3.0 RESERVOIR ANALYSIS

3.1.1 Introduction

The pressure data for the wells completed in the McMurray-Wabiskaw formations within the Surmont Area and a surrounding three-mile buffer area, as shown on **Figure RA-1**, were collected and reviewed. This procedure was used to determine whether separate gas pools could be identified from the historical pressure data and to also provide a consistent pressure dataset for use in the reservoir simulation phase of this study.

This comprehensive review was done to encompass a qualitative analysis of the pressure data already collected by the Sub-Committee and any additional data that was encountered. A quantitative assessment of the analysis results of each test was also conducted. If there was some question regarding the validity of any of the test data, the data were re-analyzed by ETI.

The software chosen for the analysis procedure was PanSystem[1], which is an industry-accepted welltest package that is used throughout the world.

The results of the Reservoir Analysis work would provide a starting point for the reservoir simulation task, as well as providing insight as to how many of the wells were in lateral communication. Maps showing regions of pressure communication were then created to outline preliminary pool delineations.

3.1.2 Technical Approach (Pressure Data Review)

The first step in the review process involved the retrieval of basic well information and listings of available pressure data from public information on file with the Energy and Utilities Board (EUB). This was done to establish the wells to be included in the study and to determine which wells had historical pressure information. In 2002 the Sub-Committee had the historical pressure data for the Surmont Area reviewed and summarized on a spreadsheet, which was provided for this study. Well data files were created at the time of the construction of the original pressure history spreadsheet and contained information related to 145 of the 146 gas wells shut-in in 2000. Microfiche were also provided for all wells in Surmont and the three-mile buffer area.

[1] PanSystem, copyright of Edinburgh Petroleum Systems Ltd.

The second step of the review consisted of cross-referencing the well information to the supplied pressure history spreadsheet to determine if any wells or data were missing. Pressures for an additional 105 wells, primarily in the buffer area, were then added to the spreadsheet. In addition, ConocoPhillips provided the most recent 2003 static gradient pressure survey reports that were available for the Surmont area, which were not necessarily yet in the public database. The EUB website was checked to determine current testing requirements in Surmont and to confirm that these pressures had been received.

Ultimately a table containing the pressure history for approximately 250 wells was constructed. The most recent pressure data contained in the table is November 12, 2003, while the first pressures shown in the spreadsheet were from 1971 at wells 10-22-83-8 and 10-27-80-6W4. Hence, the historical pressures span a period of some 32 years.

The pressure history table was then reviewed and the pressures were compared to their original source documentation. The table was then edited to provide only one valid and representative pressure at each point in time, with the following exception: if there was an initial pressure measurement followed by a deliverability test and buildup, then two pressures would be shown. The first value is the measured pre-test pressure and the second value is the post-test pressure extrapolated from a buildup or if the pressure appeared stable, the last measured pressure. All pressures were corrected from kPa (gauge) to kPa (absolute) using a barometric pressure of 93 kPa.

The original spreadsheet did not summarize KB elevation, date perforated, flow capacity (kh), skin effect, distance to observed boundaries or sufficient comments regarding test validity and results. All well files and microfiche provided were reviewed to retrieve the additional information and it was then added to the table. Well files were also created for the 105 wells that had been added to the table and the microfiche for these wells were also reviewed to obtain the necessary data.

For those pressures added to the original spreadsheet and which did not state the reservoir pressure at mid-point of perforations (MPP), the pressure at recorder run depth was corrected to MPP using the gradient of the fluid in the wellbore at the time of the pressure survey. Pre-test pressures were corrected using initial static gradient surveys and post-test pressures from the same recorder were corrected using the final gradient survey. In cases where only a static gradient survey was conducted (i.e. no subsequent buildup test was conducted) only the pressure from one recorder was selected. Pressure data from recorders that malfunctioned were not included.

It was not unusual to observe from the static gradient tests that a water gradient was present in the wellbore between recorder depth and perforations. If the static gradient survey showed only one stop in liquid and the fluid type could not be confirmed by the measured gradient, the liquid level was calculated assuming the liquid was water (9.8 kPa/m). The resulting liquid level was then shown on the pressure history table. This assumed gradient was considered reasonable, as there were numerous wells with surveys that measured essentially a fresh water gradient. No gradients representative of an oil phase were encountered, except in well 11-22-081-06W4M, as would be expected from the very lean gas compositions. The pressure response in the 11-22 well is anomalous and is discussed later. Gas gradients were often erratic due to the low pressures, and therefore an average of the final two gas gradients is shown on the table.

Finally, all pressures were then corrected to a common pool datum (+260 m SS). The correction from MPP to datum depth (DD) was determined by using an average gas composition (most of the reported gas compositions are essentially identical) to calculate a gas density and, ultimately, a consistent gas gradient. The final spreadsheet table is contained in the Appendix and on the CD-ROM in this report.

For consistency throughout the project, KB elevations, used to determine subsea elevations, have been taken from EUB well data public records. There were a few cases where the geologists identified KB values from this source that were in error. For these cases the corrected values were used.

For the 145 wells in the original spreadsheet, the accompanying wellfile usually contained a wellbore completion schematic. There were cases where an interval had been suspended or abandoned with a bridge plug, but this information was not available in the public database. It should be recognized that for the 105 wells added to the spreadsheet, information in the public domain has been accepted as presented and the individual company well files have not been reviewed.

3.1.3 Pressure Test Analysis

All pressure buildups were reviewed to determine whether the interpretation was valid. If there was more than one pressure buildup test on a well, then at least one buildup was analyzed for the Surmont lease wells (not including those wells in the buffer zone) and the buildup chosen was the one with the best data set.

There were approximately 185 wells with pressure buildups and 49 wells that had more than one buildup test (surface and/or subsurface pressure buildups). ETI staff analyzed 45 of these pressure buildups. These were either buildups that had not been previously analyzed, or the earlier analysis results were thought to be questionable.

The 45 pressure buildups were analyzed to determine permeability, wellbore skin effect, reservoir boundaries and reservoir pressure. Both a conventional straight-line analysis and a simulation of the pressure response were conducted using PanSystem software. All pressure data in the analyses were corrected from recorder depth to mid-point of perforations (MPP) using an appropriate gradient from the static gradient survey for the buildup being analyzed. The gas PVT properties were determined from the gas analysis available for the individual well. The net pay, porosity and water saturation were taken from the microfiche or well files. If not available from either source, these values were obtained from the well petrophysical properties determined in this study.

There are 169 wells with kh values that have been included in the pressure history spreadsheet. The flow capacity, or permeability thickness (kh), was indicated to vary from 100 to 30,000 millidarcy-meters (mD-m). More common were kh values in the range of 2000 to 7000 mD-m. A comparison of permeability from the pressure buildup tests was not undertaken since the net pay used in earlier analysis was not necessarily consistent with the subject study results. However, the permeability estimates in either case are in the hundreds of millidarcies (mD), not thousands of millidarcies.
There were numerous buildups that indicated reservoir anomalies that could be interpreted as a reduction in permeability or no-flow boundaries. The obvious boundary cases were where the late-time pressure derivative showed linear flow following radial flow, indicative of a linear (channel) type of reservoir. There were other cases which showed a 2:1 slope change following early radial flow,

which is indicative of a single boundary. Neither of these two scenarios is caused by a reduction in permeability. However, there were some instances where the late-time response was an upward curve, indicating either multiple boundaries or a reduction in permeability. The comments section in the pressure table identifies the various interpreted causes of the pressure behaviour. This table also shows the near-wellbore permeability thickness and the distance to the boundary anomaly. It should be recognized that the permeability estimate will affect the distance to the boundaries and the net pay used in the analysis will affect the calculated permeability.

Pressure buildup surveys consisting of less than one week of shut-in were prevalent. The radius of investigation was too short on some of these buildups to detect any reservoir discontinuities; hence these extrapolated pressures could be too low if only conventional analytical techniques were used.

In all cases where the initial reservoir pressure was low due to drainage from offset producers or the buildup data indicated obvious evidence of offset well interference effects, appropriate comments have been noted on the pressure history table

There are numerous cases where the entire pressure increase during the recorded buildup was less than 50 kPa, and pre-1990 buildup data from mechanical pressure recorders often contained limited data (less than 30 data points). In addition, the shut-ins for some of the earlier buildups were one day or less. Under these circumstances, the results for kh and skin would be considered order of magnitude, only. For the cases where the static pressure prior to the flow test ("pre-test") and the analyzed buildup pressure taken after the flow period ("post-test") were comparable, these reservoir pressure estimates were considered reliable.

Many pressure surveys were conducted using only surface recorders to measure wellhead pressure response. In these cases, fluid levels were seldom measured by acoustic well sounder equipment, and the bottomhole pressure was calculated assuming no liquid in the wellbore. Since liquid in the wellbore was not uncommon, these pressures could be low and therefore less confidence has been applied to these pressures. Most often these data were only plotted and extrapolated for reservoir pressure and were not analyzed to calculate permeability thickness (kh), wellbore skin effect, and distance to boundaries.

Typically radial flow is reached within minutes after shut-in, and the surface buildup data often lacked the time discrimination or quality of pressure readings to consider an analysis that would provide valid results.

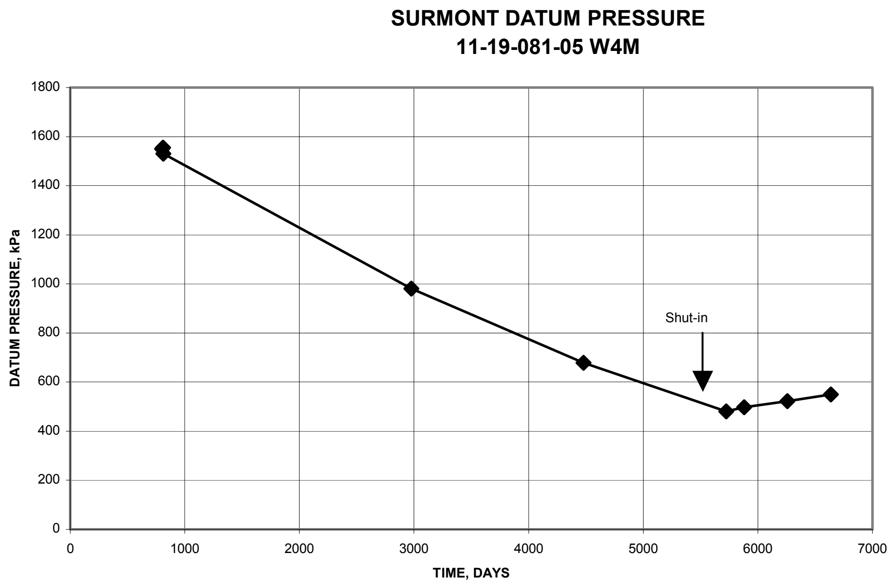
ConocoPhillips provided piezometer pressures for 51 shut-in wells on the Surmont leases. These pressures were tabulated at 6-month intervals and are contained in the Appendix. Pressures for 15 of these wells, which had pressures measured in the gas column and in which the recorder depth was provided, were corrected to datum depth using an appropriate gas gradient. ConocoPhillips also provided formation tester (RFT) pressures on the bitumen wells, but these pressures have not been included in the study, since the appropriate gradient to use, when correcting to a common datum depth, is unknown. In addition, RFT derived pressures can be influenced by the hydrostatic pressure of the drilling fluid affecting the formation prior to setting the tool seal assembly. Thus these readings may exhibit incorrect values over the short time interval that the measurement was taken.

It is interesting to consider that pressures taken on the immobile bitumen phase may not be representative of pressures in the gas column. This is noted on some of the piezometer data, where the bitumen pressure did not change from initial values, yet the gas pressure had declined significantly. This could lead to the conclusion that the bitumen can act as a bottom seal to the gas reservoirs in some cases. In instances where the bitumen pressures declined, the assumption could be made that there is a higher saturation, mobile water phase extending through or into the bitumen layer, which is exhibiting pressure response from the above gas/water system.

The calculated time to stabilization or time to reach pseudo-steady state pressure behaviour was several years for some buildups with lower permeability and boundaries near the wellbore or a very narrow channel width (less than 100 meters). This implies that once shut-in, the pressure in these wells will also continue to buildup slowly for a similar length of time. This is evidenced in the behaviour of the well pressure data taken after the field was shut-in in 2000.

Although some static gradient surveys conducted during the extended shut-in between the years 2000 and 2003 indicated that the pressure was stable or slightly erratic, there were far more cases where the pressure continued to increase with time. There were some wells such as 11-36-82-7, 10-5-83-5 and

15-2-84-6 where the pressure increased 150 to 200 kPa. This is significant considering the maximum virgin pressure for this formation in the study area was between 1150 to 1900 kPa. The following plot is an example of the type of long-term buildup response observed in many of the wells.



Conversely, only a few wells show a decline in pressure over the extended shut-in: 3-32-81-6, 15-1-82-8, 7-2-82-8, 10-27-83-5, 16-34-83-6 and 6-1-84-7W4. Except for the two wells in Twp 82 Rge 8, the remaining wells were close to water disposal wells and may have been exhibiting the effects of reduced injection volumes.

In summary, less confidence should be placed on pressures with the following attributes:

- Cases where the static gradient survey detected an obstruction or fill in the wellbore.
- Cases where a static gradient survey was conducted after the well had not been shut-in for a sufficient length of time. These pressures would be too low.

- The pressure data for most buildups taken before 1990 were monitored using mechanical pressure recorders. These recorders would not have the same accuracy or resolution as an electronic recorder. Considering the low reservoir pressures and low pressure differentials, this may cause some error.

- The calculated time to stabilization was several years for buildups that indicated the well was in the corner of the drainage area or in a very narrow channel. Hence, these pressure estimates could be too low.

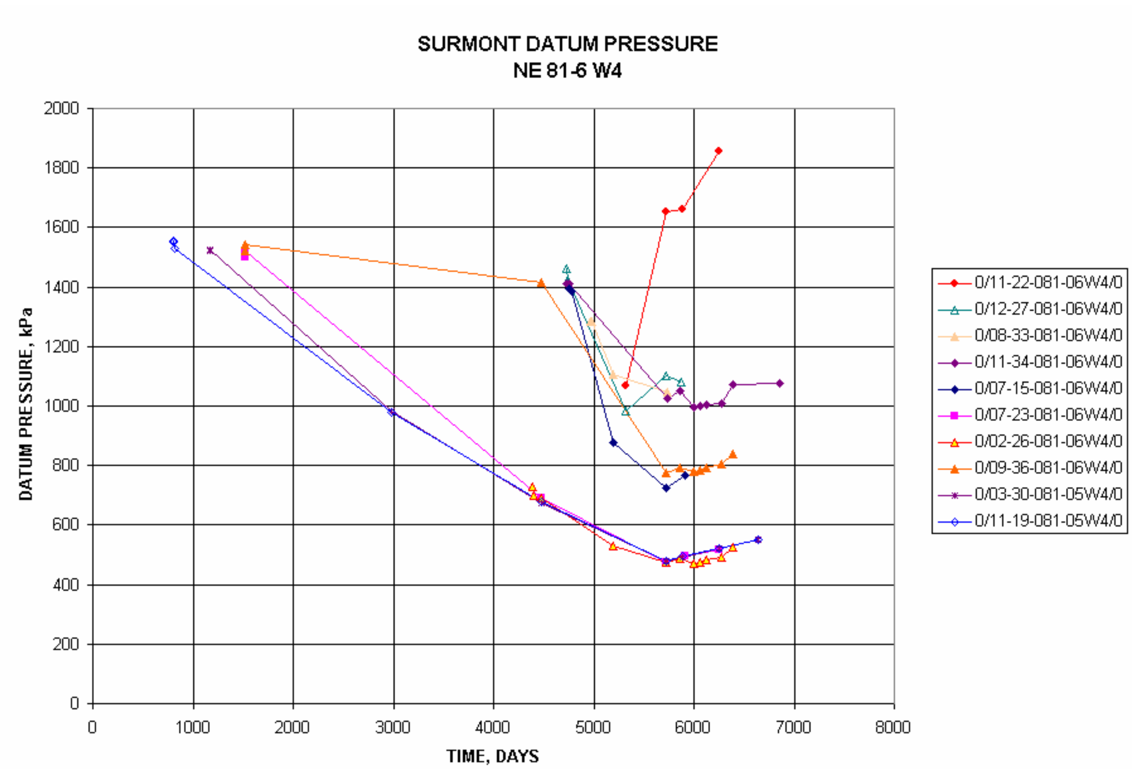
- Pressures taken from sentry readings indicated erratic pressures during lengthy shut-ins of many years (decreasing and then increasing), thus suggesting lower pressure accuracy.

- Bottomhole pressures that were calculated from surface pressure measurements. In particular, where an acoustic well sounder was not run to determine whether there was liquid in the wellbore. If there were liquid in the wellbore, these pressures would be low.

- Pressures determined from buildups that were of too short a duration to observe reservoir boundaries.

3.1.4 Pool Delineation

The data obtained from the pressure analysis work were then used to help define wells that exhibited either individual or multi-well pool behaviour. Pressure versus time data was plotted for wells and their immediate offsets within geographic areas (quarter Township to full Township, depending on well density). These plots were then qualitatively reviewed to determine which wells appeared to be in communication and which appeared to be separate. These plots are presented in the Appendix; however an example plot for the NE quarter of Twp 81 Rge 06 W4M is shown below for reference during this discussion.



From the above plot, three distinct pressure groupings are evident, each consisting of two to four wells. Time zero was established at January 1, 1986, which was the start of production in the Surmont area. The initial pressures between 1000 and 1500 days for four of the wells are all essentially the same, therefore there is no way to discriminate or determine the relationships from that early data alone. There are four other wells (7-15, 12-27, 8-33 and 11-34-081-06 W4M) that have initial pressures later in time that are somewhat lower than the earlier wells. It may be concluded that these wells are being affected by the production from the 9-36 well, since it has a similar pressure at that time. However, the later pressures from the 9-36 well fall below those from the rest of the group, except for the 7-15 well.

When the gas wells in the Surmont leases were shut-in in 2000, pressure surveys were continued to obtain additional data. This shut-in occurs at approximately 5500 days on the above plot. Thereafter, many of the wells exhibit a slow increase in pressure with time, as mentioned in the previous section of this report. The apparent erratic behaviour of the 11-34 data following shut-in was found to be caused by mechanical problems in the pressure sentry devices. This situation was later corrected to obtain the final readings.

It is during this extended shut-in period that the groupings appear more obvious, partly as a result of more pressure data being collected. The capture of the additional data during the field-wide shut-in is unique compared to most reservoirs, where dynamic (production influenced) data is usually the only available. As can be seen for the dynamic period between 5000 and 5500 days, there are only four wells that exhibit apparently undeniable pressure communication, namely the lower pressure grouping of 11-19-081-05 W4M, 3-30-081-05 W4M, 7-23-081-06 W4M and 2-26-081-06 W4M. The remaining groupings are very questionable at this point in time and are only resolved during the later static shut-in conditions.

The rapidly increasing pressures in the 11-22-081-06W4M well cannot be easily explained, as there is nothing nearby that could cause that level of pressure increase to occur. However it was interesting to note that the static gradient surveys for this well showed several stops with a measured liquid gradient of about 8 kPa/m above the denser water phase. The liquid level was also very high in the wellbore and essentially at surface on the final gradient survey in 2002.

Even though the groupings appear to be satisfactory from an analytical approach, when plotted on a map some discrepancies arise. For example, the 7-15 and 9-36 wells are located some 8 km apart and, if connected, would transverse the grouping of the higher-pressure 7-23 and 2-26 wells located between them. For them to be connected would require a very long and sinuous sand body that was not penetrated by any of the other wells. Details such as this were noted and left open to confirmation by the reservoir simulation portion of this study.

This method of detailed analysis was performed for all of the wells in the study area, including wells within the three-mile buffer zone. The buffer wells were included to ensure that the proper description of lateral communication was obtained. The results of this phase of the study are presented on **Figure RA-2**, which is a map showing the well groupings. It should be noted that what is shown on the maps are not pool boundaries in the usual sense, but merely reflect groupings of wells that appear to be in lateral pressure communication. From this analysis, there are over 100 different groupings or pools.

The pressure behaviour with time for the individual wells are contained in the Appendix Well Group plots, however, for spatial visualization, **Figures RA-3** and **RA-4** present the reservoir pressures in 1986 (prior to first gas production from Surmont) and in the year 2002 (after 2 years of shut in,) respectively. These two maps clearly show the isolated nature of the gas pools in the Surmont area.

3.2 Observations

There were several key observations that were noted from the pressure data. Most importantly, the wells are not all connected, but instead the Wabiskaw-McMurray formation in the Surmont area consists of numerous gas pools.

The observations from the Reservoir Analysis can be summarized as follows:

- The virgin reservoir pressure throughout the area ranged from near 1100 kPa in the Northeast (Twp 83 Rge 5) to over 1900 kPa in the Southwest (Twp 81 Rge 8)

- There are numerous single well and small multi-well pools throughout the Surmont area. Based on the pressure buildup behaviour (late-time linear flow), the pools exhibit an elongated shape.

- The static gradient surveys conducted during the extended shut-in after 2000, showed that the pressure takes considerable time to reach static conditions. The calculated time to stabilization was also several years for some buildups with lower permeability and boundaries near the wellbore or a very narrow channel.

- Typically, longer buildups showed reservoir anomalies that were evidence of either reduced permeability-thickness (kh) further from the wellbore or no-flow boundaries.

- Pressure buildups conducted with surface pressure measurements and without fluid level measurements may not provide reliable reservoir pressures.

- Pressures buildups of less than one-week shut-in may not observe reservoir discontinuities and the resulting analysis may yield pressures that are too low.

4.0 RESERVOIR SIMULATION

4.1.1 Introduction

As a final step in the process of quantifying the degree of lateral and vertical communication within the Surmont area, a reservoir simulation model was constructed. This was done to provide a validation of the geological model through the inclusion of inter-well, time dependent pressure response from field measurements. Without this validation step, a geological model can be considered conceptual only and, quite possibly, only one of several realizations of a given dataset. In addition, the history matching process quantifies the degree of lateral and vertical communication throughout the model area and the requirement for any aquifer support.

The wells to be matched in the simulation process were only those within the Surmont leases, as shown within the red outline in **Figure RA-1**, and excluding those wells in the buffer zone. Where communication across the Surmont lease boundary with buffer zone wells occurred, the simulation model was to consider only those buffer wells that were impacting the Surmont wells.

The simulation software chosen was Eclipse[2] due to its widespread acceptance and vetting by industry. It also has numerous choices regarding numerical capabilities, well control features and summarization of regional flows and volumes.

The result of the reservoir simulation would be a map showing the regions of influence of the wells and any resulting well groupings. This would imply that these regions would also represent the limits of lateral and vertical communication within the Surmont area, given the constraints of the current dataset.

4.1.2 Technical Approach

The technical approach taken for this phase of the study is consistent with accepted practices and consisted of several tasks, each of which is described in

[2] Copyright of Schlumberger

greater detail in subsequent sections. This particular section outlines the basic procedures of the simulation study.

One of the things that a simulator must be able do in the case of Surmont is to allow the existence of an oil phase (bitumen) below a gas-water contact. Test runs with the Eclipse software showed that this was possible and the model remained numerically stable throughout a production and shut-in period typical of wells in Surmont.

The grid size was based on what was deemed to be the maximum necessary grid block dimensions to properly model the spatial locations of the wells and still retain sufficient definition of reservoir properties obtained through upscaling the finer gridded reservoir property values from the geological model. Since, for the most part, the gas wells in question in the study area are drilled on one section (256 ha) spacing or greater, there is little to be gained, in terms of data definition, by using a grid block size that is too small.

To simplify the placement of the wells, it was determined that a grid block size of approximately 402 m square, representing one legal sub-division (16 hectares or 40 acres), would suffice. This yields 16 areal grid blocks per section. Given the relatively high permeability of the sands and lack of significant saturation changes induced by water movement (as evidenced by the minimal volumes of water produced over the life of most wells), this sizing would provide more than sufficient resolution to model any saturation changes and pressure gradients between wells. It would also provide a method of including near-well reservoir boundaries if required. The grid was extended to encompass the 3 mile buffer area surrounding the Surmont leases. The model was constructed with six layers as described in the geological section of this report, resulting in a total of approximately 66,000 grid blocks.

Once the grid had been established, the well positions and respective completion layers within the Surmont area and the surrounding buffer area were prepared for use in the model. The historical production was taken from public data and monthly gas and water volumes were converted to calendar day rates for use in the simulator. The individual reported phase rate data was used to generate total reservoir voidage rates for each well internally in the model to ensure that the correct volumes were withdrawn for the pressure match. This approach is widely used when phase mobilities have not been matched early in the history matching process. Since no gas-water relative permeability data exists to help define water production behaviour in the simulator, this approach was maintained throughout the study to ensure the representative reservoir volumes were produced. In general, most wells produce very little water and the effect on the overall historical gas production rates is minimal. The production and injection histories from the few heavy oil wells and water disposal wells completed in the McMurray sands were also included in the model.

During the history matching process, the match between the simulated and observed historical pressure data was used to qualify the geological model. Adjustments to pool boundaries and transmissibilities (essentially permeability thickness multiplied by effective cross-sectional flow area) were then made to obtain a satisfactory match. In general, most simulation studies use a value of ten percent of the observed historical pressure drop in a pool as a parameter to gauge the quality of the match. In the case of Surmont this would be approximately 80 to 100 kPa. The match obtained was well within this criterion for the vast majority of the wells.

4.1.3 Model Construction

The three-dimensional simulation model consisted of 100 rows and 109 columns of grid cells for each geological layer. A total of six layers were represented in the model. The grid block dimensions of one legal subdivision (approximately 402 m square) were chosen to simplify placement of the wells within the model and allow adequate definition to simulate fluid saturation and pressure gradients. The model grid employed the use of corner point geometry, whereby the grid cells are trapezoidal and not necessarily rectangular in the vertical dimension. This allows the cells to mimic structural drape and more accurately depict variations in layer thickness between adjacent grid blocks. The grid cells were assigned individual values of structural elevation, effective porosity, gross thickness, net-to-gross thickness ratio and horizontal permeability by upscaling the geological model grid results. Vertical permeability was set equal to 0.1 times the horizontal value as an initial starting point.

Reservoir fluid PVT properties were common for all cells. An investigation of available gas analyses over the study area indicated no significant variation in composition and an average value was chosen. The dry gas composition (typically 98 mole percent or greater of methane) coupled with the low reservoir pressures (1200 to 1800 kPa) results in nearly linear volumetric behaviour with pressure. Even so, the model used pseudo pressure internally to ensure accurate representation of gas properties over the pressure range experienced during the simulation.

Relative permeability data for the gas-water phases was not available. Therefore, a pseudo relationship that used straight lines was employed. Since the focus of the study was to determine lateral and vertical pressure communication and not future production forecasts, the use of the pseudo function has little impact. Specifying total reservoir voidage production rates rather than only gas rates further alleviated this. The model produced the combined total rate of the historical gas and water phase voidage for each well to ensure that the correct reservoir volumes were produced in obtaining the pressure match.

4.1.4 Model Initialization

Prior to the start of history matching, the simulator is required to be initialized with the reservoir fluid distributions and initial pressure. This initialization is done at gravity-capillary equilibrium to ensure that the model is quiescent at time zero. Due to the unique characteristics present at Surmont, some different modeling techniques were required, as discussed in the following sections.

4.1.5 Reservoir Fluid Distribution

One characteristic of the McMurray sands in Surmont is the presence of high bitumen saturation in the lower layers. The bitumen is immobile at reservoir temperature and requires steam injection in order to be produced. This has occurred in pilot areas in Twp 83 Rge 6 and 7 of the study area. The bitumen is overlain by water in most areas and the gas is trapped in closed structural highs above the water. Thus, the result is a gas-water contact above a water-bitumen contact. In some cases, the bitumen itself is underlain by water, which is apparently more saline than that above the bitumen. This would seem to indicate that the bitumen can act as an effective seal to the gas-water system located above it, provided that the bitumen saturation is sufficiently high enough.

In order to model the non-normal vertical distribution of the reservoir fluids in the simulator, the oil density was set to be slightly greater than the water density (i.e. less than 10 API) and the oil viscosity was set to a value of 1.0 e06 cp to ensure that it remained immobile. The oil-water contacts required in the simulator were then set equal to the value of the gas-water contacts determined from the petrophysical analysis. The simulator gas-water contacts were arbitrarily set to be 3 m above the oil-water contacts, since water-bitumen contact depths had not been established from the log analysis. This latter value was established to ensure lateral communication could exist through the water layer that would eventually be located above the immobile bitumen. When the model was subsequently initialized, the oil, being denser than the water, remained in the bottom of the reservoir, with the water above it. The oil-water and gas-oil contacts reversed places, resulting in a gas-water contact with the correct value. The gas was underlain by 3 m of water above the bitumen layer, ensuring that pressure communication could occur laterally as required.

4.1.6 Reservoir Pressure Distribution

The Surmont area has the unusual characteristic of having a substantial variation in initial reservoir pressure at a common datum depth. This variation is areal and encompasses a gas phase pressure range of near 1900 kPa in the Southwest to approximately 1150 kPa in the Northeast, a distance of nearly 29 km (18 miles). The structural elevation of the Wabiskaw-McMurray is essentially flat, so the variation cannot be accounted for in the usual manner of gravity head differences.

The best correlation of the pressure distribution is obtained by using the absolute drilled depth to the McMurray. This results in a somewhat linear trend for most of the area. The surface topography is influenced significantly by erosion and decreases in elevation by nearly 300 m from the Southwest to Northeast. However, this may be only coincidental and cannot totally explain the initial pressure distribution encountered.

One explanation that has been expressed by others as the cause of the pressure distribution is the dynamic effect of an aquifer and its subsequent pressure loss as it flows across the field area. While it may be possible to construct such a model that would yield a steady state pressure distribution, it would be quite a unique situation. The aquifer would additionally have to be very weak to allow the gas pressure to fall to such a low level during the production life, with no significant evidence of pressure support. If this were the case then the gas production should have caused equivalent depletion of the aquifer pressure as well. However, the pressure history shows that near virgin pressures are encountered near depleted wells. This is shown, for example, in the 06-25-081-6 well that had an initial pressure of 1625 kPa in 01/97. The offsetting 07-05 well located to the south and the 06-17 well to the north had pressures of 990 and 1319 kPa respectively near that time.

If the varying initial pressures were to be used in the model, the result would be a non-equilibrium condition that would cause gas and water to flow from the higher pressure to the lower pressure areas. The observed pressure differential is more than that attributed to hydraulic head differences in most cases, therefore most of the gas would flow and collect at the Northeast edge of the model area as the pressure eventually equilibrated across the field. Since gas is actually present over the entire Surmont area and pressures are not in equilibrium, this would indicate that the gas is unable to move laterally very well, if at all. This is also evidenced in the variation in gas-water contacts observed between groups of wells in addition to differences in historical pressure trends.

As a starting point for the simulation, the model was initialized with the wells located within isolated pools, as determined from the reservoir analysis phase of this study. Each of the pools was equilibrated with its respective initial pressure. The outlines of the well groupings for the pools are shown schematically on **Figure RA-2**. Areas outside of the well groupings were set equal to a common initial pressure. As the history matching process proceeded, the pool boundaries were either expanded to include additional area and more wells or shrunk to exclude them. New pools were then defined for those areas and wells that had been excluded.

4.1.7 Conceptual Modelling

As an adjunct to the history matching process, several conceptual models were constructed to observe the pressure response of a single well in a system with known reservoir properties and geometry. These were used to help determine what was responsible for the increasing pressure trend noted in some wells after the field was shut-in.

The conceptual models were constructed using average reservoir properties and the six-layer description of the full field model. Layers 1 and 2 contained gas and connate water, layer 3 contained the gas-water contact and the water-bitumen contact, and layers 5 and 6 contained bitumen and connate water. Layer thickness was set equal to 5 m and porosity was constant at 30 percent. Permeability was varied as a parameter in the various cases studied. In all cases, the well was produced for 1825 days (5 years) and then shut in for an extended time to observe the pressure response.

Since much of the sand deposition was channel-form, the geometry studied was of various aspect ratio (length divided by width) rectangular reservoirs. The well was located near one end of the simulated channel to ensure that maximum pressure differences would be seen. In a single case where the well was placed in the centre of the reservoir for comparison, the pressure response was essentially halved, as would be expected.

Several cases were investigated using aspect ratios of 10:1, 20:1 and 40:1 with a constant permeability of 500 mD. As can be seen **in Figure RS-1**, the results were essentially identical, indicating that aspect ratio is not a controlling factor in the nature of the pressure response at this level of permeability.

When the aspect ratio was kept constant and permeability was varied from 250 mD to 1000 mD, as shown in **Figure RS-2**, there was significant difference in pressure behaviour. What is most significant is, that even with relatively high permeability, there is a significant time period, of almost 2 years, over which pressure still increased with time during the extended shut-in period. This is not immediately intuitive, since most would assume that the pressure would stabilize almost immediately with this level of permeability.

It appears that, in low pressure, and therefore highly compressible reservoir systems, pressure equilibration can take a significant amount of time to occur. As a comparison, the initial pressure was set to 10 times the base value and the well was produced for 5 years. The average reservoir pressure at the end of production was approximately 10800 kPa. The 500 mD case showed almost no further increase in pressure with time after a shut-in time of 200 days had elapsed versus over 600 days at a low average pressure of approximately 1010 kPa. **Figure RS-3** shows the response for the high-pressure case.

For the homogeneous systems studied, it can be stated that permeability changes have a significant effect on pressure equilibration after production. In the case of significant heterogeneities, as would be the case in Surmont, the character and magnitude of the response would undoubtedly be accentuated.

4.1.8 History Match Results

This section of the report documents the results of the history matching process, whereby the initial model description was modified to result in a match of the observed pressures for the wells within the Surmont area. Wells within the buffer area, while included in the model, were not to be matched if they were proven to be separate and not impacting the pressures of those wells inside the Surmont area proper.

For the most part, the well groups obtained during the reservoir analysis work held up during the simulation phase. There were some groups that had wells added and probably an equal number that had wells removed. The map shown on **Figure RS-4** shows the resulting groupings from the history match. These pool groupings indicate which wells are in lateral pressure communication. The individual pools themselves are isolated and do not communicate laterally. **Figure RS4-A** is the same map with the wells with piezometer data overlain to show connection to the well groups. Not all of the wells could be assigned to groups based on the piezometer readings alone. **Table RS-4** is a reconciliation of this dataset.

In order to obtain the match, horizontal transmissibilities, pore volumes and pool boundaries were adjusted. In only one or two cases was it necessary to severely restrict the vertical communication between one or more layers to obtain a history match. It is apparent that the geological layers are in vertical pressure communication in almost all cases. In some instances where the pore volume within a pool grouping was reduced to match the overall pressure level, it is possible that some layers or portions of layers may be isolated vertically from the remainder. However, there is no practical way of determining whether it is a lateral or a vertical or a combination of both barriers that exists. Simulator pressures within the bitumen saturated layers maintained virgin pressure, a phenomenon noted from the piezometer measurements in the field. This confirms that the bitumen acts, in these areas of high bitumen saturation, as an effective bottom seal to the overlying gas-water system.

The adjustment in horizontal transmissibility required in some cases may be the result of a reduction in flow capacity due to reservoir heterogeneities rather than a reduction in actual permeability. Core descriptions indicate that the sands can be quite heterogeneous and laminated, locally restricting flow within the reservoir.

An important insight obtained from the history matching was the ability to match the increase noted in some well pressures during the extended shut-in period that commenced in 2000. These pressure increases are the result of reduced permeabilities or transmissibilities within some groups (pools). Reduced permeability values were in the range of 100 mD, as compared to the high-end permeability pools (1000 mD), where no substantial increase in pressure with time is evident. Pressure distributions within the lower permeability pools are not uniform, even after several years of shut-in, and the gradients that are present allow the observed pressure increases to occur. The qualification of the increasing pressure response is detailed in the preceding section, wherein conceptual, single well channel models were simulated to observe the pure pressure response.

Therefore, it is not necessary to provide an aquifer response to achieve these increasing pressure trends. This appears to be logical, since the other alternative would be to eliminate or substantially reduce aquifer support in selected pools that did not show increasing pressure with time. This is counter-intuitive, as the higher permeability areas would be expected to be in better pressure communication with an aquifer. In addition, the pressure response of all but a few wells was satisfactorily matched, prior to the field being shut-in, with a volumetric (non-aquifer supported) model.

The individual well matches are shown in **Figures RS-5** through **RS-93**, while **Table RS-1** gives comments regarding the individual matches, related to the quality of the observed pressure data.

4.1.9 History Match Problem Wells

No reservoir simulation history match is ever perfect due to the complexity of the depositional architecture and the sparseness of the control points. It is to be expected that in any study, a few wells will cause the majority of the problems in obtaining an overall match. However, these few wells do not usually change the main results or conclusions inferred by matching the majority of the wells successfully.

Due to the overall size of the Surmont area and the number of wells involved, there were a few wells in which satisfactory matches with the observed data could not be obtained or the well behaviour explained. Most of these problems resulted from the inability to accurately match the trend of the pressures following the shut-in of the field in 2000. This is most likely due to small-scale heterogeneities near the well that are not adequately addressed in the geological model and the subsequent coarser upscaling to the model grid. These wells are summarized in **Table RS-2** and their history match plots are contained in the Reservoir Simulation (RS) Figures section of the report.

4.1.10 Gas in Place

The gas in place for each of the pools was determined from the history matching process. The original and remaining gas in place for each is contained in **Table RS-3** along with the list of wells attributed to each pool. Note that this list of wells includes only those that have pressure history and/or production only. Other wells may be located within a defined pool, but absence of data prevents confirmation of this.

4.2 Observations

The reservoir simulation phase resulted in the following observations:

- The well groupings identified by the reservoir analysis phase, for the most part, were found to be valid.

- The extent of lateral communication in the McMurray-Wabiskaw formations over the Surmont area is limited and the gas reserves are located within many smaller pools.

- Vertical communication appears to be continuous throughout the geological model layers, where net reservoir is mapped. This is not to say that all layers are in vertical communication at any one point, but the overall effect is for vertical pressure communication to exist within individual pools.

- The atypical initial reservoir pressure distribution is maintained as a result of the absence of lateral pressure communication.

- It is not necessary to invoke aquifer response to match the well pressure behaviour that has occurred since shut-in in 2000

TABLES