ADDENDUM TO FINAL REPORT
February 2005

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PREFACE

After review of the final report by the Sub-Committee, several questions were raised, as to be expected on a study of this magnitude, pertaining both to methodology and results of the work. In addition, there was a request for additional work, not required for the completion of the tasks contained in the original scope, to be completed along with clarifications and editorial corrections of some items in the report.

This addendum presents the results of the additional tasks and also contains a series of questions prepared by the Sub-Committee and the responses by Exploitation Technologies Inc. (ETI), regarding the original publication. The editorial corrections to the final report have been issued as replacement or additional pages for manual insertion into that document.

It should be noted that several of the questions arose due to a misunderstanding by the Sub-Committee of the work process used in the construction of the geological model. This pertains to an internal, optional "workflow" document used by the PETREL geological software. The ETI geologists did not use this option and therefore, when the Sub-Committee reviewed the supplied PETREL database and the "workflow" document, it appeared as though only a few wells had been used in the preparation of the entire geological model of Surmont. Of course, this is in error, as in excess of 600 wells were investigated by ETI and used in the construction of the model. This misunderstanding was not identified until after the questions had been formalized and transmitted to and subsequently responded to by ETI at a meeting. Therefore, the reader should view the questions and responses related to the adequacy and correctness of the geological model with this in mind, otherwise some questions may appear to be somewhat confusing to one who has read the complete report.

AD1.0 GEOLOGY

The Sub-Committee requested that Exploitation Technologies Inc. prepare additional geological maps, over and above those that were required for the tasks in the original project scope. These were to be isopach contour maps of Net Water Sand (Above Bitumen) and Net Gas pay.

AD1.1 Methodology for Picking Gas Contacts and Top of Bitumen

The top of the bitumen and base of the gas zones were picked in order to sum the water-bearing part of the interval between the two; in addition, a new summation of the gas interval from the base of gas to top of basal Wabiskaw was also run. Those picks are listed in various Excel files attached to this report. There are two immediate issues associated with these two tasks:

1. The base of gas picked during the main project work was the base of neutron/density porosity crossover (**Xov**). For the purposes of mapping, the contact so picked was called the **G-W**. As pointed out by the project petrophysicist, there are some additional cases of gas in shaly sand zones that may not exhibit **Xov**, but by subjective judgment could possibly be included in a summation of total "net" gas pay.

2. As pointed out in the final report and in one or more of the presentations to the Sub-Committee, *bitumen saturation exists throughout the McMurray cores described for this project wherever there is permeability*. The amount of saturation decreases upward but *is not typically zero* even in gas zones. Therefore, one cannot pick the top of bitumen without a defendable definition. Otherwise, the first permeable sand below gas would always be declared the top of bitumen, resulting in a meaningless final map.

Taking the two above issues into consideration, the final results traces from the petrophysical work (results.las files) were loaded into presentation software and reviewed. The loaded traces included Gamma Ray (**GR**), Effective Porosity (**PhiE**), the crossover from the combined original density and neutron porosity (**Xov**), and Water Saturation (**Sw**).
The traces were investigated for evidence of gas in shaly zones based on the presence of low **Sw** intervals with **PhiE** of at least 14%. Based on this subjective pick, a new marker called **G-W2** was picked in 155 wells. The summation of the interval between this marker and the top of the basal Wabiskaw gives the

maximum possible volume of gas within the interval. Many of these also have a **Xov G-W**, which establishes a minimum gas volume for the interval in those wells with both picks.

Initially it was feared that it would be difficult to distinguish wells with shaly gas sands from those with significant bitumen saturation, but it was soon discovered that the two are distinct. The bitumen section is characterized by a decreasing **Sw** downward (please review the saturation profiles in the PETREL Project provided at the end of the original work for examples). The trend is very consistent regardless of facies distribution. The **Sw** in the shaly gas sands is much more erratic (as one would expect) and this feature effectively distinguishes between the two in almost all wells (exceptions always exist).

The top of the bitumen for this exercise was picked at the point where, on average, the bitumen saturation stabilizes at a relatively uniform value. This is typically at a **Sw** of 20% or less. Therefore, the top of the main bitumen, which is probably very similar to what is picked as "commercial" bitumen (where thickness is sufficient), was picked using a cut-off of about 20% (exceptions exist but do not alter the outcome). Interestingly, the minimum **Sw** of the main bitumen sands is 5-10% (or more) lower than comparable good quality thick sands in the gas column; this is especially evident to the eye in those thick clean sands that contain both gas at the top and main bitumen at the base. The interval between the top of main bitumen and the base of gas is hereafter called the "**bitumen transition zone**".

The saturation profiles indicate that in thick permeable sands, where **Xov** is definitive in locating the **G-W** contact, low **Sw** porous zones are present immediately below the gas column. Therefore, based on such saturation profiles and the previously noted core descriptions, it can be emphatically stated that the decreasing **Sw** downward in the bitumen transition zone does in fact represent increasing bitumen content. It is herein recommended that the bitumen saturation in the **bitumen transition zone** should be quantified by future core analyses and calibrated to log analyses results.

Bitumen zones are oil-wet. Therefore, the wettability of the zone changes vertically as well as the **Sw**. Water contained in the lower part of the **bitumen transition zone** is trapped within bitumen-occluded pores. The upper part is more water-wet or partially water-wet, in which case the water is bound-water. In either case, little mobile water would be expected. Therefore, it can be concluded that the so-called aquifer zone between the gas and bitumen is not likely capable of yielding much water and certainly is not an aquifer in any common usage of the word. In order to test this conclusion, it is herein recommended that the Sub-Committee review all perforated intervals that include zones below established gas contacts, for evidence of water production. Perhaps the volumes of water thus produced (if any) could then be calibrated against the saturation profiles in order to predict water production tendencies in future wells.

The following cutoffs were used to identify clearly "wet" zones:

Vsh < or = 40%
PhiE > or = 14%
Sw > or = 60%.

AD1.2 Mapping Results

The new maps were prepared in SURFER, using a 25 m grid and the default Krigging algorithm. The results of mapping the newly defined intervals are presented below as **Figures ADG-1** to **ADG-3.** The maximum net gas thickness map **(Fig**. **ADG-1**) defines the net pay interval from **G-W2** to the top of the basal Wabiskaw. The minimum net gas map (**Fig. ADG-2**) defines the net pay interval from the original **G-W** to the top of the basal Wabiskaw. The water-bearing zone map (**Fig ADG-3**) is defined as the interval of reservoir rock with 60% or greater water saturation between the top of the main Bitumen and the lowest gas contact.

Great care must be exercised in using these maps for a number of compelling reasons:

1. At the Sub-Committee's request, the net gas maps have been contoured as if there are no pool boundaries. There are in fact over 50 separate pools with distinctive yet poorly defined boundaries within the simulation area alone. Moreover, structural mapping (using additional data points and 2D seismic) indicates that nearly all production is associated with closed, very low amplitude highs; such accumulations are also strongly controlled by local stratigraphic trapping. On the other hand, closed lows between are largely barren of gas. These situations are not reflected on the continuous contoured map provided.

2. Because of the dramatic changes in reservoir stratigraphy between channel and non-channel facies packages and sparse drilling in many sections, the map of high water saturation likewise shows continuity that is probably far over-stated.
3. As noted above, intervals of high **Sw** do not necessarily imply significant mobile water. Areas of mobile water can only be identified and confirmed from reliable production data.

AD1.3 Cross-Section Index Maps

The Sub-Committee requested index maps for the cross-sections that were included in the original report. These have been addressed as follows:

Figure ADG-4 is a complete index map of all of the Pool cross sections presented in the original report with pool boundaries included (original Figs.G-36 to G-92, inclusive).

Figure ADG-5 is a complete index map of all other cross sections in the original report that were not displayed on an index map in that report (original Figs. G-13 to G-25 and G-29 to G-32, inclusive).

AD2.0 RESERVOIR SIMULATION

ETI was requested to provide six maps of the field pressure distribution at specific times. Simulator data was to be displayed as a class map, with colour coded symbols for various pressure ranges, while field data was to be contoured, ignoring pool boundaries. The data and the time periods used are detailed below:

- Initial pressure of wells was to be contoured. This was modified to initial pool pressures from simulator data only, since some pools had infill wells drilled after discovery and the measured pressures from the later infill wells would cause contouring anomalies, if production had already taken place. The data for this map was to be presented as a classed post map with colour ranges for pressure groups as **Figure ADRS-1**. Also presented on the map are posted values of valid field initial pressures for each pool.

- Field pressures prior to shut-in were initially requested. The field was shut-in in April 2000 and there was little data available at that specific point in time. Field wide pressure surveys were taken over the first and second quarter of 1999 and again in the third quarter of 2000. Contour maps of both of these distributions were prepared as an alternative. These two maps are included as **Figures ADRS-2** and **ADRS-3**.

- Field pressures for the end of 2003. This was modified to using the last pressure available in 2003, since very little data was available at the end of the year. Most of the pressures used were from the first quarter. This map is included as **Figure ADRS-4**.

- Simulator pressures were posted for April 2000, just prior to shut-in. This map is presented as **Figure ADRS-5.**

- Simulator pressures were posted for January 31, 2004, which is the last available from the model. This is shown as **Figure ADRS-6**.

AD3.0 MISCELLANEOUS

The Sub-Committee requested a "workflow" description of both the PETREL specific task, which is described as follows:

AD3.1 Workflow Steps Utilized In PETREL Mapping Stage

1. Petrophysical results files received in both LAS and Excel spreadsheet digital formats.

2. Load Well Header data (UWI, UTM X location, UTM Y location, and KB) into PETREL, using PETREL ASCII loader.

3. Import LAS files for each well, matching well trace names and LAS file name.

4. Extract mapping parameters from petrophysical results files by layer (layers 1-5); these parameters are net reservoir thickness (net h), average effective porosity (PhiE), and calculated permeability (k). The remaining other required mapping parameters are derived from correlation database, namely, top of Layer 1 structure and gross thickness (gross h). Net-to-Gross then is calculated on a spreadsheet using the derived net h/gross h.

5. All required mapping parameters merged into new Excel spreadsheet designated as the mapping database.

6. Each mapping parameter (z) extracted along with the proper x and y. Text files (required for loading into PETREL) are created for each layer for each property all having the three column format of x,y,z.

7. Import miscellaneous data such as dipmeter data.

8. Set up boundary conditions (x,y limits) and grid size (distance between grid nodes) for project. The initial grid size was 50 x 50 m. The grid size was later reduced (upscaled) to one appropriate for the simulation model.

9. For each property and for each layer, make 2D Surface.

    a. The structural surface was constructed from more data points than the property surfaces because there are more correlation wells than results wells.

b. A distinction needed to be made between points that were nulled and those that were zero. Zero points are valid contouring points; nulled points (those that are often set to something like –999 in most mapping programs) are invalid mapping points. For example, those grid nodes assigned a value by contouring extrapolation of less than the cutoff for average porosity (14%) or less than .5 mD for permeability need to be nulled; these points are not zero. The same areas of nulling need to be consistent for all properties. For this purpose, a mapping polygon(s) is (are) digitized for each layer. PETREL allows the points within such designated polygons to be "blanked" (nulled).

c. Edit each created Surface where appropriate.

10. For each final surface, set an appropriate final color fill, contour interval, and labels.

11. Export the grid nodes for each mapping file in a standard x,y,z format for importation into ECLIPSE.

12. Export the surfaces in graphic format for report.

13. Build a well template that displays the appropriate log traces at an appropriate scale, with color fill, and input cored intervals.

14. Build final cross sections using the well section template.

15. Export cross sections in graphic format for report.

AD3.2 Integrated Project Workflow

A request was also made for new work which would include a diagrammatic representation of the workflow by and between disciplines for the entire project. This is presented as a series of **Figures ADM-1 to ADM-5**.

AD4.0 FINAL REPORT QUESTIONS AND ANSWERS

This section presents the text of the formalized questions from the Sub-Committee regarding the final report methodology and conclusions and the resulting responses from ETI. Comments from the Sub-Committee relating to the presentation or formatting of figures, tables and text in the report have not been included in this section.

Requests pertaining to specific Deliverables:

Deliverables are listed in boldface and numbered *and specific requests of the Sub-Committee (SC) follow in italics.* ETI's response follows each statement or request.

1. **Our written assessment of our interpretation of the geology and petrophysics of the various gas pools.**

SC:

For every conclusion presented would ETI provide a reference to the substantiating data and analysis within the body or appendices of the report.

General conclusions must be referenced to exceptions and an explanation provided in the text (e.g. Page 7: "Vertical communication appears to be continuous throughout the geological model layers where net reservoir is mapped." and Page 78 – "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.')

ETI:

It is uncommon for technical reports, papers or journals to repeat the data or paraphrase the discussion leading to the conclusions. Such an unusual presentation of results was not requested in the original RFP nor offered in the ETI proposal. Nonetheless, if the Sub-committee would like this material added to a revised report, this can be done. Please note that it will make reading the conclusions more cumbersome and less direct.

2. **Maps of net reservoir, porosity, structure and permeability and boundaries of each pool with cross-sections through multi-well pools.**

SC:

Provide a net gas pay map which accounts for all wellbores within the study area and includes:

ETI:

A net gas pay map was not a specific deliverable of this project as noted in the above statement from the RFP. It is important to reiterate that the object of the study was to provide a simulation model that could be used to evaluate lateral and vertical pressure communication. The simulation model does not use a net gas pay map as input, rather it uses gross and net reservoir thickness, to which is applied the appropriate gas-oil, gas-water or oil-water contacts and capillary pressure data to enumerate the saturation distributions within the vertical reservoir column.

SC:

- *any cutoffs that were used to create the map*

ETI:

The cutoffs used for the creation of the net reservoir values are cited in several places throughout the report as follows:

> *"The net reservoir values include Vshale, PhiE, and k cutoffs (in this case 40%, 14%, and 0.5 md respectively) but no water saturation cutoff. Water saturations in the model were indirectly calculated from the petrophysical data by generating pseudo-capillary pressures describing connate saturations and related transition zones. These data were then correlated with derived permeabilities and used to establish the saturation relationships for the different reservoir rock types."*

SC:

- *pool boundaries; including observation and oil sand evaluation (OV) wells where reasonable to include (eg: through gas-water contacts).*

ETI:

The shapes of the pools (location of boundaries) are quite subjective due to the fact that typically there is no more than one well per section (and in some places less than one per section). However, the volume contained in the pool and the wells included within each pools are defined through the analysis and interpretation of the pressure data and verified through the simulation history matching process. Hence, the physical boundaries may be changed if new control becomes available but the volumes will change little, if at all. Such boundary adjustments do not affect the outcome of the study and are tangential to the objective, which was to define the presence of lateral pressure communication between pools.

SC:

- *interpreted stratigraphic and/or structural control between pools;*

ETI:

Given that in most gas accumulations, there is typically no more than one well per section (and in some places less than one per section), comments with regard to the geological reasons for the pool separation are speculative at best, given the complex depositional environment. Nor does such conjecture offer much assistance in defining the reservoir volume incorporated in the history matched results. This work can be added to the project with the proviso that such conclusions are provisional and subject to endless argument.

SC:

- *contact elevation and type of contact for each well / pool (e.g. gas-water contact, gas-shale contact);*

ETI:

The elevations of the contacts are provided in the report as Table G-5.

SC:

Re-do cross-sections to provide structural cross-sections for all interpreted gas pools, illustrating structural control for pools.

ETI:

There was no specification in the RFP for the type or format of the cross sections. The cross sections were constructed in PETREL through each pool to best show the stratigraphic differences between wells. Given that most wells are located in small, isolated pools, the use of such cross sections to illustrate 'structural control' relating to trapping is not of great significance. Structural cross sections could be prepared for each pool if desired, but this is an add-on to the original work.

3. A summary of the results of the history matched simulation model, including communication between regions and potential aquifer influence and properties.

SC:

The geological representation in the simulation included on the CD does not represent the McMurray geology in Surmont.

ETI:

The preceding comment is not correct. The simulation model in fact includes all of the upscaled mapped geological information, including structure, net-to-gross, average porosity, and average permeability. The following is a quote from the first page of the geology report:

> *"The purpose of the reservoir simulation study is to resolve certain issues related to the production of gas overlying bitumen. Therefore, all geological activities that do not specifically contribute to the understanding of the relationship of gas production to bitumen recovery, by means of history matching wells using the simulator, are not relevant to this study. It is important to state this at the outset, so that expectations of the geological output are realistic."*

Hence, the model utilized represents only the McMurray geology required for simulation. It does not include a detailed facies model (for which there is inadequate data in any case in the gas pools). Neither does it include a paleontological model, a migration history model, or any other type of construct that was not required for simulation.

> ***SC:***
>
> *The static geological model created in PETREL contains only 3 up scaled wells in the study area and only the porosity was modeled.*

ETI:

As documented in the final report:

> *"Final cutoffs determined from the petrophysical study were used to create summations of average properties for each mapped reservoir layer. These values were mapped used a 50 m x 50 m grid. Interpolated and/extrapolated areas characterized by average values that fell below the cutoffs were blanked in the final grids. The geological grid was then upscaled to a 402.34 m x 402.34 m simulation grid, which is one grid cell per legal subdivision (LSD)."*

> ***SC:***
>
> *The distribution used is SGS with the PETREL defaults (5 km*5 km**).***

ETI:

With respect to the contouring algorithm used in the static model, the SGS (Sequential Gaussian Simulation) was *not* used. The convergent gridder was used as the default. Quoting from the PETREL Help Manual page 1026:

> *"The convergent gridder is a control point orientated algorithm (rather than grid point) which will converge upon the solution iteratively adding more and more resolution with each iteration. This means that the general trends are retained in areas of little data whilst detail is honored in area where the data exists. This is a good general algorithm which works well with most data."*

Various contouring algorithms were reviewed to see the sensitivity of the algorithm to the final solution. Krigging was not available as an option within PETREL, because the number of grid points exceeded the limits of the software. In ETI's opinion the convergence algorithm the best gridding tool available for these data. In any case, the results and conclusions obtained by the simulation are insensitive to the contouring method employed.

> ***SC:***
>
> *Also, in the simulation, no flow boundaries were created around the gas pools using the ISOLNUM keyword in Eclipse™. These boundaries are artificial and not clearly tied to any geology. Another geological realization is required which is more representative of geology and another simulation needs to be run.*

ETI:

These boundaries are in some cases artificial and not tied directly to geology, but they are constrained by the sparse geological data. The simulation model was employed to verify the existence of inter-well pressure communication and, in doing so, the plausibility of the geological interpretation. The geology was incorporated into the simulator in terms of the absence or presence of net reservoir sand and the relative quality of the sand within the mapped area. In some cases this undoubtedly caused the flow paths or pore volumes to vary considerably within the area contained within the specified no flow boundaries.

During the course of the history matching process, the no flow boundaries were adjusted in many times to include or exclude wells or areas in order to achieve the best overall match. The final history match pool boundaries are considered to be the best result that honours all data. For this reason, another simulation, based on a different geological interpretation (if that were possible, given the data) would no doubt look very similar, if not identical to the one already presented.

Of minor note, the ISOLNUM keyword pertains to the simplification of the numerical solution within the model and is not the mechanism used to specify the no flow boundaries. These boundaries are implemented by modifying the individual grid block transmissibilities at the edges of the respective pools.

SC:

Explain the geological reasons for omitting an active aquifer and / or prepare a simulator history match including an active aquifer.

ETI:

The presence or lack of an aquifer and its strength are determined by engineering and production data not from static (geological) data per se. The aquifer was not omitted in the geological work, in that the mapping incorporated the entire gross and net reservoir, whether hydrocarbon or water filled. The explanation for the absence of an active aquifer is explained in the Reservoir Engineering section of the report. If a satisfactory history match was achieved without an active aquifer, then a comparable solution would be difficult to achieve with one. The aquifer support either exists or it doesn't; there are not two correct solutions to this problem.

SC:

The new geological realization must use actual gas-water-oil contacts.

ETI:

The static (geological) model does not include gas-water-oil contacts, as it is inappropriate. In the static model, no saturation information is required. The dynamic model reflects the contact data provided by the geologist. The following is from the report:

> *"The net reservoir values include Vshale, PhiE, and k cutoffs (in this case 40%, 14%, and 0.5 md respectively) but no water saturation cutoff. Water saturations in the model were indirectly calculated from the petrophysical data by generating pseudo-capillary pressures describing connate saturations and related transition zones. These data were then correlated with derived permeabilities and used to establish the saturation relationships for the different reservoir rock types."*

There may be some confusion regarding the use of gas-water contacts in the model due to the nature of the initial equilibration concept. It was noted in the discussion attached to these Sub-committee requests (Reservoir & Simulation, item 3) that the gas-water contact was established 3 m above the base of the water. This statement is incorrect. Due to the requirement to have the bitumen (oil) below the water, what the simulator considers in the input data to be the 'oil-water' contact was set equal to the correct gas-water contact elevation and the simulator 'gas-water' contact was set 3 m below this. When the model was initialized with an oil density greater than water, the contacts 'flipped over' and the gas-water contact appeared at the correct elevation, with a 3 m water zone beneath it and the bitumen zone below the water. This procedure was described in the report.

> ***SC:***
>
> *In the bitumen, the endpoints of the relative permeability curves matched the initial fluid saturations removing any fluid movement in this zone. The new realization should use saturations from well logs and appropriate relative permeability curves.*

ETI:

No relative permeability relationships were supplied for the bitumen and water. However, considering that the cold bitumen is immobile at any saturation value, the relative permeability to water would be a function of the impairment of the permeability by the bitumen, rather than a normal function of two-phase flow effects. It is conceivable to have high water saturations (higher than connate) within the bitumen zone that are immobile due to the plugging of pore throats by the bitumen. Pieziometer data shows high pressures in the bitumen zone and depleted pressures in the overlying water and gas, implying a discontinuous water phase and no water phase flow in the bitumen. However, even if there was a case to be made for water mobility to exist in the bitumen, the simulation pool boundaries extended through the entire McMurray zone. Thus any water movement below or through the bitumen could not provide a path for pressure communication to lateral offsets. The volume of water contained within the bitumen is minor compared to that in the overlying water zone and would have no impact on pressure response seen in the gas phase.

SC:

Prepare the statistics (RMS, R^2) that measure the quality of history match for each shut-in well's pressure post 2000. Indicate whether the value is within an appropriate range.

ETI:

The use of statistical parameters to evaluate the quality of a history match is not a common approach. Their use can provide erroneous indicators: for example, in a sample of three observed points in a linear relationship, a line passing though all three points would have an R2 value of 1.0, as would a line that passed through the centre point, but at a 90 degree angle to the trend. This is one reason that automatic history matching is not yet the panacea of reservoir simulation.

Generally, the quality of the simulation is based on trend matches, deemed appropriate by the simulation engineer, of observed data. In terms of absolute values, the difference between observed and simulated pressure data is usually expressed as a percentage, typically 10 percent, of the historical pressure drop. For example, a reservoir that had declined 1000 kPa would be expected to have an average +/- 100 kPa tolerance on the simulated versus observed pressure match. In the ETI proposal presented to the Sub-Committee, the match criterion was expressed as +/-70 kPa. Most of the matches are well within this tolerance, typically less than 30 kPa.

SC:

Provide a table of definitions or criteria for facies, rock type, and flow units and how they were integrated in the geological model and subsequently in the reservoir simulation.

ETI:

The final report states:

> *"In terms of reservoir simulation, flow units comprise the basic building blocks. Numerical models allow flow to occur in three dimensions through the faces of a cube of reservoir material. The nature of the reservoir material in the flow unit is not consequential provided that the capillary pressure, relative permeabilities, and endpoint saturations are the same or very similar. Rock units with similar pore size distribution and pore throat dimensions are referred to as "rock types". The flow model requires identification of barriers and changes in the rock type to track flow. Hence, the issue of depositional facies per se can be irrelevant (especially in intervals with significant diagenesis). There may be several rock types within a reservoir, which may or may not coincide with a specific facies. There may be more than one rock type within a flow unit. If present, the distribution of the multiple rock types within the flow unit (layer) does have to be accounted for in the static model."*

Therefore, there is no basis for constructing a table with facies criteria. The flow units are the six layers defined for the study. As discussed in the report, flow in non-channel areas is vertically constrained to zones between widespread shales; these same zones are then vertically connected in almost all cases within channel complexes, where thoroughgoing shales are absent. Rock type changes are addressed in a simulator primarily as transmissibility factors, as determined from well test data, general pressure data, fluid contact changes, and history matching criteria. The location of rock type changes cannot be handled geologically in an area with sparse well control (where most gas is located), especially given the areally restricted nature of rock units in the Surmont area.

4. Summaries for each pool or observed region of influence containing:
- Geological and petrophysical summary for each well
- Original and remaining recoverable gas for each pool
- Wells included in each region

SC:

Which 28 wells were chosen for the permeability study?

ETI:

There were 28 wells with overburden data AND Kvert data.

After review, only 26 wells were actually used as listed here:

00/04-22-083-06 W4M/0

00/04-24-083-07 W4M/0

AA/07-15-083-07 W4M/0

09/05-24-083-07 W4M/0

AA/01-11-083-07 W4M/0

AA/11-14-083-06 W4M/0

AA/13-22-083-06 W4M/0

AA/14-14-082-07 W4M/0

AA/16-09-082-07 W4M/0

AA/02-23-083-07 W4M/0

AA/01-12-083-07 W4M/0

AA/01-14-083-07 W4M/0

AA/02-25-083-06 W4M/0

AA/10-13-083-07 W4M/0

AA/12-24-082-07 W4M/0

AA/16-30-082-06 W4M/0

AA/01-35-082-07 W4M/0

AA/03-27-083-06 W4M/0

AA/07-19-083-06 W4M/0

AA/09-30-083-06 W4M/0

AA/10-06-083-06 W4M/0

AA/10-23-082-07 W4M/0

AA/10-24-083-06 W4M/0

AA/14-23-083-06 W4M/0

AA/14-26-083-06 W4M/0

AA/14-27-083-06 W4M/0

- Average reservoir parameters for each pool

SC:

What was the Rw (water resistivity) value used?

ETI:

Rw was graded from 0.35 at surface to 0.30 at 600 meters. The average Rw at the Wabiskaw/McMurray was 0.33 ohm-m.

SC:

The median permeability in the model of 1.7D appeared reasonable; explain the very large std. deviation (2.8D), and maximum of 28.4 D.

ETI:

The range of the core data is 0.05 md to more than 21000 md. The core porosity range is 0.179 to 0.414. With the transform generated from the core data, a porosity of 0.416 gives 29000 mD so the data range is supported by the core data. Any parameter with that large a range will have a large standard deviation.

SC:

Which shale beds were used to normalize scaling differences in which wells or pools?

ETI:

The log analysis program picked the GR shale line automatically in the 5 meter interval above the Basal Wabiskaw pick. This was a very uniform shale interval. The clean line was picked automatically in the cleanest sand between the Basal Wabiskaw to top of Devonian interval.

SC:

What is the GOR used in the bitumen?

ETI:

No data was provided that contained the solution gas content of the bitumen. However, for completeness, the bitumen was assigned a GOR of that varied linearly with pressure, from 0.0 sm/m3 at 0.0 kPag to 1.0 sm3/m3 at 5000 kPag. This had no impact on the simulation results, as the pressure in the bitumen remained at initial conditions due to lack of mobility.

- A description of observed aquifer influx for each region or pool
- Cross-flow between pools or regions within a specified time frame

5. A map showing the interpreted regions of influence.

SC:

Provide a map which also includes drilled observation and appropriate OV wells.

ETI:

A map incorporating the observation wells has been prepared. There was no significant change in pool boundaries, as the data from the observation wells was inconclusive as to their lateral connection in the majority of cases.

6. Geological, petrophysical and reservoir engineering models and ancillary data on CD.

SC:

Please provide a schematic of ETI's depositional model for the Wabiskaw / McMurray Formations, based on the facies observed in core. Define or illustrate tidal channel, tidal creek, bay, tidal flat, mixed flats, sand flats, interfluve, main channel systems.

ETI:

This is not a deliverable from the RFP. As stated above, facies per se is not an important consideration in building a static model for the purposes of this study. The model directly utilizes summation data from petrophysics. In any case, quantitative rock property extrapolations assigned based on a facies model would be hampered from the start because of the sparse data control and limited spatial size of individual facies elements. The text does include ample discussion of the generally accepted facies model for the Wabiskaw-McMurray as a whole and needs no further elaboration here. In any case, the limited size of the core budget (as originally approved by the Sub-Committee) and limitations of the project schedule did not provide funds or time for this type of work. As stated in the report:

"The primary purpose for an independent review in the present study was to provide calibration to the log signatures. Interestingly, the most important information gleaned from the core work related to saturation issues."

SC:

Provide descriptions of all cores examined in the course of this study. Please include:
- a legend of symbols used;
- annotation to show layers and markers;
- open hole logs and log analysis results plotted at the same scale as the core description and displayed adjacent to the descriptions, for comparison purposes.

ETI:

The Sub-Committee was asked on several different occasions (after the cores were described) if they wanted to sponsor a final drafting of the cores described by ETI's sedimentologist, and if so what was required. Each time the response was that there was no interest in following through with this effort. If the Sub-Committee now wishes this data to be included, a cost estimate will be prepared for their approval.

SC:

Provide a list of the data used and excluded from all wells.

ETI:

With regard to geology see Tables G-1 to G-5; in addition, all petrophysical data provided was used in the mapping (see petrophysical results).

This concludes the list of questions to which ETI was to respond.

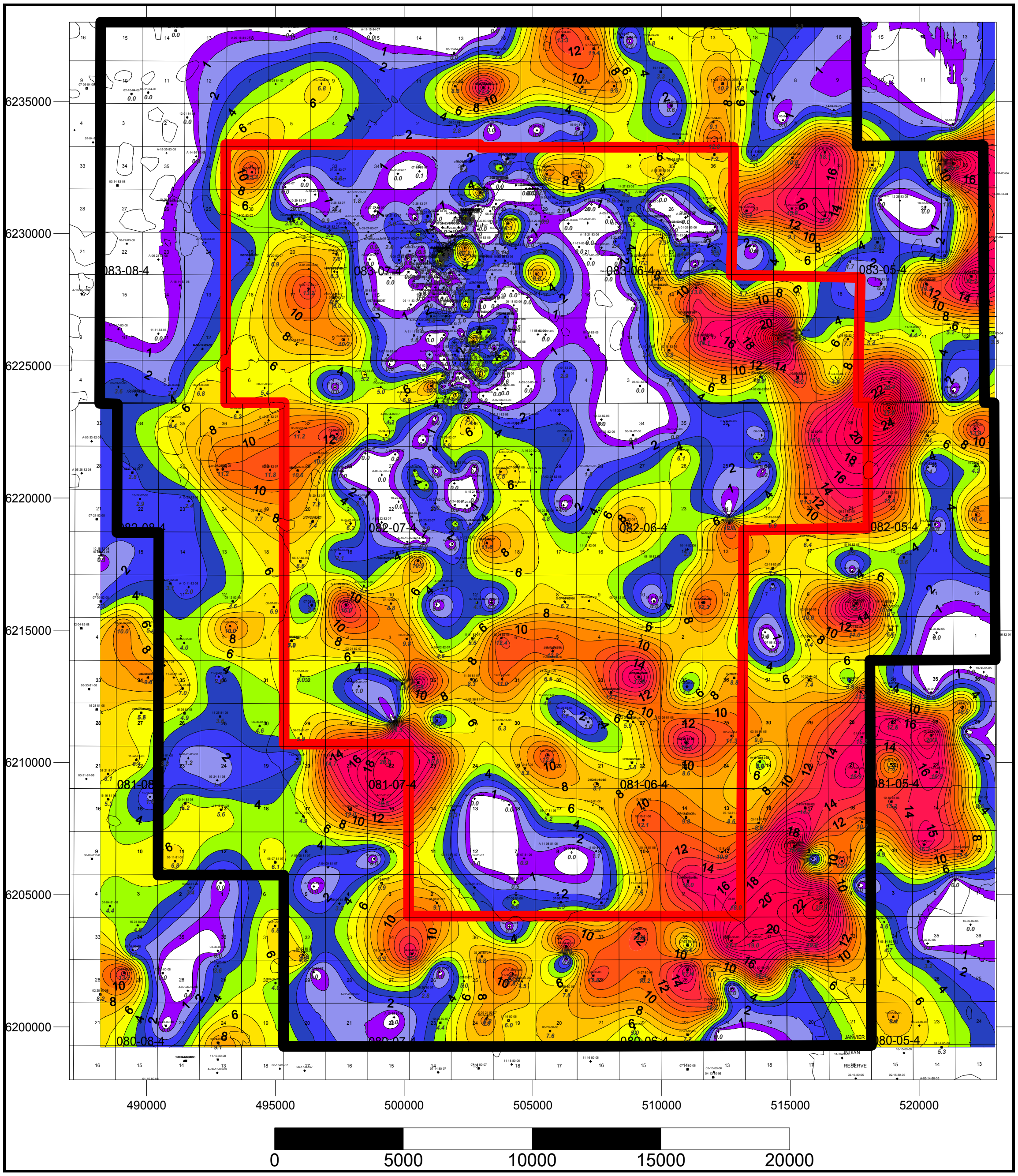


Figure ADG-1: Maximum Thickness Map of Net Gas Interval; gas-water contact defined by loss of neutron-density crossover in good sands and estimated loss of gas in shaly sands based on relative changes in water saturation and quality of reservoir. Pool boundaries are ignored for contouring purposes.

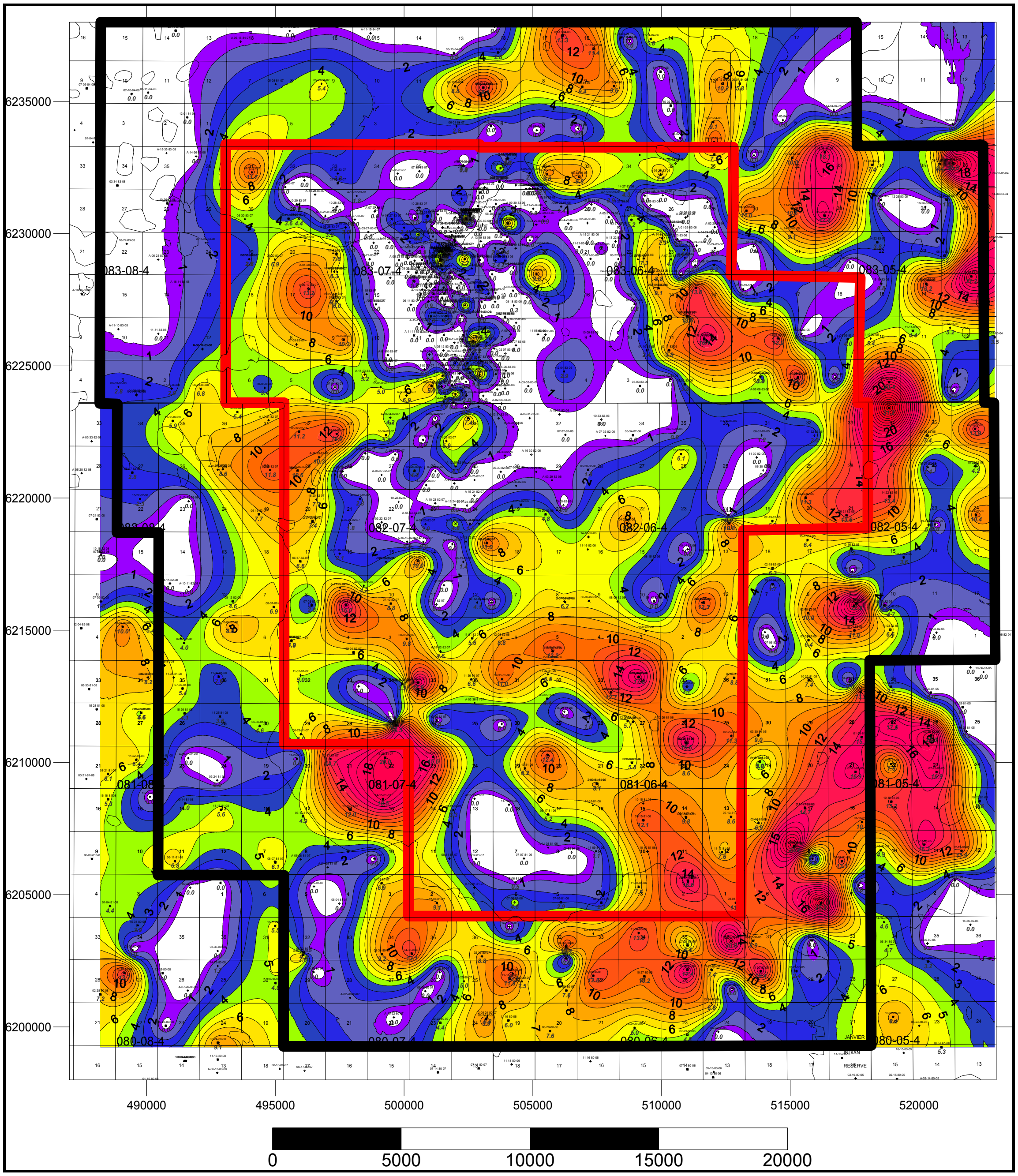


Figure ADG-2: Minimum Thickness map of Net Gas Interval; gas-water contact exclusively defined by loss of crossover on neutron-density curves. Pool boundaries are ignored for contouring purposes.

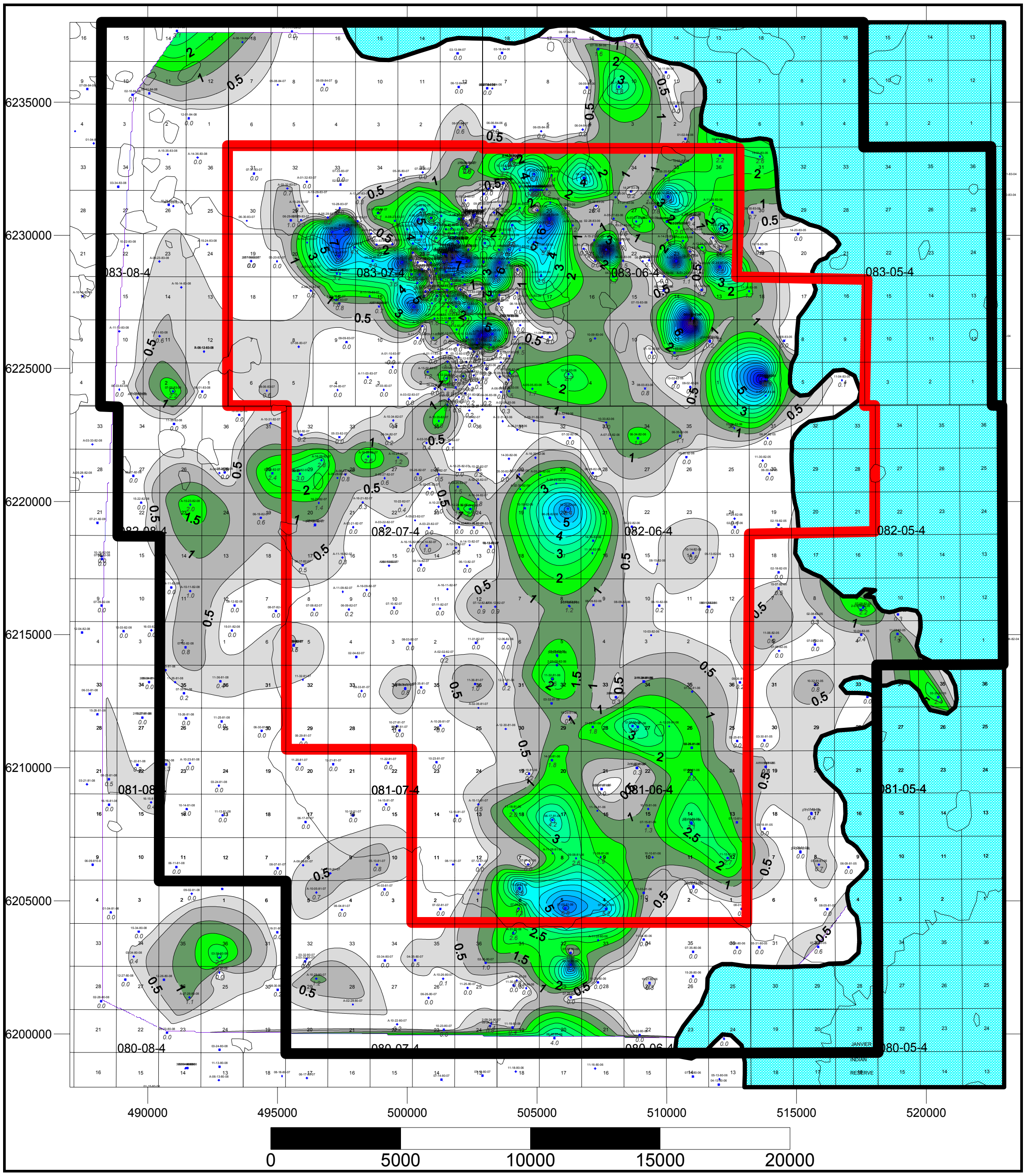


Figure ADG-3: Thickness map of Water Interval with Water Saturation of 60% or higher; Blue patterned area indicates locations with no bitumen.

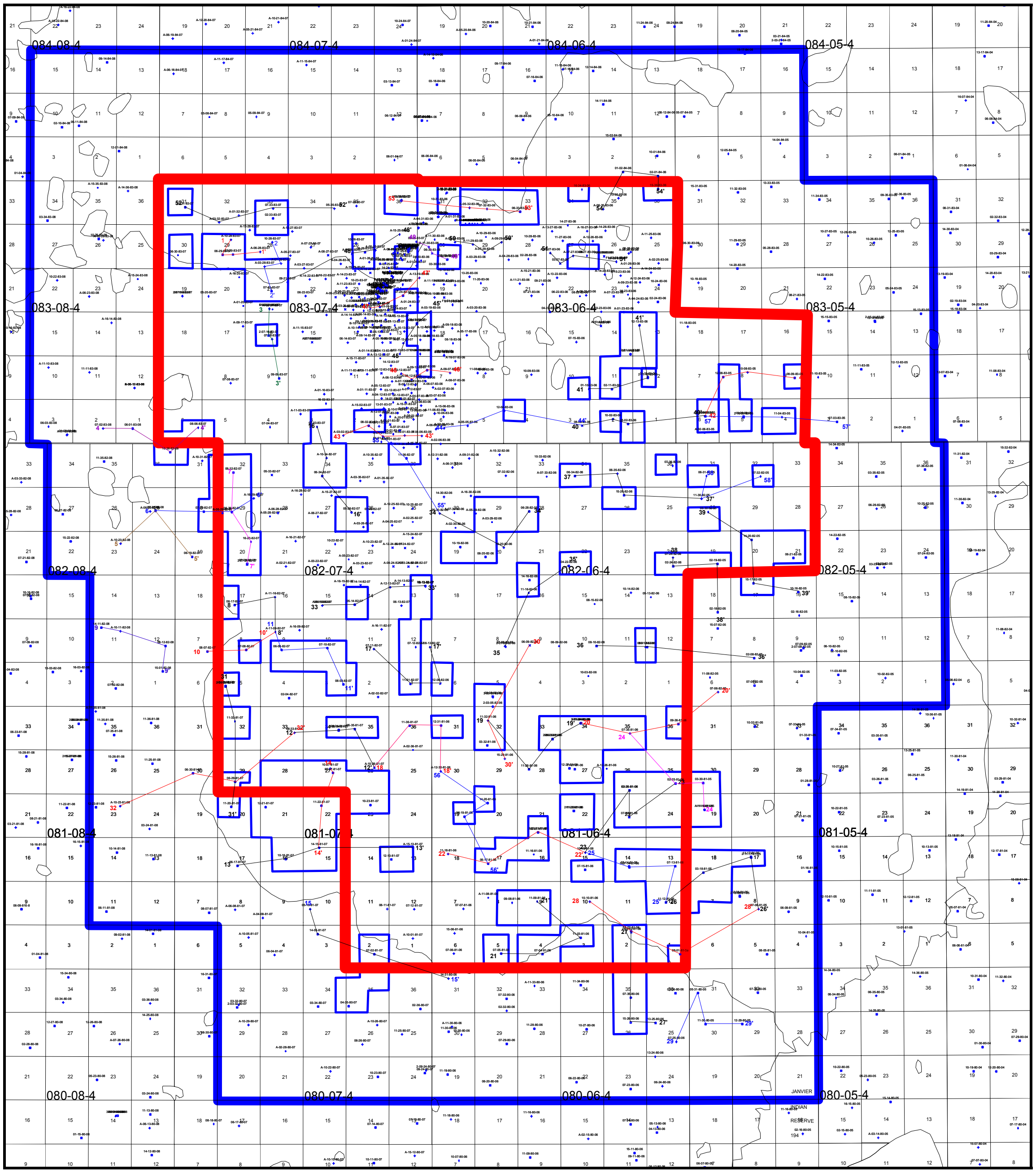


Figure ADG-4: Index Map of Pool Cross Sections; Heavy Red Line = Boundary of Simulation Area; Heavy Blue Line = Boundary of Buffer Area; Blue Boxes = Pool Boundaries from Reservoir Simulation Results.

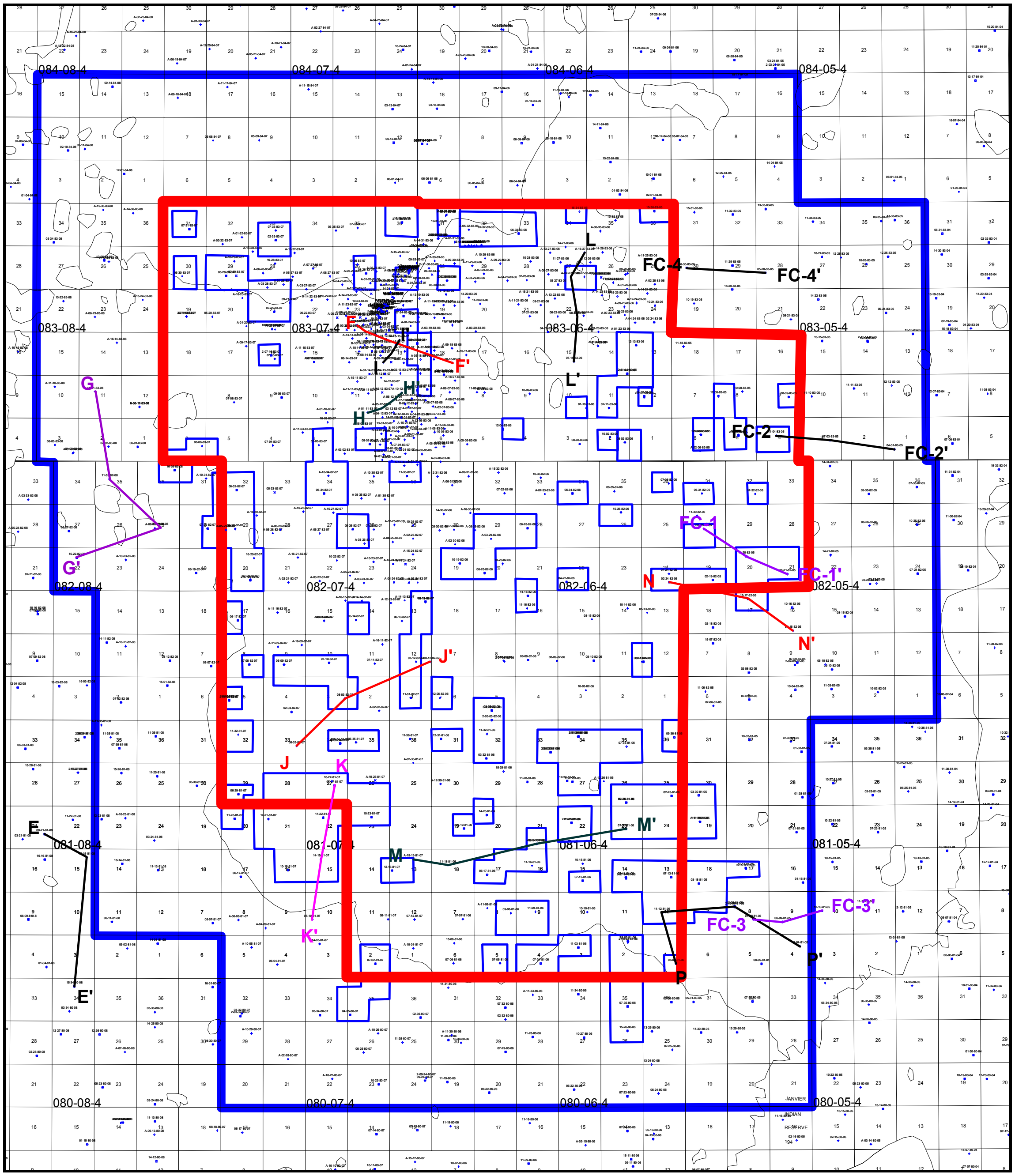
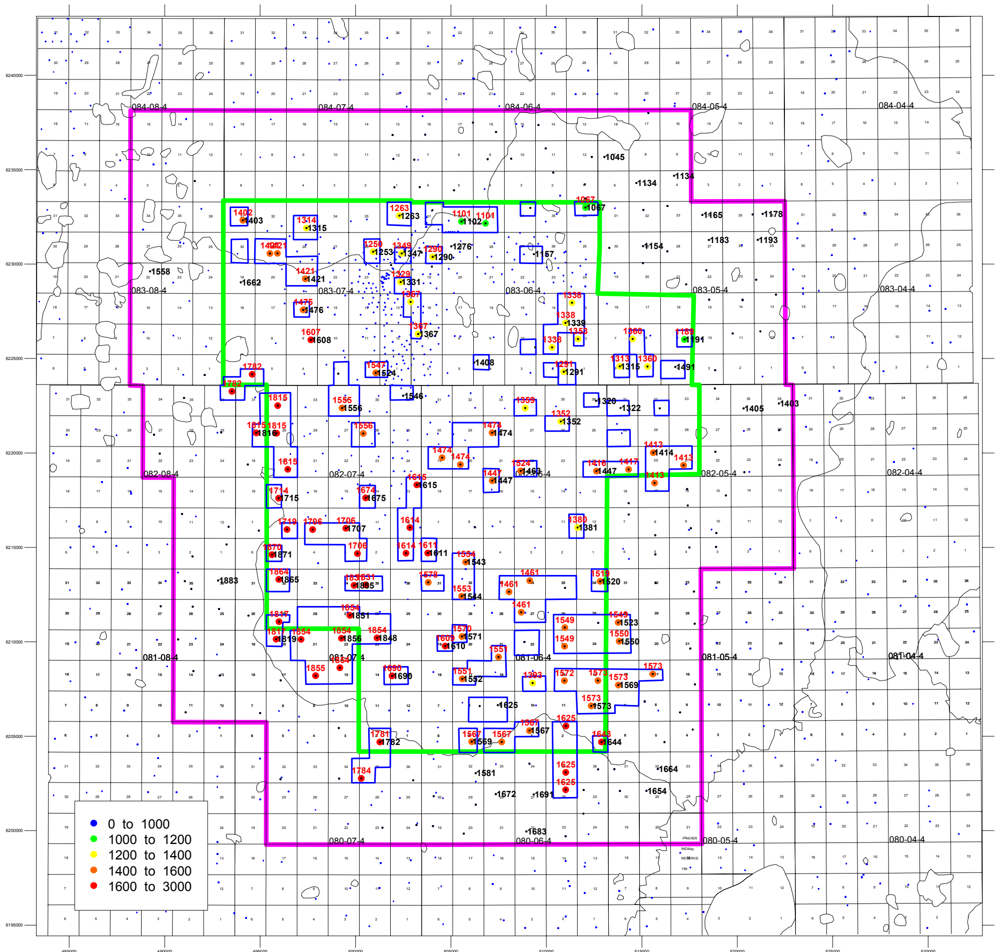
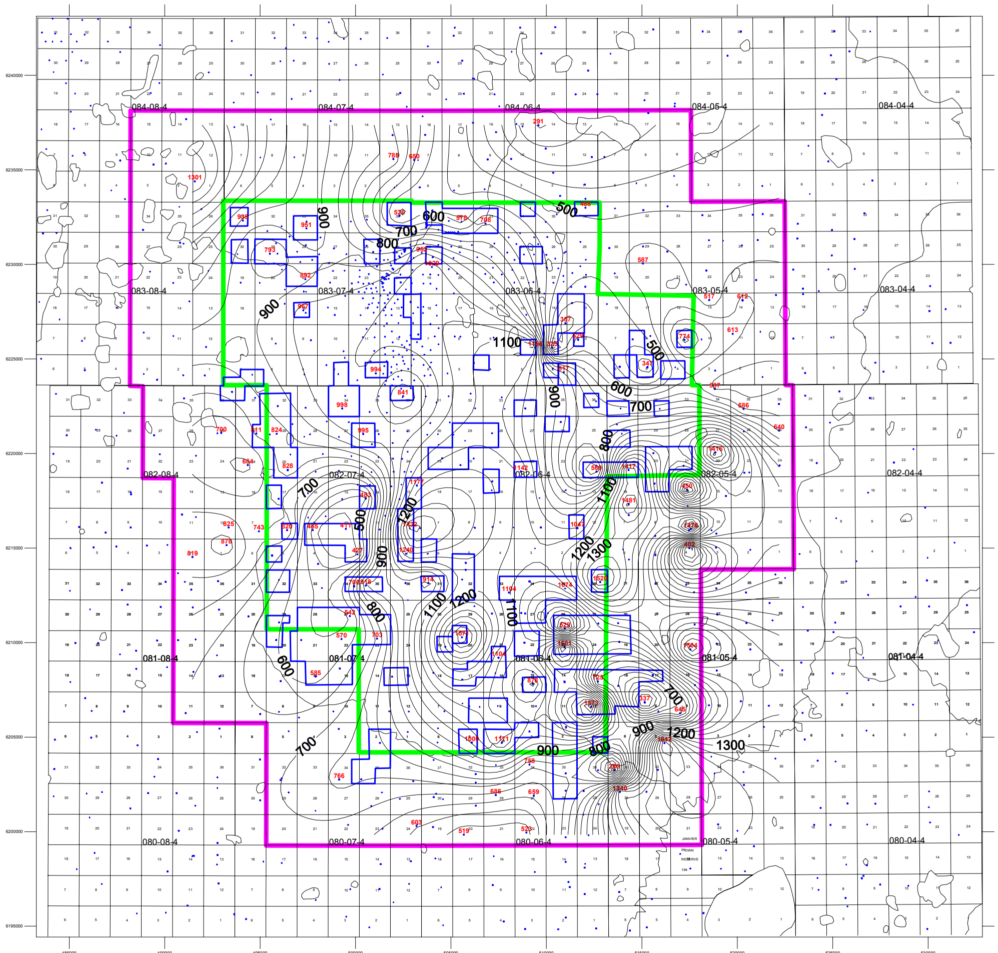


Figure ADG-5: Index Map of Non-Pool Cross Sections; Heavy Red Line = Boundary of Simulation Area; Heavy Blue Line = Boundary of Buffer Area; Blue Boxes = Pool Boundaries from Reservoir Simulation Results.



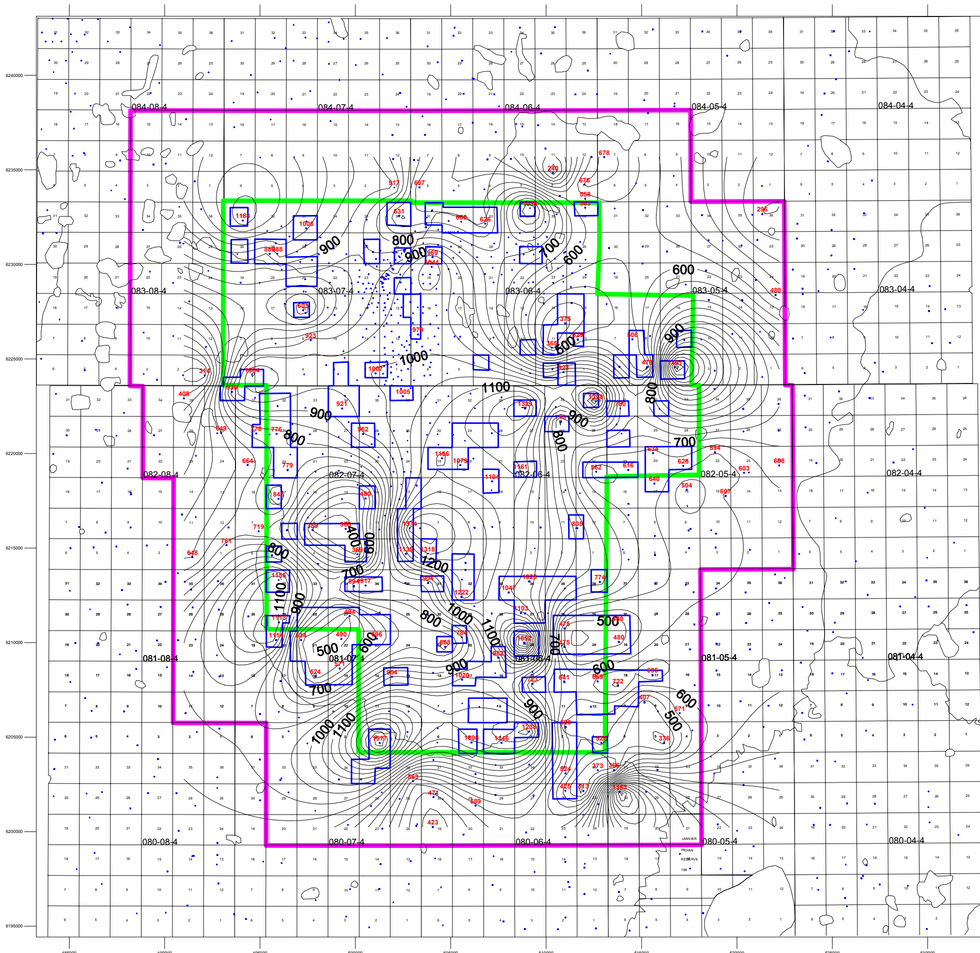
SIMULATOR INITIAL PRESSURES, kPa
JANUARY, 1986
VALID FIELD PRESSURES IN BLACK

Figure ADRS-1



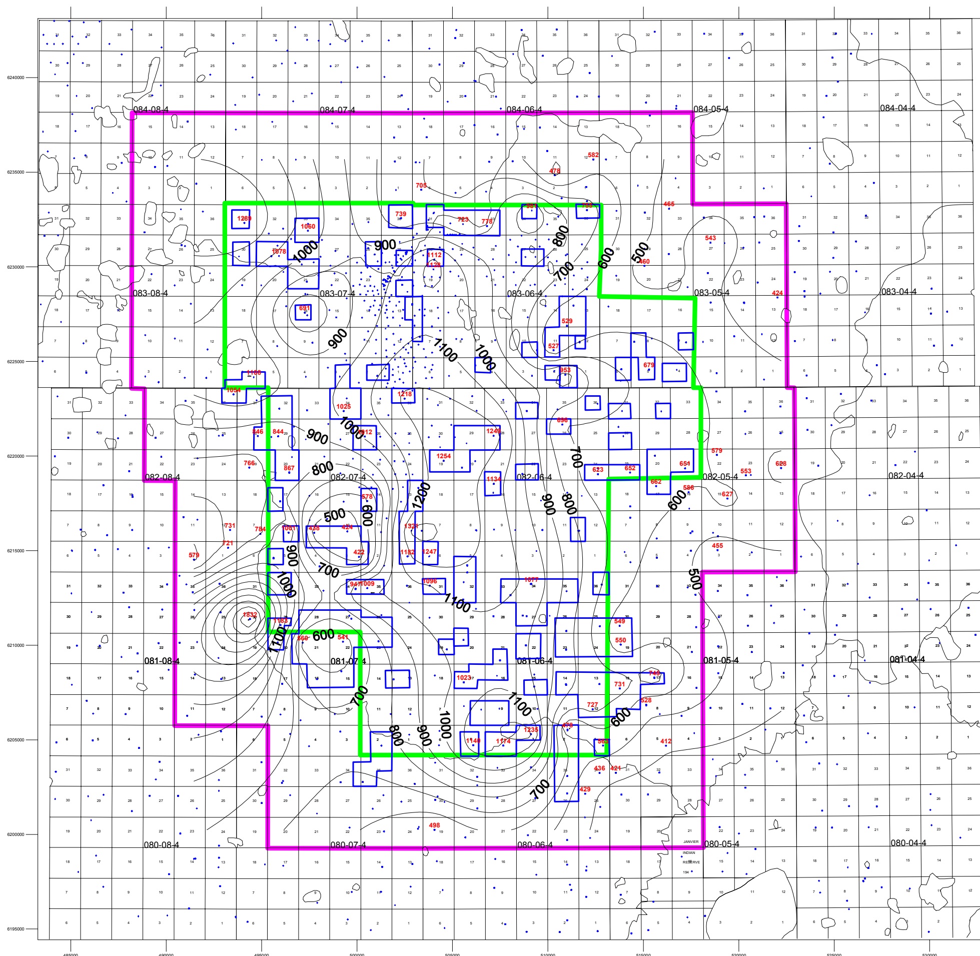
FIELD PRESSURES, kPa
1st & 2nd QUARTER, 1999

Figure ADRS-2



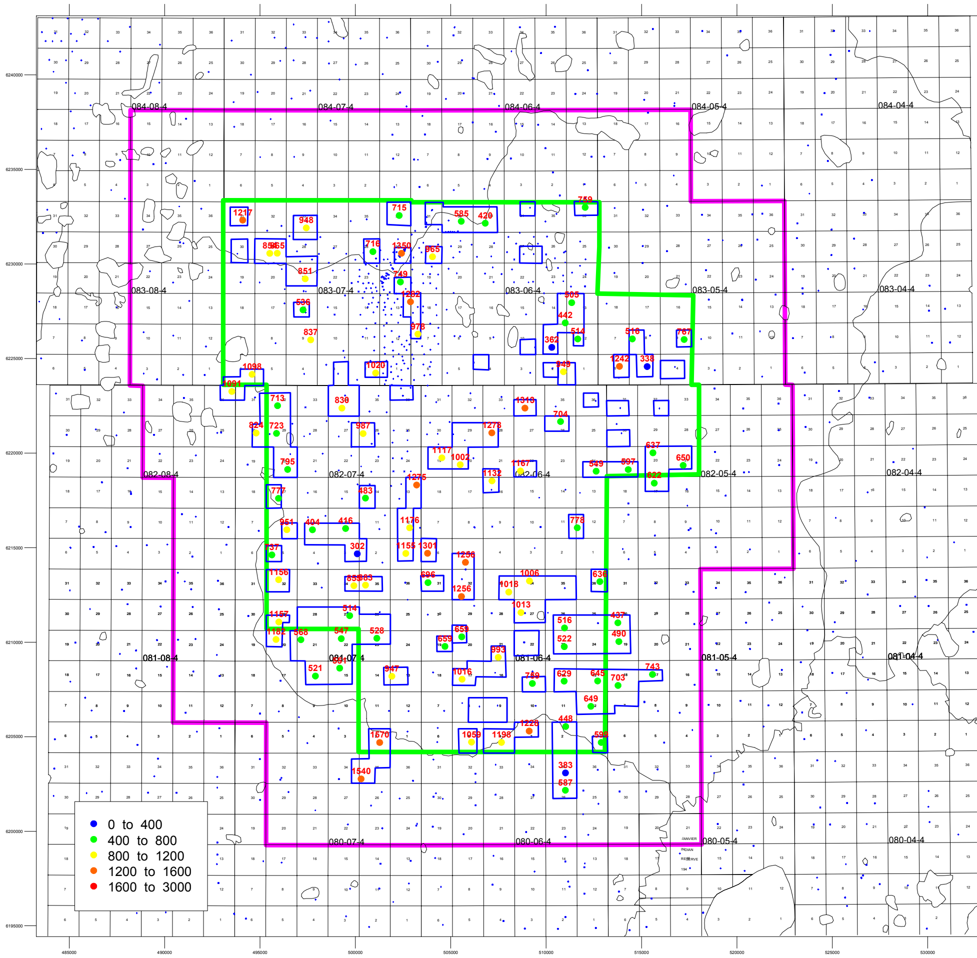
**FIELD PRESSURES, kPa
3rd QUARTER, 2000**

Figure ADRS-3



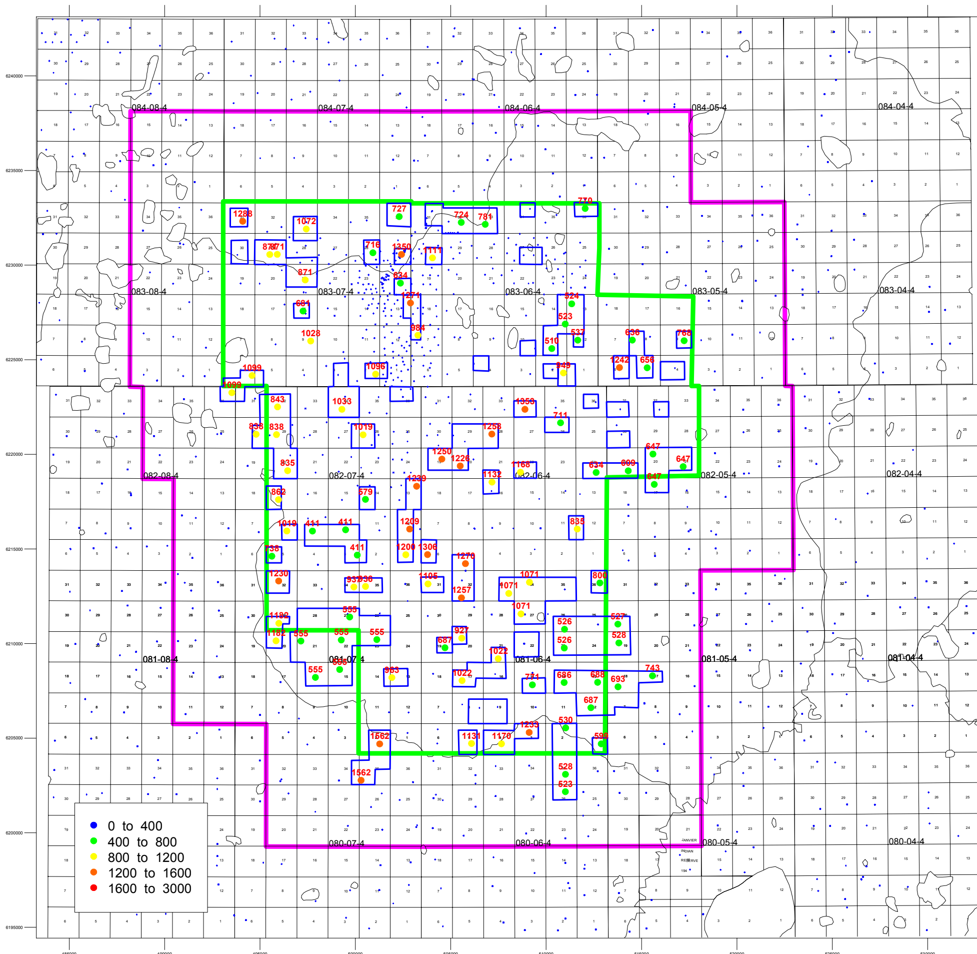
FIELD PRESSURES, kPa
LATEST VALUE 2003

Figure ADRS-4



SIMULATOR PRESSURES, kPa
APRIL, 2000

Figure ADRS-5



SIMULATOR PRESSURES, kPa
JANUARY, 2004

Figure ADRS-6

SURMONT STUDY WORKFLOW

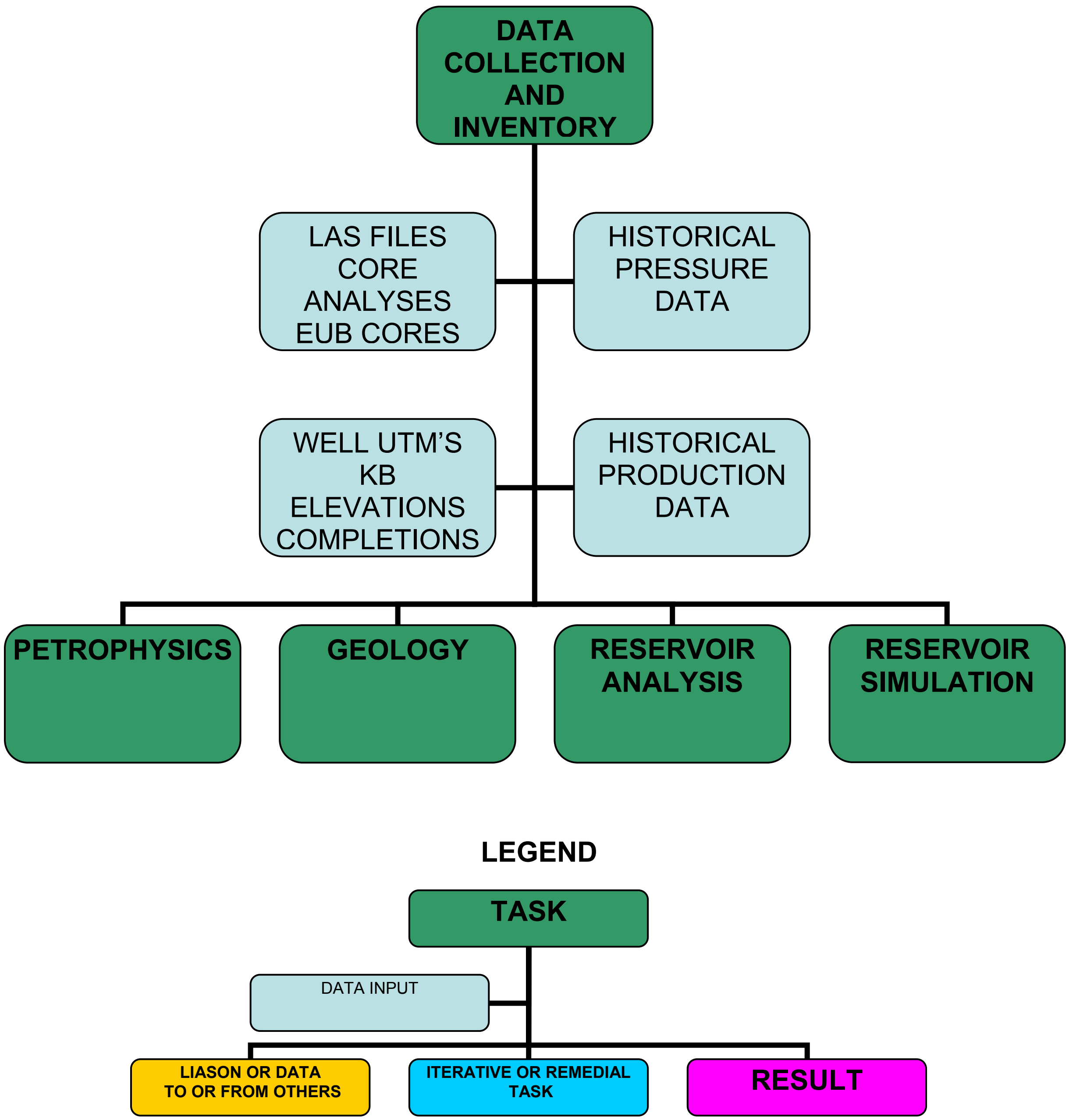


Figure ADM-1

SURMONT STUDY WORKFLOW

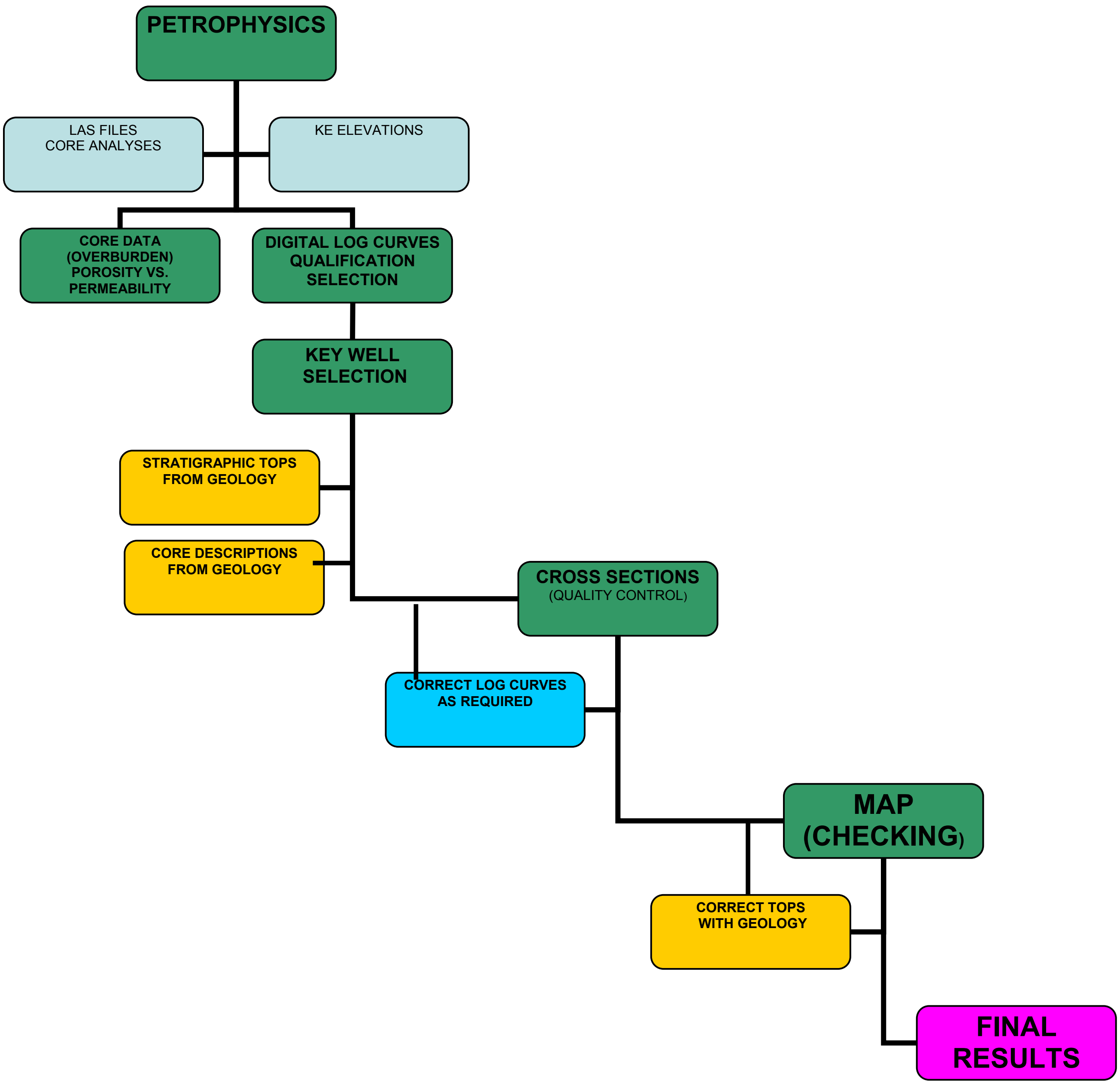


Figure ADM-2

SURMONT STUDY WORKFLOW

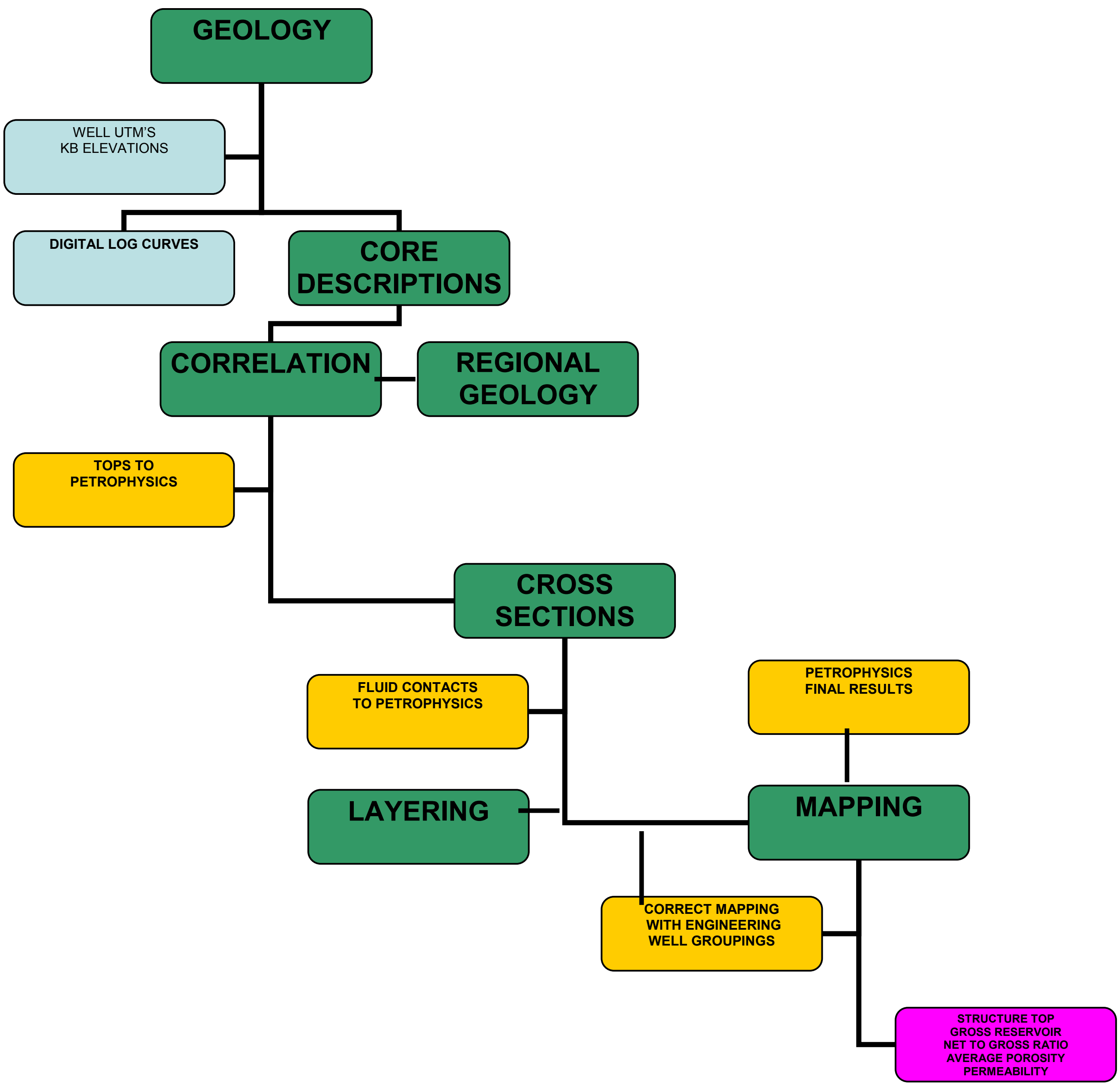


Figure ADM-3

SURMONT STUDY WORKFLOW

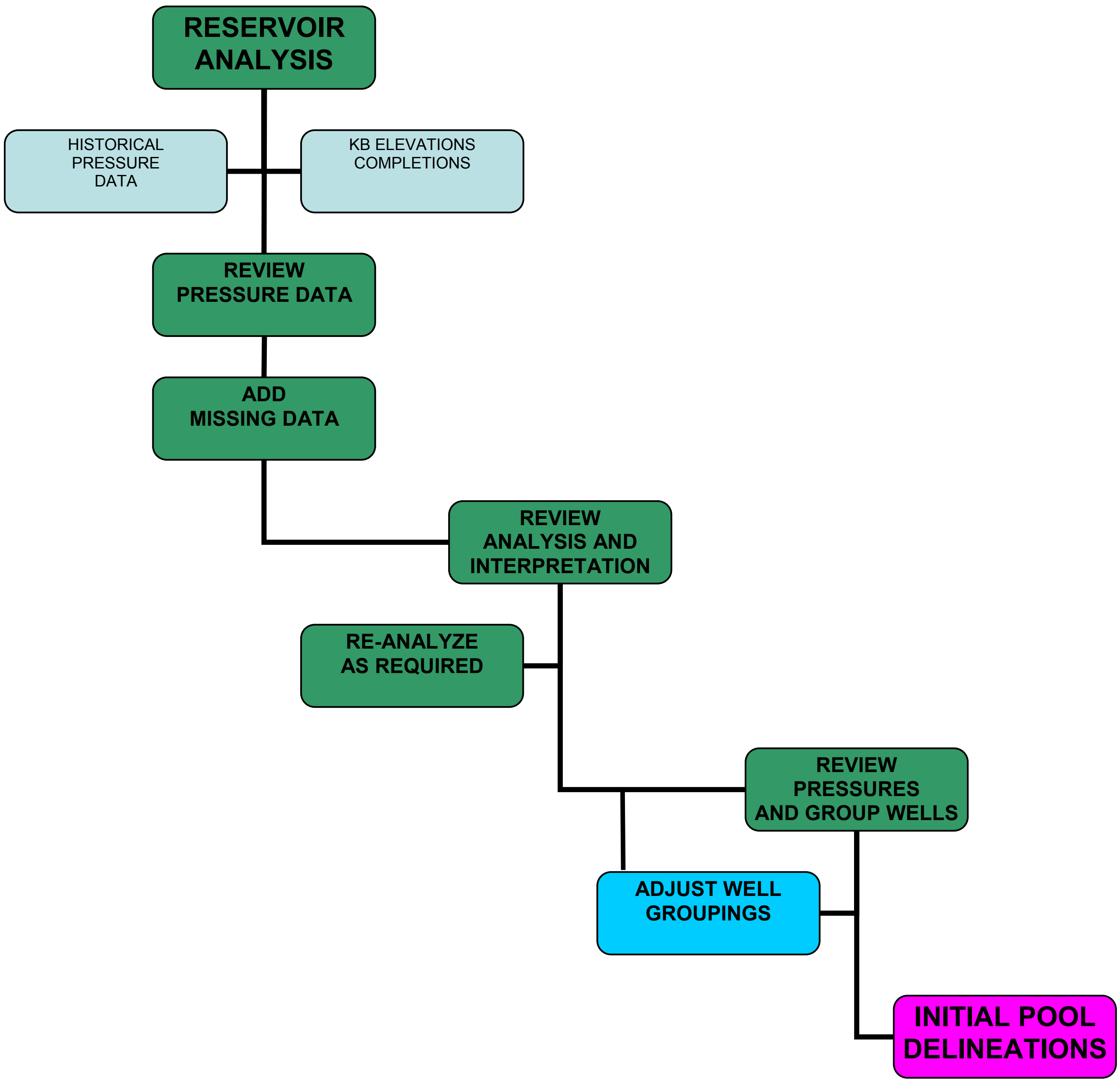


Figure ADM-4

SURMONT STUDY WORKFLOW

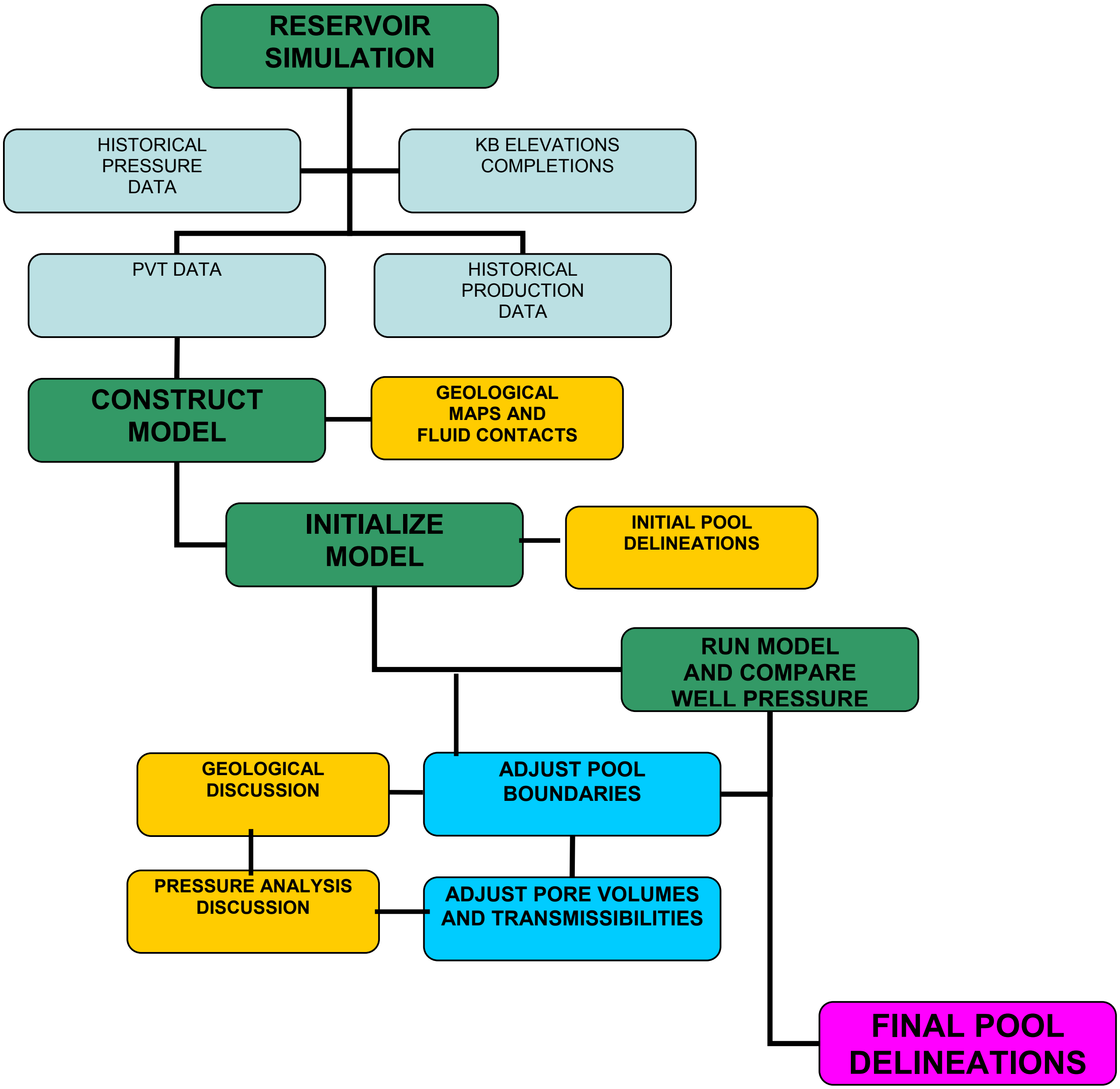


Figure ADM-5