A case for renewed development of a mature gas field: the Devonian Swan Hills Formation at Kaybob South field, Alberta, Canada

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ABSTRACT

In 1961 approximately 104,772 x 10^6 m^3 (3.7 trillion ft^3) of in-place sour gas resources were discovered within the Late Devonian Swan Hills Formation (Beaverhill Lake A pool) at Kaybob South field of west-central Alberta. Production at Kaybob South is managed as three operational units (Gas Units #s 1, 2 and 3) and commenced in 1968 at Gas Unit #1 with the secondary recovery of natural gas liquids and condensate from produced gas and re-injection of by-product lean sweet gas. Liquid and gas production through this process of gas cycling continued at Gas Unit #1 until 1983, after which gas was harvested through pressure depletion. Cumulative gas production to date at Gas Unit #1 suggests that only 47–56 percent of the in-place gas will be ultimately captured by the remaining productive wells. This relatively low recovery is attributed to wellbore mechanical failure resulting from corrosive formation fluids, and both wellbore and reservoir permeability loss caused by the precipitation of hydrocarbon liquids and various mineral precipitants.

Work presented in this study suggests that the drilling of 17 infill development wells may capture between 1,183 x 10^6 m^3 (42 bcf) and 5,192 x 10^6 m^3 (183 bcf) of by-passed gas resources. These reserve additions, combined with the 651 x 10^6 m^3 (23 bcf) reserves that are anticipated to be recovered by the current producing wells in their remaining well life, will increase the ultimate recovery at Gas Unit # 1 to 63–77 percent of OGIP. This recovery factor is comparable to analogous Swan Hills Formation gas pools within the region.

The Swan Hills Formation at Gas Unit #1 accumulated as a platform margin succession of shallow marine carbonates that are partitioned into five high-frequency depositional sequences (HFS-2 through HFS-6). HFS-2 through -4 are characterized by an aggradational to slightly retrogradational stacking pattern, whereas HFS-5 and -6 are stacked in a more strongly retrogradational fashion. The priority assigned to future development wells should take into account the geologic attributes that influence well performance. The best reservoir quality and production performance is associated with dolomitized reef margin and stromatoporoid shoal facies associations. Due to pervasive fracturing, sequence boundaries and associated facies distributions are not thought to compartmentalize flow units. Future development wells may be ranked according to their location relative to the predicted distributions of dominant facies, structural position, gas-saturated pore-volume thickness, Kmax permeability, fracture density, and proximity to currently producing wells. Following assessment of all prospective development wells, three prospects were successfully drilled during the 4th-quarter of 2006 and 2007 and serve as an independent test that strengthens the geologic interpretation and confirms the existence of significant bypassed gas resources that may be captured through infill development.

RÉSUMÉ

En 1961 environ 104,772 x 10^6 m^3 (3.7 trillion pi^3) de ressources de gaz acide in situ ont été découvertes à l’intérieur de la formation de Swan Hills du Dévonien tardif (Beaverhill Lake, gisement A) au sud du champ pétrolifère de Kaybob South, dans l’Alberta central-ouest. La production, dans Kayob South, est gérée en trois unités opérationnelles (unités de gaz #s 1, 2 et 3), et a débuté en 1968 par l’unité de gaz #1 avec la récupération secondaire de liquides de gaz naturel, et de condensat provenant du gaz produit, et avec la re-injection de sous- produit de gaz pauvre non-corrosif. La production de liquide et de gaz, au moyen du procédé de cyclage de gaz, a été poursuivie sur l’unité de gaz #1 jusqu’en 1983, suivie d’une récolte de gaz par déplétion de pression. À ce jour, la production cumulative de gaz sur l’unité de gaz #1, suggère que seulement 47–56% du gaz in-situ sera finalement capturé par les puits productifs restants. Cette récupération relativement basse est attribuée à la panne mécanique de
is a sour, i.e. H₂S-bearing, retrograde gas-condensate pool (1993; Oldale and Munday, 1994). The Beaverhill Lake A was discovered in 1961, and is the largest of the 15 gas pools within the Beaverhill Lake Group field within the WCSB. Kaybob South Lake A at Kaybob South field that ranks as the second largest Devonian gas fields were discovered prior to 1970 (Oldale and Munday, 1994). The majority (95 percent) of the 626 pools within the 40 largest in-place gas reserves within the WCSB (Reinson et al., 1993), that is managed as three contiguous operational units: Gas Units #1, #2, and #3 (GU1, GU2, GU3) (Figure 2A). In-place gas resources at Kaybob South are 104,754 x 10⁶m³ (3.7 trillion ft³), and provide 41 percent of the in-place resources within the Swan Hills shelf margin play (Reinson et al., 1993). A total of 156 development wells that target the Beaverhill Lake A have been drilled at Kaybob South, and the majority of these (56 percent) were drilled before 1970. Prior to this study, only four development wells had been drilled since 1995. Production at Kaybob South began in 1968 at GU1 with the secondary recovery of natural gas liquids through gas cycling, i.e. the recovery of hydrocarbon liquids from produced gas and subsequent re-injection of the lean sweet gas by-product back into the GU1 reservoir. The initial phase of gas injection at GU1 was followed by gas depletion in 1983 (Figure 3). Gas cycling at GU2 and GU3 began in 1970 and 1972, respectively, and culminated with gas depletion in 1990 (Carr and Fiori, 2004). With all three units, gas depletion coincided with the transition from active field development to more passive “harvest mode” management and depletion (Carr and Fiori, 2004). Based upon the history of gas injection and production relative to original in-place gas resources at the Beaverhill Lake A GU1, this study evaluates and tests the potential for renewed field development based upon an evaluation of the geologic controls on reservoir performance.

**GEOLOGIC SETTING**

Sedimentary fill within the WCSI includes a thick (>6 km) succession of middle Proterozoic to Paleocene strata that record an initial phase of Precambrian-Cambrian rifting, an intermediate phase of foreland subsidence during the Devonian and Mississippian, and two concluding phases of foreland subsidence during the Middle Jurassic to Early Cretaceous and Late Cretaceous to Paleocene (Wendte, 1992a as summarized by Atchley et al., 2006; Wendte et al., 1998; Root, 2001).
Thermal maturation of organic-rich Devonian source rocks during the latter two phases of Mesozoic to earliest Cenozoic foreland subsidence yielded hydrocarbons that migrated updip and charged Devonian reservoirs (Wendte, 1992a as summarized by Atchley et al., 2006; Creaney et al., 1994).

The reservoir interval at Kaybob South field consists of dolomitized platform margin carbonates of the Devonian (early Frasnian) Swan Hills Formation (Figure 4). The Swan Hills accumulated as an assortment of variably sized, generally reef-rimmed shallow marine carbonate banks that are collectively identified in the literature by several paleogeographic names, e.g. Swan Hills Complex (Oldale and Munday, 1994) and Northwest Swan Hills Bank (Wendt and Uyono, 2005) (Figure 1). The Swan Hills Complex, as referred to in this

![Middle-Late Devonian paleogeography of a portion of the Western Canada Sedimentary Basin, Alberta (modified from Wendte and Uyeno, 2005, and Podruski et al., 1988). Kaybob South field is located along the southwestern edge of a narrow, northwest-trending reentrant into the Swan Hills Complex. The Swan Hills Complex accumulated as a generally aggradational to retrogradational succession of shallow marine carbonates that were surrounded to the northwest, north and east by the deeper waters of the Central Alberta Basin.](image-url)
paper, has been attributed to the accumulation of shallow marine carbonate sediment atop basement uplifts (Martin, 1967; Keith, 1970), and/or antecedent paleotopographic highs that were initially formed by differential compaction of distributary sandstones and interdistributary mudrocks of the underlying “Gilwood delta complex”, and later enhanced by aeolian deflation of the post-Gilwood Fort Vermilion Formation (Jansa and Fischbuch, 1974). Time-equivalent basinal limestones of the Waterways Formation accumulated within the Central Alberta Basin that surrounds the Swan Hills Complex to the northwest and southeast (Figure 1). The Swan Hills Complex is located near the deep foreland axis of the WCSB and is bounded to the southwest by the Late Cretaceous to earliest Tertiary Laramide Fold and Thrust Belt (Wright et al., 1994) (Figure 1).

Kaybob South field is associated with a platform marginal reef succession located adjacent to the southwestern edge of a narrow, less than 10 km wide, northwest-trending linear embayment within the Swan Hills Complex (Figure 1). This embayment is filled with basinal shales and limestones of the Waterways Formation, and its linear nature is suggestive of precursor faulted basement control (Keith, 1970).

**DATA AND METHODS**

Results presented in this study are based upon a dataset of 66 wells correlated within a grid of 20 stratigraphic cross-sections that extend across both GU1 and the northernmost portion of GU2 (Figure 2B). All available core from the Swan Hills Formation (1494 m of core from 60 of the 66 total wells) were described to document the vertical distribution of lithology, carbonate texture (after Dunham, 1962; Embry and Klovan, 1972), dominant allochems, mechanical and biological sedimentary structures, porosity type and relative abundance (after Choquette and Pray, 1970), fracture density and abundance, and cement type and relative abundance. Core descriptions were digitized and merged with digital core analysis porosity and permeability data to assess facies-specific trends of porosity and permeability, and to allow the transfer of facies descriptions onto well logs for sequence stratigraphic interpretation within the cross-section grid (Figure 2B). Facies, fracture, and structural maps were generated for each depositional sequence correlated within the gas-saturated portion of the Swan Hills reservoir interval, and pore volume, composite facies and fracture density maps were produced for the entire Swan Hills

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**Fig. 2** Basemap for the Kaybob South study area. (A). Kaybob South field is subdivided into three operational units, Gas Units 1–3, within the Beaverhill Lake A pool. The study area location is indicated by the inset box. (B). Detailed map of study area. Well logs are correlated within a grid of 20 stratigraphic cross-sections. East-trending dip cross-sections are indicated by solid black lines, and northwest-trending strike cross-sections are indicated by dashed black lines. Cored wells are highlighted with an open circle around well symbols.
interval. In-place and recoverable gas volumes for GU1, along with estimations of drainage area for current producers and anticipated recoverable gas volumes for prospective well locations are based upon the parameters presented in Table 1.

**FACIES AND RESERVOIR QUALITY**

**FACIES MODEL**

Thirteen facies are observed within the Swan Hills Formation at Kaybob South GU1, and although dolomitized, are strikingly similar to those previously described by Murray (1966), Leavitt (1968), Havard and Oldershaw (1976), Wendte and Stoakes (1982), Kaufman and Meyers (1989), Wendte and Muir (1995), and Chow and Wendte (2005) within the Swan Hills at Carson Creek South, Judy Creek, Rosevear and Snipe Lake fields (Figure 1). The diagnostic attributes by which facies at GU1 are recognized are summarized in Table 2, and representative core photographs are provided in Figure 5. Estimations of water depth provided on Table 2 are derived from Wendte and Stoakes (1982), Wendte (1992b) and Wendte and Muir (1995). Environmental interpretations of facies are based upon both their sedimentary features, and recurring position within gradational shallowing-upward successions, i.e. “Walther’s law” sensu Walther (1894).

**FACIES AND RESERVOIR QUALITY**

The relationship between facies and reservoir quality within the Swan Hills Formation at GU1 is homogenized by a complex history of diagenesis that includes a relatively early phase of extensive dolomitization and secondary porosity enhancement, and multiple later stages of secondary porosity enhancement and destruction through stylolitization, fracturing and dissolution, and dolomite, anhydrite and calcite cementation. Similar diagenetic histories have been documented within the Swan Hills at Rosevear and Hanlan fields (Walls and Burrowes, 1990; Saller et al., 2001) where dolomite reservoirs are characterized by significantly higher porosity (factor of 2–5x) and permeability (factor of 2–63x) than their limestone counterparts (Saller et al., 2001). Within the Swan Hills Complex, early dolomite replacement is attributed to seepage reflux and thermal convection of Late Devonian evaporitic brines (Wendte et al., 1998; Potma et al., 2001), whereas later episodes of saddle dolomite, anhydrite and calcite cementation are interpreted to have been derived from the recycling of ions from Middle Devonian anhydrite, and brines produced from the compaction of basinal siliciclastics during Late Cretaceous through Paleocene deep burial (Wong and Oldershaw, 1981; Kaufman et al., 1990).

Comparison of facies-specific trends of core analysis porosity and Kmax permeability and core observed estimations of
fracture density are provided in Figure 6. Although the distribution of data for facies within each of these three categories overlaps significantly due in large part to diagenetic overprint, some meaningful trends are nonetheless recognized when data are combined into subaerially-exposed (facies 12, 13), platform interior (facies 9–13), reef margin (facies 4, 5 and 8), stromatoporoid shoal (facies 6, 7), and slope to basinal (facies 1–3) facies associations (Figure 6). The highest overall values of porosity and fracture density coincide with the reef margin and stromatoporoid shoal associations, whereas in descending order progressively lower values are observed for the platform interior, subaerially-exposed, and slope to basinal associations (Figure 6A, C). Trends of Kmax permeability are similarly high for the platform interior, reef margin, and stromatoporoid shoal associations, are slightly reduced in comparison for the subaerially-exposed association, and are even lower for the slope to basinal association (Figure 6B). These trends are corroborated by production data from wells where completion intervals are restricted to specific facies associations (Figure 7). Wells with completions within the reef margin and stromatoporoid shoal associations, whereas in descending order progressively lower values are observed for the platform interior, subaerially-exposed, and slope to basinal associations (Figure 6A, C). Trends of Kmax permeability are similarly high for the platform interior, reef margin, and stromatoporoid shoal associations, are slightly reduced in comparison for the subaerially-exposed association, and are even lower for the slope to basinal association (Figure 6B). These trends are corroborated by production data from wells where completion intervals are restricted to specific facies associations (Figure 7). Wells with completions within the reef margin association have maximum daily production rates that are approximately 75 percent higher than stromatoporoid shoal completions, and 100 percent higher than basinal completions (Figure 7). No wells are completed exclusively within the subaerially-exposed association, and only two wells are completed within the platform interior association.

**SEQUENCE STRATIGRAPHY**

A recent literature summary by Atchley et al. (2006) suggests that the Devonian stratigraphic record of the WCSB is encoded with the composite effects of a cyclic hierarchy of accommodation change. The Devonian Upper Givetian and Frasnian stages record a long-period transgressive episode that constructively interfered with the even longer-period Kaskaskia transgression to produce a retrogradational platform carbonate stratal succession that culminated in maximum flooding and drowning of the isolated Swan Hills (Beaverhill Lake Group) and Leduc (Woodbend Group) platforms and deposition of basinal deposits that include the sapropelic shales of the Duvernay Formation. Following maximum flooding, the Frasnian concluded with the progradational (highstand) basinfilling platform carbonates of the Winterburn Group (Sloss, 1963; Bassett and Stoudt, 1967; Johnson et al., 1985; Stoakes, 1988 and 1992; Creaney et al., 1994; Oldale and Munday, 1994; Potma et al., 2001). A “second-order” unconformity bound sequence has been attributed to this long-period accommodation event by Potma et al. (2001), who further subdivide the stratal succession into three groupings of nine “third-order” sequences that approximate major lithostratigraphic subdivisions and reflect higher frequency cycles of accommodation change, i.e. Beaverhill Lake sequences 1–3 (BHL-1, -2,
and -3), Woodbend sequences 1–3 (WD-1, -2, and -3), and Winterburn sequences 1–3 (WI-1, -2, and -3). The specifics of the sequence stratigraphic interpretation proposed by Potma et al. (2001) are debated, and the reader is encouraged to evaluate Potma et al. (2002) and Wendte and Embry (2002) for contrasting viewpoints.

Comparison of the Swan Hills Formation at Kaybob South to the regional stratigraphic correlations of Potma et al. (2001) suggest that the GU1 reservoir interval likely coincides with the upper portion of BHL-2 and most, if not all, of BHL-3 (Figures 4 and 8). Extensive previous work on the Swan Hills Formation indicates that BHL-1, -2, and -3 are further subdivided into numerous regionally correlative shallowing-upward cycles of platform growth that range from 10–20 m in thickness (e.g. Carozzi, 1961; Jansa and Fishbuch, 1974; Wendte and Stoakes, 1982; Wendte, 1992a,b; Wendte and Uyeno, 2005). Five such shallowing-upward cycles occur within the gas-saturated reservoir interval at GU1 and are designated in this study as high-frequency sequences 2 through 6 (HFS-2 through HFS-6) (Figure 8). High-frequency sequence boundaries are

<table>
<thead>
<tr>
<th>Table 1. Field discovery and production parameters for the Swan Hills Formation at Kaybob South field Gas Unit #1.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Discovery Information</strong></td>
</tr>
<tr>
<td>Year discovered</td>
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<tr>
<td>Max condensate production</td>
</tr>
<tr>
<td>Max gas production</td>
</tr>
<tr>
<td>Current gas production</td>
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<tr>
<td>Drive mechanism</td>
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<tr>
<td>Initial (Current) reservoir pressure</td>
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<tr>
<td>Trap</td>
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<tr>
<td>Original gas/water contact</td>
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<tr>
<td><strong>Reservoir Characteristics</strong></td>
</tr>
<tr>
<td>Average depth to reservoir</td>
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<tr>
<td>Average original net pay</td>
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<tr>
<td>Average porosity</td>
</tr>
<tr>
<td>Median Kmax permeability</td>
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<tr>
<td>Average Sw</td>
</tr>
<tr>
<td>Initial (Current) Temperature</td>
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<tr>
<td>Initial (Current) Bg</td>
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<tr>
<td><strong>Production Information</strong></td>
</tr>
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<td>Field Area</td>
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<tr>
<td>Well count</td>
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<tr>
<td>Total wells</td>
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<td>Gas Injection wells</td>
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<tr>
<td>Water Injection wells</td>
</tr>
<tr>
<td>Cored wells</td>
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<tr>
<td>Average well spacing</td>
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<tr>
<td>Original gas in place</td>
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<tr>
<td>Cumulative gas production</td>
</tr>
<tr>
<td>Recovery factor</td>
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<tr>
<td>Initial Gas Composition</td>
</tr>
<tr>
<td>Hydrocarbon</td>
</tr>
<tr>
<td>Hydrogen sulfide</td>
</tr>
<tr>
<td>Non-hydrocarbon</td>
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Table 2. Summary table of features diagnostic to lithofacies observed within the Swan Hills Formation at Kaybob South field, Gas Unit #1.

<table>
<thead>
<tr>
<th>Facies Designation</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
<th>13</th>
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<tbody>
<tr>
<td><strong>Environment</strong></td>
<td>Burrowed Nodular (23–35 cm)</td>
<td>Lower Slope (14–30 cm)</td>
<td>Slope Sand (&gt;10 cm)</td>
<td>Slope Debris (&lt;10 cm)</td>
<td>Narin and Narin Debris (0–14 cm)</td>
<td>Stromatoporoid Shelf-Open (&lt;10 cm)</td>
<td>Stromatoporoid Shelf-Restricted (&lt;10 cm)</td>
<td>Reef Flat (&lt;10 cm)</td>
<td>Amphipora Lagoon (&lt;10 cm)</td>
<td>Beach (high-energy intertidal)</td>
<td>Shelf Sand (shoreface to lower intertidal)</td>
<td>Tidal Flat (low-energy intertidal)</td>
<td>Subaerial Exposure Complex</td>
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<td><strong>Whole-Rock (Matrix) Texture</strong></td>
<td>mudstone-packstone</td>
<td>floatstone (wackestones-packstone)</td>
<td>packstone-grainstone</td>
<td>rudstone (packstone-grainstone)</td>
<td>floatstone-rudstone (wackestones-packstone)</td>
<td>floatstone-rudstone (wackestones-packstone)</td>
<td>floatstone-rudstone (wackestones-packstone)</td>
<td>floatstone-rudstone (wackestones-packstone)</td>
<td>grainstone</td>
<td>wackestones-packstone</td>
<td>inherited from pedogenically-altered precursor facies</td>
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<tr>
<td><strong>Diagnostic Grains</strong></td>
<td>pelmatozoa, brachiopod</td>
<td>wafer stromatoporoid</td>
<td>stromatoporoid fragments, intraclasts, lithoclasts</td>
<td>encaustic and abacular stromatoporoid</td>
<td>stromatoporoid fragments, bulbous stromatoporoid</td>
<td>stromatoporoid fragments</td>
<td>stromatoporoid fragments</td>
<td>Amphipora</td>
<td>Amphipora</td>
<td>undiff. skeletal fragments, peloids, oooids</td>
<td>Amphipora, undiff. skeletal fragments, peloids</td>
<td>inherited from pedogenically-altered precursor facies</td>
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<tr>
<td><strong>Other Grains</strong></td>
<td>gastropod, undiff. skeletal debris, foraminifera</td>
<td>intraclasts, pelmatozoa, brachiopod, Thaornitroidea</td>
<td>-</td>
<td>undiff. skeletal fragments, peloids, pelmatozoa, brachiopod, Thaornitroidea</td>
<td>cylindrical and bulbous stromatoporoid, peloids, undiff. skeletal fragments, Thaornitroidea</td>
<td>Amphipora, peloids, undiff. skeletal fragments</td>
<td>Amphipora, peloids, undiff. skeletal fragments, peloids, Amphipora</td>
<td>peloids, undiff. skeletal fragments, small stromatoporoid fragments, intraclasts</td>
<td>inherited from pedogenically-altered precursor facies</td>
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<tr>
<td><strong>Sedimentary Features</strong></td>
<td>dark matrix, Thaornitroidea burrows, common wispy styloite seams</td>
<td>massive, poorly-sorted</td>
<td>massive, Thaornitroidea burrows, moderately-sorted</td>
<td>growth framework</td>
<td>lighter brown matrix, massive, poorly-sorted</td>
<td>darker brown matrix, massive, poorly-sorted</td>
<td>massive, moderately-sorted</td>
<td>massive</td>
<td>circumgranular bladed cement, pendent cement, beach bubbles</td>
<td>lamina, fenestrae, root traces</td>
<td>deltidal green clay, solution pipes, geopetal structures, pedogenetic carbonate nodules (&lt;0.5 cm)</td>
<td>root traces</td>
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<td>.080</td>
<td>.100</td>
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<td>.081</td>
<td>.088</td>
<td>.091</td>
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<td>.059</td>
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<td><strong>Median Core Kmax (md)</strong></td>
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<td>26 md</td>
<td>30 md</td>
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<td>45 md</td>
<td>40 md</td>
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<td><strong>Median Core Kv (md)</strong></td>
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<td><strong>Median Core K90 (md)</strong></td>
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<td>21 md</td>
<td>12 md</td>
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<td>B</td>
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<td>C</td>
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<td>A</td>
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<td><strong>Representative Core Photos</strong></td>
<td>Figure 6A</td>
<td>Figure 6B</td>
<td>Figure 6C</td>
<td>Figure 6D</td>
<td>Figure 6E</td>
<td>Figure 6F</td>
<td>Figure 6G</td>
<td>Figure 6H</td>
<td>Figure 6I</td>
<td>Figure 6J</td>
<td>Figure 6K</td>
<td>Figure 6L</td>
<td>Figure 5M, N</td>
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</tbody>
</table>
Fig. 5. Core photographs representative of facies observed within the Swan Hills Formation at Kaybob South Gas Unit #1. (A) Facies 1 (burrowed nodular) pelmatazoan mudstone. 00/14-06-62-19W5/0 at 3217.2 m (10,555’). (B) Facies 2 (reef slope) wafar stromatoporoid skeletal boundstone within the 00/01-26-62-20W5/0 at 3214.2 m (10,545’). (C) Facies 3 (slope sand) skeletal-peloid grainstone with well-developed moldic and interparticle porosity. 00/07-25-60-19W5/0 at 3339.4 m (10,956’). (D) Facies 4 (slope debris) skeletal rudstone with well-developed interparticle, moldic and solution-enlarged fracture/channel porosity. 00/13-21-61-19W5/0 at 3232.7 m (10,606’). (E) Facies 5 (reef margin) stromatoporoid framestone with growth framework and intraparticle porosity. 00/02-23-62-20W5/0 at 3253.8 m (10,675’). (F) Facies 6 (open marine stromatoporoid shoal) stromatoporoid floatstone with abundant moldic pores after large stromatoporoid fragments. 00/03-1-61-19W5/0 at 3285.5 m (10,779’). (G) Facies 7 (restricted stromatoporoid shoal) cylindrical to bulbous stromatoporoid, oncoid floatstone. Note the darker-colored (likely more organic rich) matrix material in comparison to photo (F). 00/03-16-61-19W5/0 at 3270.2 (10,729’). (H) Facies 8 (reef flat) coarse stromatoporoid, skeletal rudstone. 00/05-25-60-19W5/0 at 3357.7 m (11,016’). (I). Facies 9 (Amphipora lagoon) Amphipora floatstone. Porosity includes molds after Amphipora, and solution voids associated with stylolites. 00/16-01-62-19W5/0 at 3229.7 m (10,596’). (J). Facies 10 (beach) Amphipora rudstone with abundant interparticle and moldic porosity, and white, pore roof lining microstalactic carbonate cement suggestive of undersaturated vadose conditions. 00/06-23-62-20W5/0 at 3228.2 m (10,591’). (K). Facies 11 (shelf sand) peloid, coated grain grainstone with abundant interparticle and moldic porosity. 00/07-20-61-19W5/0 at 3251 m (10,667’). (L). Facies 12 (tidal flat) Amphipora, skeletal floatstone with abundant interparticle and moldic pores overlain by algal lamina and dolomite cement filled (white) fenestra. 00/11-17-61-19W5/0 at 3268.0 m (10,899’). (M). Facies 13 (subaerial-exposure) lithoclastic breccia with interparticle detrital green clay. 00/10-16-61-19W5/0 at 3268.4 m (10,723’). (N). Facies 13 (subaerial-exposure) undifferentiated carbonate host-rock with abundant solution channels lined with bladed dolomite cement (white) and filled (as a geopetal structure) with an early stage of dark skeletal carbonate packstone and later stage of detrital green clay. 00/16-1-62-20W5/0 at 3219.0 m (10,561’).
Fig. 6. Univariate summary statistics of porosity (A), Kmax permeability (B), and fracture density (C) versus both facies and facies associations. Plots are based upon all Swan Hills Formation core and associated analyses within the study area (compare with Table 2). Facies associations A (platform interior), B (reef margin) and C (stromatoporoid shoal) have the highest values of porosity and Kmax permeability. The highest fracture density coincides with facies associations B and C.
most easily recognized along the eastern platform margin at
GU1 where shallower-water facies below a sequence boundary
are abruptly overlain by deeper-water facies of the overlying
sequence (Figure 8). In addition, although the upper boundaries
of HFS-2, HFS-3, and HFS-4 all provide evidence of subaerial
exposure, i.e. facies 13, only the uppermost HFS-4 sequence
boundary coincides with a well-developed paleosol that is cor-
relative across most of the GU1 platform interior (Figure 8). A
similar paleosol has been documented by Chow and Wendte
(2005) to coincide with the R₄ surface (stratal nomenclature
sensu Wendte, 1992b) at Judy Creek field. Atchley and
McMurray (2000) suggest that the R₄ surface at Judy Creek can
be correlated approximately 80 km southwest to Fox Creek
field where it also provides evidence of prolonged subaerial
exposure. Comparison of GU1 stratigraphic cross-sections to a
depositional-dip-oriented stratigraphic cross-section provided
by Atchley and McMurray (2000) for Fox Creek field, located
only 15 km to the east, indicates that the R₄ surface at Fox
Creek is likely equivalent to the top HFS-4 sequence boundary
at GU1. Furthermore, Potma (2007, pers. comm.) indicates that
the R₄ surface, i.e. top HFS-4 sequence boundary, likely coinci-
des with the top of the BHL-2 “third-order” sequence (com-
pare figures 4 and 8).

At Kaybob South GU1 HFS-2 through -4 stack in an aggra-
dational to slightly retrogradational fashion and are character-
ized by a narrow (approximately 800 m wide), northwest-
trending reef margin facies association that is located adjacent
to the basinal linear reentrant into the Swan Hills Complex
(compare figures 1 and 8). Shelfward (west), the reef margin
transitions into a stromatoporoid shoal association that, through
time, becomes more continuous along depositional strike and
wider, i.e. from approximately 500 m wide within HFS-2 to
approximately 1600 m wide within HFS-4, and transitions even
further shelfward into an extensive interior lagoon/shoreline
complex (Figure 8). Above this succession, HFS-5 and -6 stack
retrogradationally and both are dominated by an extensive stro-
matoporoid shoal association and onlapping and/or contempo-
raneous slope debris and basinal deposits (Figure 8). HFS-6 is
overlain by a drowned unconformity (sensu Schlager, 1992)
that separates the Swan Hills from the overlying Waterways
Formation (Figure 8).

**Production Optimization**

**Reserve Estimates and Recovery to Date**

Gas-entrapment at Kaybob South field is related to: 1) both
southwestward regional structural dip and compactional drape
across the reef margin; 2) top-seal provided by the imperme-
able basinal limestone and shales of the overlying Waterways
Formation; and 3) lateral (northeast) closure against the north-
west-trending embayment into the Swan Hills Complex that is
also filled with the Waterways Formation. The gas-saturated
portion of the GU1 study area is 24 km long, and up to 6.5 km
wide and 42 m thick. The original gas-water contact prior to the
onset of gas cycling in 1968 ranged from –2356.5 to –2366 m
sub-sea, and had an average value of –2359 m sub-sea
(Figures 9 and 10). Due to southwestward structural dip, the
thickest portion of gas-saturated reservoir occurs along the
eastern edge of GU1 and largely coincides with the highly
porous and permeable reef margin and stromatoporoid shoal
facies associations of HFS-2 through -5 (Figure 8). Estimates
of original in-place gas (OGIP) for GU1 range from an
expected value of 28,600 x 10⁶ m³ (1.01 trillion ft³) to a high-
side value of 35,113 x 10⁶ m³ (1.24 trillion ft³). OGIP estimates
are calculated on the basis of pore-volume (phi-m) mapping
that assumes original gas-water contacts between –2359 m sub-
sea (loswide-case) and –2362 m sub-sea (highside-case)
(Figure 11), and an original Bₙ of 0.003742 and water satura-
tion (Sw) ranging from 0.12 to 0.10 (Table 1).

Remaining in-place gas reserves (RIGR) range from an
expected value of 12,488 x 10⁶ m³ (441 bcf) to a highside value
of 17,868 x 10⁶ m³ (631 bcf), and reflect the sum of the OGIP

![Box and whisker plot](image-url)
Figure A

The figure shows a cross-sectional view of a geological section with detailed layers, markers, and annotations. The section includes the following key elements:

- **Date and Location**: Three specific dates and locations are marked: 00/06-12-61W5/0, 00/06-07-19W5/0, and 00/12-09-19W5/0.
- **Geological Layers**: Layers are color-coded and labeled with various markers such as Gamma Ray, Density Porosity, Core Interval, Perf. Interval, and more.
- **Interval Markers**: Markers for Interval Transit Time and TOP OF SWAN HILLS are indicated.
- **Prospects and Locations**: Locations and prospects are marked on a grid, with specific labels such as Prospect #9, Prospect #5, and Prospect #4.

Figure B

The figure presents a map with prospect locations labeled HFS-3, HFS-4, and HFS-2. The map includes a legend for Facies Association or Individual Facies, with categories like Subaerially Exposed, Platform Interior, Slope Debris, Basinal, Stromatoporoid Shoal, and a combined category. Additional symbols and markers are used to represent cored intervals, well locations, and other geological features.

LEGEND

- **Facies**
  - Subaerially Exposed
  - Platform Interior
  - Slope Debris
  - Basinal
  - Stromatoporoid Shoal
- **Combinations**
  - Combined as platform interior on maps
- **Cored Intervals**
  - Solution-enlarged fractures
- **Original Contacts**
  - Original gas-water contact (-2359m)
- **Interpretations**
  - Interpreted facies (with core control)
  - Interpreted facies (without core control)

Scale: 5 km
Fig. 8. Stratigraphic cross-section A–A’ and corresponding dominant facies maps for high-frequency sequences (HFS) 2 through 6. HFS designations within the paper, e.g. HFS-6, identify the stratigraphic interval that underlies the numbered (2–6) sequence boundaries. Superimposed on each facies map is a structural contour map of the upper, i.e. numbered, sequence boundary and the average position of the original gas-water contact (~2359 m sub-sea). HFS-2 through 4 stack aggradationally and are characterized by a well-developed, narrow (approximately 800–1600 m wide) and linear reef margin, and HFS-5 and 6 stack retrogradationally and are dominated by an extensive platform edge stromatoporoid shoal complex. The highest overall fracture density is generally associated with the forereef margin and stromatoporoid shoal facies associations. Due to westward structural dip, the thickest gas-saturated reservoir interval largely coincides with the reef margin facies association of HFS-2 through 5 along the eastern platform edge. Gas entrapment is provided by the lateral- and top-sealing basinal Waterways Formation.
The total produced gas volume at GU1 that has not been re-injected back into the Swan Hills reservoir is 16,112 x 10^6 m^3 (464 bcf), and subtraction of the cumulative produced gas volume of approximately 27,070 x 10^6 m^3 (956 bcf). The cumulative produced gas volume includes gas that was directly marketed and gas that was processed for natural gas liquids and condensate and then re-injected back into the reservoir interval as lean sweet gas. By applying an Sw of 0.12 to 0.10 and subsequent re-injection of by-product lean, sweet gas. Over this period of gas cycling, the concentration of H2S at GU1 has been reduced from its original value of 17.7 percent to as low as 4 percent in some areas (Carr and Fiori, 2004), and correspondingly, the retrograde tendencies and corrosive properties of the reservoir interval have possibly been diminished.

**DEVELOPMENT DRILLING STRATEGY AND GEOLOGIC EVALUATION**

As of this writing, ten wells are productive and three shut-in wells are viable candidates for reactivation at GU1. Based upon production decline analysis, these 13 wells are collectively anticipated to recover additional gas reserves of 651 x 10^6 m^3 (23 bcf). Without additional drilling, the reserve additions provided by these wells will only contribute 2–3 percent to the estimated 46–56 percent of gas recovered to date from the OGIP. Comparison of the conceptual drainage area forecast for each of these 13 wells with the top Swan Hills structure map highlights the large, gas-saturated area of GU1 that will remain bypassed unless additional development wells are drilled (Figure 12). Although true drainage area estimations, as are oftentimes calculated for oil wells, are not directly applicable to high permeability gas reservoirs such as the Swan Hills Formation at Kaybob South, the conceptual drainage area is provided to highlight the large portion of the GU1 gas-saturated reservoir that is yet to be depleted. With this in mind, at least 17 additional infill wells could be drilled to increase the recovery efficiency with limited (if any) production interference (Figure 12). Lowside-, expected, and highside-case cumulative recoverable gas reserves for these prospective wells are estimated at 1,183 x 10^6 m^3 (42 bcf), 2,755 x 10^6 m^3 (97 bcf), and 5,192 x 10^6 m^3 (183 bcf), respectively. Table 4 tabulates these reserves and itemizes the variables used in their calculation. We classify the bracketed lowside- to highside-case range as “proved reserves” for both individual prospects and their cumulative summation, i.e. reserves having a recovery probability of at least 90 percent (sensu Rose, 2007). When the potential reserve additions for these prospects are combined with the 651 x 10^6 m^3 (23 bcf) that are anticipated to be

estimates and cumulative injected gas volume of 10,959 x 10^6 m^3 (387 bcf), and subtraction of the cumulative produced gas volume of approximately 27,070 x 10^6 m^3 (956 bcf). The cumulative produced gas volume includes gas that was directly marketed and gas that was processed for natural gas liquids and condensate and then re-injected back into the reservoir interval as lean sweet gas. By applying an Sw of 0.12 to 0.10 and present-day Bg of 0.0082 to the RIGR at GU1, and considering the total storage capacity and structural configuration of the Swan Hills reservoir (Figures 11 and 12), the current depth to the base of the gas-water transition is predicted to occur between –2340 m and –2350 m sub-sea.

The total produced gas volume at GU1 that has not been re-injected back into the Swan Hills reservoir is 16,112 x 10^6 m^3 (569 bcf), a value that comprises between 46 percent and 56 percent of the OGIP depending on whether the calculation is based upon the previously discussed expected- or highside-case estimate of OGIP. Furthermore, the rate of additions to cumulative gas production reached an asymptotic plateau at GU1 during the mid-1990s suggesting that a significant increase in the percentage of recovered in-place reserves is unlikely from the remaining productive wellbores (Figure 3). As such, the recovered gas to date suggests a recovery factor (RF) that is well below both the 77 percent producible gas RF for Kaybob South field and the 87 percent average producible gas RF for the other four largest Beaverhill Lake A gas pools of central Alberta that are anticipated by the Alberta Energy and Utilities Board (Table 3). Potential limitations to recovery efficiency at GU1 include the sour, retrograde nature of the reservoir interval, and the potential for reservoir and borehole damage from the accumulation of mineral precipitants (scale) during production (Carr and Fiori, 2004). The corrosive nature of the sour reservoir fluids often compromises wellbore mechanical integrity, and the reduction of pressure near the wellbore may reduce reservoir permeability by inducing the precipitation of hydrocarbon liquids and various mineral precipitants within effective pore space. These factors have historically impacted both the life and reservoir drainage efficiency for wells across Kaybob South field, and have required a downspace well density as great as 4 wells per 259 hectares (640 acres) in portions of the field, i.e. as wells and/or reservoirs were damaged prior to complete reserves depletion, new offset wells were drilled to assist in the capture of otherwise bypassed reserves (Carr and Fiori, 2004). These adverse reservoir conditions may have been reduced through time at GU1 owing to its fifteen-year history of processing hydrocarbon liquids from produced raw gas and subsequent re-injection of by-product lean, sweet gas. Over this period of gas cycling, the concentration of H2S at GU1 has been reduced from its original value of 17.7 percent to as low as 4 percent in some areas (Carr and Fiori, 2004), and correspondingly, the retrograde tendencies and corrosive properties of the reservoir interval have possibly been diminished.

**DEVELOPMENT DRILLING STRATEGY AND GEOLOGIC EVALUATION**

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recovered by the 13 currently producing or shut-in wells, the resulting ultimate recoverable reserves provide a RF ranging from 63–77 percent for the expected-case OGIP value of 28,600 x 10^6m^3 (1.01 trillion ft^3) for GU1. The upper limit of this producible RF estimate falls near the range anticipated for the other four largest Beaverhill Lake A gas pools within the Swan Hills Complex (Table 3). Furthermore, a possible serendipitous benefit to the 15-year history of lean, sweet gas injection at GU1 is that a higher proportion of future recovered reserves are anticipated to be marketable due to the reduction in H_2S concentration.

Because the reservoir interval is fractured and charged with gas, high-frequency sequence boundaries, and intra-sequence facies transitions throughout the Swan Hills reservoir are unlikely to serve as barriers to fluid flow (Figure 8). Facies associations do, however, have demonstrable influence on reservoir quality and associated gas productivity rates (Figures 6 and 7). Although all 17 development prospects contain proved reserves within a bracketed range, variability in the geological attributes encountered at each prospect location will influence both the rate at which reserves are produced and the associated volumes recovered. Intuitively, the highest flow rates are anticipated to coincide with prospects located in the structurally highest positions where gas-saturated reservoir thickness is greatest, and where the reservoir interval is highly-fractured and dominated by the reef margin facies association. Furthermore, the large-diameter vuggy, growth framework and channel pore networks typical of the reef margin facies association will likely provide higher cumulative gas production, because larger-diameter pores adjacent to well-bore perforations would require more time to potentially plug with production-induced mineral precipitants.

Deliberations within the asset management team of geologists and engineers involved at GU1 produced the following semi-quantitative equation that captures the consensus viewpoint on the relative importance of each geologic attribute in determining the likelihood of favourable well performance (LFWP). Similar probabilistic approaches are commonly used

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**Fig. 10.** Scatter plot of the subsea depth of the gas-water transition versus rig release date. Gas-water contact values are based upon porosity-conductivity well logs where the transition zone is clearly observed (e.g. Figure 9). Variability in the position of the gas-water transition through time in large part reflects both gas cycling from 1968 through 1983 and gas production after 1983. Prior to the onset of gas cycling in 1968, the average position of the gas-water contact was –2359 m (–7739').
to characterize the likelihood of geological success during exploration (e.g. Rose, 1992), but are rarely used during field development and production (Rose, 2007).

\[
\text{Likelihood of favourable well performance (LFWP)} = \text{structural value} \times 3 + (\phi-m \text{ value} \times 3) + (\text{fracture value} \times 2) + (\text{facies value} \times 1) + (K_{\text{max}} \text{ permeability value} \times 0.5) - (\text{offset drainage value} \times 0.5)
\]

The geologic “values” represent map attributes that have been subjectively distilled into ranges that are assigned numbers of 1 (lower likelihood of insuring favourable well performance), 2 (intermediate likelihood of insuring favourable well performance) or 3 (higher likelihood of insuring favourable well performance), and are subjectively weighted by multiplication factors of 0.5 to 3x, as agreed upon by the management team, to capture their perceived influence in determining prospect performance. One exception is that the offset drainage value for each prospect is assigned a –1, if the prospect is located within 16 hectares (40 acres) of an offset conceptual drainage area, or 0, if the prospect is not located within 16 hectares (40 acres) of an offset conceptual drainage area (Figure 12). The offset drainage value addresses the likelihood of encountering anomalously high gas-water contacts, i.e. water cones, which are potentially associated with actively producing wells. The bracketed range of map attributes used to define all other “values” vary from map to map as illustrated on the total Swan Hills pore-volume map (Figure 11), top Swan Hills structure map and accompanying conceptual drainage area map (Figure 12), composite Swan Hills dominant facies map (Figure 13), total Swan Hills $K_{\text{max}}$ permeability map (Figure 18), and the originally gas-saturated Swan Hills reservoir interval within the study area. Prospective infill development locations are indicated by white stars, and the criteria for assignment of pore-volume “values” as used in the calculation of “likelihood of favourable well performance” (LFWP) is summarized within the map legend. Prospective wells are numbered according to their LFWP rank, and coincide with the prospect #s appearing on Table 4. Lower numbers have a greater likelihood of favourable well performance. An explanation of how cumulative LFWP is calculated for prospective development locations is provided on Table 4.

![Image](image.png)

Fig. 11. Pore-volume (phi-metre) map of the originally gas-saturated Swan Hills reservoir interval within the study area. Prospective infill development locations are indicated by white stars, and the criteria for assignment of pore-volume “values” as used in the calculation of “likelihood of favourable well performance” (LFWP) is summarized within the map legend. Prospective wells are numbered according to their LFWP rank, and coincide with the prospect #s appearing on Table 4. Lower numbers have a greater likelihood of favourable well performance. An explanation of how cumulative LFWP is calculated for prospective development locations is provided on Table 4.
RENEWED DEVELOPMENT OF THE MATURE KAYBOB SOUTH GAS FIELD

Fig. 12. Structural contour map of the top Swan Hills Formation within the study area, and superimposed ultimate recoverable drainage area estimates for currently producing and shut-in (SI) wells. The variables used in the calculation of drainage area (from minimum to maximum potential range) are provided within the map legend. Prospective infill development locations are indicated by white stars, and the criteria for assignment of structural “values” as used in the calculation of “likelihood of favourable well performance” (LFWP) is summarized within the map legend. Prospective wells are numbered according to their LFWP rank, and coincide with the prospect #s appearing on Table 4. Lower numbers have a greater likelihood of favourable well performance. An explanation of how cumulative LFWP is calculated for prospective development locations is provided on Table 4.

Table 3. In-place resources, producible and marketable recovery factors, and proportion of H\textsubscript{2}S for the five largest Beaverhill Lake gas fields within the Western Canada Sedimentary Basin (Oldale and Munday, 1994, supplemented with data from the Alberta Energy and Utilities Board). RF = recovery factor, m\textsuperscript{3} = cubic metres, OGIP = original gas in place, TCF = trillion cubic feet.
Table 4. Prospect geologic "likelihood of favourable well performance" (LFWP) ranking and reserves estimation. Prospects with higher LFWP values are interpreted to have a higher likelihood of success.

BCF = billion cubic feet, m³ = cubic metres.

<table>
<thead>
<tr>
<th>PROSPECT #</th>
<th>Geologic LFWP Sum</th>
<th>Recoverable Reserves (10⁶ m³/BCF)</th>
</tr>
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<td></td>
<td>Lowside</td>
<td>Expected</td>
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<tr>
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</tr>
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<td>2</td>
<td>23.5</td>
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<td>29/1.0</td>
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<tr>
<td>17</td>
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<td>50/1.8</td>
</tr>
<tr>
<td>TOTAL</td>
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<td>2755/97</td>
</tr>
</tbody>
</table>

Variables used in reserves estimation:

*Lowside-case: Bg = .0084, Sw = 0.15, RF = 56%, drainage area = 69 hectares (171 acres)
*Expected-case: Bg = .0082, Sw = 0.12, RF = 69%, drainage area = 125 hectares (308 acres)
*Highside-case: Bg = .0078, Sw = 0.10, RF = 80%, drainage area = 167 hectares (462 acres)

*Drainage area estimates are based upon the average drainage area calculated for the 11 current producers at Kaybob South Gas Unit #1 (expected-case) and one standard deviation above (highside-case) and below (lowside-case) the average value (compare with Figure 12). RF values reflect a range observed within analog Swan Hills gas fields of the Western Canada Sedimentary Basin (Table 3). Sw values are based upon a porosity range of 7–9%, typical of the Gas Unit #1 reservoir interval, as observed on scatter plots of core-derived porosity versus Sw data for 24 wells occurring within 7 comparable Swan Hills fields within central Alberta. Porosity-thickness estimates for each prospect are based upon map-observed values (Figure 11) to the predicted current base of the gas-water transition (~2340 to ~2350 m subsea).

Calculation of geologic LFWP sum = (structural value x 3)+(phi-m value x 2)+(fracture value x 2)+(facies value x 1)+(Kmax permeability value x 0.5)+offset drainage value x 0.5). See figures 11–15 for an explanation of how the preceding LFWP values were determined. The weight given to each value category, i.e. from 0.5x to 3x, reflects the perceived importance of each category in the successful outcome of a prospective well.
ability map (Figure 14), and total Swan Hills fracture density map (Figure 15). Following this procedure, the LFWP was calculated for the 17 development prospects identified at GU1, and the prospects are listed in their resulting rank order on Table 4 and their location and corresponding rank number appear on Figures 11–15. Note on Table 4 that prospects are listed in descending order of LFWP, and that this order correlates closely with the predicted reserves.

TEST OF CONCEPT: DRILLING RESULTS

During late 2006 through late 2007, prospect #5 (unique well identifier, UWI, 102/16-31-61-19W5/0), prospect #4 (UWI 100/16-30-61-19W5) and prospect #9 (UWI 102/4-13-62-20W5) were drilled and provide an independent evaluation of the geologic framework and strategy for development drilling described in the preceding section of the paper (Figs. 8, 11–15). Prior to drilling, predictions were made for each prospect regarding the sub-sea depth at which the Swan Hills Formation and gas-water transition would be encountered, the likely succession of HFSs and associated facies that would occur within the reservoir interval, and the range of recoverable reserves that would be produced. Table 5 provides a comparison of the pre-drill predicted versus post-drill actual disposition of these attributes. As forecast, all three wells encounter the Swan Hills Formation along the shelf edge crest within 2 m of its predicted sub-sea depth, and the reservoir interval occurs eastward of the HFS-5 downlap edge and includes HFS-2, -3, and -4 in a stratigraphic position comparable to that depicted between UWI 00/16-09-61-19W5 and UWI 00/05-15-61-19W5/0 on cross-section A–A’ of Figure 8. Although core was not cut in these wells, the high porosity and relatively low gamma ray activity observed on logs from all three wells within HFS 2–4 are
suggestive of the reef margin facies association (compare figures 8 and 16). The reduced well log porosity and increasing gamma ray activity above HFS-4 in all three wells are interpreted as the slope to basinal facies association (compare figures 8 and 16). Although variable between wells, the base of the gas-water transition ranges from –2342.2 m (prospect #4, 100/16-30-61-19W5) to as deep as –2345.6 m sub-sea (prospect #5, 102/16-31-61-19W5), and compares favourably with the pre-drill prediction of –2340 to –2350 m sub-sea (Figure 16).

**COMPLETION RESULTS AND LESSONS LEARNED**

Prospect #5 (102/16-31-61-19W5) was the first of the three wells drilled, and was perforated 9 m above the base of the gas-water transition within what is interpreted as the uppermost reef margin facies association of HFS-4 through the overlying slope to basinal facies association to the top of the Swan Hills Formation (Figure 16). Initial tests from this interval were as high as 70 x 10^3 m^3/day (2.5 x 10^6 ft^3/day) with higher water production than anticipated at 117 m^3/day (736 barrels/day), and based upon comparison to production decline curves from similar wells within GU1, was expected to recover 256 x 10^6 m^3 (9 bcf). Following initial production testing, however, daily gas rates decreased to 13 x 10^3 m^3/day (0.5 x 10^6 ft^3/day). Several factors may have contributed to the underperformance of prospect #5 (102/16-31-61-19W5). First, perforations were possibly plugged by mineral precipitants that resulted from a wellbore chemical treatment that was administered soon after the initial production testing. This is suggested by an initial decline in gas production rates to 13 x 10^3 m^3/day (0.5 x 10^6 ft^3/day) on
January 31, 2007 immediately after the chemical treatment, and subsequent gradual increase in production rates to $31 \times 10^3$ m$^3$/day ($1.1 \times 10^6$ ft$^3$/day) by September 1, 2007. Increasing production rates following the initial decline may be related to the gradual dissolution of perforation-clogging mineral precipitants by undersaturated produced formation water. Second, increased water production may reflect poor cement of the production casing and resultant behind-pipe encroachment of water from the gas-water transition to the perforated interval. Cement failure is a possibility inasmuch as the reservoir temperature measured within prospect #5 (102/16-31-61-19W5) was 120ºC, but the integrity of the cement used to complete the well is not assured by the manufacturer above reservoir temperatures of 110ºC. The existence of open cavities (channels) within the casing cement is also suggested by cement-bond wireline well logging. Third, water may also have been delivered to the perforations by fractures within the reservoir interval that extend through the gas-water transition. The lowermost perforations within prospect #5 (102/16-31-61-19W5) occur 9 m above the base of the gas-water transition, and likely coincide with the highly-fractured reef margin facies association (Figure 16).

The completion strategy for prospects #4 (100/16-30-61-19W5) and #9 (102/4-13-62-20W5) were modified to take into account the experience gained from prospect #5 (102/16-31-61-19W5). Production casing in both wells is set with thermal cement appropriate for high-temperature reservoir conditions,

Fig. 15. Median fracture density map for the entire Swan Hills Formation within the study area. Fracture density is based upon visual estimations of fracture density on a per-foot basis for all core recovered within the reservoir interval. Fracture density is reported in imperial units, rather than metric, because almost all cores were originally collected and are now curated in imperial units. Prospective infill development locations are indicated by white stars, and the criteria for assignment of fracture "values" as used in the calculation of "likelihood of favourable well performance" (LFWP) is summarized within the map legend. Prospective wells are numbered according to their LFWP rank, and coincide with the prospect #s appearing on Table 4. Lower numbers have a greater likelihood of favourable well performance. An explanation of how cumulative LFWP is calculated for prospective development locations is provided on Table 4.
Both wells were perforated within the slope to basinal facies association above a thin (<1m thick) shale that occurs atop HFS-4 (Figure 16). The slope to basinal facies association sharply overlies HFS-5 and HFS-4 basinward of the HFS-5 downlap edge (Figure 8), and because of its relatively low fracture density (Figures 6C, 8), may reduce the likelihood of fracture-induced water production. The likelihood of water production in both wells is also minimized by the thin, potentially water-baffling shale that occurs beneath the perforations, and by the increased standoff from the gas-water transition, i.e. the distance between the lowermost perforations and the base of the gas-water transition. Standoff within prospects #4 (100/16-30-61-19W5) and #9 (102/4-13-62-20W5) is 14 m and 10 m, respectively, whereas standoff in prospect #5 (102/16-31-61-19W5) is only 9 m. The initial production test was 90 x 10^3m^3/d (3.2 x 10^6ft^3/day) for prospect #4 (100/16-30-61-19W5) and 150 x 10^3m^3/d (5.3 x 10^6ft^3/day) for prospect #9 (102/4-13-62-20W5). In both wells, gas production as of this writing has been water-free, and decline curve comparison with similar GU1 wells suggests that prospect #4 (100/16-30-61-19W5) will recover 161 x 10^6m^3 (5.7 bcf) and prospect #9 (102/4-13-62-20W5) will recover 243 x 10^6m^3 (8.6 bcf), values consistent with pre-drilling estimates (Table 5).

### Conclusions

1) The Beaverhill Lake A pool (Swan Hills Formation) within the Kaybob South study area accumulated as a complex of 12 platform margin to interior depositional environments that were periodically subjected to prolonged episodes of subaerial exposure. Although the relationship between facies and reservoir quality is homogenized by diagenetic overprint, trends of porosity, Kmax permeability, fracture density, and well performance coincide with facies associations, i.e. groupings of related facies. Porosity, Kmax permeability, fracture density, and rates of maximum daily gas production are highest within the reef margin (facies 4, 5 and 8) and stromatoporoid shoal (facies 6 and 7) associations.

2) The study interval is likely equivalent with the upper portion of the “third-order” Beaverhill Lake 2 (BHL-2) and most, if not all, of the Beaverhill Lake 3 (BHL-3) sequences of Potma et al. (2001). The BHL-2 and -3 are partitioned into 5 high-frequency sequences (HFS-2 through HFS-6) that are characterized by an aggradational to slightly retrogradational stacking pattern within HFS-2 through -4, and a retrogradational stacking pattern within HFS-5 and -6. Due to southwestward structural dip, gas is stratigraphically trapped against the eastern platform margin at Kaybob South, and the gas-saturated reservoir at Gas Unit #1 (GU1) largely coincides with the reef margin and stromatoporoid shoal facies associations of HFS-2 through -5. Because the study interval is highly fractured and gas-charged, high-frequency sequence boundaries and intrasequence facies distributions do not likely compartmentalize the reservoir into flow units.

3) Expected-case original in-place gas (OGIP) resources at GU1 are 28,600 x 10^6m^3 (1.01 trillion ft^3). Cumulative production to date from all wells, and anticipated recoverable reserves from the remaining 13 productive wells (including shut-in...
Fig. 16. Well logs for prospect #5 (102/16-31-061-19W5/0), prospect #4 (100/16-30-061-19W5/0), and prospect #9 (102/4-13-062-20W5/0). Annotated on the logs are the upper sequence boundaries for HFS-2, -3, and -4, interpreted facies distributions, gas-water transition zone, perforation interval, and production and reserves statistics.
wells) will collectively capture only 48–59 percent of the OGIP. Low recovery is attributed to premature wellbore mechanical failure induced by corrosive formation fluids, and near-wellbore formation damage related to the precipitation of hydrocarbon liquids and minerals within effective pore space (Carr and Fiori, 2004).

4) Although Kaybob South was discovered as a sour retrograde gas reservoir in 1961, the fifteen year practice from 1968–1983 of processing hydrocarbon liquids from produced sour gas and re-injection of by-product lean, sweet gas has lowered the concentration of H₂S from its original value of 17.7 percent to as low as 4 percent in some areas, and correspondingly, has likely diminished the pool’s retrograde tendencies. This history, along with the limited recovery provided by former and current producing wells, suggests that future recovery at GU1 may be enhanced through additional development drilling. At least 17 infill wells could be drilled at GU1, and are predicted to have recoverable reserves that range from 1,183 x 10⁶m³ (42 x 10⁹ft³) to 5,192 x 10⁶m³ (183 x 10⁹ft³). Combination of these reserve additions with the 651 x 10⁶m³ (23 x 10⁹ft³) that are anticipated to be recovered by the 13 current producers increases recovery to approximately 63–77 percent of OGIP. An increased proportion of recoverable reserve additions are likely marketable due to a reduction in the H₂S concentration that resulted from the 15-year history of lean, sweet gas injection.

5) The average position of the original gas-water contact at Gas Unit #1 was –2359 m (7739’) sub-sea. The current base of the gas-water transition is predicted to occur between –2340 m (–7677’) and –2350 m (–7710’) sub-sea.

6) Future development wells may be prioritized through a semi-quantitative assessment of “likelihood of favourable well performance” (LFWP) that takes into account structural position, proximity to current producers, thickness of the gas-saturated pore volume, dominant facies, Kmax permeability, and total fracture density. Following assessment of the 17 prospective infill wells referred to in point 4 above, the #5 (102/16-31-19W5), #4 (100/16-30-61-19W5) and #9 (102/4-13-62-20W5) ranked prospects were drilled during late 2006 and late 2007. All three wells are consistent with the sequence stratigraphic interpretation of the reservoir interval, and the pre-drill interpretations of the sub-sea depth to the top of the Swan Hills Formation and the gas-water transition.

7) Prospect #5 (102/16-31-61-19W5) was the first well drilled and initial testing provided high rates of gas production. Upon production, however, daily gas rates were comparatively low and daily water rates were high. The underperformance of prospect #5 is possibly related to the plugging of perforations by mineral precipitants that were induced by a chemical treatment administered after the initial well test, and high water production may be in response to poorly-cemented production casing and/or perforations placed near to the gas-water transition where fractures within the reservoir interval may extend through the gas-water transition.

8) Prospects #4 (100/16-30-61-19W5) and #9 (102/4-13-62-20W5) were drilled after prospect #5 (102/16-31-61-19W5), and their completion strategy was modified to take into account the experience gained from prospect #5 (102/16-31-61-19W5). Care was taken to insure proper cementation of the production casing, and no chemical treatments were applied to the perforated intervals. Perforations were placed farther above the base of the gas-water transition (than prospect #5) within the water-baffling slope to basinal facies association that occurs above HFS-4. This completion strategy resulted in sustained water-free gas production of 60 x 10³m³/d (2.1 x 10⁶ft³/day) for prospect #4 (100/16-30-61-19W5) and 100 x 10³m³/d (3.5 x 10⁶ft³/day) for prospect #9 (102/4-13-62-20W5), and based upon decline analysis, both wells are predicted to provide recoverable reserves that range from 161 x 10⁶m³ (5.7 bcf) to 243 x 10⁶m³ (8.6 bcf).

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