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Early Determination of Reservoir Flow Units Using an Integrated Petrophysical Method

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Abstract

This paper uses case histories to introduce a graphical method for easily quantifying reservoir flow units based on geologic framework, petrophysical rock/pore types, storage capacity, flow capacity, and reservoir process speed. Using these parameters and four graphical tools, this paper outlines a quantitative approach to transform rock-type-based zonations into petrophysically based flow units that can be input into a numerical flow simulator. This method provides a tool for determining the minimum number of flow units to input into a numerical flow simulator that honors the foot-by-foot characteristics at the wellbore.

A flow unit is a stratigraphically continuous interval of similar reservoir process speed that maintains the geologic framework and characteristics of rock types. Rock types are representative reservoir units with a distinct porosity-permeability relationship and a unique water saturation for a given height above free water level.

The ideal data for this method is continuous core porosity, permeability, and saturation information drawn from throughout the entire reservoir. If such a data set is not available, it is necessary to calibrate wireline log data with core information to produce reliable estimates of porosity, permeability, and saturation. A full discussion of these data transforms are beyond the scope of this paper.

The four graphical tools used to determine flow units are: Winland porosity-permeability cross plot, Stratigraphic Flow Profile (SFP), Stratigraphic Modified Lorenz Plot (SMLP) and Modified Lorenz Plot (MLP).

This method begins by establishing rock types within a geologic framework. The geologic framework allows the flow units to be interpreted within a sequence stratigraphic model determining well-to-well correlation strategies. The key flow unit characteristics to be identified are barriers (seal to flow), speed zones (conduits), and baffles (zones that throttle fluid movement).

This integrated, petrophysically based method of determining flow units has been successfully used in a wide array of reservoirs. We have applied it to young, unconsolidated sediments; structurally complex naturally fractured/vuggy carbonates; low permeability "tight" formation gas sands; diagenetically altered carbonates; complex mixed lithologies; and interbedded sand-shale sequences.

The earlier in the life of a reservoir this process is used, the greater the understanding of future reservoir performance. This method allows the user to employ the least number of flow units and honor the character of the foot by foot data for simulation studies.

Key Definitions

Due to various working definitions of some of these terms in the literature, it is necessary to define the key terms used in this approach:

Rock Types

Rock/Pore Types - are units of rock deposited under similar conditions which experienced similar diagenetic processes resulting in a unique porosity-permeability relationship, capillary pressure profile and water saturation for a given height above free water in a reservoir [1].

Winland Plot[2,3] - a semi-log crossplot of permeability (mD) versus porosity (%), with isopore throat lines (R35 Ports).

R35 Ports correspond to the calculated pore throat radius (microns) at 35% mercury saturation from a mercury injection capillary pressure test. They can be calculated directly from Winland's equation (eq.1) or other equations based on permeability and porosity[4,5]. In equation 1, permeability is input in millidarcies and porosity in percent.

$$\text{Log R35} = .732 + .588 * \log(K) - .864 * \log(PHI) \quad \ldots\ldots(1)$$

Flow Units

Flow Unit - is a stratigraphically continuous interval of similar reservoir process speed that honors the geologic framework and maintains characteristics of rock types[6]

K/PHI Ratio on a foot-by-foot basis is a relative measure of reservoir process speed[7] (RPS) and is a simplified form of diffusivity, ignoring viscosity and total compressibility.

Storage Capacity - the product of porosity and thickness.
Flow capacity - the product of permeability and thickness.
Flow Unit Speed - (FUS) percent flow capacity divided by percent storage capacity.

Graphical Tools

Stratigraphic Modified Lorenz (SMLP) - a plot of percent flow capacity versus percent storage capacity ordered in stratigraphic sequence. If the data is continuous (smoothed), it should be constructed using every sample available. It offers a guide as to how many flow units are necessary to honor the geologic framework.

Stratigraphic Flow Profile (SFP) - a plot used to display flow unit interpretation containing a correlation curve (GR or VCL), a generalized core description, porosity, permeability, R35, K/PHI ratio, percent storage capacity and percent flow capacity.

Modified Lorenz Plot (MLP) - a plot of flow capacity versus storage capacity that is computed on a flow unit basis and maintains stratigraphic position. This plot is unlike the original Lorenz Plot[8] in that it preserves the stratigraphic information.

An Overview of the Procedure

The continuing effort to optimize information about a reservoir from small sample data sets[9,10] (routine and special core analysis, cuttings, photos, descriptions, and wireline data) has resulted in an upscaling process carried forward to reservoir performance simulation. This process uses techniques well-documented in the literature, plus a new application introduced in this paper. Flow units determination is presented using a series of cases with increasing reservoir complexity.

Managing the data sequentially to optimize its value is very important. Five critical steps, if followed, will result in flow units that honor the geologic framework, maintain the foot-by-foot character of the data, and can be used for numerical flow simulation. The procedure is:

1. Identify rock types and illustrate on a Winland porosity permeability cross plot.
2. Construct an SMLP by computing on a foot-by-foot basis the percent flow capacity (permeability thickness) and percent storage capacity (porosity thickness).
3. Select preliminary flow unit intervals based on inflection points from the SMLP. These preliminary flow units must be verified using the SFP, geologic framework, R35 curve and K/Phi ratio.
4. Prepare final SFP with correlation curve, porosity, permeability, K/Phi ratio, R35, percent storage capacity and percent flow capacity curves
5. Construct an MLP by ordering final flow units in decreasing flow unit speed (FUS), and interpret significance of flow units.

Case Study 1 Platten Dolomite

The Platten Dolomite illustrates these techniques with real field data. The Platten Dolomite is a 45 meter thick member of the Zechstein Group, which forms important gas reservoirs in the southern part of the North Sea Permian Basin. Reservoir facies deposited in shallow water are controlled by depositional energy overprinted by diagenetic processes. The Platten was deposited as a series of shoaling carbonate cycles which typically begin with a trangressive mudstone unit. As carbonate production filled the available accommodation space, skeletal-peloidal wackestones, peloidal packstones and peloidal and oolitic grainstones were deposited. Three nearly complete cycles or parasequences are identified (Figure 1 core description), and these form the basic building blocks of the Platten reservoir.

Depositional texture generally controls porosity and permeability. However, this straightforward relationship can be partially obscured by diagenesis, mainly anhydrite cementation destroying reservoir quality in some high-energy grainstones and fractures enhancing permeability in some lower-energy packstone and wackestone units.

Despite these exceptions, three petrophysical rock types are identified in the Platten Dolomite (Figure 2). Rock Type 1, oolitic grainstones with well-developed intercrystalline and oomoldic pore systems, form the best reservoirs, with porosity ranging from 10% to 30% and permeability ranging from 20 mD to over 1000 mD (Figure 2). In contrast Rock Type 3, mudstone units, typically has lower porosity (7% to 22%) and much lower permeability (.1 mD to 10 mD) due to the smaller dolomite crystal size. Rock Type 2 is difficult to distinguish due to partial overlap with rock types 1 and 3. It consists of packstone and wackestone facies with intermediate reservoir quality. Calculated R35 values for Rock Type 1 (oolite grainstones) are 5 to over 20 microns, Rock Type 2 R35 values are 2 to 10 microns and Rock Type 3 is less that 2 microns.

After identification of rock types, flow units are defined to upscale this geological and petrophysical description for reservoir simulation. Our suggested method for defining flow units requires interpretation of three related plots. First, the SMLP of percent storage capacity (%PhiH) versus percent flow capacity (%KH) is made for the reservoir interval using continuous (foot-by-foot) core porosity and permeability (Figure 3) or log derived porosity and predicted permeability. For introducing of these concepts, we are ignoring the effect water saturation has in reducing storage capacity. In practice, ignoring saturation is very dangerous.

The shape of SMLP curve is indicative of the flow performance of the reservoir, and the final flow units should retain this character (Figure 4). Segments with steep slopes have a greater percentage of reservoir flow capacity relative to storage capacity, and by definition, have a high reservoir process speed. They are called speed zones. Segments with flat behavior have storage capacity but little flow capacity and are typically reservoir baffles if laterally extensive. Segments with neither flow nor storage capacity are seals, if laterally extensive. Preliminary flow units (speed zones, baffles and seals) are interpreted by selecting changes in slope or inflection points (Figure 3).

The SFP (Figure 1) refines the flow units as intervals with relatively consistent K/Phi ratio. This dimensionless ratio related directly to R35, is an excellent tool for identifying potential barriers, baffles, and speed zones. After the flow units have been refined, the percent flow and storage capacity are calculated for each unit. Figure 4 displays the refined flow unit interpretation and the continuous Stratigraphic Modified Lorenz data. It is important that the final flow unit interpretation retains the shape of the raw data. In the case of the Platten Dolomite at least nine flow units are required.

The SFP (Figure 1) illustrates the relationship between reservoir process speed (K/Phi), reservoir quality (R35), the stratigraphic framework and log response. This plot is the basis for correlating flow units to offset wells within a sequence stratigraphic framework to build a three dimensional flow unit reservoir description for simulation.

The final plot for understanding flow unit performance is the MLP (Figure 5). To create it, the previously defined flow units are sorted and plotted in decreasing flow unit speed (FUS). In this case Figure 5 illustrates the importance of Flow Unit 5. This flow unit has the highest K/Phi ratio and the MLP clearly shows it accounts for 49% of the Platten flow capacity while it has only 10% of the storage capacity. This speed zone is composed primarily of Rock Type 1 (oolitic grainstone). It is critical to identify and map this flow unit to predict performance of the Platten Dolomite. Flow units 2, 4, and 6 all have the same flow unit speed and collectively contribute 35% of the flow capacity and 33% of the storage capacity. Flow Units 3, 7, and 9 are baffles accounting for over 35% of the Platten storage capacity and less than 10% of the flow capacity. These flow units correspond to Rock Type 3, mudstones. Flow Unit 1 is a anhydrite seal contributing neither flow or storage capacity.

Case Study 2 Cherry Canyon Sandstone

In the second more complex case, the Cherry Canyon Sandstone produces oil in numerous, small (< 5 MMBO) fields in the Delaware Basin of West Texas and New Mexico. This Late Permian sandstone was deposited as part of a lowstand basin-filling clastic sequence. Interpreted depositional environments are deep-water slope or basin-floor channels and associated levee overbank environments. Traps are combination structural-stratigraphic. Channels form the critical element of the trap in addition to the reservoir. Channel sands which are massive with occasional floating clasts and fluid escape structures, are interpreted as sandy debris flows or Bouma A deposits. Overbank deposits are thinly bedded, very-fine grained sand or silt interpreted as distal turbidites. Typically they are poor quality to non-reservoir quality rock. Also interbedded with these terrigenous clastics are basinal limestones, which are non-reservoir quality rock.

Rock Types 1, 2, and 3 defined by core and thin section observations reveal a unique porosity-permeability relationship (Figure 6) and capillary pressure profile. Rock Type 1 is massive, very-fine grained sandstone, with porosity ranging from 18% to 25% and permeability ranging from 3 mD to 60 mD. Calculated R35 values vary from 1 micron to nearly 4 microns, centering at 2 microns (Figure 6). Rock Type 2 is thin-bedded, very-fine grained sandstone and silt with flat or ripple laminations and occasionally extensively bioturbated. Porosity ranges from 8% to 18%, and permeability ranges from .1 mD to 10 mD. Calculated R35 values range from 2 microns to less than .5 microns. Rock Type 3 is basinal limestone and silty shale. Porosity is less than 10%, permeability is less than .1 mD, and calculated R35 values are less than .5 microns.

Flow units are defined using methodology similar to that in the previous example. The continuous SMLP (Figure 7) reveals speed zones, baffles and seals. This Cherry Canyon Sandstone example is more homogeneous than the previous Platten Dolomite example. Despite this, eight flow units are defined and verified with the SFP and SMLP (Figure 8 and 9). It is important that the final flow unit interpretation retains the shape of the continuous data; in this case, at least eight flow units are required.

Flow Unit 4 is a speed zone containing 37% of the flow capacity and 22% of the storage capacity (Figure 10). Flow Unit 1 is a baffle or seal containing no flow capacity and very little storage capacity. Flow Units 2, 6, and 8 are thin but laterally continuous baffles, which are important to quantify in reservoir simulation.

In this discussion, permeability has been single-phase air permeability. To simulate insitu reservoir permeability, air permeability should be adjusted for stress corrections to the appropriate reservoir conditions and hydrocarbon permeability with a connate water saturation. If these data are available, corrections to the air permeability are recommended. If these data are not available, it is strongly recommended that air permeability be calibrated to reservoir conditions with pressure transient analysis (PTA).

PTA flow capacity (total KH) is considered most representative of average reservoir permeability. Flow units based on air permeability are calibrated by equating total air permeability KH to total PTA KH and distributing the flow capacity according to the relative percentages for each flow unit. This calibration step is illustrated for the Cherry Canyon Sandstone as follows:

The total air permeability, KH, for the Cherry Canyon core is 1788 mD-ft. Adjusting for stress and K_{oil} at Swi results in a total KH of 813 mD-ft. Based on PTA of a build-up test, the total KH for the reservoir is 366 mD-ft. This is accepted as the best estimate of reservoir total KH. Each flow unit is adjusted by the %KH so that the total system permeability matches the PTA interpretation and each flow unit retains its relative importance. These adjusted flow units are now ready for simulation.

This logical sequence assumes that the PTA and core data are measuring similar properties. In most cases, this is a safe assumption; however, in some reservoirs, particularly naturally fractured reservoirs, core data and PTA tests may be sampling permeability of different scales. In cases such as this, there may be no good way to partition PTA KH.

A Schematic Two Well/Two Flow Unit System

Numerical flow simulation is used in a simple schematic approach to verify the anticipated well performance from flow unit analysis. A simplified two well/two flow unit case follows (Figure 11).

The reservoir was modeled as a dry gas (gas gravity 0.58) on 640 acre spacing and produced at a constant wellhead pressure of 1500 psi. Initial reservoir pressure was set at 5200 psi. The simulation was completed using an in-house multiwell, multi-dimensional, single-phase simulator. The petrophysical flow unit data is summarized in Table 1.

	H (ft)	Phi (%)	K (mD)	K/Phi	KH (mD/Ft)	PhiH	%PhiH	%KH	R35 μ	FUS
Well A										
Unit 1	20	25	100	400	2000	5	24	93	5	3.9
Unit 2	80	20	2	10	160	16	76	7	.5	.09
Total	100				2160	21	100	100		
Well B										
Unit 1	80	25	100	400	8000	20	83	99	5	1.19
Unit 2	20	20	2	10	40	4	17	1	.5	.05
Total	100				8040	24	100	100		

Table 1 Flow Unit model input.

Well A and B both have the same pay thickness of 100 ft; however, the distribution of zone thickness, storage capacity, and flow capacity are significantly different (Figure 12 and 13). The difference in flow and storage capacity is the key to understanding well performance. The flow unit speed (FUS) relates the differences of percent flow to storage capacity in the wells because the K/Phi ratio and R35 for both zones are equal.

The anticipated performance difference can be qualitatively predicted from the MLP (Figure 14). Well A should have a steep/sharp decline period that is relatively short. Unit 1 accounts for 93% of the flow capacity and 24% of the storage capacity. Therefor, the long-term performance of Well A should be dominated by Unit 2 with its long shallow decline period of nearly constant production. Unit 2 contains 76% of the storage capacity and 7% of the flow capacity.

Well B anticipated performance from MLP (Figure 14) should be a steady decline period due to its Unit 1 containing 99% flow capacity and 83% of the storage capacity. This zone will dominate. A short period of late pressure support can be expected at low rates as Unit 2 accounts for 1% of the flow capacity and 17% of the storage capacity.

Figure 15 (Well A) and Figure 16 (Well B) show the simulated performance curves with well rate vs. time, flow unit performance, and cumulative gas produced. The simulation indeed verifies the anticipated results.

Obviously these simplified cases do not contain the complexity of multiphase flow or complex reservoir fluids. But, they do show that an understanding of flow unit distribution can predict differences in well performance. The earlier in the life of a reservoir that flow unit distribution is understood the greater the insight into how to manage the hydrocarbon resources.

Conclusions

This method works for estimating production potential and conducting scoping studies in the early stages of Production New Ventures (PNV) and Exploration New Ventures (ENV) because it allows modeling various sensitivities that sometimes are overlooked. Integrating flow potential to encompass flow capacity, storage capacity, flow units, rock types and the geologic framework is a major improvement over using the traditional net pay method. The integrated approach produces more informed decision than traditional methods.

The methodology, parameters, and tools, though simple, are quite powerful and can be used in almost every reservoir type.

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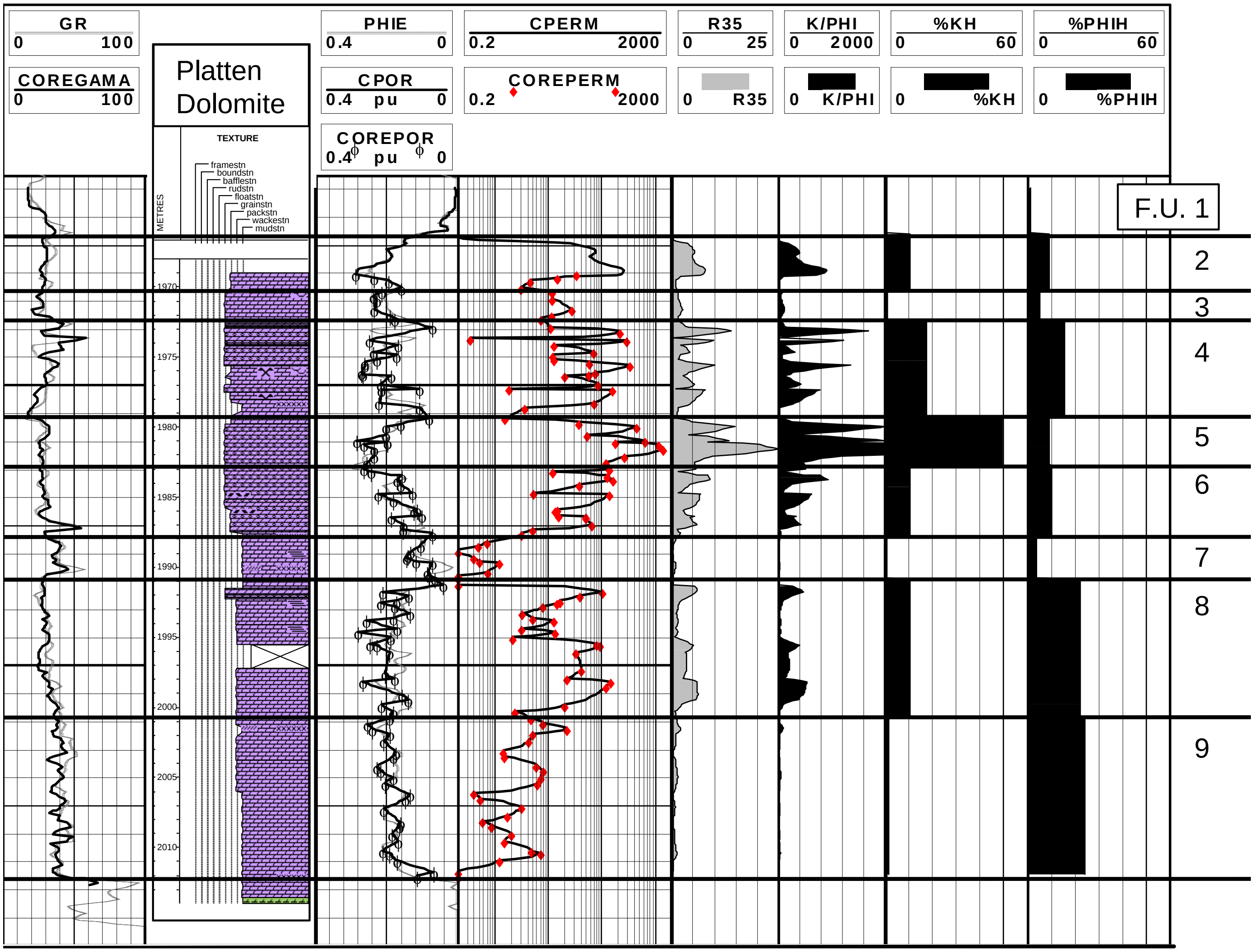

Figure 1: Platten Dolomite Stratigraphic Flow Profile (SFP)

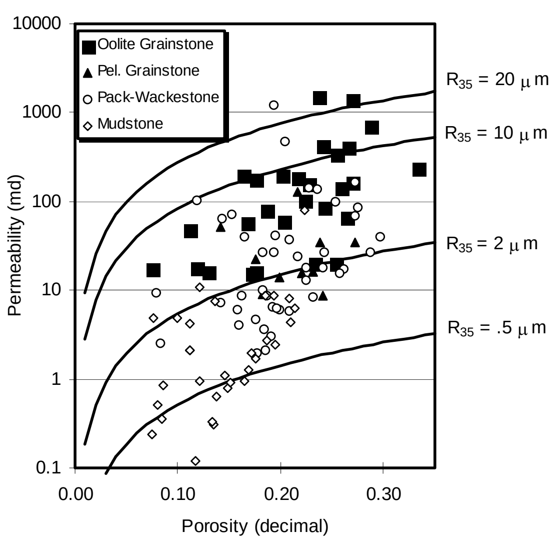

Figure 2: Winland Porosity-Permeability Plot Platten Dolomite

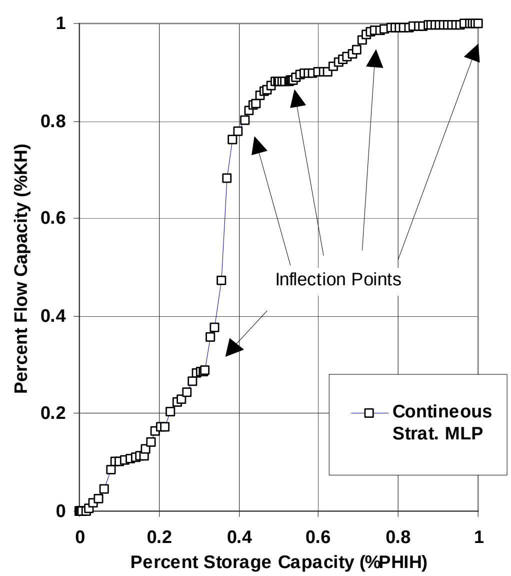

Figure 3: Platten Dolomite Uninterpreted Stratigraphic Modified Lorenz Plot (SMLP).

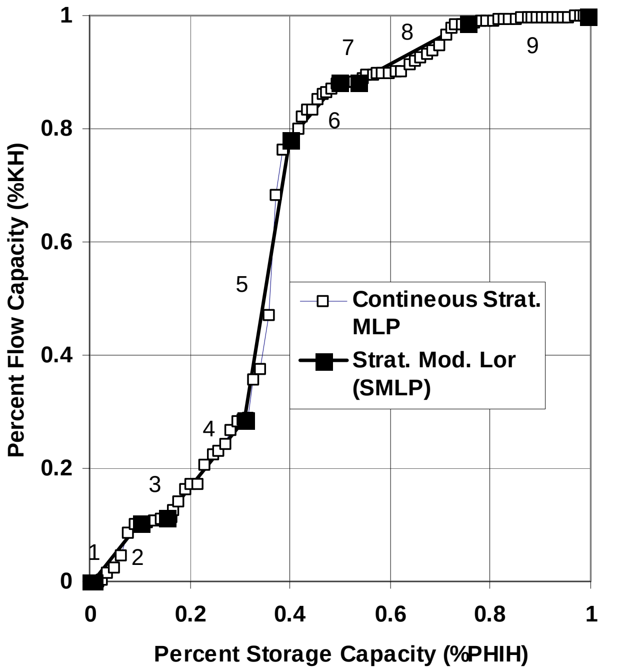

Figure 4: Interpreted continuous Stratigraphic Modified Lorenz Plot (SMLP) Platten Dolomite.

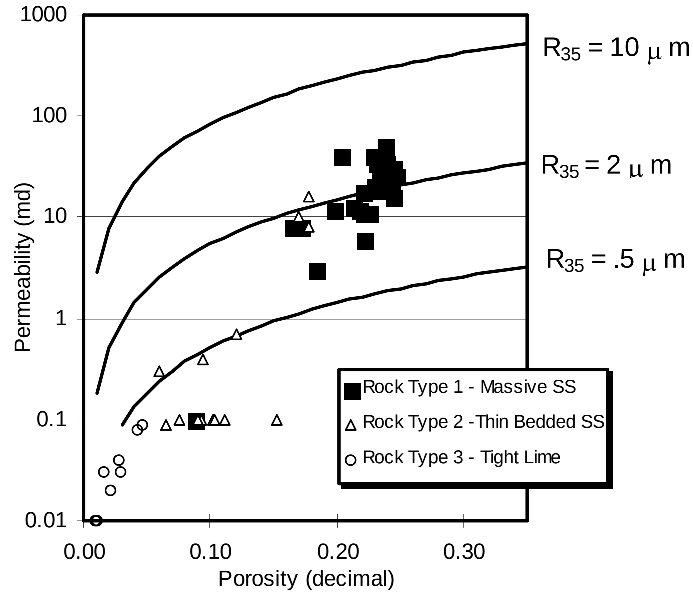

Figure 6: Winland Porosity-Permeability Plot, Cherry Canyon Sandstone. Porosity and Permeability data from whole core analysis. Rock Types based on core and thin section description.

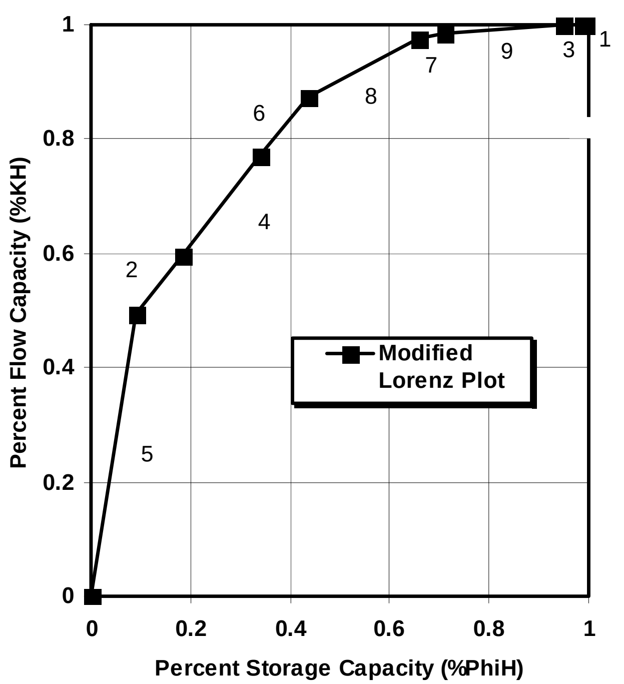

Figure 5: Platten Dolomite, Modified Lorenz Plot (MLP).

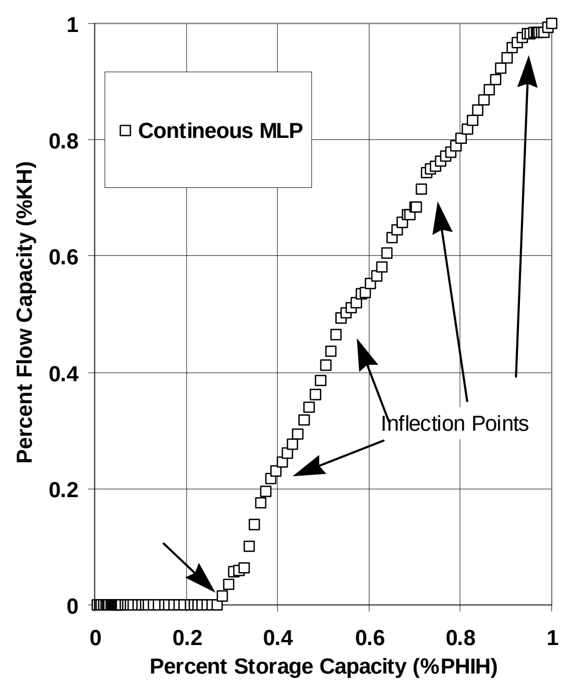

Figure 7: Uninterpreted continuous SMLP Cherry Canyon Sandstone

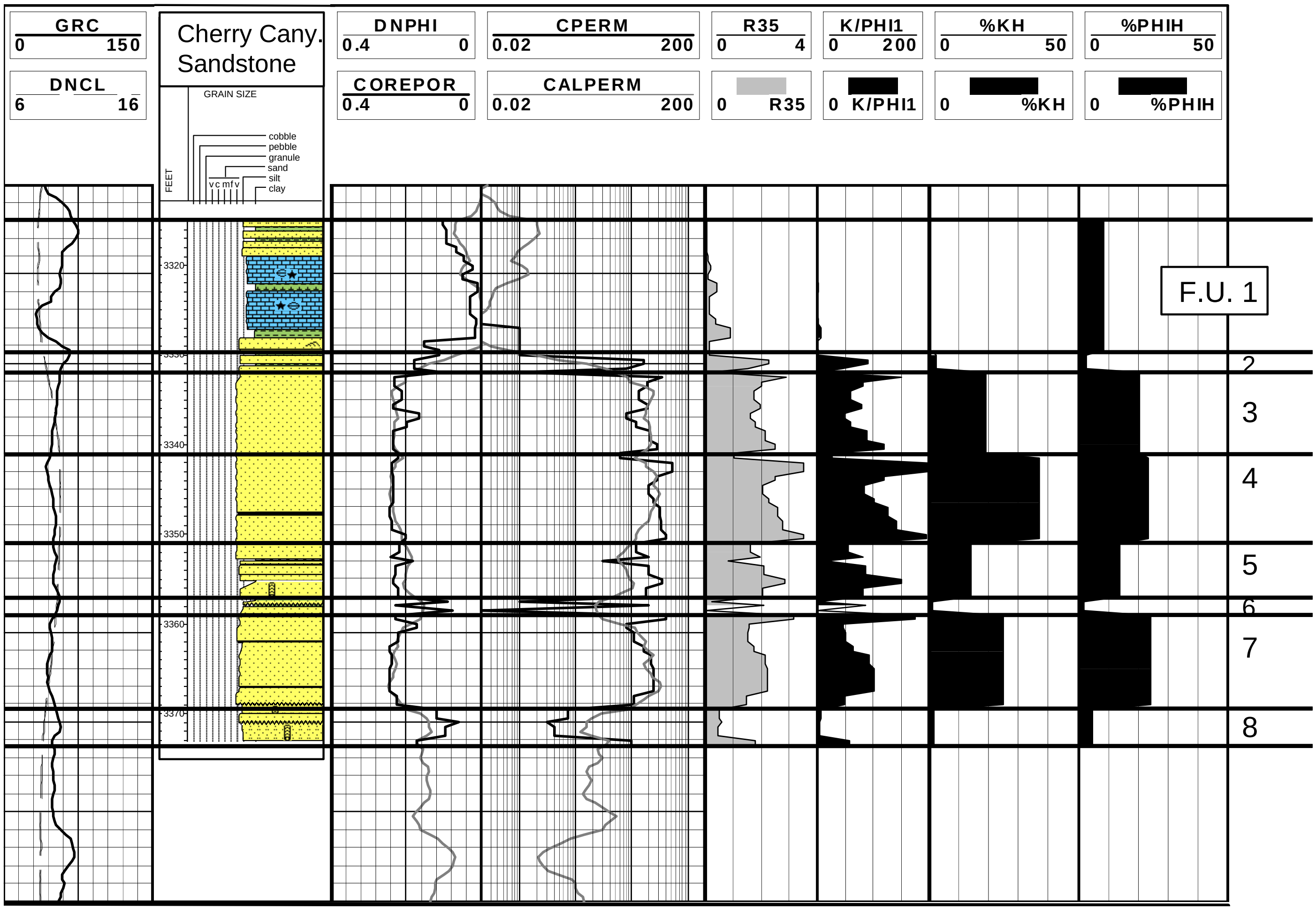

Figure 8: Cherry Canyon Sandstone Stratigraphic Flow Profile

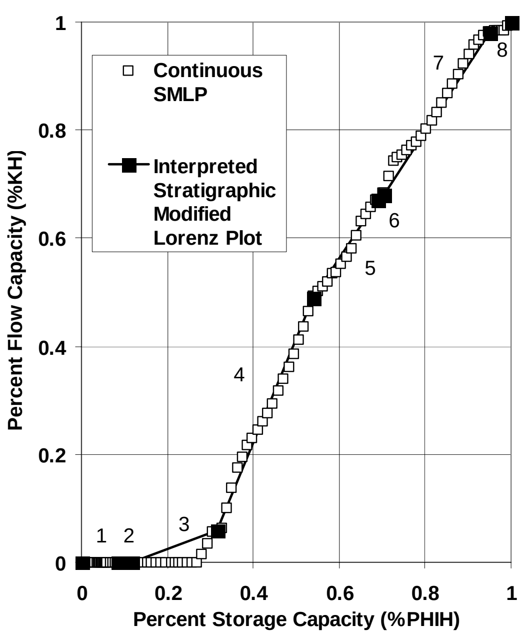

Figure 9: Interpreted SMLP Cherry Canyon Sandstone

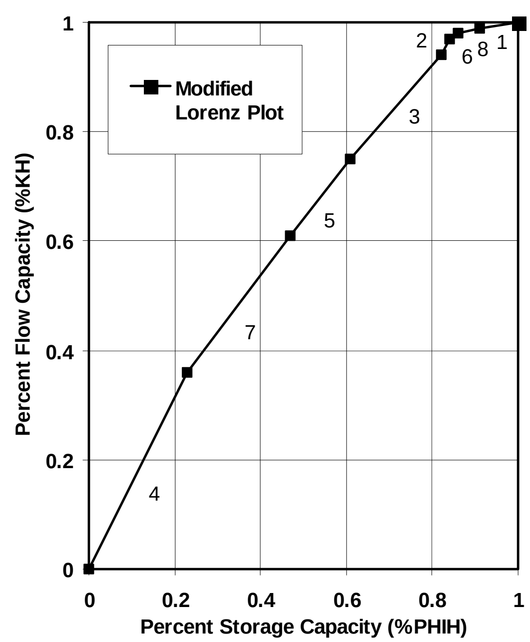

Figure 10: MLP Cherry Canyon Sandstone

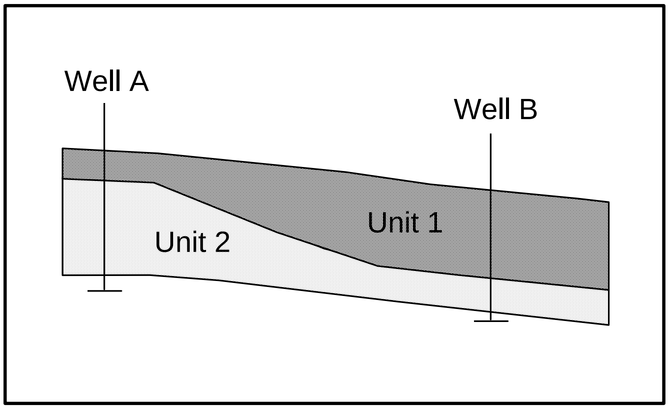

Figure 11: Schematic Two well/Two layer model.

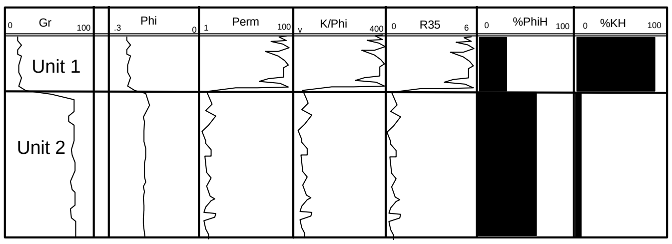

Figure 12: Schematic Stratigraphic Flow Profile (SFP) Well A

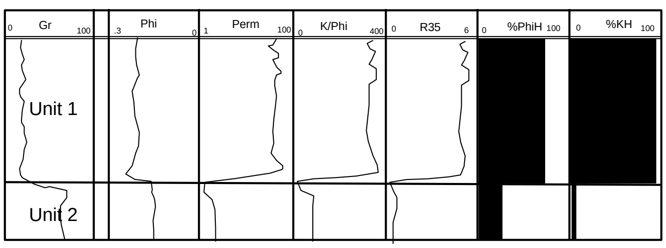

Figure 13: Schematic Stratigraphic Flow Profile (SFP) Well B

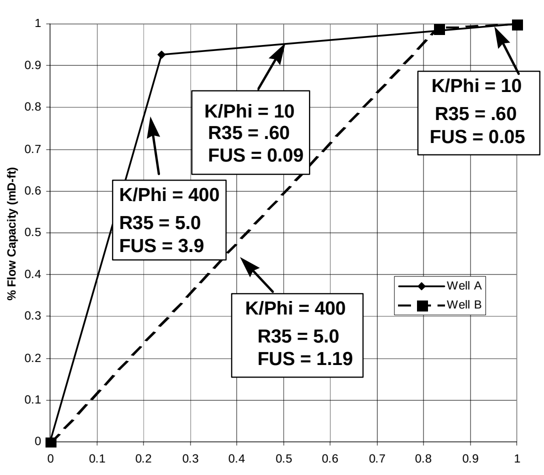

Figure 14: SMLP and MLP for flow units in two well/two layer model

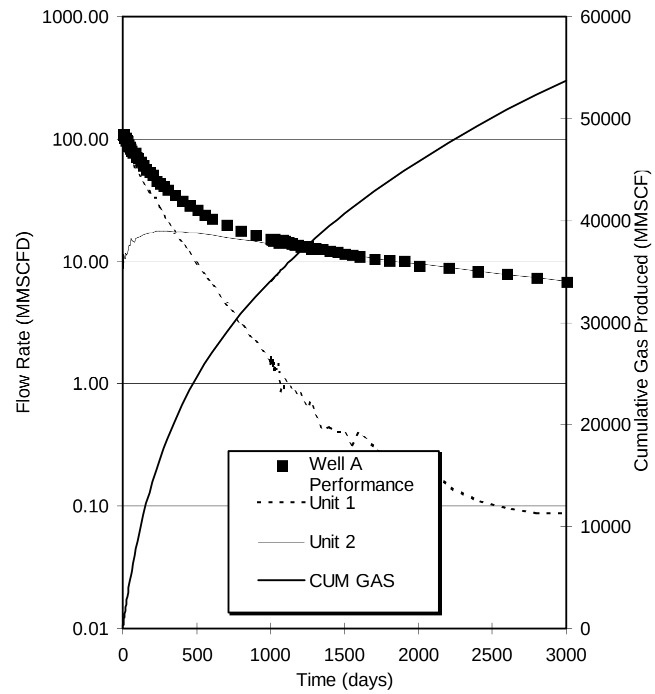

Figure 15: Well A Model Results

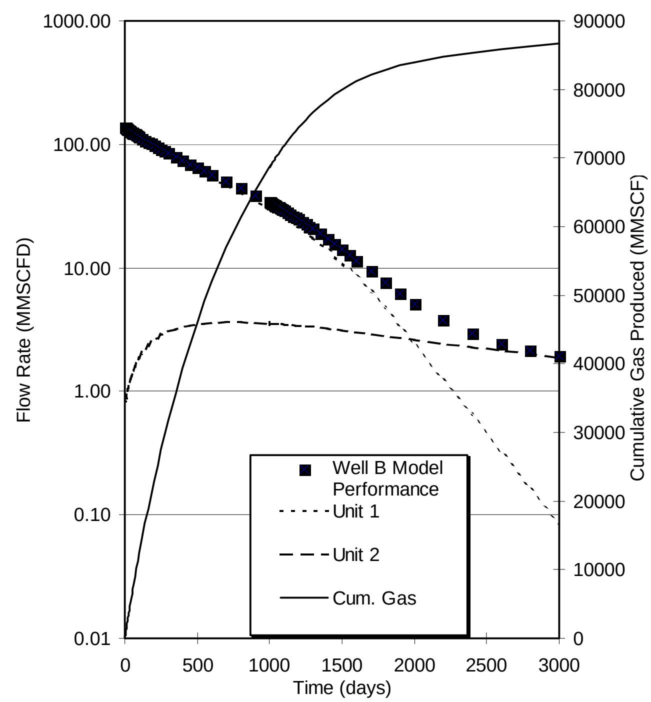

Figure 16: Well B Model Results