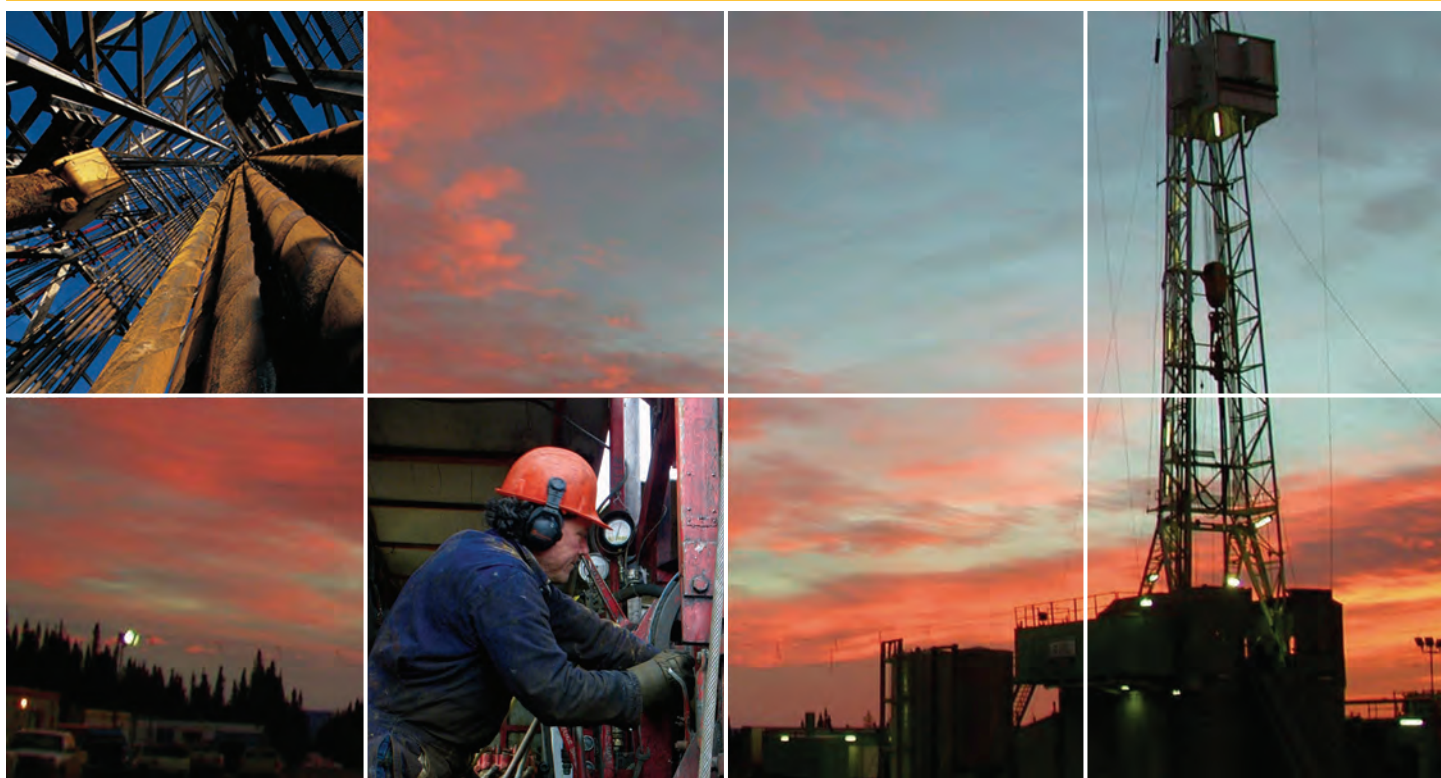


Conventional Natural Gas Play Atlas Northeast British Columbia

Petroleum Geology Publication 2006-01



Oil and Gas Division
Resource Development and Geoscience Branch



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The Northeast BC Play Atlas

The Resource Development and Geoscience Branch of the BC Ministry of Energy and Mines and Petroleum Resources (MEMPR) in partnership with the National Energy Board (NEB) have undertaken an assessment of British Columbia's undiscovered resources. The final report entitled *Northeast British Columbia's Ultimate Potential for Natural Gas Report - 2006A* is now available through both the NEB and MEMPR websites. To access the report on the provincial government website, go to:

<http://www.em.gov.bc.ca/subwebs/oilandgas/resource/cog/cog.htm>.

While this new report covers all of BC's gas potential areas, the major focus of the assessment is the quantification of the remaining undiscovered conventional gas potential of NEBC.

As a companion to the joint NEB/MEMPR Northeast British Columbia's Ultimate Potential for Natural Gas report, MEMPR has developed this *Conventional Natural Gas Play Atlas, Northeast British Columbia*. The play atlas was created to provide a framework for the assessment process and to provide a reference point for future analyses. As is the case with any resource estimate, the current play definitions represent a snapshot in time as they continually evolve through the interplay of new geological concepts, technological developments and changing commodity prices.

The Conventional Natural Gas Play Atlas contains both established and conceptual plays, and also contains some plays that could arguably be identified as unconventional. For the purpose of both the joint NEB/MEMPR resource estimate and the play atlas, a broad definition of "conventional gas resources" was utilized. Within this atlas, play definitions generally include the spectrum of resource exploration concepts that have been traditionally exploited in British Columbia's portion of the Western Canadian Sedimentary Basin (WCSB), and are considered proven and developable with today's technology. They are relatively low risk and thus have a high probability of being commercially productive. Unconventional resources, were deemed to be those resources that were generally not currently productive as of year end 2003. Examples include coalbed gas (CBG), some tight gas, shale gas and gas hydrates. Although unconventional CBG and shale gas resources are now contributing significantly to U.S. production stream they are for the most part currently unproven in NEBC.

In addition to this hardcopy version, a CD will also be available that will include all maps and descriptions in a digital format and a complete database presenting results of the joint NEB/MEMPR Northeast British Columbia's Ultimate Potential for Natural Gas Report - 2006A.

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1.0 Northeast BC Geographic Areas

To aid in subsequent analysis, northeast British Columbia has been subdivided into six resource regions: Liard Basin & Fold Belt; Fort Nelson/Northern Plains; Fort St. John; Northern Foothills; Southern Foothills; and the Deep Basin.

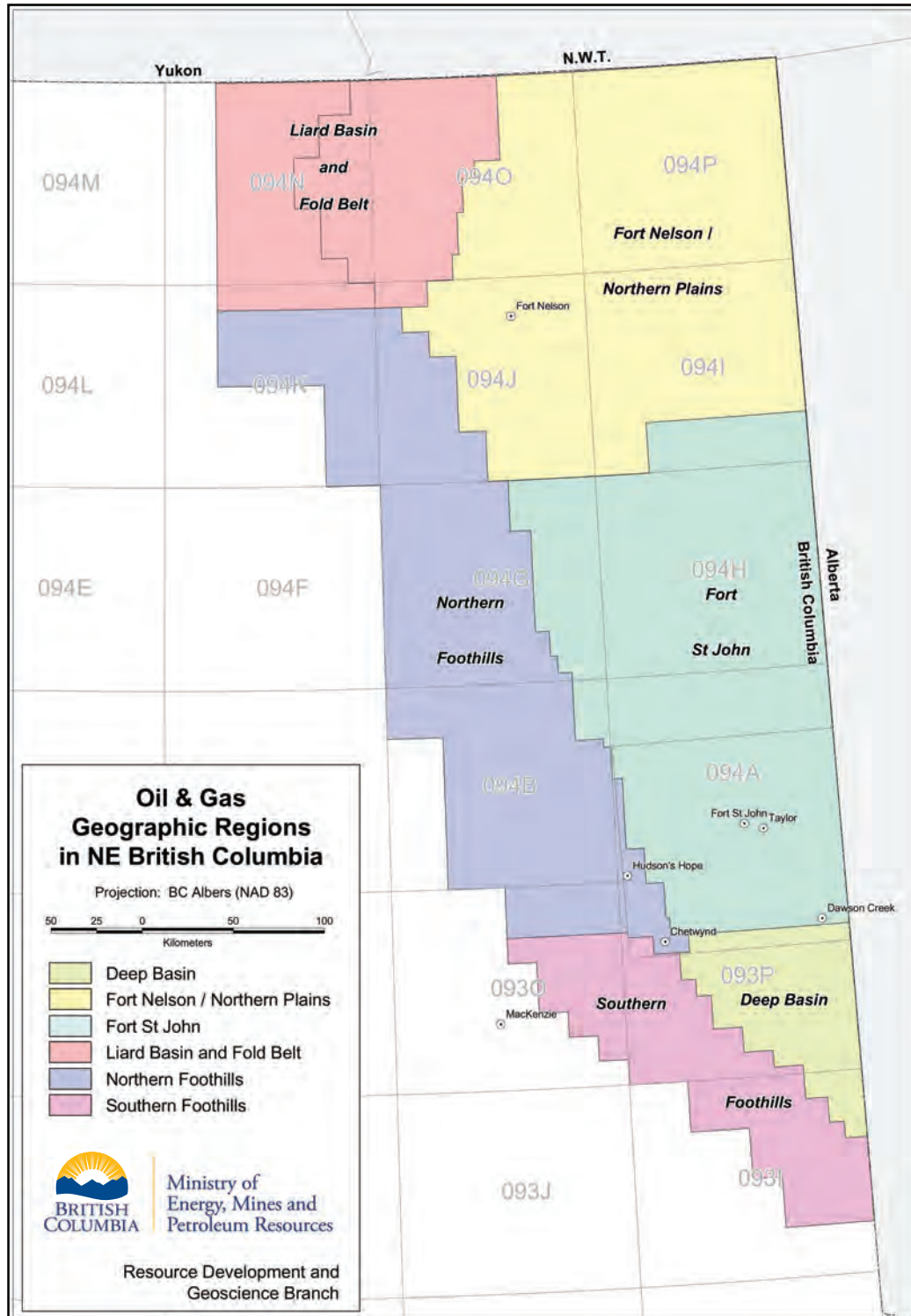


Figure 1. Resource regions of northeast British Columbia utilized within this report.

1.1 Liard Basin & Fold Belt

Bounded to the north by the Northwest Territories and Yukon Territory and to the south and east by the Northern Foothills and Northern Plains, respectively, the Liard Basin is a relatively unexplored region situated immediately east of the Cordilleran fold and thrust belt. For the purpose of this assessment, the Basin has been combined with the Liard Fold and Thrust Belt, a region with significant Laramide deformation. In northeast British Columbia, the Liard Basin & Fold Belt covers an area of approximately 1.25 million hectares and contains over five kilometres of sedimentary strata of Cambrian to Upper Cretaceous age. Potential hydrocarbon objectives occur in the Devonian Dunedin/Nahanni Formation, the Mississippian Banff, the Debolt and Mattson formations, the Permo-Pennsylvanian Kindle and Fantasque formations, the Triassic Toad Formation, and the Cretaceous Chinkeh and Scatter formations. The Nahanni Formation holds significant potential in dolomitized reservoirs in the structural belt. The Debolt, Mattson, Kindle, Fantasque formations, and possibly the Triassic Grayling and Toad formations, are potential objectives in structural closures on the Bovie Lake structure along the margin of the basin. To the east on the platform, stratigraphic traps within the Banff and Debolt formations are also potential objectives.

1.2 Fort Nelson/Northern Plains

Located in the northeast corner of British Columbia, the Fort Nelson/Northern Plains region (Figure 1) covers an area of 3.85 million hectares. In terms of oil and gas exploration, the region has been active since the 1960's with the search for natural gas dominated by the Middle Devonian Keg River, Pine Point and Slave Point carbonate plays. These plays have high reserves and high deliverability and include BC's largest recognized gas accumulation at Clarke Lake (3.7 Tcf OGIP). However, within the last 10 years, the Upper Devonian Jean Marie Formation has become the major target for operators and natural gas from this interval now dominates new production from the region.

Other potential hydrocarbon objectives in the Fort Nelson/Northern Plains region are the Debolt, Pekisko and Shunda subcrop edges. Cretaceous targets include a detrital lag at the top of the Mississippian and the Bluesky Formation. New conceptual gas opportunities may also be found in Tertiary/Quaternary sediments similar to the Sousa play in NW Alberta.

In addition, the region is a major contributor to the province's oil production stream. There is continued development of the Hay River Bluesky heavy oil pools along with the revival of the Desan, Pekisko and Shunda oil pools.

1.3 Fort St John

The Fort St John region covers an area of 3.7 million hectares and continues to be the hub of activity and production for the province. The region has a variety of geologic settings, which combine to offer good quality, low-risk, gas and oil prospects through stacked multi-zone potential. The deep (2 800 to 3 200 metre true vertical depth) Slave Point play along the Hotchkiss Embayment continues to entice exploration since the discovery of the Ladyfern A, B and C pools (762 Bcf OGIP) in 2000. Deeper conceptual plays also occur in the Middle Devonian clastics and Keg River carbonates. On the western side of the area, Laramide-induced folding and structural trapping provides opportunity for gas in the Debolt, Halfway, Charlie Lake and Baldonnel formations and various Cretaceous sands. The Fort St. John Graben houses numerous structural and stratigraphic objectives ranging from hydrothermal dolomites in the Wabamun Formation to sands in the Mississippian Kiskatinaw and Permian Belloy formations. Traditional targets in the region have been the Triassic stratigraphic and erosional edge plays in the Montney, Doig, Halfway, and Baldonnel formations and numerous Charlie Lake members. Lower Cretaceous clastics have also been sought after in the region, with the Dunlevy, Gething and Bluesky formations being major production horizons. Recently, both the tighter Gething sands in erosional valley systems and lowstand Notikewan sands have been the target of focused development north of the Peace River Block.

1.4 Deep Basin

The Deep Basin region comprises an area of 692 000 hectares and offers thick sequences of stacked, regionally extensive, gas-saturated Mesozoic clastic reservoirs. Traditionally, exploration has focused on identifying stratigraphic sweet spots in the Cadotte and Falher formations that feature conventional reservoir quality. In fact, some of these conglomeratic reservoirs continue to offer some of the highest initial deliverability rates in the province. The tight gas component of the Deep Basin, however, offers a huge potential resource that is just beginning to be exploited. In the BC Tight Gas Exploration Assessment (BC MEM 2002), the gross OGIP resource is estimated at 70 to 200 Tcf. Potential Deep Basin tight gas targets include the Cardium, Dunvegan, Cadotte, Bluesky, Cadomin, Nikanassin, Halfway, Doig and Montney formations. In 2004, development of the Cadomin Formation began in earnest and as of early 2006 production had reached above 140 MMcf/d.

1.5 Northern Foothills

The Northern Foothills Region (Figure 1) incorporates an area of 2.9 million hectares and covers mostly foothills and mountainous terrain. Laramide-aged structures provide the opportunity for structural traps where natural gas may accumulate. Prospective intervals include Cretaceous clastics but traditional targets are the Triassic Baldonnel, Charlie Lake and Halfway formations as well as the Mississippian Debolt Formation. The western boundary of the Triassic play is constrained by outcrop and subsequent breaching of any trap. The Mississippian play is typified by the Sikanni and Pocketknife fields where natural gas is trapped in linear northwest trending thrust-fault related structural features. To the east of the Northern Foothills Region Devonian Keg River and Slave Point formations are hosts to major natural gas accumulations, such as in the Clarke Lake area. These occur in ancient barrier reef complexes and atoll trends which, despite limited deep well control, can be traced into the Northern Foothills. Conceptually, these rocks are extremely prospective in areas where they have been structurally uplifted raising the possibility of significant undiscovered natural gas accumulations in the region. The western limit for Devonian play-types is defined by a line about five to ten kilometres west of the outcrop belt of Devonian or older sediments. This five-to-ten kilometre wide band accounts for the possibility of encountering second-sheet Devonian reservoir in an overthrust scenario.

1.6 Southern Foothills

The Southern Foothills region (Figure 1) of northeast British Columbia covers an area of 1.2 million hectares. The region has varied topography ranging from low rolling hills in the east to anticlinal hills with a relief of up to 1,800 metres in the west. This topography reflects the composition and structure of underlying bedrock, which consists of Paleozoic age carbonates in the southwest to Upper Cretaceous clastics in the northeast. Exploration for natural gas in the Southern Foothills region tends to hold a moderate to high associated risk along with high capital costs. Offsetting this is the potential within these folded and faulted structures for hydrocarbon traps containing large reserves of natural gas, sometimes with extraordinary productivity. Faulted Triassic Baldonnel and Charlie Lake formations are the principal exploration targets in the region.

2.0 Spatial Cumulative Resource/Reserve Mapping

In support of the joint NEB/MEMPR Northeast British Columbia's Ultimate Potential for Natural Gas Report - 2006A, spatial data representing produced, discovered and undiscovered gas resources have been created. For ease of reference, acronyms for specific data products are assigned as follows:

Discovered (Reserves):

GIP – Gas in Place

IEGR – Initial Established Gas Recoverable

IEGM – Initial Established Gas Marketable

RGR – Remaining Gas Recoverable

RGM – Remaining Gas Marketable

Production:

ARGP – Annual Raw Gas Produced

CRGP – Cumulative Raw Gas Produced

CMGP – Cumulative Marketable Gas Produced

Undiscovered:

UGIP – Undiscovered Gas In Place

URECVR – Undiscovered Recoverable Gas

UMARKT – Undiscovered Marketable Gas

Ultimate Resource:

ULGIP – Ultimate Gas in Place (GIP + UGIP)

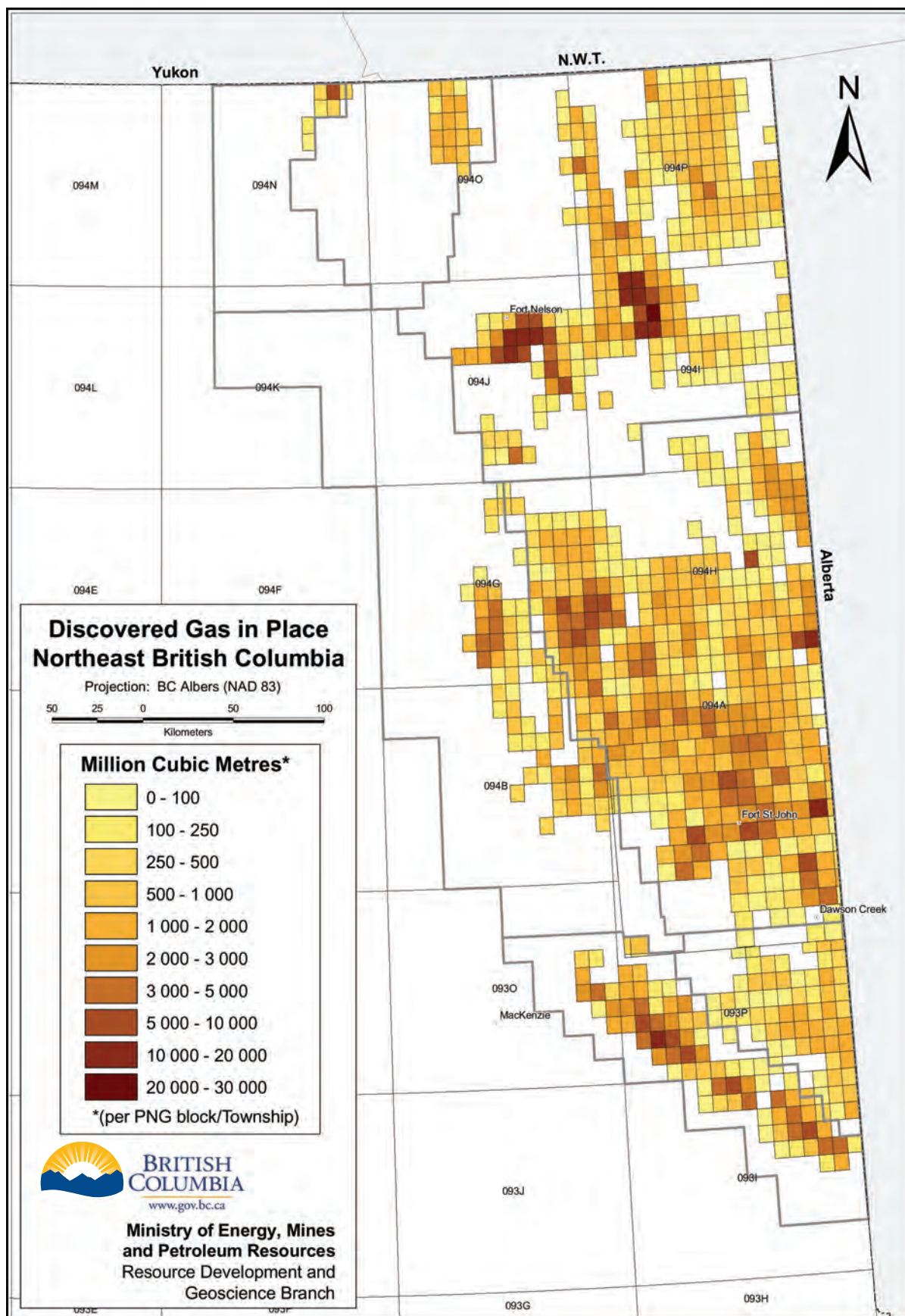
ULRECVR – Ultimate Recoverable Gas (IEGR + URECVR)

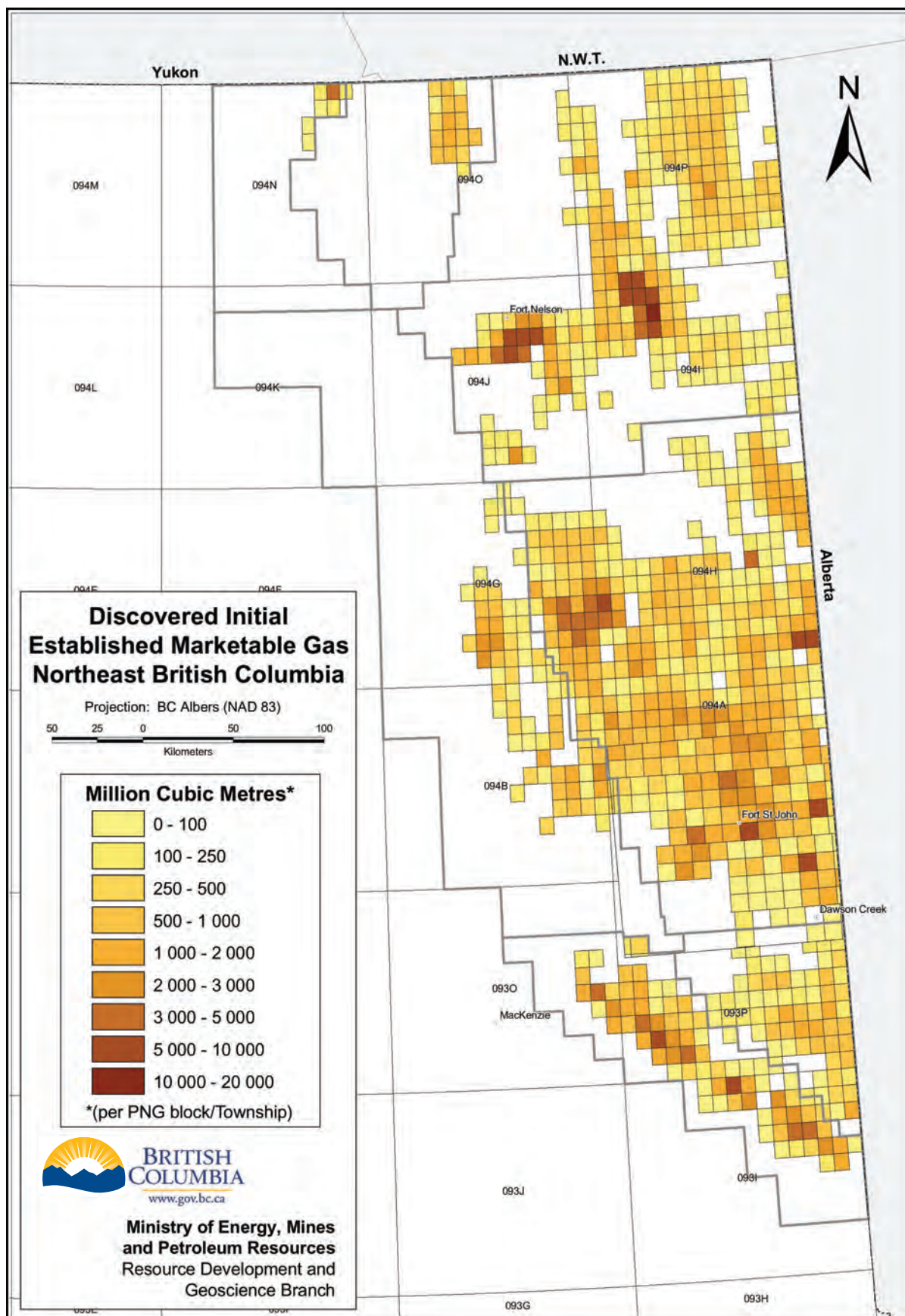
ULMARKT – Ultimate Marketable Gas (IEGM + UMARKT)

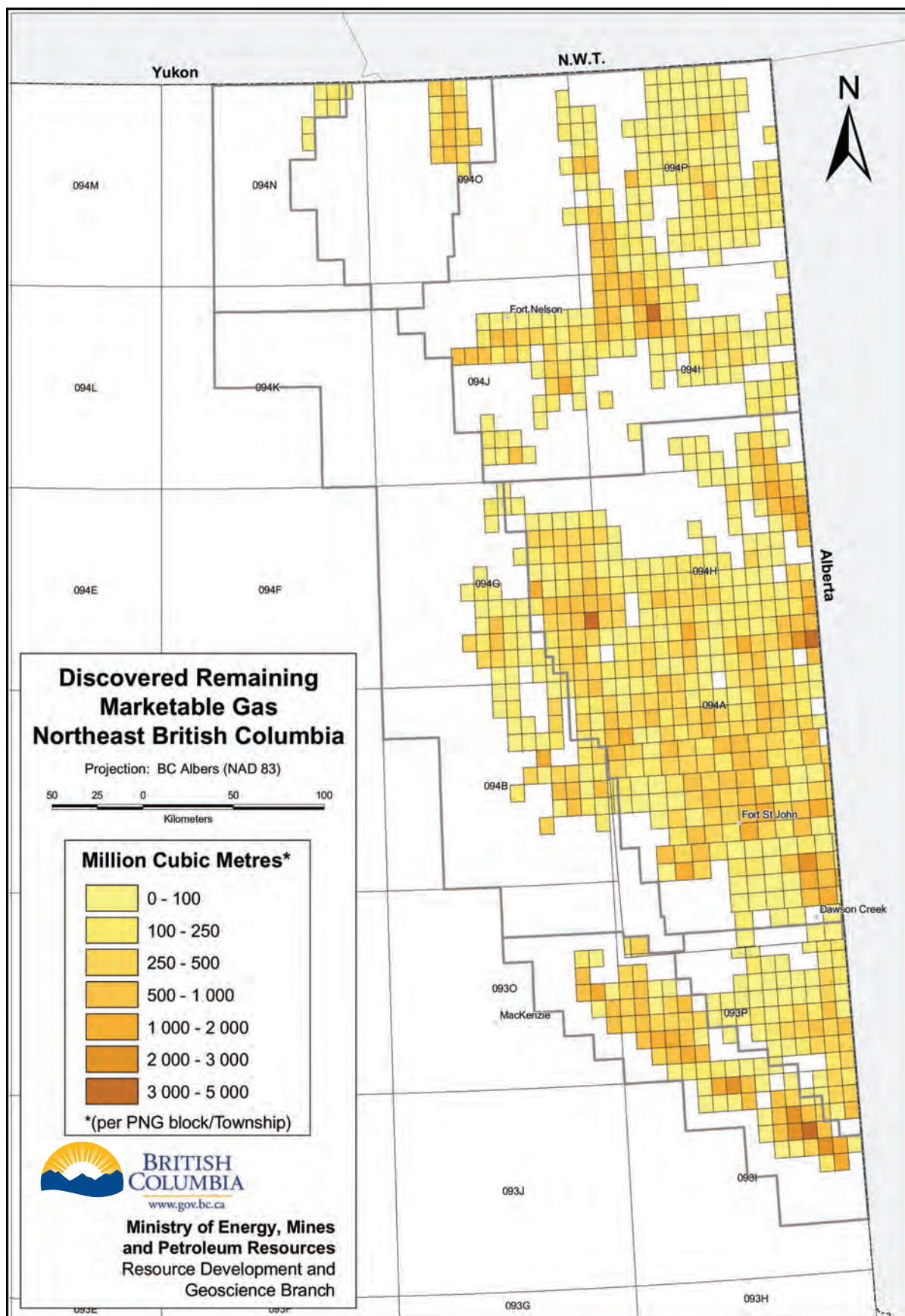
ULREMMARKT – Ultimate Remaining Marketable Gas (RGM + UMARKT)

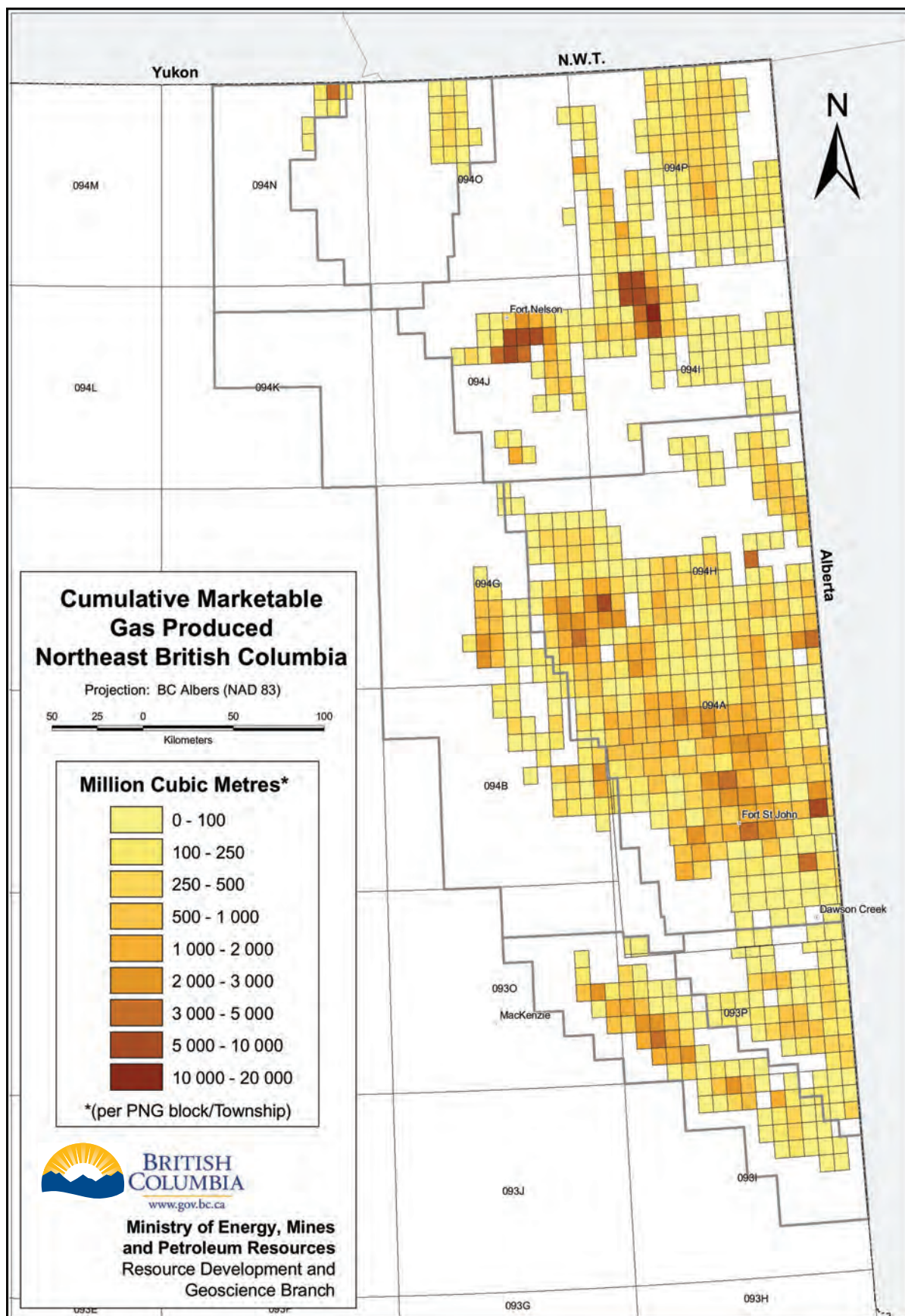
A series of maps were created to spatially display cumulative data for all plays throughout northeast British Columbia:

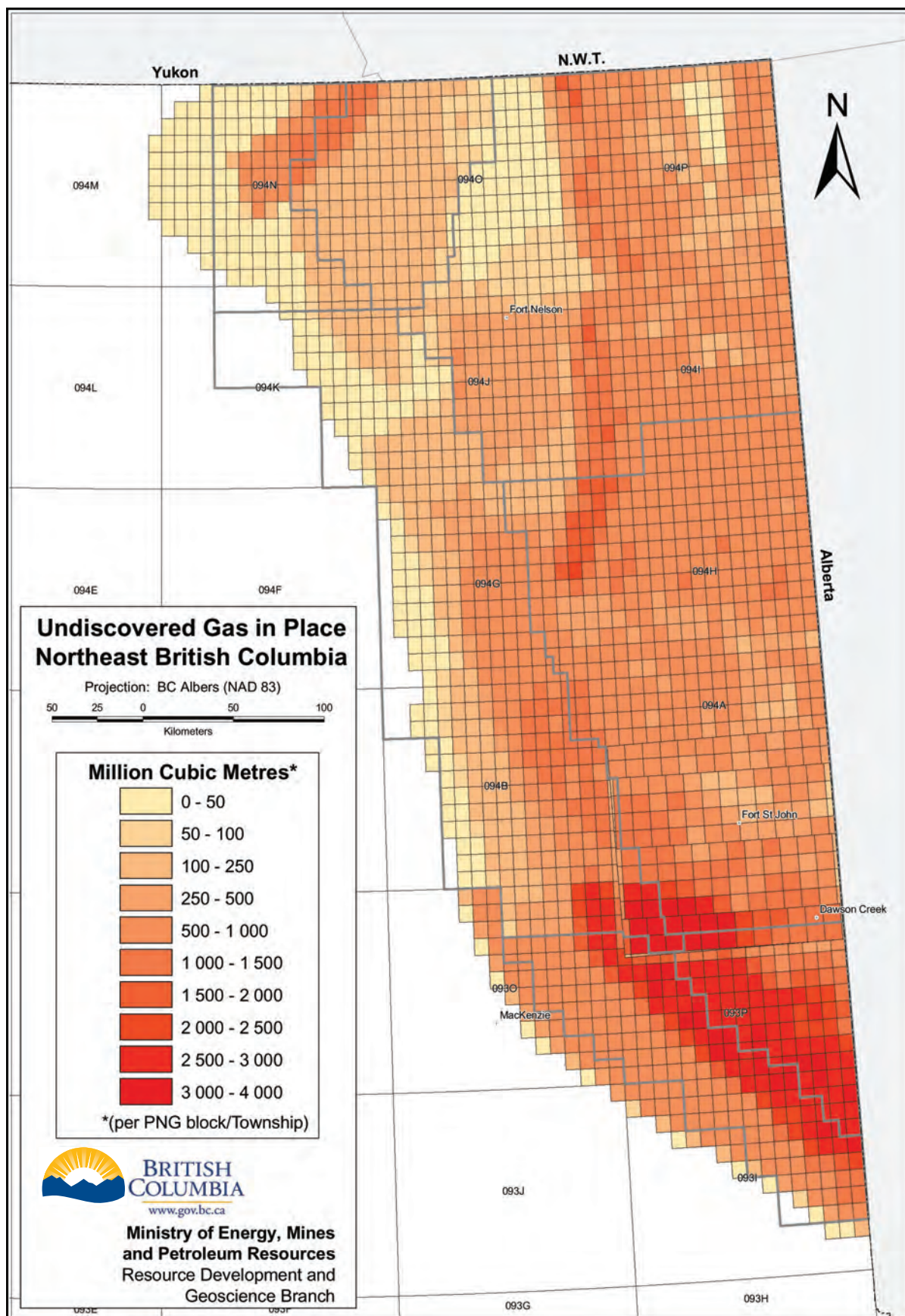
1. Discovered Gas In Place
2. Discovered Initial Established Gas Marketable
3. Discovered Remaining Marketable Gas
4. Cumulative Marketable Gas Produced
5. Undiscovered Gas In Place
6. Undiscovered Marketable Gas
7. Ultimate Gas In Place
8. Ultimate Marketable Gas
9. Ultimate Remaining Marketable Gas

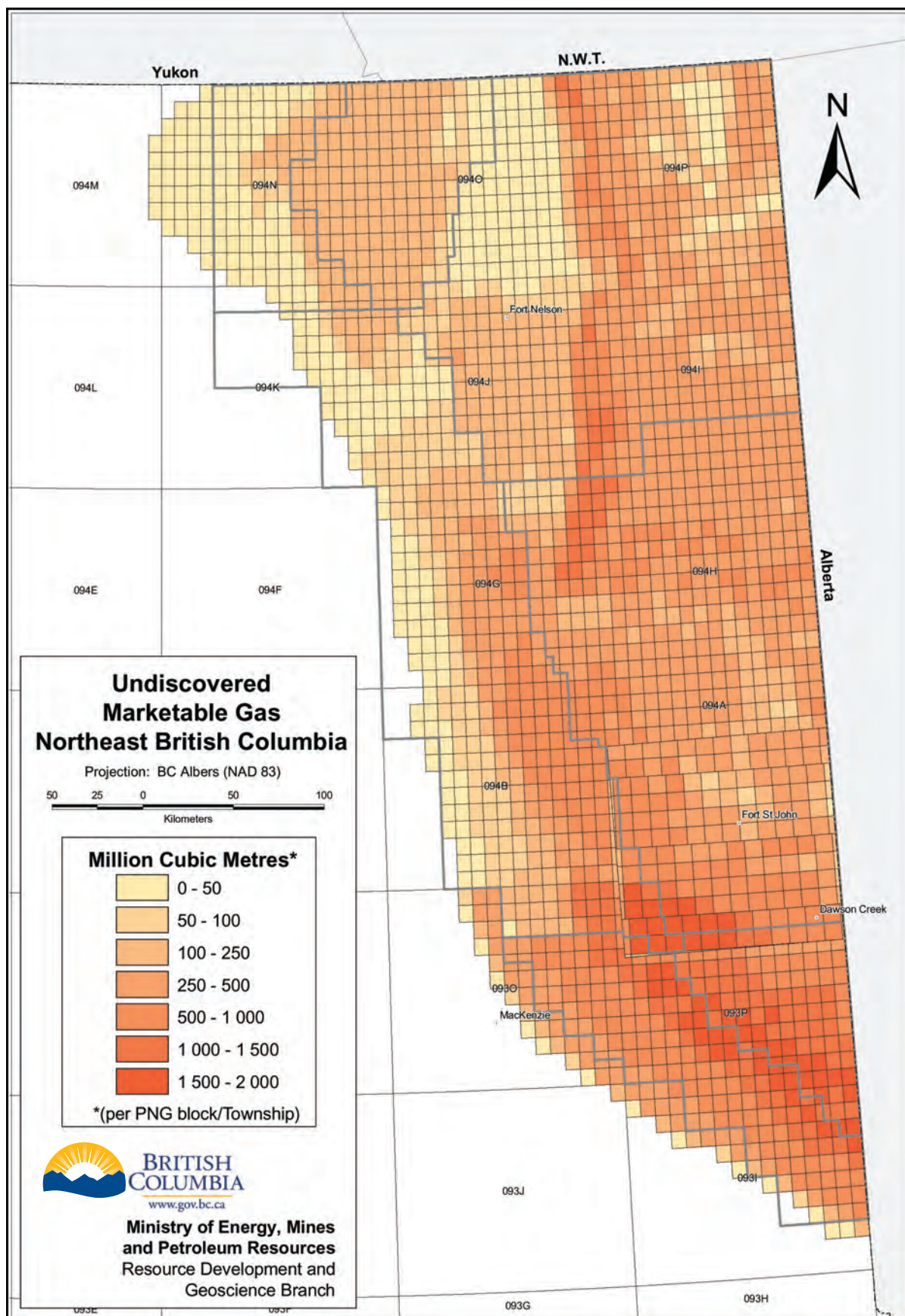


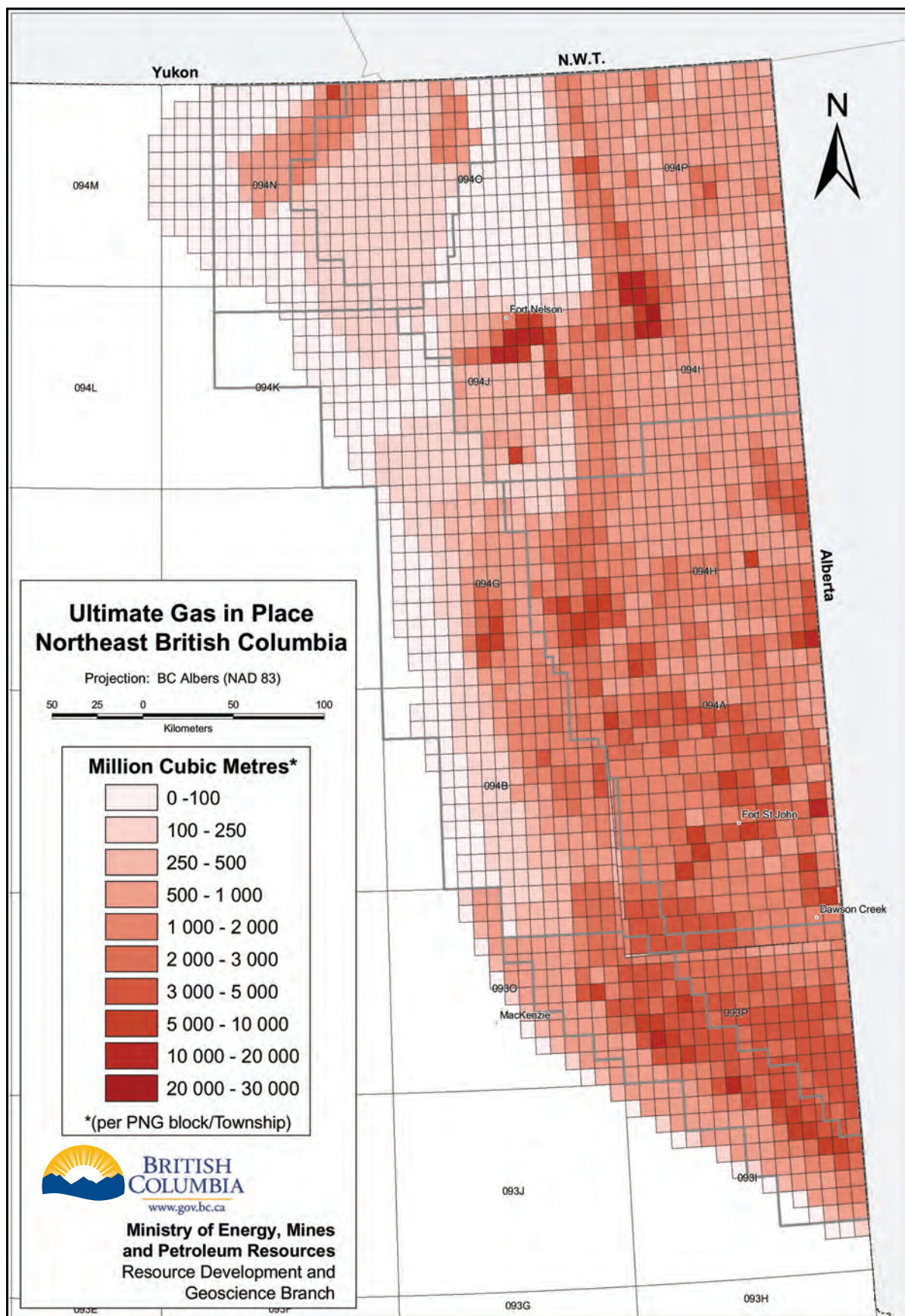


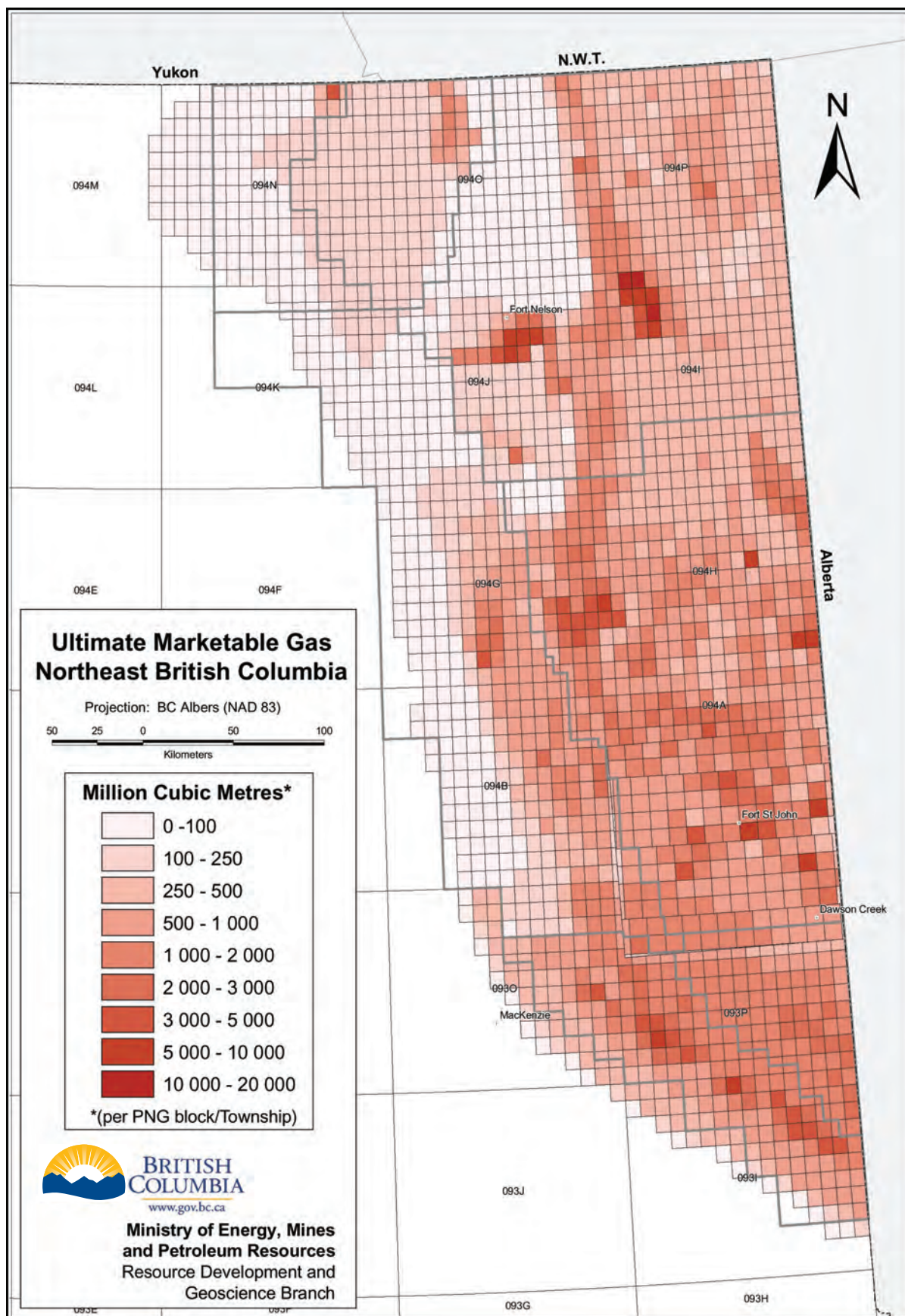


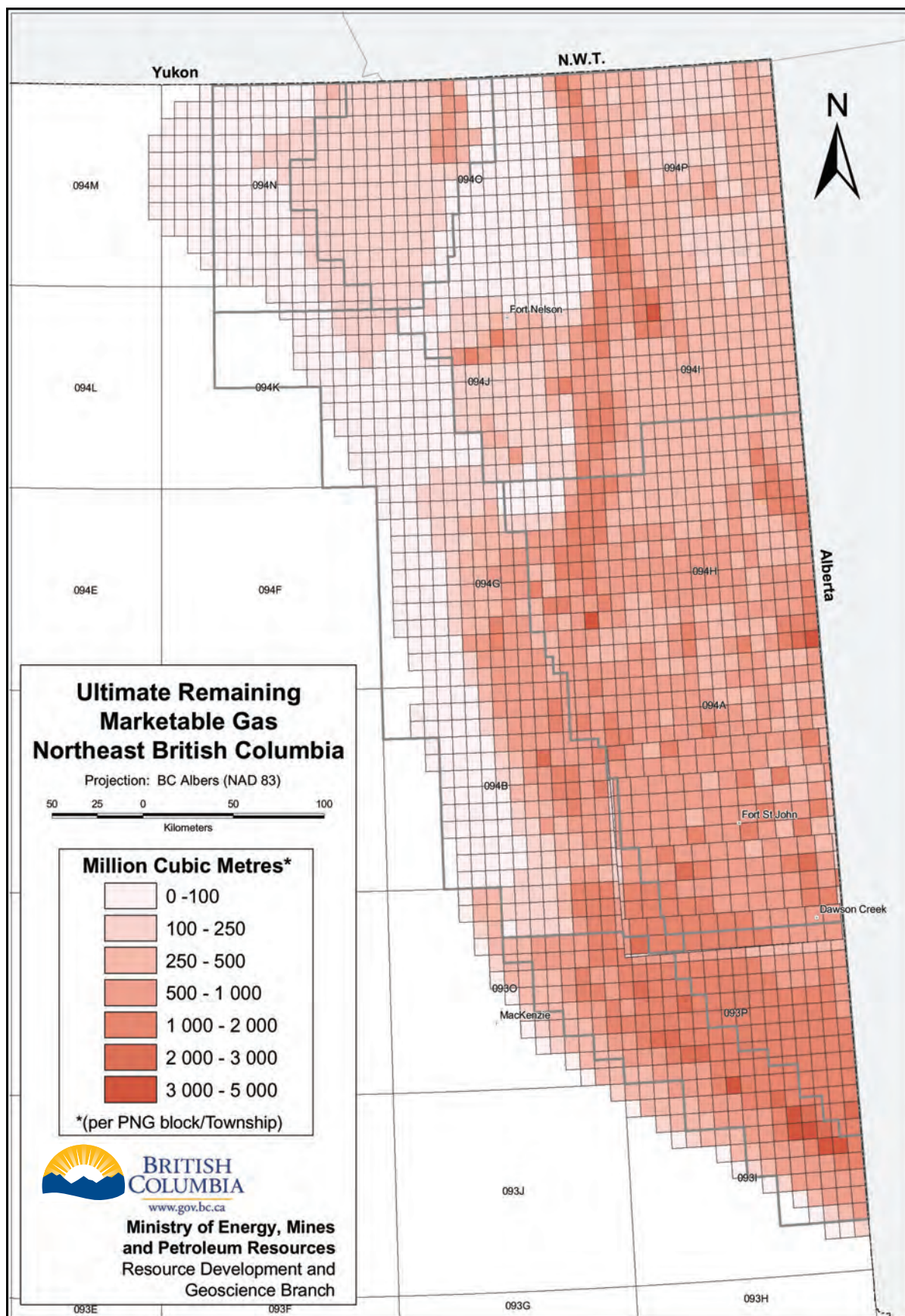












3.0 Methodology

Values for the aforementioned categories were assigned to PNG grid NTS units (and quarter sections in the Peace River Block) across northeast BC as appropriate. These values were calculated using a mix of tabular and spatial data sources. Reserve data were obtained from the Oil and Gas Commission. These data are structured by Pool Designation Area (PDA). The unique code for each PDA is a composite of the Area (Field) Code, Formation Code and Pool Sequence Code. Values for reserve data were linked spatially to polygons representing PDAs. Where PDA polygons were not found, reserves were attributed evenly across the field in which the PDA was identified. Reserve values for 'other area' PDAs with no corresponding polygon were attributed to the PNG grid cell identified by the PDA Pool Sequence Code.

Production data were gathered from the Oil and Gas Commission in a separate file from the reserve data. These tabular data were linked spatially in the exact same method as described above for reserves data.

Undiscovered gas resources, as provided by project participants, correspond to mapped areas of play potential. As these data represent undiscovered resources, areas corresponding to previously identified pools were removed from each play potential area. Additional areas were removed around the locations of wells that had penetrated the play and not identified reserves. With polygons now representing unexplored areas for each play, resource numbers were applied to the polygons and average values per area-unit were calculated. These polygons were then intersected with the PNG grid and net resource values for each grid unit were subsequently calculated. The PNG grids for each play type were then combined and summarized spatially to calculate the total undiscovered resource value for each grid unit.

Ultimate resource values were calculated by combining the spatial products created from the reserves and undiscovered data and then summarizing by grid unit.

Contributions to Error:

Reserve values for "other area" PDAs were attributed to a single grid unit. This may have been better represented by attributing the reserve and production values to the drill spacing unit representing the well location (*i.e.* four grid units).

As described above, for some PDAs with no corresponding polygons, reserve data were spread evenly across the field in which the PDA was identified. Areas representing the location of these gas reserves could not be removed from the undiscovered play potential areas. It is likely that, for these fields, there are areas where the undiscovered resource potential within fields should be decreased and, in turn, increased elsewhere. With the absence of PDA polygons there is no solution to this problem. There are 87 PDAs for which this is the case, occurring in 60 fields. Given the small number of PDAs, this error is likely not significant when observed regionally.

4.0 Play Descriptions

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4.1 Tertiary / Quaternary

Much of the bedrock in the structurally undeformed portion of northeastern British Columbia is incised by late Tertiary to Quaternary valleys. Irregular bedrock topography and paleovalleys are filled by thick sedimentary successions, typically 150 to 200 metres thick, but in places exceeding 300 metres (e.g. well b-47-L/94-I-5). During the Quaternary glaciations, these valleys were filled with glaciofluvial, glaciolacustrine and morainal sediments.

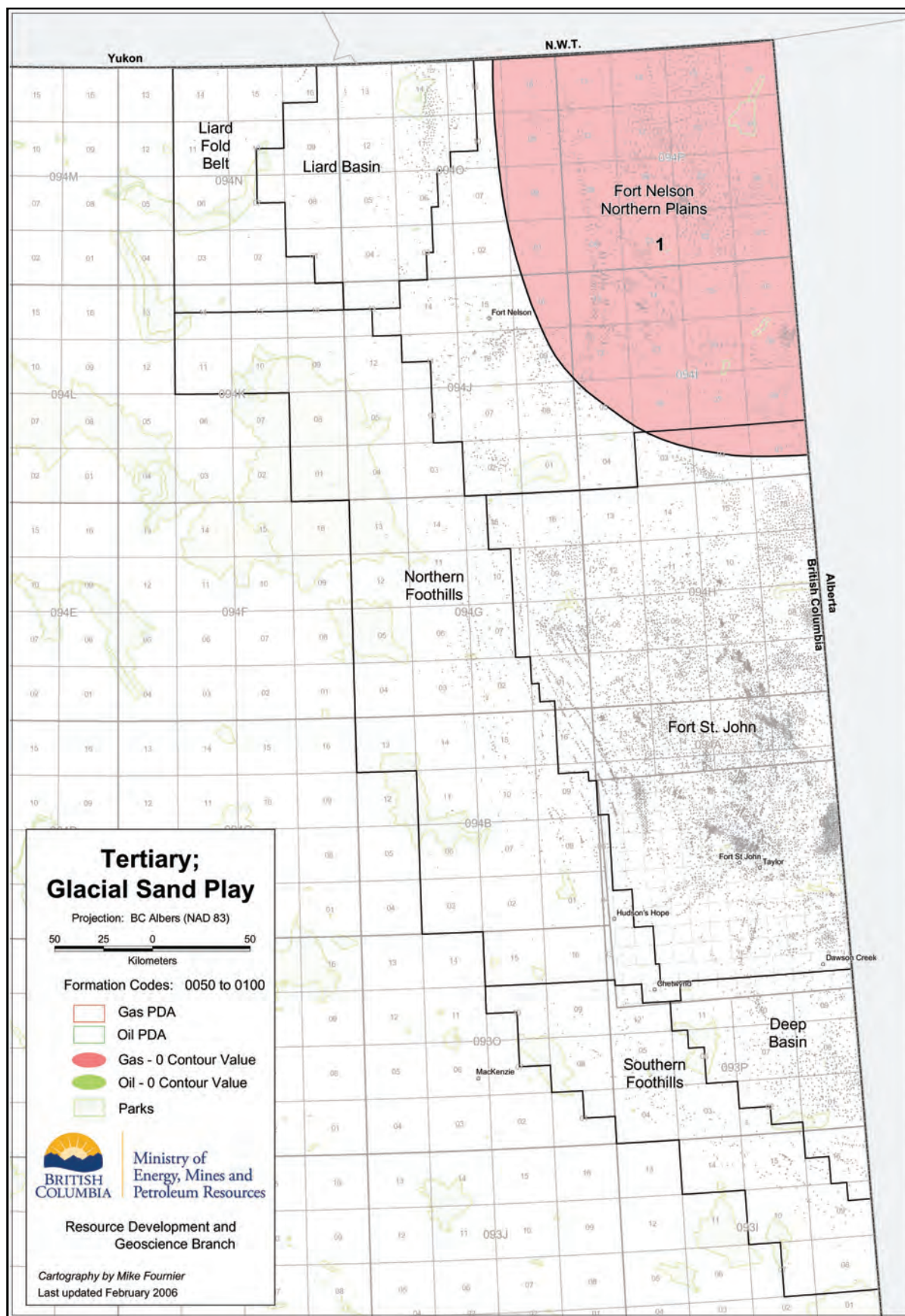
The general stratigraphy of the valley fills can be summarized as preglacial fluvial sand and gravel, overlain by Quaternary glacial sediments, which originated either from the Cordilleran Ice Sheet to the west or from the westward-advancing Laurentide Ice Sheet. Ice-advance glaciofluvial sand and gravel, and glaciolacustrine silt and clay are overlain by clay-rich till and retreat phase glaciolacustrine silt, sand and clay and glaciofluvial sand and gravel.

Buried glaciofluvial and preglacial sand and gravel may be potential reservoirs where over-consolidated, impermeable clay-rich till and glaciolacustrine sediment provide a seal. Gas may charge the reservoirs from biogenic or thermogenic (bedrock seep) sources.

There is no reported production from Quaternary pools in British Columbia. Pressurized aquifers and gas blow-outs from valley-fill successions have been noted in drilling reports (e.g. wells b-93-L/94-P-10, a-94-L/94-I-9). Quaternary gas reservoirs may have been overlooked because they occur in the shallow subsurface, commonly in the depth range in which surface casing is set. Alternatively, producing zones in Quaternary or late Tertiary sediments may be misidentified as Upper Cretaceous channel fills.

Fort Nelson Northern Plains Region

Play 1. Northern Plains Valley Fill Play—Although late Tertiary / Quaternary sediments are found across northeastern B.C., thick valley-fill successions are best developed in the Fort Nelson Northern Plains Region. In addition, gas has been produced from Quaternary reservoirs in nearby northwestern Alberta from the Sousa and Rainbow areas, where the geological setting is similar to that of northeast British Columbia. For example, well 6-13-112-24W5 produced 101 e⁶m³ gas between May 2000 and August 2005 from Quaternary strata, but is misidentified in public databases as a Dunvegan pool.



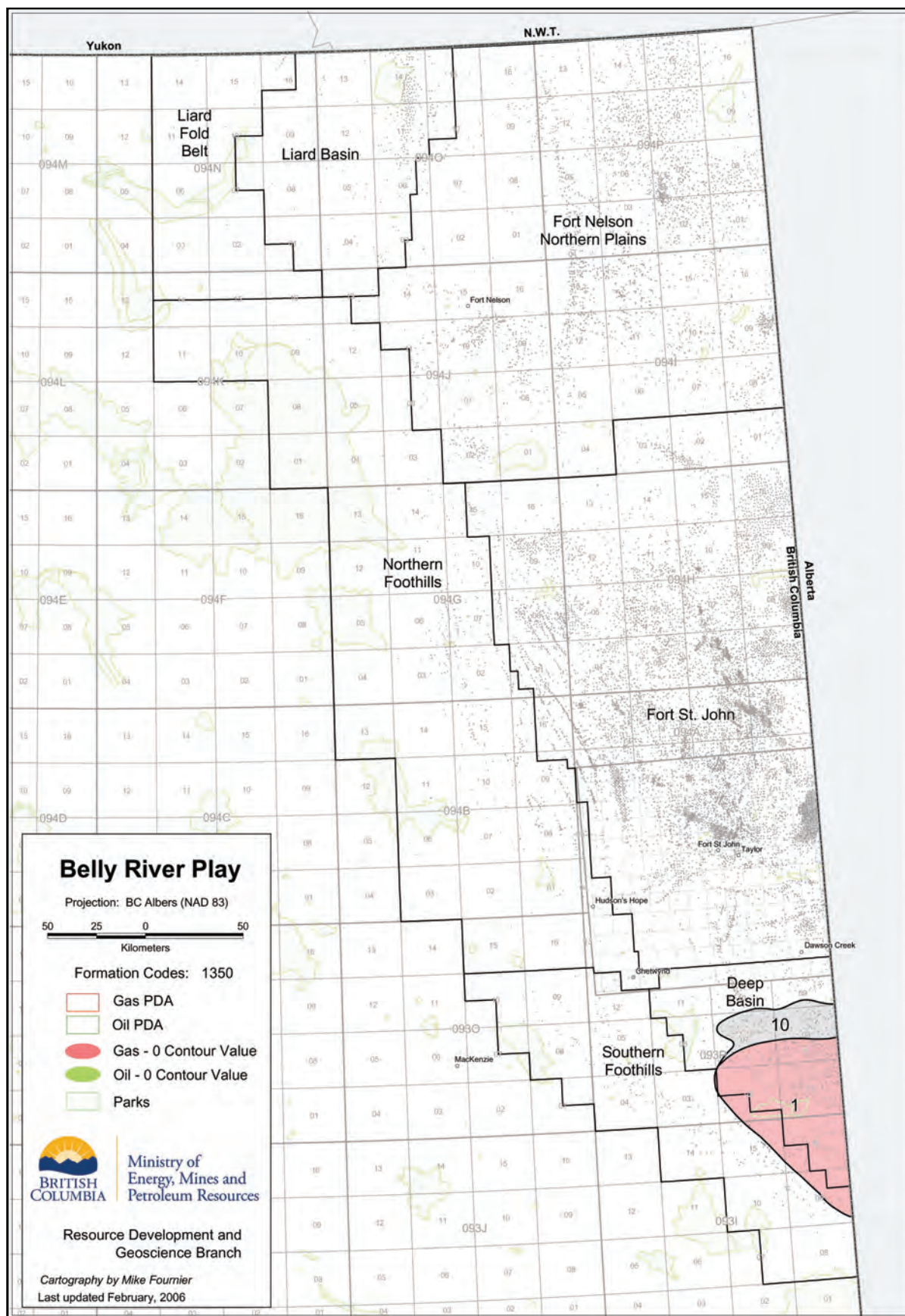
4.2 Belly River

Belly River strata (more correctly termed the Wapiti Group in northeastern B.C.) form a thick, eastwardly-thinning clastic wedge along the western flank of the Western Canada Sedimentary Basin. Fluvial to alluvial plain strata are stacked in thick successions lacking internal stratigraphic markers, conformably overlying Upper Cretaceous Smoky Group shales (Dawson, et. al., 1994). The upper Belly River is exposed at surface in northeastern B.C., limiting prospectivity to more deeply-buried parts of the section.

Deep Basin Region

Play 1. Deep Basin Stratigraphic Play—Belly River prospectivity is limited to the Deep Basin Region, south of the Peace River Block. Potential productive characteristics can be inferred from producing wells in the Elmworth-Wapiti area of west-central Alberta. Gas will be found in stratigraphic traps formed by fluvial channel sandstones encased in impermeable floodplain strata. Along the western edge, Belly River sandstones may be prospective in individual thrust sheets along the eastern margin of the Southern Foothills.

There is no known Belly River production in northeastern B.C.



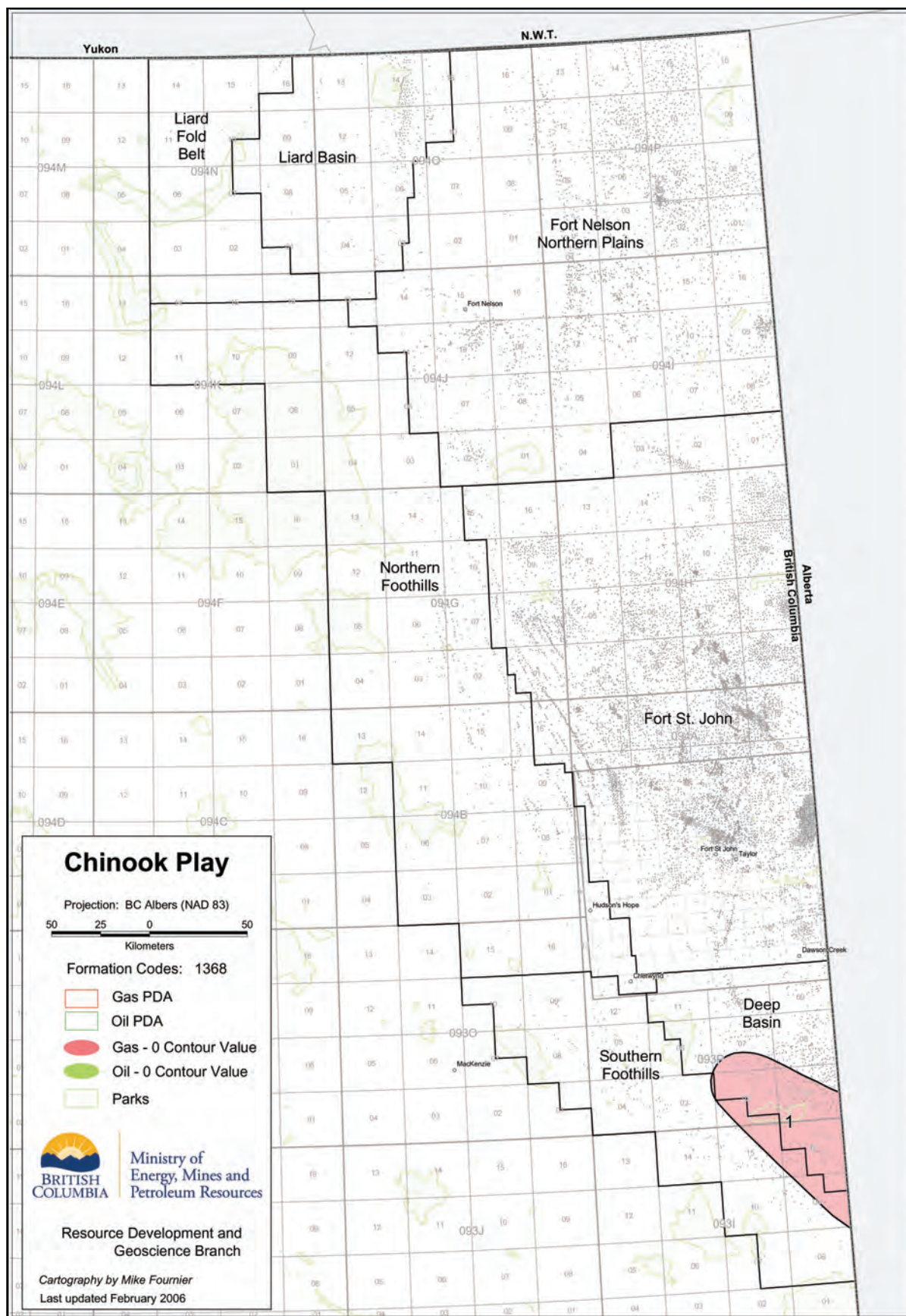
4.3 Chinook Member

The Chinook Member (also known as the Chungo Member) was deposited in shoreface to marginal marine settings on the northwestern flank of the Late Cretaceous Colorado / Smoky seaway (Leckie, et. al., 1994). Northwest-southeast trending coarsening-upward shoreface sandstones are encased in marine shales, forming well-defined stratigraphic traps about 30 metres below basal Belly River / Wapiti sandstones.

Deep Basin Region

Play 1. Deep Basin Stratigraphic Play—The Chinook hosts gas and oil production at Red Rock and Chicken in west-central Alberta, and the trend can be extrapolated northwestward into the southern Deep Basin Region of B.C. Prospectivity will be limited to narrow high-quality reservoir trends within the indicated play area; detailed mapping will be required to identify these trends.

There is no known Chinook production in British Columbia.



4.4 Cardium Formation

Cardium strata comprise a northeasterly-prograding shoreface / alluvial plain complex, mappable along the western flank of the WCSB as far north as Twp. 75-77 (Plint and Walker, 1987). In northeastern B.C., Cardium reservoir potential is confined primarily to the Kakwa Member, which consists of a coarsening-upward sandstone succession from 15 to 50 metres thick (Figure 2). Upper shoreface / foreshore conglomerates cap the succession locally. Overlying Cardium “zone” sands, which are productive in adjacent Alberta, are poorly developed. Marine shales of the underlying Kaskapau Formation and overlying Muskiki Formation are regional seals, isolating the Cardium hydrodynamically from other reservoirs.

A gas-saturated Deep Basin regime within the Cardium is defined in west-central Alberta, and can be extrapolated northwestward into British Columbia. Cardium strata crop out on the eastern flank of the Southern Foothills, and in the northern part of the Deep Basin area, thus confining prospectivity to the south and east.

Deep Basin Region

Play 1. Deep Basin Play—Gas and oil are produced from well-sorted upper shoreface to foreshore sandstones and conglomerates within the hydrocarbon-saturated Deep Basin in west-central Alberta. Prospectivity is determined primarily by presence of economic reservoir quality, although local prospects may occur in overlying Cardium “zone” sands. The Deep Basin play can be traced northwestward into British Columbia, but most production is situated 100 km or more from the B.C. border. The updip play boundary is loosely defined as occurring downdip of the regional aquifer system, where water is the primary reservoir fluid.

The Cardium Deep Basin play contains a large resource of gas in place, but most in strata with subeconomic reservoir quality. This can therefore be regarded as a tight gas play. There is no Cardium production in the Deep Basin Region, but Tupper b-A4-D/93-P-8 tested low-rate gas upon completion.

Play 2. Regional Aquifer Play—Although occurring in the same depositional setting, Cardium sandstones in the regional aquifer contain formation water, as demonstrated by test recoveries and log responses. Gas may occur in small and subtle structural or stratigraphic traps, but no examples have been discovered to date.

Southern Foothills Region

Play 1. Deep Basin Play—This play can be traced westward into the eastern part of the Southern Foothills Region. Structural deformation may give rise to structural trapping opportunities, or reservoir enhancement through fracturing. However, traps may be breached by faulting, particularly in this very shallow reservoir section.

No production has been documented to date.

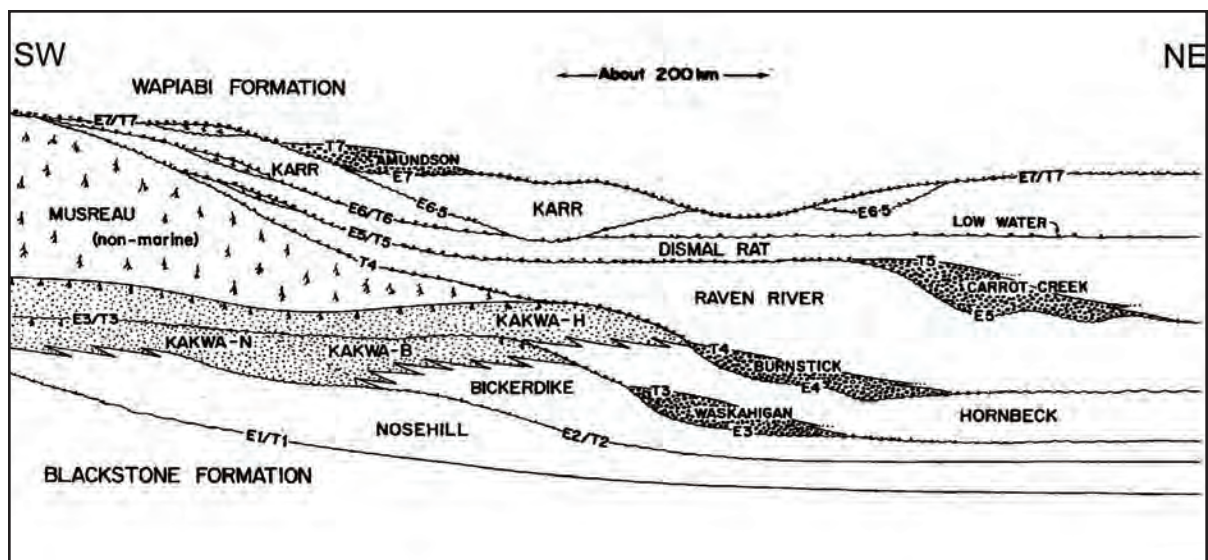
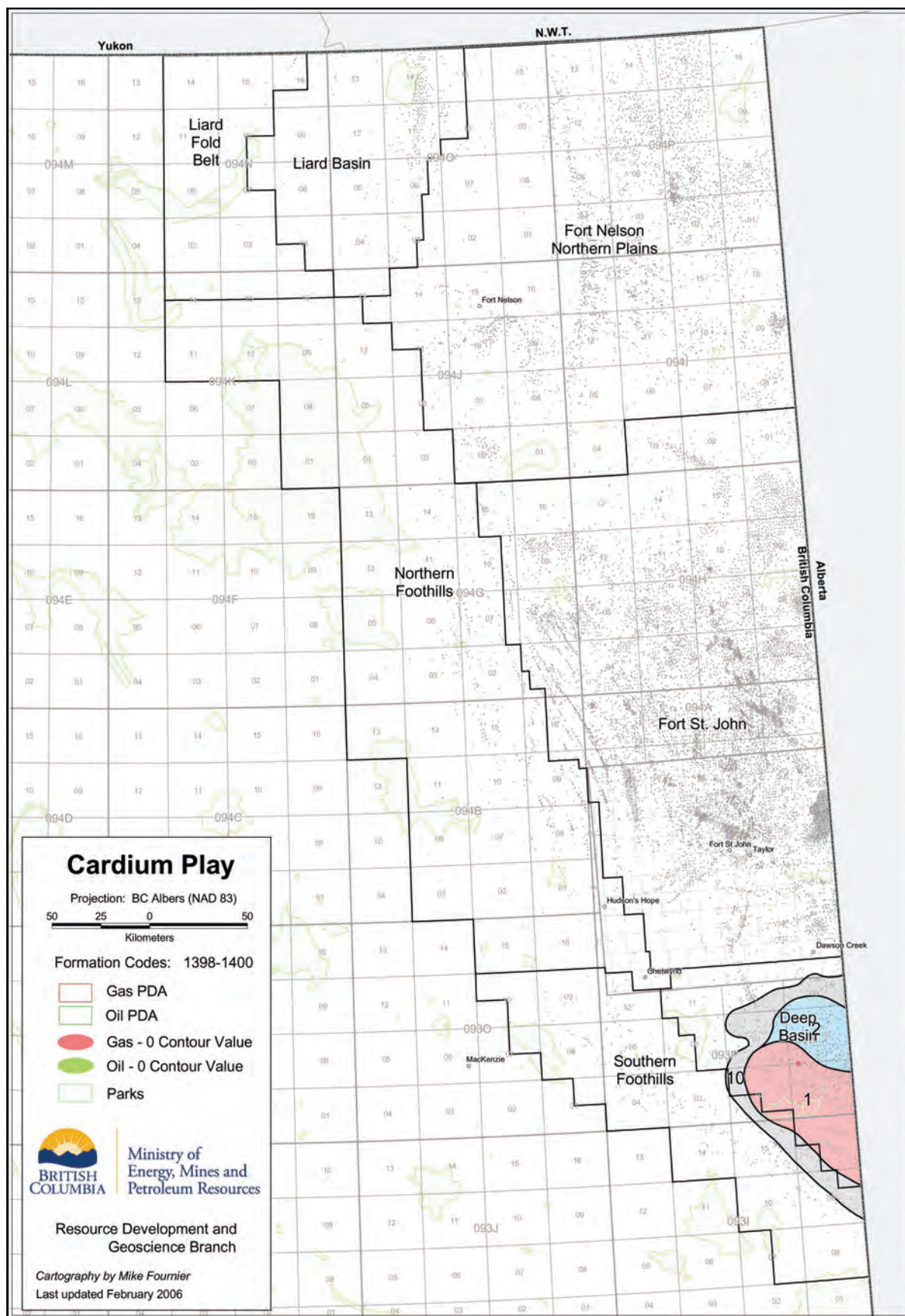


Figure 2. Schematic regional cross-section, Cardium Formation, west-central Alberta and adjacent British Columbia (from Plint and Walker, 1987). Regionally continuous sandstones of the Kakwa Member host large gas resources, but exhibit poor to moderate permeabilities.



4.5 Doe Creek Member

Doe Creek sandstones lie within the lower part of the Kaskapau Formation, as part of a transgressive marine package overlying the Dunvegan fluvial / deltaic clastic wedge (Wallace-Dudley and Leckie, 1995) (Figure 3). Reservoir sandstones occur in linear, shoreline-parallel trends, generally less than five metres thick, and exhibiting good conventional reservoir quality. Isolated sandstones in the overlying Pouce Coupe and Howard Creek members may also be included in the Doe Creek play interval.

In Alberta, the Doe Creek produces gas and oil from numerous pools in the Elmworth – Valhalla area. Moving westward into B.C., the interval becomes more gas-prone, and reservoir sandstones become thinner and more isolated.

Deep Basin Region

Play 1. Deep Basin Play—The Deep Basin Play area is defined to occur within the mapped outcrop limits of the Doe Creek, such that the formation is buried sufficiently to be hydrocarbon-charged and isolated from meteoric water influx. Gas is trapped stratigraphically within shallow marine sandstones, encased in impermeable marine shales. One oil producer occurs at Kelly Lake (I/93-P-1).

The Doe Creek Deep Basin play extends northward into the southern fringe of the Fort St. John Play Area, and westward into the eastern part of the Southern Foothills Play Area. However, while the play concept remains identical, it is generally not prospective in these areas because of shallow burial depths.

Doe Creek pools occur in the northeast at Cutbank and Kelly, and to the southwest at Hiding Creek.

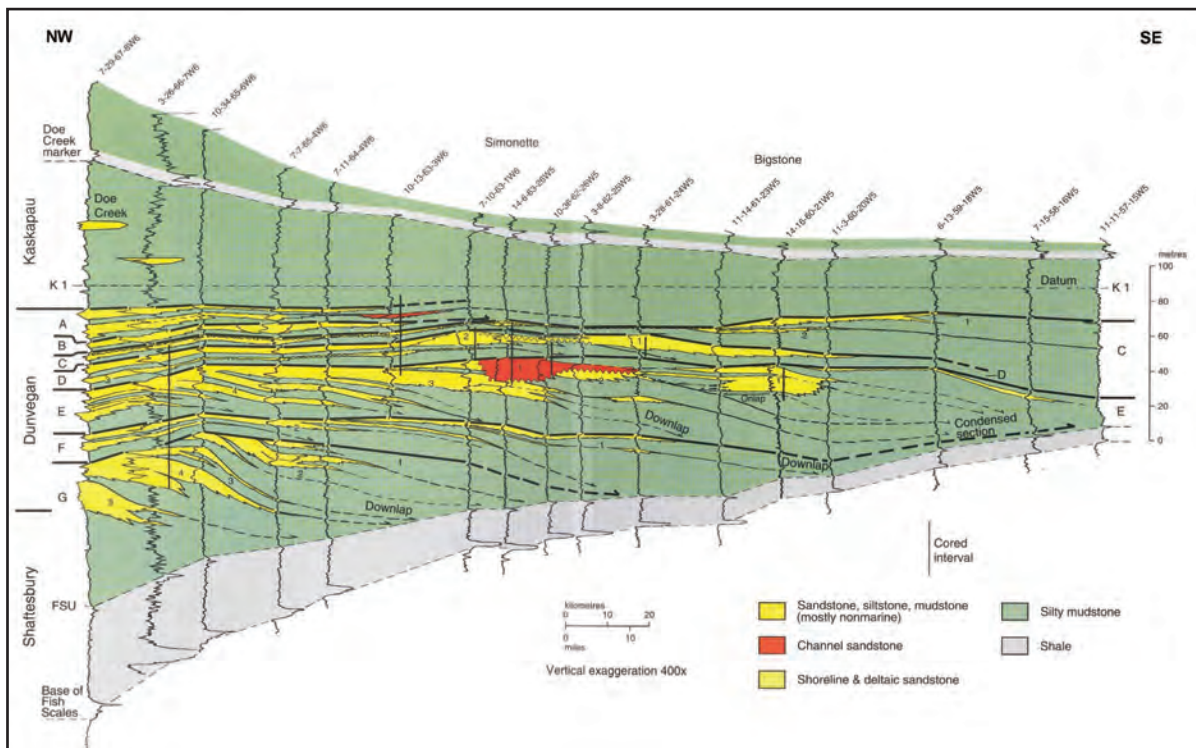
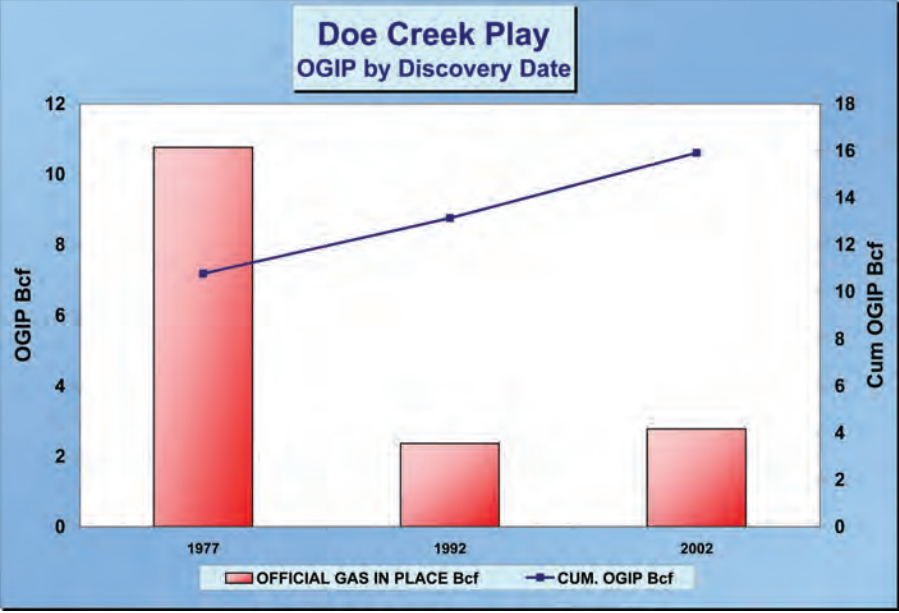
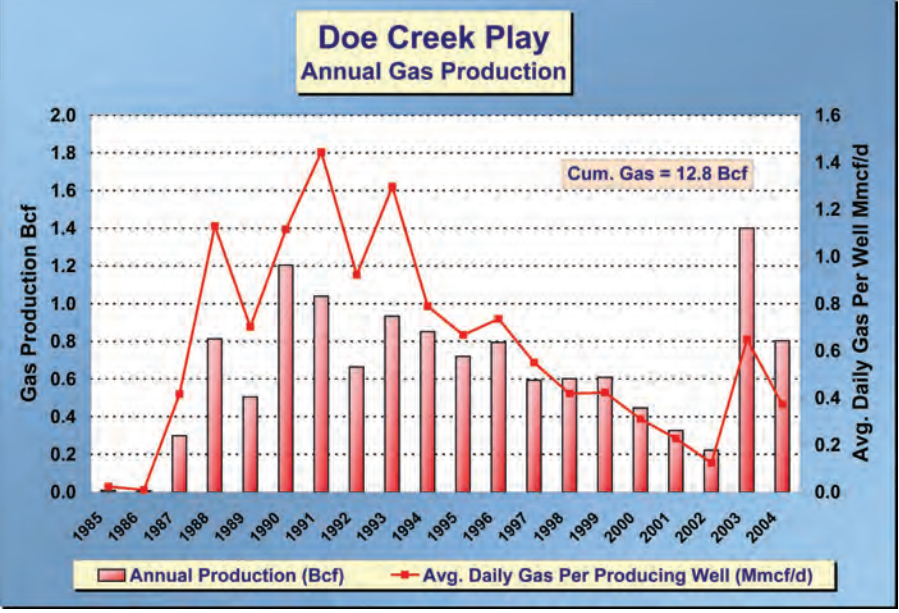
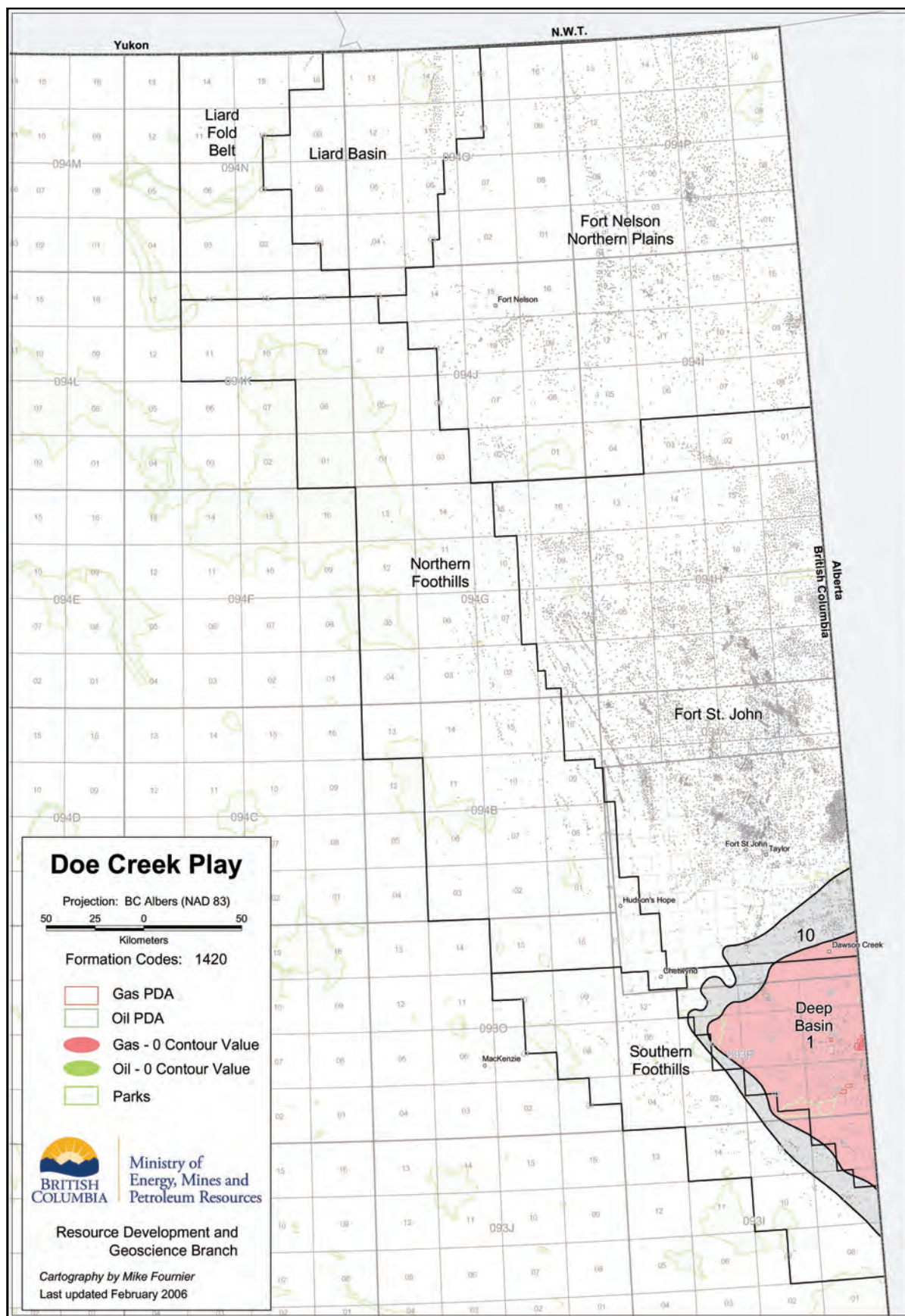


Figure 3. Schematic regional cross-section, Dunvegan Formation and Doe Creek Member, illustrating extensive sandstone reservoir development to the northwest, and basinward (southeastward) shale-out and downlap of individual allomembers (from Bhattacharya, 1994).

| Doe Creek Play - All Pools by OGIP | | | | | | | | |
|------------------------------------|-----------|----------|-----------------------------|------------------------|-------------------|---------------------------|----------------------|-----------------|
| AREA | FORMATION | POOL SEQ | OFFICIAL GAS IN PLACE (MM3) | INIT EST GAS MKT (MM3) | REM GAS MKT (MM3) | OFFICIAL GAS IN PLACE BCF | INIT EST GAS MKT BCF | REM GAS MKT BCF |
| Cutbank | Doe Creek | A | 305 | 244 | 20 | 11 | 9 | 1 |
| Hiding Creek | Doe Creek | A | 79 | 64 | 35 | 3 | 2 | 1 |
| Kelly | Doe Creek | B | 67 | 57 | 19 | 2 | 2 | 1 |
| Totals | | | 451 | 365 | 73 | 16 | 13 | 3 |





4.6 Dunvegan Formation

Dunvegan strata form a large, southeasterly-prograding wedge of deltaic and shoreface sediments, which originated in far northern B.C. and the Territories, and reached a distal edge in west-central Alberta (Stott, 1982; Bhattacharya, 1994). It lies between marine shales of the Shaftesbury Formation below and the Kaskapau Formation above (Figure 3, page 27). Dunvegan sandstones were deposited in deltaic to shoreface settings at the seaward limit of several regressive subunits, and in associated distributary channels and valley fills.

Dunvegan reservoirs produce over a broad area of west-central Alberta. Reservoir quality generally decreases westward into B.C., largely as the result of compaction associated with significantly deeper paleoburial. North of the Deep Basin, Dunvegan strata crop out or are at such shallow depths that reservoir pressures and effective trapping become significant issues.

Deep Basin Region

Play 1. Deep Basin Play—The Deep Basin Play area is defined to occur within the mapped outcrop limits of the Dunvegan, such that the formation is buried sufficiently to be hydrocarbon-charged and isolated from meteoric water influx. Potential reservoir sandstones are generally fine- to medium-grained, and suffered considerable degradation by burial compaction during Early Tertiary time. Specific play fairways are difficult to map, as most sandstones were deposited in areally-limited fluvial to deltaic bodies; persistent linear shoreline trends are relatively uncommon.

The Dunvegan Deep Basin play extends northward into the southern fringe of the Fort St. John Play Area, and westward into the eastern part of the Southern Foothills Play Area. However, while the play concept remains identical, it is generally not prospective in these areas because of shallow burial depths.

There is only one producing Dunvegan gas well at Kelly Lake (I/93-P-1), although the zone has flowed non-economic gas rates on DST and perforation in several other wells.

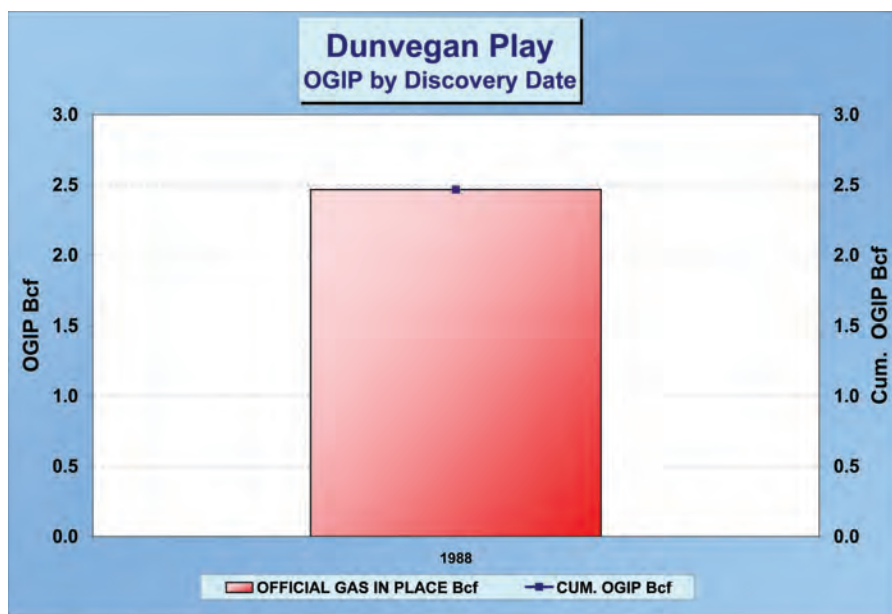
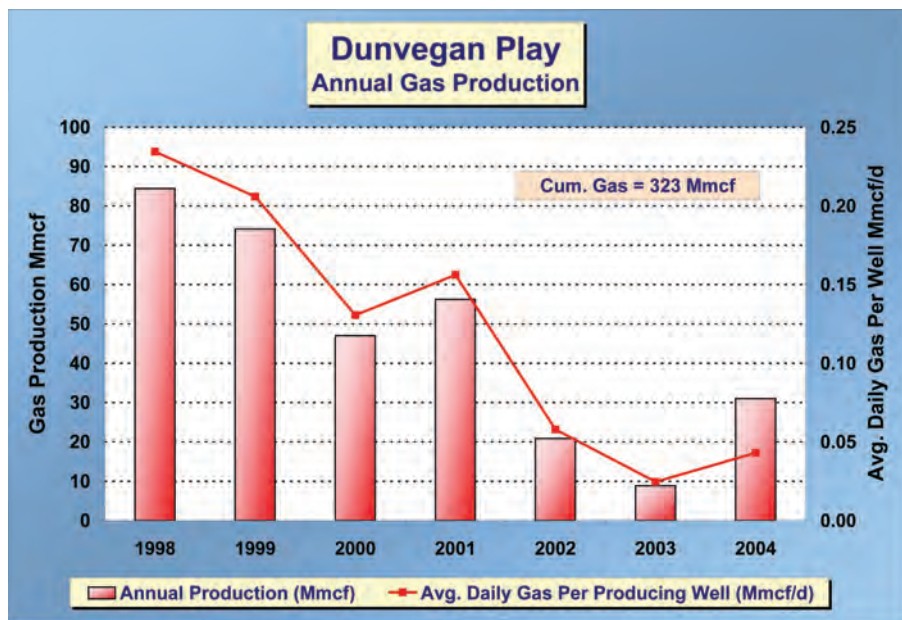
Fort St. John Region

Play 2. Shallow Gas Play (Conceptual)—Dunvegan sandstones exhibit much better reservoir quality in the Fort St. John Region, as they have experienced much less burial compaction than in the Deep Basin. Stratigraphic trapping of gas within channel to marginal marine sandstones may occur, but has not yet been demonstrated. Much of the Dunvegan section in wells in this area will be behind surface casing, and thus has not been adequately evaluated in conventional boreholes.

Liard Basin Region

Play 3. Shallow Gas Play (Conceptual)—Massive Dunvegan conglomerates in the Liard Basin offer excellent reservoir potential, but trapping potential is poor because of widespread surface exposure. Toward the centre of the basin, capping Kotaneelee shales may provide adequate seals. The Dunvegan section is very shallow in most existing boreholes, and has not been systematically evaluated.

| Dunvegan Play - All Pools by OGIP | | | | | | | | |
|-----------------------------------|-----------|----------|-----------------------------|------------------------|-------------------|---------------------------|----------------------|-----------------|
| AREA | FORMATION | POOL SEQ | OFFICIAL GAS IN PLACE (Mm3) | INIT EST GAS MKT (Mm3) | REM GAS MKT (Mm3) | OFFICIAL GAS IN PLACE BCF | INIT EST GAS MKT BCF | REM GAS MKT BCF |
| Kelly | Dunvegan | A | 70 | 51 | 44 | 2 | 2 | 2 |
| Total | | | 70 | 51 | 44 | 2 | 2 | 2 |



4.7 Sikanni / Goodrich Sandstones

Sikanni / Goodrich strata comprise up to seven coarsening-upward deltaic to shoreface successions in northeastern B.C. They overlie marine shales of the Buckinghorse and Hasler formations, and are capped by Cruiser and Sully shales. Sikanni / Goodrich sandstones are predominantly fine-grained, somewhat argillaceous litharenites, petrographically similar to fine-grained Cardium sandstones.

The Goodrich is recognized in outcrop in the Peace and Pine River areas, while the Sikanni has been mapped in the vicinity of Sikanni Chief River and northward (Stott, 1982; Pedersen and Schroder-Adams, 2001). Gross thicknesses up to 240 metres have been recorded, although most sections are substantially less. In the subsurface, the Sikanni / Goodrich occupies a long, narrow trend, bounded to the east by a poorly-defined sandstone progradational limit (Figure 4). Much of the prospective fairway is very lightly explored.

Fort St. John Region

Play 1. Sikanni / Goodrich Play—Sikanni and Goodrich sandstones thin and pinch out over a few tens of kilometres east of outcrop, but one or more sands are consistently developed along the western flank of the Fort St. John area. Traps may occur as stratigraphic pinchouts or structural closures associated with Foothills tectonics. Although penetrated by numerous wells, the Sikanni / Goodrich has been tested in fewer than ten. One well tested gas after frac, but there has been no production.

It appears that the Sikanni / Goodrich contains a large gas in place resource, but that economic reservoir quality and continuity have not yet been established.

The Sikanni / Goodrich play extends into the adjacent Deep Basin, Fort Nelson, and Southern and Northern Foothills Play areas. The main fairway is bounded to the north by the appearance of Sikanni sandstones in outcrop in the Fort Nelson area, but re-appears to the north in the Liard Basin Play area.

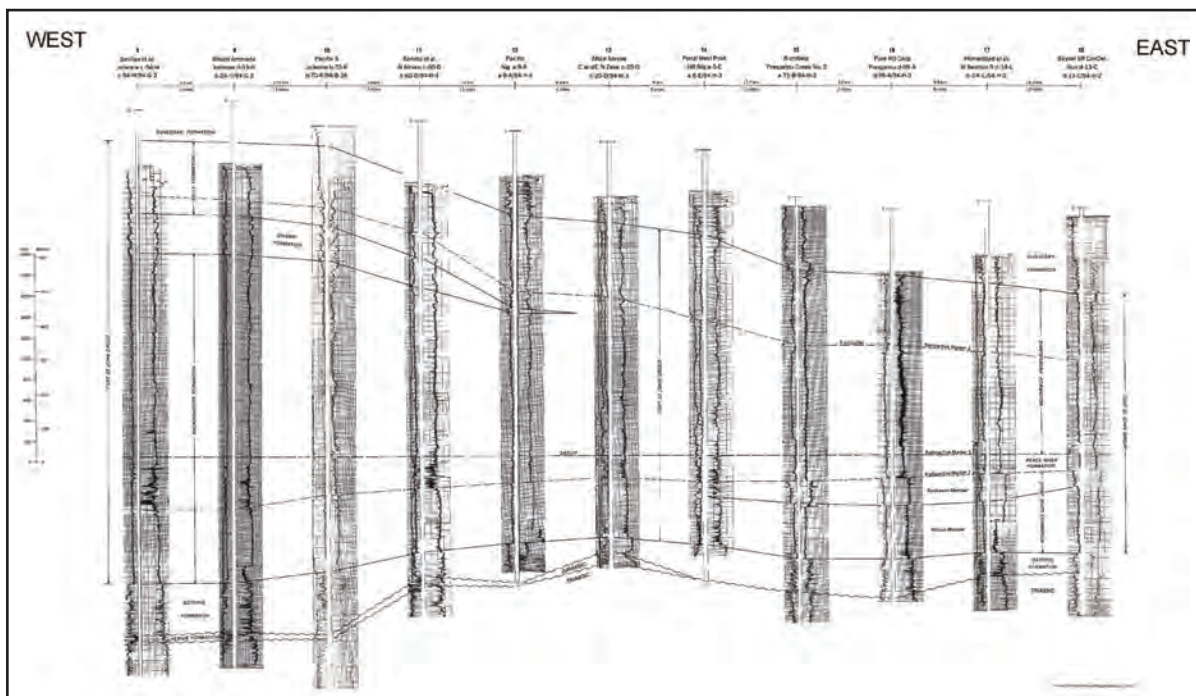
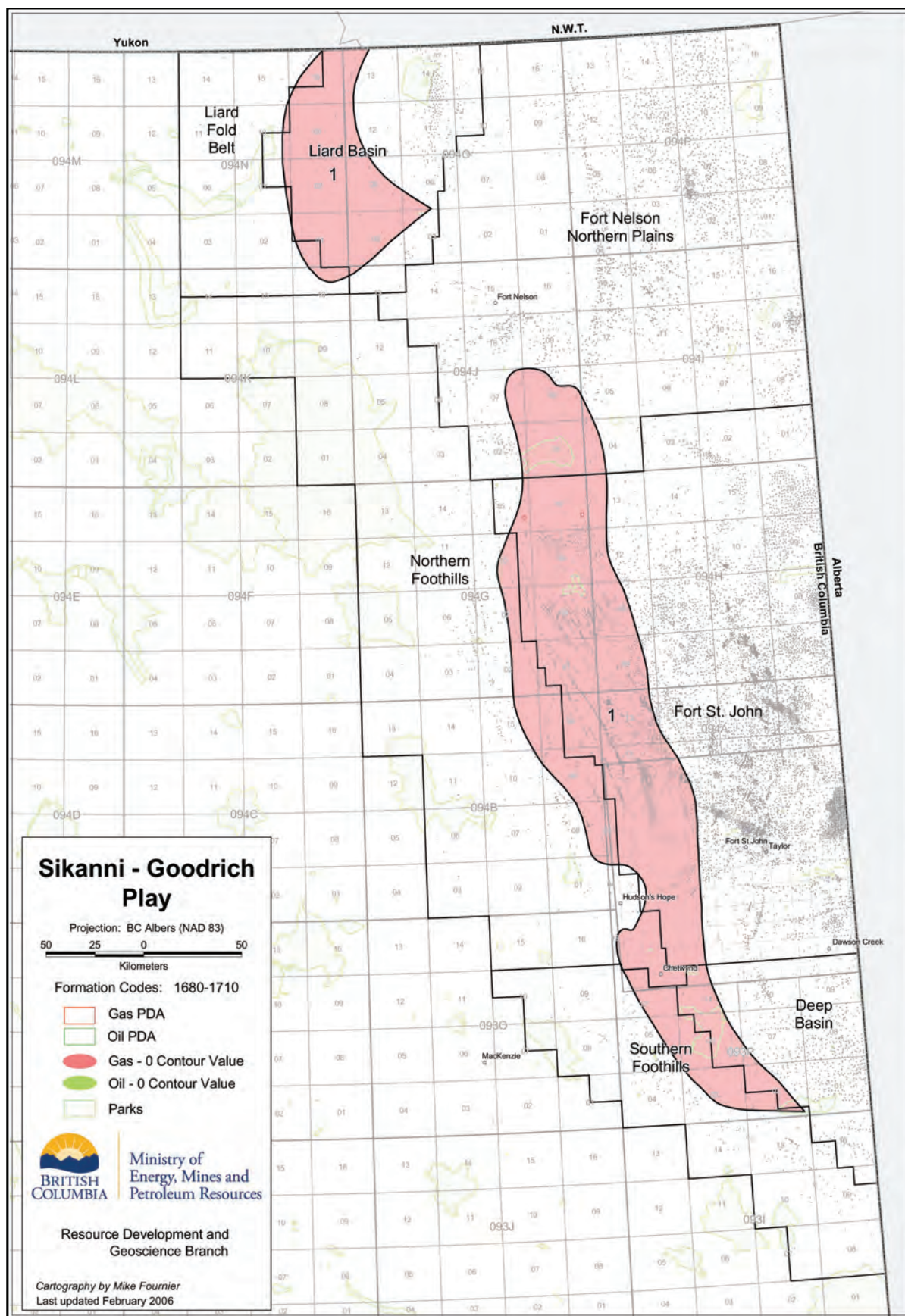


Figure 4. West-east regional cross-section, illustrating eastward pinchout of stacked Sikanni sandstone successions within the uppermost Lower Cretaceous Fort St. John Group marine shales (from Stott, 1982).



4.8 Scatter Formation

The Scatter Formation is found in the Liard Basin and northward into the southern Northwest Territories. It was deposited in shallow marine shelf to shoreline settings, and is encased by marine shales of the Garbutt Formation below and the Lepine Formation above (Leckie and Potocki, 1998). From major depocentres to the west and southwest, the Scatter thins eastward, although there is no well-defined eastern sandstone limit.

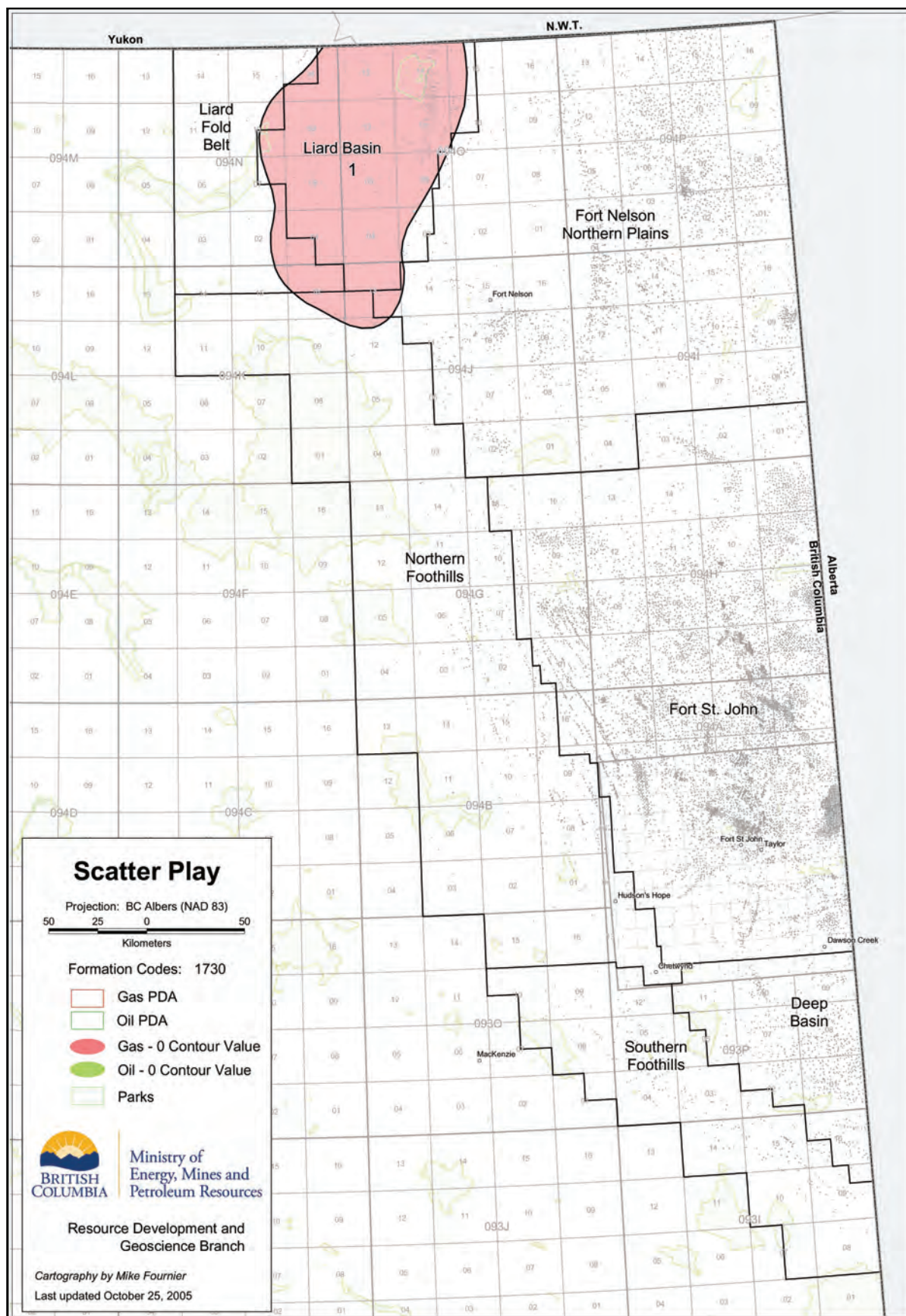
Scatter sandstones are silty to very fine-grained, moderately- to well-sorted, matrix-rich, moderately to poorly porous, glauconitic and lithic. Compaction has greatly reduced porosity and permeability; in addition, locally abundant calcite cement has further reduced reservoir quality.

Liard Basin Region

Play 1. Liard Basin Play—Present-day burial depths range up to about 1700 metres, increasing to the southwest. Considerable gas potential exists for the Scatter in stratigraphic pinchouts and possible fault traps; net sandstone thicknesses exceed 100 metres in the western part of the Liard Basin. However, Scatter sandstones have produced no hydrocarbons to date, and reservoirs are difficult to evaluate on well logs because of their heterolithic bedding.

All Scatter penetrations to date have been targeted for deeper objectives. There has thus been no systematic effort to evaluate the Scatter reservoir with carefully-designed drilling and completion programs. A systematic uphole evaluation of the Scatter over the Maxhamish Field would help to quantify its productive potential.

Scatter play potential laps into the adjacent Liard Fold Belt and Northern Foothills Play areas, where structure may play a greater role in reservoir and trap development.



4.9 Paddy Member

Paddy strata were deposited across the southern Deep Basin in alluvial plain to bay/lagoonal environments at the culmination of a widespread regional transgressive/regressive cycle. To the north, the Paddy grades into a regional, southwest-northeast trending sandy shoreface / barrier that can be traced from outcrops in the B.C. Foothills to the Peace River Valley near Peace River town in Alberta.

The Paddy section in the B.C. Deep Basin is dominated by fine-grained clastics and coals, and lacks regional stratigraphic markers (Smith et. al., 1984). Locally, valleys incised from the top of the Paddy are filled with sand-dominated estuarine facies (Leckie and Singh, 1991). Paddy strata cap Cadotte shoreface sandstones and related facies with a subtle unconformity that decreases in magnitude northward. Marine Shaftesbury shales cap the Paddy and provide an excellent upper seal.

Deep Basin Region

Play 1. Estuarine Valley Fill Play—High-quality reservoir sandstones, up to 25 metres thick, occur within north-south trending estuarine valleys at the top of the Paddy (Figure 5). Optimal reservoir facies are medium-grained or coarser sublitharenites to quartzarenites, featuring well-developed primary intergranular and secondary solution porosity. Finer-grained sandstones exhibit poorer quality, with less extensive solution porosity and more tortuous, intricate porosity networks.

The Estuarine Valley Fill Play lies within the hydrocarbon-saturated Deep Basin regime, so that productivity is a function of reservoir quality and volume, without consideration for trapping. The northern limit of the Deep Basin defines the northern boundary of the Play area; this limit is defined in northern 93-P-8 by updip water recoveries, but is poorly defined to the west. Relatively few upper Paddy valley segments are likely to occur west of Cutbank/Tupper, as increasing thickness of the overall Paddy section indicates expanding accommodation space, and thus less likelihood of lengthy valley incisions

Producing gas pools occur at Cutbank, Kelly, Noel, and Tupper Creek, most in a well-defined valley trending north through the middle of 93-P-1 and 93-P-8.

Play 2. Northern Barrier Play—In the northern shoreface / barrier trend, fine-grained Paddy strata grade into more homogeneous, sandier- and coarsening-upward sandstones. In the southern part of the trend, the reservoir is more heterogeneous, with interbedded argillaceous facies. Sandstones are generally fine- to medium-grained with local coarser facies. Reservoir quality is generally good in the east, but degrades westward with burial compaction and associated cementation.

Gas is trapped in subtle structures providing closure within massive shoreface sandstones on the northern flank of the trend. Locally, a stratigraphic component of trapping may occur to the south, as reservoirs are compartmentalized by interbedded argillaceous facies.

Producing pools are found at Dawson Creek, Doe, and Sunrise.

Play 3. Northeast Deep Basin / Backbarrier Play (Conceptual)—This play occupies a position intermediate between Plays 1 and 2, encompassing an area where gas may be trapped stratigraphically in the northern reaches of estuarine valley fills, or in backbarrier splays and channels. There is no established production, although economic reservoir quality has been established in several wells that have tested wet.

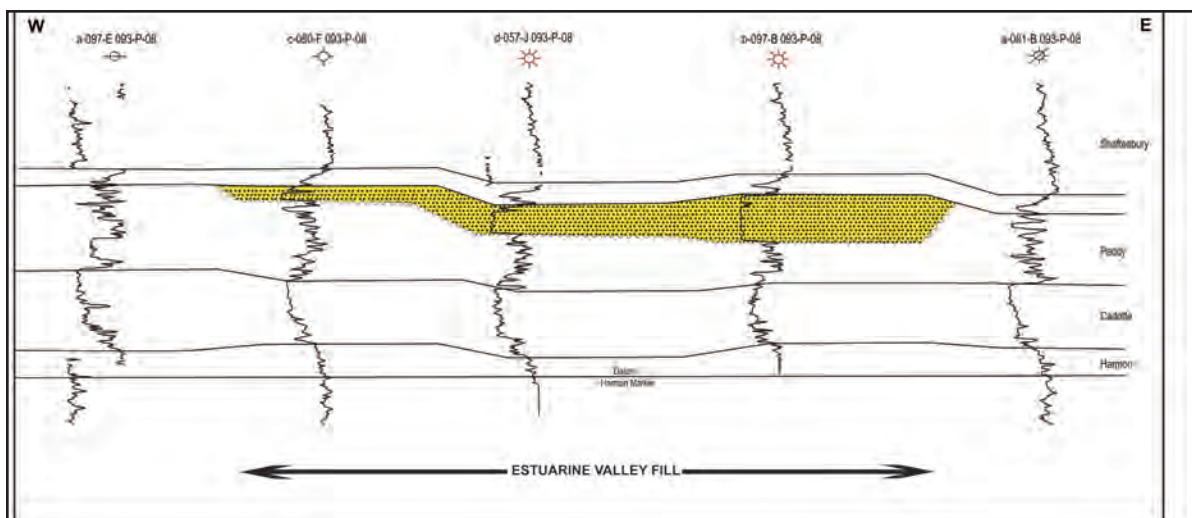
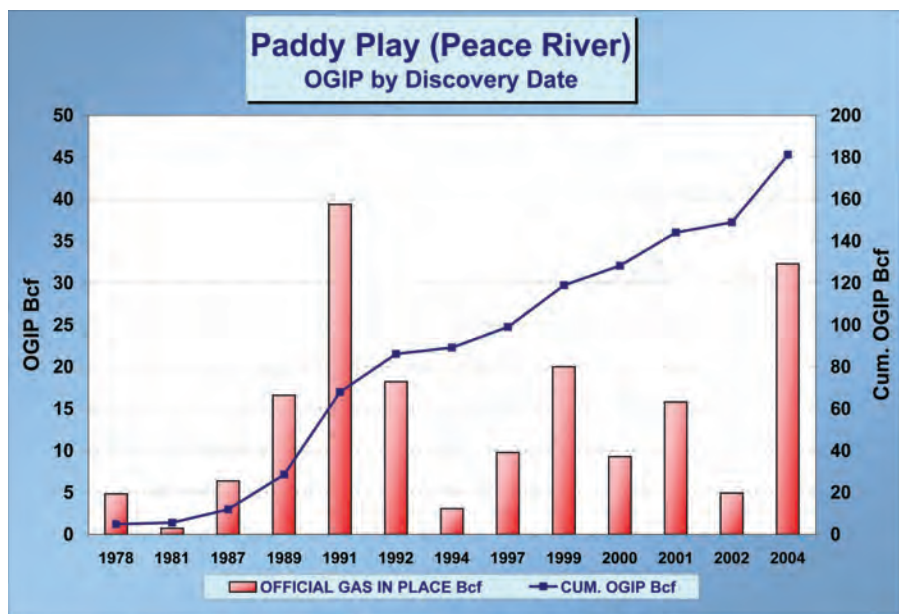
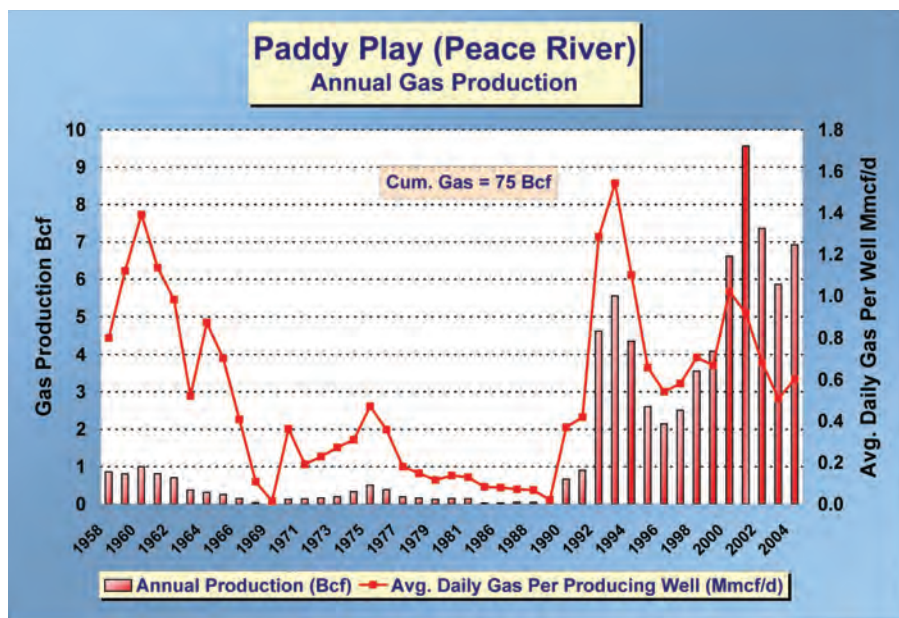
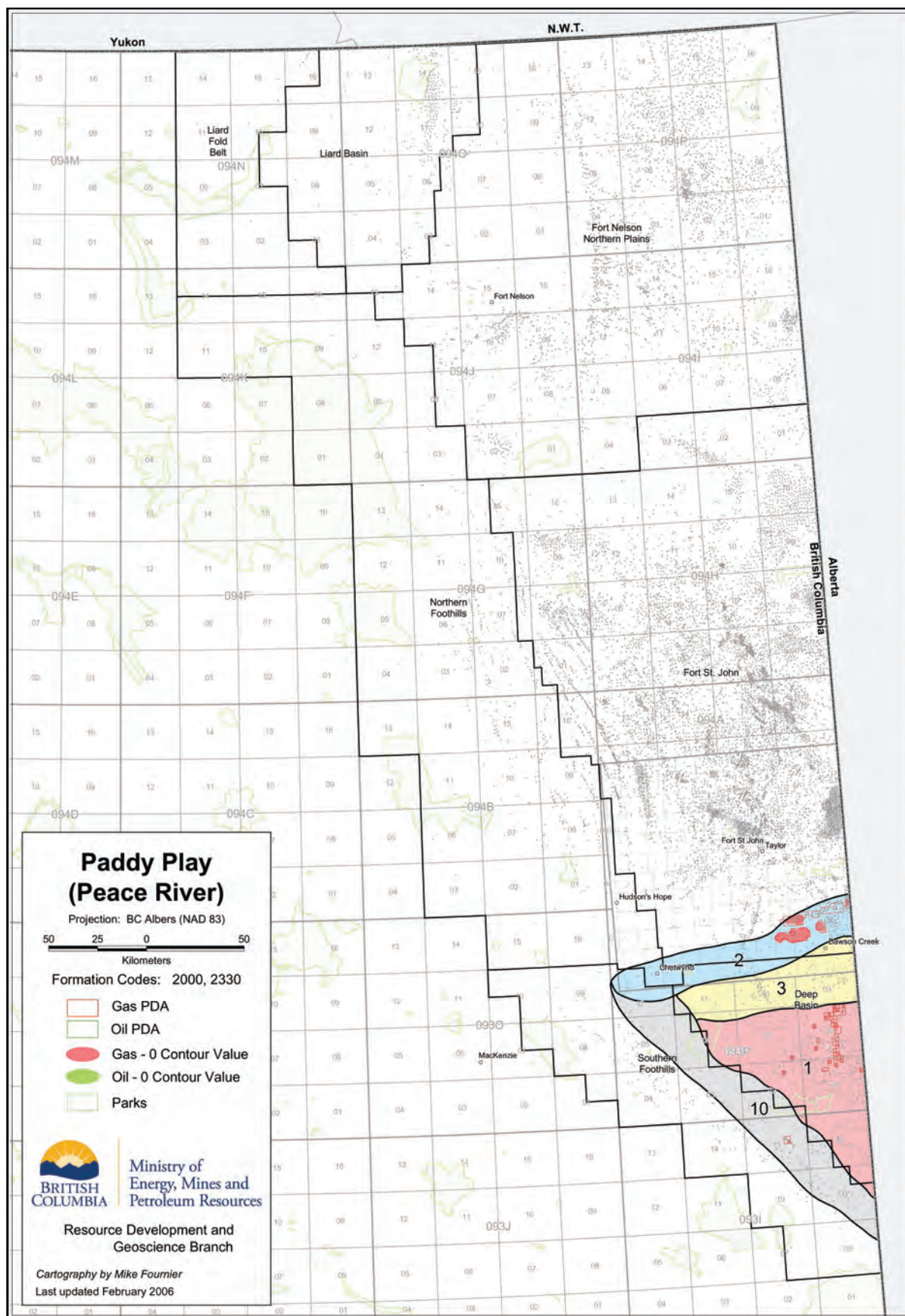


Figure 5. Estuarine valley-fill reservoir development, upper Paddy Member, Tupper Creek area of B.C. Deep Basin. Clean, blocky sandstones in b-97-B and d-57-J wells are highly productive.

| Paddy Play (Peace River) - Top 10 Pools by OGIP | | | | | | | | |
|---|-----------|----------|-----------------------------|------------------------|-------------------|---------------------------|----------------------|-----------------|
| AREA | FORMATION | POOL SEQ | OFFICIAL GAS IN PLACE (Mm3) | INIT EST GAS MKT (Mm3) | REM GAS MKT (Mm3) | OFFICIAL GAS IN PLACE BCF | INIT EST GAS MKT BCF | REM GAS MKT BCF |
| Cutbank | Paddy | H | 567 | 491 | 447 | 20 | 17 | 16 |
| Cutbank | Paddy | B | 567 | 427 | 91 | 20 | 15 | 3 |
| Tupper Creek | Paddy | A | 381 | 324 | 83 | 13 | 11 | 3 |
| Noel | Paddy | D | 359 | 249 | 68 | 13 | 9 | 2 |
| Other Areas | Paddy | A | 359 | 304 | 232 | 13 | 11 | 8 |
| Cutbank | Paddy | G | 348 | 301 | 274 | 12 | 11 | 10 |
| Tupper Creek | Paddy | G | 277 | 235 | 187 | 10 | 8 | 7 |
| Tupper Creek | Paddy | D | 275 | 65 | 31 | 10 | 2 | 1 |
| Tupper Creek | Paddy | I | 263 | 224 | 139 | 9 | 8 | 5 |
| Tupper Creek | Paddy | H | 244 | 173 | 80 | 9 | 6 | 3 |
| Other Pools | | | 1,495 | 1,026 | 593 | 53 | 36 | 21 |
| Totals | | | 5,134 | 3,818 | 2,225 | 181 | 135 | 79 |





4.10 Cadotte Member

The Cadotte Member was deposited during northerly progradation of coarse clastic shorelines across the west-central portion of the Western Canada Sedimentary Basin. It comprises sandier- and coarsening-upward successions of sandstone and conglomerate, very similar to those of the Falher and Notikewin Members, although generally thicker and more completely developed (Smith et. al., 1984). An erosional edge marks the southern boundary around Township 60 in Alberta. The northern limit is defined by a northerly facies change to more distal fine-grained clastics, approximately coincident with the Paddy northern barrier edge.

Cadotte reservoirs consist of moderately- to well-sorted granule to small pebble conglomerates, deposited in upper shoreface to foreshore environments. Reservoir quality is best in well-sorted upper shoreface to foreshore conglomerates. An immense, almost untapped tight gas resource exists in moderate-porosity, low-permeability fine-grained middle shoreface sandstones.

Deep Basin Region

Play 1. Deep Basin Shoreface Play—East-west trending shoreface to foreshore sandstones and conglomerates host numerous Cadotte gas pools. A subnormally-pressured, gas-saturated Deep Basin regime characterizes this area, so conventional traps are not identified. The northern edge of the Deep Basin demarcates the northern boundary of the Play Area.

Cadotte gas pools are clustered along the northern margin of the Play Area, where reservoir quality is best developed. Optimal reservoir quality occurs in thick, well-sorted conglomerates forming stratigraphic “sweet spots”. Increased burial compaction degrades reservoir quality downdip, while a regional valley complex has incised and reworked shoreface strata in the Noel area (Figure 6) (Hayes, 1988).

Cadotte Deep Basin pools occur at Hiding Creek, Jackpine, Kelly, Moose, and Noel.

Play 2. Regional Aquifer Play—Cadotte shoreline clastic reservoirs continue north of the Deep Basin edge, becoming generally thicker and exhibiting greater reservoir quality as far north as Brassey (E/ 93-P-10). Within the Regional Aquifer Play Area, however, the reservoirs are regionally wet, and gas pools occur in discrete east-west shoreline trends. Trapping appears to be stratigraphic, although specific controls on particular accumulations are poorly understood. Thus, the highly productive Sundown Cadotte ‘A’ pool was not successfully offset until 17 years after it was first put on production.

Regional Aquifer pools are found at Brassey, Cutbank, Sundown, and Tupper Creek. The northern reaches of the Regional Aquifer play lap into the southeastern corner of the Fort St. John Area.

Southern Foothills Region

Play 3. Foothills Play—Cadotte reservoir trends and quality become less predictable in the Foothills, reflecting proximity to sedimentary source areas and greater sediment accumulation in the foredeep. High-quality, well-sorted conglomerate reservoirs are thus relatively rare and laterally discontinuous. Fracturing associated with structural deformation may locally improve reservoir quality, although this has not been documented conclusively within the Cadotte. Gas-saturated Deep Basin conditions prevail in the eastern reaches of this play area, indicating the presence of a large tight gas resource.

Small Cadotte pools produce at Grizzly North and Ojay.

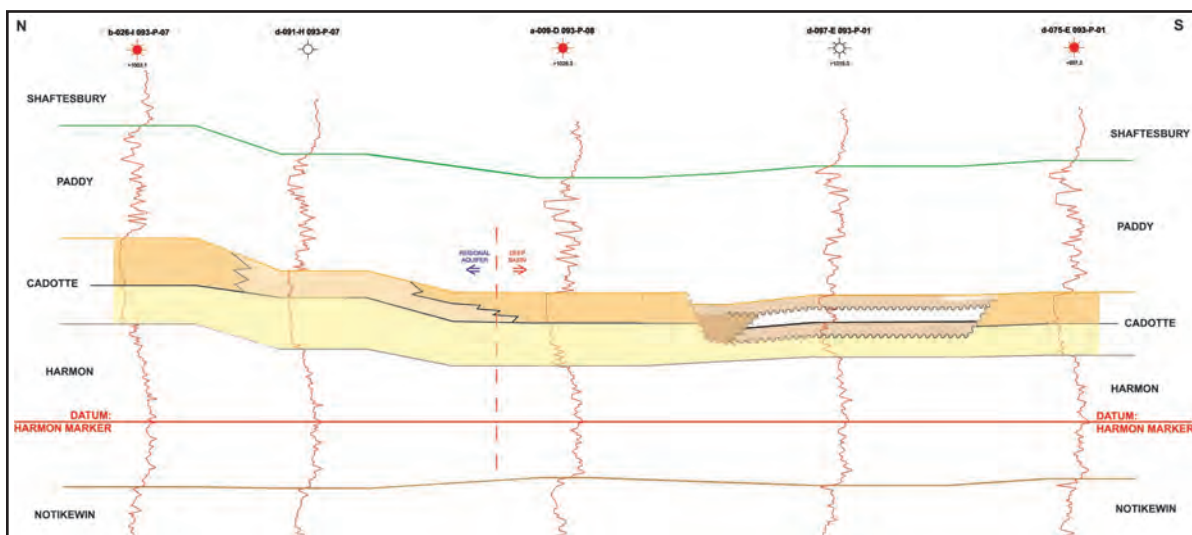
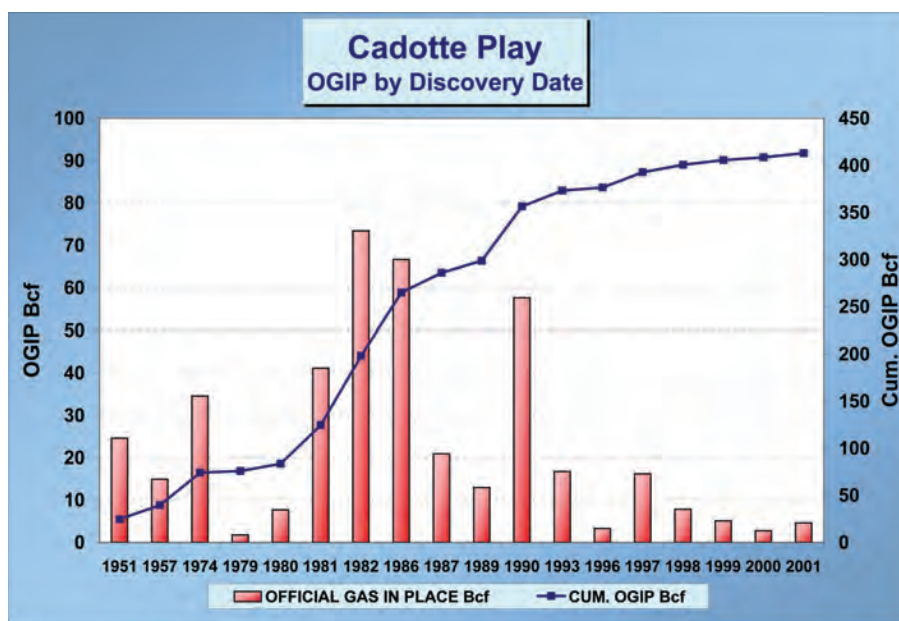
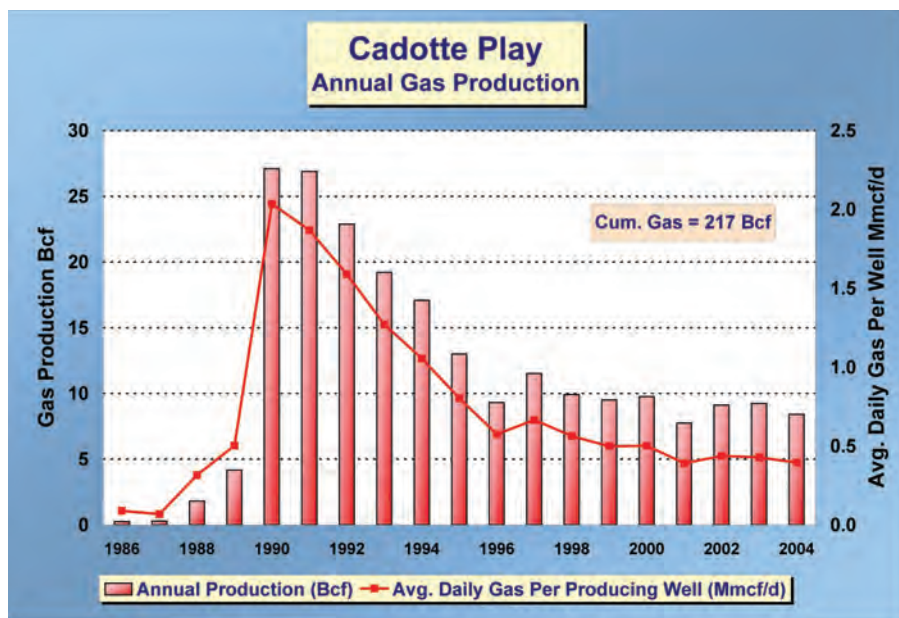
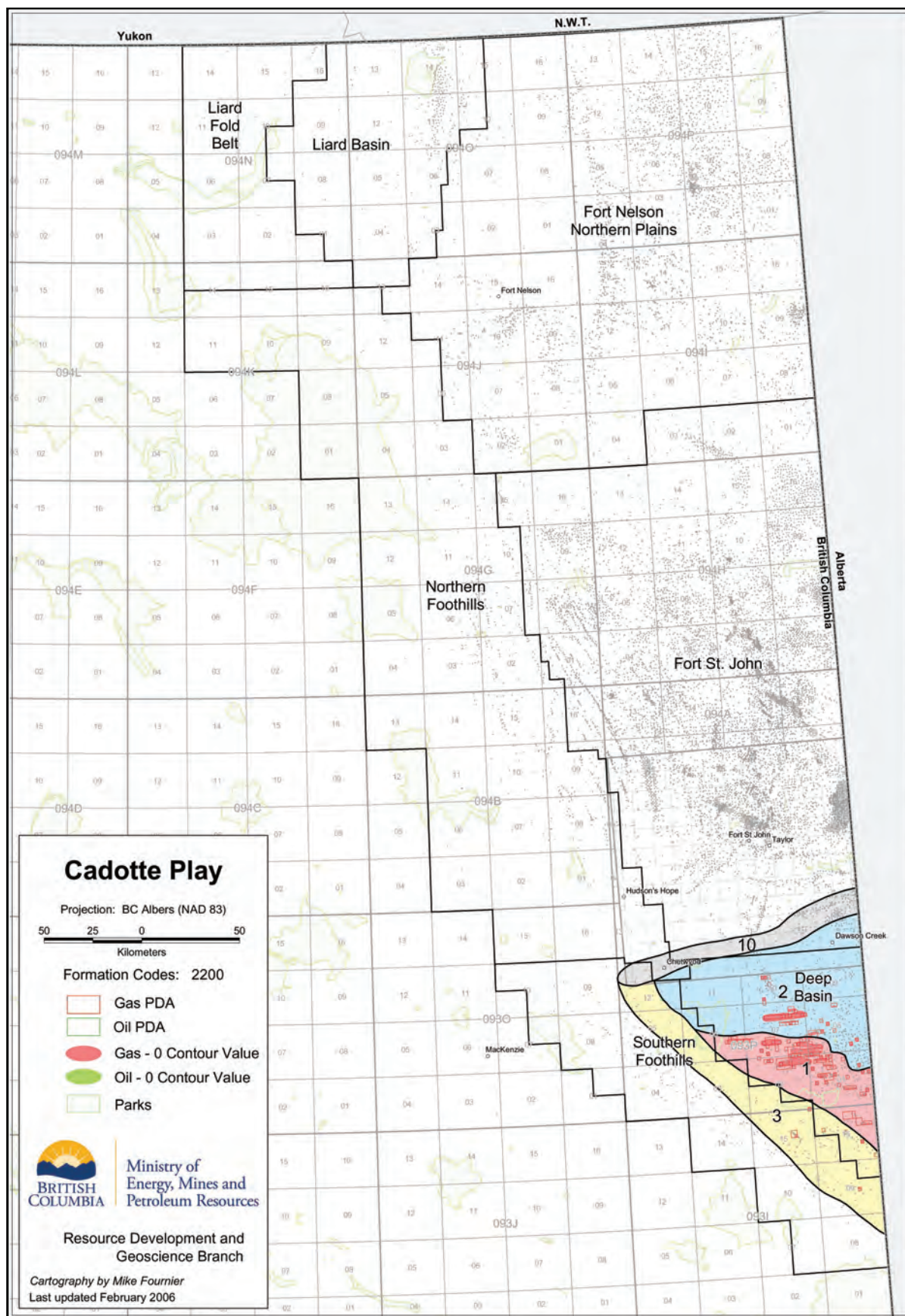


Figure 6. Regional cross-section, Sundown-Noel area. Well b-26-I has produced >23 BCF from a discrete, narrow trend of high-quality shoreface/foreshore conglomerates and sandstones in the Regional Aquifer play area. Well d-91-H penetrates a sand-dominated upper shoreface section with subeconomic permeabilities. Wells a-9-D and d-75-E produce gas from more widely-distributed conglomeratic reservoirs in the Deep Basin play area. Well d-97-E penetrates a regional valley trend incising Cadotte shoreface strata.

| Cadotte Play - Top 10 Pools by OGIP | | | | | | | | |
|-------------------------------------|-----------|----------|-----------------------------|------------------------|-------------------|---------------------------|----------------------|-----------------|
| AREA | FORMATION | POOL SEQ | OFFICIAL GAS IN PLACE (Mm3) | INIT EST GAS MKT (Mm3) | REM GAS MKT (Mm3) | OFFICIAL GAS IN PLACE BCF | INIT EST GAS MKT BCF | REM GAS MKT BCF |
| Sundown | Cadotte | A | 2,080 | 1,764 | 87 | 73 | 62 | 3 |
| Noel | Cadotte | A | 1,417 | 1,198 | 205 | 50 | 42 | 7 |
| Noel | Cadotte | M | 1,140 | 852 | 212 | 40 | 30 | 7 |
| Doe | Cadotte | A | 979 | 627 | 627 | 35 | 22 | 22 |
| Moose | Cadotte | A | 788 | 664 | 182 | 28 | 23 | 6 |
| Sunrise | Cadotte | A | 698 | 137 | 63 | 25 | 5 | 2 |
| Noel | Cadotte | L | 529 | 398 | 20 | 19 | 14 | 1 |
| Dawson Creek | Cadotte | A | 423 | 332 | 128 | 15 | 12 | 5 |
| Jackpine | Cadotte | A | 348 | 261 | 91 | 12 | 9 | 3 |
| Noel | Cadotte | D | 327 | 242 | 88 | 12 | 9 | 3 |
| Other Pools | | | 2,971 | 2,079 | 1,035 | 105 | 73 | 37 |
| Totals | | | 11,701 | 8,553 | 2,739 | 413 | 302 | 97 |





4.11 Spirit River Formation

The Spirit River Formation is the product of a basinwide progradational episode during mid-Albian time. In the B.C. Deep Basin, it comprises six major stacked shoreface successions, termed (from the top down) Notikewin, Falher A, B, C, D, and F (Figure 7) (Smith et. al., 1984). An individual cycle typically consists of a coarsening-upward succession, passing from very fine-grained sandstones to coarse sandstone or conglomerate, capped by continental mudstones and coals. Recent work has illustrated more complex internal stratigraphic relationships, which can be important at field development scale (e.g., Casas and Walker, 1997).

To the north, Spirit River shorefaces grade to finer-grained, more distal facies. Individual Notikewin and Falher submembers lose their identity, as capping conglomerates and coals pinch out seaward. North of about Township 87, only the uppermost sandstone remains, overlying a succession of shelfal siltstones and shales. This unit has been recognized as an important gas reservoir only since the late 1990's.

Spirit River sandstones grade up from underlying Wilrich Member marine shales, and are capped by transgressive marine shales of the Harmon Member in the south and Buckingham Formation in the north.

Deep Basin Region

Play 1. Deep Basin Falher / Notikewin Play—Falher and Notikewin cycles typically coarsen upward from very fine- to fine-grained, swaley cross-stratified middle shoreface sandstones, to cross-bedded conglomeratic sandstones and sandy conglomerates of the upper shoreface (Figure 8). In map view, each is characterized by a southerly transgressive limit, north of which conglomeratic sweet spot reservoirs are optimally developed along trends up to tens of kilometres long. Sweet spots occupy only a small proportion of the overall reservoir volume; low-permeability sandstones are volumetrically very dominant.

Falher and Notikewin pools lie within the subnormally-pressured, gas-saturated Deep Basin regime. The northerly limit of the Deep Basin varies for each submember, but none are well defined, as each

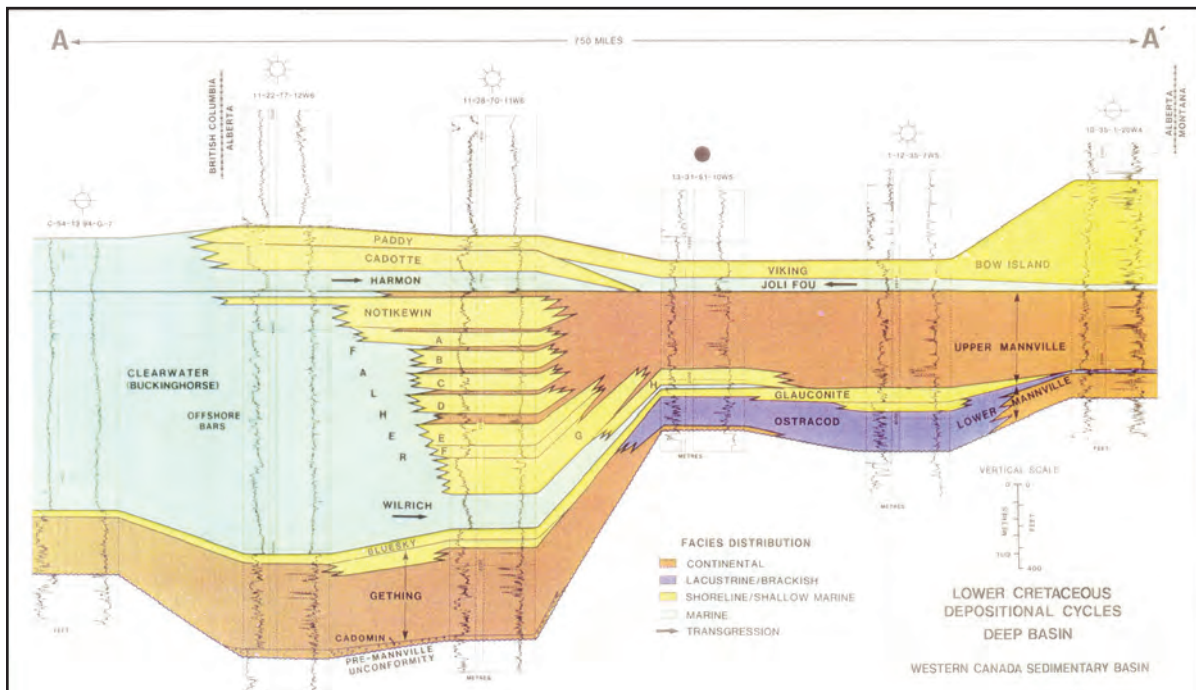


Figure 7. Regional stratigraphic framework, Spirit River Formation. Falher and Notikewin shoreline/shallow marine reservoir sandstones and conglomerates prograde across the west-central Alberta and British Columbia Deep Basin area (from Jackson, 1984).

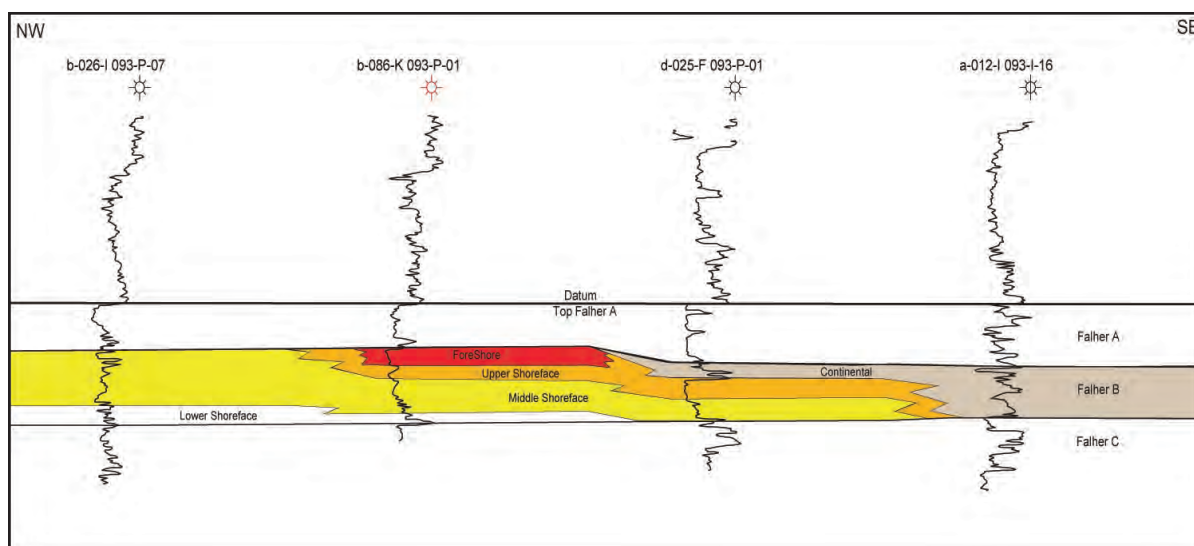


Figure 8. Cross-section illustrating progradation of the Falher B submember across the B.C. Deep Basin. Continental facies in the south pass northward to shoreface sandstones and conglomerates, which in turn grade to distal shoreface and offshore fine-grained clastics. Well b-86-K has produced >7 BCF from well-sorted foreshore and upper shoreface strata.

lies within poorer-quality, more distal sandstone facies north of the conglomerate reservoir trends. A generalized northerly limit demarcates the play area.

Pools in the Deep Basin Falher / Notikewin Play occur at Hiding Creek, Jackpine, Kelly, and Noel.

Fort St. John Region

Play 2. Northern Shoreface Play—North of the Deep Basin, the Spirit River comprises sandier- and coarsening-upward successions deposited in shoreface to deltaic settings. Feldspathic litharenites are the dominant rock type; they range from lower fine- to upper medium-grained, are poorly- to moderately-sorted, and comprise angular to subrounded grains. Kaolinite, chlorite, and carbonate minerals are the primary cements. Conventional log analysis does not adequately evaluate these reservoirs, as feldspars, clays, and partially dissolved grains elevate gamma log readings, and produce wide density-neutron separation and low resistivity readings in reservoir-quality sandstones.

Spirit River northern shoreface reservoirs produce gas with relatively little water. There are very few tests outside of the main producing pools, and most of these have recovered mud or flowed low-rate gas. No regional aquifer has been documented, and a regional gas-saturated (Deep Basin) regime may exist.

The first major discovery in the northern shoreface play was made in 1997 at Pickell, through evaluation of the uphole section in a well targeted for deeper Cretaceous targets. Similarly, the Ladyfern and Drake pools were discovered during development of the Ladyfern Slave Point play in 2001/2002. Both areas are now under active development.

Spirit River Northern Shoreface pools occur at Buick Creek, Buick Creek North, Drake, Milligan Creek West, Pickell, and Velma.

Southern Foothills Region

Play 1. Foothills Falher / Notikewin Play—This play represents the westerly continuation of the Deep Basin Falher / Notikewin Play into the Southern Foothills Area. Isolated production appears to be governed by the same stratigraphic controls as in the Deep Basin, but reservoir quality and continuity is generally poorer. Structural overprint is apparently minor, although fracture enhancement of stacked sandstone / conglomerate reservoirs may occur.

Foothills Falher / Notikewin pools occur at Ojay, Grizzly North, and Redwillow River.