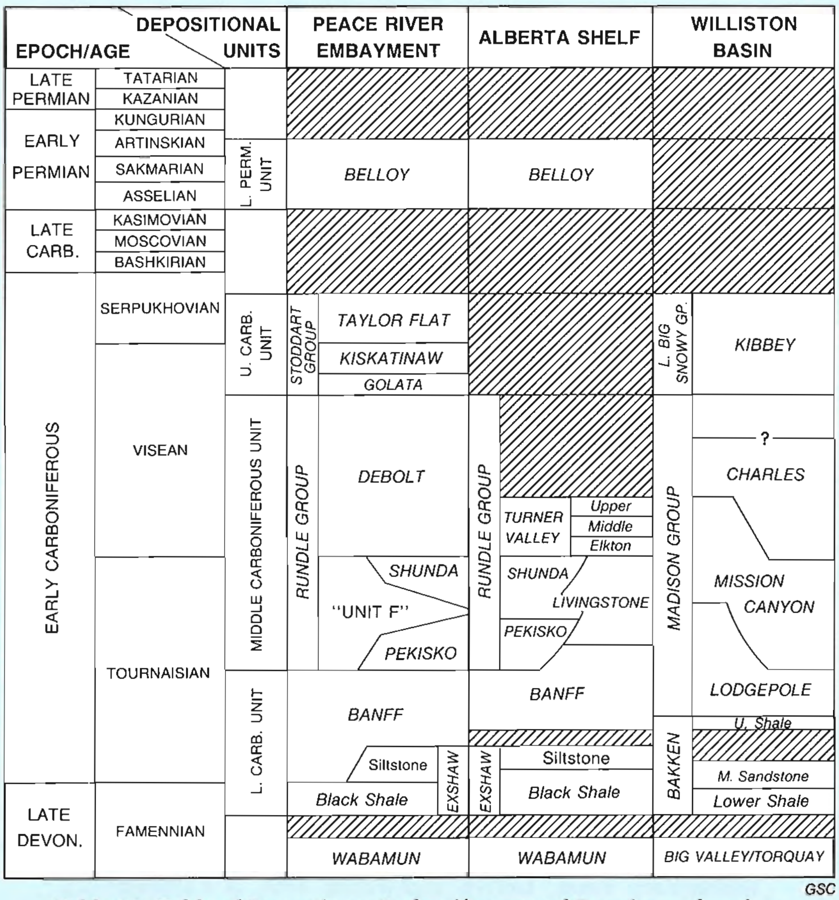


Table 23. Table of Formations, Carboniferous and Permian, subsurface of Western Canada Sedimentary Basin.

Formation. In Peace River Embayment they either overlie the Banff Formation or intertongue with slope facies of the Prophet Formation and an unnamed formation called unit F (Richards *et al.*, in press). They overlie shallow water deposits of the Banff Formation on the Alberta Shelf. The middle depositional unit includes formation F, the Pekisko, Shunda, and Debolt formations in the Peace River Embayment and northwards; the Pekisko, Shunda, Turner Valley and Livingstone formations of the Alberta Shelf; and the Mission Canyon and Charles formations in the Williston Basin (Table 23) (Richards *et al.*, in press).

The upper depositional unit (Upper Visean to Serpukhovian) does not occur on most of the extensive Alberta Shelf, because of either non-deposition or erosion. Where present in the Peace River Embayment and the Williston Basin it conformably overlies rocks of the middle depositional unit (Richards, *et al.*, in press). In the Peace River Embayment, it consists of prodeltaic Golata shale overlain by fluvio-deltaic and shallow marine Kiskatinaw sandstones. Marine Taylor Flat carbonates cap the upper depositional unit (Table 23). Equivalent rocks in the subsurface of northeastern British Columbia were deposited in the Prophet Trough (Fig. 42) and include the Golata prodeltaic shale and fluvio-deltaic and marine sandstone, shale and carbonates of the Mattson Formation.

In the Williston Basin the upper depositional unit is represented by sandstones, siltstones, evaporites, and carbonates of the Kibbey Formation which were deposited in intertidal to marginal marine environments.

The Permian is represented by the Belloy Formation (Asselian to Artinskian) in the subsurface of the Peace River Embayment, and by the Kindle (Asselian to lower Artinskian) and Fantasque (upper Artinskian to Kazanian) formations in the Foothills and on the interior plains of northeastern British Columbia. It is separated from the Carboniferous by an erosional unconformity, and is, in turn, unconformably overlain by Triassic or Jurassic rocks. Syndepositional (or pre-Permian) block faulting in the embayment was responsible for the variable paleotopography which influenced lithofacies distribution. The Belloy contains lower and upper, dominantly carbonate, members separated by a sandstone member. All three members were deposited in a shallow marine environment. (Halbertsma, 1959; Henderson *et al.*, in press; and Naqvi, 1972).

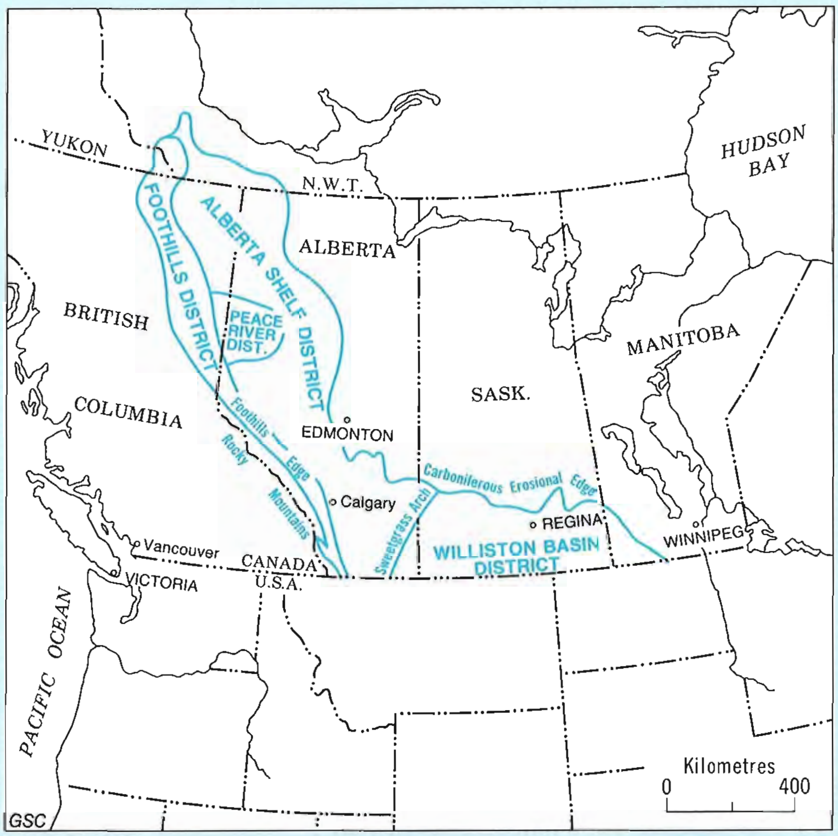


Figure 43. Carboniferous Exploration Districts, Western Canada Sedimentary Basin. Eastern exploration limit is Carboniferous erosional edge, southern limit is the International Boundary, and western limit is Rocky Mountains or Carboniferous hot line.

PETROLEUM OCCURRENCE

Approximately 18% of the in-place conventional oil reserves of the Western Canada Sedimentary Basin occur in the Carboniferous and Permian deposits. Most of the oil is trapped below unconformities in southeast Saskatchewan, southwestern Manitoba, and central Alberta. These traps are formed at the northeast truncation of shelf carbonate reservoir beds as well as in outliers immediately beyond this limit (Fig. 54). Reservoirs are typically grainstones and packstones that were dolomitized during several late Paleozoic and Mesozoic periods of erosion. Continental and marine Mesozoic seals are present above and surrounding the reservoirs. Seals are also formed by cementation at the unconformity between the Carboniferous and Mesozoic. Restricted-marine subtidal to supratidal carbonate and evaporite beds that cap each transgressive-regressive Carboniferous cycle commonly form seals (Kent, 1984). Petroleum source beds are the product of deposition in deeper water. They are now situated below and down-dip from oil pools. (Brooks *et al.*, 1987; Osadetz and Snowdon 1986). Migration and entrapment may have occurred in the late Cretaceous to Tertiary.

Structural traps are of secondary importance in the Carboniferous and Permian Systems. They include the Laramide compressional fold and thrust fault traps in the Foothills Belt of Western Canada; block faults and related folds of the Peace River Embayment, (many were reactivated in the Mesozoic); and salt solution, block fault, and meteorite impact structures (Sawatzky, 1975) in the Williston Basin. Reservoirs and seals are similar to those described for the unconformity traps.

In addition, oil has accumulated in stratigraphic traps related to depositional facies or diagenetic changes within any given depositional cycle.

Most unconformity-related plays have a long history of exploration and exploitation. They are entering their fourth decade of exploration. Commonly, intensive exploration followed the initial discovery along any particular reservoir edge trend, soon locating most of the significant petroleum accumulations. The Carboniferous and Permian structural plays are in regions dominated by the occurrence of gas. This makes the assessment of oil potential difficult. The stratigraphic plays are either not substantiated or conceptual, and may form an important future oil resource base if adequate exploration techniques are developed for them.

PETROLEUM EXPLORATION DISTRICTS

There are four petroleum exploration districts in the Carboniferous and Permian of the Western Canada Sedimentary Basin; they are defined by unique geography, oil source and migration paths, and trap configurations (Fig. 43). The Williston Basin, Alberta Shelf, and Peace River districts are directly related geographically to the Carboniferous tectonic and depositional elements of the basin. The fourth is the Foothills District which is defined on the basis of Laramide deformation. It contains depositional elements of the Alberta Shelf and Peace River districts, but except for one field, is in the gas zone and is therefore not given separate treatment.

The Carboniferous is the principal oil exploration target of the Canadian portion of the Williston Basin and also of the Foothills District, but is of lesser relative importance throughout the remainder of Alberta and British Columbia. Most of the Carboniferous and Permian reserves (94%) occur within reservoirs of the middle depositional unit in the Alberta Shelf and Williston Basin districts.

Oil exploration for Carboniferous prospects is limited to the area bounded by the erosional edge on the east and north, the Carboniferous hot line and the eastern edge of the front ranges of the Rocky Mountains on the west, and the International Boundary on the south.

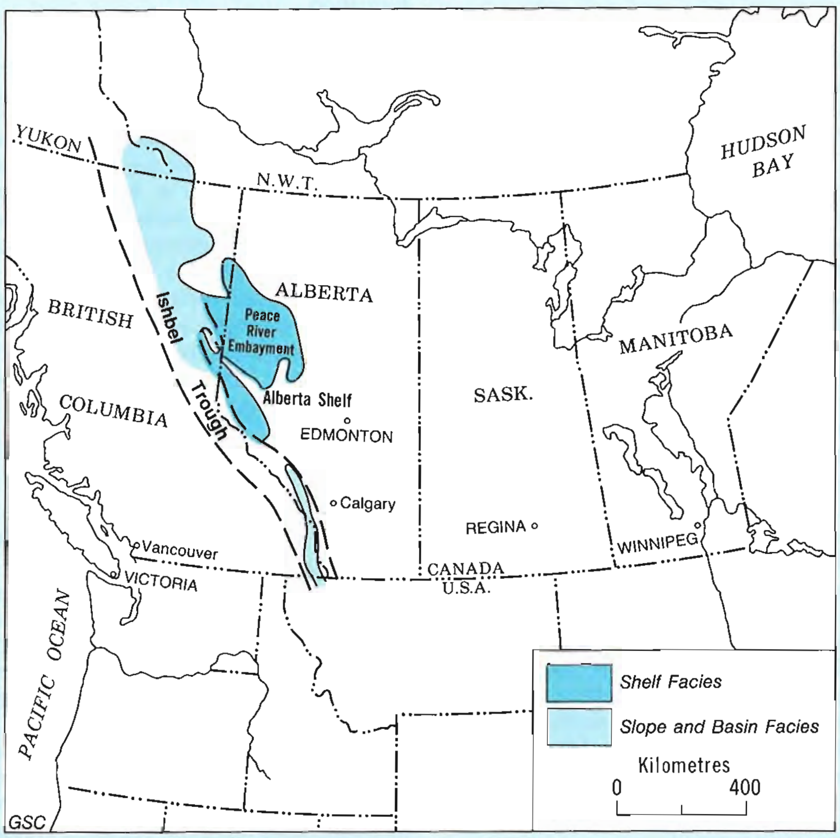


Figure 44. Distribution of Permian Rocks, Western Canada Sedimentary Basin. Dashed line is approximate and assumed position of Ishbel Trough (after Henderson *et al.*, in press).

PEACE RIVER DISTRICT

The Peace River District is the area of the Carboniferous Peace River Embayment and the Prophet Trough in northwestern Alberta and northeastern British Columbia. It is bounded to the west by the eastern limit of the Foothills and to the south, east, and north by the Alberta Shelf (Fig. 43).

DEPOSITIONAL AND TECTONIC HISTORY

Rocks of the three Carboniferous depositional units and the Permian Belloy Formation were deposited and preserved in the Peace River Embayment (Figs. 42 and 44). The Permian Kindle and Fantasque formations were deposited in the adjacent Prophet Trough. The thickness and distribution of individual units was strongly influenced by the epeirogenic movement that created the Embayment through the late Paleozoic (Lavoie, 1958). The depositional and tectonic history of this interval is discussed in detail by Richards *et al.*, (in press), and Henderson *et al.*, (in press).

The lower depositional unit of the Carboniferous consists of the Exshaw Formation basinal black shale to siltstone cycle and the overlying Banff cycle. Subsidence initiating the Peace River Embayment occurred prior to and during Exshaw deposition (Late Famennian to Lower Tournaisian), although parts of the former Devonian arch system remained emergent, as evidenced by local occurrences of Banff coarse clastic rocks lying directly on Precambrian crystalline basement. More pronounced subsidence during Early Middle Tournaisian resulted in widespread deposition of the lower Banff basinal shale and lime mudstone. The upper Banff consists of slope to shelf grainstone and packstone overlain by restricted shelf to supratidal carbonates. During this time the Peace River Embayment was linked to the Prophet Trough in the west, and had poorly defined boundaries with the surrounding Alberta Shelf.

The Embayment was still linked to the Prophet Trough but became well defined relative to the Alberta Shelf during deposition of the middle depositional unit. During this interval the Peace River Embayment was distinctly subsident relative to the Alberta Shelf area, largely as a result of block faulting and regional flexure. An unnamed formation, unit F (Richards *et al.*, in press) is the oldest component of the middle depositional unit, and consists of slope and shelf shales and carbonates that are lateral moderately deep-water equivalents of the Pekisko and Shunda formations of the Alberta Shelf. Restricted shelf to supratidal carbonates of the Shunda Formation overlie unit F locally.

The Debolt Formation conformably overlies the Shunda in the east, and unit F in the west, and represents a second major transgressive-regressive depositional cycle. It consists of several minor cycles of open shelf carbonates that grade upward into restricted shelf to supratidal carbonates.

During deposition of Upper Visean and Serpukhovian sediments of the upper depositional unit, the Peace River Embayment was well defined, but still opened westward into Prophet Trough. During Late Visean time, the northern margin of the embayment became more clearly defined as the eastern margin of Prophet Trough stepped basinward (westward). Peace River Embayment was the site of active block faulting that resulted in rapid thickness variations in the Golata, Kiskatinaw, and Taylor Flat formations. Several minor transgressions and regressions occurred during this time of dominantly clastic sedimentation. Prodeltaic Golata shales are overlain by fluvio-deltaic and probable slope deposits of marine Kiskatinaw sandstone, shale, and carbonate. Taylor Flat marine carbonate and sandstone is the youngest Carboniferous unit in the embayment east of the Rocky Mountains. Within the subsurface part of the Prophet Trough, west of the Bovie Fault zone in northeastern British Columbia, the Golata and Mattson formations were deposited during the late Visean and Serpukhovian. They are dominantly northerly-derived prodeltaic shale and fluvio-deltaic sandstone.

During the latest Carboniferous and Early Permian, widespread downwarping and block faulting occurred in the Peace River Embayment, where the Asselian to lower Artinskian Belloy Formation was deposited. The Belloy consists of three informal members: a lower carbonate, a middle sandstone, and an upper carbonate, all of which contain sandstone. Toward the west, the Belloy grades into shale and siltstone (Kindle Formation) deposited in the Ishbel Trough (Fig. 44). Post-Belloy erosion, caused either by uplifts or regression, has removed much of the Belloy section in the region.

PETROLEUM GEOLOGY

Discoveries in Carboniferous and Permian plays in the Peace River District currently amount to 41 x 10^6 m^3 OIP, about 3% of the Carboniferous and Permian in-place oil discovered in the Western Canada Sedimentary Basin. Traps are dominantly structural or composite structural-stratigraphic, formed by post-Belloy reactivation of Peace River structures. Reservoirs include Belloy and Kiskatinaw sandstones and Debolt carbonates. Seal rocks consist of equivalent age shales, siltstones, or impermeable carbonates, and Mesozoic shales. Within this district, gas is the dominant pooled hydrocarbon either because of source type or because of the timing of maturation relative to deformation and trap formation.

EXPLORATION PLAYS

Four established plays and five conceptual plays were analysed in the Carboniferous and Permian systems of the Peace River District. The two families of plays are described in the following section, but quantitative treatment of estimates is described for only one of the established plays. The undiscovered oil potential of the district is estimated to be low relative to other regions, because of the tendency towards gas rather than oil.

Conceptual Plays

Five conceptual plays were considered in this assessment of a district that presently has few oil reserves. Of major concern in each of these plays is the possibility that generation and migration of hydrocarbons has occurred prior to the formation of traps, especially in cases where the trap is formed by block faulting in the Peace River Embayment. A positive factor in assessment of potential is that there are few wells drilled off structures in this District. Any stratigraphic traps that might exist in these locations have not been explored enough to be condemmed..

There are two conceptual plays in the **Banff Formation** shelf carbonate units. One involves **structural** trapping, with associated porosity enhancement; and the other involves **stratigraphic** trapping, related to depositional or early diagenetic porosity development in this normally impermeable formation.

Unit F may also have structurally or stratigraphically trapped oil in shelf grainstone or in slope carbonate debris flows or in Waulsortian mound reservoirs.

The cyclical nature of the **Debolt** shelf carbonates presents opportunities for stratigraphic traps, provided that there is adequate porosity development and access to oil migration pathways.

Finally, the **Mattson Formation** in the subsurface of northeastern British Columbia and the southern part of the District of Mackenzie may contain oil in structures or in the variety of stratigraphic traps associated with deltaic deposits.

Established Plays

The Belloy-Peace River play is the only established play in this District with enough discoveries to warrant detailed analysis using the discovery process model.

There are two separate plays involving rocks of the Debolt Formation, one related to Peace River District structures, the other to Laramide deformation near the Foothills. The **Debolt-Peace River** play normally contains gas in structural traps in the Peace River District, but three single-well oil pools occur at Normandville, Eaglesham, and George in Alberta. Reservoir rocks are usually coarse crystalline dolomite interbedded with argillaceous limestone seal rocks. The oil at Normandville and Eaglesham may be related to underlying Devonian oil that has migrated into the Debolt through fault and fracture systems. The pools are all less than 0.5 x 10^6 m^3 OIP in size and have poor recovery factors (less than 10%).

The **Debolt Structure** play is restricted to the western part of the district where Laramide deformation characteristic of the Foothills extends under the Plains region. Only one oil field, Blueberry with 4 pools has been discovered. It has a total volume of 10.5 x 10^6 m^3 OIP. The field is on a long northwest trending anticline, offset by younger faults. The Debolt reservoir consists of dolomitized shelf grainstones and packstones that lie near the pre-Mesozoic unconformity. The reason for the unique accumulation of oil at Blueberry in an otherwise dominantly gas bearing area is not understood.

There are two oil pools in the **Kiskatinaw** play at Josephine and Shane in Alberta, where the oil appears to be stratigraphically trapped in distributary channel splay sandstones. These sandstones form promising exploration targets, despite the small pool sizes (under 1 x 10^6 m^3 OIP), as they may not require structural closure.

BELLOY — PEACE RIVER

Play Definition: This oil play was defined to include pools and prospects in structural-stratigraphic traps that occur where rocks of the Belloy Formation are involved in fault-bounded structures in the Peace River Embayment. The play area is defined by the limit of the disturbed belt to the west, the Belloy erosional edge to the north and east, and the limit of Peace River structural deformation to the south (Fig. 46).

Geology: The Belloy Formation consists of fine grained, rounded, mature dolomitic quartz sandstone and sandy dolomite coquina, deposited in a shallow marine near-shore environment. Traps occur in local and regional horst blocks where reservoir- to seal-rock transitions occur, both by facies change and as a result of truncation by Mesozoic rocks. Pre-Permian and probable Permian faulting controlled Belloy facies distribution, and post-Permian faulting controlled Mesozoic erosion. Although structure is the dominant control for petroleum accumulation, the stratigraphic components are also essential in completing trap configurations.

The pools in this play have sandstone reservoirs that have good permeability, porosity from 10 to 20%, water saturation from 25 to 50%, and recovery factors from 10 to 35%. An increase in amount of dolomite cement results in a corresponding decrease in reservoir quality. Laterally equivalent Belloy siltstone and shale and overlying Mesozoic shale form the seal rocks. Oil may be sourced from the underlying Carboniferous or overlying Triassic sections, and probably migrated in Laramide or post-Laramide time.

Exploration History: The first oil discovery in the play, in 1951, occurred in the large Belloy gas field on the Belloy fault. More significant finds were subsequently discovered at Eagle and Stoddart in the 1970s (Table 24). The play has not received much attention since that time. Total volume discovered to date is 40 x 10^6 m^3 OIP distributed in 14 pools. Pool sizes range from 0.04 x 10^6 to 21 x 10^6 m^3 OIP.

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 11 x 10^6 m^3 OIP, expected to occur in 26 additional pools. The largest remaining pools are expected to be in the range of 1 x 10^6 to 4 x 10^6 m^3 OIP (see Fig. 45).

TABLE 24

BELLOY — PEACE RIVER PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Eagle West A1	21.60	1976
2	Stoddart West	6.79	1970
3	Eagle B	4.79	1973
4	Eagle West A2	4.47	1976
9	Stoddart South A	0.90	1978
10	Stoddart C	0.72	1964
21	Stoddart South C	0.11	1979
22	6-21-85-19	0.10	1979
23	Fort St. John D	0.09	1972
24	6-25-85-20	0.07	1979
25	Belloy A	0.07	1951
26	16-19-85-19	0.06	1979
27	Stoddart South A	0.06	1979
29	Two Rivers B	0.04	1979

- Total Discoveries : 14
- Discoveries in the Top 30 Pools : 14
- Total Pool Population : 40

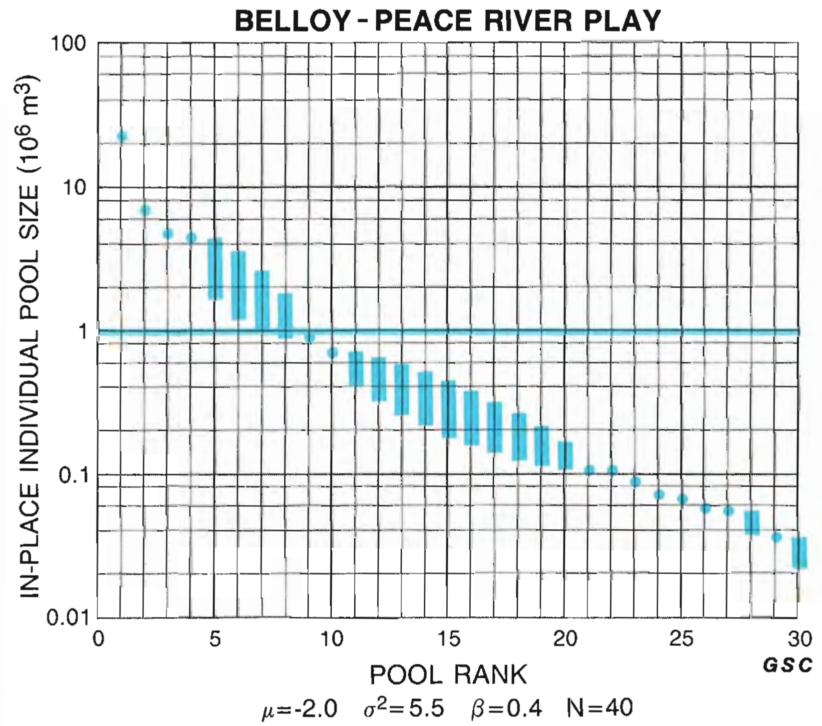


Figure 45

ALBERTA SHELF DISTRICT

The Alberta Shelf District includes the area lying between the Banff erosional edge to the east and north and the Foothills to the west, extending from the Sweetgrass Arch in the south to the southwestern District of Mackenzie (N.W.T.) in the northwest. It does not include the area of the Peace River Embayment and the Prophet Trough in northern Alberta and northeastern British Columbia which is treated as a separate district (Figs. 42 and 43).

There is one play involving structures in the Foothills of Alberta, the Turner Valley Play, which should belong in a separate Foothills District. Because the stratigraphic treatment of the Alberta Shelf District adequately includes the Turner Valley play, and because only one field is involved, this play has been included in the Alberta Shelf District for convenience.

DEPOSITIONAL AND TECTONIC HISTORY

The Carboniferous succession of the Alberta Shelf can be divided into three depositional units (Richards *et al.*, in press). Deposits of the Exshaw Formation and those of the overlying Banff Formation constitute the lower depositional unit. The Exshaw cycle comprises a lower black-shale unit deposited in moderately deep water (below fair-weather wave base) and an overlying unit of siltstone, sandstone, and limestone deposited in moderately deep to shallow water (above fair weather wave base).

In most areas rocks of this cycle lie unconformably upon the Devonian Wabamun or Big Valley formations, and are generally disconformably overlain by the Banff Formation, which forms the second shallowing-upward cycle. Within the Banff, basal black shale passes upward into deep water siltstone and silty carbonate that are in turn overlain by slope to shallow subtidal carbonate shelf sediments. Shallow subtidal restricted-marine carbonates and intertidal to supratidal carbonate, sandstone, siltstone, and shale cap the cycle.

The middle depositional unit comprises five main shallowing-upward cycles. High-energy marine grainstone constitutes the transgressive basal part of the cycles. The overlying carbonates and terrigenous fine-grained clastics record regression and deposition in restricted-marine subtidal to supratidal settings. The five cycles consist of the following transgressive-regressive couplets: (1) Pekisko Formation — Shunda Formation; (2) Elkton Member — Middle Member of Turner Valley; (3) Upper Member of Turner Valley — Wileman Member of Mount Head; (4) Baril Member — Salter Member of Mount Head; and (5) Loomis — Marston and Carnarvon Members of Mount Head Formation.

North of, and within, the Peace River Embayment, the lower part of the Debolt Formation is equivalent to the Turner Valley. On the plains of southernmost Alberta correlatives of the Shunda and Turner Valley formations occur in the Livingstone Formation. Several stages of Late Paleozoic and Mesozoic erosion have removed all but the lower two cycles from most of the Alberta Shelf District. The distribution of these rocks is now restricted to western Alberta, where erosion has dissected and altered them along their respective subcrop edges (Fig. 42).

Shallow marine Belloy sandstones of Permian age were preserved between two major unconformities adjacent to the south side of the Peace River Embayment (Fig. 44). The incomplete nature of the Belloy section and the irregular distribution of the sandstone between the unconformities make stratigraphic and environmental interpretations difficult.

Unlike the Williston and Peace River districts, the Alberta Shelf lacks evidence of significant Carboniferous and or Permian epeirogenic movements. The only important tectonic event was the westward tilting and uplift of the Carboniferous rocks during the Mesozoic orogenies.

PETROLEUM GEOLOGY

Most of the oil reserves in the Alberta Shelf District occur in high energy shelf carbonates of the Pekisko Formation and the Elkton Member of the Turner Valley Formation in unconformity traps along their subcrop edges (Fig. 46). Seal rocks include the low energy carbonates and shales that cap each of the transgressive lower parts of the five main Carboniferous shallowing-upward cycles, and the Mesozoic shales and siltstones that overlie the reservoirs. Potential source rocks are the deep water shales and carbonates of the Exshaw and Banff and overlying Mesozoic marine shales. Migration and entrapment probably occurred in the late Cretaceous or early Tertiary.

The most prolific producing region is a triangular-shaped zone between Harmattan, Twining, and Medicine River, immediately north of Calgary. Reservoirs at the base of the Mesozoic section also produce in this region, which suggests that Carboniferous and Mesozoic oil pools at or near the unconformity may have a common source and migration history. All of the Carboniferous pools have associated gas.

The total volume of in-place oil in the Alberta Shelf District including the Turner Valley foothills play, is 495 x 10^6 m^3. Most large pools were discovered prior to 1960; subsequently only relatively minor discoveries have been made.

EXPLORATION PLAYS

Eight established plays and three conceptual plays have been analysed in the Carboniferous and Permian Systems in the Alberta Shelf District. The two families of plays are described in the following section, but quantitative treatment of estimates is limited to six of the established plays.

Heavy oil pools have been included in the assessment of some plays within this District, in cases where they lie within the geologic and geographic bounds of the play definitions.

Conceptual Plays

The only conceptual plays considered in this region involve depositional or diagenetic facies changes in the **Elkton, Shunda,** and **Pekisko formations** downdip from their respective subcrops. These units are typically impermeable southwest of the subcrop, and thus any porosity development down-dip should create a stratigraphic trap. Components of stratigraphic traps do occur in the Elkton gas pool at Brazeau, though this play is also related to the Elkton wedge edge. The potential of the stratigraphic plays is difficult to assess as the extent of reservoir development and the access to petroleum migration paths is unknown.

Established Plays

Six of the eight established plays were evaluated using the discovery process model. Of these, the Elkton, Pekisko and Banff (central Alberta) Edge plays are considered mature. The Sweetgrass Arch, Banff Edge (southern Alberta), and Desan plays are still in an active exploration stage.

Two of the established plays contain too few discoveries for detailed analysis and are treated as immature. The first of these is the **Belloy Edge** play which has two oil pools in Belloy sandstone outliers at Virginia Hills, south of the Peace River Embayment (Fig. 46). The thin Belloy sandstones form excellent reservoirs, with 10 to 30% porosity and good permeability. Lateral and seat seals are provided by restricted marine shale and carbonate of the Shunda Formation, and the upper seal consists of Mesozoic shale. This play could occur within an area where the main Belloy subcrops beneath the Mesozoic in west-central Alberta. Exploration is difficult, as seismic methods cannot always be used to define the Belloy erosional edge or identify erosional outliers east of it.

A second established play that was treated as immature is the **Turner Valley** play. This structural play, located in the Foothills District, represents the eastern component of Laramide compressional deformation that created the Rocky Mountains. The play area includes a number of southwest dipping imbricate listric thrust fault slices and related fold structures. The first discovery of wet gas at Turner Valley was made in 1914 in a Lower Cretaceous sandstone. The Carboniferous gas cap was discovered in 1924, and the oil leg in 1936. This was the first major discovery of conventional oil in the Western Canada Sedimentary Basin. The Turner Valley Field, with two pools, is the only oil discovery in the play. The pools are in skeletal grainstone and packstone (shelf-dolomite) reservoirs of the Turner Valley Formation. The field lies beneath the Mesozoic unconformity in an anticlinal closure above a simple southwest dipping thrust fault. Total in-place volume of oil in the two pools is 159.4 x 10^6 m^3. The reasons for this unique occurrence of a large oil accumulation in an otherwise gas area are not known. Until the controls on this accumulation are better understood, the potential associated with this play is very difficult to assess.

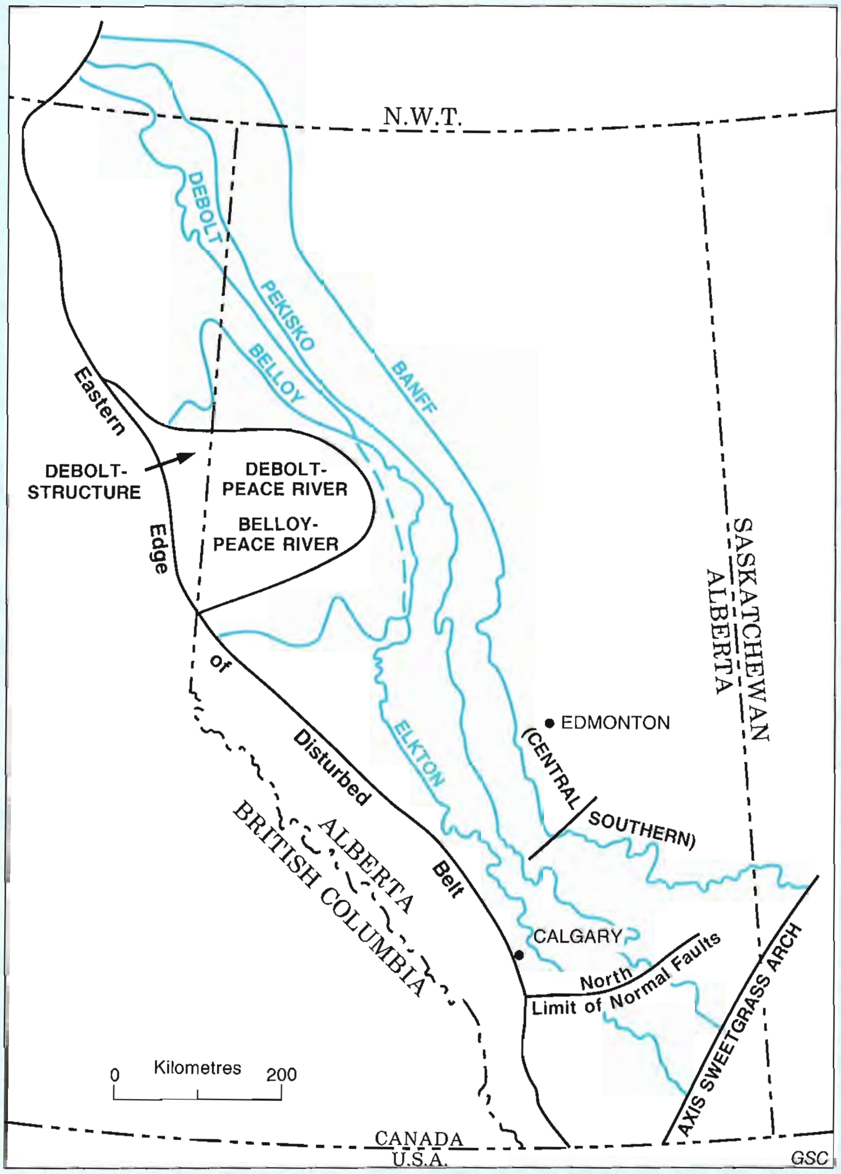


Figure 46. Carboniferous Erosional Edges and Play Areas, Alberta Shelf and Peace River districts. Established play areas are along the erosional edges of each reservoir unit.

CARBONIFEROUS — SWEETGRASS ARCH

Play Definition: This oil play was defined to include all prospects and pools in carbonates of the Livingstone and Banff formations in structural and combination stratigraphic-structural traps. The play area extends across southern Alberta from the Sweetgrass Arch to the eastern edge of the disturbed belt and is bounded on the north by the limit of normal faults (Fig. 46).

Geology: Block faults and anticlines related to Laramide tectonics on the Sweetgrass Arch form structural traps in the Carboniferous section. This deformation also enhanced or created reservoirs by inducing local fracturing of the shelf carbonate rocks. Most of the presently discovered oil pools occur immediately beneath Jurassic shale and siltstone seal rocks, where unconformity-related processes also enhanced porosity in reservoirs of the Livingstone section. Other pools are sealed by impermeable Carboniferous carbonates. The Exshaw or Bakken shales may be the oil source, with migration facilitated by fracture systems.

Pools are typically less than one section in areal extent and have net pay that varies from 2 to 30 m, porosity from 5 to 16%, and recovery factors from 3 to 30%.

Exploration History: Some of the initial exploration in western Canada occurred on structures of the Sweetgrass Arch which could be mapped at the surface, such as the Del Bonita oil pool discovered in 1936. Since that time seismic has been used to define drilling locations along the strike of long, linear structural elements, with discoveries from 1961 into the 1980s. Several pools are single well, limited reservoirs, and are not included in the data summary.

Total in-place oil volume discovered to date is 5 x 10^6 m^3. This volume occurs in 11 pools, with pool sizes ranging from 0.04 to 2 x 10^6 m^3 OIP (Table 25).

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 12 x 10^6 m^3 OIP, expected to occur in 29 additional pools (Fig. 47). All of these pools are comparable in size to the existing pools.

Within the play area, drilling density is relatively low beneath the Mesozoic unconformity and, considering the small size of the oil accumulations and structural closures, there is room for several undiscovered pools within this play.

TABLE 25

CARBONIFEROUS — SWEETGRASS ARCH PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
2	Claresholm A	1.92	1972
3	Claresholm B	1.34	1972
11	Reagan A	0.46	1958
12	Spring Coulee Rundle	0.41	1950
13	Del Bonita Rundle	0.40	1936
19	Keho Pekisko A	0.24	1979
22	Keho Elkton A	0.19	1973

- Total Discoveries : 11
- Discoveries in the Top 30 Pools : 7
- Total Pool Population : 40

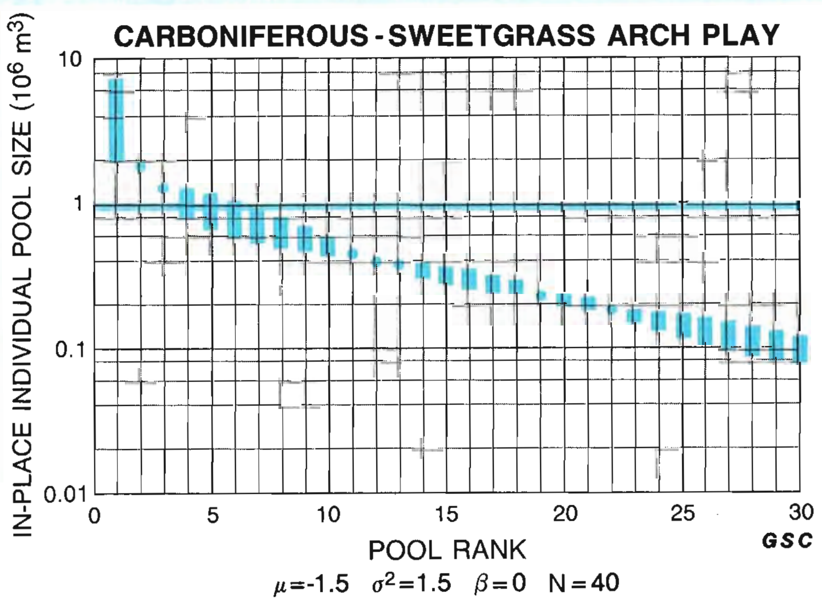


Figure 47

BANFF EDGE — SOUTHERN ALBERTA

Play Definition: This oil play was defined to include pools and prospects in unconformity or stratigraphic traps in carbonate shelf rocks of the Banff Formation. The play area is restricted to the part of the erosional edge south of Township 45 (Fig. 46).

Geology: The Banff of southern Alberta comprises a thick shallowing-upward cycle consisting of: a deep water, low energy argillaceous lime mudstone at the base; an intermediate higher-energy interval of lime wackestone, packstone, and grainstone; and an upper interval of shallow-water lime wackestone and shale. The middle unit forms the reservoir in traps at or near the sub-Mesozoic unconformity. Facies changes within the Banff are responsible for a stratigraphic component to some traps. Mesozoic shales form top seals and may also be the oil source rocks. Other potential source rocks are the Exshaw shale and the Banff carbonate and shale.

Exploration History: This is an immature play with only 6 pools, containing in total less than 1 x 10^6 m^3 OIP (Table 26). Recent discoveries in the Craigmyle area will add to this total, but are not included in this summary. Pools typically have low production rates (less than 10 m^3/d) and low recovery factors (less than 20%).

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 1 x 10^6 m^3 OIP, expected to occur in 19 additional pools (see Fig. 48). This estimate may be very low considering the relative immaturity of the play. The addition of the recent discovery data will probably significantly increase the reserve base and the play potential, particularly if new pools are larger than those included in this assessment.

TABLE 26

BANFF EDGE — SOUTHERN ALBERTA PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Watts A	0.28	1970
2	Sullivan Lake A	0.20	1982
3	Atlee-Buffalo A	0.19	1982
4	Westerose South A	0.14	1980
8	Drumheller B	0.07	1979
21	Fenn West A	0.01	1977

- •Total Discoveries : 6
- •Discoveries in the Top 30 Pools : 6
- •Total Pool Population : 25

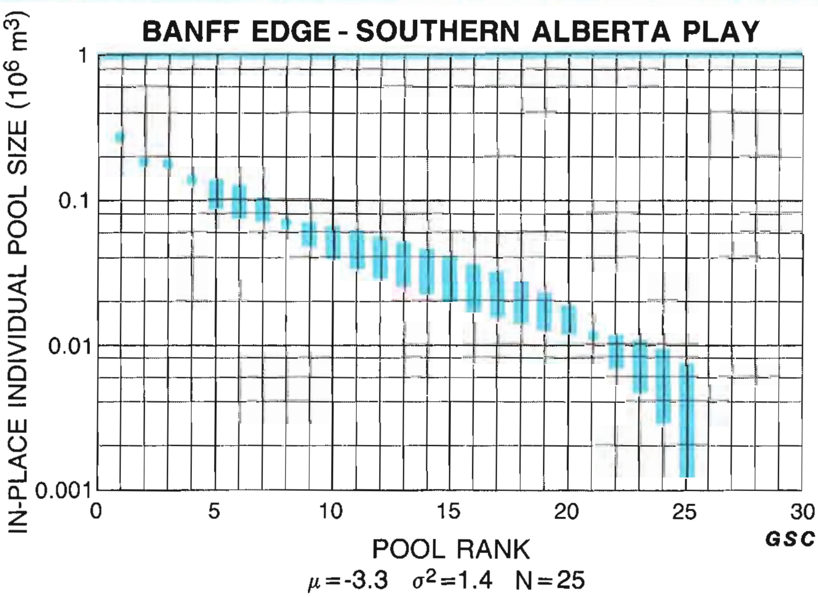


Figure 48

BANFF EDGE — CENTRAL ALBERTA

Play Definition: This oil play was defined to include pools and prospects developed along the erosional edge of Banff Formation shelf carbonates in unconformity traps. The play occurs in the "Clarke's Member" of the Banff, restricted to the central Alberta part of the erosional edge between Townships 45 and 70 (Fig. 46).

Geology: The Banff Formation, where it has not been partially eroded, is approximately 200 m thick. It is a shallowing-upward cycle comprising a lower interval of low-energy, deep water argillaceous lime mudstone; a middle part with higher energy lime wackestone, packstone, and grainstone; and an upper part with shallow water deposits that include siltstone, cryptalgal laminites, and argillaceous dolomite. These upper deposits are probably restricted-marine facies. The middle unit, informally termed the "Clarke's Member", forms dolomite reservoir rock at its erosional edge. The pools beneath the unconformity typically occur in paleotopographic highs.

Lateral and top seal rocks are Banff limestone and Mesozoic shale. Possible oil source rocks are Exshaw, Banff, and Mesozoic shales. Pools in this play have reservoirs with pool areas less than 3 sections, net pay from 3 to 30 m, porosity from 10 to 20%, water saturation from 30 to 40%, and recovery factor from 1 to 45%.

Exploration History: The first oil discovery in the play was Glenevis in 1954, probably found by chance while exploring for deeper Devonian prospects. Subsequent activity, related to improvements in the ability of the seismic tool to detect the reservoir "highs", led to discoveries at Cherhill in the mid-1960s and Highvale in the late 1970s (Table 27).

The total in-place volume of oil discovered to date is 37 x 10^6 m^3 occurring in 32 pools. Pool sizes range from 0.1 x 10^6 to 8 x 10^6 m^3 OIP.

Play Potential: The estimated undiscovered potential for this play has a median expectation value of 13 x 10^6 m^3 OIP expected to occur in 48 additional pools (Fig. 49). All but two of the pools would be less than 1 x 10^6 m^3 OIP in size. There are large parts of the play area that are under-explored and should be considered prospective for extension of this play. The large H pool at Highvale, for example, was found quite recently.

TABLE 27

BANFF EDGE — CENTRAL ALBERTA PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Alexis A	7.58	1968
2	Highvale H	4.56	1981
3	Highvale A	4.20	1978
4	Glenevis	3.62	1954
5	Cherhill A	2.78	1966
6	Cherhill I	1.88	1967
8	Cherhill M	1.69	1982
10	Cherhill D	1.20	1979
12	Cherhill C	1.10	1977
13	Cherhill G	1.02	1980
14	Cherhill B	1.00	1969
17	Pembina A	0.71	1981
18	Cherhill H	0.69	1979
21	Highvale G	0.55	1981
22	Majeau B	0.53	1974
23	Highvale D	0.50	1978
24	St. Anne A	0.49	1978
27	Cherhill L	0.38	1976
28	Highvale F	0.38	1981
29	Cherhill F	0.35	1981
30	Highvale E	0.35	1978

- Total Discoveries : 32
- Discoveries in the Top 30 Pools : 21
- Total Pool Population : 80

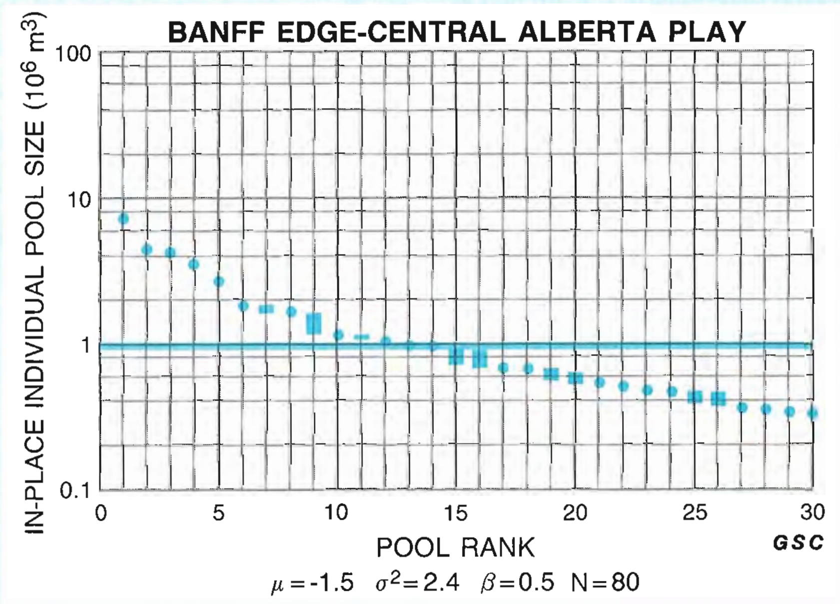


Figure 49

PEKISKO EDGE

Play Definition: This oil play was defined to include all pools and prospects in unconformity traps at the erosional edge of the Pekisko Formation. The play area includes the erosional edge extending from the Peace River District to the Sweetgrass Arch (Fig. 46).

Geology: The Pekisko shelf grainstones are composed primarily of echinoderm and bryozoan fossil fragments deposited in high energy environments. They are usually well cemented, but have developed good porosity near their erosional edge, possibly due to unconformity-related diagenetic processes. Traps were formed where marine Mesozoic shale- and silt-filled channels surround Pekisko erosional remnants and where extensive Mesozoic marine shales overlie the main Pekisko erosional edge. The Shunda Formation may form both the top seal and part of the reservoir section in some pools.

Pools in this play are from a quarter section to two townships in area. Reservoirs have good permeability, porosity from 5 to 15%, water saturations between 20 and 50%, and recovery factors from 1 to 20%.

Exploration History: The relatively continuous exploration activity within this play over the last three decades has resulted in 78 discoveries with a total reserve of 210 x 10^6 m^3 OIP. Initial finds such as Twining, Gilby and Medicine River were probably made while exploring for Leduc reefs. Subsequent activity has led to smaller pool discoveries in the central Alberta region.

Pool sizes range from less than 0.1 x 10^6 to 90 x 10^6 m^3 OIP (Table 28).

Play Potential: The estimated undiscovered potential in this play has a median expectation value of 10 x 10^6 m^3 OIP, expected to occur in 32 additional pools. The largest remaining pool would be about 3 x 10^6 m^3 OIP (Fig. 50).

TABLE 28

PEKISKO EDGE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Twining	89.00	1952
2	Twining North	37.60	1961
3	Rowley A	8.76	1960
4	Sylvan Lake B	7.95	1962
5	Cessford B	6.80	1973
6	Medicine River I	6.36	1954
7	Paddle River Rundle	6.04	1956
8	Medicine River N	5.00	1963
9	Medicine River E	3.38	1963
10	Bigoray A	3.32	1969
12	Davey A	3.11	1958
13	Sylvan Lake C	2.62	1963
14	Greencourt A	2.51	1961
15	Medicine River C	2.18	1961
16	Sylvan Lake D	1.91	1960
17	Blueridge A	1.72	1968
18	Princess A	1.71	1946
19	Swalwell F	1.67	1979
20	Swalwell A	1.62	1965
23	Medicine River R	1.32	1973
27	Matziwin A	1.05	1962
28	Haro Pekisko B	0.98	1980
29	Princess B	0.87	1978
30	Medicine River B	0.87	1959

- Total Discoveries : 78
- Discoveries in the Top 30 Pools : 24
- Total Pool Population : 110

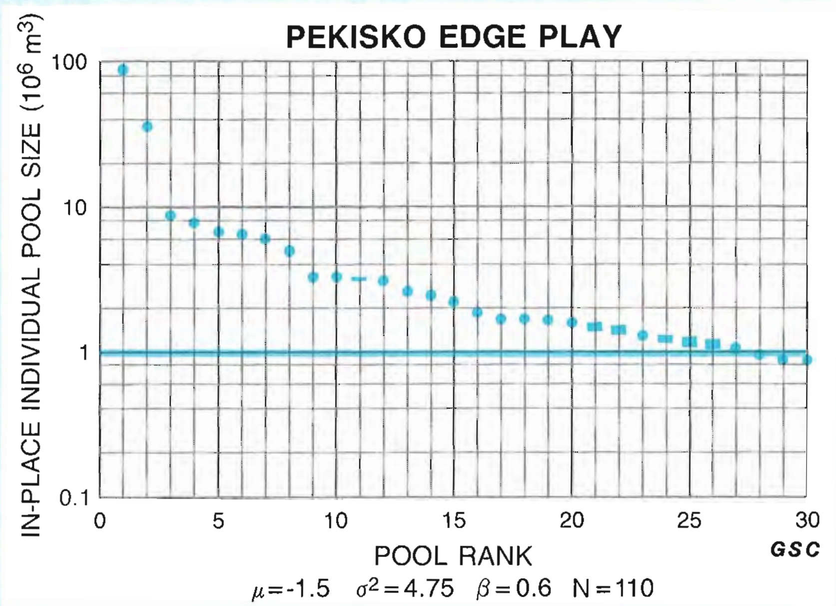


Figure 50

ELKTON EDGE

Play Definition: This oil play was defined to include all pools and prospects in unconformity traps at the erosional edge of the Elkton Member of the Turner Valley Formation. The play area includes the erosional edge from the Peace River Embayment to southern Alberta (Fig. 46).

Geology: The Elkton Member of the Turner Valley Formation consists of high-energy shelf dolomite and lime wackestone, grainstone, and packstone containing echinoderm and bryozoan fragments. Diagenesis of the complex depositional fabric has created vuggy, pinpoint, and intercrystalline porosity. Deep erosional channels in parts of the play area create a large number of traps whose lateral and top seals are formed by Mesozoic shallow marine, deltaic, and fluvial shales.

Pools in this play have reservoirs that range from a quarter section to a half township in area, net pay thicknesses from 1 to 25 m, porosities from 5 to 15%, and recovery factors from 5 to 35%.

Exploration History: The total volume of oil discovered to date is 110 x 10^6 m^3 OIP occurring in 36 pools. These were discovered during relatively continuous exploration over the last three decades (Table 29). Pool sizes vary from 0.1 x 10^6 to 33 x 10^6 m^3 OIP.

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 15 x 10^6 m^3 OIP. This potential is expected to occur in 24 additional pools including 3 in the 3 x 10^6 to 4 x 10^6 m^3range (Fig. 51). Most of the remaining pools would be less than 1 x 10^6 m^3 OIP and will probably be found in small erosional remnants in the established southern oil-prone part of the play area. Seismic surveys should be able to detect the presence of Elkton outliers, provided they have sufficient vertical relief.

TABLE 29

ELKTON EDGE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Harmattan East Rundle	32.70	1957
2	Harmattan East Rundle C	29.90	1955
3	Sundre Rundle	13.20	1955
4	Westward Ho A	6.87	1955
5	Sylvan Lake C	4.77	1963
9	Sundre B	2.70	1960
10	Crossfield East D	2.70	1965
11	Crossfield E	2.26	1967
12	Gladys C	1.70	1978
13	Windfall A	1.60	1957
15	Caroline B	1.27	1963
16	Crossfield G	1.23	1974
17	Medicine River B	1.12	1973
18	Crossfield East A	1.06	1968
19	Sylvan Lake B	0.87	1963
22	Crossfield East F	0.63	1976
23	Crossfield C	0.60	1963
24	Medicine River C	0.52	1974
25	Lanaway A	0.48	1974
26	Sylvan Lake F	0.45	1963
27	Sylvan Lake J	0.44	1984
28	Gladys E	0.42	1978
29	Gladys D	0.37	1979
30	Caroline F	0.36	1980

- •Total Discoveries : 36
- •Discoveries in the Top 30 Pools : 24
- •Total Pool Population : 60

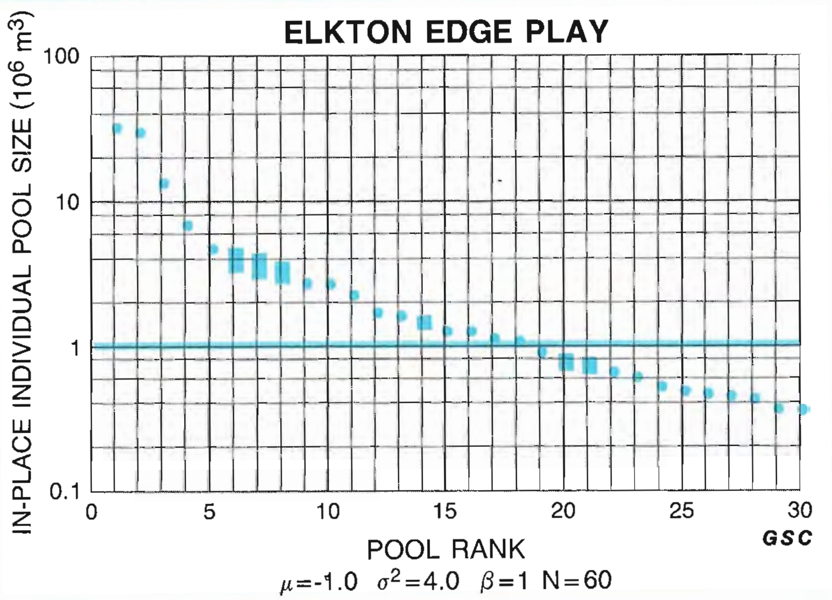


Figure 51

DESAN

Play Definition: This oil play was defined to include all pools and prospects in structural and structural-stratigraphic traps formed in shelf carbonates of the Pekisko, Shunda and Debolt Formations. The play area extends from the Pekisko subcrop edge to the eastern edge of the disturbed belt in northeastern British Columbia, north of the Peace River Embayment.

Geology: There are three main types of trap in this complex play. Stratigraphic-depositional traps formed where porous reservoir rocks grade laterally and vertically into seal rock as facies change; stratigraphic-erosional, where dolomite reservoir beds, particularly in the Debolt, are truncated against Mesozoic shale and chert forming unconformity traps; and structural, where oil is accumulated either in reservoirs on horst blocks or in grabens where reservoir beds have been preserved from erosion.

The Shunda and Pekisko reservoirs are typically lime grainstone. Post-depositional cementation, compaction, and dolomitization significantly reduced original porosity and permeability in the reservoir beds (H. Majid, pers. comm.). Reservoirs are commonly interbedded with impermeable limestone and shale, forming several stringers with a total pay thickness of less than 15 m. Though reliable recovery factors and pool areas are unknown due to the lack of sustained production, it is expected that a lack of a natural drive mechanism and of good permeability will allow only a small fraction of the in-place oil to be produced.

The oil is a medium crude, and may have an indigenous source.

Exploration History: Following the initial discovery at Desan in 1983, approximately 100 wells have been drilled, resulting in the discovery of 17 pools in the Pekisko Shunda, and Debolt Formations in the Desan and Tooga fields (Table 30).

TABLE 30

DESAN PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
3	Desan Pekisko C	2.27	1984
5	Desan Pekisko F	2.23	1984
8	Desan Pekisko A	1.49	1984
11	Desan Shunda A	1.11	1983
20	Tooga Debolt A	0.71	1984
22	Desan Pekisko B	0.64	1984
30	Desan Shunda E	0.41	1984

- •Total Discoveries : 17
- •Discoveries in the Top 30 Pools : 7
- •Total Pool Population : 80

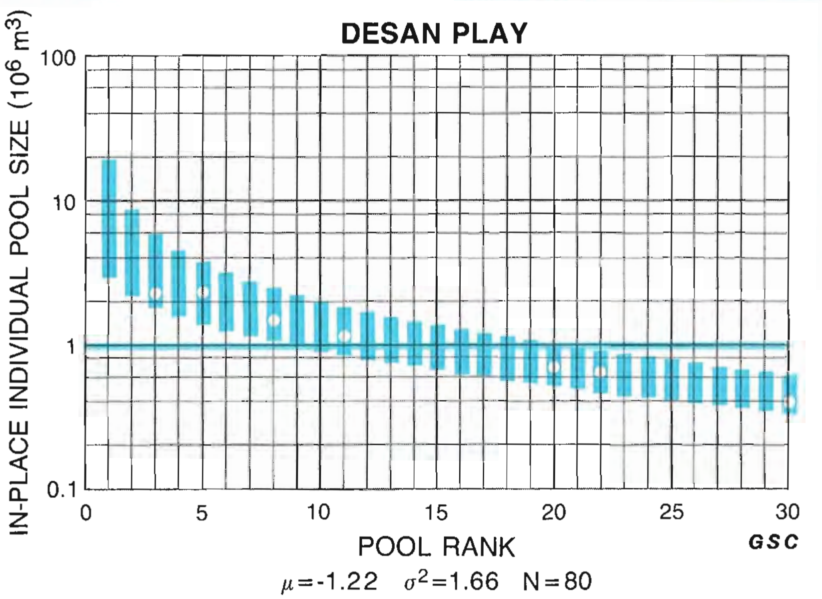


Figure 52

Play Potential: The estimate of total resource for this play has a range from 27 x 10^6 to 65 x 10^6 m^3 OIP with a median expectation value of 42 x 10^6 m^3 OIP. Because the discovered pool sizes are not yet well defined the individual discoveries are not matched to the predicted pools (Fig. 52). The recoverable resource, however, will probably be a comparatively low value, based on poor initial production performance of the early discoveries.

WILLISTON BASIN DISTRICT

The Williston Basin District is bounded by the Sweetgrass Arch to the northwest, the Carboniferous erosional edge to the north and east, and the International Boundary to the south (Fig. 43). Since the early 1950s, the focus of exploration for Carboniferous oil has been for unconformity-related traps in the eastern part of the basin.

DEPOSITIONAL AND TECTONIC HISTORY

The lower shale and middle sandstone-siltstone members of the Bakken Formation (Famennian to Tournaisian) unconformably overlie the Big Valley or Torquay formations, and represent the first cycle of deposition in the lower Carboniferous unit. The second cycle consists of the upper shale member of the Bakken Formation and parts of the Lodgepole Formation. The sediments of the lower and middle Carboniferous units form an offlapping succession, composed dominantly of carbonate and evaporite strata of the Madison Group. The stratigraphy, sedimentology and stratigraphic setting of the Madison Group, the productive interval, has been analyzed by Edie (1958), Fuzesy (1960), Kent (1984), and McCabe (1963). The regional setting of Lower Carboniferous sedimentation is discussed by Gutschick *et al.*, (1980). The Madison Group consists of the basin, slope, and shallow-shelf carbonates and subordinate clastics of the Lodgepole Formation, the high energy shelf deposits of the Mission Canyon Formation, and the low energy, commonly restricted-marine and evaporitic shelf deposits of the Charles Formation. The boundaries of these formations are diachronous: in the centre of the basin the upper parts of the Lodgepole are time-equivalent to the Mission Canyon of the middle Carboniferous unit (Table 23; Figure 53). Thin Kibbey sandstone of the upper Carboniferous unit is preserved only in the central part of the basin near the International Boundary.

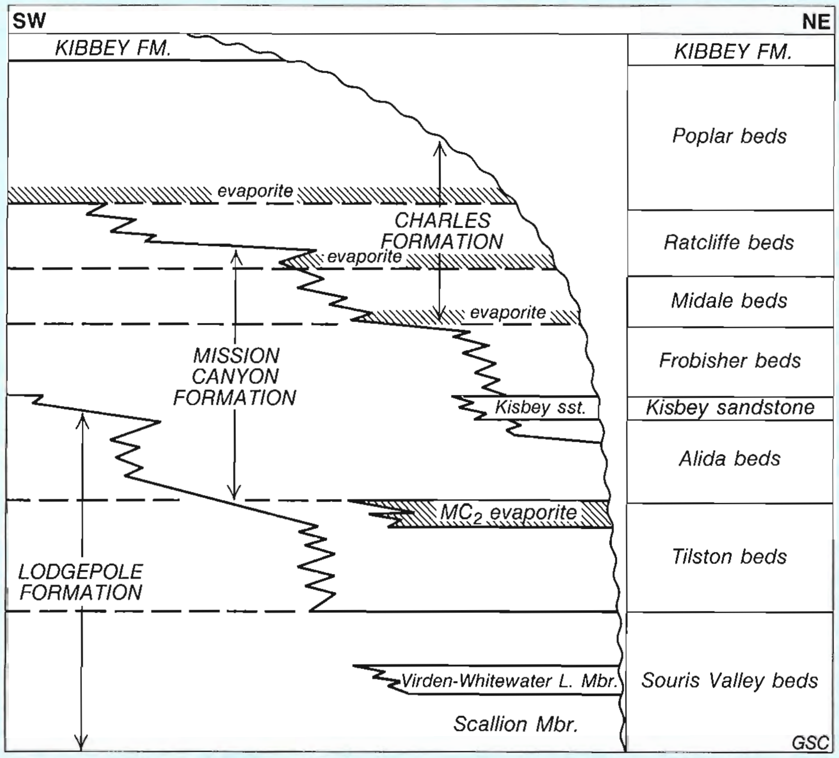


Figure 53. Stratigraphic Relationships — Madison Group, Williston Basin.

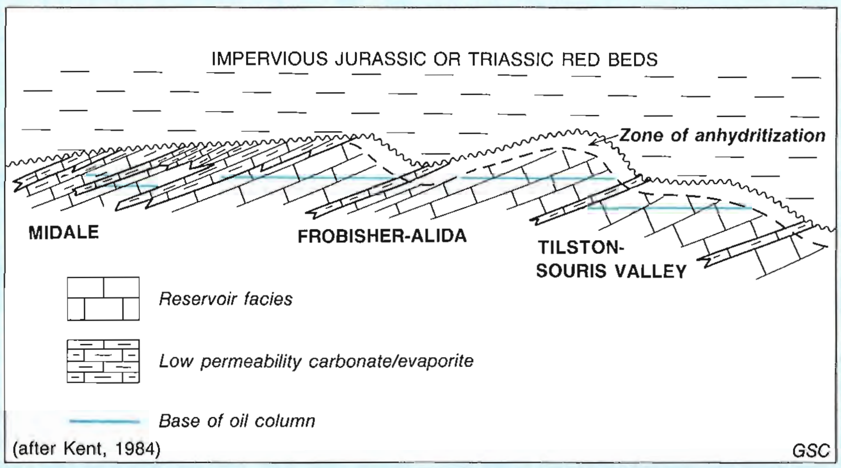


Figure 54. Schematic Section of Unconformity Traps, Williston Basin

Repeated minor transgressive-regressive events resulted in several cycles of deposition that are particularly evident on the basin margins. Each cycle contains a basal subtidal grainstone and packstone unit that is overlain by restricted-marine, shallow-subtidal to intertidal and supratidal carbonates and evaporites. Local usage in eastern Saskatchewan has applied an informal terminology to the reservoir units within each of the cycles. Figure 53 illustrates the relation of these "beds" to the formal lithostratigraphic units. By local usage the evaporitic unit that should be the top of each cycle is assigned to the base of the overlying named beds. Each evaporite unit does however, have the informal name of the beds in the cycle it belongs to. For example, the evaporite at the base of the Ratcliffe beds is termed the Midale evaporite.

At the close of the Paleozoic Era the strata of the Williston Basin were uplifted and the basin margins were eroded, giving the Lower Carboniferous formations regional dip. The preserved Carboniferous strata occur in the Swift Current Platform in the west, a region of relatively shallow dipping slope and basinal facies; and in the main Williston Basin, a moderately dipping region where the entire range of Mississippian facies was preserved. Deposition of Triassic or Early Jurassic, subaerial and shallow marine deposits of the overlying Watrous and Amaranth formations sealed the unconformity.

PETROLEUM GEOLOGY

Most oil pools in the Madison Group of southeastern Saskatchewan occur in unconformity-related traps (Fig. 54); the sub-Mesozoic erosional surface combined with the primary facies change provide the trap. Variants of the basic geometry are the result of paleotopography on the erosion surface; alteration of original facies because of secondary infilling by anhydrite, chert, or dolomite; and porosity enhancement by leaching of the original facies by groundwater during erosional events. The evaporites that cap each Carboniferous depositional cycle form top and seat seals that isolate pools within the stratigraphic succession. Exploration trends occur where porous grainstones and packstones deposited at the base of the cycles subcrop at the unconformity against the seal rocks of the overlying Mesozoic successions. Each deepening event also resulted in accumulation of potential petroleum source rocks in the Lodgepole Formation (Brooks *et al.*, 1987; Osadetz and Snowdon, 1986).

Three other trap types occur in the Williston Basin District. The first is stratigraphic and is formed where early dolomitization developed pods of reservoir rock within typically impermeable rocks of a single depositional unit. The only pools in this type are in the Ratcliffe beds along the Oungre trend in southern Saskatchewan (Hartling *et al.*, 1982). The second type is structural, formed by multi-stage solution of Devonian salt beds, as at Hummingbird (Smith and Pullen, 1967). The third type is also structural, related to suspected meteorite impact craters (Sawatzky, 1972).

In all trap types, migration occurred from basinal oil sources updip toward the eroded margins of the Carboniferous units, probably during the late Mesozoic or early Tertiary.

Oil in these plays amounts to approximately two thirds of the remaining established reserves of light and medium crude oils of Saskatchewan, and eighty-five per cent of the remaining established reserves of Manitoba (Manitoba Energy and Mines, 1985; Saskatchewan Energy and Mines, 1985). Initial in-place reserves totalled approximately 818 x 10^6 m^3.

EXPLORATION PLAYS

The long and colourful exploration history of the Williston Basin has been focused mainly on the unconformity-related plays. Oil was first discovered in Lower Carboniferous carbonates of the Williston Basin during 1949 in Husky Refining Company's Northern Pacific No. 1 well, located in Fallon County Montana (Hamke *et al.*, 1966). By 1951 oil had been discovered at both Daly, Manitoba (McCabe, 1963), and Richey, North Dakota (Hamke *et al.*, 1966). The first Paleozoic oil production in Saskatchewan followed the discovery of heavy crudes in the Bakken sandstone of the Coleville pool in west-central Saskatchewan. The first discovery of oil in carbonate reservoirs of Lower Carboniferous age was near Ratcliffe in 1952 (Fuller, 1956). Exploration along the Manitoba play trend was largely completed by 1957, although exploration for subcrop plays in Saskatchewan continued at a high level into the 1960's before diminishing. Exploration of the diagenetic-stratigraphic and structural plays occurred during the middle 1960s. Significant additions to the reserve base continued to the end of the 1970s with the discovery of Midale zone pools at both the Tatagwa and Bryant fields. Additions to reserves continue to the present day, although these later discoveries are not volumetrically significant.

Conceptual Plays

The conceptual plays believed to exist in the Carboniferous lie along migration paths in a very petroliferous part of the stratigraphic section of the Williston Basin. The boundaries of the Canadian portion of each play are set at the International Boundary to the south, the erosional edge of each reservoir unit to the east and north, and the zone of fresh water recharge to the west (Fig. 55). This low salinity zone is deemed

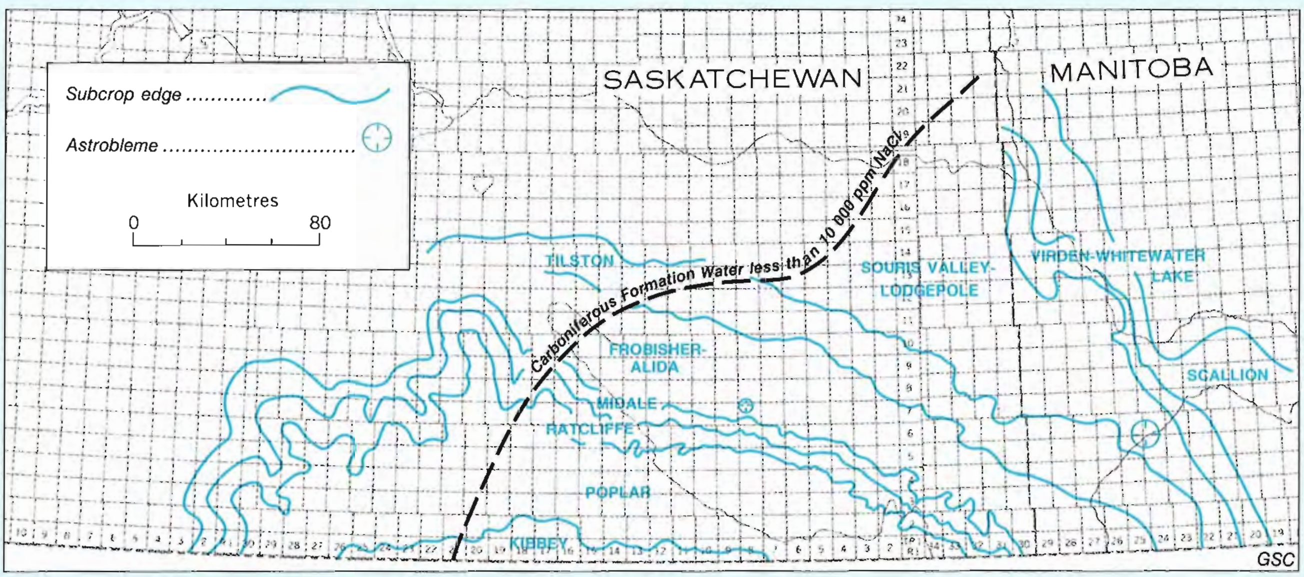


Figure 55. Carboniferous Plays, Williston Basin District. Play areas lie between the International Boundary to the south, the zone of low salinity formation water to the northwest, and the erosional edges of each reservoir unit to the northeast.

to have flushed or biodegraded any pooled oil that may have accumulated prior to the establishment of this hydrodynamic system.

Both stratigraphic and structural plays were considered in this analysis. Stratigraphic plays in the **Lodgepole Formation** included the assumption of reservoirs within Waulsortian mounds and carbonate turbidite or debris flows encased in basinal carbonate and shale seal rocks. There are no known oil pools in these reservoir types to date in the entire Williston Basin, though mounds are exposed in central Montana (Smith, 1982). The more important stratigraphic traps are thought to exist in the **Mission Canyon** and **Charles formations**, in known reservoir units, downdip from their erosional edges. Such reservoir facies could be sealed by subtle diagenetic or depositional facies changes. This type of trap could be expected in the Souris Valley, Tilston, Alida, Frobisher and Midale beds, in a situation like the established Ratcliffe play at Oungre.

Structural plays would involve all **Bakken Formation** and **Madison Group** reservoir units that have been affected directly by post-Carboniferous deformation or have been draped over features created as the result of either salt solution, or meteorite impact, or local structural deformation. Pronounced single or multi-stage solution of the underlying Prairie evaporite is known to have affected the trapping of some of the Ratcliffe and Birdbear pools in Saskatchewan. The Viewfield impact structure produces from the Frobisher beds adjacent to their erosional edge. Laramide reactivation of intra-basinal features such as the Nesson and Cedar Creek anticlines is responsible for structural-stratigraphic entrapment of most of the Carboniferous oil in the United States portion of the basin.

Established Plays

Six of the seven established plays were assessed in detail. Four of these are well explored unconformity-related plays. The fifth is a structural play and the sixth a stratigraphic play: both of these are being actively explored.

Oil has been discovered in structural, stratigraphic, and unconformity related traps in sandstones of the **Bakken Formation** at Roncott and Rocanville in Saskatchewan. Recent exploration successes have also been reported in western Manitoba, although the data on the discoveries was not available to the assessors. A major problem with the Bakken play is the limited distribution of reservoir-quality sandstone within this formation.

LODGEPOLE

Play Definition: This oil play was defined to include all pools and prospects within: the Virden, Whitewater Lake, and the Scallion Members of Manitoba; the unnamed upper Lodgepole of Manitoba; and the undivided Lodgepole of eastern Saskatchewan and westernmost Manitoba. The play area is bounded by the arcuate trend of the subcrop edges of each member extending to the International Boundary in the south and to the zone of low salinity formation water in the west (Fig. 55).

Geology: The pools occur along two producing trends. Pools at the subcrop of the Virden and Whitewater Lake members occur along a trend from Lulu Lake to Virden Field in unconformity-related traps. West of this trend are pools of the Daly, West Butler and Kirkella fields. The Daly Field is a combined structural-stratigraphic trap, although structure is the main control. This structural culmination may have interfered with any farther northward migration of hydrocarbons in this area. The other two fields in this region are in reservoirs in the unnamed upper Lodgepole of Manitoba. The traps resulted from dolomitization and replacement by anhydrite in a zone occurring beneath the eroded surface of the Lower Carboniferous succession.

The carbonate reservoirs possess intergranular, vuggy, and fracture porosity caused by several diagenetic events, including leaching of reservoir beds during sub-Mesozoic erosion. Average porosity values within the pools range between 8% and 13%, although porosity values as high as 40% are associated with leached Scallion Member cherty carbonates (Berg, 1956). Pool average water saturations range from 29% to 52%, formation volume factors are 1.04 to 1.07, and recovery factors vary from 30% to 45%.

Exploration History: In December 1951 the Calstan Daly 15-18-10-27W1 well was completed as the discovery well in the Daly Field. Approximately 56 x 10^6 m^3 OIP have been discovered in 19 pools assigned to this play (Table 31). The largest pool, at Daly, was also the initial discovery with a find of 24 x 10^6 m^3 OIP.

Play Potential: The estimate of the undiscovered potential for this play has a median expectation value of 4 x 10^6 m^3 OIP. This represents approximately 7% of the total expected resource. The estimate assumes a total pool population of 40 pools, 21 of which remain undiscovered. The largest remaining undiscovered pool is estimated to be less than 1 x 10^6 m^3 OIP (Fig. 56).

TABLE 31

LODGEPOLE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Daly 51-02-01	23.74	1951
2	Virden-Ro 53-07-29	12.13	1953
3	Virden 53-12-11	4.85	1953
4	Virden-Ro 53-07-29	3.31	1953
5	Virden 53-12-11	2.29	1953
6	Arkella 57-09-19	1.40	1957
7	Routlege 56-01-12	1.24	1956
8	Maples 55-02-20	1.24	1955
9	Ebor 54-08-31	1.05	1954
10	West Butler 55-11-03	0.94	1955
13	North Routlege 57-12-22	0.54	1957
14	Whitewater 58-09-17	0.52	1958
15	Woodnorth 54-04-15	0.51	1954
16	Maples 55-02-20	0.43	1955
17	North Routlege 55-12-22	0.43	1955
23	Ebor 54-08-31	0.24	1954
24	Routlege 56-01-12	0.21	1956
28	Lulu Lake 52-12-19	0.13	1952
29	West Butler 55-11-03	0.11	1955

(Pool nomenclature from Wallace-Dudley, 1982)

- **Total Discoveries : 19**
- **Discoveries in the Top 30 Pools : 19**
- **Total Pool Population : 40**

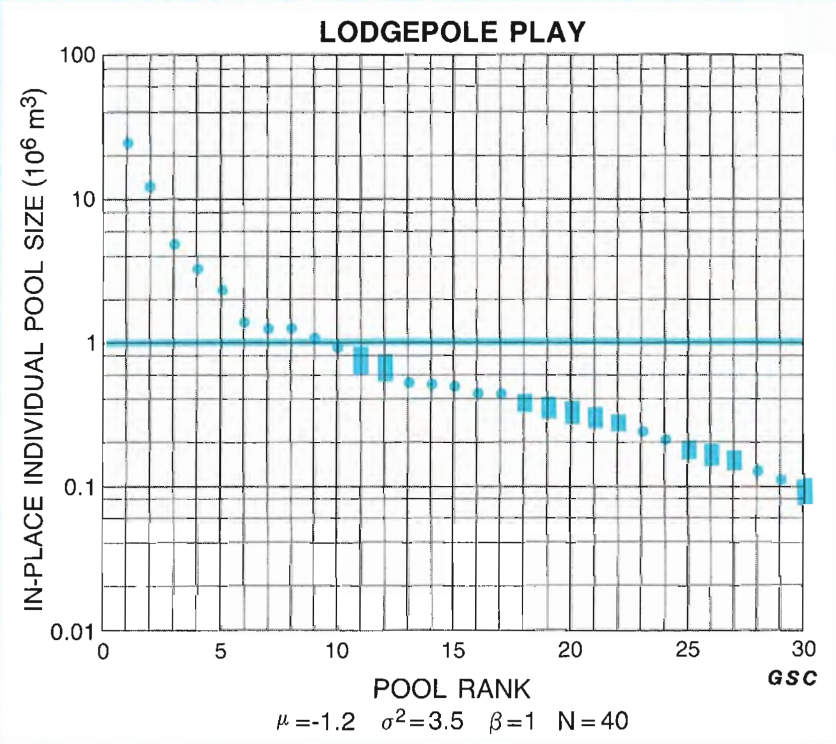


Figure 56

SOURIS VALLEY — TILSTON

Play Definition: This oil play was defined to include all pools and prospects in Souris Valley (Lodgepole Formation) and Tilston beds (Mission Canyon Formation) and equivalent strata in southeastern Saskatchewan and southwestern Manitoba. The play area is defined by the arcuate northwesterly trend of the subcrops of these two units from the International Boundary to the zone of low salinity formation water in the west (Fig. 55).

Geology: The pools in this play occur in unconformity traps near the subcrop of the upper Lodgepole and Mission Canyon formations. The shelf carbonate facies of the Lodgepole and Mission Canyon formations form good reservoirs with ranges in porosity from 7 to 15%, water saturation from 35 to 50%, and recovery factors from 9 to 54%. The average primary recovery factor for medium oil pools is 15%; for light oil pools it is 25%. The higher recovery factors are associated with secondary recovery schemes. Top seals are either impermeable beds of the overlying Watrous Formation, or porosity occlusion at the unconformity surface. In the Parkman Field lower argillaceous limestone of the Lodgepole forms a seat seal (Miller, 1964). This field is unique as there is a continuous oil column through the Tilston and Souris Valley beds.

Paleotopography on the unconformity preserved irregularly shaped knolls of Carboniferous rocks that contain reservoir facies and have become important traps in this play.

Exploration History: The initial discovery was made by the Owen Tilston Province 5-32-5-29W1 well in July 1952. Production from this interval in Saskatchewan was augmented by the discovery of the Whitebear pool in November 1954. The largest field in this play was discovered in January 1959 at Parkman (Miller, 1964). Exploration continued throughout the 1960s with the last major discovery being that of the South Parkman Tilston-Souris Valley pool in 1969. Approximately 41 x 10^6 m^3 OIP has been discovered in 20 pools assigned to this play (Table 32).

Play Potential: The estimate of the undiscovered potential for this play has a median expectation value of 6 x 10^6 m^3 OIP, which represents approximately 12% of the total resource. The potential is expected to occur in an additional 12 pools, all of which are expected to be less than 1 x 10^6 m^3 OIP (Fig. 57).

TABLE 32

SOURIS VALLEY — TILSTON PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Parkman Tilston — Souris Valley	23.71	1957
2	Kenosee Tilston	4.03	1958
3	White-Bear Tilston	2.73	1957
4	Frys Tilston — Souris Valley	2.41	1961
5	Moose Mountain Tilston	1.80	1960
6	South Fletwode Tilston	1.32	1961
7	Hazelwood Tilston	1.21	1963
8	Parkman South Souris Valley	1.01	1964
11	Moose Valley Tilston	0.74	1958
12	Edenvale Tilston	0.73	1963
13	Parkman Tilston	0.70	1959
15	White-Bear Tilston — Souris Valley	0.52	1963
18	Lightning Tilston	0.41	1957

- •Total Discoveries : 20
- •Discoveries in the Top 30 Pools : 13
- •Total Pool Population : 30

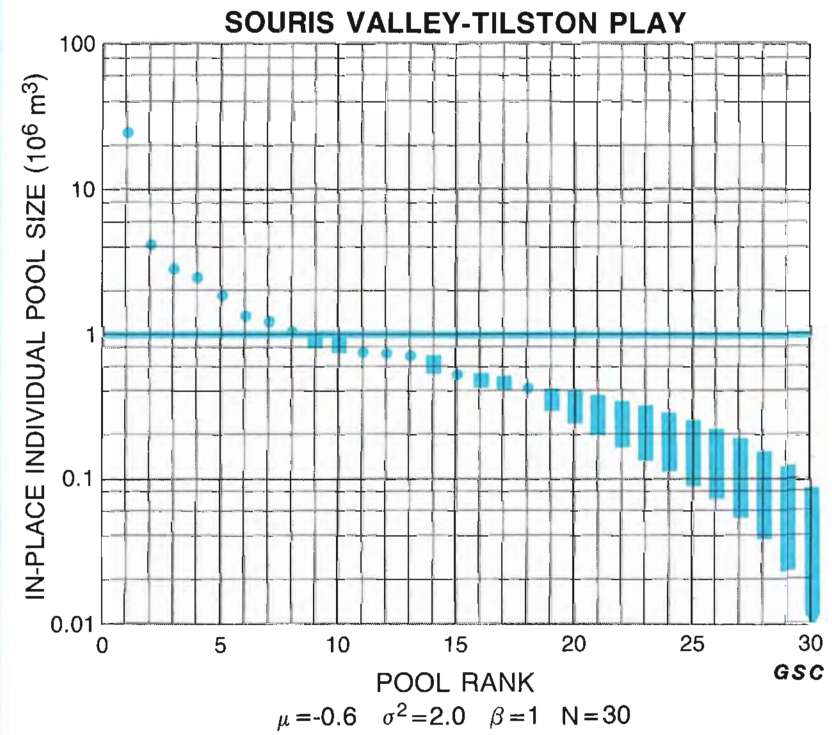


Figure 57

FROBISHER — ALIDA

Play Definition: This oil play was defined to include all pools and prospects in Frobisher-Kisbey- Alida beds (Mission Canyon Formation) in reservoirs related to the subcrop unconformity. The play area is defined by the arcuate trend of the erosional edge of the Frobisher and Alida beds, from the International Boundary in southwestern Manitoba to the zone of low salinity formation water in southwestern Saskatchewan (Fig. 55).

Geology: The pools occur in a play trend that is limited below by evaporites and shales at the top of the Tilston interval (MC2 evaporite and shale of Edie, 1958) and above by the base of the Frobisher Evaporite (Charles Formation). There are no widespread barriers to permeability within the stratigraphic interval from the base of the Midale beds to the top of the Tilston beds (Fig. 53). In the lower portion of this interval at or near the subcrop of the Alida and Kisbey beds is a series of topographic prominences on the erosional surface of Paleozoic rocks. This forms the Alida-Nottingham trend of Edie (1958). The reservoirs are commonly bioclastic and oolitic grainstones of the Alida beds. They are sealed at the overlying unconformity either by alteration of the Carboniferous strata or by tight zones in the overlying Watrous Formation. A second trend occurs in the Frobisher Beds, where entrapment also occurred at or near the sub-Watrous unconformity. The latter pools, however, do not appear to be as strongly influenced by topography on the erosional surface. Pools sealed by overlying evaporites within the Carboniferous succession form a third group producing from this interval. They often underlie, although they are separate from, pools in the Midale Member of the Charles Formation (Fuzesy, 1960). The final group of pools occurs in structures at or near the subcrop edge. The most notable of these is Viewfield, a structure interpreted to be an astrobleme (Sawatzky, 1972).

Source of the oils is believed to be mainly indigenous within carbonates of the Madison Group; however, the oil in some pools, (i.e. Gapview) is known to have migrated from source rocks in the Bakken.

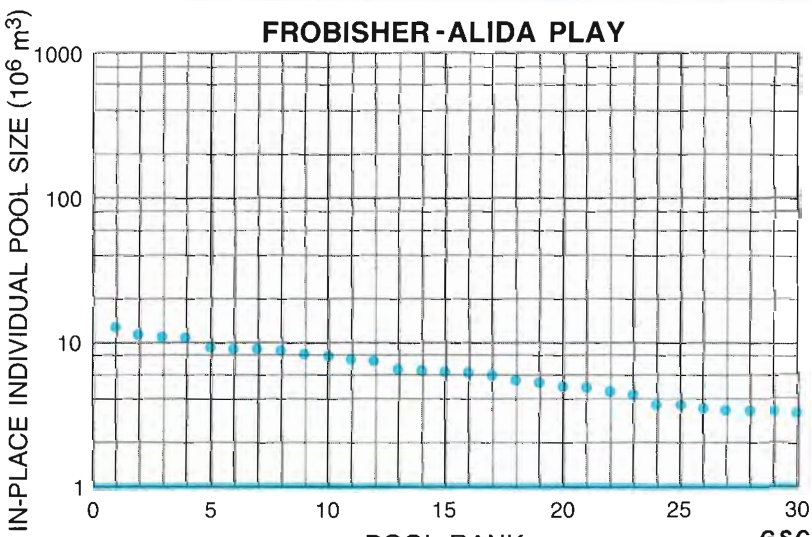
The carbonate shelf rocks form good reservoirs, with porosities ranging from 7 to 20%, water saturations from 26 to 50%, and recovery factors from 10 to 50%. The average primary recovery factor for medium oil pools is 15%: for light oil pools it is 25%. The higher recovery factors are associated with secondary recovery schemes.

TABLE 33

FROBISHER — ALIDA PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Alida-East Alida	11.25	1954
2	Willmar Frobisher — Alida	11.20	1957
3	Queensdale-E Frobisher — Alida	11.05	1957
4	Innes Frobisher	10.45	1963
5	Nottingham Alida	9.40	1956
6	Alida West Alida	9.11	1955
7	Hastings Frobisher	8.94	1959
8	Rosebank Frobisher — Alida	8.66	1955
9	Ingoldsby Frobisher-Alida	8.33	1955
10	Lost Horse Hill Frobisher-Alida	8.21	1963
11	Viewfield Frobisher	7.90	1968
12	Workman Frobisher	7.58	1960
13	Rosebank Alida	6.51	1955
14	Steelman Frobisher N	6.44	1954
15	Viewfield Frobisher N	6.34	1968

- Total Discoveries : 78
- Discoveries in the Top 30 Pools : 30
- Total Pool Population : 90



$\mu=0.5$ $\sigma^2=1.25$ $\beta=0.4$ N=90

Figure 58

Exploration History: Approximately 253 x 10^6 m^3 OIP have been discovered in 78 pools assigned to this play (Table 33). Several significant discoveries within the three major exploration trends were made in 1954, including the initial discovery at Pierson in Manitoba and the Frobisher and Midale Fields in Saskatchewan. Discovery at the Viewfield impact site was made in 1968.

Play Potential: The estimate for the undiscovered potential of the play has a median expectation value of 14 x 10^6 m^3 OIP **(Fig. 58).** This potential is expected to occur in an additional 12 pools, each of which would be less than 2 x 10^6 m^3 OIP. Existence of several trap configurations leaves opportunity for considerably more pools than the analysis suggests.

MIDALE

Play Definition: This oil play was defined to include all pools and prospects in the carbonate shelf unit termed "Midale beds" of the Charles Formation, in traps at and immediately downdip of Midale beds subcrop edge. The play area is defined by the zone of Midale subcrop extending from the International Boundary to the zone of low salinity formation water in southeastern Saskatchewan (Fig. 55).

Geology: The Midale beds are dominantly carbonate grainstones that lie between the Frobisher and Midale evaporites, anhydritic units of the Charles Formation (Fig. 53).

Two types of closely related stratigraphic trap occur in this play. The first is the typical unconformity-edge trap with the porous reservoir facies sealed by the overlying Mesozoic rocks. The second is a variant where the seal of the trap is within the Carboniferous rocks themselves and was created by the total occlusion of the porosity by diagenetic alteration and cementation that resulted from fluids reaching the reservoir from the erosion surface. Oils are sourced both from the Madison Group and Bakken Formation basinal strata that underlie and occur downdip of the reservoirs (Osadetz and Snowdon, 1986).

The excellent quality carbonate reservoirs have porosities varying from 8 to 30%, water saturations from 30 to 50%, and recovery factors from 5 to 60% (Smith, 1980). The average primary recovery factor for medium oil pools is 15%: for light oil pools it is 25%. Higher recovery factors are associated with pools on secondary or tertiary recovery schemes. The detailed geology of several large pools has been discussed by Kaldi (1982), Nesbitt (1958), Parker (1956), Smith (1980), and Wegelin (1984).

Exploration History: The initial discovery in this play was at Midale in 1953, followed by Frobisher, Weyburn, Lampman, and Steelman in 1954 and 1955. Active exploration of the play continued up to the close of the 1970s with the discovery of the Tatagwa, Bryant and Minard Fields. A total of 450 x 10^6 m^3 OIP has been discovered in 53 pools (Table 34).

Play Potential: The estimate for the undiscovered potential of the play has a median expectation value of 26 x 10^6 m^3 OIP, that is approximately 5% of the total resource in the play. This potential is expected to occur in an additional 37 pools, all of which are on the order of 2 x 10^6 m^3 OIP or less (Fig. 59).

TABLE 34

MIDALE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Weyburn U	117.00	1954
2	Midale-CN U	56.87	1953
3	Steelman U1	24.98	1954
4	Steelman U2	18.39	1954
5	Steelman U3	16.64	1954
6	Steelman U4	13.37	1954
7	Weyburn N	12.19	1954
8	Steelman U5	11.39	1954
9	Midale-CN N	8.63	1953
10	Tatagwa Z	8.25	1978
11	Carnduff U1	7.62	1955
12	Steelman U6	6.47	1954
13	Steelman N	6.25	1954
14	Glen-Ewen Z	6.01	1956
15	Pinto Z1	5.67	1957

- **Total Discoveries : 53**
- **Discoveries in the Top 30 Pools : 30**
- **Total Pool Population : 90**

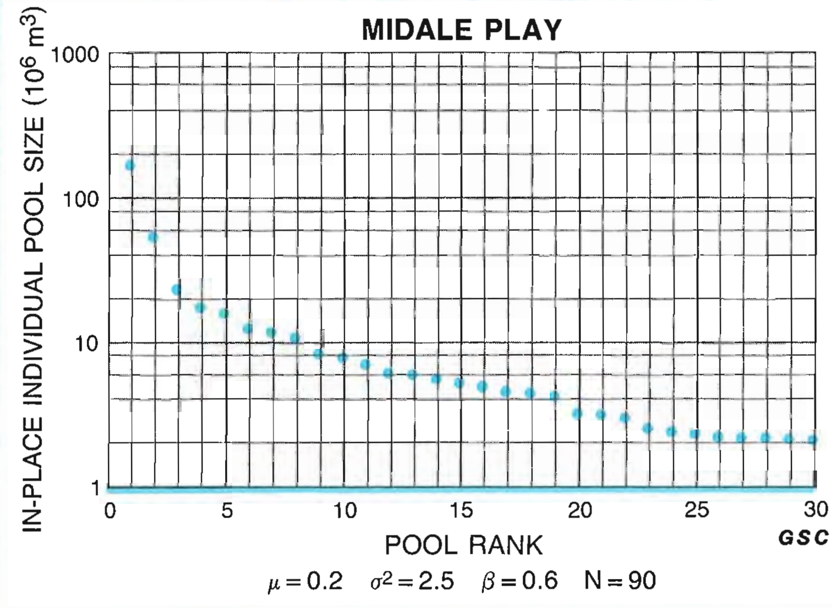


Figure 59

RATCLIFFE STRUCTURE

Play Definition: This oil play was defined to include all pools and prospects in the Ratcliffe beds (Mission Canyon and Charles formations) that are on structural features in the central portion of the Williston Basin in southern Saskatchewan. The play area is bounded by the Ratcliffe subcrop edge, the International Boundary, and the zone of low salinity formation water in southeastern Saskatchewan (Fig. 55).

Geology: The Ratcliffe beds are shelf carbonates that lie between evaporites of the Charles Formation. They contain good carbonate reservoirs, with ranges in porosity from 8 to 14%, water saturation from 35 to 50%, and primary recovery factors from 7 to 26%. Pools on enhanced recovery programs have recovery factors as high as 56%. Seals for the reservoirs are provided by overlying evaporites (Oungre evaporite). Source of the oil is not known, but is presumed to be from either Madison basinal carbonate or Bakken shale.

The structures that create traps were formed by collapse as the result of either single or multi-stage solution of the underlying Prairie Evaporite (Hartling *et al.*, 1982; Smith and Pullen, 1967). There may also have been epeirogenic movement associated with formation of these structures, either directly, or by influencing the solution of the Prairie Evaporite.

Exploration History: The Socony Central Leduc Del Rio Ratcliffe No. 1 (5-30-1-15W2) well completed during November 1952 was the initial discovery in the Hoffer pool of this play. Little further activity was successful until the middle of the 1960s when discoveries were made at Hummingbird, Flat Lake, Hoffer and Lake Alma. A total of 16 x 10^6 m^3 OIP has been discovered in 7 pools (Table 35).

Play Potential: The estimate for the undiscovered potential of this developing play has a median expectation value of 17 x 10^6 m^3 OIP, or about a third of the total resource in this play. This potential is expected to occur in an additional 23 pools, 6 of which are in the 1 to 5 x 10^6 m^3 size range (Fig. 60). The ability of the seismic method to delineate these structures suggests that these pools will be easier to locate than those in the stratigraphic and unconformity plays of the Williston Basin.

The estimates of the number of pools and play potential are probably low.

TABLE 35

RATCLIFFE STRUCTURE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Flat Lake V1	8.22	1965
2	Hummingbird	4.12	1966
5	Lake Alma	1.82	1965
8	Hoffer U	0.98	1964
20	Flat Lake L	0.34	1965
21	Hoffer L	0.32	1964
25	Flat Lake M	0.19	1965

- **Total Discoveries : 7**
- **Discoveries in the Top 30 Pools : 7**
- **Total Pool Population : 30**

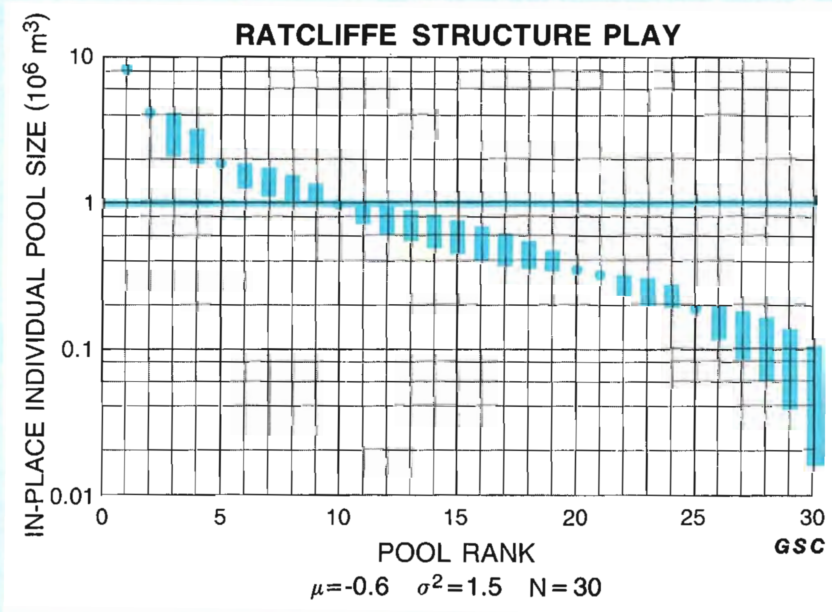


Figure 60

RATCLIFFE STRATIGRAPHIC

Play Definition: This oil play was defined to include all pools and prospects in the Ratcliffe Beds (Mission Canyon and Charles formations) in stratigraphic traps formed by updip porosity pinchouts. The play area is bounded by the Ratcliffe subcrop edge, the International Boundary, and the zone of low salinity formation water in southeastern Saskatchewan (Fig. 55).

Geology: The Ratcliffe beds consist of normal to restricted marine shelf carbonates and evaporites. The carbonate reservoirs have 3 to 7 m of net pay, 15 to 25% porosity, water saturations averaging 45%, and primary recovery factors between 4 and 12%.

The traps are primarily stratigraphic, with minor structural control (Hartling *et al.*, 1982). Early diagenetic dolomitization of restricted marine sediments, presumably caused by seepage refluxion of hypersaline brines, formed well-cemented seal rocks that now occur updip of partially dolomitized shelf carbonate reservoir rocks. The source rock for the oil in these traps is unknown, but is presumably either Madison basinal carbonate or Bakken shale.

Exploration History: The largest pool in this play was discovered at Oungre in 1959. In the ten years following that initial discovery five more pools have been found at Oungre, Freda Lake, Neptune, and Skinner Lake (Table 36). Total play reserves are approximately 34 x 10^6 m^3 OIP, with 15 x 10^6 m^3 OIP occurring in the Oungre pool.

Play Potential: The estimate for the undiscovered potential of the play has a median expectation value of 14 x 10^6 m^3 OIP, which is approximately 30% of the total resource in the play. This potential is expected to occur in an additional 24 pools, most of which are expected to be less than 1 x 10^6 m^3 OIP. The expected pool size diagram (Fig. 61) indicates that most of the resource is concentrated in a small number of large pools that have already been discovered. The remaining pools will probably have small areas and be difficult to detect by seismic exploration methods.

TABLE 36

RATCLIFFE STRATIGRAPHIC PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Oungre	14.53	1959
2	Freda Lake	6.98	1967
3	Skinner Lake	5.37	1969
4	Neptune	4.07	1967
6	Oungre	1.83	1959
10	Skinner Lake	1.01	1969

- **Total Discoveries : 6**
- **Discoveries in the Top 30 Pools : 6**
- **Total Pool Population : 30**

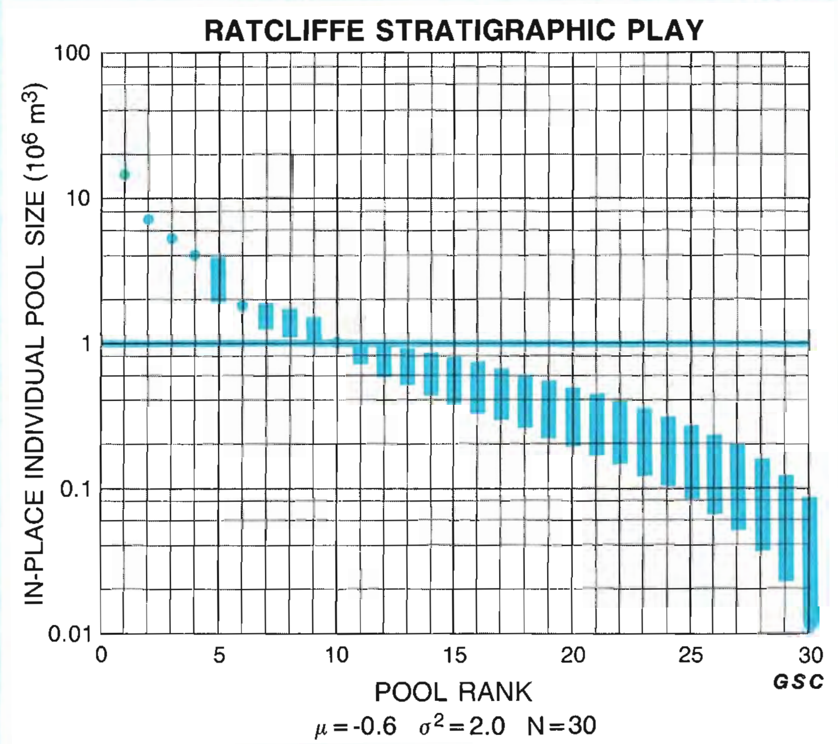


Figure 61

TRIASSIC AND JURASSIC SYSTEMS

The Triassic and Early and Middle Jurassic strata of the Absaroka sequence represent the closing phases of craton-related sedimentation typified by the carbonate-dominated Paleozoic successions. These Mesozoic sediments contain numerous carbonate units but are mainly clastics. The cratonic facies are easterly derived, westward-thickening deposits that faced open marine environments on the shelves and slopes of the ancient North American craton.

Late Jurassic strata, by contrast, were siliciclastic units deposited in a Foreland Basin that was a product of the developing orogeny on the western margin of the craton. Although Late Jurassic and later sedimentation was dominated by those westerly derived components, lesser amounts of sediments having an easterly provenance contributed to the stratigraphic record. Within the Alberta Basin, the base of the Oxfordian is assumed to contain the initial phases of Foreland Basin sedimentation. In the Williston Basin the oldest sediments of this phase are Barremian or Aptian (Lower Cretaceous).

DEPOSITIONAL STYLES AND DISTRIBUTION

Triassic and Early to Middle Jurassic strata of the Alberta and Williston basins were deposited on a broad marginal cratonic shelf over which shallow marine conditions prevailed. A broad ancestral Sweetgrass Arch separated the two basins, though it was periodically flooded in the Jurassic. The Peace River region was the main depocentre of the Alberta Basin. Apparently it maintained a basinal configuration, inherited from the late Paleozoic, through the Triassic and most of the Jurassic. The balance between sedimentation and episodic sea level fluctuation controlled the distribution of the various sedimentary facies. The gradual but relentless northward drift of the North American continent had by this time placed it in paleolatitudes where carbonate deposition was less favoured. Accordingly most of the rocks are of clastic origin. Marine incursions onto the craton, particularly during the Triassic Period, were less extensive than those that had occurred during the Paleozoic. Although the present distribution of Triassic rocks is the product of later erosion (Fig. 62), the preserved sediments commonly exhibit shoreline or near-shoreline facies at their eastward erosional limit, suggesting that this approximates their original depositional limit. In contrast, it has not been possible to delimit the original extent of Jurassic rocks.

The provenance of much of the Triassic sediment in the Alberta Basin is thought to be Permian and Carboniferous rocks of the emergent craton to the east and north. These low relief regions supplied the mature multicycled quartz-rich clastics that are the dominant sediment. The provenance of the Alberta Basin Jurassic was mainly from exposed Carboniferous and Devonian rocks to the east, except for the latest Jurassic which came from the rising orogenic welt in the west.

In the Alberta Basin the sediments of the Triassic were deposited during three major shoreline fluctuations. The resulting cycles

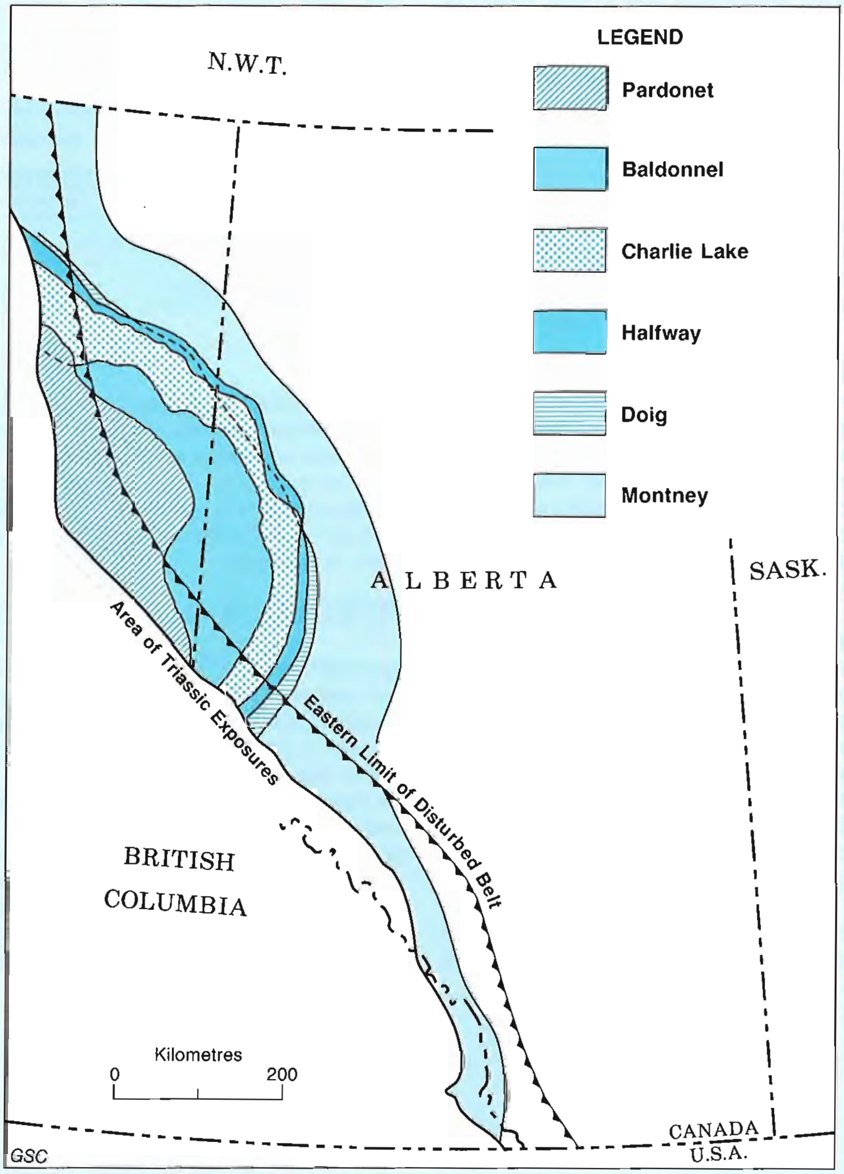


Figure 62. Distribution of Triassic rocks, Western Canada Sedimentary Basin.

record the balance between sea level movements and clastic influx or sediment progradation during the Early, Middle, and Late Triassic epochs (Table 37). Evidence for lesser order fluctuations is apparent within each cycle, expressed as the vertical stacking of closely related facies in repetitive sequences. The Lower Triassic succession is dominated by siltstones and shales that thin and become more sandy towards the eastern shoreline. In the deeper parts of the shelf, dark shales are more common and appear to have been deposited under more euxinic conditions. Middle Triassic sediments also include drab euxinic shales, but contain a higher percentage of sandstone units in the eastern proximal facies. A relatively broad shelf of complexly interbedded sabkha evaporites, shallow marine carbonates and coarse shoreline clastics characterizes the Upper Triassic. Equivalent offshore deposits were normal marine siltstones, sandstones, and skeletal carbonates.

There is no record of proven Triassic sedimentation preserved in the Canadian portion of the Williston Basin. Parts of the Watrous-Amaranth redbeds may be Triassic, though they defy a definitive age assignment.

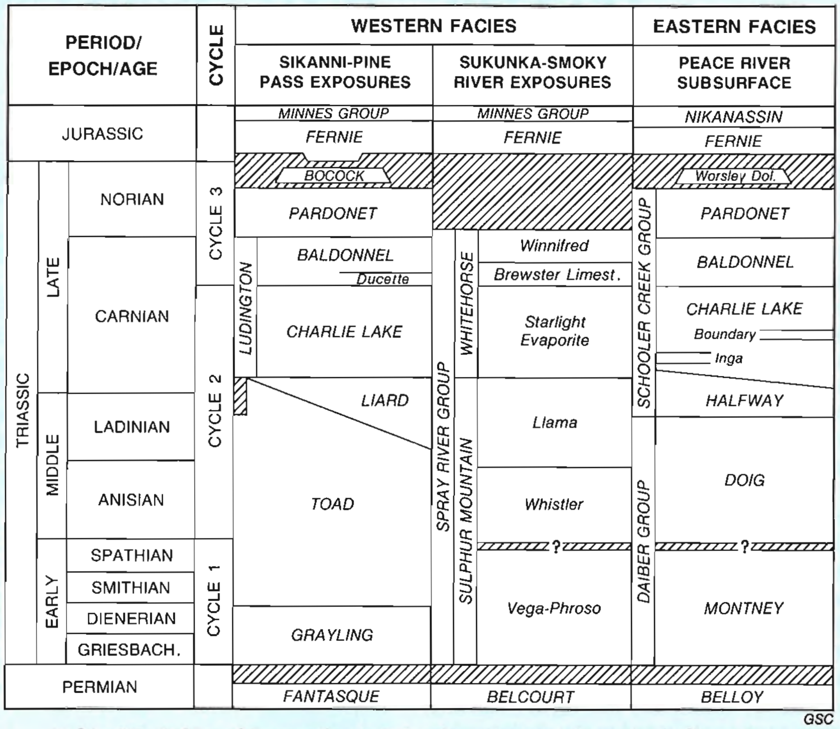


Table 37. Table of Formations, Triassic, Western Canada Sedimentary Basin.

The Early and Middle Jurassic succession of the Alberta Basin comprises dominantly fine-grained clastic sediments deposited on a broad cratonic shelf during transgressions that advanced from the west. Minor sands and carbonates were deposited within this succession. Abrupt fluctuations of sea level resulted in several widespread erosional intervals within the section. A broad precursor to the Laramide Sweetgrass Arch was established as a positive feature during Jurassic sedimentation. Apparently the Sweetgrass Arch limited deposition on the southern part of the Alberta shelf and separated this region from the Williston Basin. Post-depositional erosion over much of Western Canada eliminated most of the sedimentary record except in the Foothills and the immediately adjacent subsurface (Fig. 75).

Renewed subsidence during the Middle Jurassic resulted in the deposition of a thick sandstone, shale, and evaporite succession the Williston Basin. Easterly derived sediments prograded into the basin and by Late Jurassic time had overlapped the Sweetgrass Arch to merge with the clastics derived from the Columbian orogenic activity in the west.

PETROLEUM OCCURRENCE

Approximately 10% of the discovered initial reserves of the conventional oil of the Western Canada Sedimentary Basin occurs in rocks of Triassic and Jurassic age. About half of this occurs in the Triassic rocks of the Peace River region of British Columbia and adjacent Alberta, primarily in stratigraphic traps. Most of the Jurassic oil accumulations are stratigraphically trapped in sands at updip porosity pinchouts, in the western portion of the Williston Basin. Although abundant potential source rocks are recognized within the Triassic and Jurassic successions, none have yet been positively correlated with the pooled hydrocarbons.

PETROLEUM EXPLORATION DISTRICTS

Prospective regions for exploration focused on Triassic or Jurassic oil pools are the most geographically restricted of any in the Western Canada Sedimentary Basin. Within the Alberta Basin, Triassic targets are essentially limited to the Peace River District of northeastern British Columbia and northwestern Alberta. Jurassic production occurs in the Central and Southern Alberta District and in the Williston Basin-Sweetgrass Arch District, in a small number of plays.

PEACE RIVER DISTRICT

Triassic strata of the Alberta Basin only occur in appreciable thickness in the Peace River District (Figs. 44 and 62) and in a long narrow strip preserved adjacent to and within the Foothills and Rocky Mountains. The distribution of Jurassic sandstones is extremely limited, either because of non-deposition or erosion.

DEPOSITIONAL AND TECTONIC HISTORY

Rocks of the Triassic System occur in the subsurface primarily within an embayment on the craton that is centred on the Peace River Embayment of Carboniferous and Permian age (Fig. 62). Differential subsidence of this region with respect to the surrounding cratonic areas presumably occurred during and after the Triassic. The local preservation of this depocentre is the only subsurface evidence (though indirect) of Triassic epeirogenic movement.

The Triassic System is characterized by three major transgressive-regressive cycles (Table 37). Within each, varied, yet related styles of deposition occurred on the cratonic marginal shelf. The cycles consist of: Early Triassic Montney distal shelf and shoreline clastics; Middle to early Late Triassic (lower Carnian) Doig-Halfway-Charlie Lake shelf and shoreline related clastics with minor evaporite and carbonate units; and middle Late Triassic (upper Carnian to Norian) Baldonnel-Pardonet shallow water carbonates. The cycles are characterized by shallowing-upward patterns usually consisting of a thin transgressive facies followed by deposition of a thick regressive facies. Regression commonly resulted in total withdrawal of marine conditions resulting in disconformities or hiatal surfaces. Epeirogenic activity in source areas, climatic change (Gibson, 1975), and relative sea level change, all combined to produce the observed variations in depositional facies.

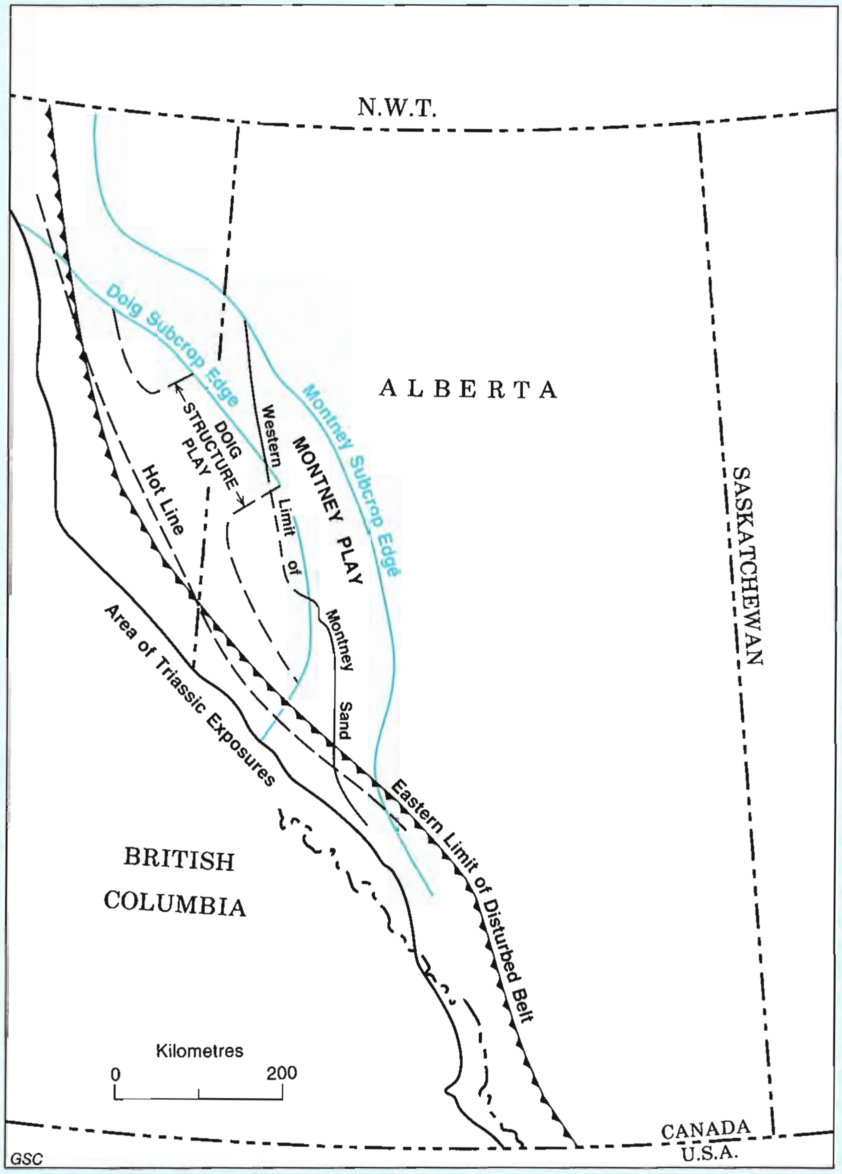


Figure 63. Montney and Doig Formations, Play Areas.

The deposits of the transgressive phase of the first (Early) Triassic cycle, whose distribution is shown in Figure 63, are dominated by thin-bedded calcareous shale and argillaceous siltstone (Barss *et al.*, 1964) assigned to the lower Montney Formation (approximately Griesbachian and Dienerian) and its western equivalents. Locally developed basal transgressive lag deposits consist of phosphatic pebble conglomerate, chert, and sandstone (Gibson, 1975). Towards the eastern limits of the shelf, fine grained glauconitic sandstones are interbedded with the shales.

The regressive deposits or second portion of the cycle are represented by the middle to upper Montney Formation (approximately Smithian and Spathian) and its western equivalents. These strata consist of thick bedded dolomitic to calcareous siltstone with minor limestone and sandstone. They are characterized by increased grain size, glauconite, bioclasts, ripple marks and cross-laminae that are interpreted as the product of near shoreline deposition. Porous sandstone and coquina (reservoirs for oil and gas in the Sturgeon-Kaybob areas), represent marked progradations of shoreline-related facies onto the shelf.

The second cycle (Middle to early Late Triassic) is characterized by an overall progradation or westward shift of the shoreline. The distribution of these rocks is shown in Figure 64. Thick clastics of the lower Doig Formation rest on phosphatic lag deposits over a hiatal surface and are in turn overlain by regressive nearshore sandstones of the upper Doig and Halfway formations. The Charlie Lake Formation closes the cycle. It consists of interbedded evaporites, redbeds, sandstones, and limestones, and represents marked regression, as shorelines were translated toward western parts of the region.

The two principal Halfway lithofacies and main reservoirs are well sorted fine- to medium-grained quartz sandstones, and coquinoid sandstones. The coquinoid sandstones consist of quartz grains and pelecypod-brachiopod-crinoid fragments, in a matrix of fine crystalline dolomite (Cant, 1986; Halton, 1983). Westward of the shoreline facies, the Halfway occurs as a blanket deposit of fine-grained sandstone ("continuous" sand, Clark, 1961; Armitage, 1962) with rare limestone interbeds. This facies is interpreted to represent lower shoreface and open shelf depositional environments. The transition from Halfway to basal Charlie Lake Formation represents progradation of Charlie Lake supratidal back-barrier sabkha sediments over Halfway sandstones. The Halfway sandstone — Charlie Lake evaporite contact is distinct in the eastern subsurface, but becomes less so westward where the Charlie Lake is dominated by open marine sandstone (Armitage, 1962; Barss *et al.*, 1964).

The Charlie Lake Formation (Fig. 65) is characterized by abrupt lateral and vertical variations of lithofacies. Major lithofacies include anhydrite, evaporitic dolomite, dolomitic and ferruginous siltstone, fine grained sandstone, stromatolitic carbonate, and fine grained sandstones. Most are considered to have been deposited in shallow water evaporitic environments.

Strata of the third cycle include limestone, siltstone and dolomite of the Baldonnel and Pardonet formations that represent a return to normal shallow marine conditions. This cycle differs from the previous cycles in that it is dominated by deposition of carbonates. The cycle is defined by a transgressive lower Baldonnel (upper Carnian) phase, overlying Charlie Lake evaporites, followed by upper Baldonnel and Pardonet (Norian). The cycle is capped by regressive Bocock limestone that is preserved only in the centre of the basin. The Bocock Formation is restricted to the outcrop belt where it occurs sporadically. The rocks are resistant, light grey, bioclastic, granular- to micritic- limestones that overlie the Pardonet Formation (Gibson, 1975). This facies records very shallow water deposition.

The Worsley or Tangent dolomite, yet to be dated, rests on top of the Charlie Lake Formation (where Baldonnel and Pardonet formations are absent) in the Worsley region of northwestern Alberta. Possible correlative units include the Pardonet and Bocock formations, as well as the lowest part of the Jurassic Fernie Formation.

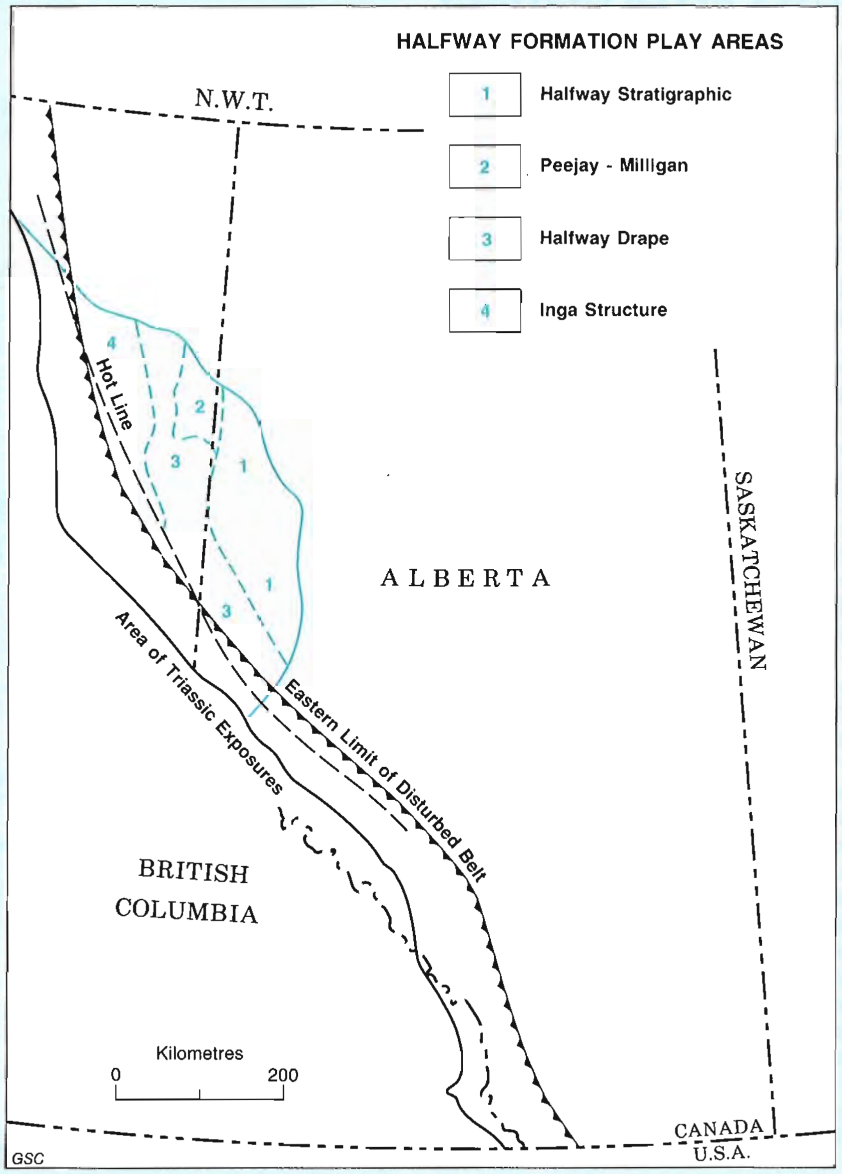


Figure 64. Halfway Formation Play Areas.

The contact of the Triassic with the overlying Jurassic Fernie Formation is unconformable throughout the Peace River region. The pre-Jurassic erosional surface merges eastward and northward with the pre-Cretaceous erosional surface; the net effect of the two erosional events has been to reduce the eastern extent of preserved Triassic sediments.

Jurassic sedimentation in the Peace River District consists of two cycles deposited prior to and one cycle deposited at the base of the Foreland Basin succession. The first cycle consists of "basal Fernie" shale and limestone, followed by deposition of the Nordegg Member phosphatic shale, calcareous and non-calcareous shale, and cherty limestone. The second cycle consists of an unnamed shale and a sandstone termed Rock Creek (Lackie, 1958). The sandstone may not be the equivalent of Rock Creek Member in outcrop of western Alberta. At the base of the fourth cycle Fernie "Green Beds" were deposited upon an unconformity. In central Alberta another intervening third cycle of deposition occurs over the time span of the unconformity (Table 47). The unconformity is interpreted to represent a minor rejuvenation of the Peace River Arch during the Middle Jurassic

(Poulton, in press; Davies and Poulton, 1986). The "Green Beds" form the base of the Foreland Basin succession and grade upward into the marine "Transition Beds" of the Fernie Formation and the overlying continental, Jurassic and Cretaceous, Monteith Formation of the Minnes Group.

PETROLEUM GEOLOGY

The Triassic of the Peace River District accounts for approximately 4% of the in-place and recoverable conventional oil reserves in the Western Canada Sedimentary Basin. Most of the Triassic oil is pooled in stratigraphic traps related to nearshore lithofacies. Many pools have some additional element of structural control such as drape over deeper structural or morphological features, penecontemporaneous structural control on depositional facies, or later fault-related enhancement of reservoirs. Reservoirs generally have good porosity and permeability. Evaporitic facies form the lateral and top seals of the traps. Potential source rocks are inferred to have been deeper water organic-rich facies known to lie down dip in the Triassic succession. Oil may also have been derived from potential source rocks in other systems.

EXPLORATION PLAYS

Eleven established plays and two conceptual plays were analysed in the Peace River District. All the oil plays are in reservoirs of Triassic age, with no opportunities envisioned in Jurassic rocks. The Jurassic sandstones that occur in this district are unproductive and, for convenience, are included in the Rock Creek play of the Central and Southern Alberta District.

Conceptual Plays

Because of the limited exploration area and the fairly long history of exploration to date, most trapping concepts have been tested. Only one conceptual play was analysed for this report, that being the **Baldonnel Drape** play. Although no oil discovery has yet been announced in this play, a number of natural gas discoveries have been made that attest to both reservoir and trap development.

Established Plays

For the purposes of this assessment the Triassic oil pools of the Peace River District were allocated to eleven exploration plays. Nine of these plays have a sufficient number of pools to have allowed analysis using the discovery process model. The two plays not given rigorous analysis are the **Worsley-Tangent** play and the **Charlie Lake-Baldonnel subcrop** play. Assigned to the Worsley-Tangent play are two discoveries (Worsley, 1961; Hamelin Creek, 1980) in similar dolomite reservoirs of uncertain, but presumed Triassic, age. Both pools occur in erosional outliers unconformably overlying earlier Triassic rocks. Porosity in these dolomite units has been enhanced by diagenesis associated with the pre-Jurassic erosional event.

The **Charlie Lake-Baldonnel subcrop** play was defined to include pools and prospects associated with the subcropping erosional edge of Charlie Lake and Baldonnel dolomites. Three discoveries in the Spirit River-Rycroft-Saddle Hills area have been made in dolomites where the porosity has been enhanced during the pre-Jurassic erosional event. This play was the focus of significant exploration activity during the period 1983-85 resulting in a number of additional discoveries.

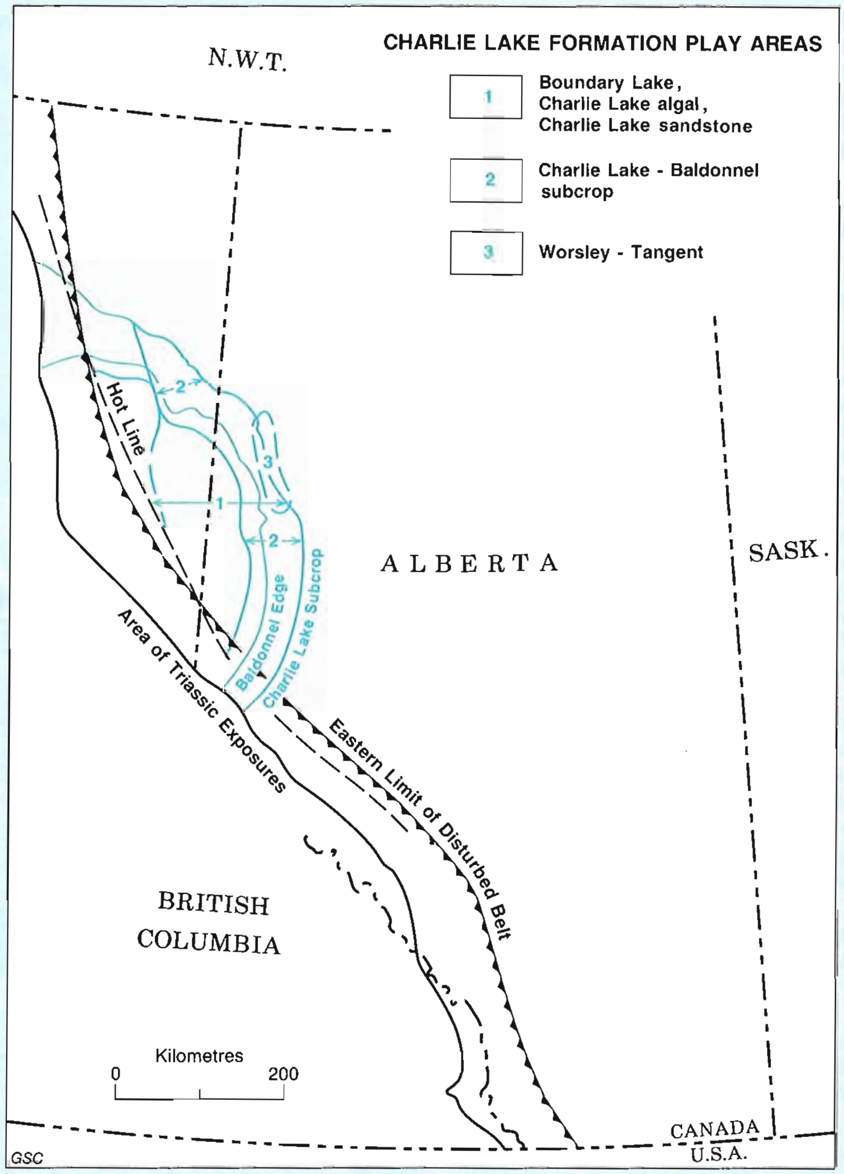


Figure 65. Charlie Lake Formation Play Areas.

MONTNEY

Play Definition: This oil play was defined to include all pools and prospects in sandstones and coquinas of the Montney Formation in porosity pinchouts caused by facies change; in unconformity traps; and in drape structures. The play is limited to the present distribution of Montney sandstones, a belt about 130 km wide to the west of the subcrop edge (Fig. 63).

Geology: Reservoirs occur in four sandstone and dolomite members of the Montney Formation that probably represent progradational pulses of shoreface sand, interbedded with distal to proximal shelf strata. The principal reservoir lithology is sandy and silty coquinoid dolomite. Less productive reservoirs include very fine- to fine-grained, argillaceous, silty, quartzose sandstones, cemented with carbonate (Metherell, 1966; Miall, 1976). Pools have reservoirs with intergranular and moldic porosities ranging from 3 to 15%, net pay ranging from 2.7 to 7.0 m and recovery factors from 11 to 25%.

The facies pinchout traps are caused by the lateral termination of reservoir-facies sandstone and coquina where they change to siltstone and shale units. Erosional truncation results in traps where the pre-Jurassic unconformity surface truncates progressively older Triassic units eastward, including the Montney Formation, as at the Sunset Field. Drape of Montney reservoirs over Leduc reef topography formed the trap at the Sturgeon Lake South Field. Lateral and top seal rocks are the Montney siltstone-shale facies and the Jurassic Nordegg shales. Shales within the Nordegg and Montney formations are likely source rocks.

Exploration History: The first discovery in this play at Sturgeon Lake South, in 1955, was in a Leduc development well (Shell Oil Company, 1956; Sproule and Boggs, 1956). Sunset Field and Kaybob South were found in 1960 and 1963; the only discovery since then has been a second pool at Sunset in 1975. Exploration may be inhibited by the limited thickness, erratic distribution, and relatively poor seismic definition of the reservoir units.

There are currently 5 pools in the play with a total of 44.4 x 10^6 m^3 OIP (Table 38).

TABLE 38

MONTNEY PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Kaybob South A	34.25	1963
4	Sturgeon Lake South A	4.77	1955
5	Sunset A	4.13	1960
9	Sturgeon Lake South B	1.20	1952
18	Sunset B	0.11	1975

- •Total Discoveries : 5
- •Discoveries in the Top 20 Pools : 5
- •Total Pool Population : 20

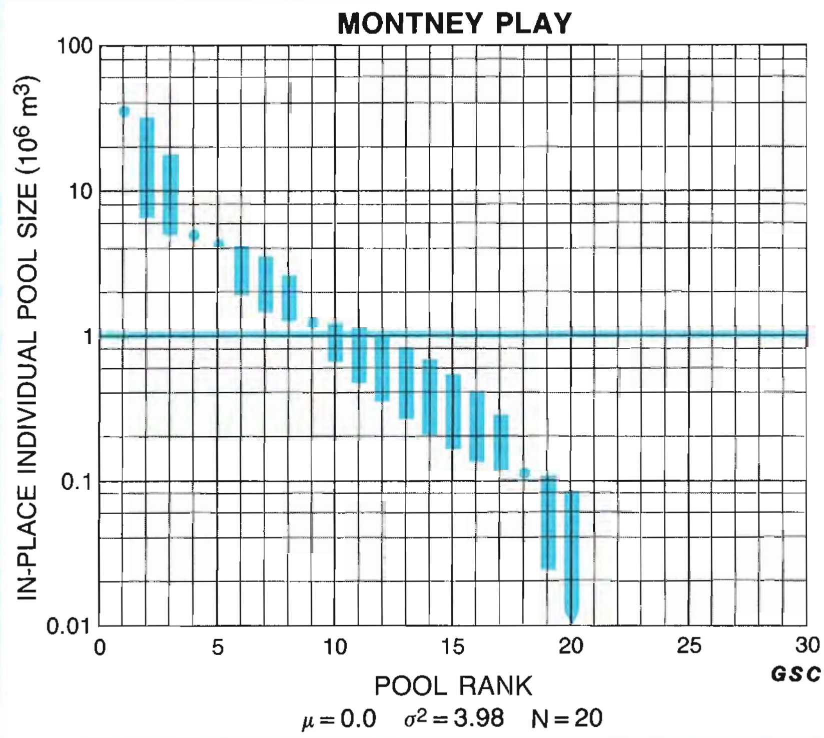


Figure 66

Play Potential: The undiscovered potential for this play is estimated to have a wide range from 22 to 54 x 10^6 m^3 OIP and a median value of 34 x 10^6 m^3 OIP. This potential is estimated to occur in 15 pools, the largest of which has a median value of 14 x 10^6 m^3 (Fig. 66).

DOIG STRUCTURE

Play Definition: This oil play was defined to include all pools and prospects in drape features and anticlines in the Doig Formation. The play area is bounded by the hot line in the Foothills to the west, and the Doig erosional edge to the north, east and south (Fig. 63).

Geology: The play, centred in the Peace River Block, relies on structures that developed from Laramide thrusting near the Foothills and drape over fault structures on the Peace River Arch.

Reservoir sandstones of the Doig Formation are variable in composition and are distributed sporadically throughout the region. They are interbedded with the siltstones and shales that dominate the formation. The sandstones occur in the uppermost parts of the formation, representing part of the regressive transition to the Halfway Formation sandstones. Sandstones are crosslaminated, crossbedded to massive, very fine- to fine-grained, silty, shaly, carbonate cemented and locally coquinoid (Armitage, 1962; Aukes and Webb, 1986; Fulton, 1966). Depositional settings range from distal shelf in the west to shoreline in the east.

Oil pools have areas of less than 1 section, net pay from 2 to 15.5 m and porosity from 6 to 11%; recovery factors average 8%. Top seal rocks are an impermeable facies of Halfway sandstone, whereas seat and lateral seal rocks consist of the surrounding Doig shale and siltstone. Possible source rocks include Doig shale and siltstone, Charlie Lake evaporites and Jurassic Fernie shale.

Exploration History: The play is relatively new, the first oil discoveries having been at Red Creek and Buick Creek in 1976. To date there are 11 pools in the play with a total of 2.3 x 10^6 m^3 OIP (Table 39). The largest pool is at Buick Creek with an initial in-place volume of 1.1 x 10^6 m^3.

Potential: The estimated undiscovered potential for this play has a median expectation of 2 x 10^6 m^3 OIP. This potential is expected to occur in 19 additional pools. The largest undiscovered pool (the second largest predicted pool in the play) should contain between 0.4 and 1.0 x 10^6 m^3 OIP (Fig. 67). The deep parts of the play area to the south and the westernmost part of the area are expected to be gas prone. In the eastern part of the play, in Alberta and around the Peejay-Milligan trend in B.C., the Doig sandstone is overlain by porous Halfway and therefore has no top seal for traps.

TABLE 39

DOIG PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Buick Creek B	1.06	1976
3	Stoddart West A	0.42	1977
4	Buick Creek A	0.34	1977
10	Stoddart West B	0.09	1980
11	Cache Creek A	0.08	1978
12	Fireweed A	0.08	1978
14	2-28-84-21	0.06	1978
15	Red Creek B	0.06	1976
16	Cache Creek B	0.04	1979
19	Fireweed B	0.03	1978
20	B-6-D/94-A-14	0.03	1978

•Total Discoveries : 11
•Discoveries in the Top 30 Pools : 11
•Total Pool Population : 30

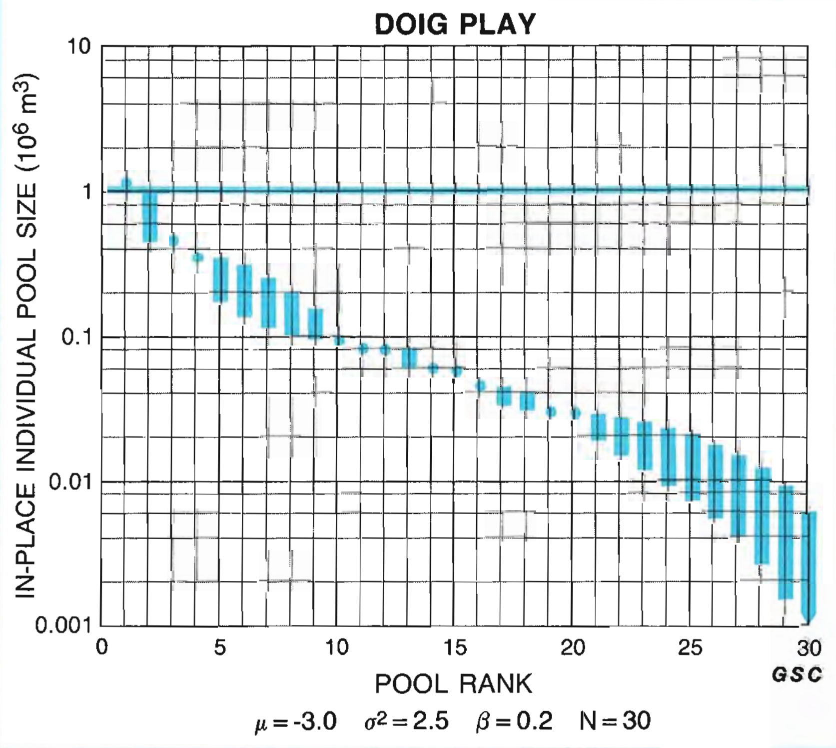


Figure 67

PEEJAY — MILLIGAN

Play Definition: This oil play was defined to include all pools and prospects in sandstones of the "discontinuous" phase of the Halfway Formation where they filled isolated erosion lows on the eroded Doig surface, and were subsequently sealed by overlying evaporitic rocks. The play limits are defined by the erosional (or depositional) edge in the east and north, the change in facies to "continuous" Halfway sandstone to the west and south, and by a transition eastward to an area in which sandstones were deposited in a different setting upon a smooth, uneroded Doig surface (Fig. 64).

Geology: This play, centred in the Peejay-Milligan area, involves a part of the Halfway Formation deposited in a shoreline environment. The reservoirs consist of isolated lenses of quartzose and coquinoid sandstone filling erosional lows on the Doig surface (Fulton, 1966). The sandstones are in the form of elongate, southeast-trending bodies, arranged en echelon with a step-like eastward displacement. This arrangement may reflect fault patterns on the underlying Doig surface.

The crossbedded sandstones are fine- to medium-grained, rounded to subrounded, poorly cemented with carbonate and silica. Chert, collophane pellets, and shell fragments are common. Reservoirs have both intergranular and vuggy porosity and, less commonly, some moldic porosity.

Pools in this play have reservoirs with porosity ranging from 8 to 28%, averaging about 15%; net pay from 0.8 to 5 m; and permeability up to one darcy. The recovery factor averages about 30%, but ranges from 1 to 54%.

Exploration History: Oil was discovered at Milligan Creek in 1957 in a well drilled updip of a gas show. Development of the area proceeded slowly, because of poor surface access and winter-only operations, until 1961. Peejay, Beatton River, Wildmint and Weasel fields were found during this period. Subsequent development of the area proceeded at a steady pace until the mid-1970s.

There are currently 35 discovered pools containing 44 x 10^6 m^3 OIP (Table 40) in this play. The two largest pools are in the Peejay Field and together contain 14.7 x 10^6 m^3 OIP.

Play Potential: The estimated remaining potential for this play has a median expectation value of 5 x 10^6 m^3 OIP. This potential is expected to exist in 15 additional pools, the largest of which is estimated to contain between 1 and 2 x 10^6 m^3 OIP (Fig. 68). Small pools will most likely occur in the immediate area of established fields and, possibly, of the larger pools in less explored areas to the north and southeast.

TABLE 40

PEEJAY — MILLIGAN PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Peejay Unit 2	8.93	1965
2	Peejay Unit 1	5.80	1959
3	Wildmint A1	3.80	1960
4	Weasel Unit 1	3.69	1965
5	Beatton River A	3.42	1958
6	Peejay Pacific Arco	2.85	1964
7	Peejay Unit 3	2.12	1959
8	Weasel Unit 2	1.73	1965
9	Wolf	1.72	1966
10	Milligan Creek A	1.71	1957
12	Peejay West A	1.05	1962
13	Bulrush A	0.94	1963
14	Currant A	0.79	1965
17	Weasel West A	0.63	1971
18	Beatton River C	0.59	1971
19	Wildmint A2	0.58	1962
21	Wildmint B	0.45	1962
24	Elm A	0.34	1971
25	Weasel B	0.33	1965
26	Beatton River D	0.30	1971
27	Bulrush B	0.29	1977
29	Weasel F	0.24	1961

- Total Discoveries : 35
- Discoveries in the Top 30 Pools : 22
- Total Pool Population : 50

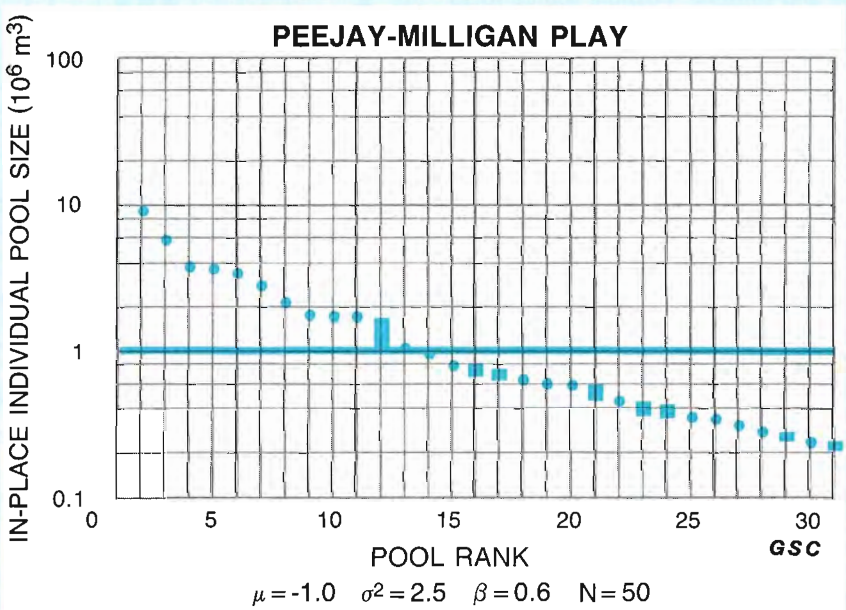


Figure 68

HALFWAY STRATIGRAPHIC

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic traps in Halfway Formation reservoirs. The play area is centred over the Alberta part of the Peace River Arch where Halfway sands occur as an eastward-tapering blanket-like deposit. It is limited to the east and north by the erosional edge of the Halfway Formation. The western boundary is transitional with the Peejay-Milligan play area, and with the eastern limit of continuous Halfway sandstones (Fig. 64).

Geology: The Halfway Formation occurs over a broad arc-shaped area, and contains sandstones that dip and thicken in a southwestern direction, essentially perpendicular to the NW-trending multiple shorelines which are attributed to progradational pulses of sedimentation. The Halfway Formation consists of a sequence of interbedded clastics, evaporites, and carbonates. A composite sedimentation model can be constructed with elements of longshore bar, barrier island, and sabkha environments (Barclay and Leckie, 1986). Within a belt parallel to the shoreline, bar sandstones and coquinoid storm ridge sandstones form reservoirs arranged en echelon at a slight angle to it. Other coquina reservoirs occupy former tidal channels which intersect the bars and trend perpendicular to the shoreline. Lateral seals are finer-grained sandstones and siltstones that were deposited between the reservoir rocks. Top seals are Charlie Lake evaporites. The ages of some of the reservoirs are ambiguous and some pools are currently labelled as Doig Formation. As these pools have the same characteristics as those of Halfway Formation they were included in this play.

The reservoirs commonly contain both oil and gas: they are uncommonly underlain by thin downdip water columns. Bar sandstones consist of fine grained, well sorted and subrounded grains of quartz with good intergranular porosity. Permeabilities are reduced due to secondary quartz overgrowths and anhydrite infill of pores. Coquinas consist of a mixture of sand and dolomite with abundant molds of leached fossils, probably small bivalves. A typical sandstone may produce 1 to 30 m^3/d of oil, whereas a porous coquina might produce 15 to 50 m^3/d.

Pools have areas of 1/4 to 8 sections; net pays ranging from 1 to 15 m; porosity in sandstones ranging from 5 to 12% and increasing to 15 to 20% in the coquina facies; and water saturation from 12 to 70%, averaging about 40%. Recovery factor is as low as 1% but more commonly is up to 15%.

Oil source rocks are most likely the shales of the underlying Doig and Montney formations.

TABLE 41

HALFWAY STRATIGRAPHIC PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Spirit River Doig A	7.20	1983
2	Wembley Halfway B	5.73	1978
3	Grande Prairie Halfway A	4.00	1982
5	Progress Halfway B	2.35	1982
15	Spirit River Halfway D	0.72	1983
16	Gordondale Halfway B	0.69	1979
18	Wembley Doig A	0.60	1982
21	Wembley Halfway E	0.49	1983
23	Wembley Halfway D	0.45	1983
24	Hythe Halfway A	0.41	1981

•Total Discoveries : 23
•Discoveries in the Top 30 Pools : 10
•Total Pool Population : 90

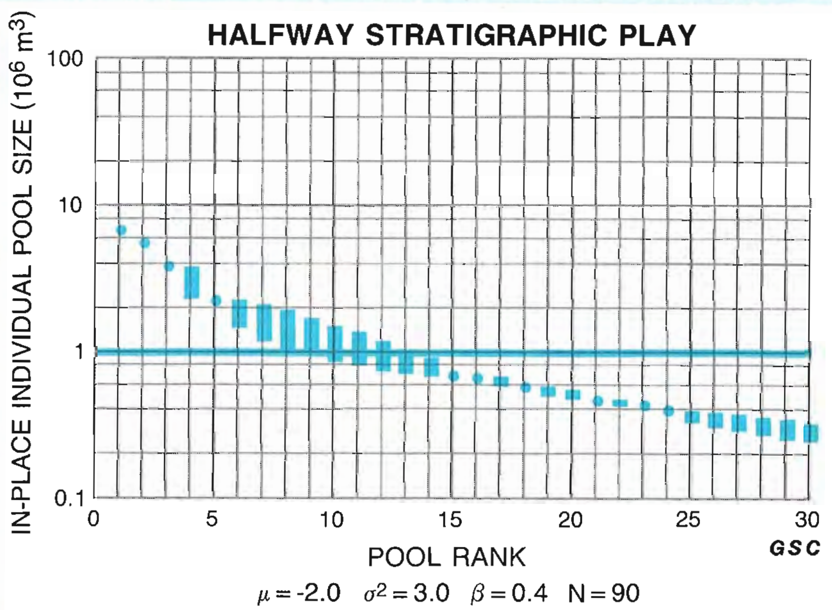


Figure 69

Exploration History: Exploration resulted in the discovery of gas at Teepee Creek in 1972 followed by the first oil discovery at Pouce Coupe in 1975. Oil exploration accelerated during the 1980s, with significant success occurring in 1984 when several new pools were discovered and reserves were doubled. A total of 23 pools in 10 fields, with 24 x 10^6 m^3 OIP had been found by the end of 1984 (Table 41).

Play Potential: The undiscovered potential in this play was estimated to have a median value of 22 x 10^6 m^3 OIP distributed in 67 additional pools. The 10 largest undiscovered pools range from 0.8 to 4 x 10^6 m^3 OIP (Fig. 69). Potential reservoir targets include longshore bars or sand waves, lagoonal bars, tidal channel deltas, eolian dunes, and sabkha algal carbonates. There is also the possibility of oil being trapped along the Halfway erosional edge, in a situation like the gas trap at Teepee Creek.

HALFWAY DRAPE

Play Definition: This oil play was defined to include all pools and prospects in sandstones of the "continuous" facies of the Halfway Formation draped over horst blocks in the Peace River Arch and Embayment. The play area is centred in the Peace River Township Block but extends to the north and south, limited to the west by the Foothills and to the east by the Halfway Stratigraphic and Peejay-Milligan plays (Fig. 64).

Geology: The northern and southern play boundaries are portions of the Halfway erosional edge. At these northern and southern limits, Peace River Arch tectonic effects are minimal and traps are caused by subtle diagenetic and facies changes within the continuous sandstone. These subtle traps also influence petroleum distribution in the central draped portions of the play. Although the southern part of the area is gas-prone, some potential for oil is anticipated.

The reservoir rock consists of quartzose sandstone, partially cemented with carbonate. The sandstones are fine grained and poorly sorted; they have a high percentage of interstitial clay. They contain less skeletal fragments than in the discontinuous facies of the formation (Fulton, 1966): correspondingly, porosities and permeabilities are lower. Oil pools have net pay ranging from 1 to 10 m; porosity values of 8 to 16%; and recovery factors averaging about 9% but ranging from 1 to 20%.

Exploration History: The first oil pool in this play was discovered during development drilling in the Boundary Lake Field in 1960. No new oil pools were added until the 1970s when new pools were discovered at Boundary Lake North, Oak, Flatrock, Montney, Airport and Two Rivers.

The play currently contains 6.6 x 10^6 m^3 OIP, distributed in 12 pools, the largest of which contains 2.2 x 10^6 m^3 OIP (Table 42).

Play Potential: The estimates of undiscovered potential for this play have a median expectation of 4 x 10^6 m^3 OIP. This potential is expected to occur in 23 additional pools, the largest of which is estimated to contain about 1 x 10^6 m^3 OIP (Fig. 70).

TABLE 42

HALFWAY DRAPE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Boundary Lake A	2.19	1960
2	Oak B	1.84	1973
4	Boundary Lake A	0.67	1960
7	5-3-84-17	0.42	1978
8	Two Rivers B	0.41	1978
12	Flatrock E	0.25	1977
14	Montney C	0.21	1978
16	Flatrock F	0.17	1982
17	Boundary Lake North D	0.17	1973
18	Boundary Lake North C	0.16	1972
25	Boundary Lake A	0.08	1980
26	Airport B	0.07	1978

•Total Discoveries : 12
•Discoveries in the Top 30 Pools : 12
•Total Pool Population : 35

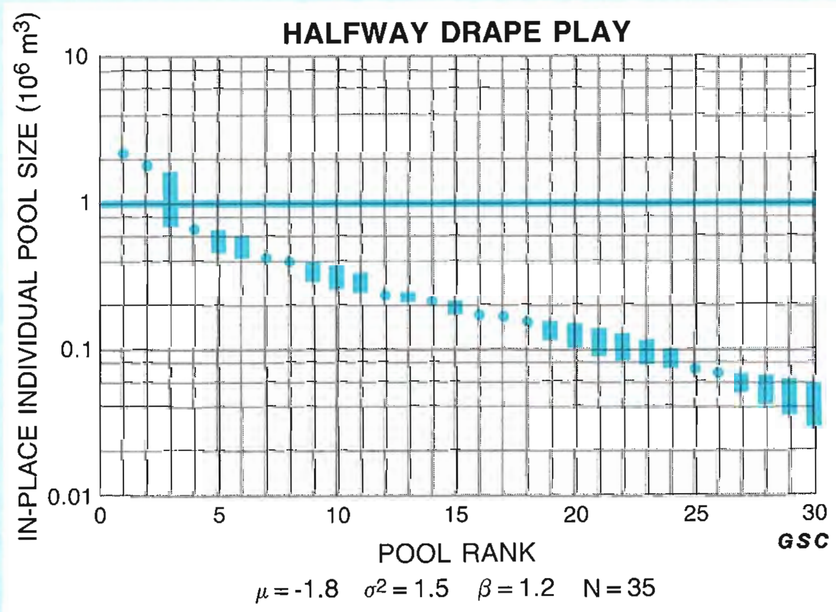


Figure 70

CHARLIE LAKE SANDSTONE

Play Definition: This oil play was defined to include all pools and prospects in the several sandstone members of the Charlie Lake Formation in the form of porosity pinchouts, unconformity traps, and drape structures. The play is restricted to the present distribution of the Charlie Lake Formation on the plains, the limits of which are the disturbed belt to the west, and the erosional edges to the east, north and south (Fig. 65).

Geology: Reservoirs occur in shallow marine sandstones deposited in a variety of supratidal to subtidal environments in an evaporitic setting. Subenvironments of sand deposition range from eolian to sabkha to shoreface. Reservoirs are sealed by anhydrite, evaporitic dolomite, siltstone and mudstone.

Trapping geometries include several possibilities: facies pinchouts, diagenetic traps, hydrodynamic traps, erosional truncation by the post-Triassic unconformity or smaller intrasystem diastems, and structural traps caused by drape over horsts or by related fault-cutoff traps.

Pools in this play have reservoirs with net pay values ranging from 0.4 to 3 m, porosities from 6 to 22%, water saturations typically at 20% but ranging from 6 to 60%, and average recovery factors of 20%. Pool areas range from 1/4 to 4 sections.

Exploration History: Early exploration, following the route of the Alaska Highway, resulted in the 1952 discovery of the largest pool, the Fort St. John Charlie Lake A pool, with 1.1 x 10^6 m^3 OIP. A second phase of discoveries progressed almost continuously from 1967 to the mid-1980s. Total volume of in-place oil in the play is 7 x 10^6 m^3, distributed in 32 discovered pools. Pool sizes are typically 0.1 to 0.2 x 10^6 m^3 OIP, and range from 0.01 to 1.1 x 10^6 m^3 OIP (Table 43).

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 6 x 10^6 m^3 OIP. This potential is expected to occur in 68 undiscovered pools, the largest of which would contain 0.3 to 0.4 x 10^6 m^3 OIP (Fig. 71). This potential may exist anywhere in the region of Charlie Lake deposition. The small size of targets limits the use of seismic methods, necessitating detailed geologic analysis for exploration.

TABLE 43

CHARLIE LAKE SANDSTONE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Fort St. John A	1.11	1952
2	Boundary Lake Cecil B	0.59	1972
3	Two Rivers Siphon	0.58	1967
4	Cecil Lake A	0.46	1976
5	Boundary Lake Cecil A	0.43	1971
6	Cecil Lake North Pine A	0.40	1972
7	Cecil Lake North Pine C	0.39	1976
9	Fort St. John A	0.30	1952
14	Cecil Lake North Pine A	0.23	1972
18	Stoddart Cecil A	0.19	1969
23	Cecil Lake Cecil C	0.16	1983
24	Squirrel North Pine A	0.16	1978
25	Cecil Lake North Pine A	0.16	1972
26	Eagle North Pine A	0.15	1977
28	Stoddart Cecil B	0.14	1976

•Total Discoveries : 32
•Discoveries in the Top 30 Pools : 15
•Total Pool Population : 100

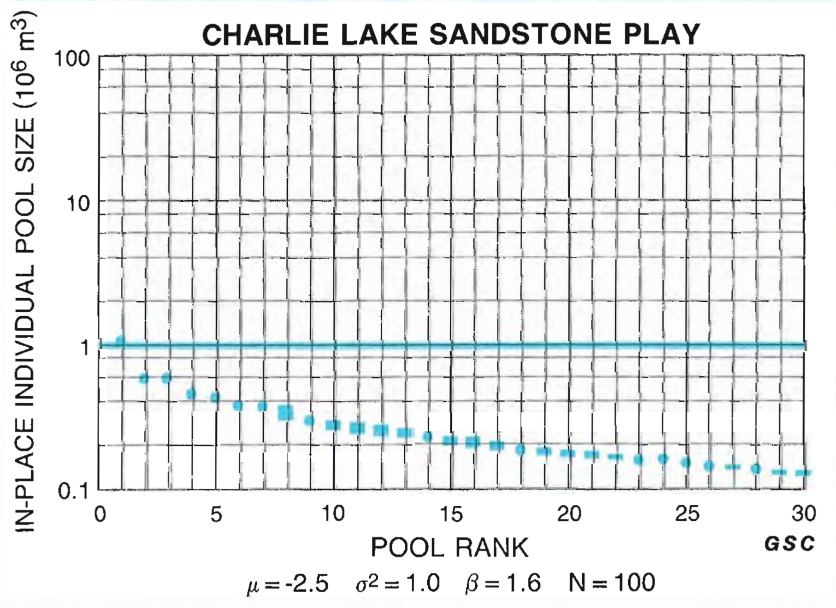


Figure 71

BOUNDARY LAKE

Play Definition: This oil play was defined to include all pools and prospects in porous algal carbonate reservoirs in the Boundary Lake Member of the Charlie Lake Formation. The play area straddles the British Columbia-Alberta border and is limited to the area of deposition of the Boundary Lake Member (Fig. 65).

Geology: The Boundary Lake Member (Armitage, 1962) reservoirs are made up of stromatolitic algal and skeletal limestone or dolostone deposited in the upper part of the Charlie Lake Formation (Roy, 1972), of Carnian age. It was deposited within a complex of evaporitic and redbed units, interpreted to have formed in shallow supratidal to intertidal environments encompassing lagoon, tidal flat, and sabkha sedimentation.

The traps are interpreted as stratigraphic facies pinchouts of reservoir carbonates into Charlie Lake evaporites by Armitage (1962). However, other workers (e.g. Roy, 1968, 1972) interpret the carbonate lenses as erosional remnants created by post-Boundary Lake erosion. In some cases distribution of oil and gas within the traps is influenced by high-angle normal faulting. Particularly notable are the large-throw Boundary Lake Fault (Sikabonyi and Rodgers, 1959) and related minor faults in the Boundary Lake Field (Roy, 1972).

Pools in this play have pool areas ranging from less than 1 section to 42 sections; net pay values ranging from 0.6 to 6 m; excellent intergranular and vuggy porosities ranging from 12 to 23%; excellent permeabilities; and typical recovery factors of 10 to 15%.

Exploration History: The Boundary Lake Field, discovered in 1955, dominates the reserves in this play, and is a principal Triassic producer in Western Canada. The Boundary Lake pools were discovered and developed in the first phase of exploration, extending to the mid 1960s. The Pouce Coupe South, Valhalla, and Flatrock pools were found in the early 1970s phase, adding 12 x 10^6 m^3 OIP (Table 44). Bonanza, Braeburn, and Mica pools were found in a late 1970s to early 1980s phase. Total reserves are 108 x 10^6 m^3 OIP in 25 pools (Table 44).

TABLE 44

BOUNDARY LAKE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Boundary Lake	42.83	1957
2	Boundary Lake	24.84	1955
3	Boundary Lake South E	9.89	1964
4	Bonanza A	6.03	1977
5	Boundary Lake	5.14	1959
6	Pouce Coupe South B	3.90	1980
8	Boundary Lake South C	3.01	1968
9	Boundary Lake South H	2.91	1973
10	Pouce Coupe South A	2.55	1971
11	Boundary Lake	2.26	1955
14	Boundary Lake	1.63	1955
16	Boundary Lake	1.35	1960
30	Valhalla B	0.51	1972

- Total Discoveries : 25
- Discoveries in the Top 30 Pools : 13
- Total Pool Population : 70

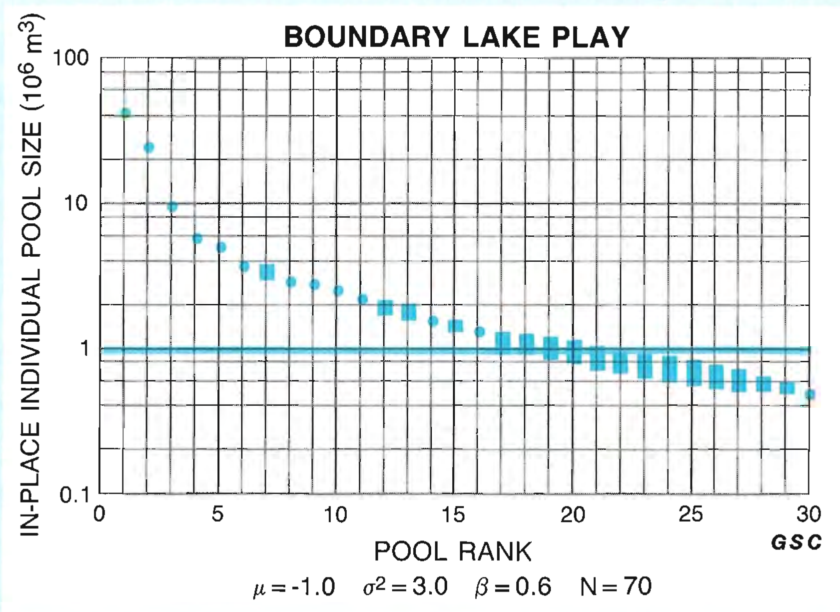


Figure 72

Play Potential: The estimate of undiscovered potential for this play has a median expectation value of 25 x 10^6 m^3 OIP. This potential is expected to occur in 45 additional pools, the largest of which is estimated to contain about 4 x 10^6 m^3 OIP (Fig. 72).

Present exploration for oil is focused on the Rycroft, Valhalla, Bonanza, Henderson Creek, and Gold Creek areas and the eastern part of the Peace River Township Block of British Columbia.

CHARLIE LAKE ALGAL

Play Definition: This oil play was defined to include all pools and prospects in porous algal carbonate reservoirs in the Charlie Lake Formation, with the exception of the Boundary Lake Member. Play limits are defined by the erosional edges of the other members of the Charlie Lake to the east, north and south, and by the transition to offshore sandstone facies westward near the western townships of the Peace River Township Block (Fig. 65).

Geology: This play is essentially the same as the Boundary Lake play but restricted to algal carbonates in other parts of the Charlie Lake Formation. The principal trapping style involves facies pinchouts: subordinate styles include erosional truncation and structural traps. Carbonate members formally recognized in northeastern British Columbia include the Mica and Nancy members. Also included are informal units in Alberta such as the Braeburn, LaGlace, Demmit and Cutbank members.

Reservoirs in this play are generally thin and laterally discontinuous; their distribution is difficult to predict. Net pays range from 0.8 to 13.4 m, porosities from 8 to 27%, in pools usually assigned 64 ha[1] in area.

Exploration History: Most pools assigned to the play were discovered between 1976 and 1982. Nine pools have been discovered, with 2.6 x 10^6 m^3 OIP. Pools range in size from 0.03 to 1.5 x 10^6 m^3 OIP (Table 45). The reservoirs typically are a secondary or tertiary exploration target, because of their unpredictable distribution and small pool size.

Play Potential: The estimate of undiscovered potential for this play has a median expectation of 4 x 10^6 m^3 OIP, expected to occur in 36 additional pools. The largest undiscovered pool is estimated to contain between 0.5 and 1 x 10^6 m^3 OIP, with most expected to be in the range of 0.05 to 0.25 x 10^6 m^3 OIP (Fig. 73). Pools are expected to be distributed throughout the area of deposition of the Charlie Lake Formation, with greatest potential in the lesser explored areas west and south of the present exploration trend. In addition, a number of productive carbonate members may already have been drilled and bypassed during exploration for other targets. Exploration in this play requires detailed stratigraphic analysis of each individual member. Seismic analysis is generally incapable of resolving the distribution of these units.

TABLE 45

CHARLIE LAKE ALGAL PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Elmworth Charlie Lk A	1.50	1979
4	Mica A	0.39	1976
7	Knopcik A	0.22	1981
11	Velma A	0.14	1976
12	Elmworth B	0.11	1979
15	Progress A	0.09	1982
16	North Pine B	0.08	1978
20	Wembley A	0.05	1981
26	Valhalla A	0.03	1981

- **Total Discoveries : 9**
- **Discoveries in the Top 30 Pools : 9**
- **Total Pool Population : 45**

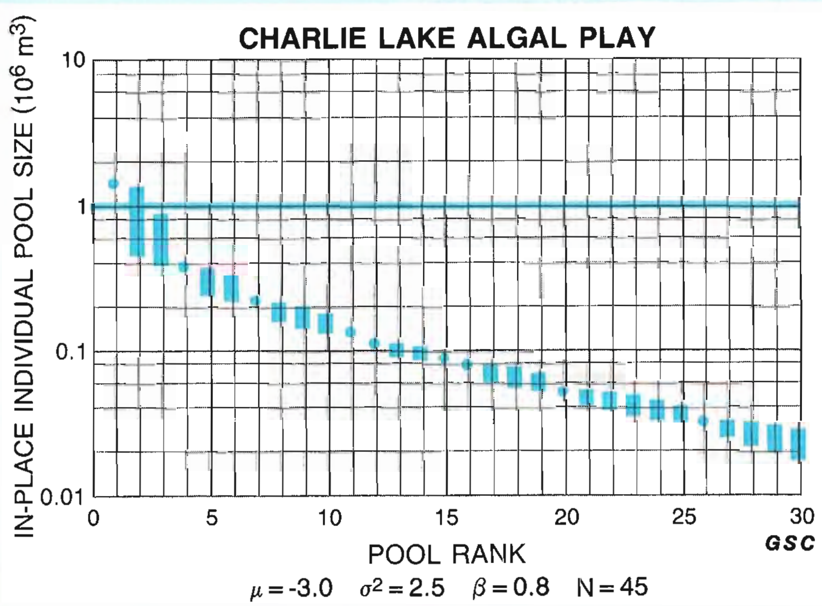


Figure 73

[1]Pool areas are reported in hectares for that part of British Columbia outside of the Peace River Township Block.

INGA STRUCTURE

Play Definition: This oil play was defined to include all pools and prospects in reservoirs within the Charlie Lake, Halfway, and Baldonnel formations that occur in anticlinal traps. The play area is restricted to the western part of the plains area of preserved Triassic rocks, where anticlinal folding occurs, adjacent to the Foothills (Fig. 65).

Geology: In pools discovered to date, oil reservoirs occur in the sandstones of Inga, Coplin and Blueberry members of the Charlie Lake Formation, and in Baldonnel carbonates. Gas reservoirs of comparable geometry occur in other units such as the Pingel and 'A' Marker members of the Charlie Lake, the Halfway sandstone, and in the Pardonet carbonate. The possibility of oil pools in these units is within this play.

The Charlie Lake sandstones (informally termed Stray Sands due to their irregular distribution) are shallow marine to nearshore sandstones deposited on a shelf within an evaporitic — redbed setting. The Halfway Formation in this region is a fine grained, carbonate-cemented, quartzose sandstone of shallow marine, possibly shoreface, origin. The Baldonnel and Pardonet formations consist of normal to restricted marine carbonates and siltstones (Barss and Montandon, 1981; Bever and McIlreath, 1984).

Reservoir characteristics of these formations vary considerably within the play area; however, they generally have low conventional porosity and commonly show enhancement of permeability by fracturing on the crests of folds.

Pools in this play have areas from 65 to 5200 ha, net pay from 1 to 9 m, average porosity values from 5 to 14%, water saturation from 11 to 49% and recovery factors averaging about 15% but ranging from 2 to 41%.

Seal rocks consist principally of the overlying Jurassic Fernie shales, as well as numerous local seal units within the Halfway to Pardonet interval, particularly the Charlie Lake evaporite beds. Source rocks identified include the Pardonet and Baldonnel formations; and Fernie shales (Barss and Montandon, 1981). Other potential source beds include the Charlie Lake evaporites and Doig-Montney shales.

Exploration History: Many of the discoveries in this play were made while exploring for deeper targets in the Carboniferous during the late 1950s to early 1960s. Oil was discovered in the Baldonnel at Inga Field in 1962. Drilling on a seismic high in the Debolt Formation (Carboniferous), similar to one at the nearby Blueberry oil field, led to the discovery of oil in the Charlie Lake Inga Member in 1966 (Fitzgerald and Peterson, 1967). Other significant discoveries include the Nig Creek (1976) and Birch (1978) fields in the Baldonnel Formation. Recently oil has been discovered in small pools adjacent to the Inga Field.

The total volume of in-place oil discovered to date is 21 x 10^6 m^3 distributed in 12 pools, with the bulk of the reserves (17.1 x 10^6 m^3 OIP) being in the Inga Field (Table 46). Pools in the play typically range in size from 0.02 to 0.26 x 10^6 m^3 OIP.

Play Potential: The estimate of undiscovered potential for this play has a median value of 8 x 10^6 m^3 OIP (Fig. 74), expected to occur in 23 additional pools. The largest undiscovered pool is expected to be in the range of 1 to 3 x 10^6 m^3 OIP. Several discoveries are expected in the 0.2 to 2 x 10^6 m^3 OIP range, with the remainder estimated to be less than 0.1 x 10^6 m^3 OIP.

TABLE 46

INGA STRUCTURE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Inga-Inga	8.26	1966
2	Inga-Inga A	6.75	1966
3	Birch-Baldonnel C	3.35	1978
6	Inga-Inga A	1.05	1966
7	Inga-Inga A	0.95	1966
15	Nig Creek-Baldonnel A	0.22	1976
18	Inga-Baldonnel A	0.12	1962
19	2-12-85-85-Coplin	0.12	1973
23	Halfway-Blueberry	0.07	1966
25	Inga-Inga B	0.05	1980
26	16-19-85-23-Inga	0.04	1979
30	6-29-84-23-Inga	0.02	1982

- Total Discoveries : 12
- Discoveries in the Top 30 Pools : 12
- Total Pool Population : 35

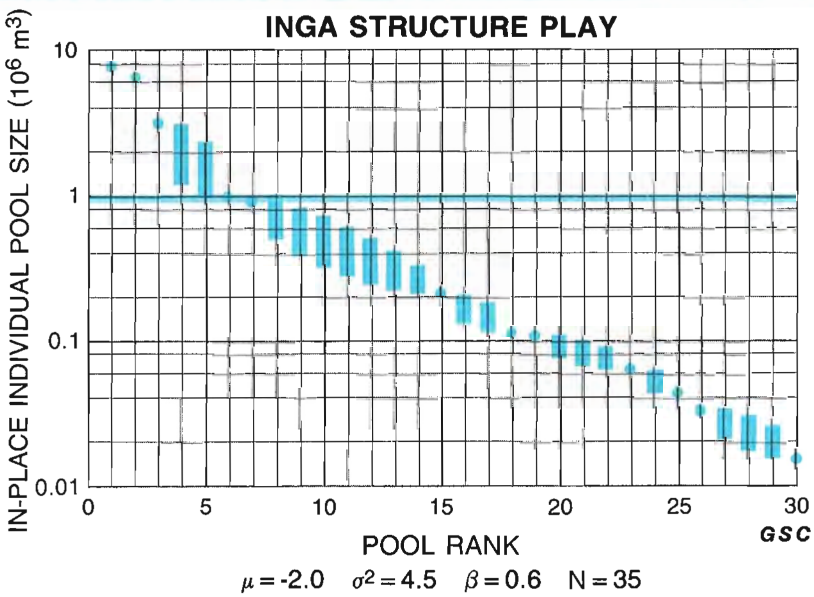


Figure 74

CENTRAL AND SOUTHERN ALBERTA DISTRICT

This District occupies the area between the Peace River and Sweetgrass Arches, east of the Foothills and west of the Jurassic erosional edge. Throughout much of Central Alberta the combined effect of pre-Jurassic and pre-Cretaceous erosion removed most Triassic strata from this portion of the Alberta Basin (Fig. 62). Only erosional remnants of what was once an extensive Jurassic cover now provide exploration targets (Fig. 75).

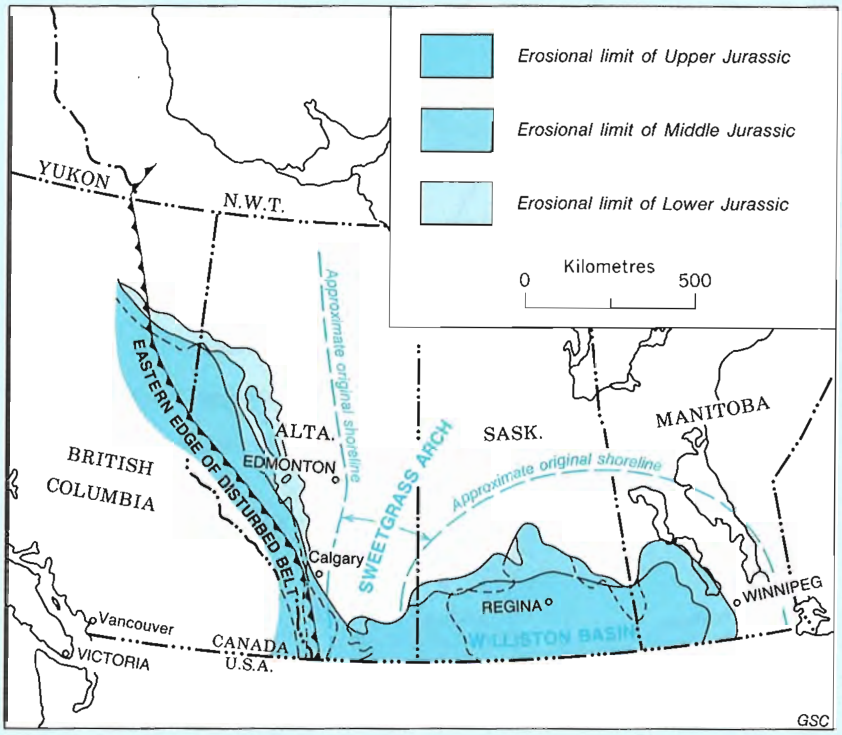


Figure 75. Distribution of Jurassic Rocks, Western Canada Sedimentary Basin (after Springer *et al.*, 1964).

DEPOSITIONAL AND TECTONIC HISTORY

Most Jurassic sediments were deposited in shelf conditions over the craton and in the adjacent miogeocline. Three major depositional cycles comprising sediments of the Fernie Group (Table 47) are represented in the sedimentary record below Upper Jurassic foreland sediments.

Each cycle, consisting mainly of clastic sediments, is characterized by a coarsening- and shallowing-upward facies profile. Evidence of shallowing in the sediments includes increase in grain size, frequency of sedimentary structures indicative of high energy, and a decrease in organic carbon content.

In this district the first cycle consists of two basin-fill events; the first is represented by Sinemurian Nordegg Member deposits. In the west, the Nordegg is primarily shale and phosphatic shale and siltstone. In the east, a basal shale passes upward into carbonate and quartz-chert sandstone facies. The second basin-fill episode consists of siltstone, limestone and shale of the Red Deer Member (Pliensbachian) in west central Alberta. The J1 channel fill sandstones (Hopkins, 1981) productive in the Gilby-Medicine River play may have been deposited during this cycle (Table 47).

The second cycle is represented by deposition of the Toarcian (to Aalenian?) Poker Chip (or Paper) Shale overlain by Lower Bajocian Rock Creek Member sandstones. The Poker Chip Shale is dark shale with local sandstone or conglomerate lenses. It was deposited on a wide shelf under conditions interpreted to be anaerobic (Poulton, 1984; Springer et *al.*, 1964; Stronach, 1984). The Rock Creek Member consists of black shale with interbeds of calcareous or ferruginous sandstone and sandy limestone and an eastern facies of fine grained, quartzose sandstone and siltstone.

The early trangressive portion of the third cycle consists of phosphatic, pyritic, fossiliferous shale, or pebbly sandstone beds overlain by fossiliferous concretionary limestone beds. The thickest portion of the third cycle is dominated by shale, including anaerobic, restricted-shelf or basin facies of dark, organic rich, silty shale of the Highwood Member (Middle-Late Bajocian) (Stronach, 1984). These shales are gradationally overlain by Bathonian Grey Beds shale, locally containing progradational pulses of higher energy clastics.

The Columbian orogeny profoundly affected sedimentation in the Late Jurassic by alteration of the basin shape and change to western provenance. Foreland Basin filling by marine sediments (Green Beds, Fernie Shale, and Passage Beds) of the eastwardly migrating foredeep trough began in the Oxfordian and was succeeded by Kootenay-Nikanassin continental sedimentation.

PETROLEUM GEOLOGY

The Jurassic of the Central and Southern Alberta District contains approximately 0.5% of the in-place and recoverable conventional oil reserves in the Western Canada Sedimentary Basin. The oil pools occur in sandstone reservoirs under the following conditions: in stratigraphic traps developed by selective deposition of sandstones on uneven erosional surfaces, by isolation of sandstone bodies by erosion, or by updip depositional or diagenetic porosity pinchouts. In some cases, drape of the Jurassic reservoir over Paleozoic erosional remnants creates the hydrocarbon traps. Seal rocks are either Jurassic or Cretaceous shales, siltstones, or impermeable sandstones. Potential source rocks may be Carboniferous, Jurassic, or Cretaceous shales.

EXPLORATION PLAYS

The Jurassic oil pools were assigned to three exploration plays in the Central and Southern Alberta District (Fig. 76). No conceptual plays were evaluated, as the limited distribution and thickness of the Jurassic section severely constrains its potential.

Established Plays

Of the three established plays, two have a sufficient number of discovered pools to

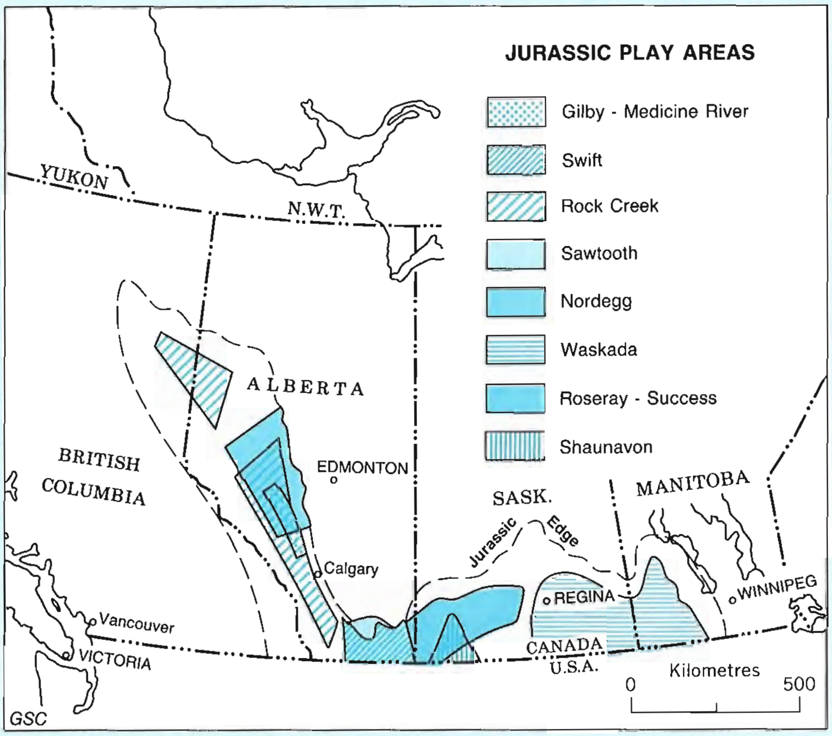


Figure 76. Jurassic Play Areas.

EPOCH	BASIN TYPE	ALBERTA BASIN CYCLES	ALBERTA BASIN: PEACE RIVER	ALBERTA BASIN: CENTRAL AND WESTERN ALBERTA	WILLISTON BASIN-SWEETGRASS ARCH: SWEETGRASS ARCH	WILLISTON BASIN-SWEETGRASS ARCH: WILLISTON BASIN	WILLISTON BASIN CYCLES
EARLY CRET	FORELAND BASIN	4	MONTEITH/ NIKANASSIN	NIKANASSIN/ KOOTENAY		? Upper Success ?	4
LATE JURASSIC	FORELAND BASIN	4	Transition Beds (FERNIE)	Passage beds (FERNIE)			4
LATE JURASSIC	FORELAND BASIN	4		Shale	SWIFT (ELLIS GROUP)	Lower Success	4
LATE JURASSIC	FORELAND BASIN	4	Green Beds	Green Beds	SWIFT	MASEFIELD (VANGUARD GROUP)	4
MIDDLE JURASSIC	CRATONIC SEA-MIOGEOCLINE	3				ROSERAY	3
MIDDLE JURASSIC	CRATONIC SEA-MIOGEOCLINE	3		Grey Beds	RIERDON	RUSH LAKE	3
MIDDLE JURASSIC	CRATONIC SEA-MIOGEOCLINE	3		HIGHWOOD	SAWTOOTH	SHAUNAVON	2
MIDDLE JURASSIC	CRATONIC SEA-MIOGEOCLINE	2	? ROCK CREEK ?	ROCK CREEK		GRAVELBOURG	2
MIDDLE JURASSIC	CRATONIC SEA-MIOGEOCLINE	2		Poker Chip Shale		WATROUS/ AMARANTH	1
EARLY JURASSIC	CRATONIC SEA-MIOGEOCLINE	2	Shale	RED DEER		?	1
EARLY JURASSIC	CRATONIC SEA-MIOGEOCLINE	1	NORDEGG	Shale			1
EARLY JURASSIC	CRATONIC SEA-MIOGEOCLINE	1		NORDEGG AND J-1?			1
EARLY JURASSIC	CRATONIC SEA-MIOGEOCLINE	1	Basal Fernie				1
EARLY JURASSIC	CRATONIC SEA-MIOGEOCLINE	1	Brown beds				1

GSC

Table 47. Table of Formations, Jurassic, Western Canada Sedimentary Basin.

have enabled analysis by the discovery process model. Only those two plays are reported in a quantitative analysis.

The **Nordegg** Play of central Alberta includes pools and prospects where oil is stratigraphically trapped in sandstones of the lowest member (Nordegg) of the Fernie Group. The traps were created during the Lower Cretaceous by the erosional isolation of sand bodies in headlands or outliers developed at the strongly incised erosional surface that defines the subcrop of the Nordegg Member. The reservoir facies sandstones are shallow marine deposits that were erratically cemented by dolomite or phosphatic minerals. Porosities range from 12 to 18%, water saturation averages 35%, and net pay ranges from 3 to 12 m. Six pools have been discovered containing 3.2×10^6 m^3 OIP.

GILBY — MEDICINE RIVER

Play Definition: This oil play was defined to include all pools and prospects that occur in Jurassic and Lower Cretaceous sandstones filling channels or valleys carved into the Paleozoic surface and sealed by impervious shales of Jurassic age. The play area is a narrow belt in south-central Alberta trending north-northwest along the Jurassic erosional edge as far north as the town of Drayton Valley and as far south as Calgary (Fig. 76).

Geology: The Gilby-Medicine River play involves a complex of erosional valleys and headlands with a variety of channel-fill units. Stratigraphically trapped pools produce from valley-fill sands, isolated Jurassic sandstone headland remnants, and sands draped over headland remnants.

The reservoir facies were deposited during the Early and Middle Jurassic, when sediments were craton-derived, but may also include younger Late Jurassic "Orogenic Facies" molasse sediments that were sourced from the Columbian Orogen to the west.

A complex drainage pattern existed where post-Paleozoic valleys cut into the Carboniferous surface, with subsequent stages of valley cutting and filling occurring during the Jurassic. Some of these deposits were then sculpted by Cretaceous erosion with the consequence that, without paleontological control, the preserved stratigraphy is difficult to interpret. Depositional environments proposed in the literature range from fluvial, to brackish near-shore, to marine. The structural reversals on the regional dip result from drape over underlying Upper Devonian Leduc-Rimbey reefs, and paleotopography resulting from post-Paleozoic erosion of the Carboniferous. Localization of the main valley trends may be inherited from underlying structural trends, or from preferential erosion of softer Carboniferous units.

Oil pools occur in Lower Jurassic J1, and Middle Jurassic to Lower Cretaceous J2 and J3 valley-fill units. Oil also occurs in erosional headlands of Lower Jurassic age. J2 units are porous, fine grained, very mature quartz arenites in contrast to the less porous J3 immature, kaolinitic chert sandstones and lithic sandstones with poorer porosity. The Detrital or J1 rocks are chert breccias and sandstones (Hopkins, 1981; Rall, 1980).

Most pools are small, with quarter section area assignments, though the largest pool is 7 sections. Net pays range from 2 to 15 m, porosities from 7 to 24%, and recovery factors from 1 to 17%. The average recovery factor is 10%.

Exploration History: Exploration in this mature play has occurred in three phases: Late 1950s — early 1960s, mid1970s, and early 1980s. The Medicine River Field was found in 1956, followed by Gilby in 1958, and Sylvan Lake in 1960. By the end of 1984 a total volume of 49 x 10^6 m^3 OIP had been discovered in 23 pools (Table 48).

Play Potential: The estimate of undiscovered potential of this play has a median expectation value of 30 x 10^6 m^3 OIP, distributed in 22 additional pools (Fig. 77). The largest undiscovered pool is expected to contain about 5 x 10^6 m^3 OIP. Stratigraphic complexities hinder understanding of the play, but also provide continued exploration opportunities.

TABLE 48

GILBY — MEDICINE RIVER PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Gilby B	12.20	1958
2	Medicine River C	9.09	1961
3	Medicine River D	8.14	1962
4	Medicine River A	5.15	1956
6	Sylvan Lake A	4.18	1961
13	Gilby F	1.76	1961
14	Sylvan Lake C	1.59	1960
18	Medicine River B	1.16	1961
22	Sylvan Lake N	0.79	1982
23	Sylvan Lake E	0.73	1963
24	Medicine River K	0.72	1974
26	Gilby I	0.61	1973
28	Gilby J	0.44	1974
29	Gilby L	0.44	1982
30	Sylvan Lake D	0.43	1962

- •Total Discoveries : 23
- •Discoveries in the Top 30 Pools : 15
- •Total Pool Population : 45

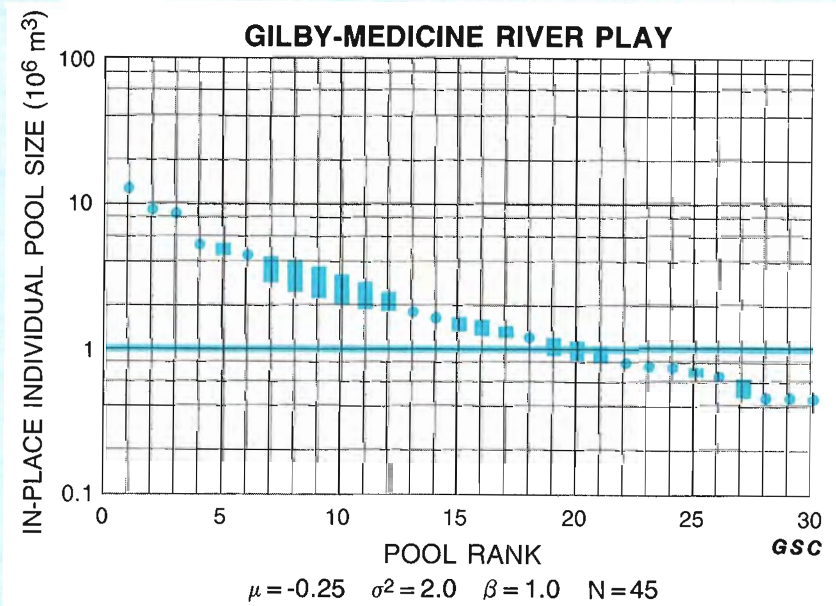


Figure 77

ROCK CREEK

Play Definition: This oil play was defined to include all pools and prospects in Rock Creek marine sandstones at updip porosity pinchouts, in erosional remnants, and in channel fill units. The play area trends northwest in a belt approximately 150 km wide, west of the Jurassic erosional edge, from the International Boundary to northeastern British Columbia (Fig. 76).

Geology: The precise age of the Rock Creek sandstone in the subsurface is unknown, but it may be equivalent to the Middle Jurassic (Bajocian), formally defined Rock Creek Member in outcrop.

The Rock Creek was deposited on a sandy shallow marine shelf strongly influenced by storm and tidal activity. Pre-Cretaceous erosion removed much of the eastern deposits and left erosional outliers along the eastern subcrop limit. The Rock Creek, in west-central Alberta, consists of two coarsening-upward cycles of quartzose and coquinoid sandstones (Marion, 1984). The sandstones are mature, well-sorted, and fine grained, characterized by flasers, ripple marks, and crossbeds. Diagenetic alterations include quartz overgrowths, calcite cement, and dolomitization of shells in the coquinas. The best reservoirs are present at the tops of the cycles.

Pools are typically less than 1 section in area. Net pays range from 1 to 20 m, porosities from 5 to 20%, water saturations from 20 to 60%, and recovery factors from 1 to 10%.

The main trap type appears to be permeability pinchouts of porous sands (possibly shallow bars) into less permeable silts or shales. Other recognized traps include cuesta-like paleohighs beneath the Cretaceous unconformity, truncated sandbars, channel-fill sands, and diagenesis-related porosity pinchouts.

Exploration History: This play is undergoing active exploration and has seen numerous small discoveries since 1979. It is expected that activity will continue. A total of 2.7 x 10^6 m^3 OIP has been discovered in 14 pools (Table 49).

Play Potential: The estimate of undiscovered potential for this play has a median value of 4 x 10^6 m^3 OIP, distributed in 21 additional pools. In this play the analysis suggests that the largest pool (0.8-5 x 10^6 m^3 OIP) has yet to be discovered (Fig. 78). Difficulties in exploration, however, include a gas-prone tendency in the play area, limited reservoir development, and unpredictable reservoir geometry. Definition of the age, and correct correlation of the Rock Creek subsurface units with the exposed member, is required for the correct interpretation of the paleogeography and sandstone distribution, essential to the exploration process.

TABLE 49

ROCK CREEK PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
3	Pembina A	0.69	1979
5	Pembina F	0.43	1982
7	Pembina B	0.24	1980
8	Pembina E	0.22	1982
9	Carrot Creek A	0.21	1979
10	Cyn-Pem G	0.18	1981
12	Willesden Green C	0.14	1983
13	Cyn-Pem C	0.13	1981
14	Normandville A	0.12	1956
15	Ferrier B	0.11	1982
16	Pembina G	0.10	1982
21	Cyn-Pem I	0.06	1983
22	Willesden Green B	0.05	1982
30	Cyn-Pem J	0.02	1983

- •Total Discoveries : 14
- •Discoveries in the Top 30 Pools : 14
- •Total Pool Population : 35

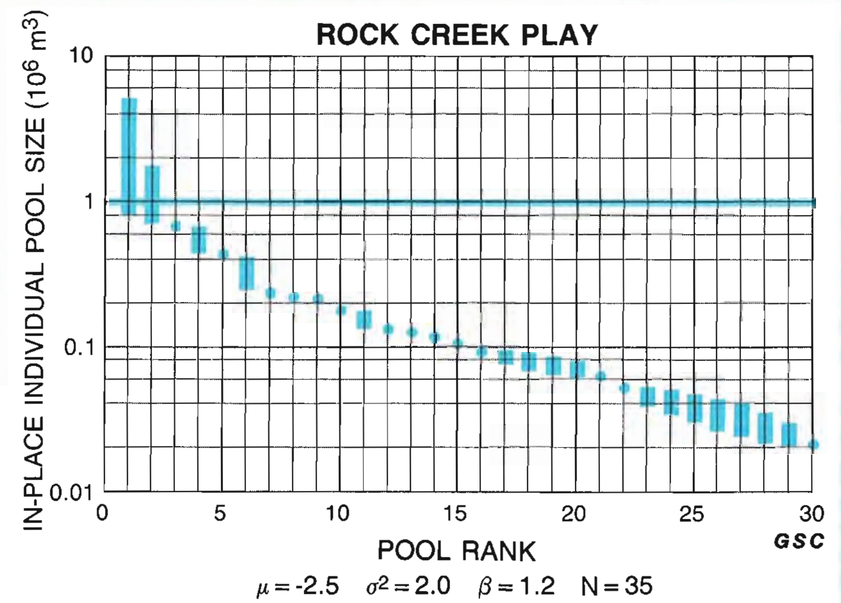


Figure 78

WILLISTON BASIN — SWEETGRASS ARCH DISTRICT

The Williston Basin — Sweetgrass Arch District is bounded on the west by the west flank of the Sweetgrass Arch and on the north and east by the subcrop of the Jurassic System. The southern boundary of assessment occurs at the International Boundary with the United States. Most of the Jurassic oil reserves in this district occur within stratigraphic traps, controlled either by primary facies changes in reservoir formations or by the sub-Cretaceous erosional surface. The Triassic has not been positively identified in the Canadian portion of the Williston Basin.

DEPOSITIONAL AND TECTONIC HISTORY

During the Jurassic the Williston Basin region was a true basin of deposition with patterns of sedimentation distinct from those observed on the continental platform and miogeocline to the west. An ancestral Sweetgrass Arch was present that effectively separated the two depocentres. There are four depositional cycles within the Jurassic System, that correspond in part to the cycles of the Alberta Basin (Table 47). The oldest is a succession of uncertain age and correlation consisting of red beds, dolomitic and anhydritic mudstones and shales, with lesser quartz sandstones. These strata belong to the lower member of the Watrous Formation in Saskatchewan and equivalent beds of the Amaranth Formation in Manitoba. These units are commonly thought to be Jurassic (Poulton, 1984). Recently, there has been a tendency to correlate them with Triassic strata of the Spearfish Formation in the United States portion of Williston Basin. There are no conclusive dates. Distribution of this succession was controlled by mild epeirogenic flexures of the craton. The most prominent feature is a northeast trending trough running from Wyoming to Manitoba. Superimposed on the northwest flank of this trough is a series of northwest trending sills and furrows which impart a distinctive trapezoidal shape to the Amaranth and Watrous sub-basins (Christopher, 1984; Figure 4).

Deposits of the second cycle represent progressive marginal onlap or an expansion of the basin during the Middle Jurassic (Bajocian) in response to renewed marine transgression. This cycle roughly corresponds to the basal part of the third cycle of the Alberta Basin (Table 47). The base of this cycle is placed at the lower contact of the undated evaporites and shales of the upper member of the Watrous Formation, to which Christopher assigned a Middle Jurassic age. These strata are overlain by the Gravelbourg Formation consisting of a lower limestone unit overlain by a shale and sandstone unit. The conformably overlying Shaunavon Formation is composed of two members: a lower argillaceous and coquinoid limestone; and an upper fine-grained quartzose, typically carbonate cemented, sandstone. The depositional facies of these rocks was strongly influenced by the underlying depositional trends in the Watrous. Sawtooth Formation marine sandstones are the equivalents of the Shaunavon, deposited over the crest and on the west flank of the Sweetgrass Arch. They are the first Mesozoic deposits preserved on the arch, and overlie eroded Carboniferous rocks.

The third cycle, also of Middle Jurassic age, consists of deposits of the lower Vanguard Group. It corresponds to the upper part of the third cycle of the Alberta Basin (Table 47). This Bathonian-Callovian cycle is composed of the Rush Lake shale and overlying marine Roseray sandstone in the Williston Basin. The Rierdon shale is the equivalent unit deposited on the Sweetgrass Arch. Later Jurassic erosion over the arch may have removed sands deposited during this cycle.

The fourth, Oxfordian- and- younger, cycle consists of the Masefield shale and conformable marine sandstones in the lower portion of the Success Formation in the Williston Basin. The Jurassic-Cretaceous boundary occurs in strata of the upper part of the Success Formation. This cycle was deeply eroded prior to deposition of beds of the Lower Cretaceous Cantuar Formation of the Mannville Group. The Swift Formation, deposited over the Sweetgrass Arch in southeastern Alberta, correlates with the Masefield shale and the lower Success. It consists of a basal marine shale that passes upward into marine sandstones. Most of the sands were derived from the west, and thus represent the first phase of Foreland Basin sedimentation in this region. The Swift is examined in the succeeding chapter because of its Foreland Basin affinities. Over most of the Williston Basin, Foreland Basin sedimentation did not begin until the Lower Cretaceous. Hence the Success Formation is evaluated in this chapter, despite being partially time-equivalent to the Swift Formation. The upper part of the Success may be equivalent to the Nikanassin in Alberta (Tables 47 and 53).

PETROLEUM GEOLOGY

The Williston Basin District is the most significant district producing oil from the Jurassic System in Western Canada, with approximately 5% of the in-place and recoverable petroleum reserves in the Western Canada Sedimentary Basin. Oil pools lie in two play areas. The most significant one trends north on the western flank of the Shaunavon Syncline, at approximately 108°30′ west longitude. The second play area, less well defined, occurs near the Carboniferous oil pools in southeastern Saskatchewan and southwestern Manitoba. In both regions oil occurs in sandstone or limestone reservoirs, in stratigraphic traps related to either updip depositional facies changes or unconformity features. Oil may be sourced from Jurassic shales or Paleozoic carbonates and shales.

Minor Jurassic oil production also occurs on the west flank of the Sweetgrass Arch, usually in drape traps over Paleozoic erosional remnants.

Most of the oil in the Jurassic of the Williston Basin — Sweetgrass Arch District is medium crude (usually 880 to 930 kg/m^3). A difference in classification schemes between Alberta and Saskatchewan has caused the Alberta crude to be classified as "heavy". Despite this, it is included in this assessment for consistency across the provincial border.

EXPLORATION PLAYS

Four exploration plays were analysed to evaluate the remaining potential for Jurassic oils in the Williston Basin — Sweetgrass Arch region. Although a number of conceptual plays can be devised, all seem to be variants or extensions of existing play concepts and were not quantitatively assessed.

Conceptual Plays

Many conceptual plays in Jurassic strata of this district are variations of the unconformity-related established plays, with superposition of different stratigraphic units as reservoirs and seals. A large subcrop region remains to be adequately tested, particularly for **Success Formation** sandstones trapped by Cantuar Formation valley-fills. Among several play concepts, Christopher (1984) includes: structural plays in Shaunavon Syncline; zones of improved permeability in the **Shaunavon Formation** updip of the existing oil field trend; and structures in the **Roseray Formation** east of the oil field trend.

Established Plays

Of the four established plays, one has too few discoveries to have been evaluated using the discovery process model, and is therefore described in this report in an abbreviated form.

The **Waskada** play (Fig. 76), located in the eastern Williston Basin, occurs in red beds of the Jurassic (?) Amaranth Formation. The reservoir occurs in laminated sandstones and siltstones near the base of the formation. Porosity is both primary intergranular, and secondary intercrystalline in the dolomite matrix. Most sands in the formation are tight due to anhydrite plugging. The reservoir at Waskada is more than a township in area and overlies pooled oil in the Carboniferous Mission Canyon Formation. The Waskada oil is known to have migrated from the underlying Mission Canyon pools (Barchyn, 1982, 1984).

SAWTOOTH

Play Definition: This oil play was defined to include all pools and prospects in the Sawtooth Formation sandstones that occur in stratigraphic facies pinchout and drape structure traps. The play occurs on the Sweetgrass Arch and is limited by depositional edges on the east and west, by the erosional edge to the north, and arbitrarily to the south at the International Boundary (Fig. 76).

Geology: Stratigraphic pinchouts were formed by localized deposition of sands in depressions on the Carboniferous erosional surface. Traps also occur where sandstones drape over topographic highs on the Carboniferous surface. Seal rocks include overlying uppermost Sawtooth shales or younger Rierdon shale.

Reservoirs consist of fine- to medium-grained quartzose sandstones. Pool areas range from 16 to 1475 ha, and reservoirs have average porosities between 12 and 26%, net pay from 1 to 7.5 m, water saturation of about 30%, and an average recovery factor of 12%.

The pools in this play are classed as heavy oil pools (density greater than 900 kg/m^3) by the Alberta Energy Resources Conservation Board (1986), but are included in this assessment as their density range of 880 to 930 kg/m^3 is considered more typical of medium crude.

Exploration History: The earliest discovery of oil in this play, in 1944, was the Conrad field, still the largest pool in the play with an in-place volume of 2.5 x 10^6 m^3 oil. Discovery of gas at Aden in 1932 predated oil discovery in the play. Exploration for oil found a number of small pools at Grand Forks in the mid 1960s and Taber North in 1980. Oil has been discovered in 12 pools with a volume of 5.2 x 10^6 m^3 OIP (Table 50).

Play Potential: The estimated undiscovered potential in this play has a median value of 8 x 10^6 m^3 OIP. This potential is expected to occur in 28 additional pools, the largest of which should contain from 1 to 2 x 10^6 m^3 OIP (Fig. 79). These numbers are probably low, as several discovered pools classed as Lower Mannville (Cretaceous) in this region may in fact be Sawtooth oil pools.

TABLE 50

SAWTOOTH PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Conrad Ellis	2.54	1944
5	Grand Forks D	0.73	1980
6	Skiff A	0.63	1964
11	Grand Forks B	0.32	1978
14	Grand Forks A	0.25	1965
16	Grand Forks I	0.21	1958
17	Taber North A	0.17	1980
18	Grand Forks F	0.16	1979
27	Grand Forks H	0.07	1978
28	Grand Forks C	0.07	1980

- •Total Discoveries : 12
- •Discoveries in the Top 30 Pools : 10
- •Total Pool Population : 40

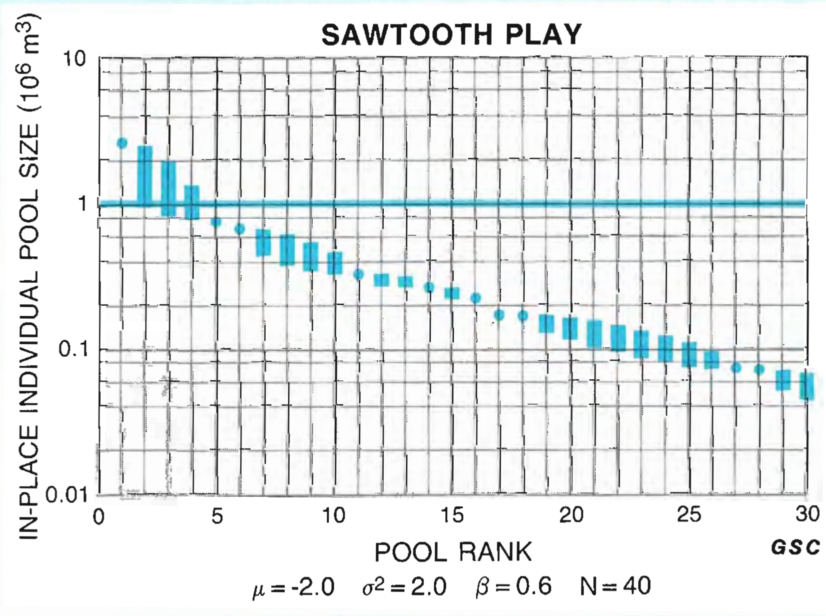


Figure 79

SHAUNAVON

Play Definition: This oil play was defined to include all pools and prospects in shallow marine and shoreline sandstones of the upper Shaunavon where they are surrounded by impervious rocks. The play area is restricted to shoreline facies of the formation along the eastern flank of the Jurassic Sweetgrass Arch (Fig. 76).

Geology: Oil pools are located in shoreline facies near the western edge of the Upper Shaunavon Member. The reservoirs consist of fine grained dolomitic quartzose sandstone and subordinate coquinoid limestone. Minor production also occurs in the Lower Shaunavon carbonates and is included in this play for convenience. Christopher (1964, 1984) attributes the oil to Paleozoic source rocks. The Shaunavon Formation however does contain marginally mature organic dark shales. Jurassic reservoirs were filled through fault and fracture systems in the Shaunavon Syncline during Early Cretaceous at the time of the rejuvenation of the Swift Current Platform. Christopher also suggests a component of entrapment due to an easterly lessening of the hydraulic gradient updip from the oil pools.

Reservoir properties are extremely variable, depending upon reservoir rock type. Typically, porosity is between 15 and 30%, primary recovery factors between 5 and 20%, and secondary recovery factors between 5 and 30%. Pool areas vary from less than 1 section to 15 sections, and net pays from 1 to 10 m. The oil is medium crude, with a density typically around 900 kg/m^3.

Exploration History: The first discovery in the play, during late 1952, followed the discovery, earlier in the year, of a medium crude in the Fosterton area in Cretaceous reservoirs. Exploration progressed quickly southward along the trend and by the end of the 1960s a total of 38 pools had been discovered (Table 51). The total in-place volume of oil discovered to date is 148 x 10^6 m^3.

Play Potential: The estimate of undiscovered potential in this play has a median value of 6 x 10^6 m^3 OIP. This potential is expected to occur in 6 additional pools (Fig. 80). These undiscovered pools may exist in structural features north and west of the established play trend as well as along the existing trend.

TABLE 51

SHAUNAVON PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Dollard	26.08	1953
2	Instow	24.43	1954
3	Rapdan	17.30	1953
4	Bone Creek	12.68	1955
5	Delta	9.40	1952
6	Butte	7.76	1967
7	Gull Lake	6.82	1953
8	Bench	4.87	1969
9	North Premier	4.15	1953
10	Rapdan	3.97	1953
11	Suffield	3.22	1963
12	Illerbrun	3.17	1965
14	Delta	2.54	1952
15	Whitemud	2.30	1963
16	Gull Lake South	1.94	1959
17	Delta N	1.70	1952
18	Rapdan	1.69	1953
19	Dollard	1.65	1953
22	Instow N	1.13	1954
23	Pennant	1.12	1965
24	Covington	1.07	1966
25	Antelope Lake	0.99	1967
26	North Premier	0.88	1953
27	Covington West	0.83	1968
28	Suffield	0.82	1963
29	Suffield N	0.81	1963
30	North Premier N	0.66	1953

- Total Discoveries : 38
- Discoveries in the Top 30 Pools : 27
- Total Pool Population : 44

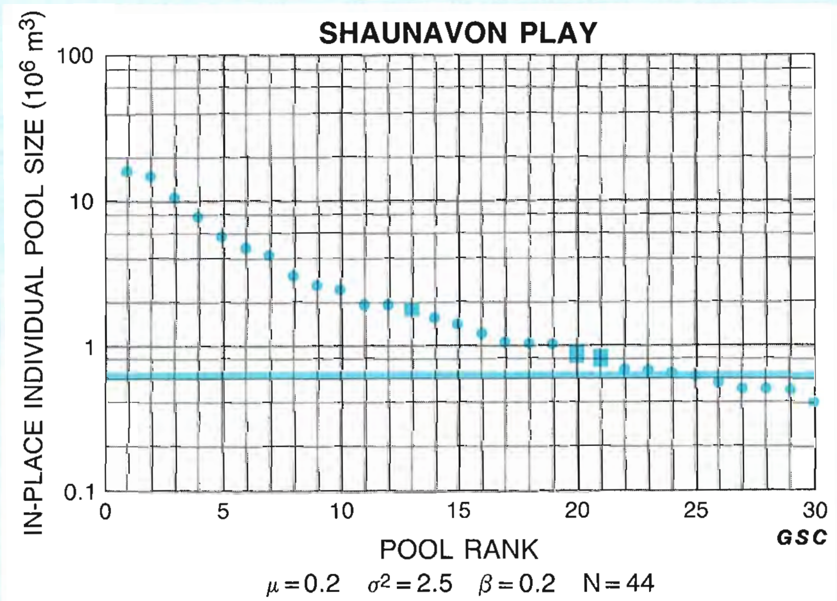


Figure 80

ROSERAY — SUCCESS

Play Definition: This oil play was defined to include all pools and prospects in the sandstones of the Roseray and Success formations in stratigraphic facies change and unconformity traps. The play area forms a narrow arcuate belt at the subcrop of the two formations (Fig. 76).

Geology: The Roseray-Success play area overlaps and extends north and northeast of the Shaunavon play in southwestern Saskatchewan. Two pools, Gull Lake and Suffield, are trapped by a combination of westerly updip facies change of the Roseray sandstones to shale and by tight valley-fill sediments of the Mannville Group to the north and east. The remaining seven major fields occur as paleotopographic highs on the eroded Roseray and Success formations. They have been sealed by relatively impermeable strata of the Mannville Group. Christopher (1984) suggests that a southeasterly hydrodynamic gradient perhaps plays a major role in confinement of the oils to the Jurassic reservoirs.

Pools vary in area from less than 1 section to 6 sections, in pay thickness from 1 to 10 m, and in water saturations from 20 to 40%. Porosities are typically over 25%. Primary recovery factors are from 10 to 20%, and enhanced recovery schemes recover another 10 to 20% of the oil in place.

Exploration History: The first discovery in this play, during January 1952, was at Fosterton. By 1958 seven major fields comprising Fosterton, Battrum, Success, Cantuar, Verlo, North Premier and Gull Lake had been discovered. In all, 31 pools with a volume of 141.9 x 10^6 m^3 OIP (Table 52) have been discovered.

Play Potential: The estimated undiscovered potential for this play has a median value of 8 x 10^6 m^3 OIP, expected to occur in 19 additional pools (Fig. 81). The largest remaining pool is expected to contain about 3 x 10^6 m^3 OIP; all other remaining pools are expected to contain less than 1 x 10^6 m^3 OIP. The estimate of total potential may be low, considering the composite nature of this play.

TABLE 52

ROSERAY — SUCCESS PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Battrum	29.00	1955
2	Fosterton	22.04	1952
3	Cantuar	13.99	1952
4	South Success	8.58	1954
5	Verlo	8.37	1956
6	Battrum	7.26	1955
7	Main Success	6.84	1953
8	Battrum	6.00	1955
9	North Premier	4.63	1955
10	Beverly	4.03	1956
11	North Premier	4.02	1955
12	Battrum	3.44	1955
14	Cantuar East	2.91	1964
15	Suffield	2.78	1965
16	Success North	2.10	1966
17	Cantuar East	1.99	1964
18	South Success	1.99	1953
19	Fosterton	1.98	1952
20	Suffield	1.88	1965
21	Hazlet	1.74	1963
22	Success-Alpha	1.44	1953
23	Battrum N	1.24	1955
24	Fosterton	1.22	1952
25	Battrum-North	1.22	1979
29	Beverly N	0.48	1956
30	North Premier N	0.39	1955

- Total Discoveries : 31
- Discoveries in the Top 30 Pools : 26
- Total Pool Population : 50

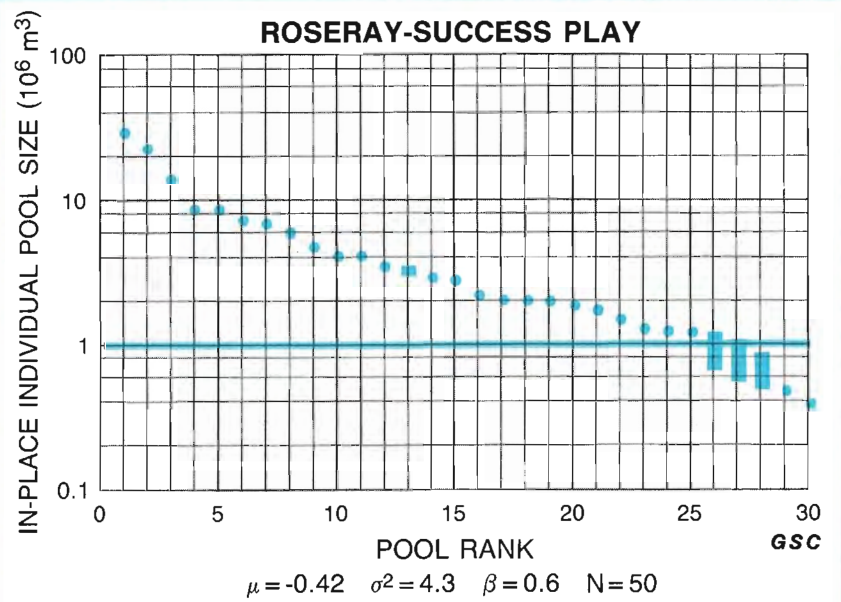


Figure 81

UPPER JURASSIC SERIES, CRETACEOUS AND TERTIARY SYSTEMS

Sediments deposited in the Foreland Basin form the second east-tapering sedimentary wedge in the Western Canada Sedimentary Basin. This wedge includes rocks of Late Jurassic to Tertiary age that have a cumulative thickness of about 8000 m (although this total thickness is not present at any one location). The strata are approximately equivalent to the Zuni sequence of Sloss (1963) and also correspond to the most important period of orogenic activity in Western Canada. The Upper Jurassic section records the transformation from a depositional regime of stable platform carbonates and shales to one with stacked wedges of molassic clastics characteristic of Cretaceous Foreland Basin deposition.

Because of the complex interplay between tectonism and eustasy during the deposition of the Upper Jurassic, Cretaceous and Tertiary molasse, and because these sediments are so very widespread, it has not proved useful to the purposes of this report to subdivide them into depositional sequences or cycles, or into geographic districts as was done in earlier chapters.

The clastic depositional settings that control reservoir and trap development recur throughout the succession, but without the regular periodicity typical of earlier, Paleozoic, strata. Mega-cycles or tectonostratigraphic assemblages (Eisbacher *et al.*, 1974; Kaufmann, 1969; and Stott *et al.*, in press) have been defined for this succession; however there is no absolute agreement upon the number or age of these cycles. Four assemblages have been selected for the present report, based on the detailed studies in Masters (1984b) and Stott and Glass (1984) and in Stott *et al.* (in press). They are distinguished by: combinations of bounding unconformities; varying amounts of coarse clastic detritus shed into the basin, caused by variations in western tectonic uplift; and variations in dominant depositional setting controlled by eustatic and tectonic events. The assemblages have been chosen for their control on reservoir and stratigraphic trap development, and ultimately petroleum reserves.

DEPOSITIONAL AND TECTONIC HISTORY

The Foreland Basin succession is a direct result of the evolution of the Canadian Cordillera. The accretion to the western margin of ancient North America of a collage of exotic terranes during the Middle Jurassic and the Middle Cretaceous caused telescoping of the Paleozoic miogeoclinal wedge onto the western margin of the craton, and overthrusting. This led to crustal loading and consequently a deeply subsiding foredeep. Sediment source direction was reversed and clastic sediments were shed cratonward from eroding, but still evolving, imbricate thrust sheets (Porter *et al.*, 1982). During Late Jurassic and Cretaceous, thick wedges of clastic sediment were deposited into the basin, predominantly from the west, southwest and northwest. At the same time, a continent-wide eustatic rise and then fall of sea level occurred (Sloss, 1963), possibly incorporating numerous transgressive-regressive cycles (Caldwell, 1984; Stott, 1984). In the Foreland Basin sequence the tectonic controls tend to dominate over the eustatic control, because the Zuni transgression could not overcome the input of orogenic detritus until mid-Cretaceous time. Cretaceous deposition reflects the very complex interplay of these transgressive-regressive cycles and pulses of tectonism that is still not fully understood. This dynamic setting led to a wide variety of stratigraphic plays that occur laterally and vertically throughout the basin.

Assemblage 1. Fernie-Kootenay (Oxfordian to Neocomian): This assemblage of sedimentary rocks is defined by upper and lower bounding unconformities (Table 53). It consists of the initial sediments of the Foreland Basin succession deposited during the Late Jurassic. In the Alberta Basin it was preserved only in the extreme western and southern parts. In the northwest, it forms two shallowing-upward and coarsening-upward cycles in the Fernie and Minnes groups. In the southwest, a single similar cycle, up to 2 km thick, occurs in the Fernie-Kootenay succession. In both regions initial deposits are starved basin "Green Beds" grading progressively upward into: marine shale; shallow marine shale, siltstone, and shelf to beach sandstone; and finally continental plain deposits (channel sands, splay sands, lagoonal muds, silts, coals) of the "Transition Beds" and Kootenay Formation. The uppermost continental strata are Early Cretaceous, and have a western provenance, indicated by the abundance of chert in the sandstones.

On the Sweetgrass Arch, a single, thin, Oxfordian to Kimmeridgian, coarsening-upward cycle is preserved. It consists of Swift Formation shallow marine shale overlain by shelf sandstone. Coarse clastic components were sourced from both the tectonic upland in the west and the craton in the east. Equivalent Williston Basin units are the Masefield Shale and the lower Success Formation (S-1).

This group of rocks is truncated by a prominent regional unconformity that resulted from uplift (due to renewed convergence at the plate margin?) and erosion during Neocomian time. This event produced a strongly dissected erosional surface and regional northwest-trending positive elements that separated large valleys in Alberta and Saskatchewan (Fig. 82A).

Assemblage 2. Mannville Group (Aptian to Albian): This assemblage lies above the major Early Cretaceous unconformity and consists of the second wedge of coarse clastics shed into the basin from the west. It is bounded by a minor upper unconformity. This is the most widespread of the assemblages and consists primarily of coarse clastic continental and shallow marine deposits. Deposition occurred during a major incursion of the Boreal Sea from the north. Transgressive phase deposits were formed as the rise in sea level overcame the influx of westerly-derived clastic sediments. They were succeeded by regressive phase deposits formed when clastic input exceeded sea level rise or basin subsidence effects. These strata belong to the Mannville Group and its equivalents listed in Table 53.

Initial deposits above the unconformity were continental coarse clastic sediments of the Cadomin, Gething, Basal Quartz, McMurray, Cutbank, and Cantuar formations, that occupied the major valley systems across Alberta and Saskatchewan (Fig. 82A). Marine incursion from the north initially flooded the valley systems, forming estuarine and shallow marine deposits in the Gething, Basal Quartz, and McMurray formations; though continental deposition occurred in the western (Gething Formation) and southeastern (Cutbank Formation, Dina Member) parts of the basin.

Continued marine transgression deposited shallow marine shale and bar sands of the upper Gething Formation in the northern part, and the Ostracod (or Ostracode) Member in the central and southern parts of Alberta (Fig. 82B). Limestone and calcareous shale are associated with the Ostracod Member. Southeast of these regions, continental deposition continued and is represented by the fluvial sandstones of the upper Dina Member (Table 53). Maximum transgression (Fig. 82C) deposited Bluesky Formation shallow marine bar sands and shales in the northwest, and beach, barrier island, and offshore bars of the Cummings and Wabiskaw members in the northeast. Progradational marine bar sands of the Glauconite informal member were deposited in central Alberta and mark the beginning of the regressive phase. The progradational units in the south are Glauconite coastal plain deposits and, landward of the initial shoreline, Glauconite fluvial channel sands and shales (Jackson, 1984).

The remainder of the Upper Mannville is composed of several progradational, basin-fill sequences that consist of: continental plain deposits in the south (Upper Blairmore); shelf, bar, and beach sands in the middle; and open marine shales of the Clearwater Formation in the north of the basin. Their spatial configuration is similar to that shown in Figure 82D. Sediment sources were from both the south and the west.

The continental plain deposits are typically interbedded shales, sands, and coals of the undivided Upper Mannville (or Upper Blairmore) Group. The marine sands are in the Falher and Notikewin Members in the west, the Grand Rapids Member in the east-central, and the Lloydminster, Rex, General Petroleums, Sparky, Waseca, and McLaren members in the eastern part of Alberta (Upper Cantuar equivalents in Saskatchewan). Notikewin and Colony Channel sands were deposited in the continental plain across central Alberta at the end of Upper Mannville deposition. The final deposits of this assemblage occur only in the northwestern parts of the basin and are assigned to the basal part of the Ft. St. John Group Table 54).

In summary, Mannville Group deposition was dominantly continental in the south, shallow marine in the centre and north, and deeper marine in the far northern parts of the basin. The complex interplay of sediment influx and eustatic sea level changes produced several depositional cycles that contain reservoir-quality sandstones deposited in fluvial channels and in shallow marine environments. The fluvial channels trend north to northwest, and marine bar, barrier island, and beach sandstones east to northeast. A marine regression with associated minor erosion separates these strata from the overlying section.

The widespread coarse clastic rocks and continental to shallow marine environments that characterize much of the Mannville Group did not reoccur in the Western Canada Sedimentary Basin until the Campanian.

Assemblage 3. Colorado Group (Albian to Santonian): The Colorado Group (Table 54)

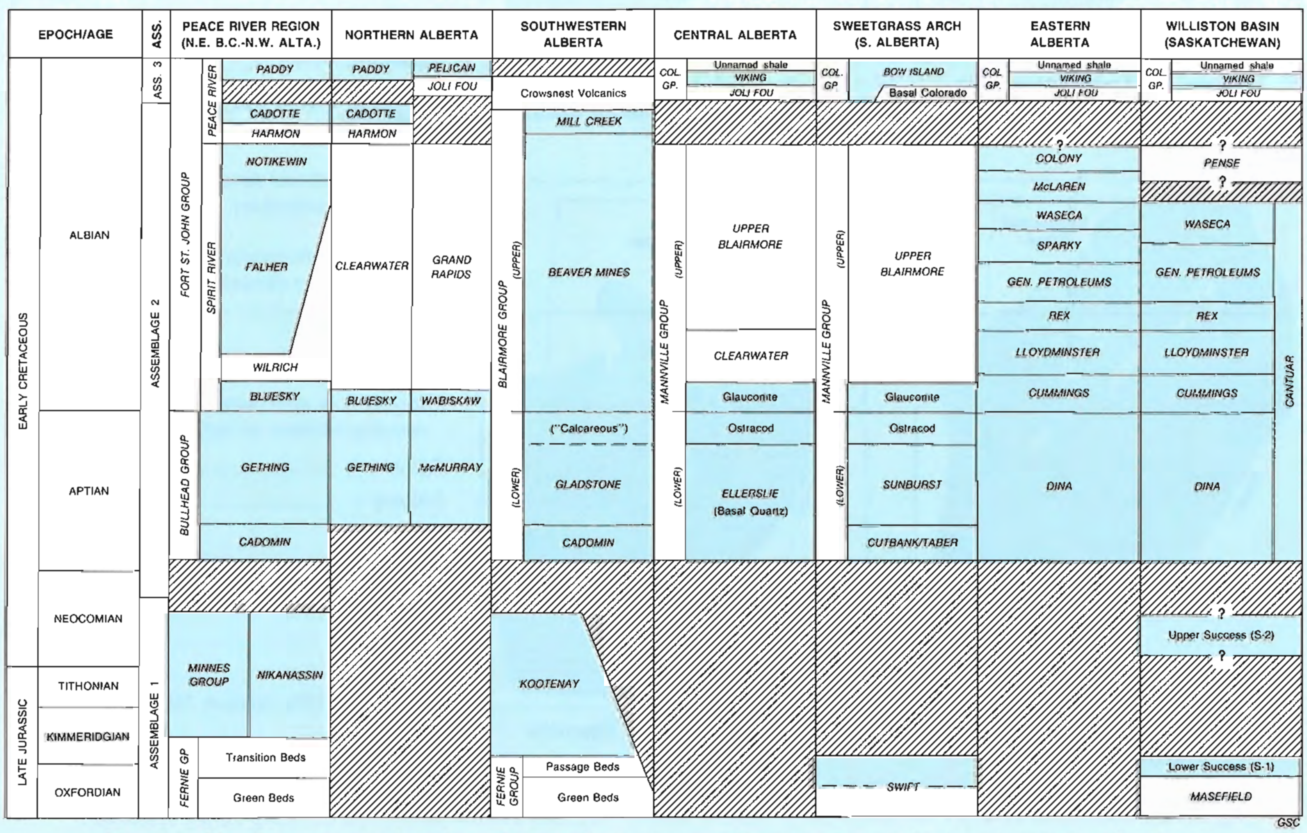


Table 53. Table of Formations, Late Jurassic to Early Cretaceous, Western Canada Sedimentary Basin (dominantly coarse clastic formations in blue).

was deposited during a time when eustasy dominated over tectonic effects in influencing sedimentation patterns. This assemblage consists of widespread marine shales with thin shallow marine coarse clastic interbeds. Continental deposits are restricted to the edges of the basin, since the Cretaceous "Western Interior Seaway" linked the northern Boreal Sea with the southern Gulfian Sea across much of western North America.

The rising sea of the Late Albian transgression removed some of the Upper Mannville sediments, reworking them into basal Colorado sandstones, then deposited the Joli Fou and Bow Island shales in the south. Equivalent Hasler shales were deposited in the northwestern part of the basin. The Joli Fou is overlain by the first major marine sandstone and conglomerate unit of this succession, the Viking Formation (Fig. 83). It typically consists of one or several regressive, coarsening-upward shale to sandstone cycles, that may have conglomerate caps formed during a period of lowstand followed by reworking with renewed transgression.

The Viking forms either large sheet-like sand bodies, or discrete linear "bars" that trend northwest through central Alberta. The upper portion of the formation becomes continental in the west part of the basin. The

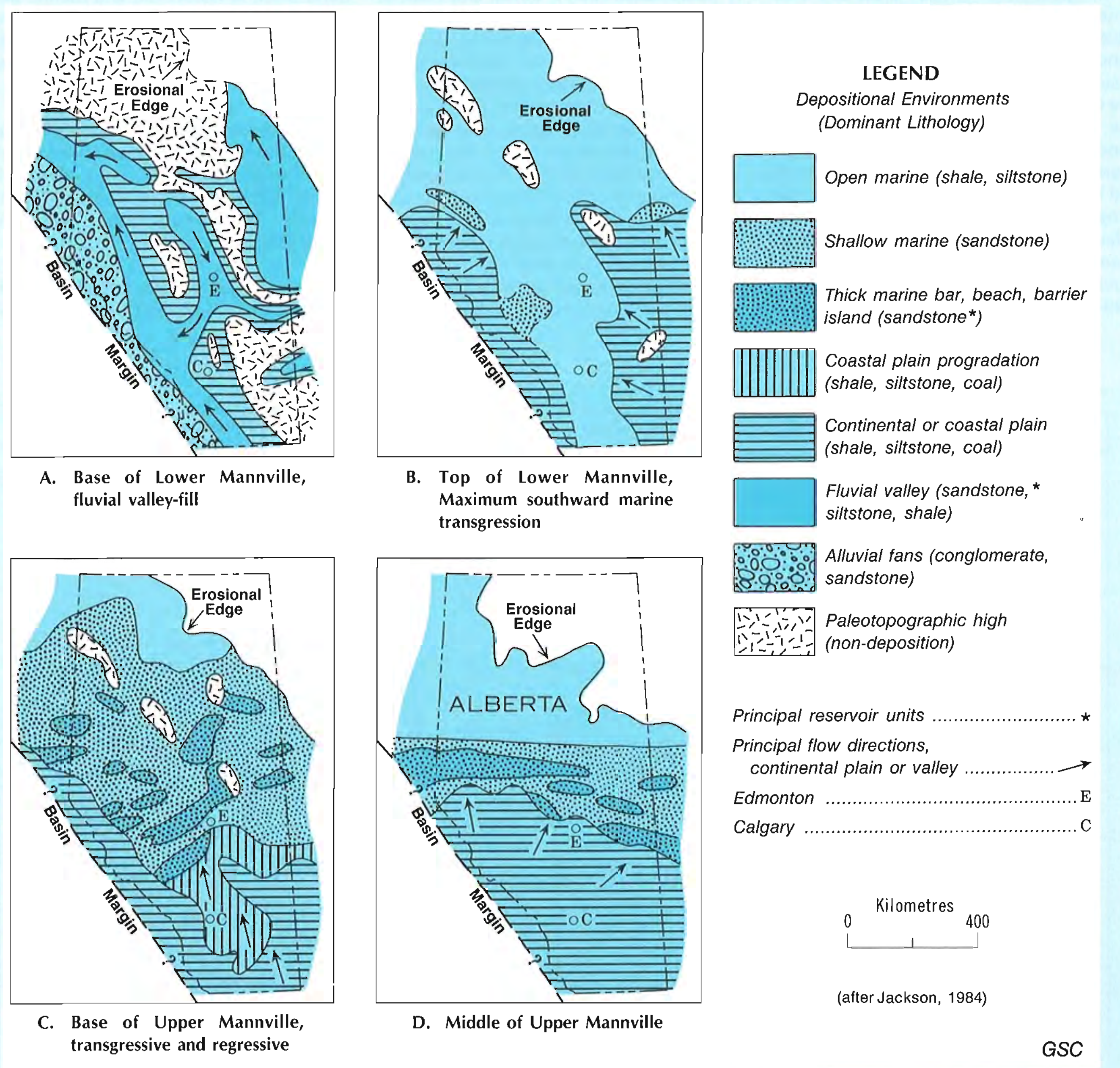


Figure 82. Mannville Group Paleogeography, Alberta Basin. Diagrams exhibit northwest-trending valley systems (A) that were inundated by southward-directed marine transgression (B, C). Regression, with minor transgressive pulses, filled the basin from south to north (C, D).

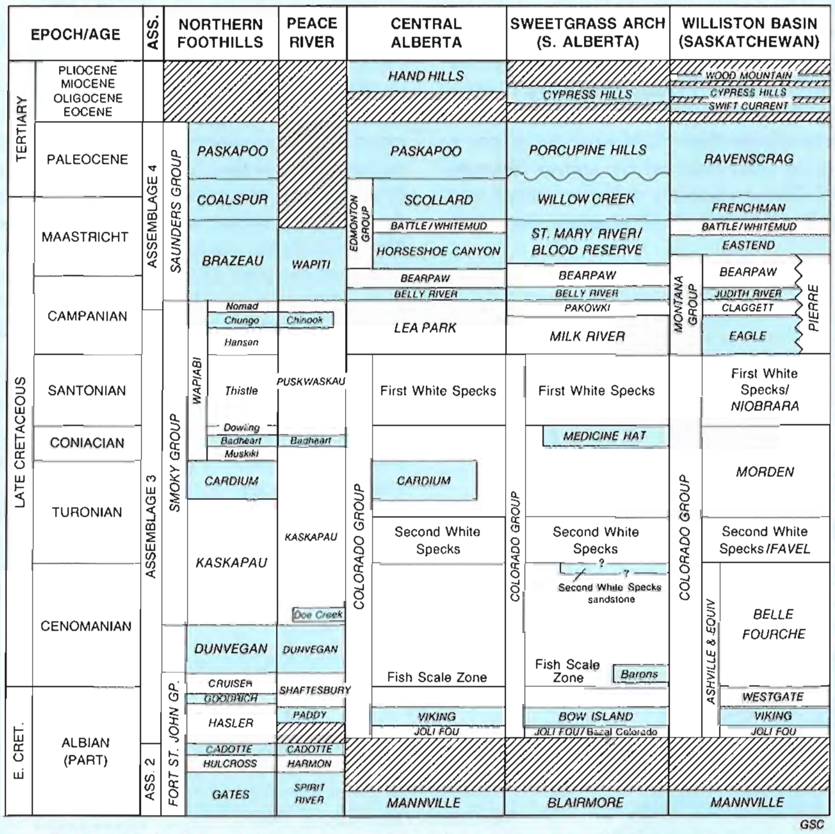


Table 54. Table of Formations, Late Cretaceous to Tertiary, Western Canada Sedimentary Basin (dominantly coarse clastic formations in blue).

Bow Island Formation in southern Alberta consists of three coarsening-upward, marine shale to sandstone and conglomerate cycles.

A thick sequence of marine deposits overlies these sandstones in central and southern Alberta (unnamed shale above the Viking, Fish Scale marker, Colorado Shale, Second White Speckled Shale). In the northwest part of the basin, the equivalent marine shales are in the Shaftesbury and Kaskapau formations. However, an extensive, multi-stage deltaic and shoreline complex with coarse clastics shed from the west, belonging to the Dunvegan Formation and Doe Creek Member, interrupts the shale sequence.

In western Alberta the second major marine sandstone-conglomerate unit, the Cardium Formation, was deposited during a Turonian regression over Colorado or Kaskapau shales. It consists of a lower coarsening-upward shale to sandstone sequence deposited on a storm-dominated marine shelf and an upper conglomeratic and sandstone unit that overlies a minor erosional surface. The sandstones were deposited in large sheets or in narrow linear trends. The upper unit mimics the lower one, but includes sands deposited in scours that crosscut the older sandstone geometry. The Cardium forms a shoreline sequence in the extreme western part of the basin.

Following Cardium deposition, a final transgressive-regressive cycle closed the marine-dominated sedimentation pattern in the Western Canada Sedimentary Basin. It consists of upper Colorado-Wapiabi shales, overlain in the south by the First White Speckled Shale. The Medicine Hat marine sandstone interrupts these shale units in southeastern Alberta. The shales are overlain by the shallowing-upward marine shelf to continental sandstones of the Milk River Formation in southern Alberta and the Chungo and Chinook members in western Alberta. They represent a progradational shoreline complex with sediment sources in the west and south. Though not deposited across most of the basin, these coarse clastics are indicative of the rejuvenation of tectonic activity to the west.

Assemblage 4. Saunders Group (Campanian to Paleocene): The final assemblage deposited in the Foreland Basin consists of three depositional units, the first two of which are characterized by thin, widespread basal marine shale passing upward into thick, coarse clastic, dominantly continental units (Table 54). The thickest strata are in the western part of the basin, adjacent to the rising tectonic upland. Uplift and cannibalization of earlier molasse deposits occurred during this time.

The initial unit consists of the Claggett, Pakowki, Lea Park, or Nomad shales at the base, followed by Judith River, Belly River or Brazeau coarse clastic rocks that represent eastward-prograding shoreline sequences. Shallow marine shelf sandstones pass upward into fluvio-deltaic and continental sandstones and shales.

Bearpaw shales lie at the base of the second cycle and are overlain by Edmonton sandstones in the eastern parts of the basin. To the north and west, coarse clastic sediments of the Saunders Group are the equivalent units. The upper parts of these strata are entirely continental, and mark the end of marine deposition in the Western Canada Sedimentary Basin. The final unit consists of Paleocene Paskapoo-Porcupine Hills-Ravenscrag coarse clastic alluvial deposits, that have a limited distribution, probably because they were removed by post-Paleocene uplift and erosion.

The youngest strata in the basin unconformably overlie the Paskapoo. They are Oligocene to Pliocene braided stream gravels.

Tectonic Events: Two major orogenies in the Cordillera west of the Western Canada Sedimentary Basin occurred during the Cretaceous-Tertiary interval. The Columbian Orogeny peaked during the Neocomian, following mid-Jurassic docking of the first composite terrane onto the western edge of the North American Craton. This orogeny was responsible, in part, for the deposition of the first two assemblages of molasse sediment. The Maastrichtian to Paleocene Laramide Orogeny followed late Albian docking of the second composite terrane, and gave rise to the deformed belt at the western margin of the basin. Deposition of the final molasse assemblage, sourced from the rising tectonic highland to the west (that included earlier molasse deposits), occurred during the Laramide Orogeny. The Laramide Orogeny was probably also responsible for the uplift of the Sweetgrass Arch that separates the Williston and Alberta basins.

The present structure of the Alberta Basin had developed by the end of the Cretaceous. The basin geometry is that of a simple syncline (the Alberta Syncline) having a long, gently southwestward dipping east limb, and a short more steeply northeastward dipping west limb. The structure is the product of the westward depression of the crust because of tectonic loading, and of blind-thrusting, at depth in the sedimentary section, that produced the short west limb. The gentle westward regional dip has been a major control on the maturation, migration, and accumulation of hydrocarbons. Source rocks that were progressively more deeply buried in the west released hydrocarbons that could migrate up-dip to the east until trapped in sealed reservoir units. This asymmetry in hydrocarbon trapping is apparent in all stratigraphic units.

PETROLEUM GEOLOGY

The only significant oil reserves in the Foreland Basin succession occur in stratigraphic traps developed by depositional facies changes in the Cretaceous second and third assemblages. Oil typically accumulates at the updip (NE) termination of sandstone or conglomerate units, where they change facies into equivalent shales. The Cretaceous rocks account for 33% of the in-place and 18% of the recoverable conventional oil in Western Canada. Only minor amounts of oil and gas occur in the first and fourth assemblages.

The Mannville assemblage is perhaps the richest hydrocarbon zone in the world (Masters, 1984a), but most of the crude resource occurs as either heavy oil or bitumen that has been biodegraded during fresh water influx near the surface at the updip (northeastern) edge of the basin. Approximately 500 x 10^9 m^3 of this former

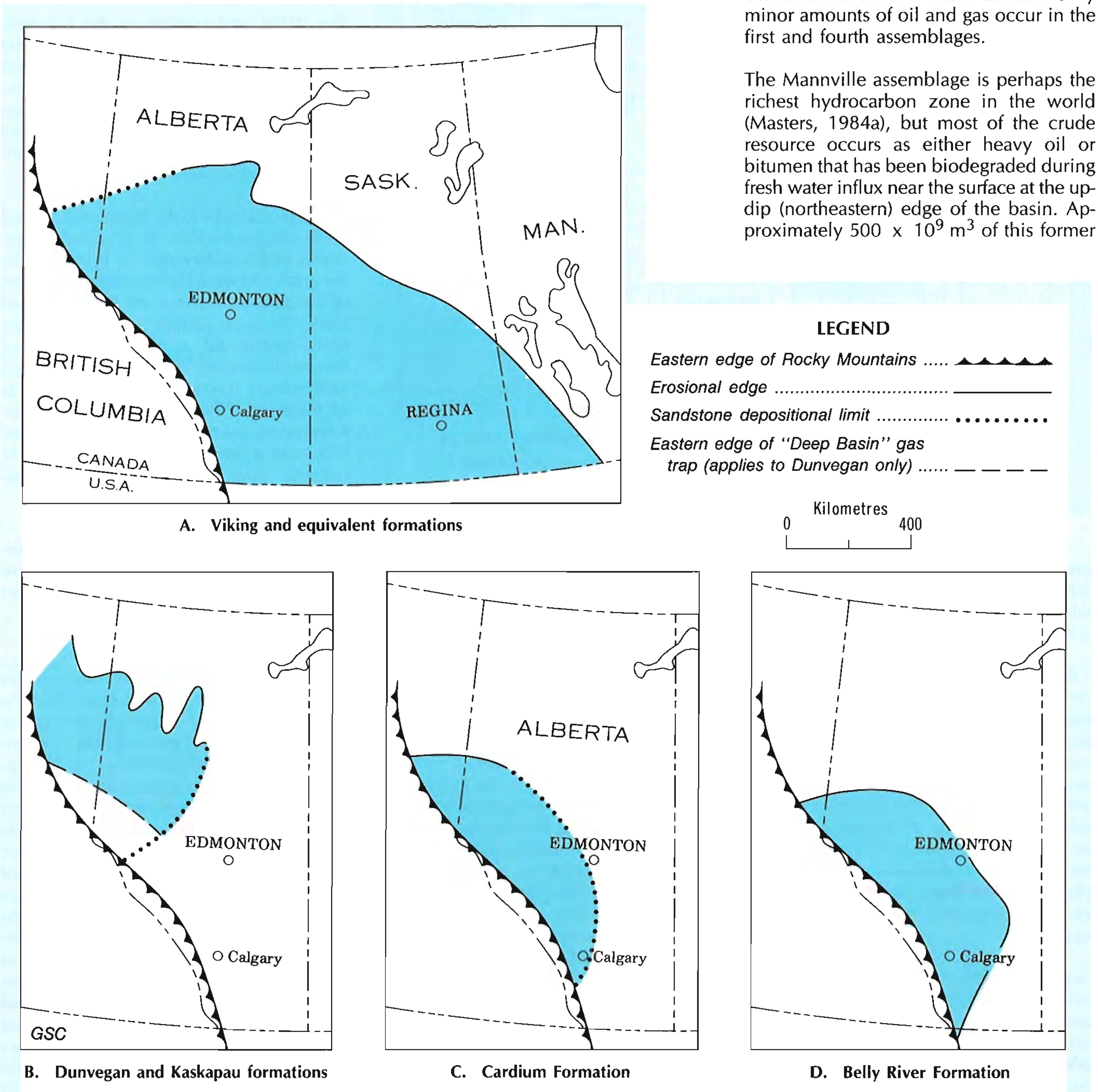


Figure 83. Colorado and Saunders Groups, Play Areas.

oil accumulation remains in place, in a large, broad anticlinal trap at the eastern edge of the basin. The implication of a field of this magnitude, that, if was still conventional oil, would dwarf all other discoveries in the world, is that long-distance migration of oil occurred, probably sourced from several Mesozoic and Paleozoic horizons. The Triassic, Jurassic, and Cretaceous are considered by Masters (1984a) to be the principal sources for this huge hydrocarbon deposit. If long-distance migration from the western parts of the basin occurred, then any stratigraphic or structural traps downdip from the heavy oil zone should have hydrocarbons in them. The nature of the hydrocarbon (gas or oil), will be dependent upon source type and migration paths. At the western edge of the basin, "Deep Basin" gas is presently being generated and trapped. This trap is estimated to contain 55 x 10^9 m^3 (20 Tcf) of gas in place. Conventional oil and gas traps and reserves occur in the Mannville Group between the "Deep Basin" gas trap and the heavy oil deposits. Mannville pools tend to occur in reservoirs related to channels (fluvial or estuarine valley-fills) and shoreline sandstones. Seals are formed by laterally equivalent or older shales.

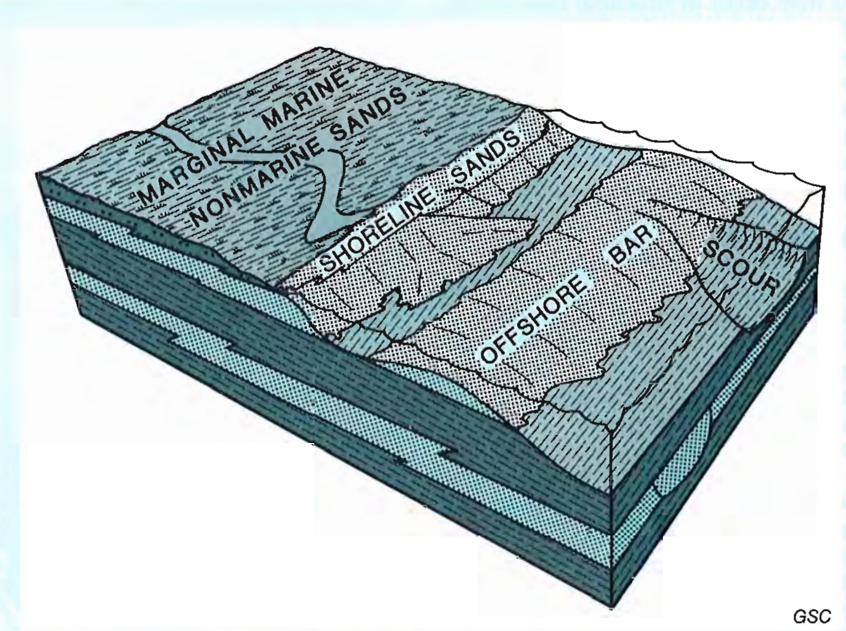


Figure 84. Depositional model for sheet, bar and scour sands.

Most of the oil reserves in the Colorado Group occur in the extensive, thin, marine sheet sandstones and conglomerates of the Cardium and Viking formations, distributed over central Alberta east of the disturbed belt. The extensive, thick marine shales that surround these reservoirs form the seals. The Pembina Cardium pool is the largest in Western Canada, with 1.18 x 10^9 m^3 OIP. Less significant oil accumulations occur in shoreline to deltaic sandstones of the Dunvegan and Doe Creek and in Cardium and Viking scour-fills (Fig. 84). The Colorado Group accounts for approximately 80% of the Cretaceous conventional oil reserves.

A problem in the assessment of oil resources arises from the difference in classification schemes for light and medium versus heavy crude oils between Saskatchewan and Alberta. Some of the Mannville pools in the vicinity of the Sweetgrass Arch in southern Alberta are classified as heavy oil, though they are comparable to Saskatchewan medium crudes (880 to 930 kg/m^3). For data processing reasons these Alberta pools have not been included in this assessment and thus will affect potential estimates to some degree.

DEPOSITIONAL STYLE AND PLAY GROUPS

Classification of trap types by environment of deposition leads to the identification of three play groups characteristic of the Foreland Basin strata. Because they are part of a depositional continuum, each play group may occur at any time and place in the Cretaceous section. However, they tend to be confined to limited stratigraphic intervals and geographic areas because of tectonic and eustatic controls. Nonmarine and shoreline facies were most prominent during the Aptian-Albian and Campanian-Paleocene tectonic pulses, whereas shallow marine facies were most prominent during the mid- Cretaceous high eustatic sea level period.

A. Shallow Marine Group

This group of plays consists of coarsening-upward sequences with sandstone and conglomerate reservoirs deposited on a shallow marine shelf. The geometry of the accumulations is either sheet-like or in linear trends oriented parallel to depositional strike. Several reservoirs may be stacked vertically. In contrast, thick marine scour-fill sandstones were deposited perpendicular to strike. Reservoir facies are commonly encased in shale source and seal rocks. Oil pools in these deposits occur most commonly in the Colorado Group. This is the most important group of plays in terms of reserves and potential. Pools are typically medium to large, and are concentrated in central Alberta and west-central Saskatchewan.

B. Shoreline Related Group

Continuous linear coarsening-upward sandstone reservoirs, oriented parallel to depositional strike, are typical of this play group. Depositional environments include beach, delta front, barrier island, tidal channel and washover facies. The sand deposits typically occur in facies contact with fine-grained sediments of shallow marine and coastal plain environments that also serve as source and seal rocks. Shoreline facies are commonly diachronous due to deposition in overall regressive or transgressive cycles and may therefore occur at several stratigraphic horizons and geographic locations within the same formation. Pools of this group of plays are generally medium to large in size and are concentrated in central Alberta and west central Saskatchewan.

C. Marginal and Nonmarine Group

This play group comprises thick, areally restricted, incised channel-and-fill units oriented perpendicular to depositional strike, as well as some small thin coastal plain deposits. Depositional environments represented are: fluvial channels, coastal plain splays, and large estuarine-valley-fill deposits. Reservoir facies are often encased in nonmarine overbank silts or nearshore marine shales that may also serve as source and seal rocks. Several fluvial settings are also related to unconformities, where Cretaceous reservoir rocks are juxtaposed against older seal rocks that form valley walls. Plays in this group characteristically have numerous small pools.

In addition to these play groups related to depositional setting, petroleum accumulations may occur in structural traps in the Williston Basin, on the Sweetgrass and Peace River arches, and in the Foothills of Alberta and northeastern British Columbia. One play with reserves occurs in shales and siltstones of the First and Second White Specks in Alberta, where they have been fractured during Laramide deformation.

EXPLORATION PLAYS

Twelve exploration plays were identified in rocks of the Cretaceous System, one play occurs in the Jurassic, and none in the Tertiary. Because of the geological complexities, the number of stratigraphic units involved and the large number of known pools, only broad definitions were attempted for Cretaceous plays. Consequently several plays, such as those in the Mannville Group, can be considered as composite plays that could be further subdivided through more detailed study. As a consequence of the lack of detailed play breakdown, no conceptual plays were considered in this chapter.

The play boundaries of the Fernie-Kootenay assemblage are defined by the erosional edges (to the north in the Williston Basin and the Sweetgrass Arch: to the east in Alberta); and by the thermally-defined gas window to the west in Alberta. Virtually all of this assemblage is in the gas window in western Alberta and northeastern British Columbia. Mannville Group plays in the Alberta Basin are delimited by the "Deep Basin" gas trap in the southwest, the occurrence of heavy oil and bitumen in the northeast, and the International Boundary in the south (Fig. 85). North of the Peace River Arch these strata contain only gas. In the Williston Basin, the International Boundary forms the southern play boundary and the poorly defined occurrence of heavy oil the northern play boundary. Colorado Group plays are primarily defined by the depositional limits of sandstone reservoirs (Fig. 83). There is probably a southwesterly limit to Colorado Group plays at an as yet undefined thermal line. In most parts of the basin it should occur west of the eastern edge of the disturbed belt, and thus is complicated by structure. Saunders Group plays are defined by the depositional limits of the individual reservoir sandstones. The Belly River Formation is the only productive interval in this assemblage.

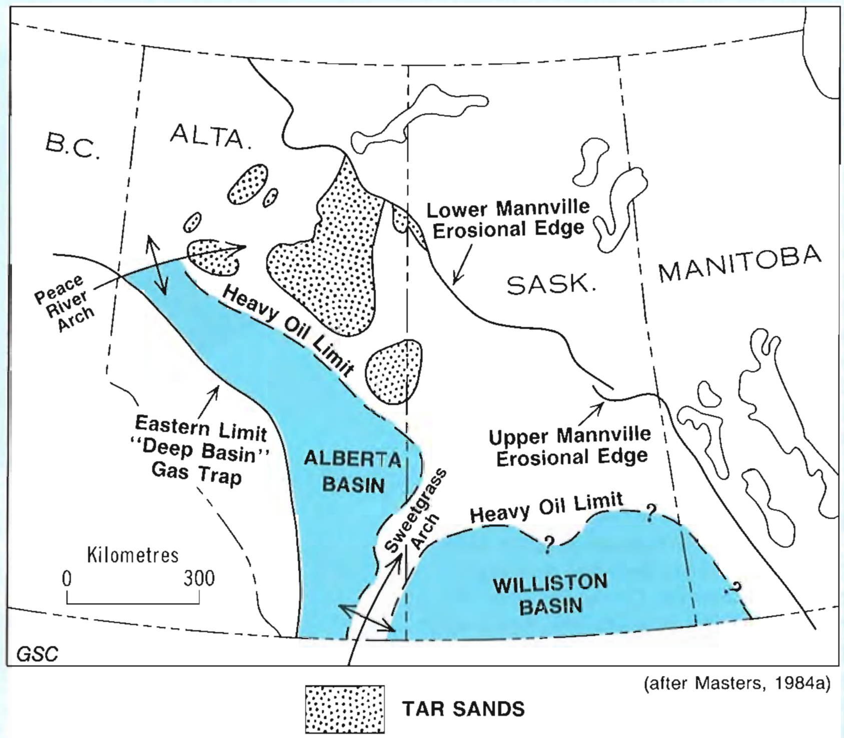


Figure 85. Mannville Group Play Areas.

Established Plays

Only one established play lacked sufficient pool data to be analyzed using the discovery process model. Of the remaining twelve plays, three contain such large numbers of pools that the analysis was made by using the option of classes of pool sizes. Therefore the results of the resource evaluation do not display plots of pools ranked by size in these three plays.

The **Swift** play occurs on the Sweetgrass Arch, and consists of traps formed at the erosional edge of the shallow marine Swift Formation where Cretaceous channeling has isolated sandstone bodies. The play also includes structural traps related to Laramide block faulting, as seen in Montana in the Flat Coulee oil field. Oil pools have been discovered at Manyberries, Alberta (McLean, 1985), and Flat Coulee, Montana. No reserve figures are reported for the Swift in Alberta, as production is comingled with the overlying Cretaceous Sunburst Formation. The "Ribbon Sand" is the reservoir unit of the upper Swift Formation, and represents the earliest phase of clastic detritus shed from the western orogen (Hayes, 1983; Poulton, 1984).

CANTUAR

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic and structural traps in sandstone reservoirs of the Cantuar Formation. The play area is roughly delimited by the Sweetgrass Arch on the west, the occurrence of heavy oil on the north, and the International Boundary on the south (Fig. 85).

Geology: Sediments assigned to the Cantuar Formation were deposited on a strongly dissected erosional surface developed on the Success and older stratigraphic units. Stratigraphic traps occur as a result both of facies change within the formation and of sealing against the walls of valleys cut into the underlying erosional surface (play group C). The deep (>130 m) though broad (1-16 km) valleys incised into the older rocks impart a strong control on the facies of the valley fill. The valley-fill deposits are in part fluvial, but mainly estuarine to marine sandstones, siltstones and shales up to 220 m thick, and are the stratigraphic equivalents of parts of the Mannville Group in Alberta (play group C). Christopher (1974) outlines in detail a number of trapping configurations and prospective areas for oil accumulations in the Cantuar succession.

Reservoir sandstones are typically fine- to medium-grained, with porosities ranging from 20 to 26%. Water saturations range from 25 to 46% and net pay from 1 to 8 m.

Exploration History: The first discovery in this play occurred in 1952 at the Cantuar Field. Approximately 51 x 10^6 m^3 OIP has been discovered in eleven pools assigned to this play (Table 55). An oil pool in lower Mannville sandstone trapped updip against a south-facing cuesta of Vanguard shale was discovered at Wapella in 1952. This pool contains 3.5 x 10^6 m^3 OIP. The pool may represent an eastern development of the Cantuar play.

Play Potential: The estimate for the undiscovered potential in this play has a median value of 46 x 10^6 m^3 OIP. This potential is expected to occur in 29 additional pools, the largest of which is predicted to contain 8 x 10^6 to 20 x 10^6 m^3 OIP (Fig. 86).

TABLE 55

CANTUAR PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Cantuar-MA Cantuar U	22.11	1952
3	Cantuar-E Cantuar U1	7.55	1967
4	Beverly Cantuar Z	7.01	1956
6	Cantuar-E Cantuar U2	4.82	1956
8	Wapella Wapella Z	3.54	1952
13	Gull Lake Cantuar U1	1.91	1953
19	Java Cantuar	1.11	1955
20	Gull Lake Cantuar U2	1.03	1953
23	Cantuar-E Cantuar U3	0.81	1956
29	Gull Lake Cantuar N	0.47	1953

- •Total Discoveries : 11
- •Discoveries in the Top 30 Pools : 10
- •Total Pool Population : 40

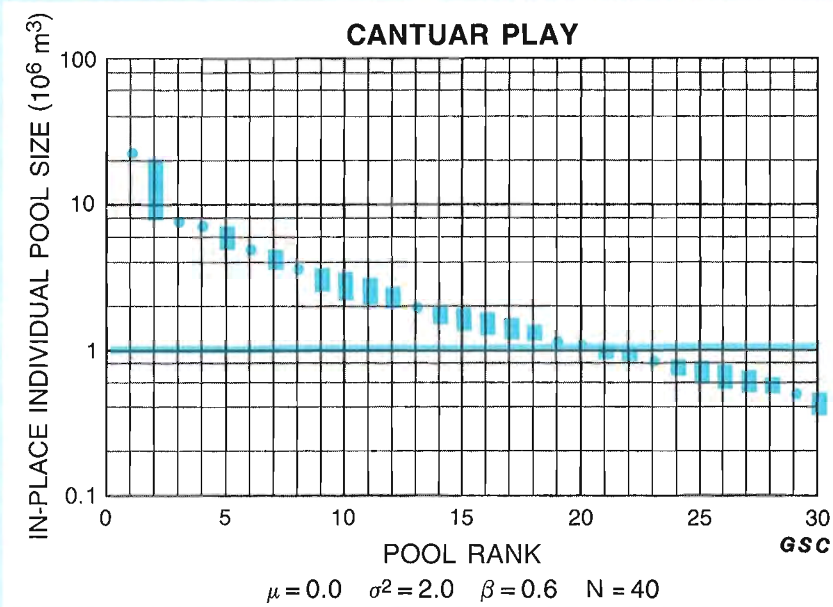


Figure 86

LOWER MANNVILLE

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic and structural traps in sandstone reservoirs of the Lower Mannville Group. It is one of the most widespread plays in Western Canada, occurring throughout central and southern Alberta between the "Deep Basin" gas trap to the west and the heavy oil fields to the northeast (Fig. 85).

Geology: Sedimentation in the Lower Mannville was controlled by tectonic activity and the topography of the underlying unconformity surface. Detritus shed into the basin from the west, south and east was deposited in a multitude of discrete facies.

The broad nature of this composite play is reflected in the wide range of reservoir characteristics and trap geometry (play group C). Most reservoirs are fine- to coarse-grained sandstone having fair porosity and permeability in traps of limited lateral extent. Reservoir units are the Sunburst, Moulton, Detrital, Ellerslie, Basal Quartz, or Cadomin formations. In cases where individual sand units cannot be identified, pools are classed as Lower Mannville or Blairmore. In these pools net pay can exceed 20 m (average 5 m), porosity is generally between 12 to 18%, pool area varies from 1/4 to 12 sections, water saturation averages about 30% and the average recovery factor is about 10%. Reservoir geometry is not readily predictable and is commonly controlled by paleotopography on the sub-Mannville unconformity surface.

Exploration History: The first discoveries in the play were made in the early 1950s and successful exploration has continued. The play covers a very broad area with numerous wells, but predictability of trap occurrence depends on understanding the details of correlation, facies distribution, and on careful mapping of the unconformity surface. Approximately 193 x 10^6 m^3 OIP has been discovered in pools assigned to this play (Table 56).

Play Potential: The median expectation of remaining undiscovered potential in this play is estimated to be 50 x 10^6 to 100 x 10^6 m^3 OIP. This oil is expected to be contained in approximately 270 undiscovered pools (Table 57). One problem with this play assessment is that some pools may not be in the Lower Mannville, although classed as such. Channel sands in the Jurassic or Upper Mannville are difficult to distinguish from the Lower Mannville in some regions. A second problem is that several pools in southern Alberta classed as heavy oil pools by the provincial board are actually medium crude. They have not been included in this assessment.

TABLE 56

LOWER MANNVILLE PLAY

Class Interval (10^6 m^3)	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
8.0-16.0			
	Wayne-Rosedale Basal Quartz B	9.81	1954
	Chigwell Mannville E	8.29	1964
4.0-8.0			
	Gilby Basal Mannville B	6.72	1957
	Niton Basal Quartz B	6.60	1965
	Carrot Creek L. Mannville M	5.77	1963
	Kaybob Cadomin B	5.76	1963
	Medicine River Basal Quartz B	5.75	1959
	Highvale L. Mannville A	4.71	1976
	1 pool undiscovered in this class		
2.0-4.0			
	Thompson Lake Blairmore	3.97	1958
	Campbell-Namao Blairmore F	3.96	1966
	Manyberries Sunburst A	3.76	1920
	Lanaway Mannville	3.50	1958
	Wayne-Rosedale Basal Quartz E	3.38	1962
	Campbell-Namao Blairmore E	2.94	1951
	Campbell-Namao Blairmore A	2.86	1949
	Manyberries Sunburst Q (incl. Swift)	2.53	1977
	Turin Lower Mannville L	2.29	1969
	Wintering Hills L. Mannville A	2.21	1965
	Wayne-Rosedale Basal Quartz GG	2.12	1976
	Coutts Moulton A	2.06	1966
	Hussar Basal Mannville O	1.91	1964
	4 pools undiscovered in this class		

- Total Expected Pools : 600
- Number of Discovered Pools : 329

TABLE 57

POOL SIZE ANALYSIS — LOWER MANNVILLE PLAY

Class Interval In-Place Pool Size (10^6 m^3)	No. of Pools Discovered	Undiscovered
0.016 - 0.031	3	12
0.031 - 0.063	15	34
0.063 - 0.13	70	115
0.13 - 0.25	95	43
0.25 - 0.5	70	45
0.5 - 1	36	8
1 - 2	19	9
2 - 4	13	4
4 - 8	6	1
8 - 16	2	0
Total	329	271

$\mu=-2.0$, $\sigma^2=1.8$, $\beta=0.6$, $N=600$

OSTRACOD MEMBER

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic and structural traps in sandstone reservoirs of the Ostracod Member of the Lower Mannville Group. The play area is confined to central Alberta, between the "Deep Basin" gas trap in the west and the heavy oil fields in the east (Fig. 85).

Geology: During deposition of the tectonically-dominated Assemblage 2, a short transgressive phase (Clearwater Sea) allowed development of a restricted marine embayment in central Alberta. Thin calcareous sandstone beds were deposited in shallow marine, brackish lagoonal and lacustrine environments. These reservoir units are encased in an argillaceous facies that provides the seal and probably also the source for the entrapped hydrocarbons (play group B). The very fine- to fine-grained calcareous sandstones, limestones and siltstones were deposited in thin discontinuous bodies within which reservoir facies are locally developed. In pools of this play, net pay ranges from 1 to 11 m (average 3 m), porosity from 5 to 25% (average 15%), pool areas are generally 1/4 section, water saturation averages about 25% and the average recovery factor is 10%.

Exploration History: The first discovery in this play was at Bigoray in 1959. Since then there has been a continuing trickle of discoveries, all small pools, within the confined play area. Many pools may have been discovered by chance during the exploration for deeper prospects. Approximately 12 x 10^6 m^3 OIP has been discovered in 32 pools (Table 58).

Play Potential: Estimates of the undiscovered potential for this play have a median expectation value of 8 x 10^6 m^3 OIP. The total population of the play was estimated to be 80 pools of which 48 remain undiscovered. The largest remaining undiscovered pool is estimated to contain between 1 x 10^6 to 3 x 10^6 m^3 OIP (Fig. 87). The most prospective exploration area is beneath the Pembina Field, in the northwestern part of the play area.

TABLE 58

OSTRACOD MEMBER PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Pembina E	3.68	1979
2	Bigoray A	2.75	1959
8	Medicine River C	0.58	1964
9	Minnehik-Buck Lake A	0.52	1980
10	Pembina G	0.49	1979
11	Medicine River P	0.47	1972
13	Medicine River B	0.35	1963
14	Bigoray B	0.32	1968
15	Medicine River W	0.32	1965
16	Alexis B	0.30	1970
17	Sylvan Lake A	0.25	1963
18	Westpem A	0.25	1981
19	Pembina D	0.24	1975
23	Pembina F	0.19	1980
25	Alexis A	0.16	1968
26	Hussar X	0.16	1977
27	Sylvan Lake F	0.14	1965
30	Hussar P	0.13	1974

- Total Discoveries : 32
- Discoveries in the Top 30 Pools : 18
- Total Pool Population : 80

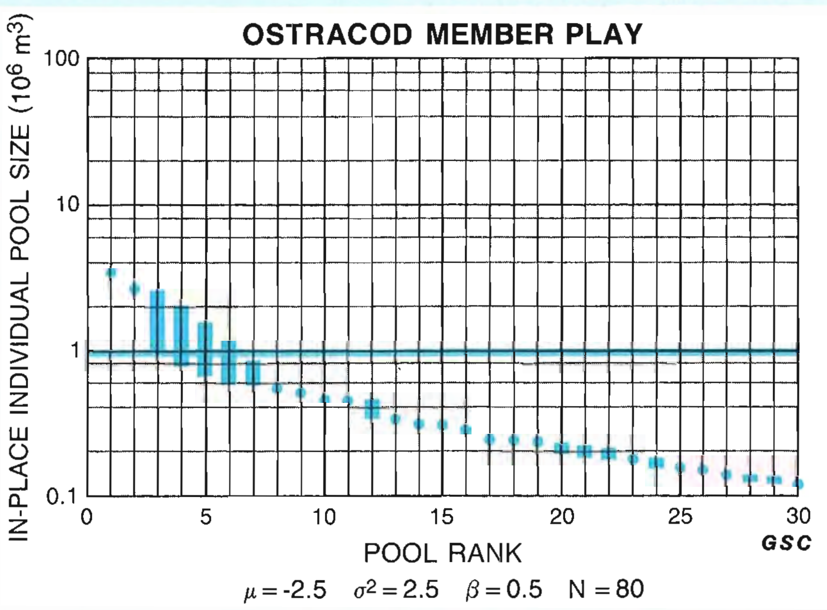


Figure 87

UPPER MANNVILLE

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic and structural traps in sandstone reservoirs of the Upper Mannville Group. Also included in the play are those pools and prospects in the Glauconite Member. The play area extends from the Lloydminster heavy oil belt near the erosional edge westwards to the "Deep Basin" gas trap (Fig. 85).

Geology: The Upper Mannville molassic sequence was deposited after the Clearwater marine transgression during the second tectonic phase of the Columbian Orogeny. The initial progradational shoreline deposits (Glauconitic sandstone of southern Alberta) were followed by dominantly nonmarine deposits shed into the basin from the west, southwest and south. Sedimentation was terminated by the regional transgression of the Colorado Sea. Most of the reservoirs are in small traps controlled by local facies change from sandstone to shale (play group B). Shoreline facies tend to occur in linear belts oriented in easterly or northeasterly trends in Central Alberta. Fluvial facies units tend to be thicker, discontinuous, and distributed along north-south trends.

The loose definition of the play allows for a wide range of reservoir characteristics and trap geometry. Most reservoirs involve fine- to medium-grained sandstone with good porosity and permeability, in traps of limited lateral extent. Net pay can reach 14 m (average 4 m), porosity ranges from 15 to 20%, pool area can be as large as 15 sections but commonly is as small as 1/4 section, water saturation averages 30%, and the average recovery factor is 12%.

Exploration History: The first discoveries in the play were made in the mid-1950s and most exploration activity since then has been concentrated in the area near the Alberta-Saskatchewan border. To date there has been 122 x 10^6 m^3 OIP discovered distributed in 177 pools (Table 59).

Play Potential: The median expectation value for the undiscovered potential is 75 x 10^6 m^3 OIP which should be contained in approximately 270 pools (Table 60). Although the play area is very broad and there have been a large number of exploration wells, the location of traps is still unpredictable. To improve upon chance, further success will require a better understanding of the details of lateral correlations and facies changes. This play also suffers from the problem of heavy oil classification in southern Alberta. Some pools may have been omitted from this assessment that probably should have been included.

TABLE 59

UPPER MANNVILLE PLAY

Class Interval (10^6 m^3)	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
8.0-16.00			
	Garrington Mannville B	9.72	1963
	Medicine River Glauconitic A	9.45	1964
	Taber North Glauconitic A	9.00	1979
4.0-8.0			
	Hussar Glauconitic A	6.98	1957
	Taber North Glauconitic C	4.48	1980
2.0-4.0			
	Provost Mannville L	3.36	1976
	Jumpbush U. Mannville A	2.82	1977
	Berry Upper Mannville C	2.53	1980
	Retlaw Mannville LL	2.48	1979
	Medicine River Glauconitic D	1.99	1963
	2 pools undiscovered in this class		

- Total Expected Pools : 450
- Number of Discovered Pools : 177

TABLE 60

POOL SIZE ANALYSIS — UPPER MANNVILLE PLAY

Class Interval In-Place Pool Size (10^6 m^3)	No. of Pools Discovered	Undiscovered
0.016 - 0.031	1	4
0.031 - 0.063	13	44
0.063 - 0.13	26	62
0.13 - 0.25	49	83
0.25 - 0.50	40	52
0.50 - 1	19	16
1 - 2	19	10
2 - 4	5	2
4 - 8	2	0
8 - 16	3	0
Total	177	273

μ=-1.7, σ^2=1.5, β=0.4, N=450

VIKING — SASKATCHEWAN

Play Definition: This oil play was defined to include all pools and prospects that occur in stratigraphic and combined stratigraphic-structural traps in the Viking Formation of Saskatchewan. The play area covers a wide region throughout west-central and southwestern Saskatchewan (Fig. 83A).

Geology: The Viking Formation is a northeasterly thinning, Late Albian sandstone-dominant unit in the Colorado Group. It records a period of depositional regression and is commonly composed of nearshore and shelf sandstones, conglomerates and mudstones arranged in coarsening-upward successions (Simpson, 1982) (play group A). The detailed arrangement of coarse clastics within the formation is complex, resulting in marked lateral and vertical variations in reservoir quality (Evans, 1970). Accumulations are typically located where facies changes within shallow marine sandstones occur on the flanks or crests of gentle structures.

Pools vary from less than 1/4 section to 1 1/2 townships in area and from 1 to 5 m in pay. Water saturations average 40% and porosities average 23%. Primary recovery factors are from 5 to 15% and secondary schemes in the larger pools add another 6 to 14% to the recoverable total. The oils in these pools are relatively heavy, low sulphur, paraffinic crudes. The source of the oils has not been resolved and may be either the Carboniferous Bakken Formation or the shales of the enveloping Colorado Group.

Exploration History: Viking oil was discovered in this play at Smiley in September 1953. Drilling through the mid to late 1950s concentrated upon exploitation of prospects along the Dodsland-Hoosier trend, where oil occurs in stratigraphic-structural traps draped over the subcrop edge of Carboniferous carbonates. In all, 15 pools with 135 x 10^6 m^3 OIP have been discovered (Table 61).

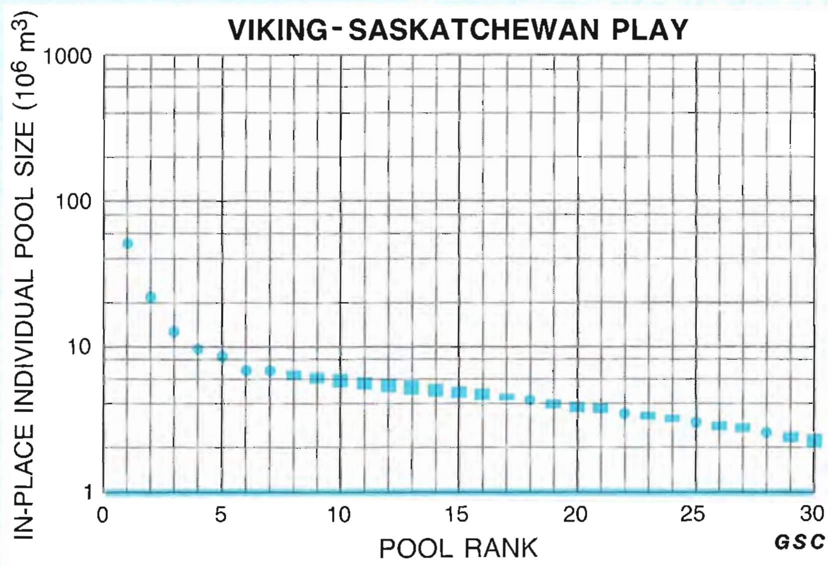
Play Potential: The estimated undiscovered potential of this play has a median expectation value of 108 x 10^6 m^3 OIP, expected to occur in 45 pools (Fig. 88).

TABLE 61

VIKING — SASKATCHEWAN PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Dodsland N	50.69	1957
2	Smiley-Dewar Z	21.47	1953
3	Dodsland U1	12.76	1957
4	Dodsland U2	9.53	1957
5	Avon-Hill Z	8.36	1959
6	Eureka U1	6.80	1954
7	Eureka U2	6.71	1954
18	Plato U	4.24	1967
22	Plato North Z	3.46	1978
25	Eureka N	3.01	1954
28	Whiteside U	2.56	1955

- **Total Discoveries : 15**
- **Discoveries in the Top 30 Pools : 11**
- **Total Pool Population : 60**



$\mu = 0.80$ $\sigma^2 = 1.5$ $\beta = 0.6$ N = 60

Figure 88

VIKING — ALBERTA

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic traps in sandstone and conglomerate reservoirs of the Viking Formation in Alberta. The play area covers most of southern and central Alberta (Fig. 83A).

Geology: The Viking progradational pulse is a complex diachronous coarse clastic wedge, developed during an early phase of the extensive Albian sea that flooded the mid-continent, joining the Boreal region and the Gulf of Mexico. It comprises a series of coarsening-upward shallow marine near-shore sediments locally including scour-fill or tidal channel deposits. These reservoirs pinch out in an updip direction to the east and northeast (play group A).

Each coarsening-upward unit is laterally continuous and consists of a transition from shale to sandstone (commonly with a conglomerate cap). Each reservoir is both overlain by and passes laterally into shales that act as seals and probably as source rocks. Reservoirs have net pay ranging from 1 to 12 m and porosity from 1 to 25%; pool areas are up to a township, water saturation is generally about 35% and recovery factor averages 10%. A disproportionately high percentage of the production is obtained from the conglomeratic facies.

Exploration History: The Viking was one of the earliest known hydrocarbon plays in Alberta (first gas discovery 1909). Oil was first discovered at Joarcam in 1949. Approximately 225 x 10^6 m^3 OIP has been discovered in 137 pools of this prolific and widespread play (Table 62). The play is at a mature stage of exploration but modern seismic mapping can still delineate new prospects, particularly in thicker scour-fill deposits.

Play Potential: The estimate of undiscovered potential in this play has a median expectation value of 87 x 10^6 m^3 OIP. The total population of pools was estimated to be 270 of which 133 remain undiscovered. The largest remaining pools are expected to contain about 12 x 10^6 m^3 OIP (Fig. 89). The more prospective exploration areas lie under the Pembina Field and to the northwest where well control is sparse.

TABLE 62

VIKING — ALBERTA PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Provost Viking CAK	84.30	1946
2	Joarcam Viking	39.40	1949
3	Joffre Viking	14.80	1953
5	Garrington Viking A	10.50	1979
6	Caroline A	9.80	1960
7	Harmattan East E	7.95	1982
9	Gilby A	6.12	1953
10	Judy Creek A	6.00	1969
11	Willesden Green A	4.74	1956
13	Redwater B	4.00	1977
14	Redwater Up-Mid-Lower	3.71	1977
20	Chigwell B	2.60	1962
21	Garrington B	2.54	1980
22	Sylvan Lake A	2.50	1964

- •Total Discoveries : 137
- •Discoveries in the Top 30 Pools : 14
- •Total Pool Population : 270

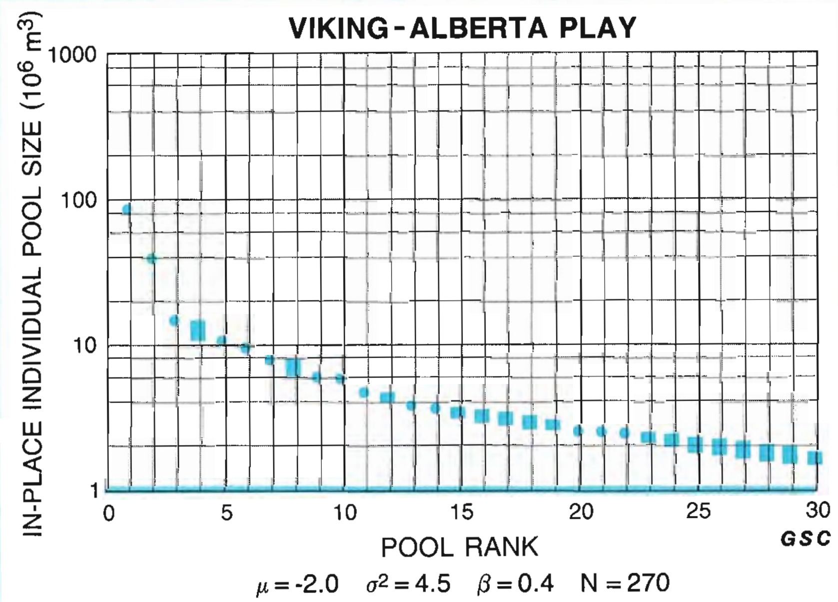


Figure 89

FIRST AND SECOND WHITE SPECKS

Play Definition: This oil play was defined to include all pools and prospects in fractured shale and siltstone reservoirs of the Upper Cretaceous First and Second White Specks divisions of the Colorado shale. The prospective area for these combination structural-stratigraphic traps extends in a narrow belt adjacent to the Foothills between the International Boundary and Peace River.

Geology: The white speckled shales of the Colorado Group were deposited during the mid-Cretaceous transgressions when there were connections between Boreal and Gulfian seas. The white specks zones contain the remains of free floating calcareous algae (coccoliths) and are equivalents of the Greenhorn and the Niobrara chalks. Minor coarsening-upward sequences from shale to siltstone within the assemblage were locally highly fractured during later Laramide deformation, thereby creating reservoir porosity and permeability.

Discoveries are generally limited to single-well pools along the edge of the disturbed belt. In pools of this play, net pay ranges from 3 to 14 m, porosity from 4 to 22% (average 15%), water saturation from 10 to 15% and the recovery factor ranges from 2 to 18%. Reservoir characteristics are variable and unpredictable because they are dependent on structural factors.

Exploration History: The play is poorly understood and, as the reservoirs are rather unpredictable and small, is generally not the primary target of exploration efforts. Most pools were discovered by chance, in the course of exploration for deeper prospects. Approximately 7 x 10^6 m^3 OIP has been discovered in 16 pools (Table 63).

Play Potential: The prospective exploration areas occur along the Foothills and adjacent areas of Alberta and northeast British Columbia in a belt 50-100 km wide. Estimates of the undiscovered potential for this play have a median expectation value of 9 x 10^6 m^3 OIP. A total pool population for the play was estimated as 50 pools of which 34 remain undiscovered (Fig. 90). The largest remaining undiscovered pool is estimated to contain from 1 x 10^6 to 3 x 10^6 m^3 OIP.

TABLE 63

FIRST AND SECOND WHITE SPECKS PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Pine Creek A	2.86	1973
5	Willesden Green B	0.73	1980
6	Willesden Green D	0.73	1980
9	Sylvan Lake A	0.48	1981
11	Pine North-west A	0.42	1975
12	Pine Creek C	0.38	1981
13	Edson A	0.35	1982
14	Lanaway A	0.33	1977
18	Crossfield B	0.25	1980
21	Crossfield A	0.21	1974
25	Caroline A	0.16	1979
30	Crossfield Jumping Pound A	0.12	1961

- •Total Discoveries : 16
- •Discoveries in the Top 30 Pools : 12
- •Total Pool Population : 50

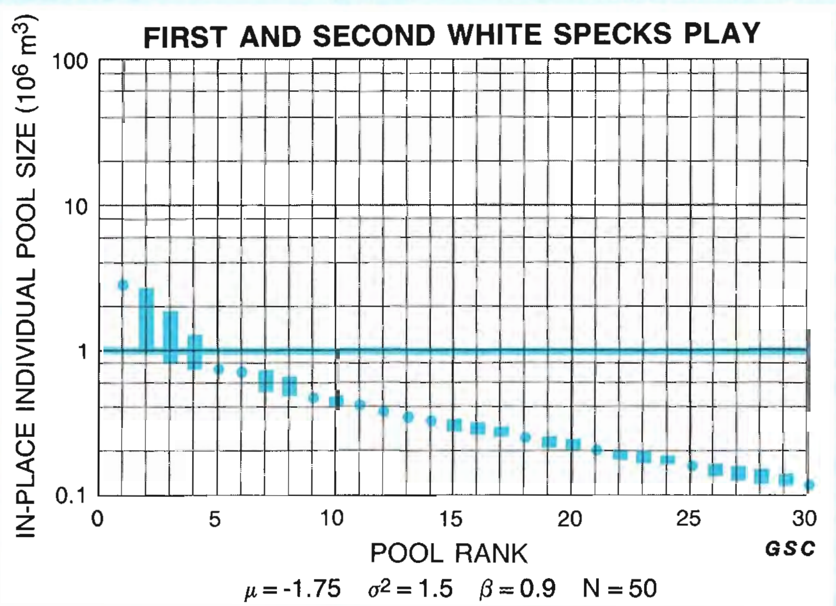


Figure 90

DUNVEGAN — DOE CREEK

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic traps in sandstone reservoirs of the Dunvegan and Kaskapau formations. The play area extends from a region of sandstone deposition south of the Peace River Arch to the edge of sandstone deposition in the south and east, and is limited by the "Deep Basin" gas trap in the west (Fig. 83B).

Geology: Reservoir sandstones were deposited in a series of shoreline and nearshore environments during deposition of the Upper Cretaceous Kaskapau and Dunvegan formations. Deltaic sediments comprising five clastic coarsening-upward cycles were shed southeastward into the Colorado sea from a highland source in northeastern British Columbia. The Doe Creek Member of the Kaskapau Formation is the youngest of these cycles. The deltaic cycles consist of nearshore marine, shoreline and distributary channel sandstones that pinch out basinward into marine shale (play group B). The older deltaic deposits prograded farthest south, and each subsequent one backstepped towards the highlands as the rate of subsidence overcame the detrital buildup. Because of the episodic backstepping it is common to find stacked reservoir units.

The reservoir facies consists of fine grained, well sorted sublithic sandstones that were deposited at the shoreline in laterally continuous, linear trends (play group B). In pools of this play, net pay ranges from 1.5 to 9.1 m (average about 4 m), porosity ranges from 10 to 24% (average 15%) including abundant secondary porosity, and pool areas range from 1/4 to 8 sections. Water saturation averages about 35% and the average recovery factor is about 10%.

Exploration History: The first discovery in the play was at Lator in 1957. Exploration activity increased with the discovery of Valhalla in 1978. Approximately 26 x 10^6 m^3 OIP has been discovered in 13 pools in northwestern Alberta (Table 64).

Play Potential: Estimates of the undiscovered potential for this play have a median value of 21 x 10^6 m^3 OIP. A total population for the play was estimated to be 50 pools of which 37 remain undiscovered. The largest remaining undiscovered pool of the play is estimated to contain 4 x 10^6 to 12 x 10^6 m^3 OIP (Fig. 91). Prospective exploration areas are to the northeast and southeast of Valhalla, near the edges of the clastic cycles. Discoveries are known from all but the fourth sedimentary cycle and there are still relatively large unexplored regions of the play area remaining.

TABLE 64

DUNVEGAN — DOE CREEK PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Valhalla I	13.20	1982
3	Waskahigan A	3.69	1967
4	Jayar A	3.45	1979
7	Lator A	1.54	1957
9	Simonette A	1.29	1980
13	Kaybob South B	0.81	1979
17	Waskahigan C	0.52	1981
24	Ante Creek A	0.29	1974
26	Jayar B	0.23	1981
29	Kaybob South A	0.17	1977

- Total Discoveries : 13
- Discoveries in the Top 30 Pools : 10
- Total Pool Population : 50

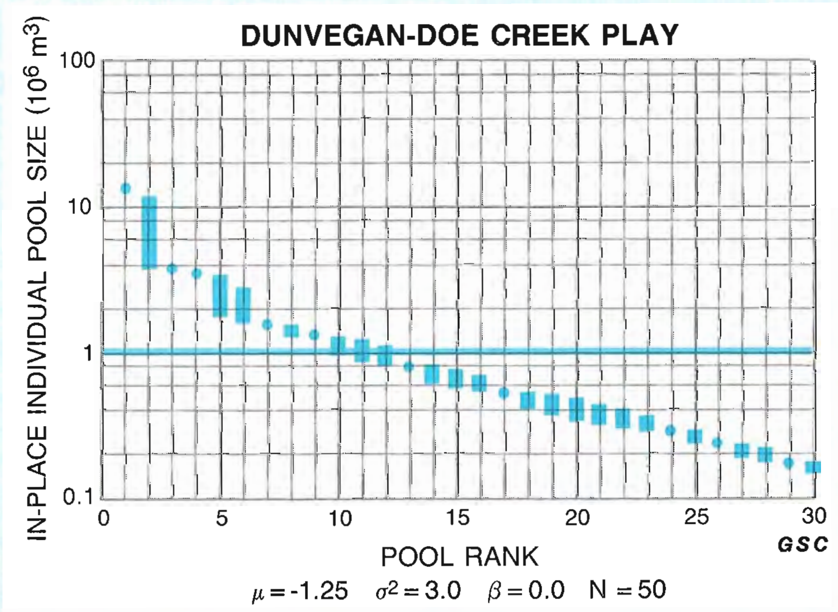


Figure 91

CARDIUM SCOUR

Play Definition: This oil play was defined to include all oil pools and prospects in stratigraphic traps in sandstones and conglomerates formed in marine scours of the Cardium Formation. The play area extends from the Cardium sandstone depositional edge in the east to the disturbed belt in the west (Figs. 1 and 83C).

Geology: Shallow marine medium- to coarse-grained sandstone and conglomerate occur within broad shallow scours (play group A). The scours are several kilometres wide, several tens of metres deep, oriented perpendicular to the shoreline, and may be cut into typical Cardium marine sandstone (Fig. 84) or into underlying Blackstone marine shale. Deposition in the scours occurred episodically. Scour filling could be expected anywhere within the play area.

The reservoirs are thick compared to those of the Cardium sheet sands. The sharply-defined reservoir bodies can be recognized by their seismic character which aids exploration efforts. There are typically several pools present in each scour. Reservoir quality varies significantly due to large variations in grain size and diagenetic alteration. Net pay ranges from 5 to 15 m, porosity ranges from 10 to 15% (including some secondary porosity), pool areas range from 1/4 to 2 sections, water saturation ranges from 10 to 30%, and the average recovery factor is 12%.

Exploration History: The first discovery in the play was at Cyn-Pem Field in 1962. However this play concept was recognized only recently (Walker, 1985) and exploration based on this new understanding is relatively immature. A total of 62 x 10^6 m^3 OIP has been discovered in 48 pools (Table 65).

Play Potential: Estimates of the undiscovered potential for this play have a median expectation value of 37 x 10^6 m^3 OIP. The total pool population for the play was estimated to be 90 of which 42 remain undiscovered. The largest remaining undiscovered pool is predicted to contain from 5 x 10^6 to 7 x 10^6 m^3 OIP (Fig. 92). Prospective exploration areas include most of west central Alberta including areas in and around discoveries in the Cardium Sheet play.

TABLE 65

CARDIUM SCOUR PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Ricinus A	14.30	1969
2	Cyn-Pem A	7.14	1962
4	Ricinus L	5.00	1969
5	Ricinus W	4.29	1976
7	Cyn-Pem D	3.65	1981
8	Ricinus V	3.16	1975
11	Ricinus D	2.38	1968
12	Ricinus T	2.26	1974
18	Cyn-Pem E	1.47	1982
21	Ricinus C	1.27	1969
23	Cyn-Pem C	1.18	1963
24	Ricinus H	1.08	1969
25	Carrot Creek F	1.07	1979
27	Ricinus F	0.95	1968
29	Ricinus X	0.87	1975
30	Ricinus S	0.82	1969

- •Total Discoveries : 48
- •Discoveries in the Top 30 Pools : 16
- •Total Pool Population : 90

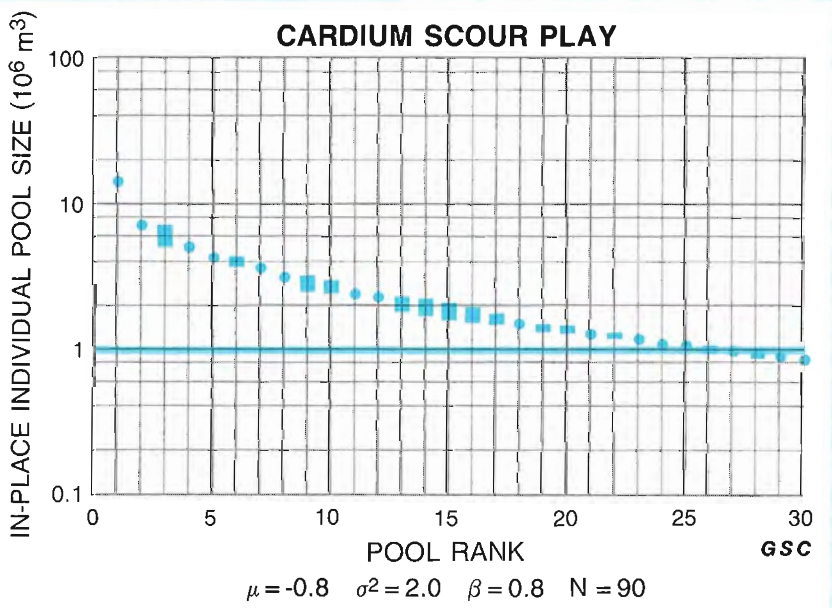


Figure 92

CARDIUM SHEET

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic traps in thin sheet sands and conglomerates of the Cardium Formation. The play area extends from the sandstone depositional edge on the east to the regional hot line on the west (Fig. 83C).

Geology: The thick Colorado shale package represents a depositional phase when Boreal and Gulfian seas transgressed into the basin and merged. Within this succession, complex diachronous and prograding Cardium clastics may be the product of either tectonic pulses or of fluctuations in sea level. The Cardium Formation consists of stacked packets of coarsening-upward shallow marine sands that pass laterally into equivalent shales (play group A). Because of a tectonically imposed regional tilt, these potential reservoirs are located down-dip from the shales that provide the lateral and top seals for the traps.

Each potential reservoir is a coarsening-upward depositional unit that starts with a transition from shale to sandstone and commonly has a conglomerate cap. The conglomeratic beds are the most prolific of the reservoir facies. Depositional units are laterally continuous. The many pools have a range of reservoir characteristics with net pay from 1 to 13 m; porosity ranges from 5 to 20%, pool areas are extremely variable, water saturation is generally 15 to 30% and the average recovery factor is 10%.

Exploration History: The Pembina Field discovery in 1953 was one of the most important in Western Canada exploration. Development drilling showed this to be a giant oil field, the largest in Canada and areally one of the largest in the world (21 townships). With the discovery of 1487 x 10^6 m^3 OIP in 128 (Table 66) pools in west central Alberta, the play is at a mature stage of exploration. Modern seismic methods can identify and map the updip limits of these Cardium reservoirs.

Play Potential: Estimates of the undiscovered potential for this play have a median expectation value of 19 x 10^6 m^3 OIP. The play is assumed to have a total population of 200 pools of which 72 remain undiscovered. The largest remaining pool is estimated to contain between 2 x 10^6 and 4 x 10^6 m^3 OIP (Table 67).

TABLE 66

CARDIUM SHEET PLAY

Class Interval (10^6 m^3)	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1024.0-2048.0	Pembina Total	1180.00	1953
64.0-128.0	Willesden Green A	117.00	1954
16.0-32.0	Ferrier E	30.80	1965
	Garrington A & B	30.10	1954
	Crossfield A	25.70	1956
	Ferrier GG	20.90	1966
	Ferrier D	18.00	1965
8.0-16.0	Caroline E	8.13	1974
4.0-8.0	Pine Creek H & I	6.10	1974
	Bonnie Glen A	4.13	1955

•Total Expected : 200
•Number Discovered Pools : 128

TABLE 67

POOL SIZE ANALYSIS — CARDIUM SHEET PLAY

Class Interval In-Place Pool Size (10^6 m^3)	No. of Pools Discovered	No. of Pools Undiscovered
0.008 - 0.016	3	4
0.016 - 0.031	3	3
0.031 - 0.063	11	10
0.063 - 0.13	32	22
0.13 - 0.25	37	21
0.25 - 0.50	13	6
0 - 1	8	3
1 - 2	3	1
2 - 4	8	2
4 - 8	2	0
8 - 16	1	0
16 - 32	5	0
32 - 64	0	0
64 - 128	1	0
128 - 256	0	0
256 - 512	0	0
512 - 1024	0	0
1024 - 2048	1	0
Total	128	72

μ=-3.3, σ^2=6.1, β=0.6, N=200

BELLY RIVER FLUVIAL

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic traps in fluvial sandstones of the Belly River Formation. The play area extends from the shoreline trend on the east to the disturbed belt in the west (Fig. 83D).

Geology: The molassic deposits representing the initial phase of Laramide deformation consist of an easterly-tapering wedge of dominantly nonmarine sediments. Most reservoir units were deposited in large fluvial channels or occur as thin crevasse splays within coastal plain overbank silts and shales. These fluvial sands are commonly discontinuous, encased in shale, and relatively small (play group C). Locally these reservoirs are stacked vertically. The overlying Bearpaw shale provides a regional seal.

The reservoirs consist of fine- to medium-grained well sorted sandstones, deposited in fining-upward linear channels or as splay blankets. They pass laterally and vertically into nonmarine shale. Net pay averages 5 m, porosity averages 15%, pool area is commonly only 1/4 section, water saturation averages 40% and the average recovery factor is about 8%.

Exploration History: The first discovery in this play was made in 1956 at Willesden Green. Approximately 22 x 10^6 m^3 OIP has been discovered in 34 pools (Table 68).

Play Potential: Estimates of the undiscovered potential for this play have a median expectation value of 26 x 10^6 m^3 OIP. The estimate assumes a total population of 100 pools of which 66 remain undiscovered. The analysis based on the discovered pools suggests that the largest pool of this population remains undiscovered. The size of this pool (Fig. 93) is predicted to lie in the range from 4 x 10^6 to 14 x 10^6 m^3 OIP.

TABLE 68

BELLY RIVER FLUVIAL PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
2	Ferrier A	4.13	1967
3	Davey B	2.50	1978
4	Tindastoll A	2.19	1980
5	Willesden Green B	1.91	1956
6	Peco A	1.61	1964
9	Willesden Green A	1.22	1961
13	Ferrier E	0.94	1980
25	Minnehik-Buck Lake F	0.54	1982
26	Ferrier B	0.52	1967
27	Gilby C	0.49	1979
28	Tindastoll B	0.48	1981

- Total Discoveries : 34
- Discoveries in the Top 30 Pools : 11
- Total Pool Population : 100

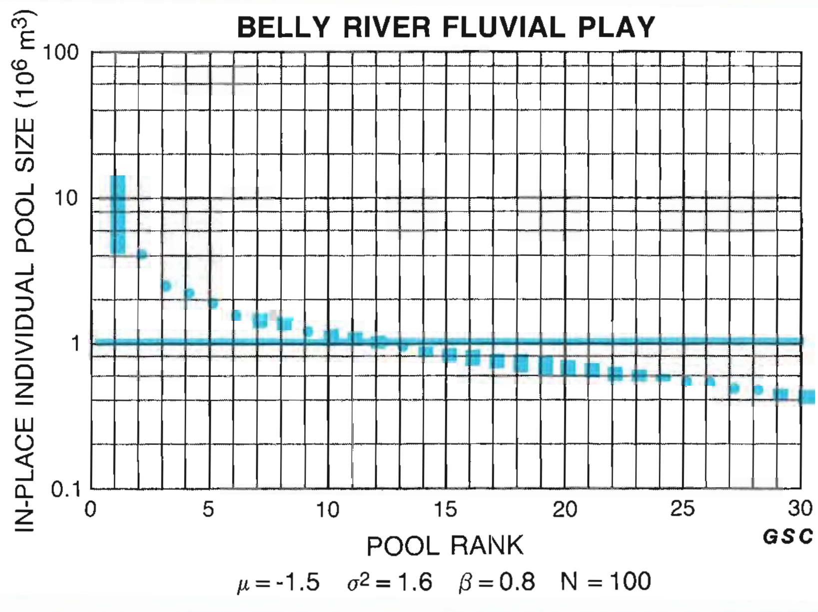


Figure 93

BELLY RIVER SHORELINE

Play Definition: This oil play was defined to include all pools and prospects in stratigraphic traps in Belly River shoreline sandstone reservoirs. The play area extends from the sandstone depositional edge in the east to the disturbed belt in the west (Fig. 83D).

Geology: The dominantly nonmarine molassic deposits associated with the initial phase of Laramide deformation resulted in diachronous prograding shoreline deposits aligned in continuous linear belts that pass basinward (now updip) into marine shales (play group B). Some estuarine and distributary environments are represented in these sediments.

Reservoir facies typically consist of fine- to medium-grained well sorted sandstones, deposited in coarsening-upward shoreline sequences that pass laterally and vertically into marine shale. Pools in this play have an average net pay of 5 m and average porosity of 19%; pool areas range from 1/2 to 4 sections, water saturation averages 50% and recovery factors average about 10%.

Exploration History: All discovered pools are in the Pembina-Keystone area of central Alberta where the first discovery in this play was made in 1954. Exploration has been concentrated in the Keystone area where 37 pools have been discovered (Table 69). Approximately 97 x 10^6 m^3 OIP has been discovered in this shallow play.

Play Potential: Estimates of the undiscovered potential for this play have a median expectation value of 54 x 10^6 m^3 OIP. The estimates assume a total population of 90 pools of which 53 remain undiscovered. The largest undiscovered pool (Fig. 94) is predicted to be in the range of 4.5 x 10^6 to 7 x 10^6 m^3 OIP. Prospective exploration areas are to the northwest and southeast of the Keystone field along the established trend and along possible additional shoreline trends to the southwest of the established trend.

TABLE 69

BELLY RIVER SHORELINE PLAY

Rank	Pool Name	In-Place Pool Volume (10^6 m^3)	Discovery Year
1	Pembina Keystone B	28.60	1958
2	Pembina Keystone C	10.30	1959
3	Pembina I	9.60	1954
4	Pembina Keystone U	8.80	1964
5	Pembina Keystone X	7.60	1965
6	Pembina Keystone M	7.00	1962
9	Pembina Keystone L	4.10	1962
10	Pembina Keystone FFF and G	3.70	1978
15	Pembina AA	2.50	1965
23	Pembina DDD	1.56	1978
25	Pembina J	1.42	1958
28	Pembina II	1.22	1967
29	Pembina TTT	1.15	1981

- Total Discoveries : 37
- Discoveries in the Top 30 Pools : 13
- Total Pool Population : 90

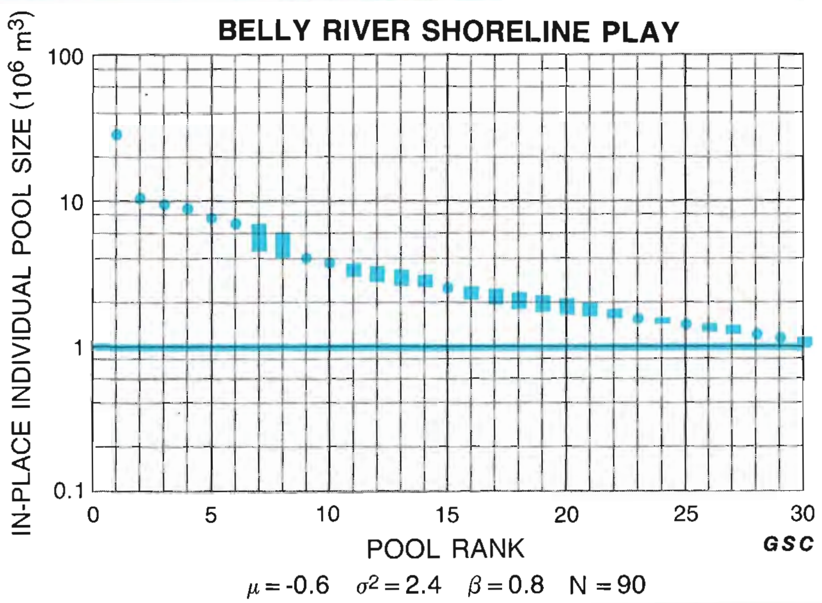
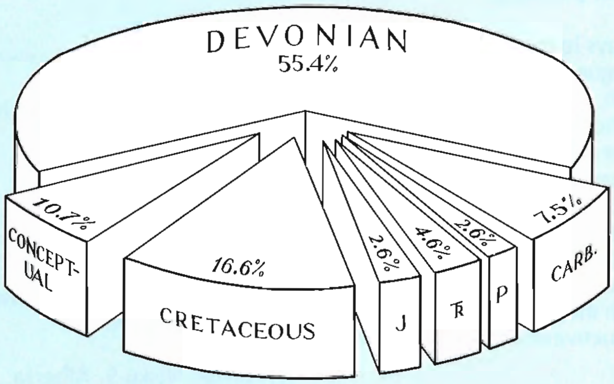


Figure 94

RESULTS AND CONCLUSIONS

The conventional light and medium oil resources associated with 78 established exploration plays and 49 conceptual plays were analyzed using methodology appropriate to the nature of the data base for each play. Fifty seven of the 78 established plays had sufficient data to use the discovery process model approach, whereas 21 of the established plays and all of the conceptual plays were evaluated using subjective methods. The discovered resources (reserves) along with estimates of the undiscovered component of the resource endowment (potential) are tabulated in Figures 96 to 99. These figures list both the total volume of oil in-place (OIP) and the recoverable component of both reserves and potential (median value) for each play arranged in stratigraphic groupings. Figure 95 lists the estimated recoverable potential by geological system. This figure illustrates the very uneven distribution of potential; more than half of the total is expected to occur in Devonian reservoirs. Cretaceous rocks contain the second most important component (17% of the total), whereas other systems contain less than 10% each. The following section includes summary comments on the reserves and potential, as well as some indication of the relative prospectiveness of each of the plays grouped by geological system.

WESTERN CANADA OIL POTENTIAL
(Median recoverable/10^6 m^3)



CRETACEOUS	**95**
JURASSIC	**15**
TRIASSIC	**26**
PERMIAN	**15**
CARBONIFEROUS	**43**
DEVONIAN	**315**
CONCEPTUAL	**61**
TOTAL	**570**

Figure 95

Devonian: Rocks of the Devonian System contain approximately 55% of the recoverable potential (Fig. 95) and 40% of the in-place potential of Western Canada distributed in approximately 1300 pools in 28 established plays. In addition, much of the 10.7% of the total basin potential assigned to the conceptual plays will occur in rocks of Devonian age. The predicted pools that are larger than 1 x 10^6 m^3 OIP represent 15% of the remaining undiscovered pool population, but account for 25% of the Devonian potential. The bulk of the potential is dispersed in a large number of relatively small pools. The largest remaining individual pools, those in the 10 x 10^6 to 20 x 10^6 m^3 OIP range, are predicted to occur in the Nisku Shelf, Leduc-Rimbey-Meadowbrook, Leduc-Deep Basin, Beaverhill Lake, and Middle Devonian Clastic plays. The plays with predicted recoverable potential greater than 25 x 10^6 m^3 are the Keg River, Middle Devonian Clastics, Nisku Shelf, Leduc-Rimbey-Meadowbrook, Leduc-Deep Basin, and the Beaverhill Lake (Fig. 96). These relatively mature plays are expected to add significant quantities of hydrocarbons to the reserve base in the near future. They already account for a large percentage of the proven reserves of Western Canada. Their oil-rich nature and the spectrum of new opportunities for exploration within them make these plays attractive exploration targets. In all cases, denser seismic control, including three-dimensional patterns, refinements in seismic-stratigraphic techniques, greater well density, and refinements in sedimentological models, will contribute to the exploration process and probably to an increase in reserves. Particular areas or trap styles that may have been neglected in the past, such as the purely stratigraphic traps in the Nisku Shelf distant from underlying Leduc reefs, may become important targets for future exploration.

In contrast, several plays are expected to have less than 5 x 10^6 m^3 total recoverable potential (Wabamun-Eroded Edge, Nisku-West Pembina, Wabamun-Peace River, Leduc-Peace River, Slave Point-Golden, Slave Point-Sawn, Bistcho, and most of the immature plays) and would not add significant amounts to future reserves. These plays typically have small predicted pool populations and thus have a greater uncertainty associated with their estimate. One uncertainty is whether the largest pool in the play has been discovered. Regardless of the perceived lower potential of these plays, individual prospects within them may still be lucrative exploration targets.

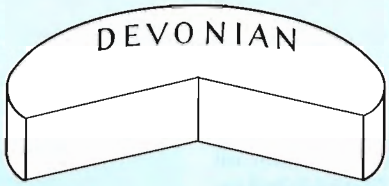
Uncertainty in the estimates is greatest in the immature plays of the Williston Basin, where sparse well control and the absence of a large sample of the possible pool populations makes assessment difficult. Any major discovery in this district could significantly influence the estimates for a play, or result in a redefinition of the play that might invalidate the existing estimate.

In general, the largest part of the Devonian potential is expected to occur in the same mature plays that are the largest contributors to the reserve base of Western Canada. Other Devonian plays, though they may possess a large number of pools and include some individually significant pools, nevertheless do not contribute materially to the total estimate of potential.

Conceptual plays in the Devonian are based upon analogues to established plays in sediments with similar sedimentology or trap configurations. It is expected that the most significant contribution to the reserve base from conceptual plays will come from Devonian rocks. Vast areas of the Williston Basin District and the Middle Devonian section of the Central Alberta District, in particular, have not yet been intensively explored although they possess characteristics similar to productive regions in the Alberta Basin.

Carboniferous and Permian: Rocks of the Carboniferous and Permian systems have 10% of the recoverable potential (Fig. 95) and 12% of the in-place potential of Western Canada distributed in approximately 400 pools in 17 established plays. Predicted pools that are larger than 1 x 10^6 m^3 OIP make up 14% of the remaining pool population and account for 30% of the Carboniferous and Permian potential. The largest individual undiscovered pools, in the 10 x 10^6 to 20 x 10^6 m^3 OIP range, should occur in the enigmatic Desan and Turner Valley plays. Major uncertainty is associated with these numbers. Only three plays, the Belloy Erosional Edge, the Midale, and the Frobisher-Alida, are expected to have greater than 5 x 10^6 m^3 recoverable potential (Fig. 97). Of these, the Belloy Erosional Edge is immature and has the greatest uncertainty associated with the estimates of potential.

DEVONIAN OIL RESOURCES
(10^6 m^3)



Play	Reserves OIP	Reserves Initial Recoverable	Median Potential OIP	Median Potential Recoverable
Beaverhill Lake	967	406.1	60	25.1
Leduc-Rimbey-Meadowbrook	576	351.4	49	29.7
Keg River	340	137.4	151	61.9
Gilwood-Mitsue	238	97.6	-	-
Nisku-Shelf	210	119.4	68	37.3
Leduc-Bashaw	97	54.3	24	14.5
Leduc-Deep Basin	90	54.2	42	25.8
Nisku-West Pembina	82	32.8	9	3.6
Middle Devonian Clastics	80	32.8	81	33.3
Slave Point-Sawn	49	6.7	23	4.6
Zama	23.2	3.6	33	5.7
Leduc-Nisku-S. Alberta	20	6.2	25	7.7
Wabamun-Peace River	16	3.1	15	2.5
Slave Point-Golden	14	5.8	8	2.7
Nisku-Meekwap	12	5.1	25	9.9
Keg River-Senex	10	2.9	33	6.6
Wabamun-Crossfield	6.6	0.6	3	0.3
Bistcho	5.5	0.8	11	1.6
Muskeg	5	0.6	32	6.4
Wabamun-Eroded Edge	5	0.8	6	0.9
Sask.-Manitoba Structure	2.7	0.5	30	5.1
Leduc-Peace River	1.9	0.3	2	0.4
Youngstown Basin	1.9	0.7	15	5.3
Blueridge-Shelf	1.1	0.2	5	1.0
Slave Point-Drape	0.4	0.04	1	0.1
Winnipegosis*	-	-	40	14.0
S. Alberta Structure*	-	-	30	6.0
Alberta-Sask. Erosional Edge*	-	-	12	3.0
DEVONIAN	**2854**	**1324**	**833**	**315**

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Figure 96

Several plays (Souris Valley-Tilston, Lodgepole, Midale, Frobisher-Alida, Elkton, and Pekisko) are perceived as very mature. Although each play has a large pool population, most pools have been discovered and the remaining untested areas are limited. Therefore little remaining potential is anticipated. The Ratcliffe-Stratigraphic, Ratcliffe-Structure, Desan, Belloy-Peace River, Banff-Southern Alberta, Banff-Central Alberta, Carboniferous-Sweetgrass Arch plays are being actively explored; however, the number of discoveries and their sizes are relatively small. These plays are not expected to add significant volumes to the reserves of Western Canada. The Turner Valley and Debolt-Structure plays each consist of a single field in a dominantly gas-charged region. They may be single field plays with no remaining potential or they may represent multi-field plays with significant undiscovered potential. The high degree of uncertainty attached to both plays cannot be resolved without more detailed analysis.

Future discoveries along the mature erosional edge plays of the Alberta Shelf and Williston Basin are expected to be small. Conceptual plays, either in structural traps or in stratigraphic traps distant from unconformities, may actually have more potential than that of established plays.

Triassic and Jurassic: Rocks of the Triassic and Jurassic systems contain approximately 7% (Fig. 95) of the remaining recoverable potential and 9% of the in-place potential of Western Canada, distributed in approximately 500 pools in 18 plays. The predicted pools that are larger than 1 x 10^6 m^3 OIP represent 10% of the remaining undiscovered pool population, but account for 22% of the Triassic and Jurassic potential. The Montney and Gilby-Medicine

River plays are expected to have the largest remaining pools (mean values of 18 x 10^6 and 5 x 10^6 m^3 OIP, respectively). The Gilby-Medicine River, Boundary Lake, Halfway Stratigraphic, and Montney plays have developed to mature status. All are expected to have a recoverable oil potential greater than 5 x 10^6 m^3, and collectively contain most of the potential in the Triassic and Jurassic (Fig. 98). All other Triassic and Jurassic plays have limited potential with the resource dispersed in large numbers of small pools.

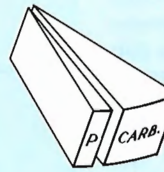
The Roseray-Success and Shaunavon plays of the Williston Basin are very mature and contain large reserves, but have little remaining potential. Other low potential plays are immature to developing, and have greater uncertainty in the estimates of potential than the mature plays.

The total potential represents 21% of the total recoverable Triassic and Jurassic oil resource. This estimate of remaining potential is low relative to other systems, principally because of the limited distribution of Triassic and Jurassic rocks in Western Canada. Possibly the estimates should be increased because most of the rocks now lie within the oil-generation window, and large areas are under-explored. In terms of richness (volume of oil relative to volume of rock), the Triassic rocks are far superior to those of any other system in Western Canada. In many plays, sparse well control and the inability of seismic techniques to delineate prospects has inhibited exploration. Improvements in technology and exploration concepts already evident in the recent drilling successes should increase the reserve base in the immediate future.

Reserve additions may be significantly above the median potential numbers, but still within the speculative estimate for the Triassic and Jurassic rocks. The limited distribution of these rocks precludes any large conceptual play potential within them.

Cretaceous: Rocks of the Cretaceous System contain approximately 17% of the recoverable potential (Fig. 95) and 28% of the in-place potential of Western Canada, distributed in approximately 1200 pools in 13 plays. The predicted pools that are larger than 1 x 10^6 m^3 OIP represent 12% of the remaining pool population, but account for 30% of the Cretaceous potential. Most plays are expected to have the largest undiscovered pool between 5 x 10^6 and 15 x 10^6 m^3 OIP, and total recoverable potentials greater than 5 x 10^6 m^3 (Fig. 99). Only the Cardium Sheet, Dunvegan, First and Second White Specks, Ostracod, and Swift are considered as low-potential plays. Of these, only the Cardium Sheet play, containing the largest pool in Western Canada at Pembina, is considered in a mature exploration stage. The play is extensively drilled and is concentrated in a small area relative to other Cretaceous plays. The other low-potential plays are immature or developing, and thus have broader uncertainty associated with potential estimates.

CARBONIFEROUS AND PERMIAN OIL RESOURCES
(10^6 m^3)



Play	Reserves		Median Potential	
	OIP	Initial Recoverable	OIP	Recoverable
Midale	450	162	26	9.4
Frobisher-Alida	253	60.7	14	5.0
Pekisko Edge	210	27.3	10	1.3
Turner Valley	159.4	22.3	30	4.2
Elkton Edge	110	30.8	15	4.1
Lodgepole	56	8.8	4	0.6
Souris Valley-Tilston	41	6.9	6	0.8
Banff Edge-C. Alberta	37	6.1	13	2.6
Ratcliffe Stratigraphic	34	6.8	14	2.8
Ratcliffe Structure	16	3.2	17	3.4
Debolt Structure	10.5	2.5	10.0	2.4
Desan	10.4	0.8	34	2.8
Carbon.-Sweetgrass Arch	5	0.5	12	1.2
Bakken	2.6	0.4	5	2.0
Banff Edge-S. Alberta	0.9	0.1	1	0.1
Debolt-Peace River	0.3	0.1	2.5	0.2
Kiskatinaw	0.2	0.1	4.0	0.4
CARBONIFEROUS	1396	339	218	43
Belloy-Peace River	40	11.1	11	3.1
Belloy-Erosional Edge	10.3	3.8	32	11.9
PERMIAN	50	15	43	15

Figure 97

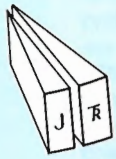
Most of the Cretaceous plays are relatively mature. In several cases potential estimates are considered low, for a variety of reasons. In the two Belly River plays, resource evaluation is difficult due to inadequate assessment (incomplete geophysical logs, lack of tests or samples) of this formation by wells that penetrated it. Future exploration in these shallow Alberta plays therefore may discover reserves in excess of the reported median potentials. The Cardium Scour is a rapidly developing play where modern seismic techniques are used to delineate prospects. Incorporation of the new pool data (since 1983) into the assessment may also increase potential estimates from those reported (Fig. 99). The Ostracod and Cantuar are developing plays that occur over broad areas with reservoir types varying with depositional setting. Both are composite plays, that if further subdivided would probably increase the total potential. The Lower Mannville and Upper Mannville are also large composite plays that are probably under-estimated in terms of total potential.

Three major problems in assessment of the Mannville Group, in addition to those already discussed, are the irregular distribution of gas in the Alberta Basin, the omission of heavy oil from the assessment where it is logically a part of a light-medium play, and the problems in stratigraphic definition, particularly of the Lower Mannville. Prediction of hydrocarbon type (gas or conventional oil) updip of the Deep Basin gas trap and downdip of the heavy oil — tar sands zone in an individual prospect is difficult, as gas and oil pools are irregularly distributed throughout the basin. The statistical consequences of exclusion of the heavy oil pools were not examined in this study. Undoubtedly some pools should be included in various Mannville plays. The problem of stratigraphic definition of Lower Mannville sediments occurs in areas where several erosional and depositional events have been superposed. Jurassic and Cretaceous sandstone reservoirs are difficult to separate without extremely detailed examination. Thus several pools designated as Mannville may be Jurassic, and vice-versa.

Aggregate Potential: The estimated recoverable oil potential for both the established and conceptual plays is shown as a frequency distribution in the right hand half of Figure 100. The distribution has a median value of 570 x 10^6 m^3 of recoverable oil, but ranges from a high confidence value of 460 to a speculative estimate of greater than 770 x 10^6 m^3. This distribution is the sum of a distribution representing the established plays with a median value of 509 x 10^6 m^3 and a narrow range of uncertainty, plus a distribution for the conceptual plays that has a median value of 61 x 10^6 m^3, an arithmetic mean value of 104 x 10^6 m^3, and speculative values greater than 300 x 10^6 m^3. This latter distribution reflects the great uncertainty and high risks associated with the conceptual plays, that to date have not been tested nor demonstrated to contain pooled oil. When the conceptual plays are re-evaluated in the future, estimates of individual plays will change dramatically; some to a zero value, others to high values in the tail of the distribution. The relatively narrow range of values associated with the distribution for the established plays is partly the result of the methodology used. The "matching process" that is a part of the discovery process model approach subjectively reduces the range of uncertainty in the analysis by accepting specified conditions for which the analysis is valid. Other options were available.

For comparison, Figure 100 also includes a graphic view of the total estimated recoverable potential relative to the remaining established reserves (684 x 10^6 m^3 as of January 1984). The total initial established reserves of about 2360 x 10^6 m^3 occur in about 3300 separate pools. In contrast,

TRIASSIC AND JURASSIC OIL RESOURCES
(10^6 m^3)



Play	Reserves OIP	Reserves Initial Recoverable	Median Potential OIP	Median Potential Recoverable
Boundary Lake	108	29.3	25	6.8
Montney	44.4	7.5	34	5.8
Peejay-Milligan	44	14.1	5	1.6
Halfway Stratigraphic	24	6.8	22	6.2
Inga Structure	21	3.2	8	1.2
Charlie Lake Sandstone	7	1.2	6	1.0
Halfway Drape	6.6	1.3	4	0.8
Charlie Lake Algal	2.6	0.4	4	0.5
Doig Structure	2.3	0.2	2	0.1
Worsley-Tangent	1.25	0.4	2	0.8
Baldonnel-Charlie Lake Subcrop	0.9	0.1	15	1.5
TRIASSIC	262	65	127	26
Shaunavon	148	35.7	6	1.4
Roseray-Success	141.9	42.6	8	2.4
Gilby-Medicine River	49	12.3	30	7.5
Waskada	26	2.1	10	1.0
Sawtooth	5.2	1.1	8	1.7
Nordegg	3.2	0.2	7	0.5
Rock Creek	2.7	0.4	4	0.7
JURASSIC	376	94	73	15

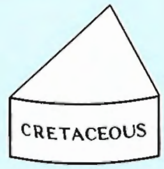
Figure 98

the estimated median potential of 570 x 10^6 m^3 oil is predicted to be distributed in more than 4000 pools. Given that future pools are expected to be more difficult to locate (lower success rate of wildcat wells), the implication is that it will require as many exploratory wells to locate the last 20% of the resource as it took to find the first 80%.

The study implies that future pools will be somewhat more difficult to locate than those that exist today. This is because most of the pools will be small, many are in stratigraphic plays that lack geophysical definition and most will require deeper than average drilling. The quality of future discoveries is expected to deteriorate because small pools may be associated with marginal reservoir characteristics. Average well productivity will be somewhat lower as a result.

All methods of estimating future resource abundance are attempts to approximate a value that will not be known with confidence until the resource is almost depleted. All methodologies have strengths, weaknesses, and limitations that tend to bias the results. In the current study a possible source of error is that the data base of provincial reserve values has been accepted as accurate, reliable and current. It is clear that some values could be expressed as a range rather than a single value, and variables such as recovery factor may change with time as prices, costs and technology change. Because of the large data base, and the limited geological and geophysical expertise available internally, it has been necessary to rely on a statistical approach to methodology with limited (but important) ability to test results against geological knowledge. In some cases it has been necessary to group some plays into a single mega-play for the present time even though this expediency can lead to error. In order to minimize any damage that may result from methodological limitations, a cautious option has been chosen wherever possible. An exception to this has been the application of existing recovery factors to future pools. However, even there, anticipated declining quality of future pools may be offset by improved future technology or economics. On balance, any limitations introduced by the methodology and approach used in the analysis are expected to have produced a cautious rather than an optimistic result.

CRETACEOUS OIL RESOURCES
(10^6 m^3)



Play	Reserves		Median Potential	
	OIP	Initial Recoverable	OIP	Recoverable
Cardium Sheet	1487	288.5	19	3.6
Viking-Alberta	225	43.5	87	16.5
Lower Mannville	193	29.1	75	11.3
Viking-Saskatchewan	135	18.8	108	15.1
Upper Mannville	122	18.4	75	11.3
Belly River Shoreline	97	19.9	54	11.3
Cardium Scour	62	12.0	37	7.0
Cantuar	51	7.5	46	6.9
Dunvegan-Doe Creek	26	2.3	21	1.9
Belly River Fluvial	22	4.5	26	5.5
Ostracod Member	12	1.8	8	1.2
First & Second White Specks	7	0.7	9	0.9
Swift	-	-	15	2.3
CRETACEOUS	2439	447	580	95

Figure 99

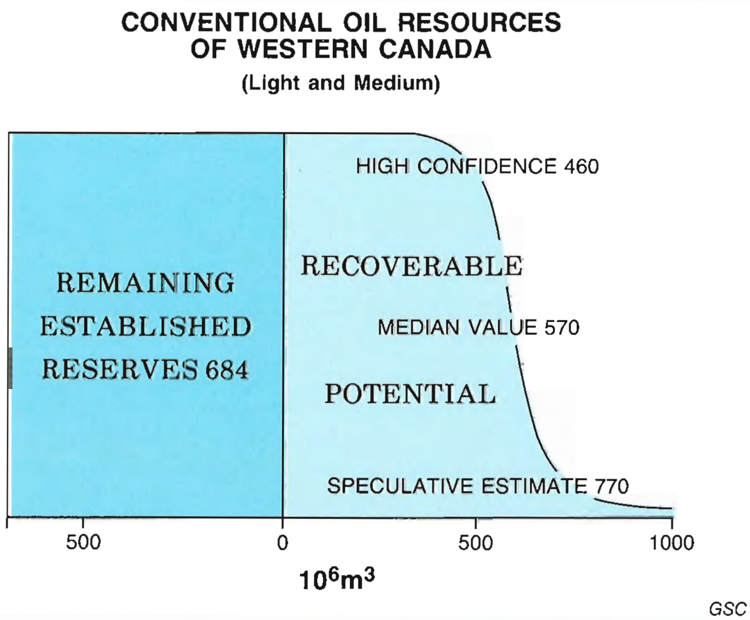


Figure 100

PART II: ECONOMIC ANALYSIS

INTRODUCTION

Part I is an assessment of light and medium conventional oil potential in Western Canada. At a median level of probability, it is estimated that at least 570 x 10^6 m^3 of recoverable light and medium oils remain to be discovered in Western Canada. This resource is distributed within two types of exploration plays — established and conceptual. Established plays have a history of discovery and production, whereas conceptual plays are unproductive to date and largely untested by the drill. The study contained in Part II is limited to analysis of established plays. Of the 78 established plays, 16 have not yet been sufficiently explored to support economic analysis. The 16 relatively unexplored plays, the median potential of which represents 11.5% of the 509 x 10^6 m^3 attributed to established plays, are assumed to be viable only with wellhead prices higher than those considered in this study.

The objective of the present study was to estimate that portion of undiscovered resource potential which is expected to be at least marginally profitable over the long term. Profitability is measured from two perspectives. *Commercial* viability is defined as profitable exploration and development after taking into consideration net royalities and taxes (accounting for net fiscal burden); in other words it is a criterion applicable to the private sector. *Economic* viability is defined as profitable exploration and development exclusive of net fiscal burden; in other words it is a criterion applicable to the public sector.

The study's methodology required estimatation of marginally *commercial* and *economic* pool sizes. The marginal pool is defined as the smallest pool which yields an expected minimum acceptable rate of return. By definition, pools larger than the marginal pool are at least as profitable. Drilling targets would include both larger and marginal prospects. The economic justification for drilling a marginal prospect is that many costs are no longer relevant at the time of a decision to drill. These costs would include land, geological, geophysical, and overhead expenditures. It is important, however, to realize that for industry to maintain exploration such costs must be recovered from larger, more profitable discoveries.

Sixty-two representative plays were examined using discounted cash-flow (DCF) analysis of individual pools. Aggregate results are presented as profitable potential curves, which estimate the volume of profitable resource as a function of price. Results are also presented at selected discrete price levels. Charts illustrating the sensitivity of results to exploration success have been included.

Throughout the analysis, it has been necessary to make a number of simplifying assumptions regarding geological, engineering, and economic factors. These assumptions are described in the report.

Acknowledgments

Three committees within Energy, Mines and Resources contribute to assessments of hydrocarbon resource potential. The Geological Potential Committee, was responsible for Part I. The Petroleum Supply Economics Committee coordinated within the Energy Commodities Sector, was responsible for Part II. The Reserves Committee provides current data on established reserves.

Information and advice regarding the analysis presented here were provided by A. Coombs, N. McIlveen, C. Seeto and A. Webster from the Energy Policy, Programs and Conservation Sector, B. Bowers and C. Gemeroy from the National Energy Board and R. Vani from the Petroleum Incentives Administration, all of the Department of Energy, Mines and Resources Canada.

Scope of Report

Estimates of resource potential do not take into account discovery rates. The time required to discover a basin's potential depends on rates of wildcatting, and the quantity and quality of geological and geophysical information that supported this drilling. These in turn depend upon generating new prospects, prices, fiscal policy, and the industry expectation of available opportunities.

Taking a long-term view of economic constraints is consistent with the methodology used to estimate resource potential. To achieve this, projections of costs are assumed constant in real terms and fiscal burden is assumed to be stable. Short-term economic conditions such as special incentives or surtaxes are not considered. In brief, many factors which influence short-term changes to activity levels are excluded. As a consequence, the economic analysis makes no attempt to estimate when resources may be profitably discovered or, in fact, whether they will be discovered.

The analysis is performed at the play level because; a) there is significant cost variation among plays and, b) required transportation and quality differentials between plays cause variation of wellhead prices.

Analysis at the play level is also consistent with the resource assessment methodology used by the Geological Survey of Canada in Part I. Due to data limitations, however, some inputs could not be disaggregated to this level.

Results are based on four profitability measures as illustrated in Figure 101.

Marginal full-cycle project analysis, as defined in this report, is the estimation of the expected profitability of a decision to drill a prospect. It is defined to include only costs associated with the drilling of exploration and development wells and the production of an oil pool over its profitable life from the time a decision is taken to drill. Predrilling expenditures, including land, geological, geophysical and overhead, associated with prospect definition are excluded. Half-cycle analysis estimates the expected profitability of a decision to develop, excluding all exploration costs.

The *commercial* estimates are based on an assumed stable long-term system of royalties and taxation. Income tax is assumed payable on a fully taxable basis (maximum tax advantage). The *economic* estimates do not take into account royalties or taxes.

ANALYSIS

METHODOLOGY

When analysing investment opportunities having different cost and revenue time profiles, it is appropriate to use discounted cash-flow (DCF) analysis. Profitability can be estimated by a number of criteria using this approach. Expected pool profitability has been estimated here for marginal full- and half-cycle costs both from a *commercial* and from an *economic* perspective.

The analysis was performed using dollars of constant 1985 purchasing power. Any distortions so introduced were considered minimal and within the accuracy of other data. The criterion used to define marginal *commercial* profitability is an expectation of a 10% real rate of return after net fiscal burden on all incremental costs. For *economic* analysis, a rate of return of 10% was also assumed in order to facilitate comparison with the *commercial* analysis.

For each play, the objective was to estimate that portion of the total undiscovered potential resource that can be expected to be profitable over the long term. The potential resource is represented by a series of discrete pool sizes, which sum to the potential resource at a given level of probability. The analysis identifies the smallest pool within the pool size distribution of the play which is just profitable. This pool is termed the marginally profitable or marginal pool within that play for each measure or criterion of profitability (Figure 101).

Once the marginal pool is identified, its potential and that of larger pools are summed to provide an estimate of the long-term profitable portion of the play's potential.

Profitability is affected by a number of factors. Recovery factor, well flow rates, pool depth and reservoir parameters, for example, all contribute. Pool size is considered to be the most important characteristic due to its role in determining wells and equipment and, hence, costs.

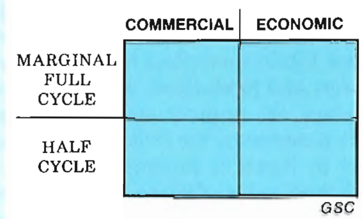


Figure 101. Project profitability matrix

MARGINAL ANALYSIS MODEL

The marginal pool within each play is identified using software known as the **Marginal Analysis Model**. The model (Figure 102) uses the play pool array, the relationship between pool size and pool area, and depth as geological inputs. The engineering inputs include production profile, recovery factor, well spacing, drilling cost, operating cost, road lease and construction costs, transportation cost and their distribution over time. The economic inputs include federal and provincial fiscal systems and crude oil prices.

The iterative process within the **Marginal Analysis Model** proceeds from a cash flow target (e.g. a 10% DCF fully taxable rate of return for a 1:8 exploration success ratio). A trial pool size is selected. The relevant economic, geological and engineering data are used to generate the recoverable resource (in-place pool size times recovery factor). The number of required production wells is calculated from areal extent and well spacing. Appropriate engineering, cost and production schedules are generated. Net cash flows are calculated based on aggregate costs, revenues, royalties and taxation. The DCF rate of return is calculated. If this rate is not sufficiently close to the target rate of return, another candidate pool size is selected. This process is repeated until the pool size is identified that just meets the target rate of return. The system ensures that development of each pool size so calculated is consistent with input geological, engineering and economic data.

The analysis requires a number of simplifications. In terms of geological and reservoir parameters, it is assumed that all undiscovered pools within a play have the same depth and recovery factor. For purposes of estimating pool development, the areal extent of a pool was estimated as a function of its in-place reserve size for each play.

Implications of Marginal Analysis

Marginal prospects are not usually exploration targets. Prospects are drilled in the expectation of discovering larger, more profitable pools. Usually, a decision to drill what may be a marginally sized pool would be based on only the marginal or incremental costs of discovery. In the study, therefore, it was assumed that there would be no significant incremental geological and geophysical expenses. For the same reason, expected marginally profitable discoveries would be drilled partly because land costs are deemed excluded from the decision. If land costs had to be included in a decision to drill a prospect estimated to be marginally profitable without land costs, then the land would not generate a significant bonus payment. Hence, land costs were not included as a *commercial* cost.

Secondary recovery on marginal pools is generally not profitable and, therefore, is not included in the marginal analysis.

The marginal pool of a play is generally found at the smaller end of the pool size distribution. As a result, possible errors introduced in identifying this pool do not significantly change the pool array sums. For example, if a marginal pool size is erroneously underestimated, because the pool area was in error, or the recovery factor or well productivity was too high, or some combination of these, the impact on the summation is generally not significant. Although the actual marginal pool size could double, thereby decreasing the estimated summation, this is still the doubling of a relatively small pool. Subtracting one or a few small pools does not significantly alter the aggregate results. This, of course, depends on the play pool size distributions.

An impact analysis was done on productivity, which is a factor that strongly influences profitability. This was done using the Nisku Shelf play. Two different production profiles were analysed. One used a conventional (historical) decline rate, the second assumed a flat production rate. Table 70 illustrates that, although well productivity significantly changes the economics of the marginal pool and hence its required size, it does not significantly alter the estimate of *commercial* or *economic* potential obtained from summing it and larger pools. The size of the marginal pool, based on a flat production profile (reduced initial well productivity) increased by 61-65% on the half-cycle analysis and by 20-33% on the marginal full-cycle. The total marginal full-cycle *commercial* potential within the play, however, falls by only 1.7% and the half-cycle *commercial* potential falls 0.5%.

Other Considerations

Prudent exploration decisions are based on as much information as possible, both quantitative and subjective. The information available for a marginal full-cycle decision may not explicitly consider such occurrances as gas discovered in the search for oil, nor the discovery of pools smaller than the marginal full-cycle minimum, which may be profitable to develop. The present marginal full-cycle analysis does not include these considerations. The expected total profitable resource should therefore be greater than that estimated in the marginal full-cycle analysis. The difference in profitable potential between the marginal full- and half-cycle analyses provides some measure of the amount of this additional profitable potential (Table 71). Finally, 11.5% of the total recoverable potential was not analyzed because pool size distributions were not available. It would, however, be reasonable to assume that some portion of this potential would be in pools large enough to support investment at prices of $\$142/m^3$ (\$22.50/bbl) or even less.

For these reasons the estimated profitable potential should be considered a low estimate.

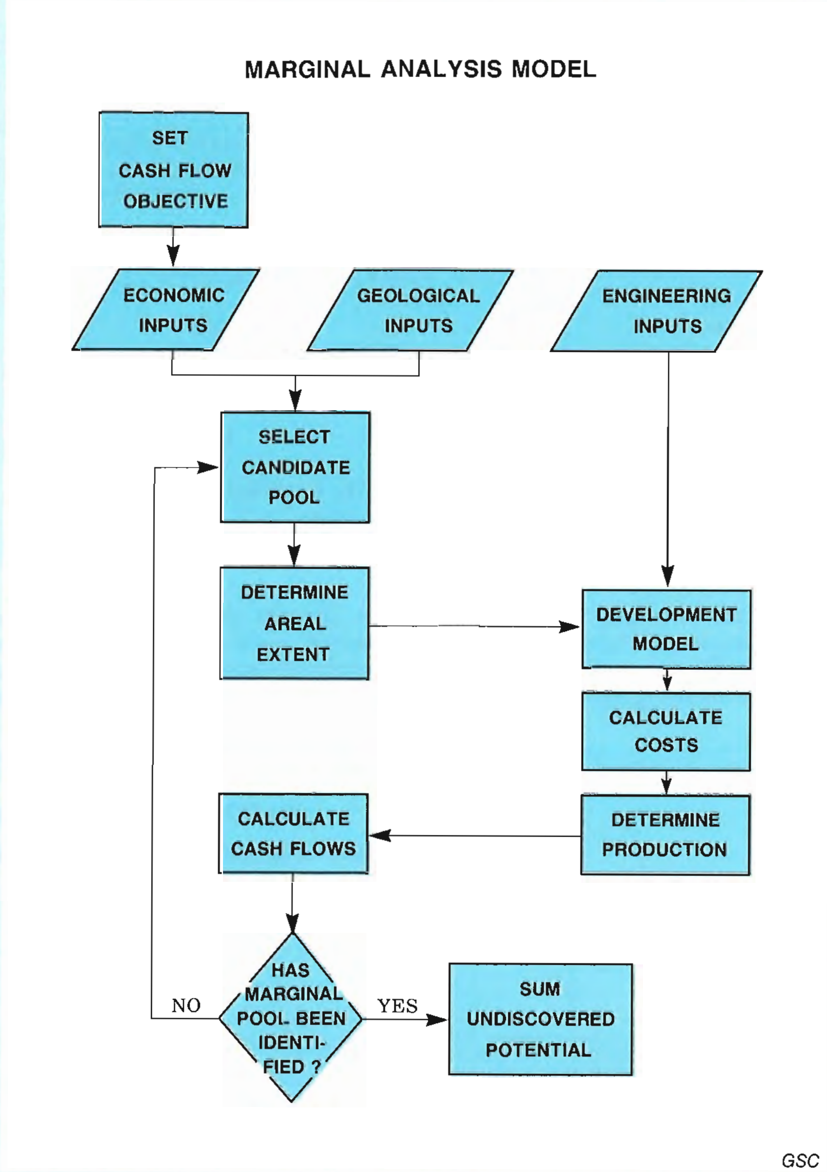


Figure 102

EXPLORATION COSTS

A decision to drill a marginally profitable prospect can be made for a number of exploration and corporate reasons. The risk of finding a pool which is only marginally profitable to drill for must be compensated by more profitable discoveries elsewhere.

A decision to drill would likely take place either in a strategic stage of exploration within a play or when most required geological and geophysical information has already been acquired. It is, therefore, reasonable to assume that a decision to drill an expected marginally sized prospect would be based partly on the fact that most geological and geophysical costs and land costs are excluded from the decision process.

An exploratory success ratio was used to allocate exploration costs to discoveries. Average finding costs were not used in the analysis because, in general, they are not applicable to marginal investment decisions. Some difficulty was encountered in identifying an appropriate success ratio from

TABLE 70

SENSITIVITY TO PRODUCTION PROFILE
Nisku Shelf Play*

	Size of Marginal Pool (10^3 m^3)		Summation of Recoverable Profitable Potential (10^6 m^3)	
	Marginal Full-Cycle	Half-Cycle	Marginal Full-Cycle	Half-Cycle
Commercial				
Flat Profile	114.4	16.7	35.7	37.0
Historical Profile	86.3	10.1	36.3	37.2
Economic				
Flat Profile	87.9	17.9	36.3	37.2
Historical Profile	73.1	11.1	36.4	37.3

*Analysis based on price at Edmonton $142 Canadian/m^3 ($22.50/bbl), and 1:8 success ratio

available data. The only available data source, at this time, is aggregate provincial data, which is biased toward higher success ratios for the following reasons. Firstly, activity directed towards heavy oil is not separated, and this activity has a relatively high rate of success. Secondly, many wells classed as exploratory tests would be classed as development wells if the true boundaries of the field were known at the time of drilling. Thirdly, it is not possible to separate oil failure from gas success without making additional assumptions: some oil "failures" are reported as gas "successes". Finally, high oil prices of the recent past have tended to increase the number of small pools counted as discoveries. Consequently a success ratio from the early seventies of 1:8 was selected. During this period, the search for light and medium oil constituted most exploration. Exploration for natural gas was of limited importance. As a sensitivity test, ratios of 1:4, and 1:12 were considered.

Geological Inputs

Estimates of potential for each of 78 established plays were generated using the assessment methodology used by the Geological Potential Committee. All available geological data for the play and engineering data on existing pools from provincial regulatory agencies were used in the hydrocarbon resources assessment **(see Part I).**

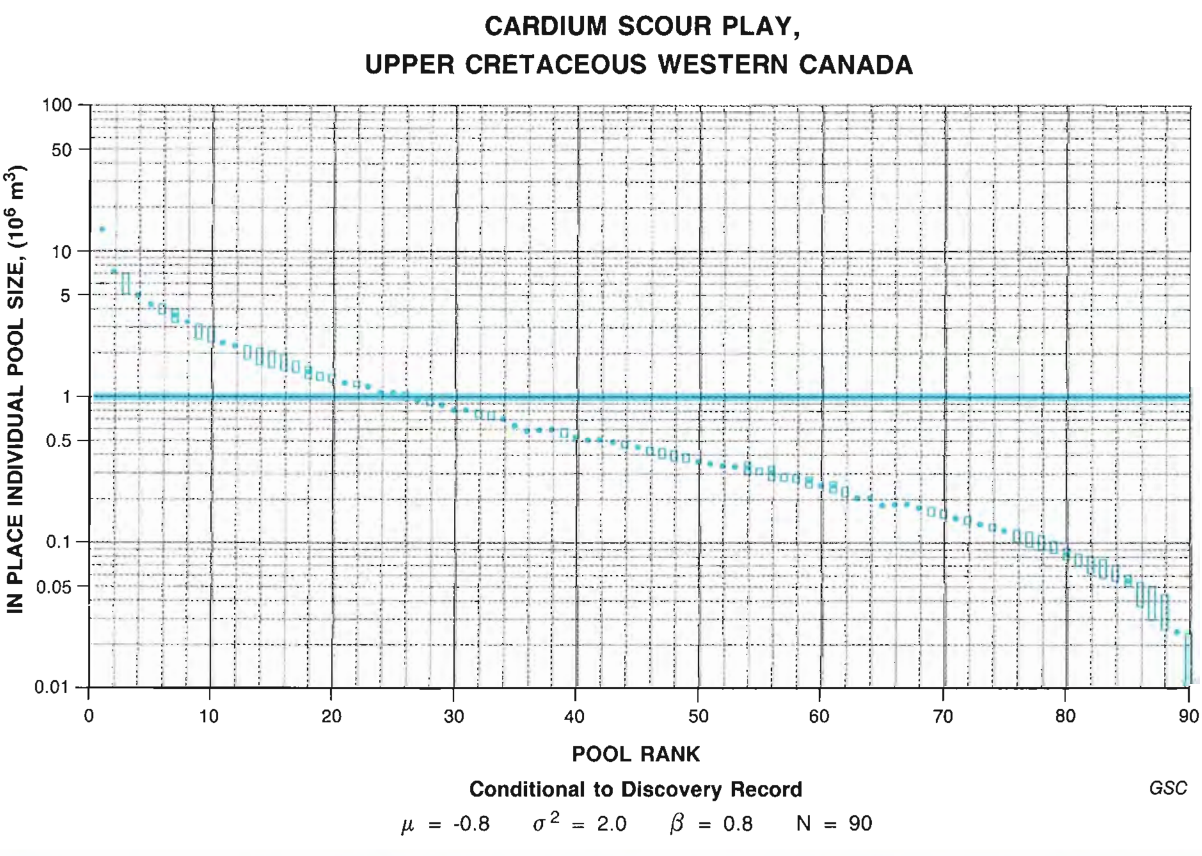


Figure 103

TABLE 71

DIFFERENCE BETWEEN MARGINAL FULL- AND HALF-CYCLE POTENTIAL

Success Ratio of 1:8 for Commercial and Economic Cases
$142/m³ (22.50/bbl)

	Resource Potential x 10^6m^3		Number of Pools	
	Marginal Full Cycle	Half Cycle	Marginal Full Cycle	Half Cycle
Commercial	354	426	757	2049
Economic	328	427	980	2046

Products of Resource Assessment

Geological and discovered pool data were used to prepare estimates of the number of undiscovered pools in a play, together with their sizes at various levels of probability.

Discovered pools were identified in each distribution and together with the remaining (undiscovered) pools form the pool array for the play. An example of such a distribution is shown in Figure 103. Discovered pools are indicated by dots, and undiscovered pools are shown as boxes. The size of the box represents the 5th to 95th percentile estimate of pool size.

Pool area is based on an empirically estimated logarithmic function in each play relating pool size (volume of oil-in-place) to pool area.

TABLE 72

PLAY DEPTHS AND RECOVERY FACTORS

	Play Depth (metres)	Recovery Factors: Average	Small Pool
CRETACEOUS			
CARDIUM SHEET	1000	0.20	0.10
VIKING-ALBERTA	1800	0.19	0.10
LOWER MANNVILLE	2100	0.15	0.10
VIKING-SASKATCHEWAN	500	0.14	0.10
UPPER MANNVILLE	1000	0.15	0.10
BELLY RIVER SHORELINE	1000	0.21	0.10
CARDIUM SCOUR	2000	0.19	0.10
CANTUAR	1000	0.15	0.06
DUNVEGAN-DOE CREEK	750	0.09	0.09
BELLY RIVER FLUVIAL	1500	0.21	0.10
OSTRACOD	2200	0.15	0.10
1st & 2nd WHITE SPECKS	2000	0.10	0.10
JURASSIC			
SHAUNAVON	1200	0.23	0.10
ROSERAY-SUCCESS	900	0.30	0.10
GILBY-MEDICINE RIVER	2200	0.25	0.10
SAWTOOTH	900	0.22	0.10
ROCK CREEK	2200	0.16	0.10
TRIASSIC			
BOUNDARY LAKE	1300	0.27	0.10
MONTNEY	1596	0.17	0.12
PEEJAY-MILLIGAN	1130	0.32	0.20
HALFWAY STRATIGRAPHIC	2150	0.28	0.12
INGA STRUCTURE	1600	0.15	0.10
CHARLIE LAKE SANDSTONE	1800	0.18	0.18
HALFWAY DRAPE	1900	0.19	0.10
CHARLIE LAKE ALGAL	1800	0.15	0.15
DOIG STRUCTURE	1900	0.08	0.05
PERMIAN			
BELLOY-PEACE RIVER	1850	0.28	0.12
BELLOY-EROSIONAL EDGE	2000	0.37	0.10
CARBONIFEROUS			
MIDALE	1400	0.36	0.20
FROBISHER-ALIDA	1100	0.24	0.20
PEKISKO EDGE	1650	0.13	0.07
ELKTON EDGE	1700	0.28	0.10
LODGEPOLE	1100	0.16	0.07
SOURIS VALLEY-TILSTON	1100	0.16	0.11
BANFF EDGE-C. ALBERTA	1500	0.20	0.12
RATCLIFFE STRATIGRAPHIC	1800	0.20	0.10
RATCLIFFE STRUCTURE	1100	0.20	0.10
DESAN	700	0.08	0.03
CARB.-SWEETGRASS ARCH	2000	0.10	0.10
BANFF EDGE-S. ALBERTA	1300	0.10	0.10
DEBOLT-PEACE RIVER	1500	0.08	0.08
DEVONIAN			
BEAVERHILL LAKE	2950	0.42	0.10
LEDUC-RIMBEY-MEADOWBROOK	1700	0.61	0.30
KEG RIVER	1800	0.41	0.30
NISKU-SHELF	1700	0.55	0.25
LEDUC-BASHAW	2000	0.61	0.20
LEDUC-DEEP BASIN	2000	0.61	0.15
NISKU-WEST PEMBINA	2800	0.40	0.30
MIDDLE DEVONIAN CLASTICS	1800	0.25	0.20
SLAVE POINT-SAWN	1600	0.20	0.10
ZAMA	1600	0.17	0.17
LEDUC-NISKU-S. ALTA	1700	0.15	0.15
WABAMUN-PEACE RIVER	1250	0.16	0.13
SLAVE POINT-GOLDEN	2000	0.35	0.30
NISKU-MEEKWAP	2000	0.40	0.15
KEG RIVER-SENEX	1300	0.20	0.10
WABAMUN-CROSSFIELD	2500	0.15	0.10
BISTCHO	1600	0.15	0.07
MUSKEG	1600	0.20	0.20
WABAMUN-ERODED EDGE	2050	0.14	0.14
LEDUC-PEACE RIVER	2800	0.20	0.15

TABLE 73

COST DATA
(thousands of 1985 dollars)

	Well Drilling /well	Road Const'n /km	Fixed Op Cost /well-month
CRETACEOUS			
CARDIUM SHEET	346	35	5.5
VIKING-ALBERTA	346	35	4.6
LOWER MANNVILLE	377	35	4.6
VIKING-SASKATCHEWAN	60	35	3.5
UPPER MANNVILLE	147	35	3.5
BELLY RIVER SHORELINE	240	35	4.2
CARDIUM SCOUR	451	35	5.5
CANTUAR	135	35	3.5
DUNVEGAN-DOE CREEK	250	80	4.2
BELLY RIVER FLUVIAL	326	35	5.5
OSTRACOD	377	35	4.6
1st & 2nd WHITE SPECKS	377	35	4.6
JURASSIC			
SHAUNAVON	160	35	3.5
ROSERAY-SUCCESS	135	35	3.5
GILBY-MEDICINE RIVER	450	35	3.5
SAWTOOTH	135	35	3.5
ROCK CREEK	450	35	5.5
TRIASSIC			
BOUNDARY LAKE	282	80	6.5
MONTNEY	334	35	5.5
PEEJAY-MILLIGAN	360	80	5.5
HALFWAY STRATIGRAPHIC	477	80	5.5
INGA STRUCTURE	427	80	5.5
CHARLIE LAKE SANDSTONE	353	80	5.5
HALFWAY DRAPE	330	80	5.5
CHARLIE LAKE ALGAL	353	80	5.5
DOIG STRUCTURE	330	80	5.5
PERMIAN			
BELLOY-PEACE RIVER	330	80	5.5
BELLOY-EROSIONAL EDGE	451	35	5.5
CARBONIFEROUS			
MIDALE	200	35	3.5
FROBISHER-ALIDA	160	35	3.5
PEKISKO EDGE	326	35	4.6
ELKTON EDGE	380	35	0.5
LODGEPOLE	160	35	3.5
SOURIS VALLEY-TILSTON	160	35	3.5
BANFF EDGE-C. ALBERTA	334	35	5.5
RATCLIFFE STRATIGRAPHIC	250	35	4.6
RATCLIFFE STRUCTURE	160	35	3.5
DESAN	200	125	5.0
CARB.-SWEETGRASS ARCH	550	35	4.6
BANFF EDGE-S. ALBERTA	280	35	4.2
DEBOLT-PEACE RIVER	425	80	5.5
DEVONIAN			
BEAVERHILL LAKE	360	35	5.4
LEDUC-RIMBEY-MEADOWBROOK	326	35	5.5
KEG RIVER	537	125	6.5
NISKU-SHELF	346	35	4.6
LEDUC-BASHAW	346	35	4.6
LEDUC-DEEP BASIN	451	35	5.5
NISKU-WEST PEMBINA	400	35	6.8
MIDDLE DEVONIAN CLASTICS	475	80	6.5
SLAVE POINT-SAWN	427	80	6.5
ZAMA	537	125	6.5
LEDUC-NISKU-S. ALTA	250	35	4.6
WABAMUN-PEACE RIVER	363	80	4.2
SLAVE POINT-GOLDEN	498	80	6.5
NISKU-MEEKWAP	451	35	5.5
KEG RIVER-SENEX	427	80	5.0
WABAMUN-CROSSFIELD	617	35	5.5
BISTCHO	537	125	6.5
MUSKEG	537	125	6.5
WABAMUN-ERODED EDGE	414	35	5.5
LEDUC—PEACE RIVER	452	80	6.8

Average play depth is based on provincial reservoir data. It was assumed that all undiscovered pools in a play would be at this depth. Play depths used in calculating drilling and completion costs are shown on Table 72.

Play average recovery factors are estimated to include primary and secondary recovery. Small-pool recovery factors (Table 72) were estimated for each play on the basis of data available from provincial records. Small-pool recovery factors were used only to estimate marginal pool size. Average play recovery factors were then applied to calculate cumulative *commercial* and *economic* potential using the pool size distributions.

Play maps were used to select parameters relevant to royalty schedules and well operating costs.

Engineering and Cost Inputs

The economic analysis is based on a system of generalized design and costing algorithms. This sytem, called the Development Model, estimates a development design based on production levels, required equipment capacities, facilities, and construction schedules. Unit cost levels were estimated from a variety of sources and used in the development model to estimate schedules of total cost.

Development Schedule

Development wells were assumed drilled over a one to three year period, depending on the number of wells required. A maximum of six wells were assumed drilled in year one, ten in year two, and the remainder in year three. Surface facilities were sized to field requirements. Each well in a given pool was assumed to have the same production profile.

Development and Operating Costs

Dry and abandoned drilling costs were estimated from data gathered by the Department of Energy, Mines and Resources and data from consultants (see Table 73). The cost of successful wells, including completion, was estimated as a function of dry well costs and depth.

Production batteries were sized to handle the highest pool production rate. For low pool production rates (less than 1590 m^3/d) battery cost/m^3 was estimated to change in direct proportion to the natural logarithm of the production rate. For rates greater than 1590 m^3/d, no further economy of scale was assumed.

Flowlines were sized to accommodate a velocity of about one metre per second. Minimum line diameter was assumed to be 50 mm. Wells were assumed to be equally spaced. Flowline installation asssumed a step out pattern from a central discovery well. Two sets of installed flowline costs were used, dependent on location. If south of Alberta Township 69, 50 mm diameter pipe was costed at $26 000 per kilometre, 75 mm pipe at $36 000 per kilometre, and 100 mm diameter pipe at $42 000 per kilometre. North of Township 68, costs were tripled.

Road construction costs vary between $35 000 and $125 000 per kilometre depending on location. These costs are presented on Table 73.

Well operating costs were estimated as functions of geographical location and well depth, and were treated as a fixed monthly charge per well. For variable operating costs (transportion to a pipe line inlet) $6/m^3 was assumed.

ECONOMIC AND FINANCIAL CONSIDERATIONS

The economic analysis assesses the profitability of exploration and development over the long term; it has intentionally not taken into consideration short-term market fluctuations resulting from changing prices and costs. The emphasis of the analysis is therefore on the total quantity of oil likely to be recovered and on the costs of finding and developing individual pools, because these are the factors most important to the future viability of the western Canadian oil industry. The results should accordingly be useful, at the federal and provincial level, for investment analysis and planning for the long term supply of light and medium oil from undiscovered resources.

Several assumptions followed from the decision to take a long-term view of the economic environment. In spite of the fact that industry has, in the past, made many technical improvements which have reduced costs, it was assumed for the present analysis that no further technical advances would take place; costs were taken as constant at 1985 levels. Fiscal measures introduced in the past to deal with specific short-term problems were not included in the analysis; details are given below.

Taking a long-term view, however, has its limitations. Results cannot be used to forecast the short to medium term. For example, in the long-term, cash flow is not a consideration because it is assumed that either expected profitable investment would be able to attract competitive financing or cash flow would be available from larger and more profitable discoveries. In the short-term, however, available cash flow may be an overriding constraint to investment and hence activity levels. In summary, no consideration is given to the many difficulties created by cyclical market conditions.

Oil Price

The price of crude oil at Edmonton was used as a reference. This price was backed up to well-heads to reflect expected transportation costs and quality differentials.

Analytical results are presented as functional relationships of profitable resource volumes to price. This is done because of expected fluctuations of the price of crude oil over the long term.

Rate of Return

The minimum required expected real rate of return after tax and royalty is assumed to be 10%. It was recognized that this rate varies from company to company, as does tax position. The marginally sized pool, or pools at the margin of activity, are defined to just yield 10%. By assumption, pools larger than the marginal pool earn greater rates of return.

Federal Taxation

Given that the analysis is intended to estimate long-term profitable potential, all fiscal items of a temporary nature have been excluded, such as Investment Tax Credits and the federal tax surcharge. A 33% federal tax, after provincial abatement, was used. A fully taxable position was assumed for the *commercial* estimates.

Provincial Fiscal Systems

Alberta: A corporate income tax rate of 11% was used and royalties were calculated according to the intent of the current legislation. Royalty holiday allowances announced by the Province on June 24, 1985 were included. This allows a royalty-free volume or period for the first well in a pool. The level of relief varies for different regions of the province. Although this may not be a long-term program, it was assumed that a program of the same value would be in effect at most times. No other incentive programs were included, because they were assumed to be either temporary, or restricted to certain classes of companies and, therefore, beyond the scope of the analysis.

Saskatchewan: The corporate income tax rate used was 17%. Royalty rates were used according to the schedule in existence prior to January 1, 1987. All oil was assumed to be "new" and Crown land was assumed for all locations. The royalty holiday system in effect prior to January 1, 1987 was used. This allows three royalty-free years for the first well in a pool (five years if a Devonian pool).

British Columbia: The corporate income tax rate used was 14% and royalty rates were applied as in the current legislation for "new" oil.

Tax Class Allocations

Capital costs were allocated to the following classes for taxation purposes:

Class 10: (30% declining balance). Includes battery cost and 25% of successful well costs.

Canadian Development Expense: (30% declining balance). Includes 75% of successful development well cost, and all road construction costs.

Canadian Exploration Expense. Includes 100% of all exploratory well costs.

Results are presented as estimated profitable potential curves. These relationships show profitable potential as a function of wellhead price referenced at Edmonton. Analyses were performed at the play level. Results, however, are presented at two levels of aggregation — total Western Canada and by geological period.

Figures 104 and 105 present the total Western Canada results, showing the expected marginal full and half-cycle quantity of *commercial* and *economic* potential at various prices. The marginal full-cycle curves are based on an exploratory success ratio of 1:8. Subsequent figures show results aggregated by geological period.

Figure 106 presents the sensitivity of *commercially* and *economically* discoverable resources to exploratory success at a Canadian price of \$142/m^3 (\$22.50/bbl). At this price the curves demonstrate a relative insensitivity of profitable resources to exploration costs. At lower prices, however, this sensitivity would be greater.

Tables 74 and 75 illustrate results at a Canadian crude price of \$142/m^3 (\$22.50/bbl) together with the number of associated pools. The price of \$142/m^3 was selected for illustrative purposes only. There is no implication that this price represents a long-term equilibrium level.

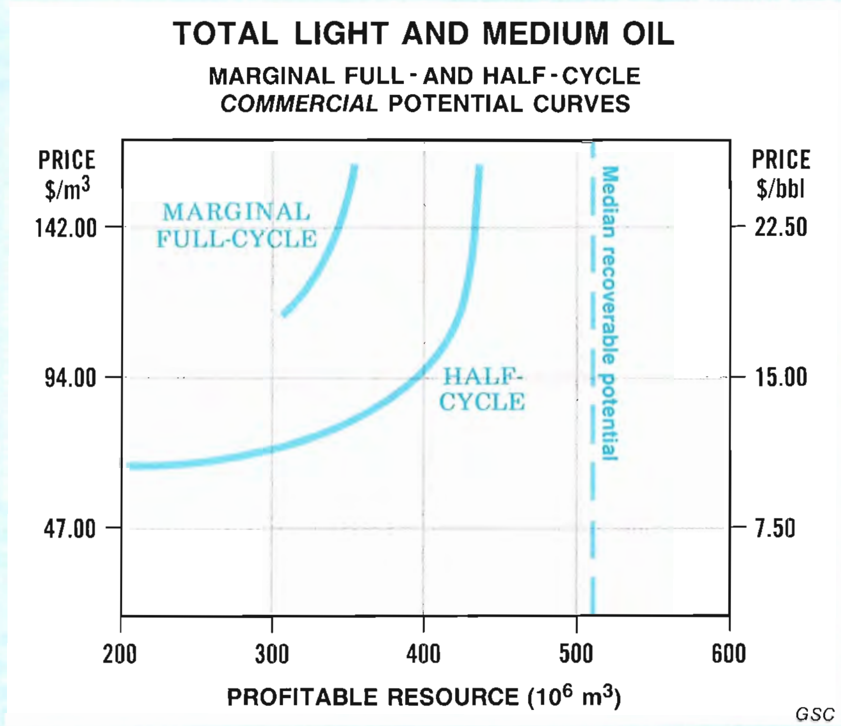


Figure 104

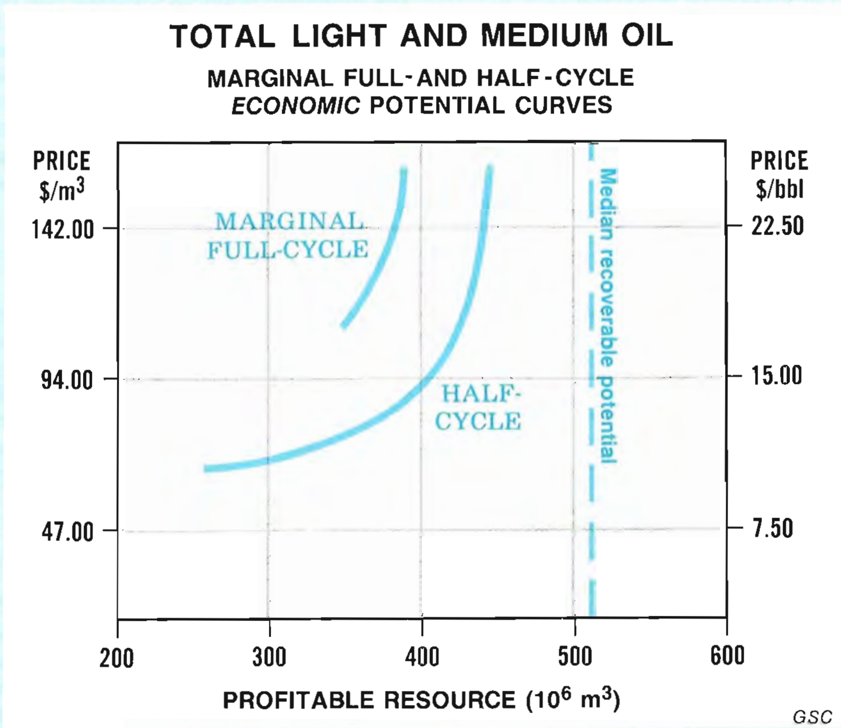


Figure 105

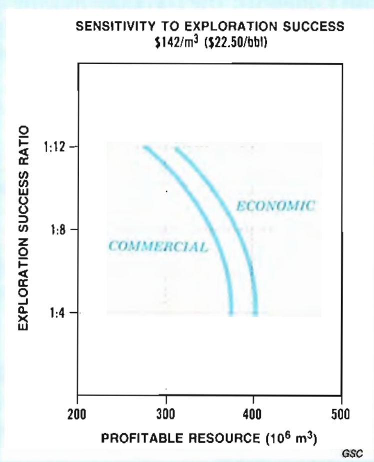


Figure 106

TABLE 74

COMMERCIAL VIABILITY
Total Recoverable potential of established plays = 509 x 10^6 m^3

	Potential With Exploration Costs 10^6 m^3	% Potential	No. of Pools	Potential Without Exploration Costs 10^6 m^3	% Potential	No. of Pools
Cretaceous	66	70	222	91	95	840
Jurassic	7	45	7	13	89	73
Triassic	7	25	7	23	87	204
Permian	6	41	8	9	58	23
Carboniferous	23	53	133	33	76	202
Devonian	246	78	380	263	83	707
TOTAL	354	70	757	431	85	2049

Analysis based on 1:8 success ratio and price of \$142 Canadian/m^3(\$22.50/bbl)

TABLE 75

ECONOMIC VIABILITY
Total Recoverable potential of established plays = 509 x 10^6 m^3

	Potential With Exploration Costs 10^6 m^3	% Potential	No. of Pools	Potential Without Exploration Costs 10^6 m^3	% Potential	No. of Pools
Cretaceous	77	81	363	91	95	815
Jurassic	9	58	9	13	89	72
Triassic	15	60	59	23	88	197
Permian	7	48	9	9	58	23
Carboniferous	26	60	145	33	76	202
Devonian	252	80	395	264	84	737
TOTAL	385	76	980	432	85	2046

Analysis based on 1:8 success ratio and price of \$142 Canadian/m^3(\$22.50/bbl)

Cretaceous Plays

There are thirteen Cretaceous plays estimated to contain 17% of the total undiscovered potential at a median probability level. Ten are located in Alberta and two in Saskatchewan. Well depths are generally near 2000 m, with a few exceptions at around 1000 m. Plays are generally south of Edmonton with one exception near the B.C. border at Dawson Creek.

Due to southerly locations, drilling, development and operating costs are moderate. Road systems are well developed and access road costs are not high.

Tables 74 and 75 show results at $142/m^3$ ($22.50/bbl). Table 76 presents summary data on Cretaceous potential and on that portion analyzed. Figure 107 presents the half-cycle *commercial* and *economic* curves. Figure 108 presents the *commercial* and *economic* sensitivity of profitable resource to exploration success at a price of $94/m^3$ ($15/bbl).

TABLE 76

CRETACEOUS SUMMARY

Established Reserves	$47 \times 10^6\ m^3$
Median Undiscovered Recoverable Potential	$95 \times 10^6\ m^3$
Number of Plays	13
PORTION SUBJECTED TO ANALYSIS	
Median Undiscovered Recoverable Potential	$91 \times 10^6\ m^3$
Number of Plays	12
Number of Pools	
Discovered	976
Undiscovered	1104
TOTAL	2080

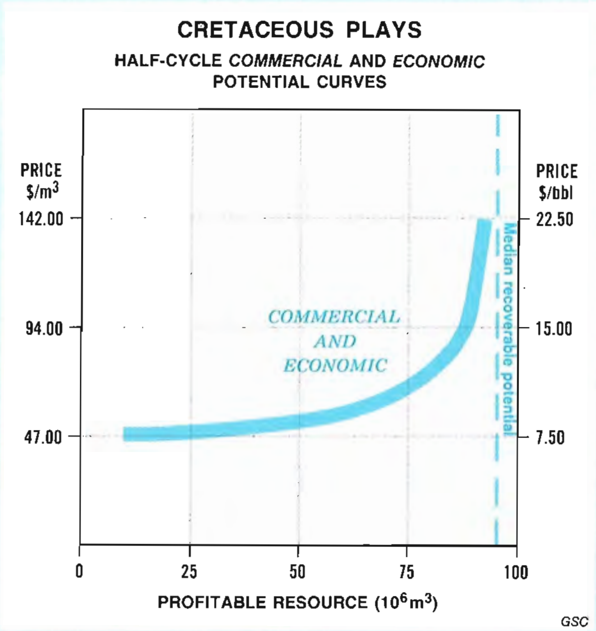


Figure 107

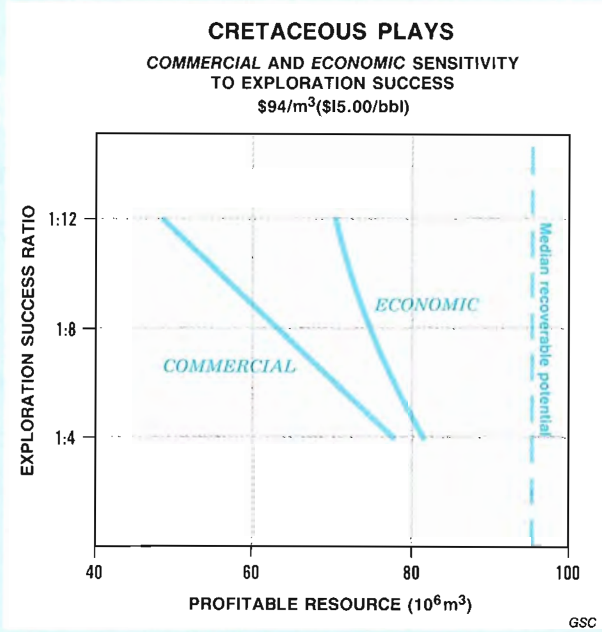


Figure 108

Jurassic Plays

There are seven Jurassic plays which fall into two groups. Four are near the Canada-US border (three of these are in Saskatchewan). The remaining are mid-way between Calgary and Edmonton. The southern plays are at depths of approximately 1000 m. The northern plays are at nearly twice this depth.

These plays are well served by existing road networks and each pool is assumed to require one-half kilometre of access road.

Table 74 and 75 show results at $142/m^3$ ($22.50/bbl). Table 77 presents summary data on Jurassic potential and on that portion analyzed. Figure 109 presents the half-cycle *commercial* and *economic* curves. Figure 110 presents the *commercial* and *economic* sensitivity of profitable resource to exploration success at a price of $94/m^3$ ($15/bbl).

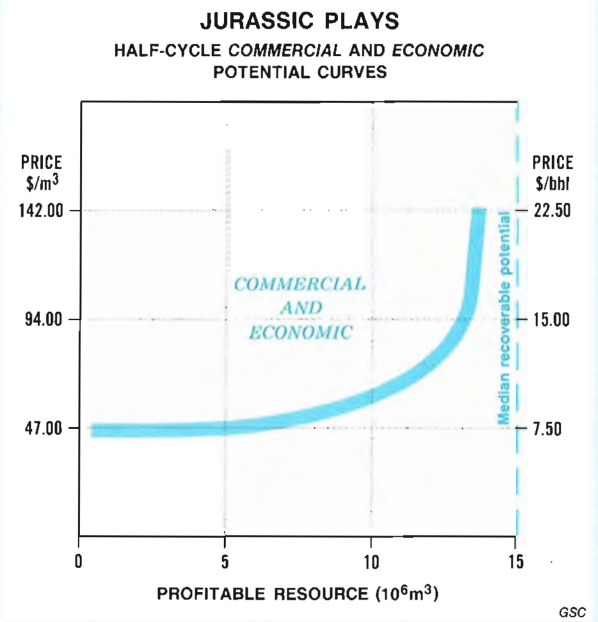


Figure 109

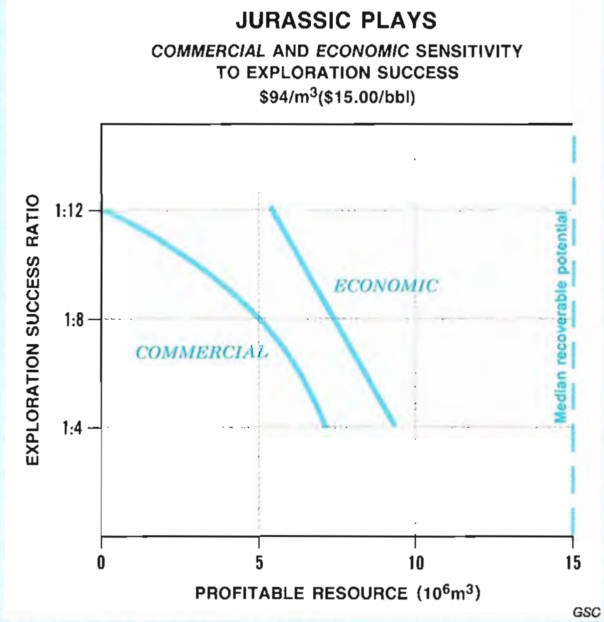


Figure 110

TABLE 77

JURASSIC SUMMARY

Established Reserves	94 x 10^6 m^3
Median Undiscovered Recoverable Potential	15 x 10^6 m^3
Number of Plays	7
PORTION SUBJECTED TO ANALYSIS	
Median Undiscovered Recoverable Potential	14 x 10^6 m^3
Number of Plays	5
Number of Pools	
Discovered	125
Undiscovered	89
TOTAL	214

TABLE 78

TRIASSIC SUMMARY

Established Reserves	65 x 10^6 m^3
Median Undiscovered Recoverable Potential	26 x 10^6 m^3
Number of Plays	11
PORTION SUBJECTED TO ANALYSIS	
Median Undiscovered Recoverable Potential	24 x 10^6 m^3
Number of Plays	9
Number of Pools	
Discovered	186
Undiscovered	309
TOTAL	495

Triassic Plays

There are eleven Triassic plays. Seven are located in British Columbia and four in Alberta. Depths range from 1000 to 2000 m. These plays are in northern areas of Alberta and British Columbia and are not well served by existing roads. Operating costs are high and roads as long as 5 km are assumed to be required for each developed pool.

Tables 74 and 75 show results at $142/m^3 ($22.50/bbl). Table 78 presents summary data on Triassic potential and on that portion analyzed. Figure 111 presents the half-cycle *commercial* and *economic* curves. Figure 112 presents the *commercial* and *economic* sensitivity of profitable resource to exploration success at a price of $94/m^3 ($15/bbl).

Permian Plays

One of the two plays is in Alberta, northeast of Edmonton; the other is in British Columbia near Fort St. John. Each is at a depth of approximately 2000 m. Each play is well served by existing roads. Pools are assumed to be within one-half kilometre of a road.

Table 74 and 75 show results at $142/m^3 ($22.50/bbl). Table 77 presents summary data on Jurassic potential and on that portion analyzed. Figure 113 presents the half-cycle *commercial* and *economic* curves. Figure 114 presents the *commercial* and *economic* sensitivity of profitable resource to exploration success at a price of $94/m^3 ($15/bbl).

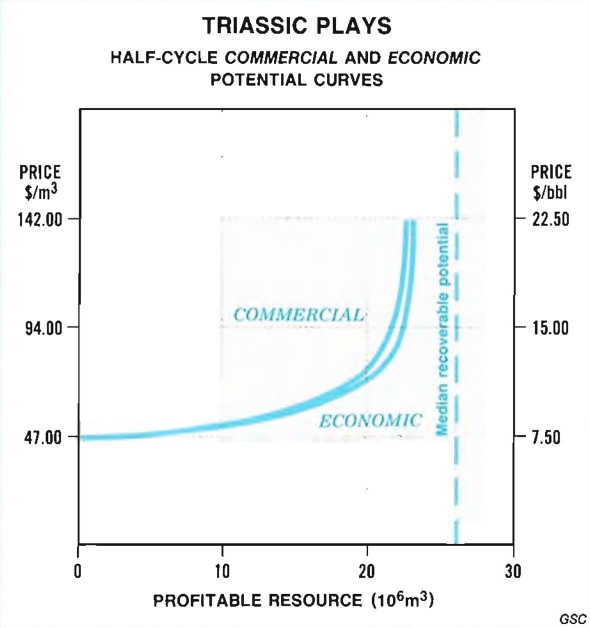


Figure 111

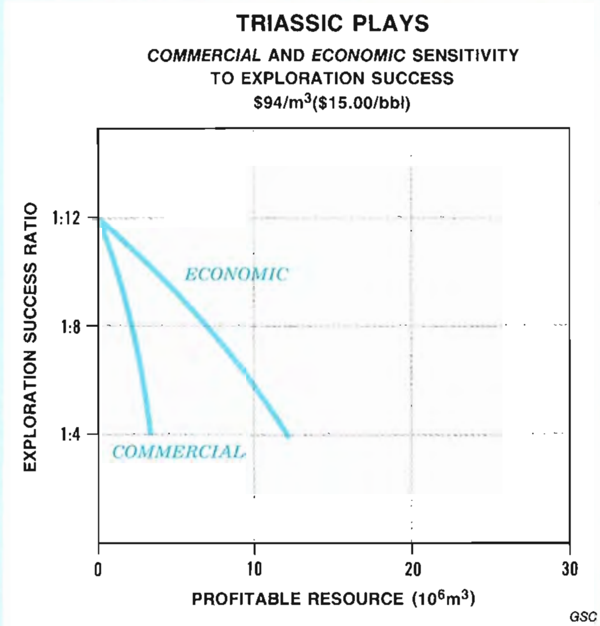


Figure 112

Carboniferous Plays

The 17 plays of the Carboniferous extend from southeast Saskatchewan through to the Peace River area of Alberta. They are estimated to contain 7.5% of the total undiscovered potential at a median probability level. The six eastern plays are at depths of approximately 1000 m while the more northerly plays in Alberta can be twice as deep. These plays cover a large and diverse area. There are consequently substantial variations in development and operating costs. Tables 74 and 75 show results at $142/m^3$ ($22.50/bbl). Table 80 presents summary data on Carboniferous potential and on that portion analyzed. Figure 115 presents the half-cycle *commercial* and *economic* curves. Figure 116 presents the *commercial* and *economic* sensitivity of profitable resource to exploration success at a price of $94/m^3$ ($15/bbl).

TABLE 79

PERMIAN SUMMARY

Established Reserves	$15 \times 10^6\ m^3$
Median Undiscovered Recoverable Potential	$15 \times 10^6\ m^3$
Number of Plays	2
PORTION SUBJECTED TO ANALYSIS	
Median Undiscovered Recoverable Potential	$15 \times 10^6\ m^3$
Number of Plays	2
Number of Pools	
Discovered	15
Undiscovered	35
TOTAL	50

TABLE 80

CARBONIFEROUS SUMMARY

Established Reserves	$339 \times 10^6\ m^3$
Median Undiscovered Recoverable Potential	$43 \times 10^6\ m^3$
Number of Plays	17
PORTION SUBJECTED TO ANALYSIS	
Median Undiscovered Recoverable Potential	$39 \times 10^6\ m^3$
Number of Plays	12
Number of Pools	
Discovered	300
Undiscovered	425
TOTAL	725

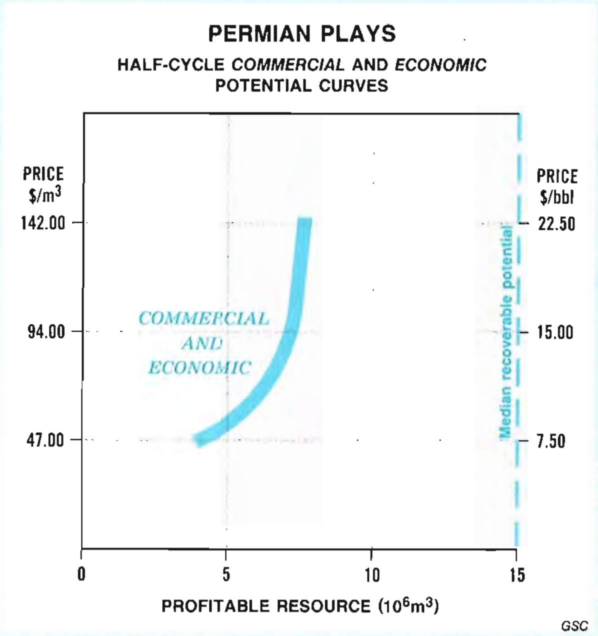


Figure 113

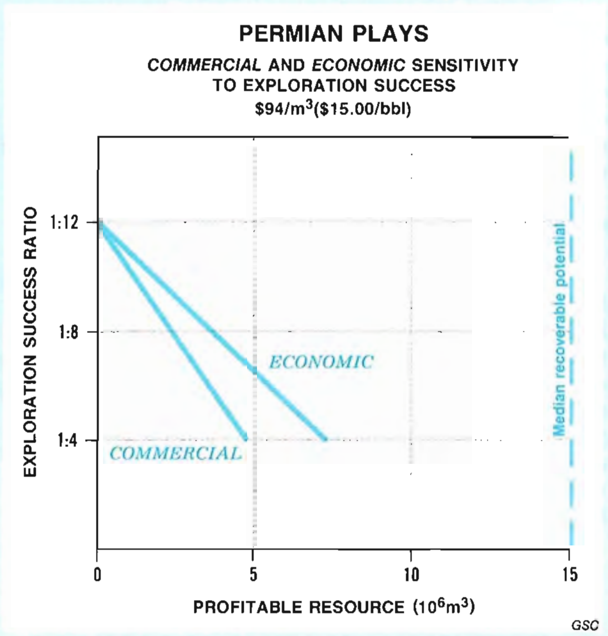


Figure 114

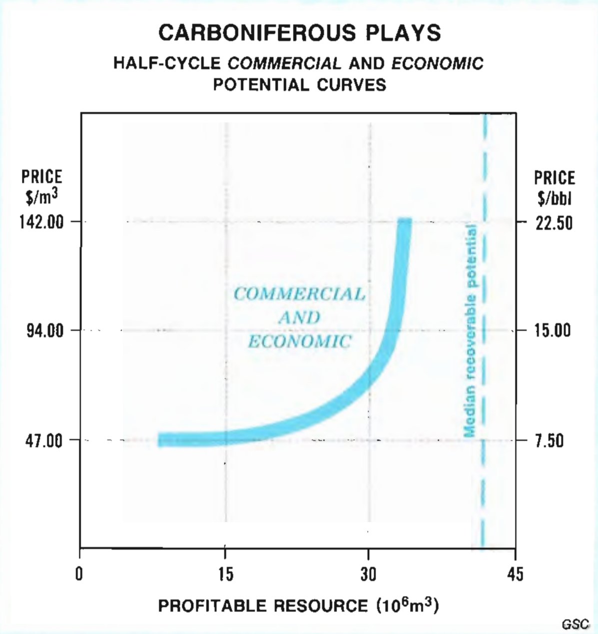


Figure 115

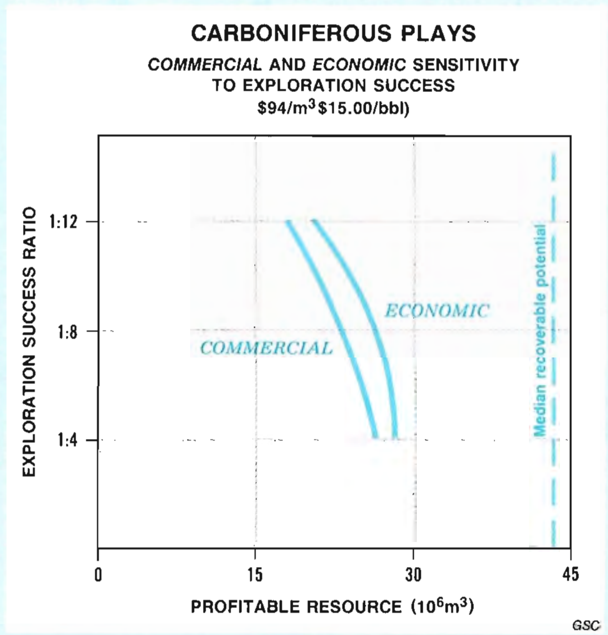


Figure 116

Devonian Plays

The 28 Devonian plays are estimated to contain 55% of the total undiscovered potential. Most of the plays are in Alberta, north of Edmonton, but two are in the south, and one play is in southern Saskatchewan. Well depth is generally at 2000 m or more.

The northern location of these plays results in high development and operating costs.

Tables 74 and 75 show results at $142/m^3 ($22.50/bbl). Table 81 presents summary data on Devonian potential and on that portion analyzed. Figure 117 presents the half-cycle *commercial* and *economic* curves. Figure 118 presents the *commercial* and *economic* sensitivity of profitable resource to exploration success at a price of $94/m^3 ($15/bbl).

TABLE 81

DEVONIAN SUMMARY

Established Reserves	**1318 x 10^6 m^3**
Median Undiscovered Recoverable Potential	**315 x 10^6 m^3**
Number of Plays	**28**
PORTION SUBJECTED TO ANALYSIS	
Median Undiscovered Recoverable Potential	**274 x 10^6 m^3**
Number of Plays	**19**
Number of Pools	
Discovered	**936**
Undiscovered	**1081**
TOTAL	**2017**

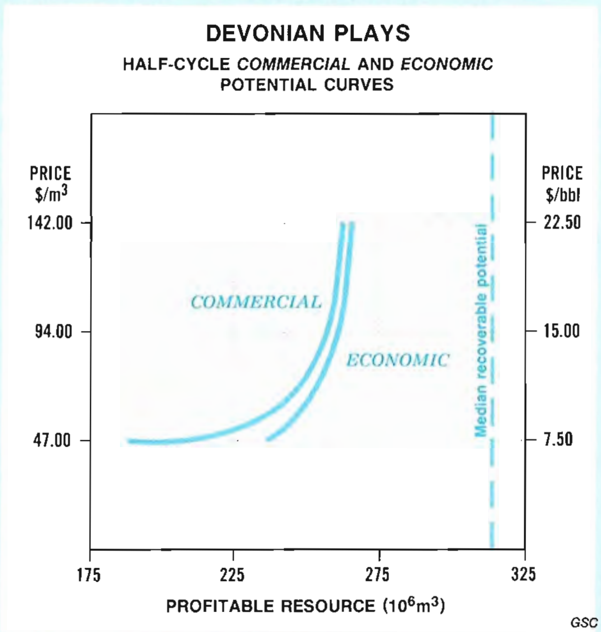


Figure 117

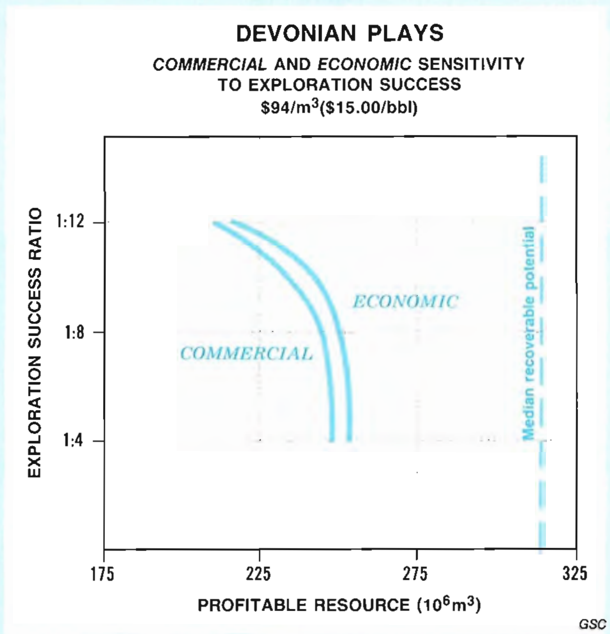


Figure 118

ECONOMIC CONCLUSIONS

The following conclusions must be viewed in a long-term context. A resource estimated to be profitable over the long term may not yield profits in the short term for a number of reasons. There may be an expectation by industry that undiscovered pools are not sufficiently large or numerous to support further exploration. Financing or cash flow may be insufficient for investment. Other resource development may be relatively more profitable.

At \$142/m^3 (\$22.50/bbl) conclusions 1-8 may be drawn:

1. For Western Canada as a whole, assuming an exploration success rate of 1:8, 70% of the total potential (at the median level of probability) is *commercially* viable over the long term. Without exploration costs, 85% of the total potential is *commercially* viable. With exploration drilling costs, the profitable potential may be found in 757 pools. Without exploration costs, the profitable potential may be found in 2049 pools. Table 74 disaggregates this information by geological period.

2. In a public or *economic* context, 76% of the total potential is viable with an exploration success rate of 1:8. Without exploration costs this increases to 85%. The profitable potential is distributed in 980 and 2046 pools respectively. Table 75 disaggregates this information by geological period.

3. An increase in exploratory success ratio to 1:4 (+ 50%) results in an approximate 4% increase in *economic* viability and a 7% increase in *commercial* viability. A decrease in exploratory success ratio to 1:12 (- 50%) results in an approximate 11% decrease in *economic* viability and a 21% decrease in *commercial* viability.

4. The bulk of profitable potential is located in the Devonian, Carboniferous and Cretaceous.

5. The *economic* margin is close to the *commercial* margin for pools in five of the six geological periods. The Triassic, with substantially more *economic* than *commercial* potential, is the exception, but accounts for only 5% of the total undiscovered potential.

6. There is significant variation in the amount of profitable potential between geological periods, ranging from 25-81% on a marginal full-cycle basis and from 58-95% on a half-cycle basis.

7. *Economically* viable potential may be found in 980 pools. *Commercially* viable potential may be found in 757 pools. If the *commercial* margin were extended to the *economic* margin, an additional 6% of potential (31.5×10^6 m^3) would become viable *commercial* exploration targets. The half-cycle *commercial* and *economic* margins are virtually the same.

8. Although the difference between *economic* and *commercial* marginal full-cycle potential is relatively small (6%), the difference in the number of pools is great (29%).

9. The aggregate half-cycle profitable potential, mostly contained in rocks of Devonian, Carboniferous and Cretaceous periods, is somewhat responsive to price in the \$47-94/m^3 (\$7.50-15/bbl) range and rapidly becomes less responsive to price in the \$94-142/m^3 (\$15-22.50/bbl) range. The portion estimated in the marginal full-cycle case similarily does not show a large response to price between \$94-142/m^3.

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