Advanced Decline Curve Modeling for Stripper Well Production Analysis

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Submitted By:
Lawrence J. Pekot
George J. Koperna Jr.
Karen D. Antoszewski

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Advanced Resources International, Inc.
1110 North Glebe Road, Suite 600
Arlington, VA 22201

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Abstract

This report documents work performed under the named contracts. Software has been developed to allow the user to evaluate gas well production data using advanced decline curve techniques. Such techniques include exponential and hyperbolic analysis, use of variable compressibility type curve and multi-layer completion effects. Results of such analyses include production forecasting and estimation of well/reservoir properties such as formation permeability, stimulation effectiveness and drainage area.

The software has been validated by comparison of software analysis results for 16 type wells that were also rigorously analyzed using reservoir simulation techniques.

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Executive Summary

Successful stripper well production requires careful attention to cost control – a requirement that extends to engineering and geologic evaluations of a stripper well's potential for remediation or production improvement. So, techniques the operator may apply in order to evaluate stripper wells in a fast, simple and reliable manner will be superior to those that do not.

In order to meet this need, Advanced Resources International's (ARI) advanced decline curve program (*METEOR*), which is designed specifically for low permeability, multiple completion gas wells, was refined to enable the operator to analyze stripper gas wells for the purposes of well remediation, recompletion or drilling options in stripper production areas. An executable copy of the *METEOR* software is included with this report for 2001 members of the Stripper Well Consortium, qualifying New York State operators and the Gas Technology Institute. *METEOR* was used to type curve match production data from a variety of stripper gas test wells that represented both geographical and reservoir diversity throughout the Appalachian Basin. To provide a basis of comparison for the type curve matching results for the test wells, ARI also conducted a rigorous history matching effort for each test well in the study, using ARI's reservoir simulation software, *COMET2*. The simulation results provided permeability, skin factor, drainage area and estimated recovery values for comparison to those results generated by the *METEOR* production type curve analysis software.

- With few exceptions, the single and multi layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, *METEOR* was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions.

- For desorption controlled reservoirs, *METEOR* will over predict drainage area values due to the presence of adsorbed gas in the shale or coal layer. To more properly account for the adsorbed gas-in-place, the reservoir's estimated porosity should be increased to provide an equivalent reservoir pore volume. Permeability and recovery values were similar to those derived from computer simulation.

- Since the *METEOR* type curve software is based on numerical formulations for fractures of infinite conductivity, differences in equivalent skin factor between simulator and type curve techniques are apparent. However, the results did reveal that well stimulated layers tended to have large fracture half-lengths while poorly stimulated zones had much smaller half-lengths. Future versions of *METEOR* should include formation damage curves within the transient portion of the type curve to improve the early time match. This would allow *METEOR* to model fracture cleanup or damage more effectively.

- *METEOR* software assumes a constant bottom hole flowing pressure for each match period. This is normally a reasonable assumption for low permeability gas wells.

However, some wells, such as the Area 16 study well, had significant long-term variation in flowing pressure. The inclusion of a rate normalization technique could further improve the accuracy of the software.

- Permeability values for the Devonian Shale (Cleveland and Lower Huron members) are fairly consistent for Areas 1 through 6 (Kentucky), ranging from 2 to 8 micro-darcies. Permeability for the Devonian Shale in Area 9 (Virginia), however, appears to be much higher (25 micro-darcies). Berea Sand permeability values appear to be much better than those determined in the Devonian Shale for Areas 1 through 6, ranging from 3 to 78 micro-darcies. Permeability estimates for the Whirlpool sand (0.10 to 0.50 md) are greater than that for the Grimsby sand (0.02 to 0.14 md). Skin factors determined during the history matching process indicate the study wells are generally very well stimulated, ranging from 0 to –4.6 for the individual reservoirs.

- Overall, well drainage areas for study wells 1 through 11 were found to be reasonable and are estimated to range from about 14 to 93 acres. Based on the data provided for the individual areas, nominal well spacing appears to be significantly larger than the history match derived drainage area, suggesting there is considerable merit to investigating more optimum well spacing scenarios. For study wells 12 through 16, drainage area estimates for the Grimsby sand were found to be small, with all but one less than 20 acres, while Whirlpool completions tended to drain areas larger than 40 acres. However, information is incomplete regarding offset well development.

- Predicted recovery efficiency values for the conventional gas reservoirs (Berea Sand, Big Injun, Big Lime, Weir, etc.) were generally much better than those for the Devonian Shale reservoirs. Because of the nature of desorption controlled reservoirs, the desorption (gas-release) process is more efficient when there is interference from offset production wells. This decreases reservoir pressure more quickly and accelerates the gas release from the shale layers.

- Even with small well spacing, recovery efficiency was very low for areas 1 and 7 due to the small permeability values, suggesting that optimum well spacing may be a function of reservoir permeability. This behavior is also apparent for the shale reservoirs, as the recovery efficiency values for Layer 2 in Area 9 are considerably greater (76% to 92%) than those experienced in Areas 1 through 6 (5% to 45%).

CHAPTER 1
Feature Upgrades and Program Modifications to *METEOR*

Introduction

The rapid analysis of produced gas volumes can be a valuable tool in evaluating the performance of low productivity (stripper) gas wells. However, in many areas around the United States, these stripper gas wells are completed in multiple reservoirs, which often complicates production analysis methodologies. Under a New York State Energy Research Development Authority (NYSERDA) program[1], Advanced Resources International, Inc. developed a layered-no-crossflow production type curve analysis program (*METEOR*) specifically for use with commingled completions. While this program offered the capability to perform a detailed two-layer production type curve analysis, and generated permeability, stimulation, drainage area and recovery estimates for each layer, the software itself was rather modest and lacked several features that would enhance its usability.

As a result, ARI has performed a multitude of software upgrades to the original, beta-version of *METEOR*, including but not limited to:

- Aarps-type hyperbolic production type curves
- Variable compressibility production type curves
- Calculation of permeability, fracture half-length, drainage area, estimated ultimate recovery, average reservoir pressure, and match quality coefficients
- Workover and restart options
- Improved plotting to include oil, water and pressure data
- Compatible data import/export
- Printing and reporting features
- Mapping interface to display results in x-y format
- Users guide

New Features/Modifications

<u>Data Input and Storage:</u> *METEOR* has been constructed to work with a variety of input file types. These file types include IHS format (*.98c), text formats (*.asc, *.csv, *.prn and *.txt) and Microsoft Excel format (*.xls). In addition, *METEOR* can incorporate input data obtained from reserve determination software such as ARIES and OGRE.

This production data is read into a Microsoft Access database hierarchy, which the user names, for rapid retrieval of production data. In addition, all type curve match derived data is also stored in the database, enabling *METEOR* to save and "remember" match results.

<u>New Program Interface:</u> **Figure 1** depicts a screen capture of the basic user interface. Drop-down menus are available across the upper left hand corner of the program to enable the user to manipulate the project file and print reports (*File*), edit the graph window (*Edit*), toggle the current view (*View*), import or edit the data (*Database*), perform type curve matching (*Analysis*), toggle and control the mapping features (*Maps*), cascade or tile the open windows (*Window*) and provide additional help (*Help*). Below the menu, six toolbar functions are provided to enable the user to rapidly open a new project, open an existing file, copy to the clipboard, print, provide help and initiate type curve matching.

If the project consists of more than one well, a list of well names can be accessed from the drop-down menu at the left of the screen. Selecting a well name will display a production chart to the right and information for the well in fields below the well name drop-down menu. In addition to the chart tab, data and map tabs are provided to allow the analyst to inspect the data and, if x and y coordinates are available for each well in the project, to view the distribution of wells and their cumulative and projected recoveries. Supplementary map views in *JPEG* or *PCX* formats, such as elevation and formation thickness, can be readily imported to the project and subsequently viewed.

Hyberbolic Type Curve Matching: *METEOR* provides the capability of estimating reservoir, completion and production parameters such as permeability, fracture half-length, drainage area and estimated ultimate recovery for one or two productive layers. To determine these parameters, the analyst must invoke the type curve analysis mode via the analysis menu or the type curve matching toolbar button, which brings up the type curve interface window (**Figure 2**).

This new window contains the means for matching the gas production data to the *METEOR* hydraulically fractured type curve. The user has been provided with a number of options at his disposal to conduct the matching process. Perhaps the most important of which are the mechanisms for moving the data in order to align it with the type curve. To align the data and type curve within the match window, the user can translate the data by clicking the appropriate arrow on the *Shift Points* four-way arrow button in the lower right corner of the window. This button shifts the data points up, down, left and right, relative to the type curve, to enable the user to match the data to the type curve. Immediately to the left of the button is a movement sensitivity slider bar, which allows fine to coarse movements on a scale of one (fine) to ten (coarse). In addition, selecting the *Move* toolbar button and then using the mouse to click and drag the data will also transfer the data.

For refinement of the match, the user has the option to view the data with various multiple point smoothing routines (*Smoothing*), with semi-log plots (*Graph*), with zooming (*Zoom* toolbar button) and, located in the upper right hand corner of the window, with a least squares difference in the y-direction for measuring match quality (*Results*). The shape of the type curve can be modified by selecting the appropriate drainage stem (*Xe/Xf*) or the Aarps hyperbolic decline exponent (*Hyper. Exponent (b)*).

As the analyst manipulates the match, *METEOR* dynamically updates the match parameters, Qmatch and Tmatch, as well as the results, for permeability (*k*), fracture half-length (*Xf*), drainage area (*A*), original gas in place (*OGIP*) and estimated ultimate recovery (*EUR*).

Besides creating a match of the data, the analyst must also input the gross (if two layers) or single-layer reservoir parameters into the database by either selecting *User Input* button or by clicking in the *Data Info* area. Within this window the user has the ability to alter reservoir data such as thickness, porosity and pressure. Once the desired estimates are entered, *METEOR* will dynamically update the results in the type curve matching window as well as in the database, provided the save (*Save*) toolbar button is depressed. As with any computer process, frequent use of the Save button is encouraged.

The gas properties can be reviewed by selecting the appropriate toolbar buttons to show the gas viscosity (*Viscosity*), z-factor (*Zfactr*) and pseudopressure, or real gas potential, (*Pseudo*) for the gas described in the user input dialogue. When selected, a graphical representation of the property on the y-axis is plotted against the x-axis range of zero to reservoir pressure.

In addition to viewing gas and PVT data, the user can export the forecasted gas production and average reservoir pressures by selecting the *Write CSV* toolbar button at the top of the window. If the variable compressibility option has been enabled (discussed later), the rate forecast for that option is included in the *CSV* formatted text file.

Restarts: *METEOR* has the capability to handle changes in operating conditions, well workovers and re-stimulations through the use of a unique restart option. To utilize the restart option, the user must first define the restart (by placing a "1" in the *Period* text box) and input the restarts beginning (*Start*) and ending (*End*) months. Subsequent restarts will be activated by incrementing the value in the *Period* text box.

The user can then re-intialize the data set in the *METEOR* type curve matching window by placing the number that appears to the right of the *Period* text box in the *Pseudo TStart* text box. As the user enters the value, the type curve restart will re-initialize, allowing the user to assess the impact of the restart period. Also, *METEOR* will automatically decrement the value in the *Pseudo TStart* text box by a value of one. Type curve matching of the restart data can then be carried out including any desired changes in bottomhole flowing pressure, reservoir pressure, thickness, etc.

Variable Compressibility Type Curve Matching: In addition to the single-layer hyperbolic type curve matching option, the analyst has the ability to estimate the impact of pressure depletion on PVT properties such as gas compressibility and gas viscosity in low permeability gas reservoirs. This effect generally manifests itself following the departure from the infinite acting portion of the type cure (or when a boundary is encountered). From a practical standpoint, this behavior is manifested as a deviation from the decline stem (selected match *Xe/Xf*) with the variable compressibility curve often crossing over the other curves to the right.

To activate this feature, the user must select the Compressibility Option check box. A heavy green line then appears, allowing the user to refine the match, as shown in **Figure 3**. To do so, the user must typically decrease the selected *Xe/Xf* match point until the variable compressibility line passes through the production data.

<u>Multi-layer Hyperbolic Type Curve Matching:</u> If the analysis is to consider multiple completions, the multi-layer matching can be performed. This must be done following a composite (single) layer match. **Figure 4** depicts the multi-layer matching window. For this analysis, the composite match (red line) is used as the basis for the matching the individual layers.

Individual layer parameters, such as thickness, porosity and water saturation must then be entered for each layer. The analyst then has the freedom to alter layer permeability, fracture half-length and drainage area for each of the two completions. Once initial values have been entered, the *PLOT* button can be depressed to review the results.

Depicted are the individual layer production estimates, their summation and the composite match result. Should the layer summation and the composite match overlay, good agreement has been achieved between the single and multi-layer analyses. If they diverge, the analyst is then free to adjust any values to achieve a quality match.

Reference

1. "Advanced Decline Curve Model for Layered, No-Crossflow Completions in the Medina/Whirlpool Gas Wells of New York.", NYSERDA contract no. 5007-ERTER-ER-99, 1999.

CHAPTER 2
Reservoir Simulation of Study Wells

Introduction

In order to assess the new software features, detailed reservoir simulation history matching was carried out on a series of study wells. History matching results were then compared to the results obtained from production type curve matching using the improved *METEOR* software.

The following discussion outlines the reservoir simulation results using *COMET2* to history match Equitable Production Company's (Equitable) eleven study wells selected from areas in Kentucky, West Virginia and Virginia and Belden & Blake Corporation's five study wells located in Pennsylvania. **Table 1** contains the results in tabular form.

Study Area Discussion

<u>*Equitable Production Company Study Areas:*</u>

Area 1 Study Well – Located in Pike County, Kentucky, this well was originally completed in the Berea sandstone from 3,273 to 3,336 feet and the Devonian Shale from 3,411 to 4,337 feet in December 1991. From the geophysical well logs, reservoir properties were determined to be thickness values of 50 and 184 feet, porosity values of 7.6% and 1% (estimated) and water saturation values of 36.2% and 30% (estimated) for the Berea sand and Devonian Shale, respectively. In mid April 2000, the well was recompleted in the Big Lime formation from 2,412 to 2,574 feet. Since this study is concerned with at most two layers, the Big Lime recompletion was not considered in this exercise.

For those layer properties still not quantified, such as reservoir pressure and shale desorption isotherm values, Equitable personnel familiar with these production areas provided estimates of initial pressure, as well as the next 5 areas, at 0.25 psia/foot. For the Devonian Shale's desorption isotherm, a literature review identified a viable isotherm (**Figure 5**)[1], which was used for all Shale formations in this study.

Figure 6 depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia). Note that the gain in production rate at approximately 3,000 days represents the completion of the Big Lime formation. To obtain this high quality match, available wellhead data was used as the production simulation constraint. Resultant values for formation permeability were determined to be 0.003 and 0.002 md for the Berea sand and the Devonian Shale, respectively, while drainage area for each of the two layers was determined to be about 14 acres.

Initial values for the well's skin factor were –4.4 and –4.3 for the Berea sand and Devonian Shale. However, following approximately 800 days of production history, the averaged (monthly) daily production rate instantaneously drops from over 20 Mcfd to about 4 Mcfd, with no accompanying explanation in the historical data files. To model this effect, the skin

Table 1 – Simulation Results

			Depth		Perfs					Match Parameters					
Area	Formation	Date	Top ft	Bottom ft	Top ft	Bottom ft	Thickness ft	Porosity %	Sw %	Pr psi	Perm md	Initial Skin	Final Skin	Area acres	20-Year Cum MMCF
1	Berea	Dec-91	3,262	3,342	3,273	3,336	50	7.2%	36.2%	815	0.003	-4.40	6.00	14.4	16.0
	Devonian Shale	Dec-91	3,342	4,440	3,411	4,337	184	1.0%	30.0%	920	0.002	-4.30	6.00	14.4	40.6
2	Berea	Feb-90	3,760	3,872	3,777	3,861	55	6.8%	46.0%	954	0.009	-4.30	-4.30	13.5	62.0
	Devonian Shale	Feb-90	3,872	4,805	3,876	4,706	214	1.0%	30.0%	1,072	0.003	-4.30	-4.30	13.5	174.0
3	Berea	Feb-93	3,210	3,330	3,316	3,330	34	7.2%	33.0%	818	0.078	-4.75	-4.75	57.6	191.0
	Brown Shale	Feb-93	3,330	3,870	3,330	3,864	187	1.0%	30.0%	899	0.005	-4.50	-4.50	57.6	271.0
4	Berea	Sep-98	2,750	2,800	2,798	2,800	6	4.9%	45.3%	694	0.030	-3.50	-3.50	22.5	7.0
	Devonian Shale	Sep-98	2,800	3,243	2,800	3,243	177	1.0%	30.0%	755	0.008	-3.50	-3.50	22.5	181.0
5	Cleveland	Jul-91	3,248		3,286	3,336	56	1.0%	40.0%	828	0.009	-4.35	-4.35	64.8	99.0
	Lower Huron	Jul-91		3,572	3,502	3,562	59	1.0%	40.0%	883	0.005	-4.35	-4.35	64.8	69.0
6	Berea	May-92	3,149	3,242		3,242	48	6.9%	28.5%	799	0.021	-3.60	-3.60	21.6	84.0
	Devonian Shale	May-92	3,242	4,212		4,096	224	1.0%	30.0%	917	0.013	-3.40	-3.40	21.6	349.0
7	Big Injun	Aug-81	2,126	2,135	2,132	2,144	12	15.7%	26.0%	398	0.031	-4.80	-4.70	72.9	95.0
8	Big Lime	Sep-98			1,498	1,575	23	10.3%	16.3%	107	0.430	-1.00	-1.00	22.5	16.0
	Big Injun/U.Weir	Sep-98			1,717	1,765	28	10.8%	32.3%	119	0.400	0.00	0.00	22.5	19.0
9	Big Lime/ Weir	Jun-97			3,570	3,778	41	4.5%	65.0%	566	0.020	-4.60	-4.00	72.9	41.4
	Devonian Shale	Jun-97			4,041	4,858	284	1.0%	30.0%	683	0.025	-4.60	-4.00	72.9	209.7
10	Big Injun	Dec-97			2,653	2,673	20	4.7%	42.9%	494	0.150	-2.00	-2.00	72.3	53.9
	Weir	Dec-97			2,718	2,809	40	4.2%	47.4%	512	0.080	-2.00	-2.00	93.0	77.0
11	Big Lime/ U, M & L Weir	Jul-98	2,365	2,924	2,386	2,925	75	6.2%	43.9%	493	0.113	-3.00	-3.00	51.6	138.0
	G Stray - Be/ Gordon	Jul-98	3,186	3,412	3,214	3,406	31	6.0%	53.6%	611	0.080	-3.00	-3.00	24.8	34.3
12	Whirlpool	Dec-92	5,491	5,505	5,494	5,498	14	10.0%	30%	1,340	0.50	-2.72	2.50	64.4	221.0
13	Grimsby	May-98	5,315	5,348	5,277	5,344	33	6.0%	30%	700	0.13	-4.50	-4.50	15.2	36.3
	Whirlpool	Aug-93	5,420	5,434	5,423	5,427	14	14.0%	30%	850	0.29	-4.00	4.50	44.6	97.5
14	Grimsby	May-98	5,093	5,180			57	5.0%	30%	800	0.04	-3.70	-3.70	14.0	48.5
	Whirlpool	Feb-85	5,208	5,220	5,212	5,216	12	10.0%	30%	1,600	0.50	-3.80	0.50	98.0	350.4
15	Grimsby	Dec-92	5,497	5,579	5,497	5,549	52	7.0%	30%	1,200	0.14	-4.00	3.00	51.0	309.9
	Whirlpool	Dec-92	5,599	5,613	5,604	5,609	14	8.0%	30%	1,200	0.45	-4.00	3.00	51.0	110.8
16	Grimsby	Dec-88	5,168	5,269	5,179		57	5.0%	30%	1,247	0.02	-3.00	-3.00	14.0	84.2
	Whirlpool	Dec-88	5,294	5,303		5,301	9	7.0%	30%	1,250	0.10	-3.00	-3.00	14.0	21.5

factor was altered from –4.4 and –4.3 to +6 in each layer. For the duration of the history match, the skin remained +6 for each respective layer.

***Area 2 Study Well* –** On February 1, 1990 this well, in Pike County, Kentucky, was completed in the Berea sand from 3,760 to 3,872 feet and in the Devonian Shale from 3,872 to 4,805 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand were estimated to be 55 feet and 6.8%, respectively. Thickness and porosity for the Devonian Shale were estimated to be 214 feet and 1.0%, respectively. The initial pressures used were 1,072 psia for the Berea and 954 psia for the Devonian Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 53 psia was used as the production constraint. Final match parameters for the Devonian Shale and Berea sand are permeability values of 0.009 and 0.0025 md and a drainage area of 13.5 acres, for both layers. The skin factor value used was -4.3 for both layers. **Figure 7** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

***Area 3 Study Well* –** On February 1, 1993 this well, in Pike County, Kentucky, was completed in the Berea sand from 3,210 to 3,330 feet and in the Brown Shale from 3,330 to 3,870 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand were estimated to be 34 feet and 7.2%, respectively. Thickness and porosity for the Brown Shale were estimated to be 187 feet and 1.0%, respectively. The initial pressures used were 817 psia for the Berea and 899 psia for the Brown Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 42 psia was used as the production constraint. Final match parameters for the Brown Shale and Berea sand are permeability values of 0.078 and 0.005 md and drainage areas of 57.6 and 90 acres, respectively. The skin factors used were -4.75 for the Brown Shale layer and -4.50 for the Berea layer. **Figure 8** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

***Area 4 Study Well* –** On September 1, 1998 this well, in Knott County, Kentucky, was completed in the Berea sand from 2,750 to 2,800 feet and in the Devonian Shale from 2,800 to 3,243 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand were estimated to be 6 feet and 4.9%, respectively. Thickness and porosity for the Devonian Shale were estimated to be 177 feet and 1.0%, respectively. The initial pressures used were 694 psia for the Berea and 795 psia for the Devonian Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 60 psia was used as the production constraint. Final match parameters for the Devonian Shale and Berea sand are permeability values of 0.008 and 0.030 md and a drainage area of 22.5 acres, for both layers. The skin factor values used were –4.75 for the Berea and –4.50 for the Devonian Shale. **Figure 9** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia). At 650 days, an increase in gas productivity is seen, which later returns to the normal decline trend. At this time, the cause of the increase is not known.

Area 5 Study Well **–** On July 1, 1991 this well, in Perry County, Kentucky, was completed in the Devonian Shale from 3,248 to 3,572 feet. This shale completion was comprised of the Cleveland, perforated from 3,286 to 3,336 feet, and the Lower Huron, perforated from 3,502 to 3,562 feet. From the provided geophysical well logs, pay thickness for the Lower Huron pay zone was estimated to be 59 feet while the pay thickness of the Cleveland shale was estimated to be 56 feet. Porosity was assumed to be 1.0% for each layer. The initial pressures used were 828 psia for the Lower Huron and 883 psia for the Cleveland. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average bottomhole pressure of 30 psia was used as the production constraint. Final match parameters were permeability values of 0.009 md and 0.005 md, respectively, over a drainage area of 64.8 acres for both the Lower Huron and Cleveland shale formations. The skin factor used for both layers was -4.35. **Figure 10** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 6 Study Well **–** On May 1, 1992 this well, in Pike County, Kentucky, was dually completed in the Berea sand from 3,149 to 3,242 feet and in the Brown Shale from 3,242 to 4,212 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand was estimated to be 48 feet and 6.9%, respectively. Thickness for the Devonian Shale was estimated to be 177 feet. The initial pressures used were 799 psia for the Berea and 917 psia for the Devonian Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average bottomhole pressure of 55 psia was used as the production constraint. Final match parameters were permeability values of 0.021 and 0.013 md over a drainage area of 21.6 acres for both the Brown Shale and Berea sand. The skin factors used were -3.6 for the Brown Shale and -3.4 for the Berea sand. **Figure 11** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 7 Study Well **–** On August 1, 1981 this well, in Fayette County, West Virginia, was completed in the Big Injun from 2,126 to 2,135 feet. From the provided geophysical well logs, thickness for the Big Injun pay zone was estimated to be 12 feet and porosity was 15.7%. The initial pressure value was estimated to be 398 psia, using a pressure gradient of 0.25 psig/ft.

To match the production history of the well, an average wellhead pressure of 40 psia was used as the production constraint. The final permeability value was 0.031 md over a drainage area of 72.9 acres. The initial skin factor was –4.8, finishing at –4.7 at the end of production history. **Figure 12** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 8 Study Well – On September 30, 1998 this well, in Nicholas County, West Virginia, was completed in three zones. The Big Lime was completed from 1,498 to 1,575 feet, the Big Injun from 1,717 to 1,735 feet and the Upper Weir from 1,755 to 1,765 feet. In order to simulate a dual completion, the Big Injun and Upper Weir formations were combined and the porosity and thickness values were averaged. From the provided geophysical well logs, thickness and porosity for the Big Lime were estimated to be 23 feet and 10.3%, respectively. Porosity and thickness averages for the Big Injun/Upper Weir were 10.8% and 28 feet, respectively. The initial pressures used were 107 psia for the Big Lime and 120 psia for the Big Injun/Upper Weir. A pressure gradient of 0.1 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 30 psia was used as the production constraint. Final permeability values were 0.43 md for the Big Lime and 0.40 md for the Big Injun/Upper Weir layers over a drainage area of about 23 acres. The skin factors used were –1.0 for the Big Lime and 0.0 for the Big Injun/Upper Weir layers. **Figure 13** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 9 Study Well – This well, located within Wise County, Virginia, was drilled and completed in four reservoirs in June of 1997. From top to bottom, the four horizons were the Big Lime, Weir, Cleveland shale and Lower Huron Shale. From the well's completion and geophysical data, total reservoir thickness, porosity and water saturation were determined for each zone. **Table 2** exhibits the log-derived reservoir data for the study well.

Table 2 – Log-Derived Reservoir Properties for Area 9

Zone 1							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Big Lime			3,570	3,587	17.0	6.8%	63.7%

Zone 2							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Weir			3,670	3,778	24.0	2.9%	123.4%

Zone 3							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Clev Sh			4,041	4,502	178.0	1.0%	30.0%

Zone 4							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
L Huron Sh			4,752	4,858	106.0	1.0%	30.0%

Since at most only two intervals can be analyzed using ARI's *METEOR* production type curve software, the four discrete reservoirs were combined into a Big Lime/ Weir layer (layer one) and a Cleveland/ L Huron layer (layer two). While total thickness for the combined layers was an additive process, the porosity and water saturation data was thickness-averaged. The final petrophysical properties for layer one were a thickness of 41 feet, a porosity of 4.5% and a water saturation of 65% (estimated due to high Weir water saturation), while layer two's properties were a thickness of 284 feet, a porosity of 1.0% (assumed) and a water saturation of 30% (assumed).

An initial pressure gradient for this area was determined to be 0.15 psig/ft, which produced against an average wellhead pressure of 50 psia. Using the wellhead pressure as the production constraint for the history matching effort, a high-quality history match of cumulative gas and gas rate was achieved (**Figure 14**). From the match, permeability was determined to be 0.02 md and 0.025 md for layer one and two, respectively. Also, the skin factor and drainage areas for layer one and two were found to be –4.6, eroding to –4 after about 500 days, and 73 acres.

Area 10 Study Well – On December 31, 1997, this well, in Fayette County, West Virginia, was completed in the Big Injun from 2,653 to 2,673 feet and the Upper Weir from 2,718 to 2,809 feet. From the provided geophysical well logs, thickness and porosity for the Big Injun and Weir pay zones were estimated to be 20 feet and 4.7% as well as 40 feet and 4.2%, respectively. An initial bottomhole pressure gradient of 0.18 psig/ft was used to estimate reservoir pressure for each producing interval.

To match the production history of the well, an average bottomhole pressure of 65 psia was used as the production constraint. The final permeability values were 0.15 md and 0.08 md for the Big Injun and Weir formations. Drainage areas were modeled at 72 and 93 acres for the Big Injun and Weir sands, respectively. Skin was estimated at a -2.0 value for the duration of the simulation for each layer. **Figure 15** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead production pressure (psia).

Area 11 Study Well – This well was completed and placed on production in July of 1998 in Fayette County, West Virginia. Five zones were perforated and stimulated from the Big Lime to the Gordon sand, where production was commingled. From the well's completion and geophysical data, total reservoir thickness, porosity and water saturation were determined for each zone. **Table 3** exhibits the log-derived reservoir data for the study well.

For this study, however, at most only two intervals can be analyzed using ARI's *METEOR* production type curve software. So, the five discrete reservoirs were combined into a Big Lime/ Middle, Upper Weir/ Lower Weir layer (layer one) and a Gordon Stray – Berea/ Gordon layer (layer two). While total thickness for the combined layers was an additive process, the porosity and water saturation data was thickness-averaged. The final petrophysical properties for layer one were a thickness of 75 feet, a porosity of 6.2% and a

Table 3 – Log-Derived Reservoir Properties for Area 11

Zone	Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Zone 1	Big Lime	2,365	2,669	2,386	2,396	10.0	5.8%	36.3%
Zone 2	M/U Weir	2,774	2,841	2,782	2,830	55.0	6.3%	43.4%
Zone 3	Lower Weir	2,914	2,924	2,917	2,925	10.0	6.1%	54.7%
Zone 4	G Stray/BE	3,186	3,222	3,214	3,283	17.0	6.2%	53.2%
Zone 5	Gordon	3,390	3,412	3,396	3,406	14.0	5.8%	54.0%

water saturation of 44%, while layer two's properties were a thickness of 31 feet, a porosity of 6.0% and a water saturation of 54%.

An initial pressure gradient for this area was determined to be 0.18 psig/ft, which produced against an average wellhead pressure of 55 psia. Using the wellhead pressure as the production constraint for the history matching effort, a high-quality history match of cumulative gas and gas rate was achieved (**Figure 16**). From the match, permeability was determined to be 0.11 md and 0.08 md for layer one and two, respectively. Also, the skin factor and drainage areas for layer one and two were found to be –3 and –3 as well as 51.6 and 24.8 acres.

<u>*Belden & Blake Corporation Study Wells:*</u>

Area 12 Study Well – This well was completed in the Whirlpool sandstone in December of 1992 from 5,494 to 5,498 feet. From the provided geophysical well logs, gross thickness and porosity for the pay zone were estimated to be 14 feet and 10%, respectively. Further, since almost no water was produced from this well, the mobile water saturation was set at 5%, with an irreducible saturation of 25%. Initial reservoir pressure was estimated to be 1,340 psi from a 48-hour post-frac pressure buildup (1,175 psi).

To match the production history of the well, casing pressure was used as the production constraint. Since the initial twelve months of casing pressure data declined from nearly 1,200 psi to about 350 psi, values for each month were input. Following the first year, four time periods where the casing pressure behaved similarly were identified. In these periods, the casing pressure values were averaged to obtain the simulation input value.

Final match parameters were a permeability of 0.5 md over a drainage area of 64.4 acres. Skin factor was found to vary during the well's producing life as:

1. +12 for the first month
2. –2.7 until 608 days
3. +2.0 until 1,491 days
4. +2.5 until the end of history

While the +12 skin value for month one was used to account for post-fracture treatment cleanup, the fracture stimulation was able to achieve a negative skin factor, thereafter. From approximately 500 days of production (see history match plot of TW #1), the simulated gas rate no longer matches history and the skin factor is adjusted to a damaged condition from 608 days to the end of history. It is not understood what may have happened to the stimulated nature of the well. However, a slightly positive skin is required to match the later time history. The history match is depicted in **Figure 17**.

Area 13 Study Well – This well was completed in the Whirlpool sand from 5,422 to 5,427 feet in August of 1993 and then recompleted in Grimsby sand from 5,277 to 5,344 feet in May of 1998. From the provided geophysical well logs, gross thickness and porosity for the pay zone were estimated to be 14.0 ft and 14% for the Whirlpool completion and 33.0 ft and 6% for the Grimsby recompletion. Further, since almost no water was produced from this well, the mobile water saturation was set at 5%, with an irreducible saturation of 25%. Initial reservoir pressure was estimated to be 850 psi for the Whirlpool sand, based on the 48-hour post-frac pressure buildup (745 psi).

To match the production history of the well, casing pressure was used as the production constraint and was input accordingly. Following the first year, two regions where the casing pressure behaved similarly were identified. In these regions, the casing pressure values were averaged to obtain the simulation input value. The well's initial skin factor was –4, which was then gradually degraded in order to make the history match, ultimately reaching a value of +4.5. Permeability was determined to be 0.3 md over a drainage area of 44.6 acres.

In 1998, the well was recompleted by adding the Grimsby formation. Without completion and pressure information for the zone, it was assumed that the gross interval was perforated, stimulated and completed. Gross properties for the Grimsby sand from geophysical logs, indicated that 33 feet of sand with a porosity of 6% was available from 5,277 feet to 5,348 feet. In order to obtain a post-1998 match, it was further assumed that the Whirlpool sand would still be contributing production. Therefore, the match variables were determined to be initial reservoir pressure, permeability and skin for the Grimsby sand.

Final history match parameters for the Grimsby were determined to be a bottomhole pressure of 700 psi, a permeability of 0.13 md, a skin factor of -4.5 and a drainage area of 15.2 acres (based on the assumed completion and match pressure). The history match is depicted in **Figure 18**.

Area 14 Study Well – This well was provided to ARI as a Grimsby sand completion that was later recompleted in the Whirlpool sand. A review of the completion and geophysical log information provided to ARI indicated that the well is in actuality initially completed in the Whirlpool sand from 5,212 to 5,216 feet in February of 1985. From the provided geophysical well logs, gross thickness and porosity for the pay zone were estimated to be 12 feet and 10%, respectively. Further, since almost no water was produced from this well, the mobile water saturation was set at 5%, with an irreducible saturation of 25%. Initial reservoir pressure was estimated to be 1,600 psi from a 48-hour post-frac pressure buildup (1,400 psi).

To match the production history of the well, casing pressure was used as the production constraint and was input accordingly. Following the first year, eight time periods where the casing pressure behaved similarly were identified. In these periods, the casing pressure values were averaged to obtain the simulation input value.

The increasing production for the first 500 days was not adequately explained through the input of the wellhead pressure. The well's skin factor was therefore varied to achieve a history match of the production data. It was theorized that during this time, the hydraulic fracture treatment slowly cleaned up and improved the well from an initial skin factor of +7.0 to –3.8 (at 500 days). During the next four thousand days, the skin factor was gradually reduced to +0.5 to obtain a match, using a permeability of 0.5 md and a drainage area of 98 acres.

In 1998, the well was recompleted by adding the Grimsby formation. Without completion and pressure information for the zone, it was assumed that the gross interval was perforated, stimulated and completed. Gross properties for the Grimsby sand from geophysical logs, indicated that 57 feet of sand with a porosity of 5% was available from 5,093 feet to 5,180 feet. In order to obtain a post-1998 match, it was further assumed that the Whirlpool sand would still be contributing production. Therefore, the match variables were determined to be initial reservoir pressure, permeability and skin for the Grimsby sand.

Final history match parameters for the Grimsby were determined to be a bottomhole pressure of 800 psi, a permeability of 0.04 md, a skin factor of -3.7 and a drainage area of 14.0 acres (based on the assumed completion and match pressure). The history match is depicted in **Figure 19**.

Area 15 Study Well – This well was completed in January of 1992 in the Grimsby sand, from 5,497 to 5,579 feet, and the Whirlpool sand, from 5,599 to 5,613 feet. From the provided geophysical logs, gross sand thickness and porosity for these intervals were determined to be 52 feet and 7% for the Grimsby sand and 14 feet and 8% for the Whirlpool sand, respectively. Additionally, the 48-hour post-frac surface pressure was reported as 1,055 psi.

The simulation was conducted using wellhead casing pressure as the simulation input in order to match historical gas production. The history matching results yielded a permeability of 0.14 md for the Grimsby sand and 0.45 md for the Whirlpool sand. Skin factor and drainage areas were modeled using degrading skin values and 51 acres for each layer, respectively. Bottomhole pressure was found to be 1,200 psi for the Grimsby sand and 1,200 psi for the Whirlpool sand. The history match is depicted in **Figure 20**.

Area 16 Study Well – This well was completed in December of 1988 in the Grimsby sand, from 5,168 to 5,269 feet, and the Whirlpool sand, from 5,294 to 5,303 feet. From the provided geophysical logs, gross sand thickness and porosity for these intervals were determined to be 57 feet and 5% for the Grimsby sand and 9 feet and 7% for the Whirlpool sand, respectively. Additionally, the 18-hour post-frac surface pressure was reported as 1,050 psi.

A review of the available pressure data (historical casing, tubing and line pressures were available) showed that a full pressure history was unavailable for this well. Further, while the first four study wells used casing pressure as the input parameter, the tubing pressure for this well varied significantly from the casing pressure. This is most likely due to the use of surfactant as a water lifting mechanism. So, the well was matched using gas rate as the simulation input in order to match the available tubing pressure data.

Figure 21 depicts the difference between available wellhead casing and tubing pressure as well as the history matched wellhead pressure. The character of the simulated response is quite good, matching the increasing casing pressures observed from about January 1993 to October of 1995.

The history matching results yielded a permeability of 0.018 md for the Grimsby sand and 0.10 md for the Whirlpool sand. Skin factor and drainage areas were modeled using –3 and 14 acres for each layer, respectively. Bottomhole pressure was found to be 1,247 psi for the Grimsby sand and 1,250 psi for the Whirlpool sand. The history match is depicted in **Figure 22.**

Conclusions

This study is wholly based on geologic, geographic and production data provided by Equitable and Belden & Blake to ARI. Although ARI has performed a detailed analysis of geophysical well logs and determined nominal drill spacing for each study area, ARI must rely on Equitable and Belden & Blake to verify the results of these analyses. Further, it is essential to point out that the results of these history match simulations and projections are susceptible to variations in the key input parameters of reservoir thickness and pressure drawdown (initial reservoir pressure less wellhead/ bottomhole production pressure).

Equitable Production Company Study Areas:

- Permeability values for the Devonian Shale (Cleveland and Lower Huron members) are fairly consistent for Areas 1 through 6 (Kentucky), ranging from 2 to 8 micro-darcies. Permeability for the Devonian Shale in Area 9 (Virginia), however, appears to be much higher (25 micro-darcies).

- Berea Sand permeability values appear to be much better than those determined in the Devonian Shale for Areas 1 through 6, ranging from 3 to 78 micro-darcies.

- Overall, estimated well drainage areas are reasonable and are estimated to range from about 14 to 93 acres.

- Skin factors used during the history matching process indicate the study wells are generally very well stimulated, ranging from 0 to –4.6 for the individual reservoirs.

- The pressure gradient (0.1 psig/ft) provided for Area 8 is the lowest value in the study, necessitating the highest permeability values (0.43 and 0.40 md) to match the production history.

- For those study wells completed later in pattern development, partial pressure depletion may not have been considered in the provided initial pressure gradients. This may lead to the determination of permeability and drainage areas values that are smaller than actual. This partial depletion effect is more pronounced for those study wells with smaller nominal well spacing values.

- Based on the provided data, nominal well spacing appears to be significantly larger than the history match derived drainage area, suggesting there is considerable merit to investigating more optimum well spacing scenarios.

Belden & Blake Corporation Study Wells:

- Permeability estimates for the Whirlpool sand (0.10 to 0.50 md) are greater than that for the Grimsby sand (0.02 to 0.14 md), which tends to agree with current perception.

- Drainage area estimates for the Grimsby sand were found to be small, with all but one less than 20 acres, while Whirlpool completions tended to drain areas larger than 40 acres. However, information is incomplete regarding offset well development.

- For the recompleted wells, the Whirlpool sand skin factors for the initial completions were modeled as degrading more rapidly than those of the later Grimsby completions. This may be an important observation concerning offset well drilling during the productive life of the initial completions as drainage areas for these Whirlpool intervals ranged from 45 to 98 acres. For the later Grimsby sand completions, the drainage areas were only 15 and 14 acres, respectively. If infill drilling is actually the cause of well performance and not degrading skin factors, then reduction in drainage area during the Whirlpool sand's producing life and not reduced (more positive) skin factors may better match the production history. This would also impact the remaining study wells.

Reference

1. Schettler, P. D., Parmely, C., "Physicochemical Properties of Methane Storage and Transport in Devonian Shale," 1991 Annual Technical Report, Gas Research Institute Contract No. 5085-213-1143.

CHAPTER 3
Multi-Layer Type Curve Matching of Study Wells and Software Verification

Introduction

With the simulation work completed, estimates of layer permeability, skin factor, drainage area and estimated ultimate recovery (**Table 1**) have been collected for each study well. These results were used as a baseline for comparison to and verification of the *METEOR* production type curve analysis software.

An important consideration when comparing the results of the simulation history matching to the production type curve matching is the presence of Devonian Shale reservoirs in some of the study well data sets. Since the Devonian Shale is a desorption-controlled reservoir (gas is adsorbed within the shale), input of the shale porosity will cause the type curve program to overestimate the drainage area required to produce the equivalent volume of gas. In those cases where shale layers are present, no attempt has been made to "gross-up" the shale porosity value to account for adsorbed gas. Therefore, results comparison wills be concerned with permeability, fracture half-length (skin factor) and 20-year ultimate recovery for those study wells containing shale-gas reservoirs.

Table 4 shows the results of the type curve matching, with restarts. The following is a discussion of the results for each area study well.

Results

<u>*Equitable Production Company Study Areas:*</u>

Area 1 – Since gas production declines dramatically at 27 months of production, a type-curve analysis restart was necessary to fully compare the simulation and type curve results. The late time increase in productivity due to the completion of a new layer in the well was not considered. **Figures 23** and **24** show the results of the single and multi layer type curve matching for the first 26 months of production. The character of the data is fairly consistent and follows the selected drainage stem (in red on **Figure 23**) very well. Input parameters for this single layer match are depicted on the bottom of **Figure 23**.

To analyze the discrete layers, a multi layer analysis was carried out (**Figure 24**). At the upper-left corner of the graphic, the commingled properties are shown from the single layer type curve match, which describe the well's idealized total recovery rate vs. time. This is also shown as the red line from **Figure 23**. Using the two other upper panels of the graphic, porosity, thickness, water saturation and Aarps decline exponent (b) can then be input for each of the two layers. Following data input, the permeability, fracture half-length and drainage area for each of the layers can then be input into the software.

Table 4 – Single and Multi Layer Type Curve Matching Results

	Commingled Match								Layer 1						Layer 2					
Area	Start month	Pi psia	Thick ft	b	Perm md	Xf ft	A acres	EUR MMcf	Thick ft	b	Perm md	Xf ft	A acres	EUR MMcf	Thick ft	b	Perm md	Xf ft	A acres	EUR MMcf
1		905	234	0.5	0.002	181	9	61	50	0.5	0.003	225	9	32	184	0.5	0.002	175	9	39
Restart	27	626	234	0.5	0.002	10	5	55	50	0.5	0.003	11	7	9	184	0.5	0.002	11	7	13
2		1,026	269	0.5	0.004	177	13	184	55	0.5	0.009	182	14	73	214	0.5	0.003	182	14	69
Restart	47	700	269	0.5	0.004	191	54	233	55	0.5	0.009	200	60	85	214	0.5	0.003	200	60	95
3		872	221	1.0	0.017	283	46	433	34	0.5	0.078	310	58	229	187	0.5	0.005	250	170	221
4		737	193	0.5	0.009	221	55	141	6	0.5	0.030	221	23	7	187	0.5	0.008	221	60	124
5		868	115	0.5	0.007	221	219	165	56	0.5	0.009	221	220	98	59	0.5	0.005	221	220	68
6		857	272	0.5	0.014	106	66	432	48	0.5	0.021	125	22	83	224	0.5	0.013	105	120	343
7		398	12						12	0.5	0.031	1,345	426	96						
Restart	59	330	12						12	0.5	0.031	231	69	96						
8		179	51	0.5	0.411	17	16	26	23	0.5	0.430	17	23	13	28	0.5	0.395	17	23	14
9		624	325	0.5	0.024	150	25	171	41	0.5	0.020	160	30	23	284	0.5	0.025	160	30	109
Restart	17	450	325	0.5	0.024	119	64	235	41	0.5	0.020	130	73	28	284	0.5	0.025	130	78	158
10		500	60	0.8	0.106	40	58	115	20	0.5	0.150	40	70	47	40	0.5	0.085	40	90	76
11		552	106	0.5	0.102	49	31	152	75	0.5	0.113	48	33	127	31	0.5	0.075	48	25	31
12		1,340	14						14	0.5	0.498	30	53	218						
13		850	14	0.5											14	0.5	0.291	95	30	109
Restart	57	650	47	0.8	0.181	129	12	111	33	0.5	0.130	105	10	25	14	0.5	0.298	105	32	82
14		939	12	0.0											12	0.0	0.493	73	194	380
Restart	150	700	69	0.5	0.120	34	15	380	57	0.5	0.040	40	14	37	12	0.5	0.502	40	15	28
15		1,200	66	0.5	0.204	29	49	407	52	0.5	0.140	29	51	369	14	0.5	0.444	29	51	174
16		1,250	66	0.5	0.031	27	15	102	57	0.5	0.020	27	15	88	9	0.5	0.103	27	15	35

Depressing *METEOR*'s plot button then creates a graphic of the predicted recovery from each layer (blue and yellow lines), their summation (orange line) and the idealized total recovery rates from the single layer match (red line). A match is achieved when the summation of layers 1 and 2 overlays the single layer match (**Figure 24**).

The restart period, from 27 months of production, was matched in the same manner. Key differences are the input of a new reservoir pressure (note the 626 psi input at the bottom of **Figure 25**) and the consideration of data only after 26 months.

The quality of the restart data was not particularly good for this study well as it appears to be gently inclining over this six year productive period. Nevertheless, a match was determined and a multi layer analysis was performed (**Figure 26**).

A comparison of the simulation and type curve results shows excellent agreement between permeability values, 0.003 md and 0.002 md for layers one and two, and cumulative recovery, nearly 57 MMscf as compared to either 61 or 55 MMscf for the type curve solutions. However, predicted drainage areas, 14.4 acres against 9 and 7 acres, were much lower than expected due to the presence of a shale layer. Simulated skin factors were found to be –4.4 and –4.3, declining to +6 in both layers, while the *METEOR* software predicted 225 and 175 feet of infinite conductivity fracture half-length (X_f), initially, and then 11 feet of fracture half-length for the restart period.

The differences in equivalent skin factor are not surprising as the *METEOR* software is based on numerical formulations for use with low permeability gas reservoirs. Hydraulic stimulations are assumed to create infinite conductivity fracture half-lengths. However, in these study well cases, the simulated stimulation response is nearly always less than the idealized infinite conductivity response (100 to several hundred feet) due to damage, suggesting the need for implementing damage curves within the transient portion (early time) of the type curve.

***Area 2* – Figures 27** and **28** depict the single and multi layer production type curve matches for the first 48 months of history. After 47 months of production, Area 2 also required a restart to match data following an extended period of shut-in. Average reservoir pressure was estimated to be 700 psia at this time based on reservoir voidage. **Figures 29** and **30** show the matches.

For the simulation work, this study well was anticipated to have permeability values of 0.009 and 0.003 md, skin factors of –4.3 and –4.3, drainage areas of 13.5 and 13.5 acres from Layers 1 and 2, respectively. 20-year recovery was expected to be 236 MMscf. Type curve results showed a good match with layer permeability values, the well was highly stimulated and large drainage areas, which were most likely due to the shale reservoir (Layer 2). In addition, recovery was estimated to be 233 MMcf.

***Area 3* –** An Aarps decline exponent of 1.0 was used to match the data for the commingled production stream. **Figure 31** depicts the effect on the type curve. The multi layer match is shown in **Figure 32**, using decline exponents of 0.5 for each layer. The results showed good agreement with permeability, fracture half-length and drainage area. As expected, the shale layer accounted for an area greater than that seen in the history matching. Simulation and type curve predicted recovery values were 462 MMcf and 433 MMcf, respectively.

***Area 4* –** Type curve matching results and graphics for Area for can be found in **Figures 33** and **34**. No restart period was required to characterize this study well's productive history. Although there was some scatter in the data, there was good agreement between type curve and simulation derived results. Layer 1 and 2 permeability values were determined to be 0.030 and 0.008 md for both cases, with highly stimulated (X_f of 220 ft and skin of –4.3) reservoirs. As a Devonian Shale layer was present, the type curve match area was considerably larger than the simulation predicted value – 60 to 22.5 acres – as expected. However, cumulative recover estimates were found to be 141 MMscf and 188 MMscf for each technique.

***Area 5* –** The Area 5 study well was completed in two portions of the Devonian Shale – the Cleveland and Lower Huron shale layers. Production data from this well was extremely high quality, leading to excellent single layer and multi layer matches (**Figures 35** and **36**). Permeability values were found to be 0.009 and 0.005 md, while fracturing indicated well-stimulated conditions (X_f of 220 ft). Estimated 20-year recoveries were almost identical for each layer, coming in at 99 and 66 MMscf for the simulation and 98 and 68 MMscf for the type curve match. Again, drainage area was over-predicted at 220 acres for each layer as compared to the simulation-derived value of 65 acres.

***Area 6* – Figures 37** and **38** show the single and multiple layer type curve matches for the Area 6 study well. The multiple layer type curve results again showed excellent agreement with those from the simulation work, with the only difference being the larger drainage area in layer 2 (shale).

***Area 7* –** The study well for Area 7 was completed in only the Big Injun formation. Since it was only a single completion, no multiple layer matching was performed. Further, a restart was needed to match the data from 59 months to the end of history due to a long-term shut-in of the well. Although the initial match (**Figure 39**) revealed a very long infinite conductivity fracture (1,345 feet) with an associated large drainage area, the well may still be in linear flow without encountering a reservoir or offset well boundary. The subsequent match of the restart data (**Figure 40**) resulted in a fracture half-length and drainage area (231 feet and 69 acres) that was comparable to the simulated results (-4.7 and 73 acres). Cumulative recovery was also found to be similar to the simulation results.

***Area 8* –** Since the simulation results indicated the skin factor to be near zero (neutral), type curve matching for the Area 8 study well could not fully replicate the simulation results due to the fact the type curves are designed for infinite conductivity fractures. Approximations were made, however, to greatly reduce the determined fracture lengths to small values (17 feet). As a result, good agreement with the simulation results were determined for permeability, drainage area and recovery for each of the two layers. **Figures 41** and **42** show the type curve matches.

***Area 9* – Figures 43** through **46** show the initial and restart type curve matches for this study well. The restart occurred following 16 months of production time. The initial match showed good agreement with permeability and indicated that the well was stimulated with a 160 ft fracture half-length. Drainage area was low due to the rapid decline seen in the data set.

The restart period also had good agreement with permeability. Additionally, a declining skin factor from the initial to the restart period (X_f of 150 to 119 ft) was seen, which agreed with the simulation case, and the drainage area was in better agreement as well. Total recovery was close between the simulation and type curve match results (251 MMcf to 235 MMcf). However, individual layers varied dramatically. This is due to the removal of the initial 16 months of production history from the computation of 20-year recovery values.

***Area 10* –** The results of the single and multi layer matching for the Area 10 study well were shown in **Figures 47** and **48**. The type curve results show good agreement with those derived from the simulation history matching. Permeability values were very close, skin factors, predicted at –2 for the simulation, were found to be 40 feet and drainage areas were within a few acres. As a result, layer recoveries were within a few MMscf from one another.

***Area 11* –** Type curve matching results were in agreement with the simulation results. **Figures 49** and **50** depict the type curve matches. Permeability and fracture half-lengths were found to compare favorably to the simulation results. However the drainage area determined for Layer 1 indicated an area (33 acres) less than the expected value of 52 acres. This discrepancy accounts for the 10 MMscf difference in Layer 1 20-year recovery.

Belden & Blake Corporation Study Areas:

***Area 12 Study Well* – Figure 51** shows the results of the single layer type curve match for this study well. Since the well was completed in only one layer (Grimsby sand), no multi layer matching was necessary. The type curve matching results compared favorably with the simulation history matches. Permeability was found to be 0.5 md, fracture half-length was about 31 feet and drainage area was determined to be 55 acres. 20-year recovery was estimated to be 218 MMscf, which was very close to the simulated result of 221 MMscf. Input parameters for this single layer match are depicted on the bottom of **Figure 52**.

Although the simulation history match estimated the skin factor to be –2.7, which is equivalent to an infinite conductivity fracture of about 5 feet in length, *METEOR* estimated the fracture length to be about 30 feet (-4.0). The differences in equivalent skin factor are not surprising as the *METEOR* software is based on the assumption of perfect transient behavior of infinite conductivity fracture half-lengths. However, in these study well cases, the reality is that the true stimulation response is nearly always less than the idealized infinite conductivity response (100 to several hundred feet) due to fracture face damage, long-term fracture cleanup and degradation, suggesting the need for implementing damage curves within the transient portion (early time) of the type curve.

Area 13 Study Well – Initially producing only from the Whirlpool Sand, the initial type curve match was conducted using the hyperbolic decline curves. **Figure 52** shows the resultant type curve match. Although the drainage area was slightly less than the history match value of 45 acres, the permeability and fracture half-length values showed good agreement with the simulation results.

Figures 53 and 54 depict the single and multi layer type curve matches for the restarted production period, following the addition of the Grimsby Sand at 57 cumulative months of production time. To match the character of the declining production, an Aarps decline exponent of 0.8 was selected to best match the data.

Along the top of the graphic, the commingled properties are shown from the single layer type curve match, which describe the well's idealized total recovery rate vs. time, also the red line from **Figure 53**. Porosity, thickness, water saturation and Aarps decline exponent (b) can then be input for each of the two layers. Following data input, the permeability, fracture half-length and drainage area for each of the layers can then be input into the software. To analyze the discrete layers, a multi layer analysis was carried out (**Figure 54**) following the single commingled analysis.

Depressing *METEOR*'s plot button then creates a graphic of the predicted recovery from each layer (blue and yellow lines), their summation (orange line) and the idealized total recovery rates from the single layer match (red line). A match is achieved when the summation of layers 1 and 2 overlays the single layer match (**Figure 54**).

A comparison of the simulation and type curve results shows good agreement between permeability values, 0.13 md and 0.29 md for layers one and two, and drainage area values, 10 and 32 acres. However, cumulative recovery and fracture half-length predictions were not as good.

Area 14 Study Well – Much like the previous study well, this well was also initially completed in the Whirlpool sand and later recompleted in the Grimsby Sand. **Figure 55** depicts the type curve match of Whirlpool production using *METEOR*'s hyperbolic decline analysis. Permeability, fracture half-length and recovery values matched reasonably well. However, drainage area was twice the simulation predicted value.

At 150 months of production, the Grimsby Sand was added to the production stream. **Figures 56 and 57** show the single and multi layer production type curve plots of the restart data. The multi layer match results for the restart period had good agreement with permeability. Additionally, a declining skin factor from the initial to the restart period (Xf of 73 to 40 ft) was seen, which agreed with the simulation case. The drainage areas were less than those predicted from the simulation case. However, the restart match does not have the capability of imposing a depleted reservoir pressure on the initial completion. So, an average pressure value was used, which may impact the volumetrics of a layer-by-layer examination. 20-year recovery values were about 380 MMscf as compared to the simulation-predicted value of about 410 MMscf.

***Area 15 Study Well* – Figures 58 and 59** show the single and multiple layer type curve matches for this study well. Estimated permeability and drainage area values were in good agreement with those values determined from the history match. Further, the small fracture half-length values concur with those simulation results indicating a strong initial skin factor (-4) declining to a damaged condition (+3).

***Area 16 Study Well* –** As with the previous study well, there was little contrast in a comparison of simulation and type curve matching results. **Figures 60 and 61** show the single and multi layer type curve matches for this study well. The overall quality of the data is quite good and it is shown in the strong match results. Permeability, fracture half-length (27 ft is equivalent to –3.8), drainage area and 20-year recovery values as determined by *METEOR* are all similar to those determined from simulation history matching.

Conclusions

Equitable Production Company Study Areas:

- With few exceptions, the single and multi layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, *METEOR* was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions, thus verifying calculation performance of the new software.

- For desorption controlled reservoirs, *METEOR* will over predict drainage area values due to the presence of adsorbed gas in the shale or coal layer. To more properly account for the adsorbed gas-in-place, the reservoir's estimated porosity should be increased. Permeability and recovery values were similar to those derived from computer simulation. For the reservoir conditions in this study, a typical porosity increase to match drainage area and skin factor was from 1% to 3.5%.

- Since the *METEOR* type curve software is based on numerical formulations for fractures of infinite conductivity, the differences in equivalent skin factor, between simulator and type curve, are not surprising. However, the results did reveal that well stimulated layers tended to have large fracture half-lengths while poorly stimulated zones had much smaller half-lengths. The inclusion of damage curves within the transient portion of the type curve would improve the early time match significantly, allowing *METEOR* to model fracture cleanup or damage more effectively.

Belden & Blake Corporation Study Areas:

- With few exceptions, the single and multi layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, *METEOR* was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions.

- Since the *METEOR* type curve software is based on numerical formulations for fractures of infinite conductivity, the differences in equivalent skin factor, between simulator and type curve, are not entirely surprising. However, the results did reveal that well stimulated layers tended to have large fracture half-lengths while poorly stimulated zones had much smaller half-lengths. The inclusion of damage curves within the transient portion of the type curve would improve the early time match significantly, allowing *METEOR* to model fracture cleanup or damage effectively.

- *METEOR* software assumes a constant bottom hole flowing pressure for each match period. This is normally a reasonable assumption for low permeability gas wells. However, some wells such as the Area 16 study well had significant long-term variation in flowing pressure. The inclusion of a rate normalization technique could further improve the accuracy of the software.

Appendix 1

METEOR v. 1.1 Help File

I. Getting Started with *METEOR v. 1.1*

A. About this help file

1. References to toolbar, menu and other control functions for the *METEOR* software are shown bold and italicized
2. A superscript 1 denotes unavailable, at the time, controls
3. A superscript 2 denotes a feature that is accessible from the production type curve analysis window

B. Compatible file types

1. *METEOR* saves files as *.mdb, which is a Microsoft Access database file
2. Data is importable in IHS format, which is *.98c. Data can be exported this way from P.I. Dwights software or downloaded from their website.
3. Other import options include text format (*.txt, *.csv, *.prn, *.asc) and Excel format (*.xls). However, for these formats, the production data must be in columnar formats. Example input files for text and Excel-based input have been included in the sample directory.

C. Creating and opening database files

1. To begin the production analysis, the user is first required to create a new project database (*.mdb) file. To do so, the user can select either the ***New Project*** toolbar button or by selecting ***File*** from the menu and then ***New***. Following the selection, a dialogue box, **figure 1**, will prompt the user to name, locate and save the new project.

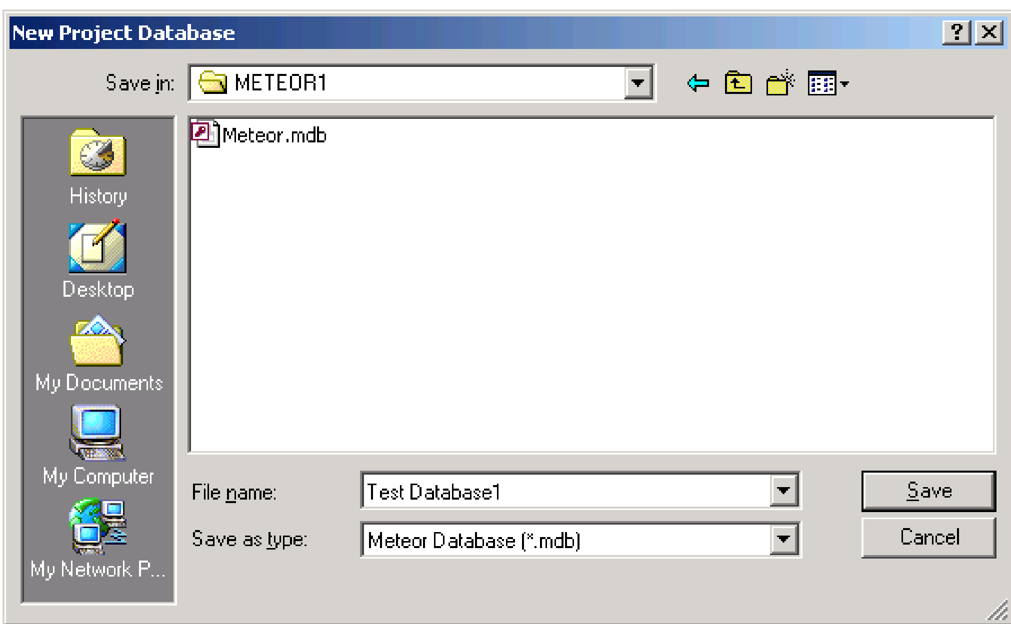

Figure 1 – New Project Database Dialog Box

2. Following the creation of the project, the user must populate the project with production data. A second dialogue box, **figure 2**, will prompt the user for the production data files to import, beginning within the directory the user created the project. Compatible file types were discussed in section B.

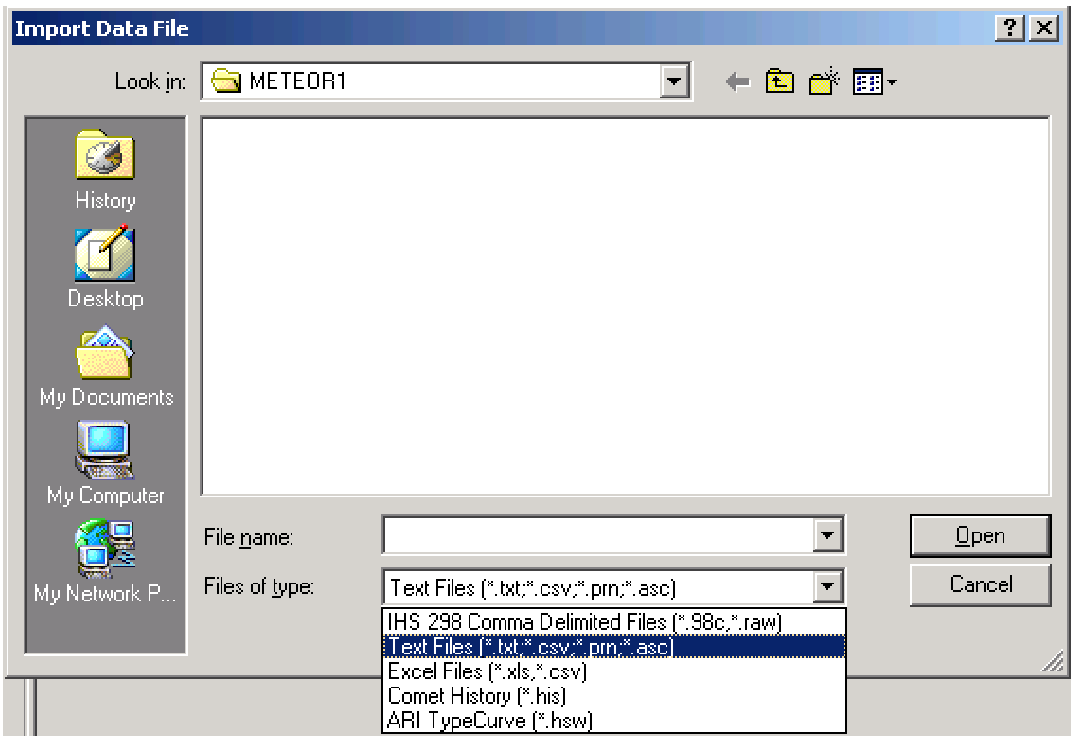

Figure 2 – Import Data File Dialog Box

3. To open an existing project the user can select ***File*** from the menu and then ***Open*** from the submenu or the user may choose to use the ***Open Project*** toolbar button. Each selection will bring up a dialogue box to allow the user to navigate to the directory containing the project. Select the relevant project and depress the ***Open*** button in the dialogue control.

D. Importing Production Data

1. Importing IHS data files (*.98c, *.raw)
   a. Open or create a new *METEOR* Database (*.mdb)
   b. When prompted, indicate the IHS data file (*.98c) to input within the import data file dialogue box, making sure the appropriate types of file ***(*.98c, *.raw)*** have been selected at the bottom of the dialogue box. If necessary, navigate to the appropriate directory containing the *.98c file using the ***Look in*** drop-down box.

c. The import process is automatic and the user is ready to begin the production type curve matching process.

2. Importing Text Files (*.txt, *.csv, *.prn, *.asc)
   a. Open or create a new *METEOR* Database (*.mdb)
   b. When prompted, indicate the text file (*.txt) to input within the import data file dialogue box, making sure the appropriate types of file ***(*.txt, *.csv, *.prn, *.asc)*** have been selected at the bottom of the dialogue box. If necessary, navigate to the appropriate directory containing the *.txt file using the ***Look in*** drop-down box.
   c. Select the ***Production*** database table for the import destination. This can be accomplished by using the drop-down menu to select "Production" and clicking the ***OK*** button. See **figure 3**.

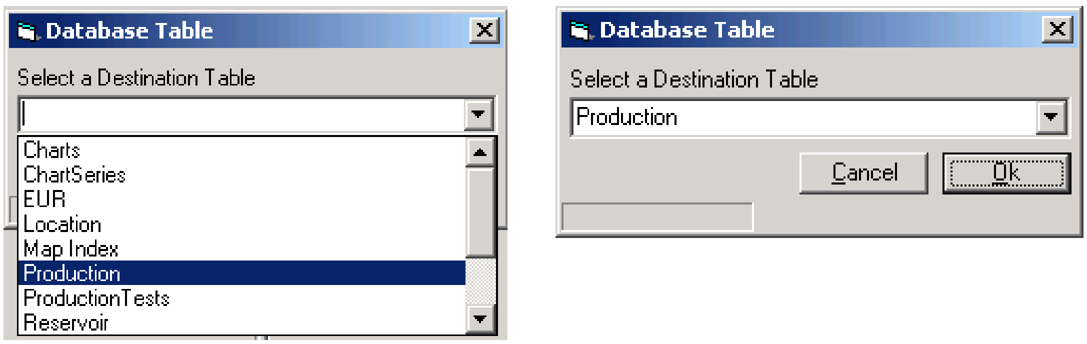

Figure 3 – Import Destination Table Dialog Box

   d. The ***Import Text File*** dialogue wizard will appear, **figure 4**.

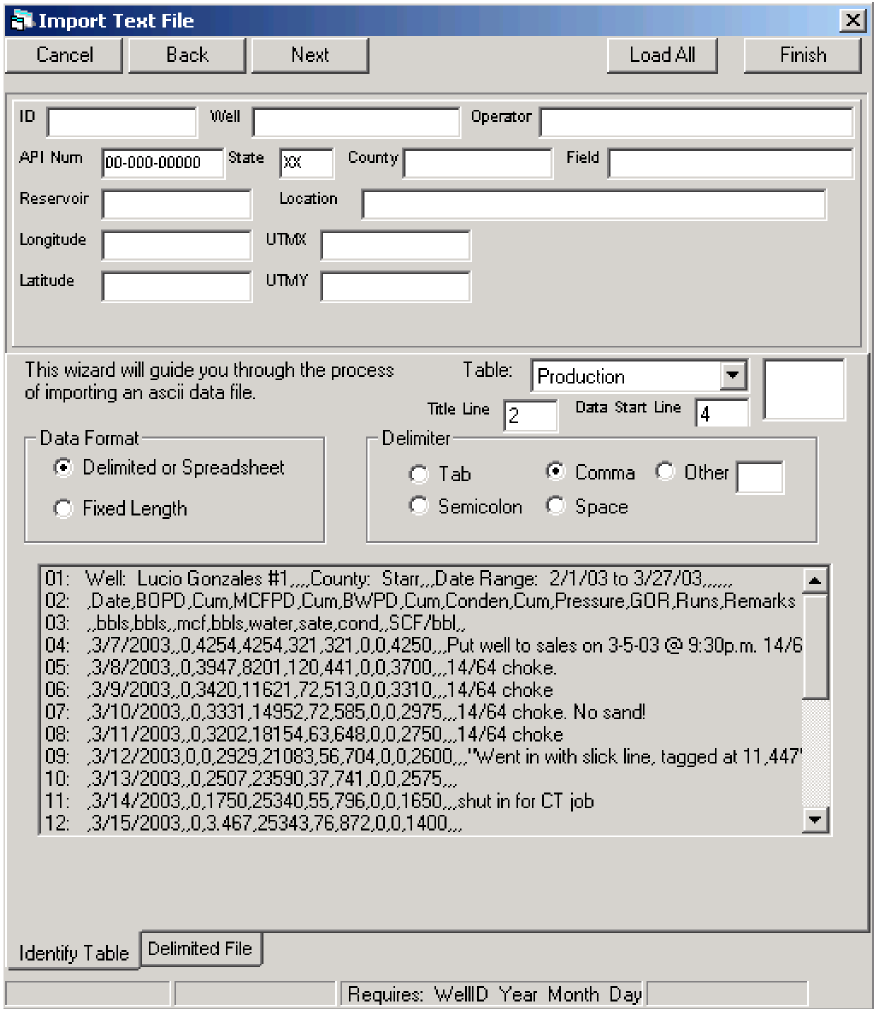

Figure 4 – Import Text File Dialog Box; Identity Table Tab

e. In the ***Title Line*** input box, indicate the line number of column header descriptions. Then, on in the ***Data Start Line*** input box, indicate the line the data begins.
f. For a delimited text file, ensure that the ***Delimited or Spreadsheet*** option under ***Data Format*** has been selected. In addition, select the appropriate delimiter for the input file.

g. The ***Import Text File*** wizard will subsequently move to the Delimited File tab window, with the data in columns, see **figure 5**.

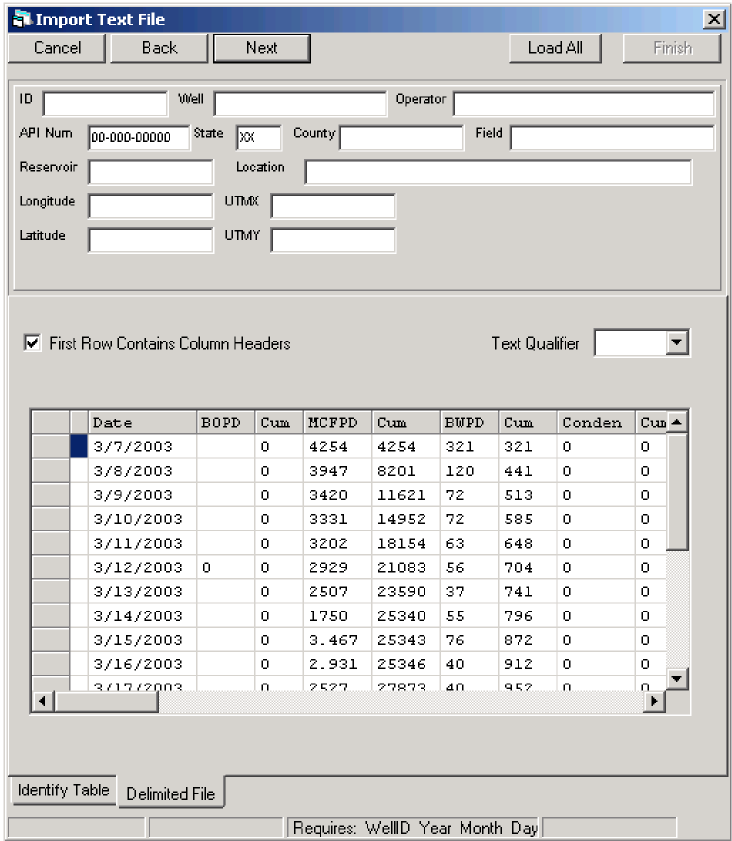

Figure 5 – Import Text File Dialog Box; Delimited File Tab

h. *METEOR* requires the input of the data to be done with the dates in Month, Day and Year columns. To convert calendar time (ie, 3/19/2003) to this format, single-click on the column header of the containing the date information. The user will be prompted to identify this as a date column. If so, select ***Yes***. The import wizard automatically generates the columns and enters the dates as Year, Month and Day in the final three columns of the worksheet. If desired, move the horizontal slider to the right to see the new data columns.

i. Select the ***Next*** button at the top of the import wizard. The ***Update Criteria*** tab will now be enabled.

j. Within the Update Criteria tab, **figure 6**, the user can indicate whether or not to ***Add New Records***, ***Update Existing Records***, and/or ***Delete Existing Records***. Depress the ***Next*** button when the criteria have been selected.

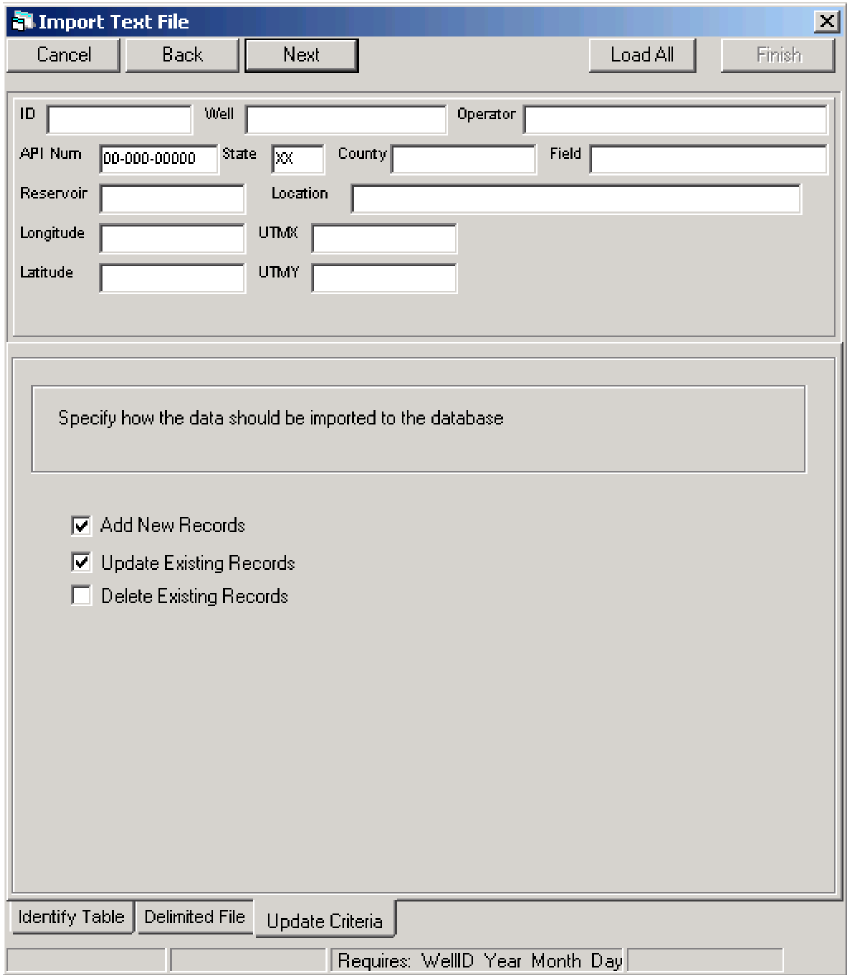

Figure 6 – Import Text File Dialog Box; Update Criteria Tab

k. The ***Assign Fields*** tab will now be enabled, **figure 7**. For importing data files, note that the bottom of the tab relates the minimum required information. Select the appropriate rate basis, ***Daily Rate***, ***Avg Daily Rate During Month***, or ***Monthly Rate*** for the dataset. NOTE: If ***Well ID*** values are not given in the input file, please enter a value in the ID input box (for a single-well input). At this time, other input values such as ***Well name***, ***Operator***, ***Field***, ***API Num.***, ***Reservoir, Location***, or well positional information may also be input (Lat/Long or UTM coordinates). For multi-well inputs, ARI recommends that these data values be input via the imported file.

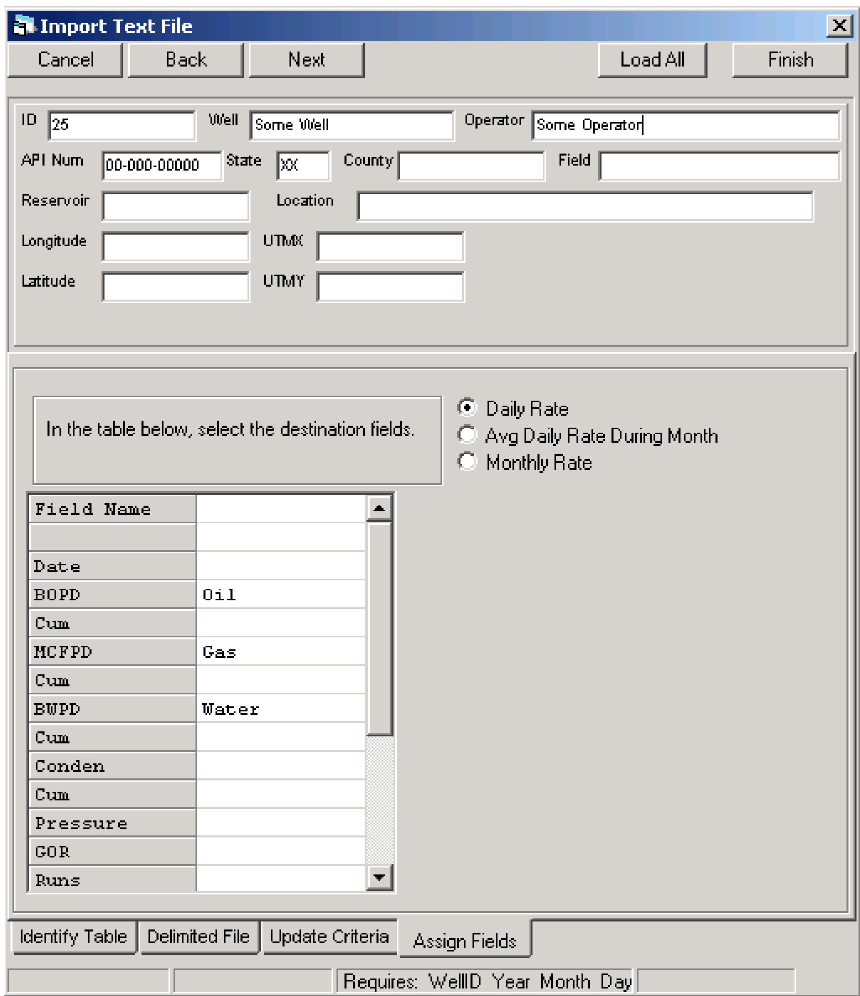

Figure 7 – Import Text File Dialog Box; Assign Fields Tab

l. Using the input worksheet in the bottom left-hand corner, select the appropriate database inputs from the drop-down menus using your mouse. Note: The header information from the .txt file has been placed on the left-hand side of the input worksheet. Directly to the right of each value, the user can access the drop-down menus for database inclusion. For example, the user's BOPD, MCFPD and BWPD will match the *METEOR* Database's Oil, Gas, and Water input criteria. See **figure 8**.

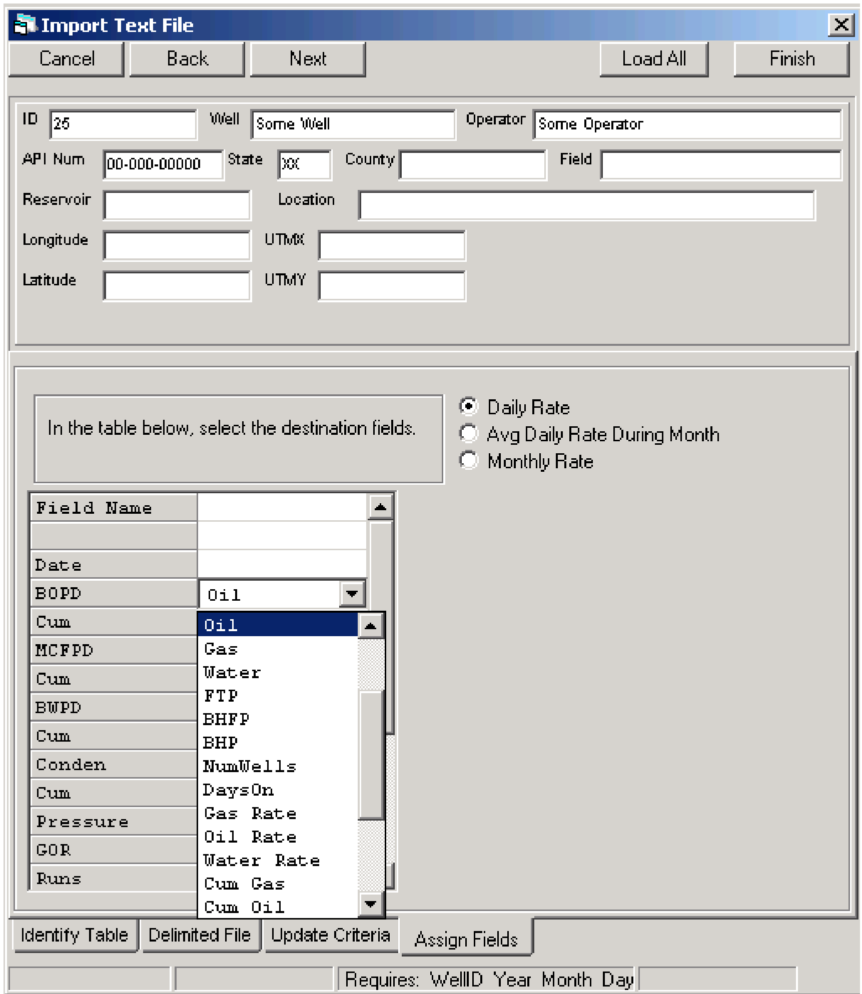

Figure 8 – Import Text File Dialog Box; Assign Fields Drop-Down Menu

m. Ensure that volume and time data (Year, Month, and Day) have been selected and depress the ***Finish*** button at the top of the window. If no well name has been selected, the user may be prompted for input.
n. The user is ready to begin the production type curve matching process.

3. Importing Microsoft Excel Files (*.xls).
   a. This version of *METEOR* was constructed using control references from Microsoft Office XP (2002). As a result, those program users employing Microsoft Excel versions prior to XP (2002) will be unable to utilize the Excel production data import protocol. If this is the case, Advanced Resources International suggests saving the Excel file as a comma delimited

text file, in either *.txt, *.csv formats, and utilizing the text importing protocol. Review Help File section I, D, 2.

b. Open or create a new *METEOR* Database (*.mdb), **figure 9**.

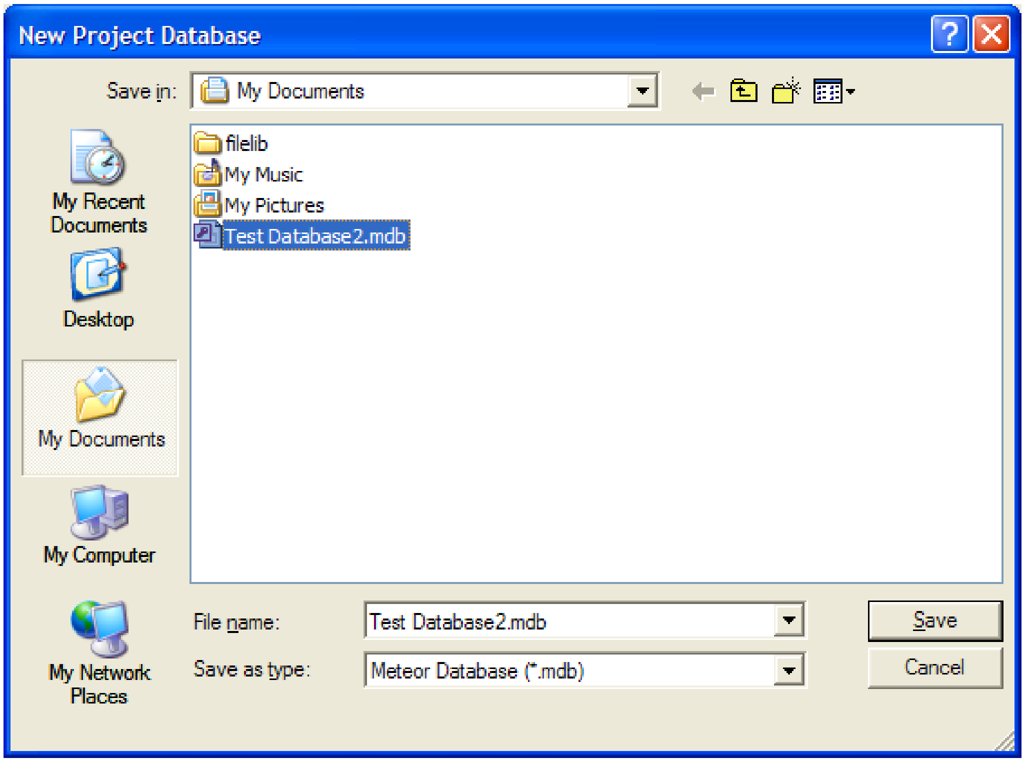

Figure 9 – New Project Database Dialog Box

c. When prompted, indicate the Excel file (*.xls) to input within the import data file dialogue box, making sure the appropriate types of file ***(*.xls)*** have been selected at the bottom of the dialogue box, **figure 10**. If necessary, navigate to the appropriate directory containing the *.xls file using the ***Look in*** drop-down box.

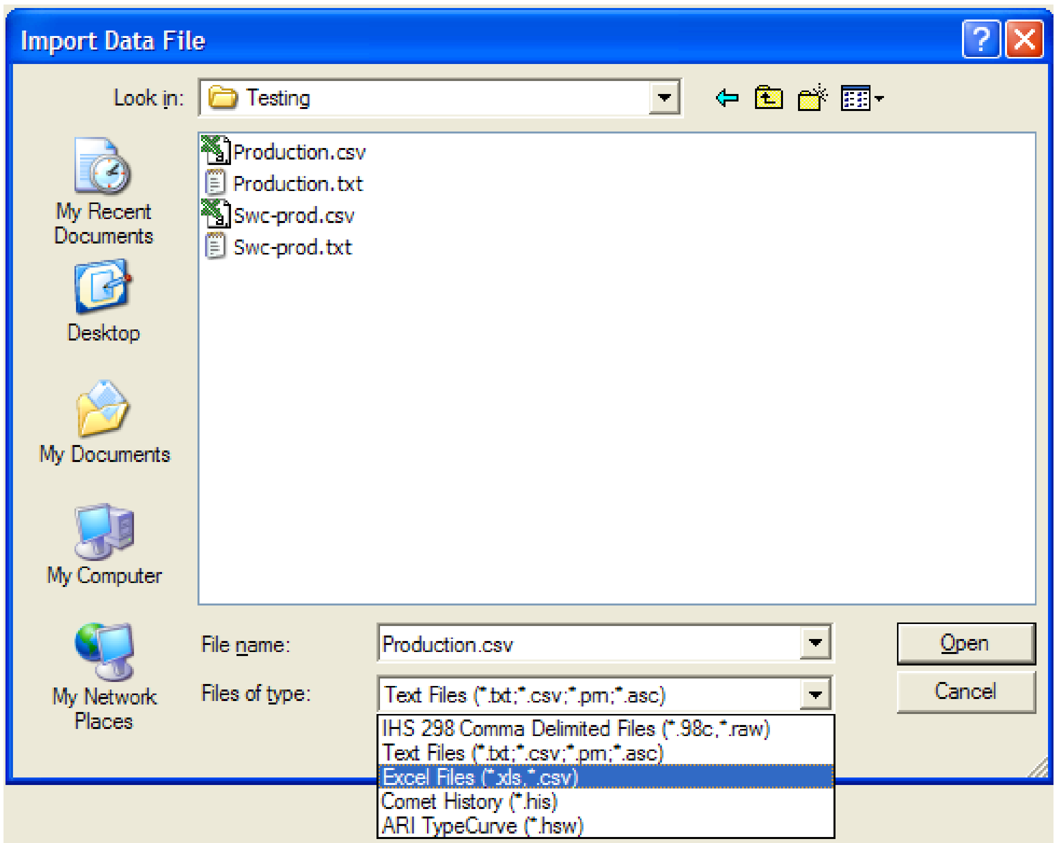

Figure 10 – Import Data File Dialog Box

d. The ***Select Import Worksheet*** will open.
e. In the upper left-hand corner, select the appropriate Excel worksheet tab containing the desired data set. The data will then appear in the bottom window, **figure 11**.

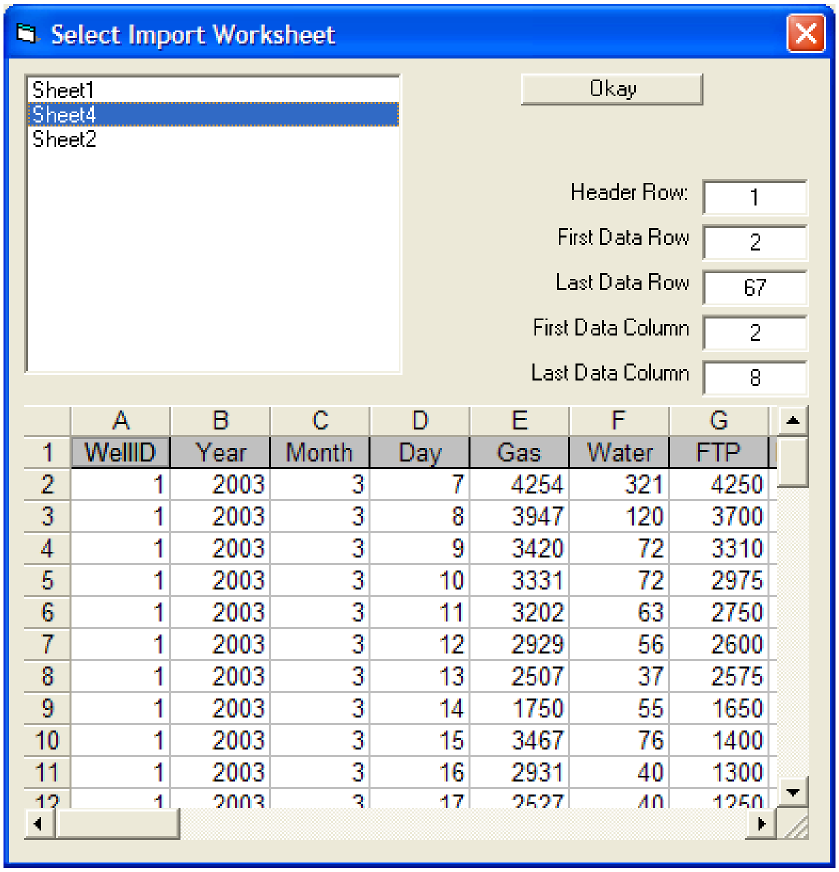

Figure 11 – Select Import Worksheet Dialog Box

f. Identify the respective positions of the ***Header Row***, ***First Data Row***, ***Last Data Row***, ***First Data Column***, and ***Last Data Column***. Any combination of numerical and alphabetical inputs for columnar input data can be used. For instance, if column number 3 contains the ***First Data Column***, a C may be used in lieu of the numeral 3. Horizontal and vertical sliders are available for scrolling the input set to confirm entries.

g. Once the row and columnar information has been entered, depress the ***OK*** button.

h. The ***Import Text File*** wizard will then appear. Select the ***Delimited File*** tab from the bottom of the window, **figure 12**. The ***Import Text File*** wizard will subsequently move to a new import window, with the import data now visible in columns.

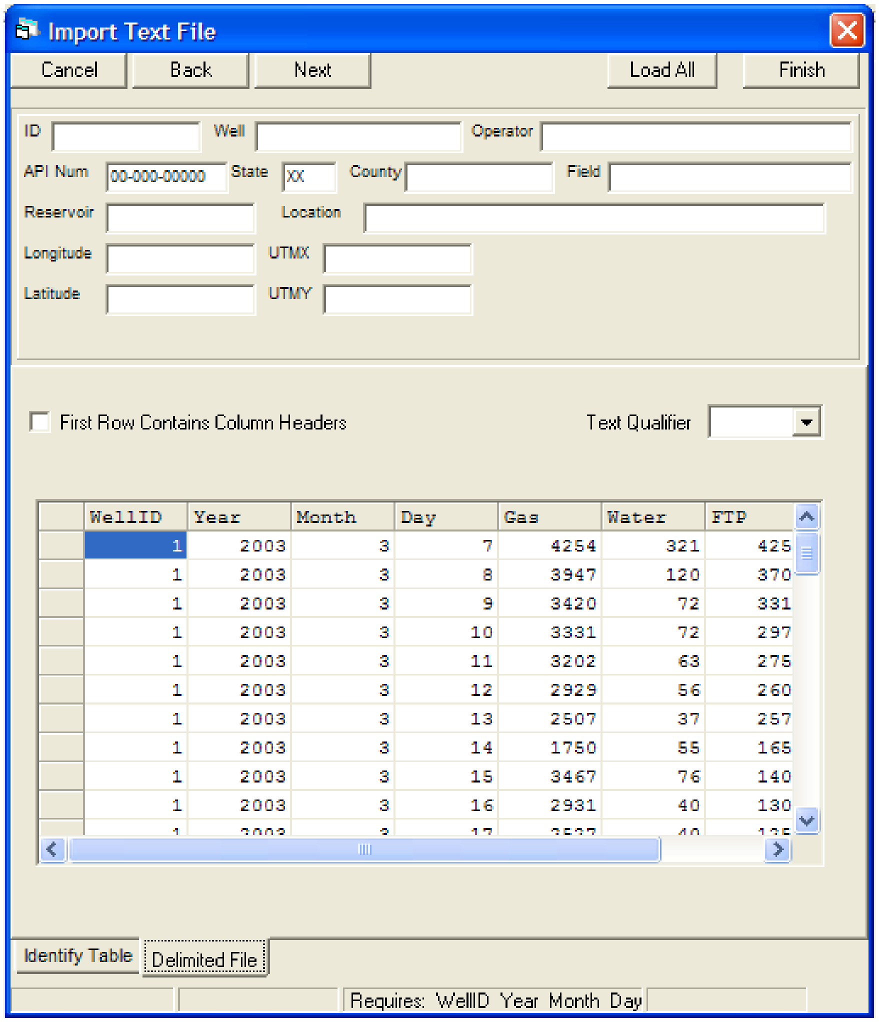

Figure 12 – Import Text File Dialog Box; Delimited File Tab

i. *METEOR* requires the input of the data to be done with the dates in Month, Day and Year columns. If it is necessary to convert calendar time (ie, 3/19/2003) to this format, single-click on the column containing the date information. The user will be prompted to identify this as a date column. If so, select ***Yes***. The import wizard automatically generates the columns and enters the dates as Year, Month and Day in the final three columns of the worksheet. If necessary, move the horizontal slider to the right to see the new data columns. If the Month, Day and Year columns are already described (as seen in **figure 12**), this step may be omitted.

j. Select the ***Next*** button at the top of the import wizard. The ***Update Criteria*** tab will now be enabled, **figure 13**.

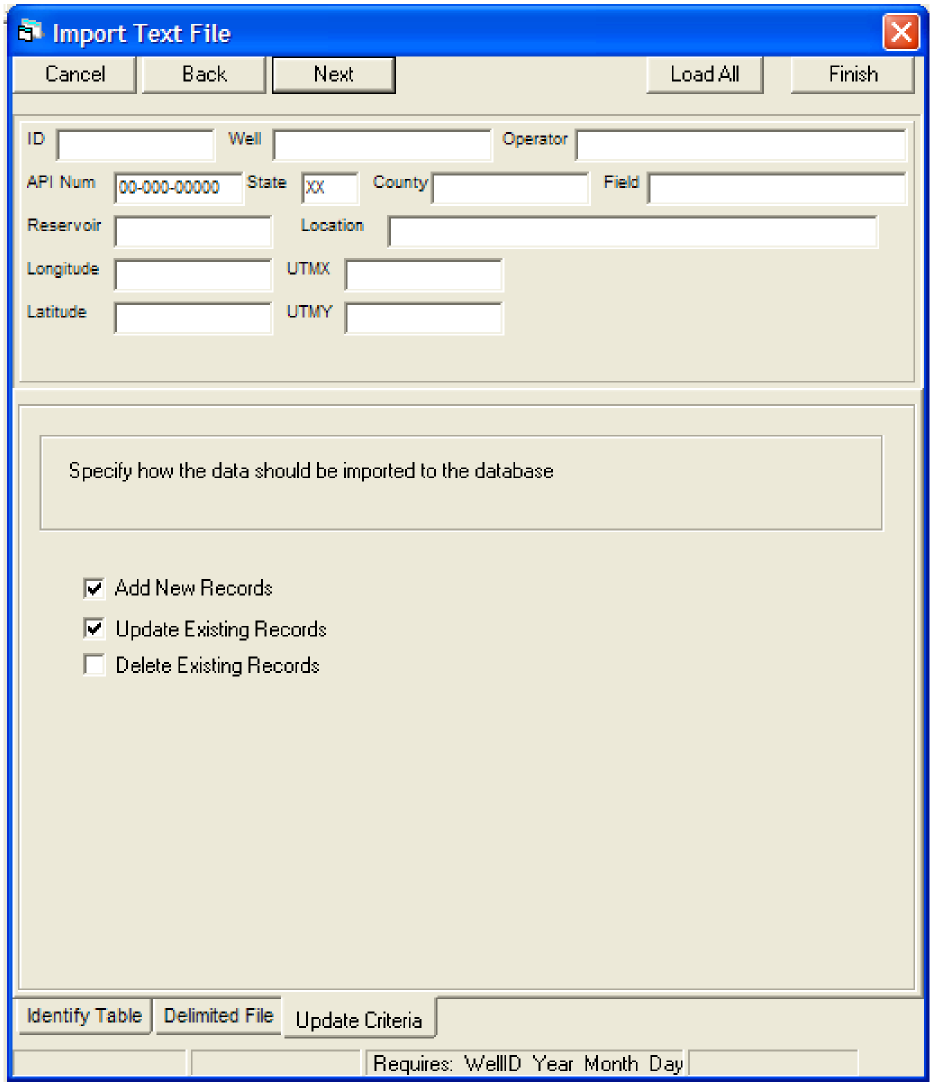

Figure 13 – Import Text File Dialog Box; Update Criteria Tab

k. Within the Update Criteria tab, the user can indicate whether or not to ***Add New Records***, ***Update Existing Records***, and/or ***Delete Existing Records*** existing records. Depress the ***Next*** button when the criteria have been selected.

l. The ***Assign Fields*** tab will now be enabled, **figure 14**. For importing data files, note that the bottom of the tab relates the minimum required information. Select the appropriate rate basis, ***Daily Rate***, ***Avg Daily Rate During Month***, or ***Monthly Rate*** for the dataset. NOTE: If ***Well ID*** values are not given in the input file, please enter a value in the ID input box (for a single-well input). At this time, other input values such as ***Well name***, ***Operator***, ***Field***, ***API Num.***, ***Reservoir, Location***, or well positional information may also be input (Lat/Long or UTM coordinates). For multi-well inputs, ARI recommends that these data values be input via the import file.

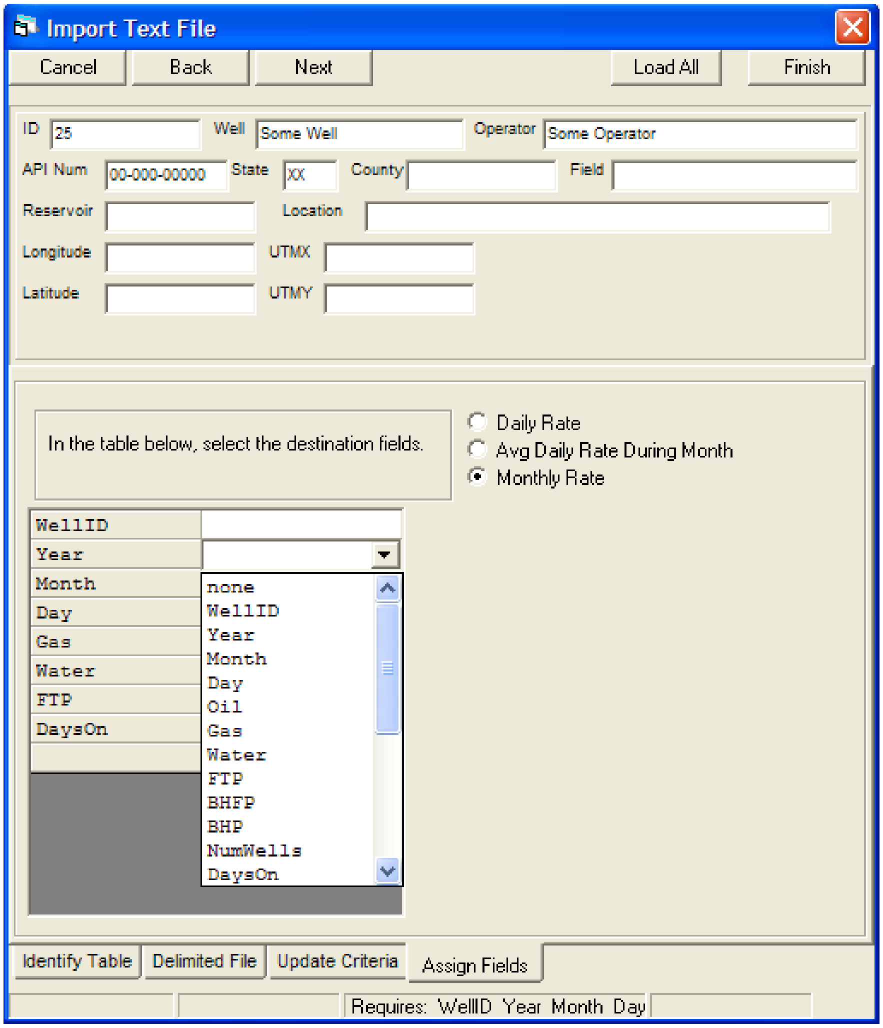

Figure 14 – Import Text File Dialog Box; Assign Fields Tab

m. Using the input worksheet in the bottom left-hand corner, select the appropriate database inputs from the drop-down menus using your mouse. Note: The header information from the .xls file has been placed on the left-hand side of the input worksheet. Directly to the right of each value, the user can access the drop-down menus for database inclusion. For example, the user's oil, gas and water rates will match the *METEOR* Database's Oil, Gas, and Water input criteria.

n. Ensure that volume and time data (Year, Month, and Day) have been selected and depress the ***Finish*** button at the top of the window. If no well name has been selected, the user may be prompted for input.

o. The user is ready to begin the production type curve matching process.

E. Viewing well data

1. A list of well names can be accessed from the drop-down menu at the left of the screen. Selecting a well name will display a production chart to the right and information for the well in fields below the well name drop-down menu. The program interface is depicted in **figure 15**.
2. The main *METEOR* window has 8 menus at the top as follows: ***File, Edit, View, Database, Analysis, Maps, Window*** and ***Help***. The functions within each are explained following.
3. The ***File*** Menu offers the following options:
    a. ***New***: Opens a new, blank project
    b. ***Open***: Opens an existing project
    c. ***Setup Printer***: To set up printer options
    d. ***Page Setup***[1]
    e. ***Print Preview***: Previews the graph in print format
    f. ***Print Chart***: Prints the chart for the active well
    g. ***Print Report***: Prints the report for the active well
    h. ***Batch Reports***: Prints reports for all wells that have been analyzed up to that point in time.
    i. ***Exit***: Exits the program
4. The ***Edit*** menu offers the following options:
    a. ***Edit Chart***: This brings up a window with options for making changes to the chart currently being worked with (see section II for details)
5. The ***View*** menu offers the following options:
    a. ***Toolbar***: Toggle on or off the toolbar
    b. ***Status Bar***: Toggle on or off the status bar at the bottom of the window
    c. ***Results Pane***: Toggle on or off the well data to the left of the chart
    d. ***Zoom/Unzoom***[1]
    e. ***Options***[1]
6. Using the ***Database*** drop-down menu you can view/manipulate the raw data using the following options:
    a. ***Import***
    b. ***Edit Well Data***
    c. ***Edit Data Tables***
7. Using the ***Analysis*** drop-down menu, the following plots can be created for each well:
    a. ***Production Plots*** (Rate vs. Calendar Time, Log Rate vs. Production Time, Rate vs. Cum Time)
    b. ***Production Type-Curve Analysis***[1]
    c. ***Variable Compressibility Decline Curve Analysis***[2]
8. The ***Maps*** drop-down menu offers the following options:
    a. ***Bubble Map*** (Cum Gas or Calc EUR)
    b. ***Background Map*** (No Background Map or Background Map from File)
    c. ***Coordinate System*** (Lat Long or UTM Coords)
    d. ***New Background Map***

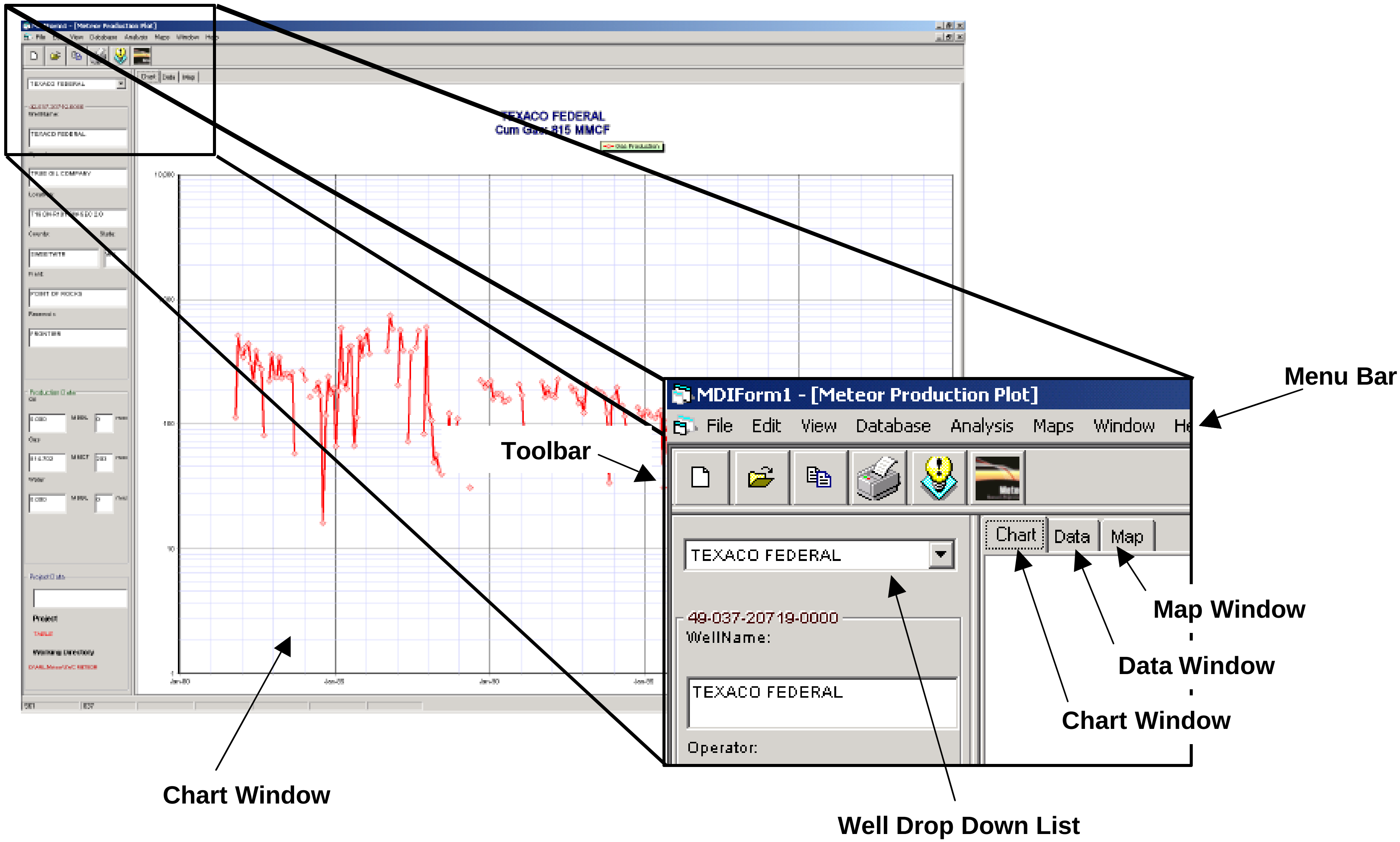

Figure 15 – *METEOR* Program Interface

9. The ***Windows*** drop-down menu allows for tiling of chart windows as well as cascading them, vertically or horizontally
10. The last menu is the ***Help*** menu. The ***METEOR*** help file can be accessed here.
11. There is also a tool bar at the top of the chart window, below the menu with the following buttons for frequently used menu features: ***New Project, Open Project, Save, Copy, Paste, Print, Help*** and the ***METEOR*** button to bring up the Hyperbolic Analysis window. Although there are no titles for the toolbar buttons, the user can "hover" the mouse cursor over a button to determine its function.

E. The Chart Window

The chart window has two additional views listed on tabs at the upper left hand of the chart. Aside from '***Chart***' there is '***Data***' which brings up the file's data in tabular format and '***Map***' which shows a locational map of all wells in the data file if positional data is available. The status bar at the bottom of the screen will display the coordinate information from the map as the cursor is moved over the screen.

There is also the option of loading in a background map from file if one is available. This background file needs to be an image file, such as a *.jpeg or *.pcx. If coordinate information is available for the corners of the image and those coordinates match the coordinate system used by the well data, the background map will align with the well locations on the ***Map*** tab. The directory location and filename for each background map must be entered into the project's *.mdb file. If more than one map is entered the arrows at the upper left of the map window can be used to toggle between the different maps.

II. Editing Charts

To edit the chart for the well currently being analyzed, bring up the Edit Chart window by selecting ***Edit Chart*** from the ***Edit*** menu. A window will appear with 8 tabs of options including ***Chart*** (including the sub-tabs ***Series***, ***Axis***, ***Titles***, ***Legend***), ***Series***, ***Export*** and ***Print***. The Edit Chart Window is depicted in **figure 16**.

A. Under the ***Chart*** tab are the following options:

1. The ***Series*** tab offers options with which the data series included on the chart can be added, removed, toggled on and off and modified.
2. The ***Axis*** tab offers options with regards to the format, numbering and appearance of the chart axes.
3. The ***Title*** tab designates the appearance of the title including font, position, style and content
4. The ***Legend*** tab turns on and off the legend and allows for formatting of fonts, symbols and the general positioning.

B. Under the ***Series*** tab are options for changing the appearance of the data series included on the chart. The color and size of the lines, points and markers can be adjusted as well as the data source.

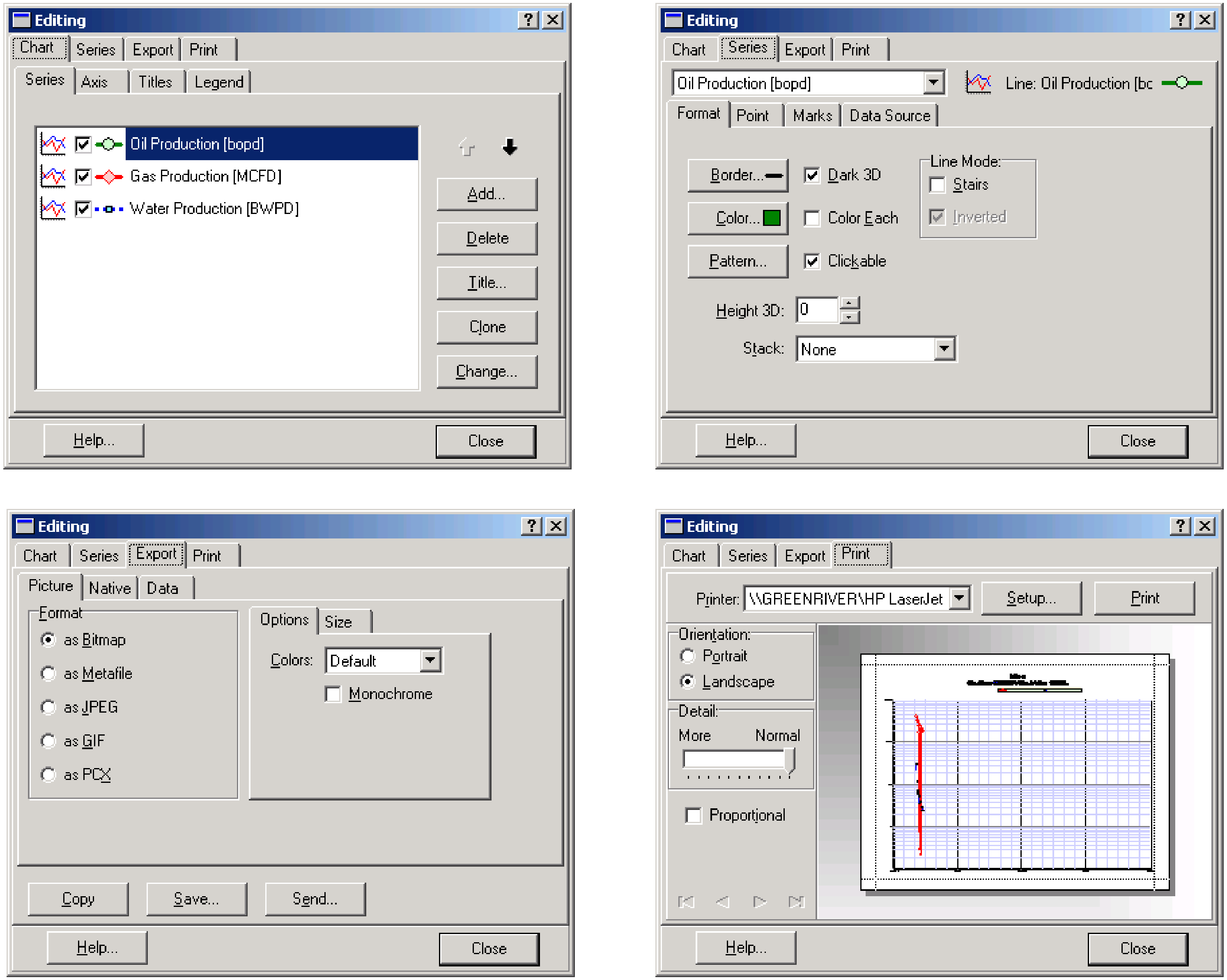

Figure 16 – Chart Editing Window

C. Under the ***Export*** tab are options for exporting the chart as the following image types: Bitmap, Metafile, JPG, GIF or PCX. The data can also be exported in the following formats: Text, XML, HTML Table and Excel.

D. The ***Print*** tab offers print set up options including orientation and level of detail as well as printer selection.

III. Single Layer Hyperbolic Type Curve Matching

A. Type Curve Matching

To type curve match a selected well, click the ***METEOR*** Button on the toolbar or under the ***Analysis*** menu choose ***Production Type-Curve Analysis***. This will bring up the Single Layer Type Hyperbolic Curves window. This window is depicted in **figure 17**. The data points can be matched to the type curve by clicking the appropriate arrow on the ***Shift Points*** four-way arrow button in the lower right corner of the window. This button shifts the data points up, down, left and right to enable the user to match the data to the appropriate type curve. Immediately to the left of the button is a ***Movement Sensitivity*** slider bar, which allows fine to coarse movements on a scale of one (fine) to ten (coarse). The data may also be shifted by selecting the Move button from the toolbar and clicking and dragging the data with the mouse. To aid in matching use the features in the lower left corner of the window, **figure 18**. Use the ***Xe/Xf*** drop-down menu to select the appropriate drainage stem the data is being matched to. Also, the hyperbolic exponent may be adjusted to change the shape of the ARPS decline curves to better fit the data. The data ***Smoothing*** option calculates a moving average of the data points on a 3-point to 11-point basis.

There are nine main toolbar features available for the user as well as two sub-toolbar features for use in the movement of the production data. The ***Save*** button acts much the same as the ***Update*** button, allowing the user to save the data match to the database file. For the movement of the data, the user can select the ***Move*** button, which allows the user to click-and-drag the data using the mouse.

Used in conjunction with the ***Move*** button, the user can alter the sensitivity of the data movements (using the mouse) by changing the setting on the ***Movement Sensitivity*** slider bcated below the toolbar. A setting of one indicates fine movements while a setting of nine indicates the coarsest data movements, see **figure 18**. The ***Update/Show Match Point*** sub-feature will plot the current match point on the type curve match. If the user then reselects this feature following additional movement of the data, the new match point will be depicted with respect to the previous match point.

The user is also supplied with ***Zoom*** and ***Unzoom*** controls for refinement of the type curve match. Selecting the ***Zoom*** toolbar button and clicking and dragging a rectangle over the area of interest enlarges the range for user review. Selecting ***Unzoom*** restores the match to the original perspective. Note: if the user zooms in more than once, the Unzoom feature will not restore the plot to the original perspective, but to the previous

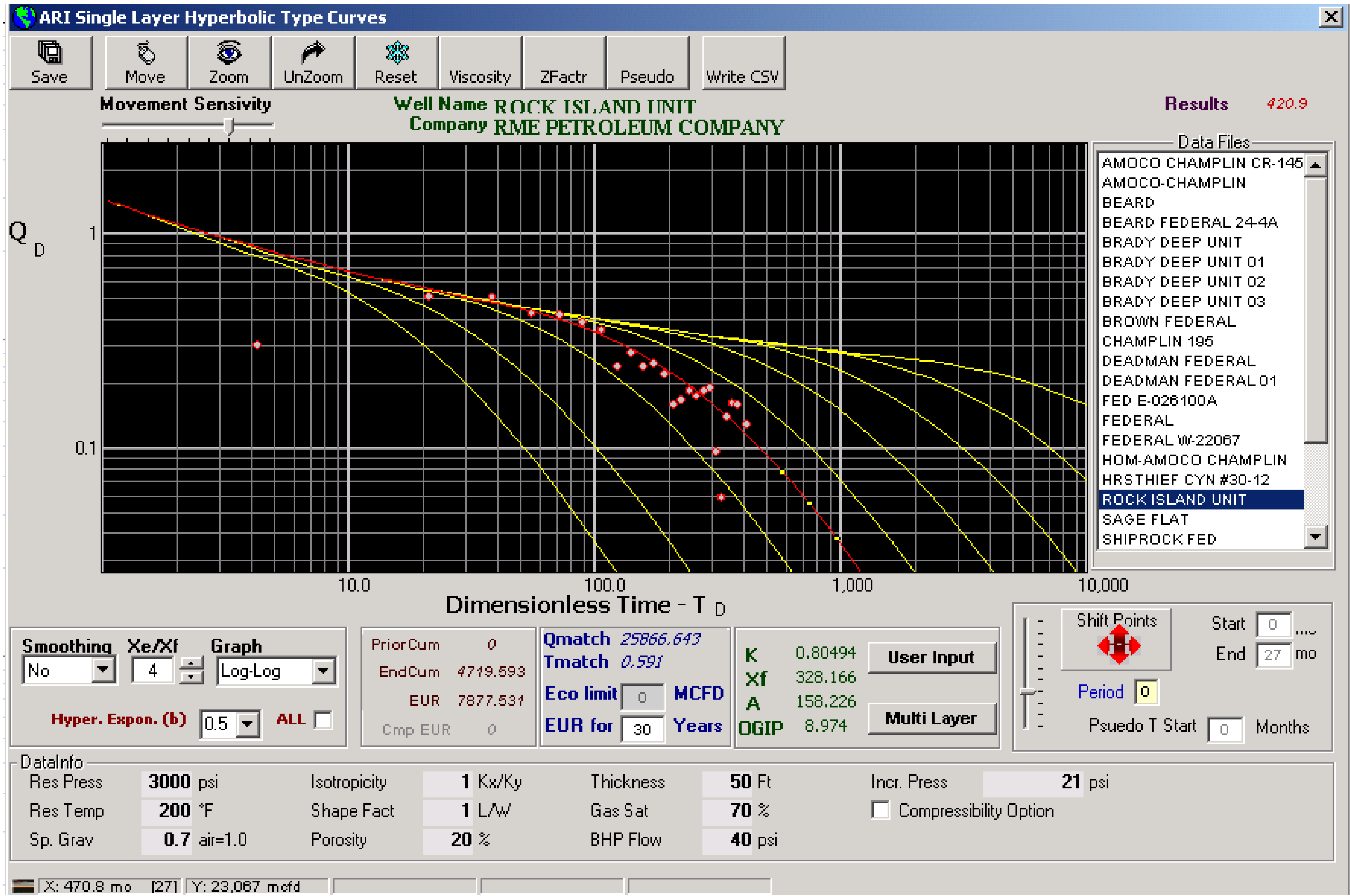

Figure 17 – Type Curve Matching Interface Window

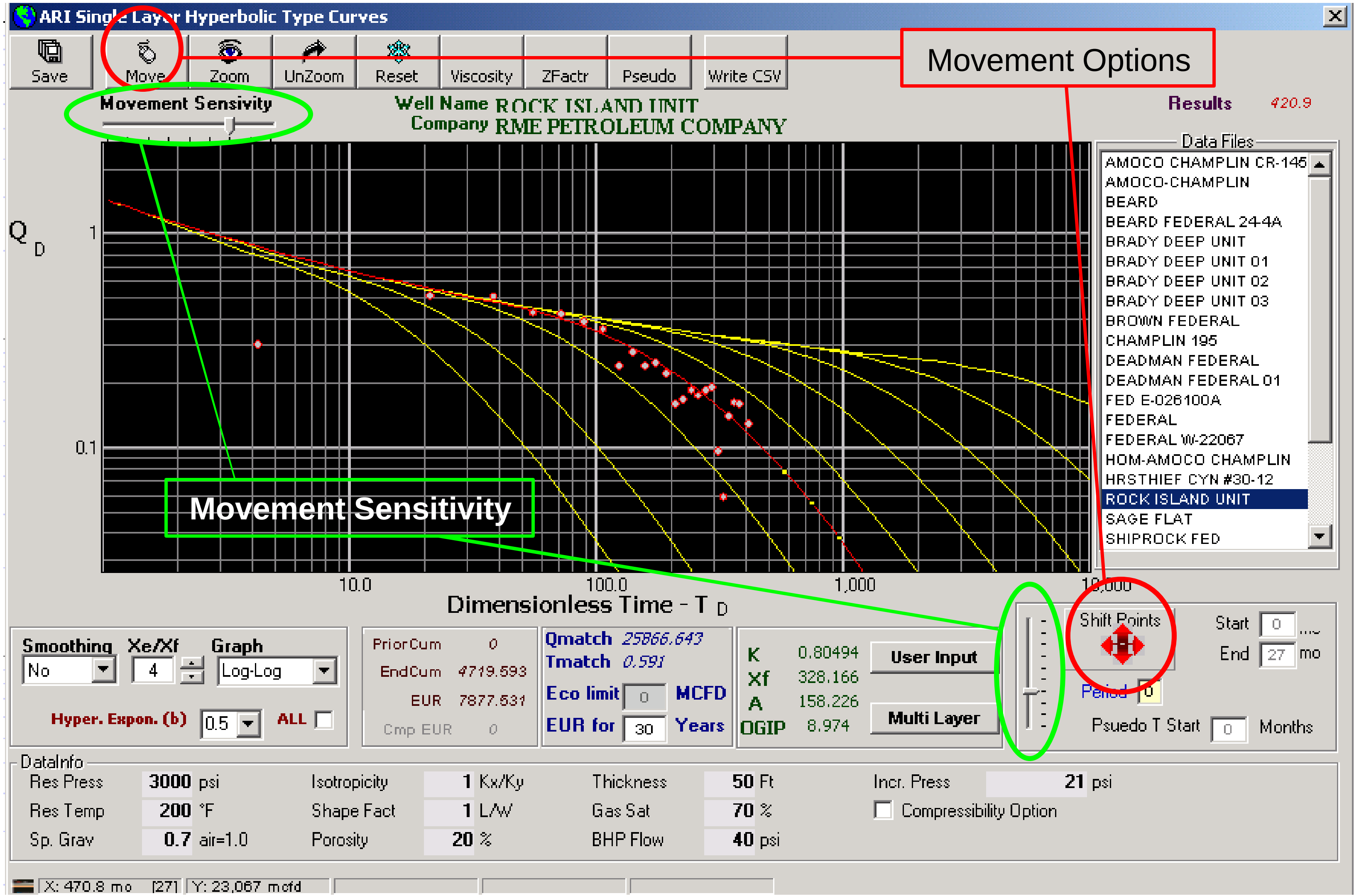

Figure 18 – Data Movement Options within the Type Curve Interface Window

perspective. To fully unzoom in this case, select the ***Reset toolbar button***, which the user can also invoke to refresh the plot.

The remaining toolbar features – ***Viscosity, ZFactr,*** and ***Pseudo*** – show the respective gas viscosity, z-factor and pseudopressure (real gas potential) for the gas described in the user input dialogue. When selected, a graphical representation of the property on the y-axis is plotted against the range of zero to reservoir pressure.

Click the ***User Input*** button to bring up reservoir and well data inputs. These can also be accessed by a right mouse click on the data into fields at the bottom of the window. After entering new reservoir and well data inputs click on the ***Update*** button. After updating, note that the calculated results are also updated. Therefore, it is important to enter representative values for reservoir and well inputs.

B. Restarts

METEOR has the capability to handle changes in operating conditions, well workovers and re-stimulations through the use of the ***Restart*** option. To utilize the restart option, the user must first type in a "1" in the ***Period*** text box. The ***Period*** text box is located to the right of the Shift Points button. If there is a second restart, a "2" is entered, and so on. Once a value is input in the Period text box, the user is prompted to save the original match. Restart controls are show in **figure 19**.

The user then must input the month, in elapsed production time that the restart will occur in the ***Start*** text box. The ***End*** text box will then contain the final production month that will be considered for type curve matching of the particular restart. Conversely, the user may wish to use the ***slider bar*** located below the ***Shift Points*** button and the ***Start*** and ***End*** text boxes to select the beginning and end of the restart period. Note that the data disappears from the type curve plot as the slider is moved from the left to the right.

After the appropriate restart period has been selected, a number will appear to the right of the ***Period*** text box. This value must be input into the ***Pseudo TStart*** text box to initialize the restart period for matching. As the user enters the value, the type curve restart will re-initialize, allowing the user to assess the impact of the restart period. Also, *METEOR* will automatically decrement the value in the ***Pseudo TStart*** text box by a value of one.

IV. Multi-layer Hyperbolic Type Curve Matching

Click the ***Multi Layer*** button to open the ***Multi Layer*** matching window, **figure 20**. Enter the appropriate information for each layer, including gas saturation, thickness, porosity and decline exponent. Once the numbers are entered, click ***Plot*** to see the curves. Complete the match by adjusting permeability, fracture half-length and drainage area until the summation curve matches with the match result curve. Use the ***Grid*** check box to toggle on and off the grid lines. Once the match is complete click the ***Update***

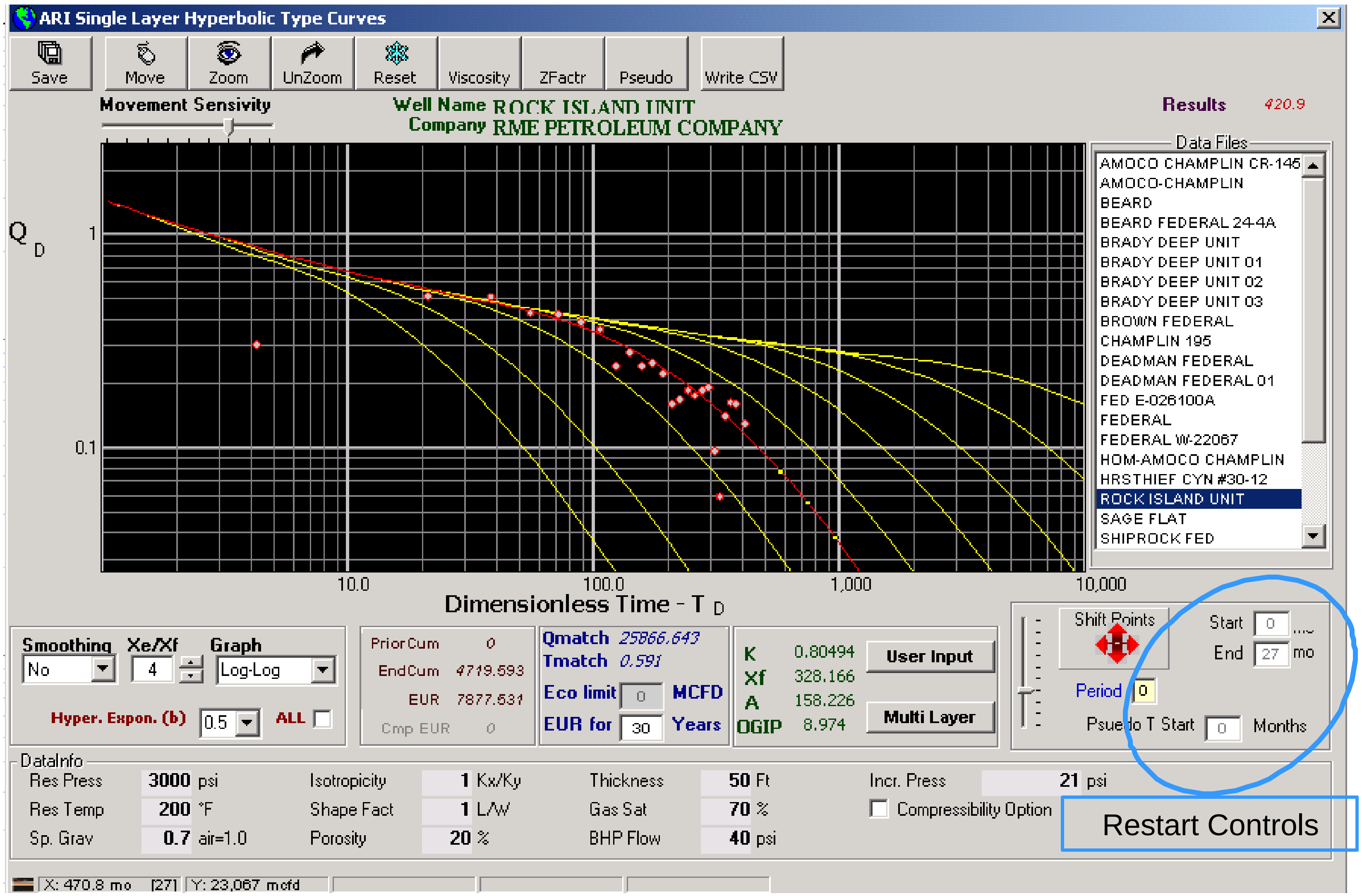

Figure 19 – Restart Controls within the Type Curve Interface Window

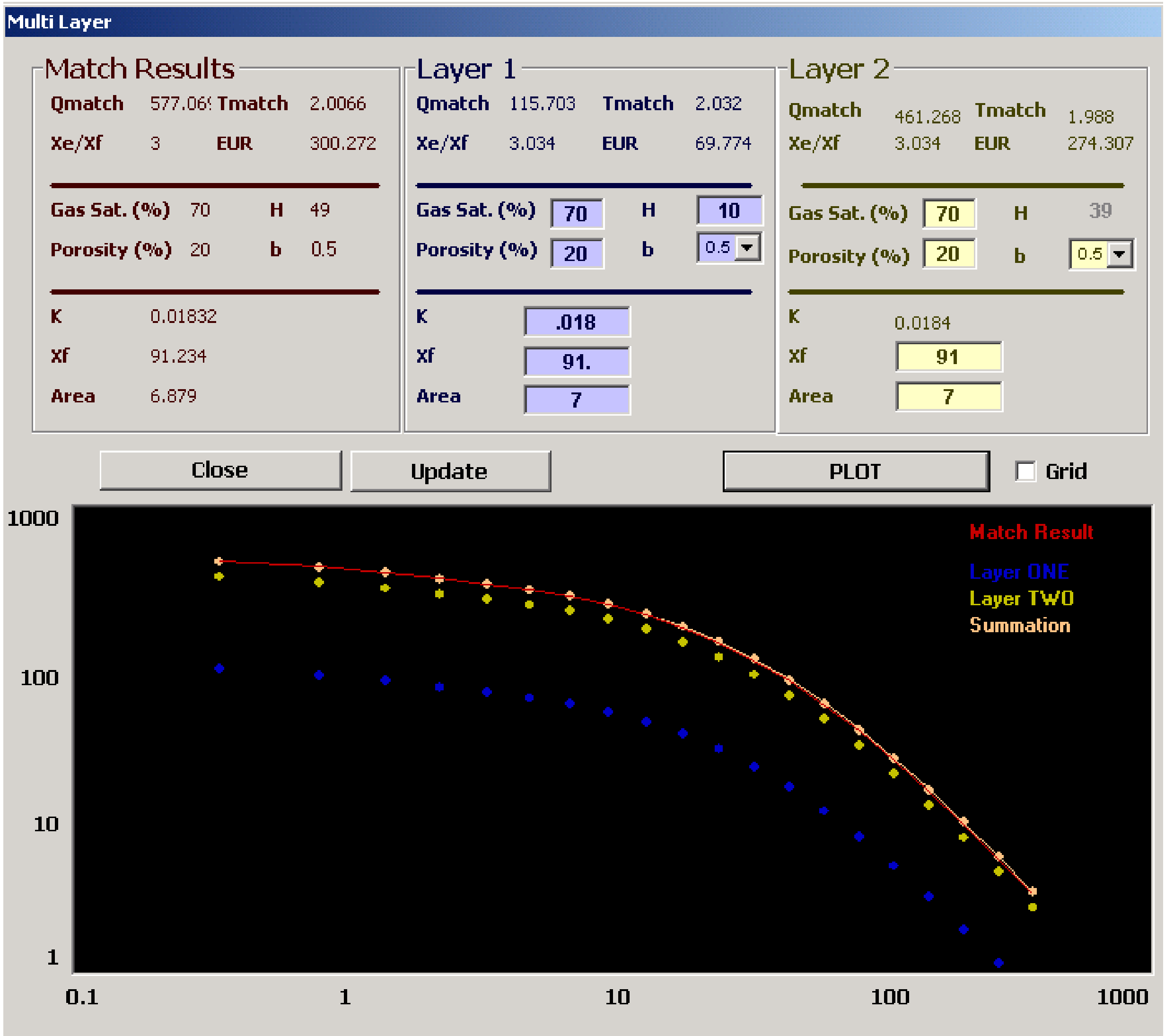

Figure 20 – Multi-layer Hyperbolic Type Curve Matching Window

button to save the match results for that well. Both this window and the Single Layer Type Curves window can now be closed and analysis begun on a new well.

V. Variable Compressibility Type Curve Matching

In addition to the single and multi-layer hyperbolic type curve matching options, the user also has the capability to estimate the impact of pressure depletion on PVT properties such as gas compressibility and gas viscosity in low permeability gas reservoirs. This effect generally manifests itself following the departure from the infinite acting portion of the type cure (or when a boundary is encountered). From a practical standpoint, this behavior deviates from the decline stem (selected match Xe/Xf) and often crosses over others to the right. The Variable Compressibility Type Curve Matching option is shown in **figure 21**.

To activate this feature, the user must select the ***Compressibility Option*** check box. A heavy green line then appears, allowing the user to refine the match. To do so, the user must typically decrease the selected Xe/Xf match point until the variable compressibility line passes through the production data.

VI. Disclaimer

This software was prepared as an account of work sponsored agencies of the United States Government and the State of New York. Neither the United States Government, the State of New York nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of the software.

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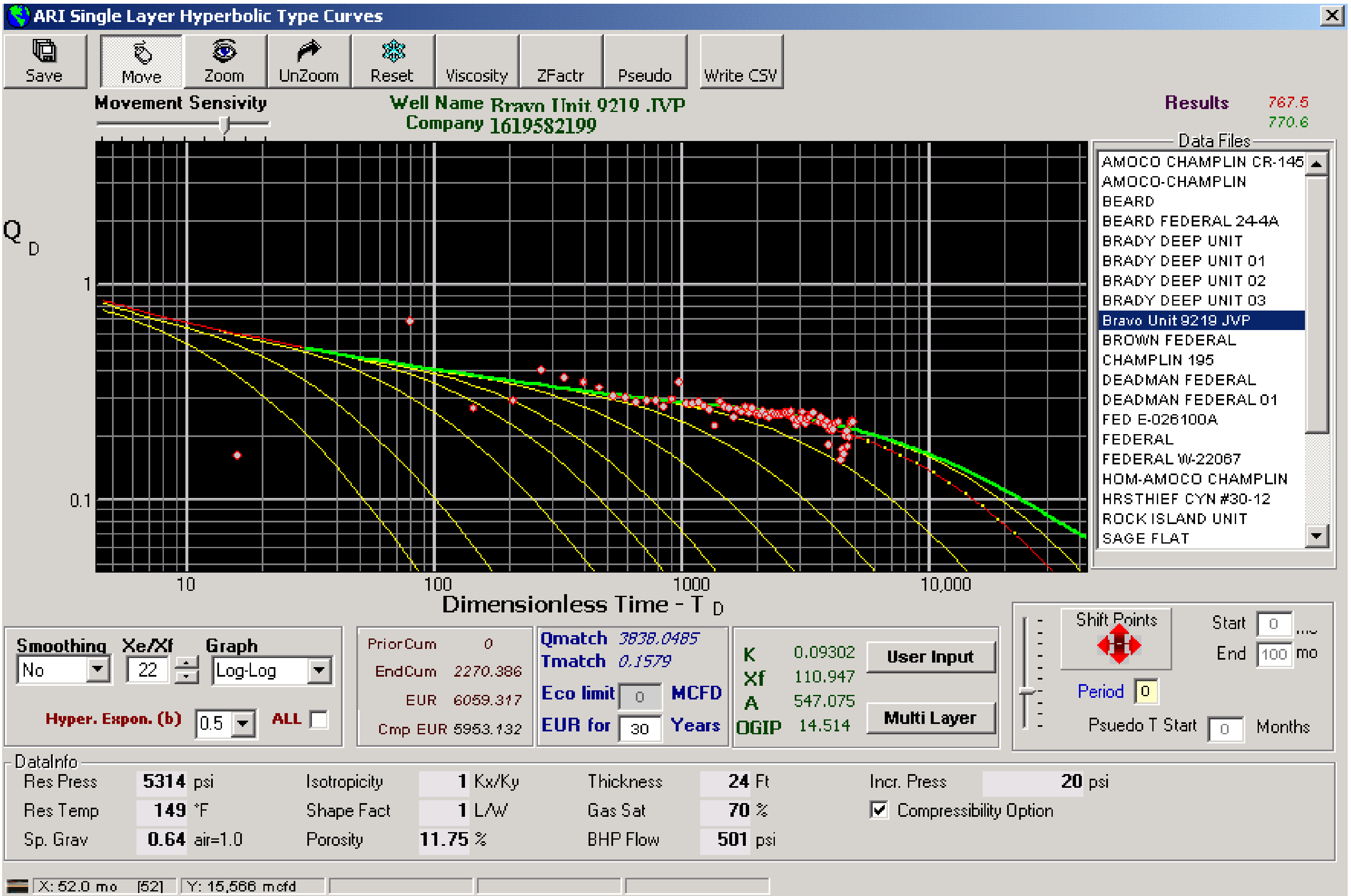

Figure 21 – Variable Compressibility Type Curve Matching Option

Appendix 2

***METEOR* Software Installation CD**

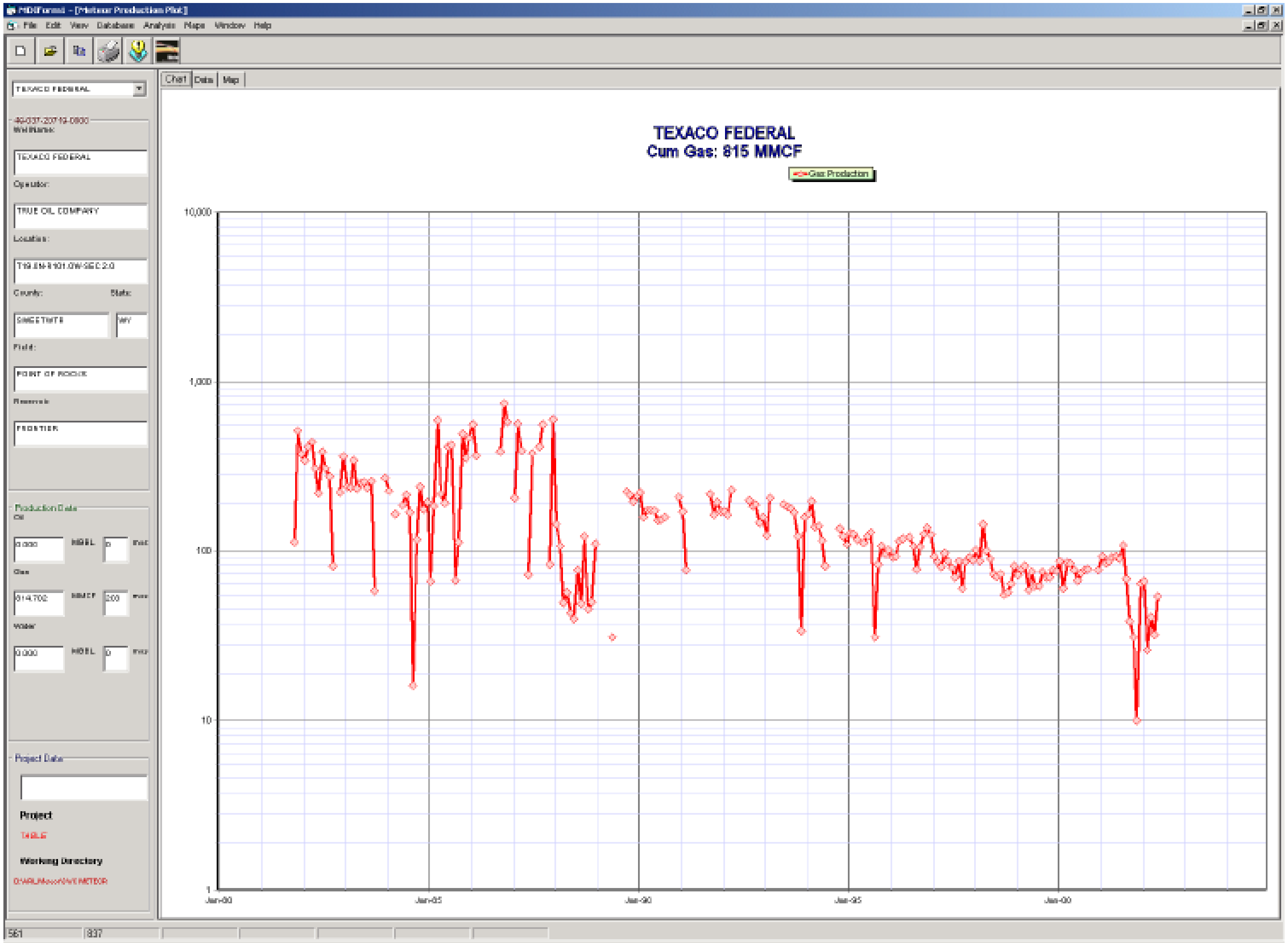

Figure 1 – *METEOR* Program Interface

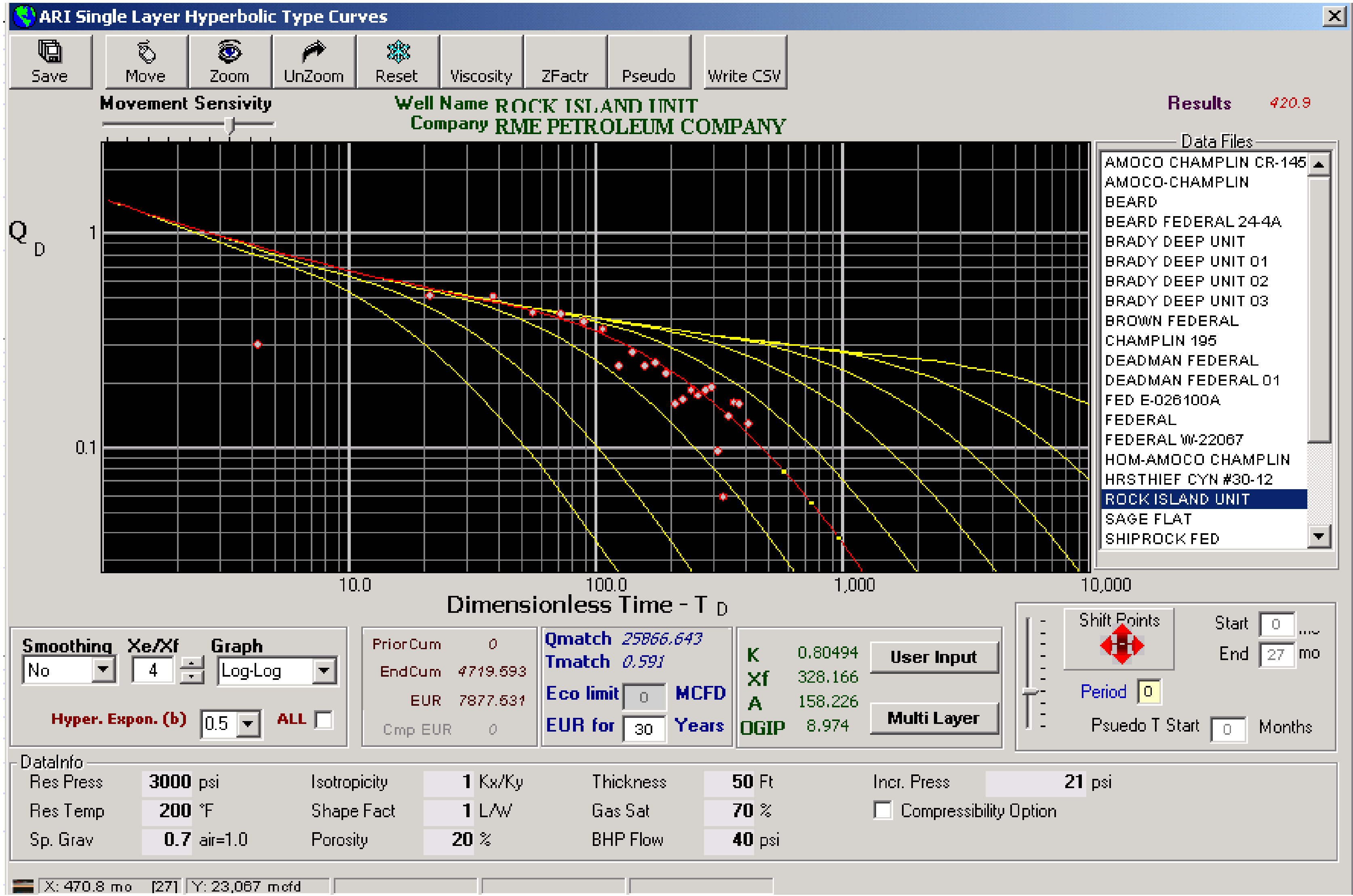

Figure 2 – *METEOR* Single-Layer Hyperbolic Type Curve Matching Interface

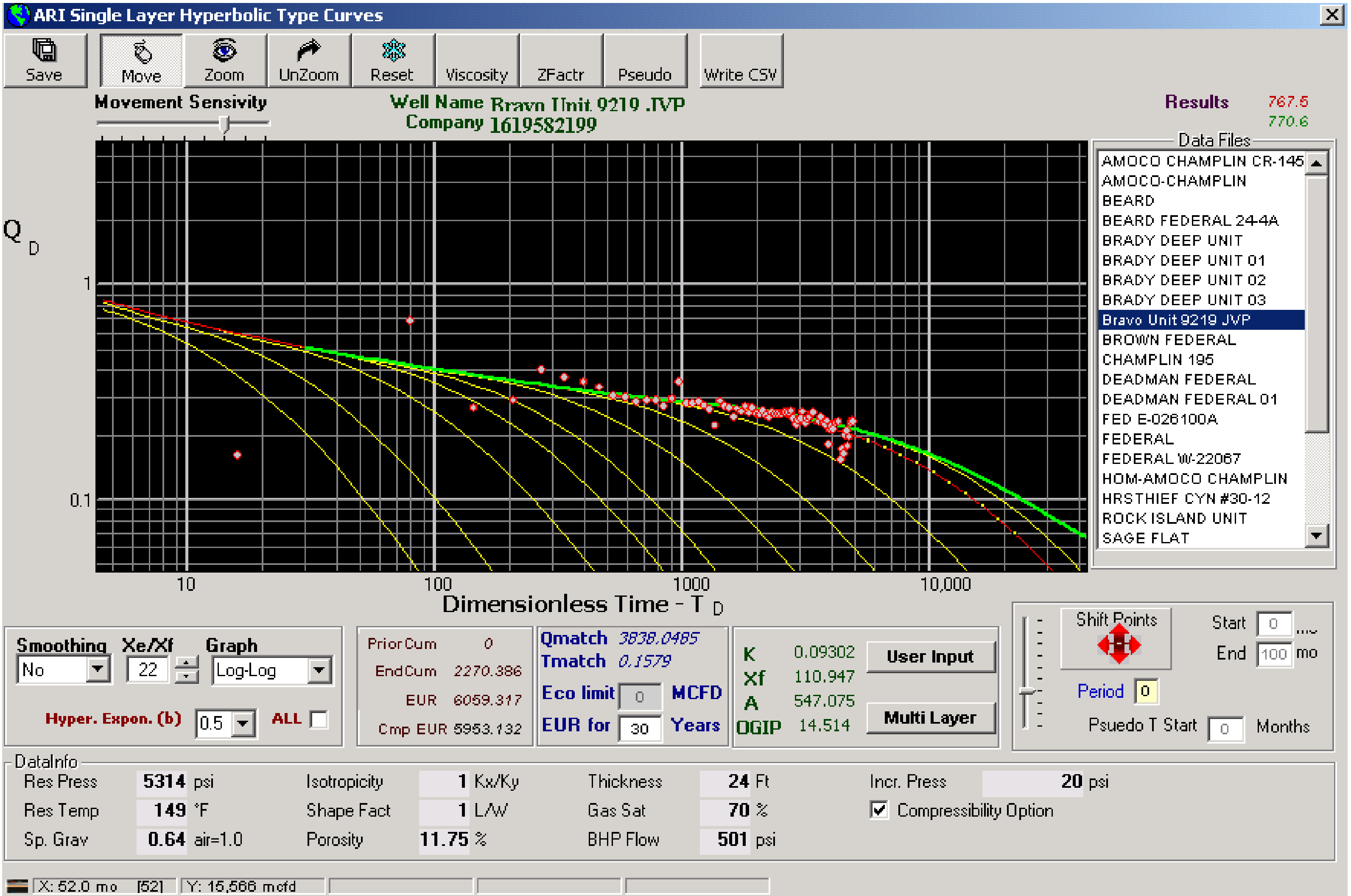

Figure 3 – Variable Compressibility Type Curve Matching Option

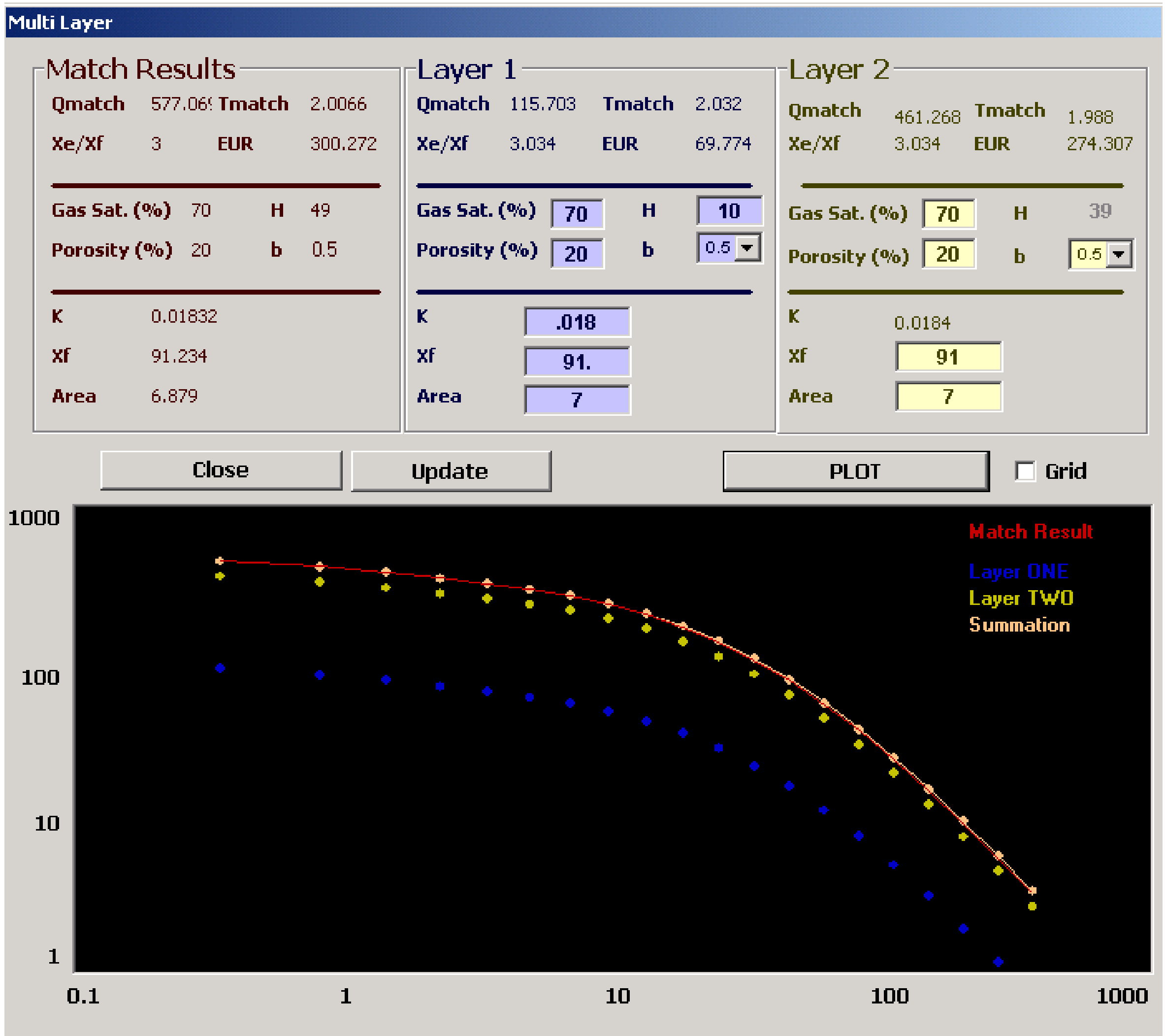

Figure 4 – *METEOR* Multi-Layer Hyperbolic Type Curve Matching Interface

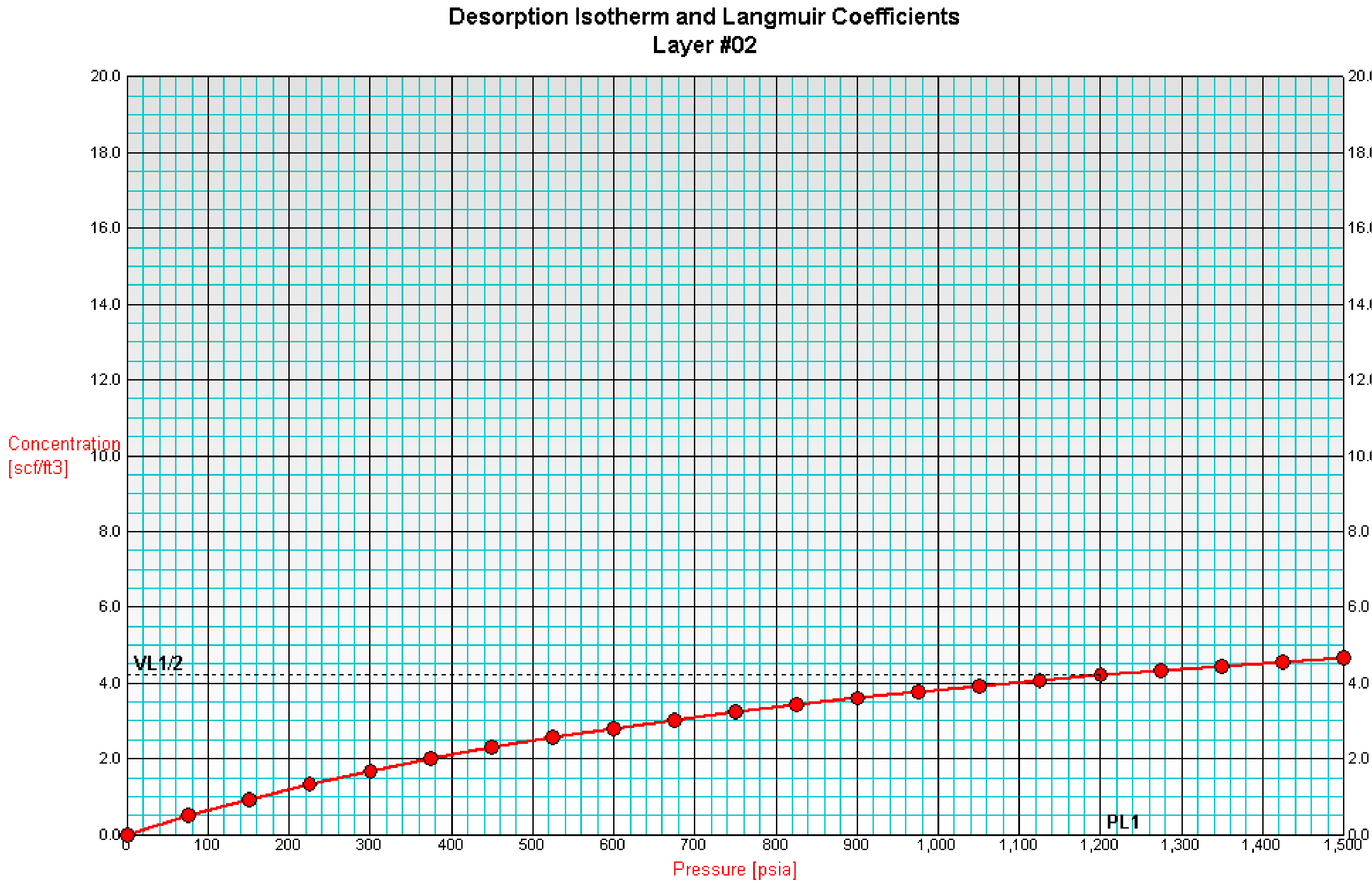

Figure 5 – Devonian Shale Adsorption/Desorption Isotherm

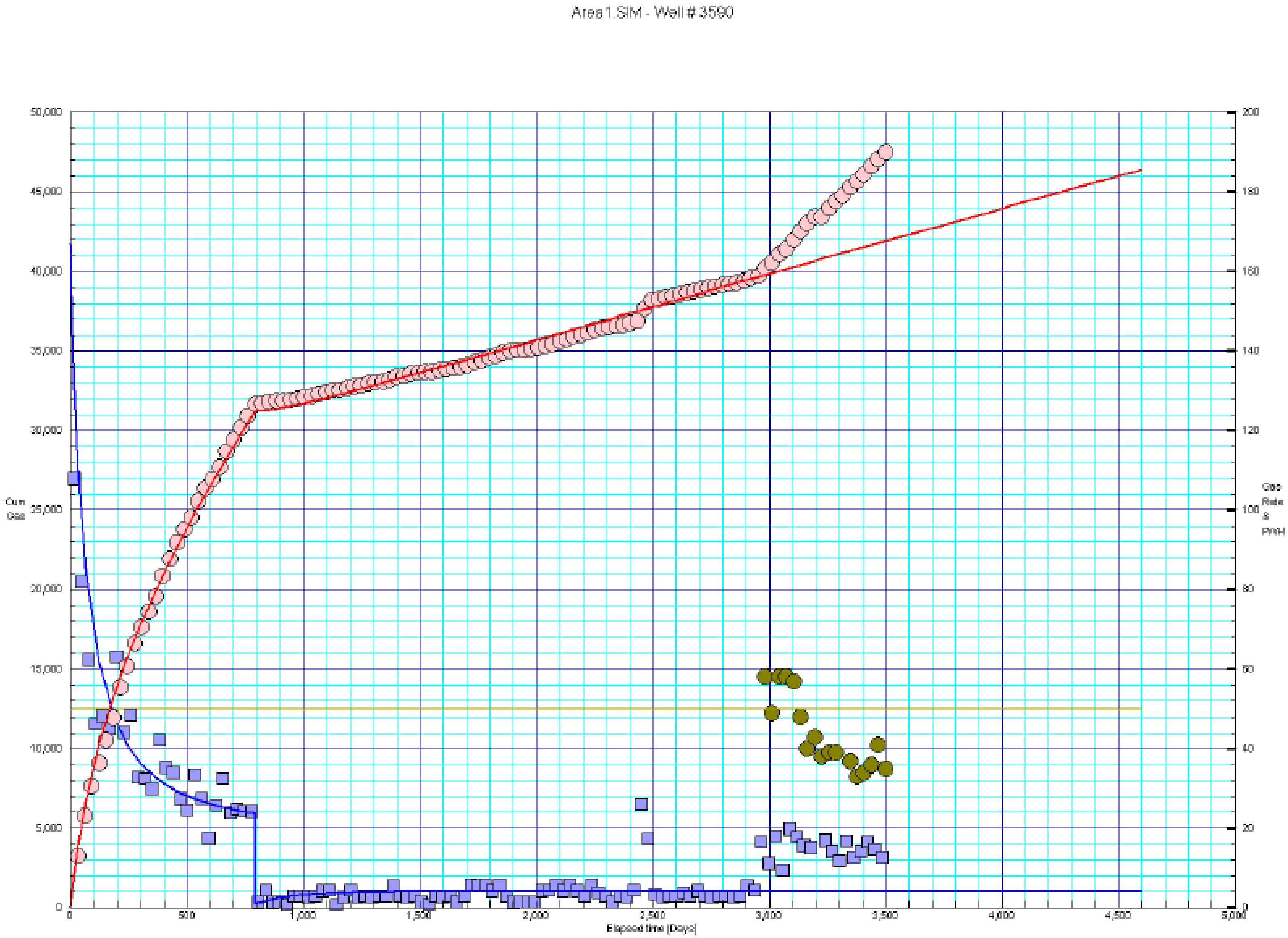

Figure 6 – History Match for Area 1

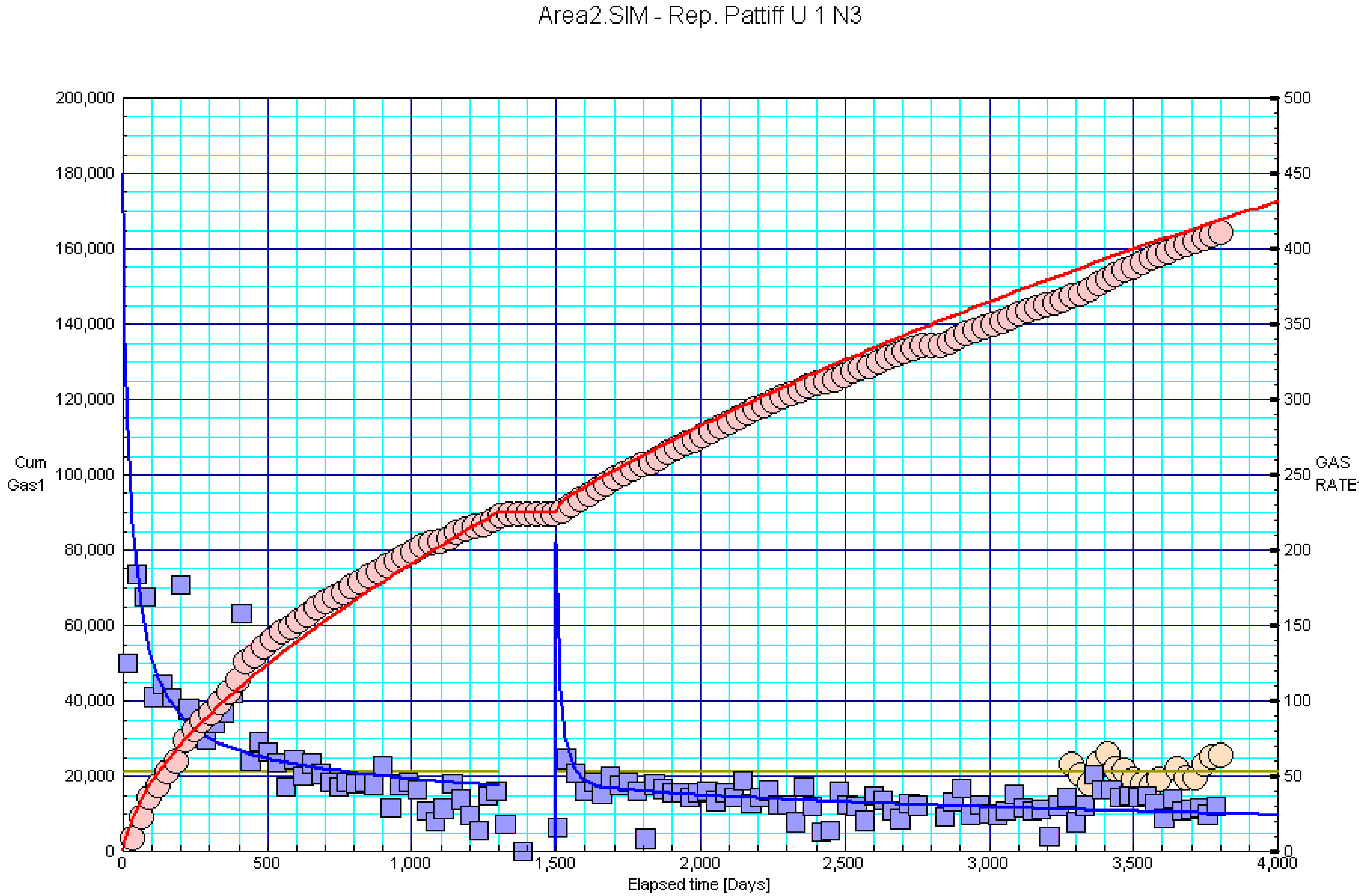

Figure 7 – History Match for Area 2

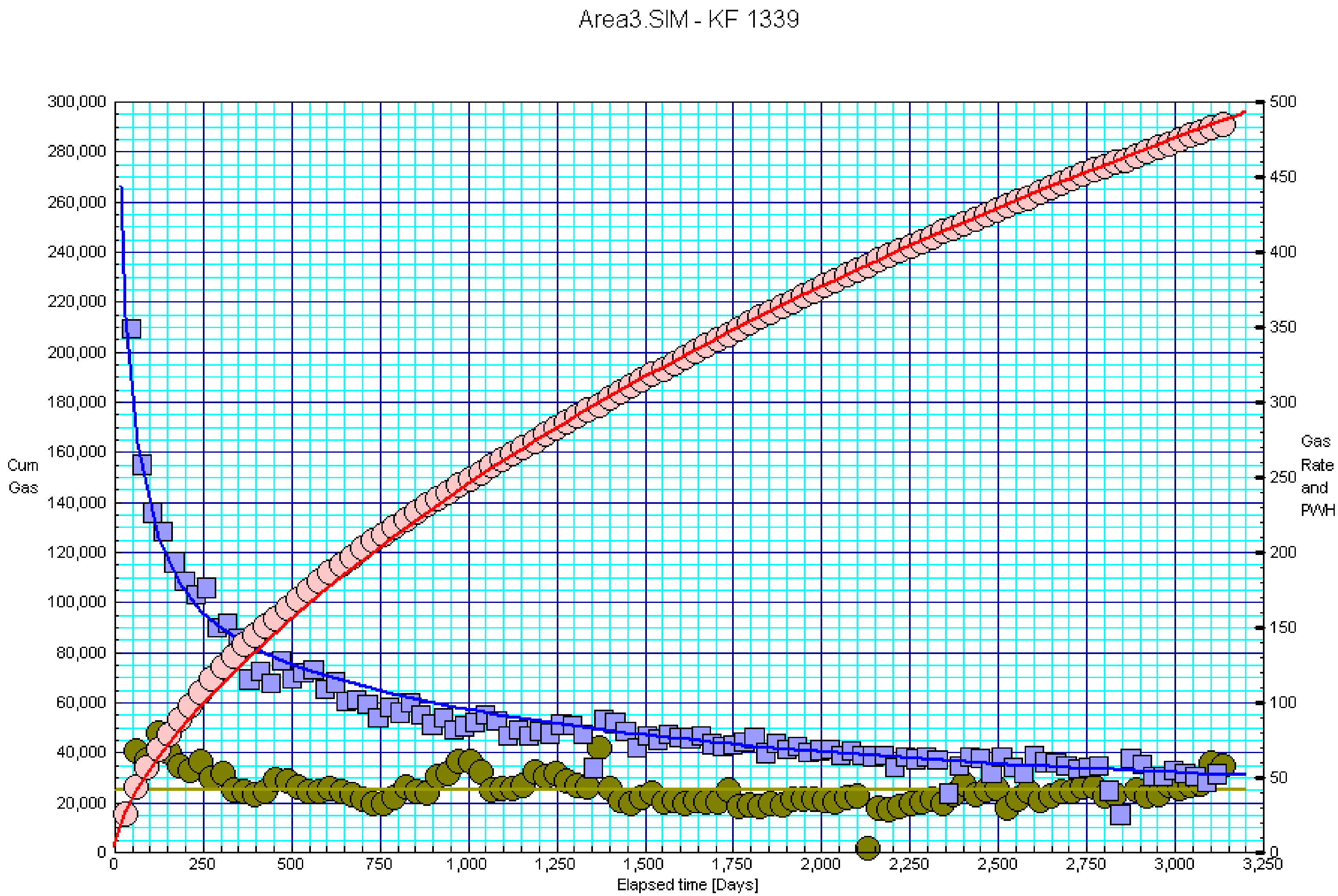

Figure 8 – History Match for Area 3

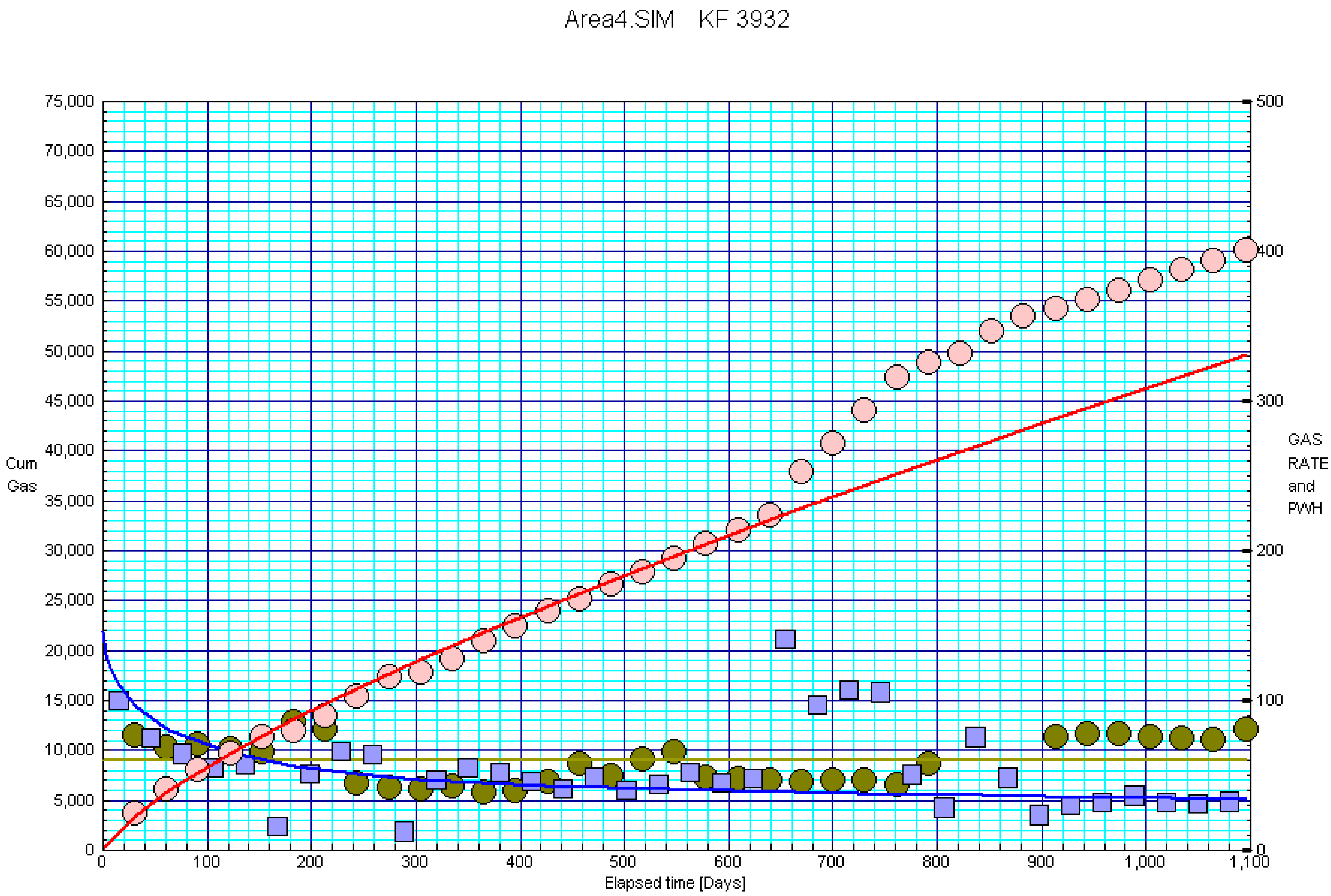

Figure 9 – History Match for Area 4

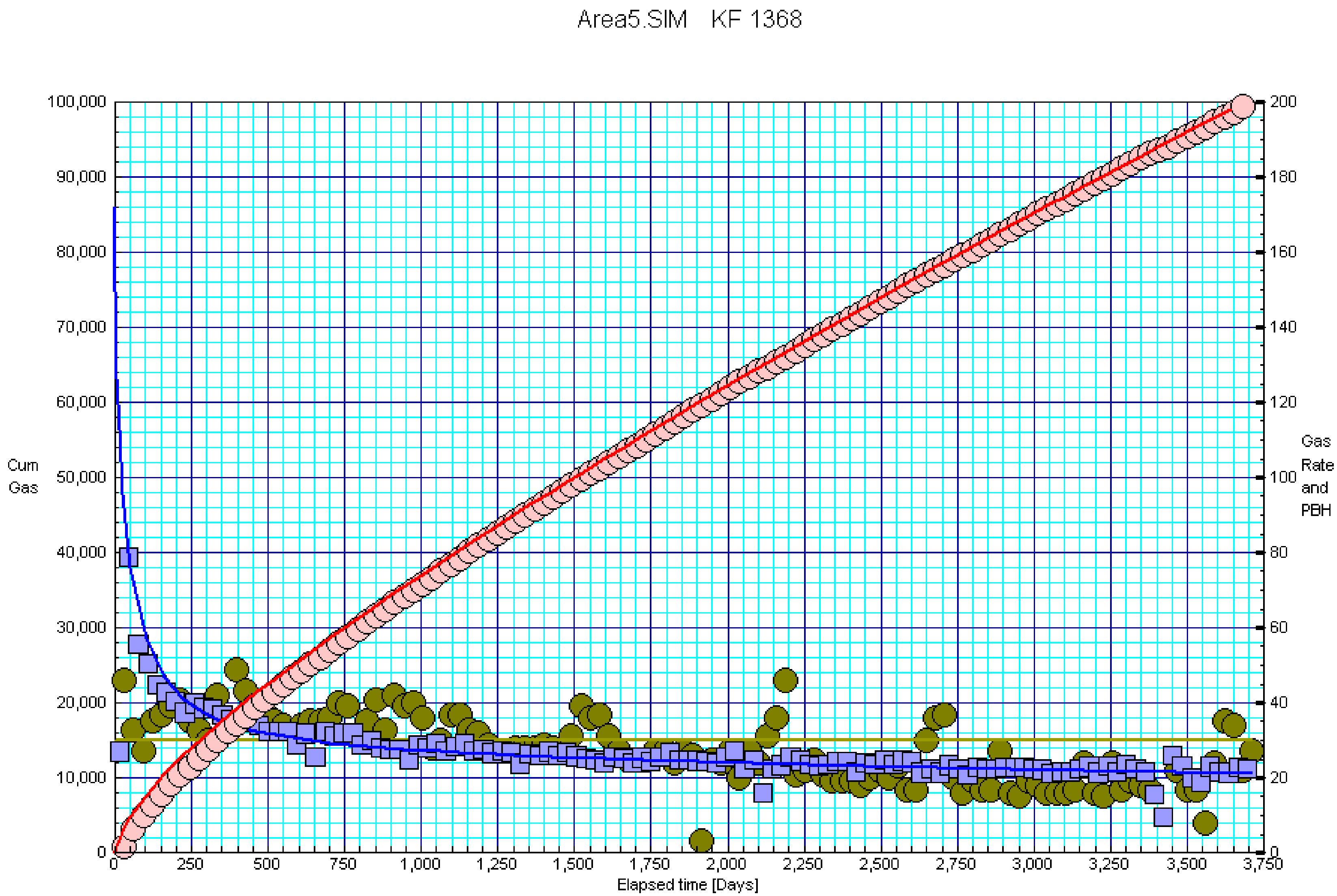

Figure 10 – History Match for Area 5

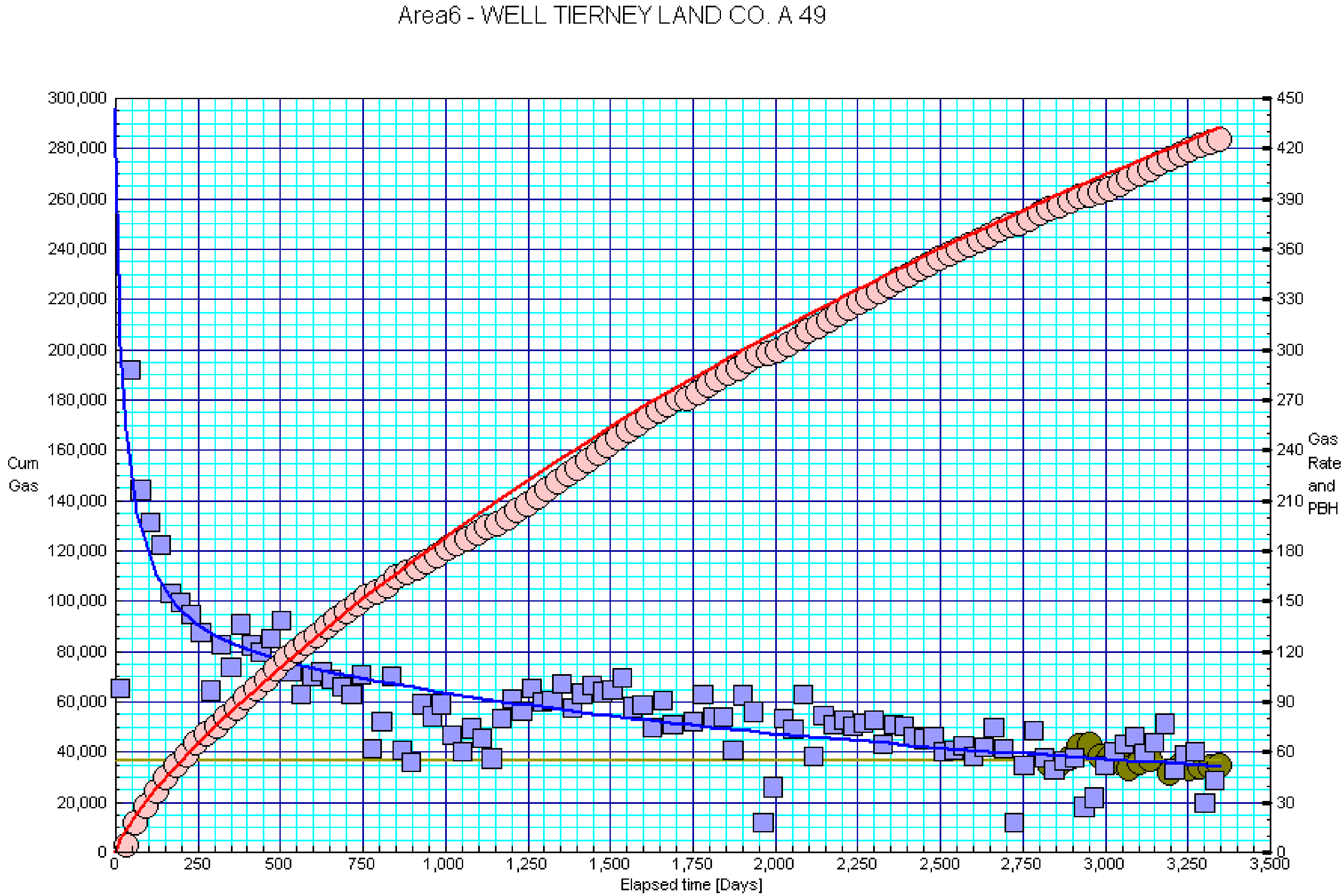

Figure 11 – History Match for Area 6

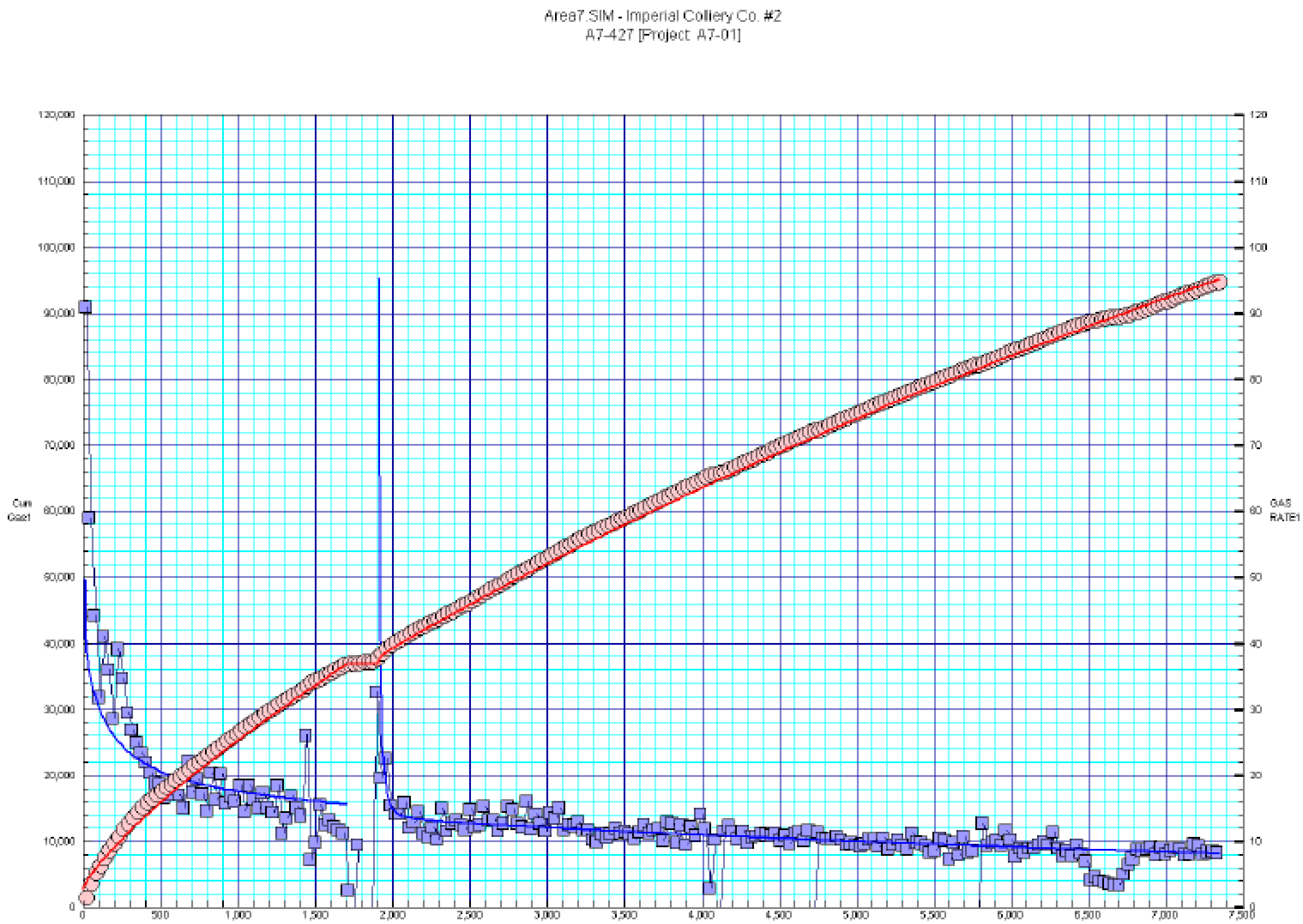

Figure 12 – History March for Area 7

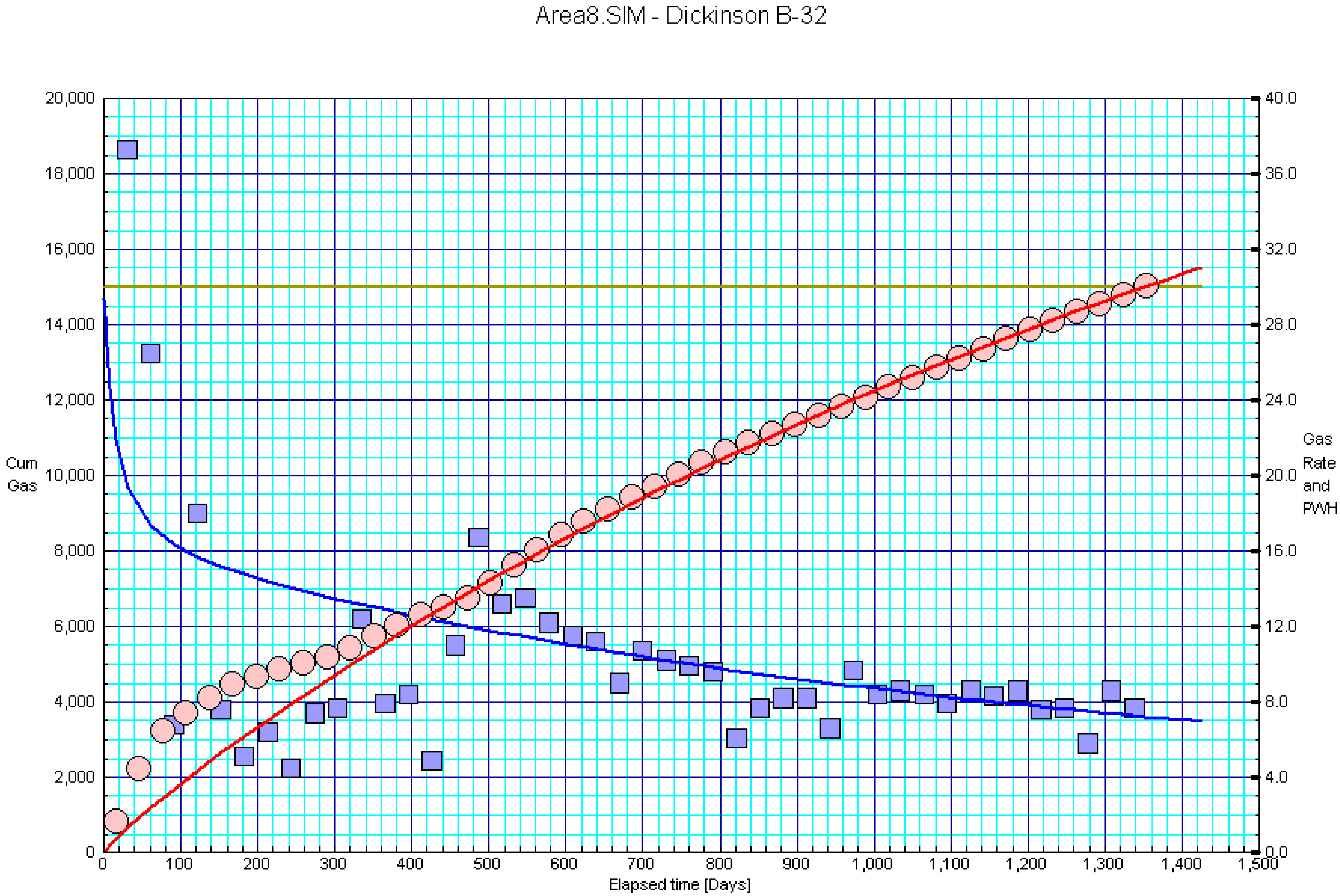

Figure 13 – History Match for Area 8

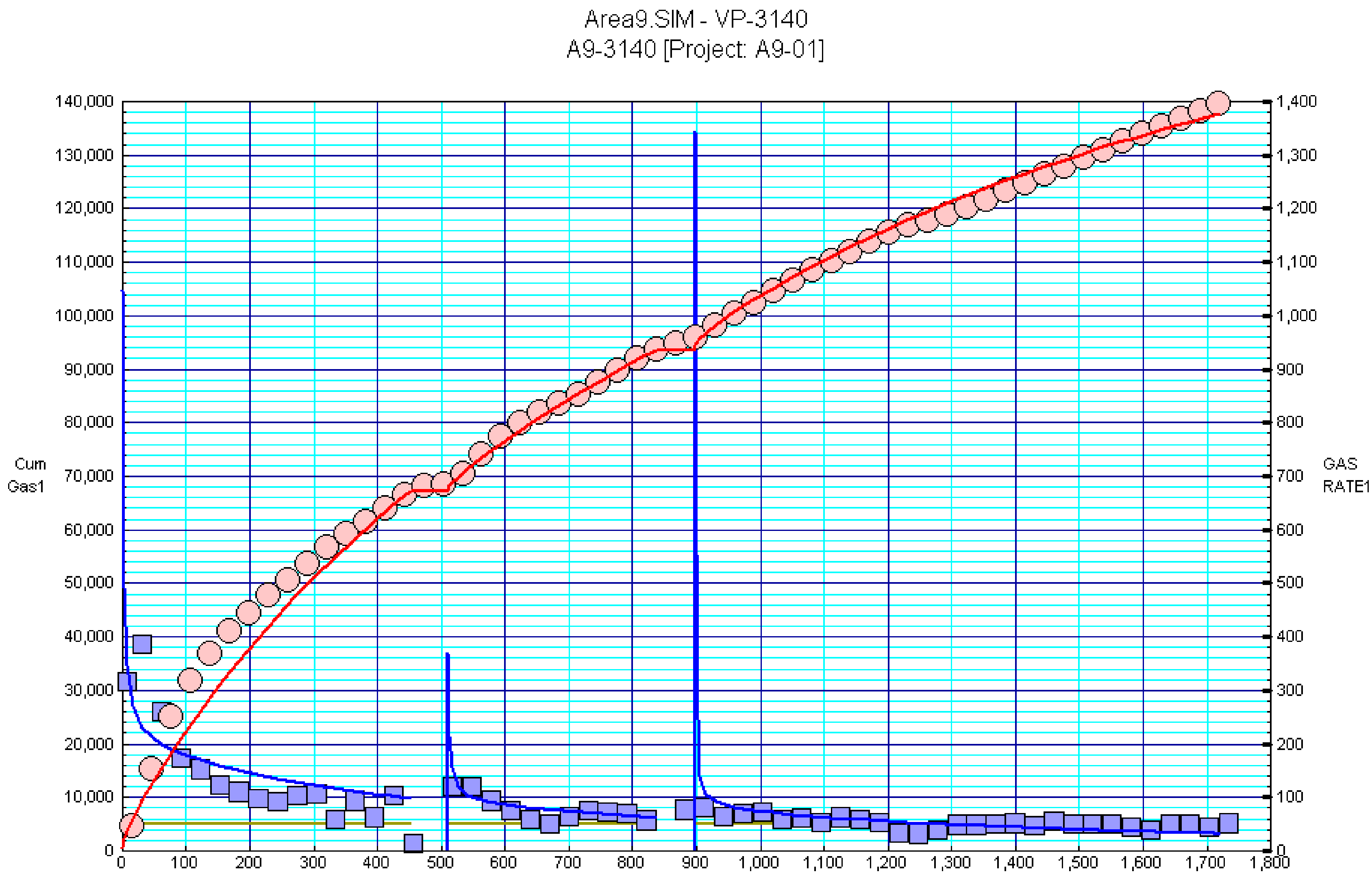

Figure 14 – History Match for Area 9

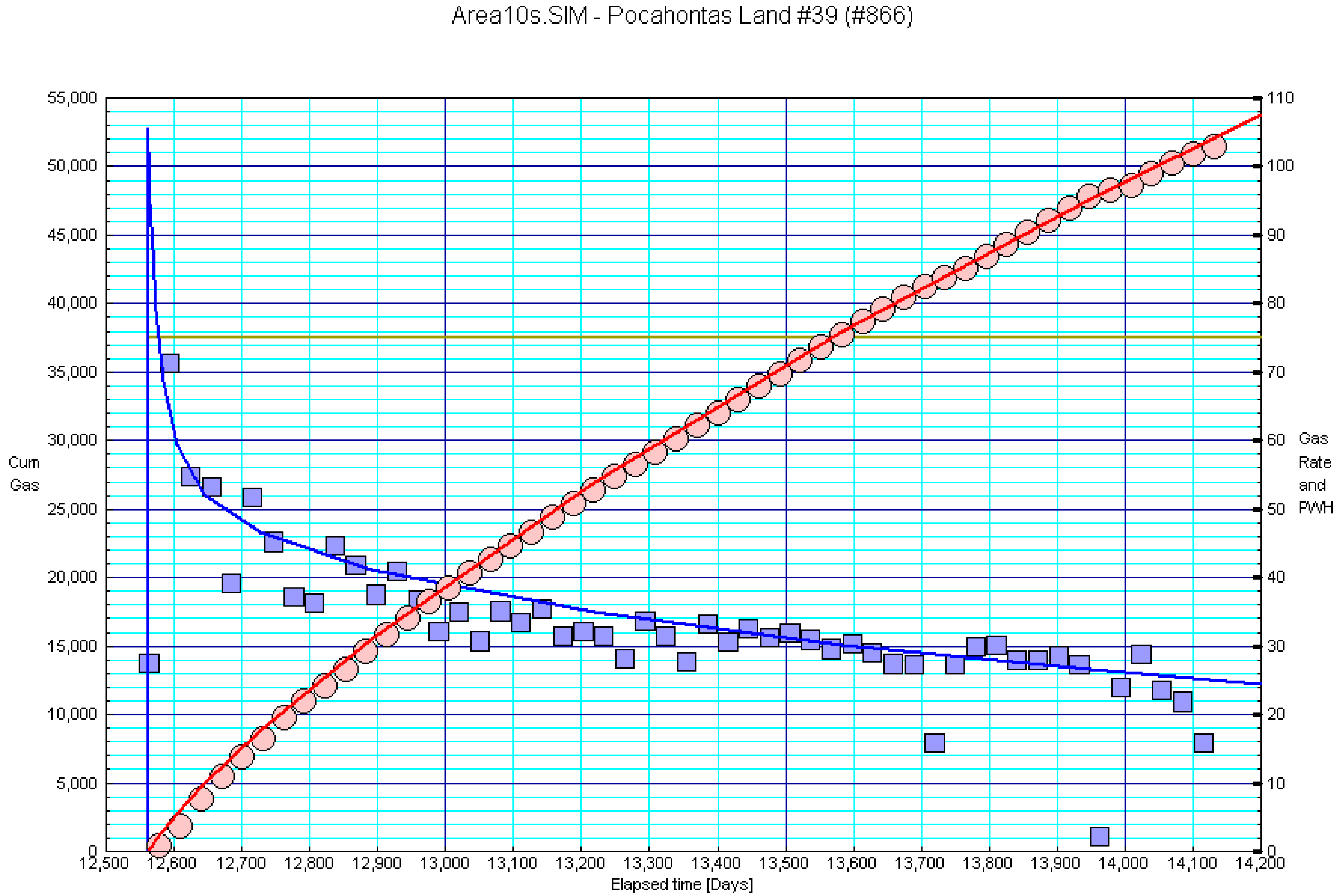

Figure 15 – History Match for Area 10

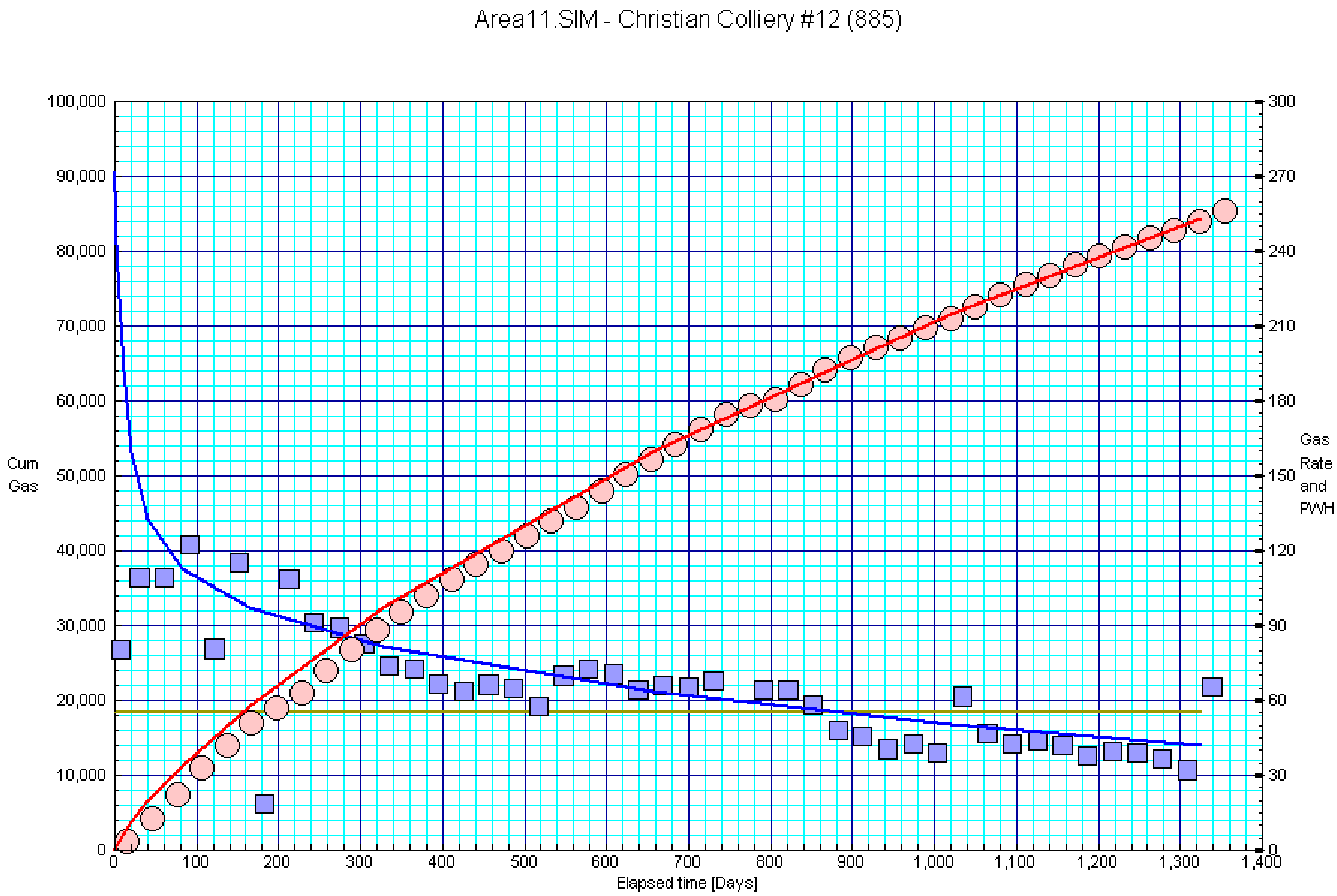

Figure 16 – History Match for Area 11

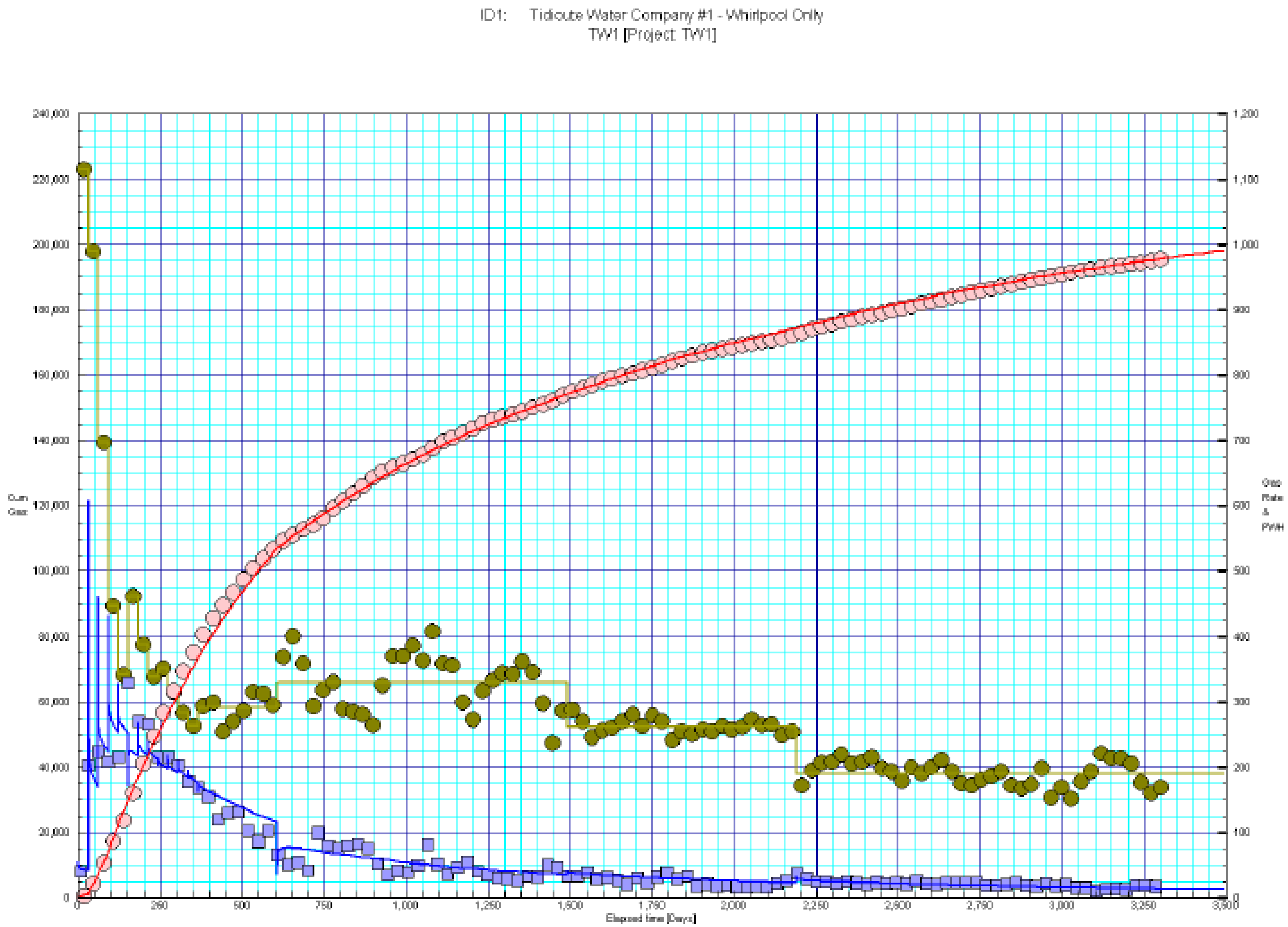

Figure 17 – History Match for Area 12

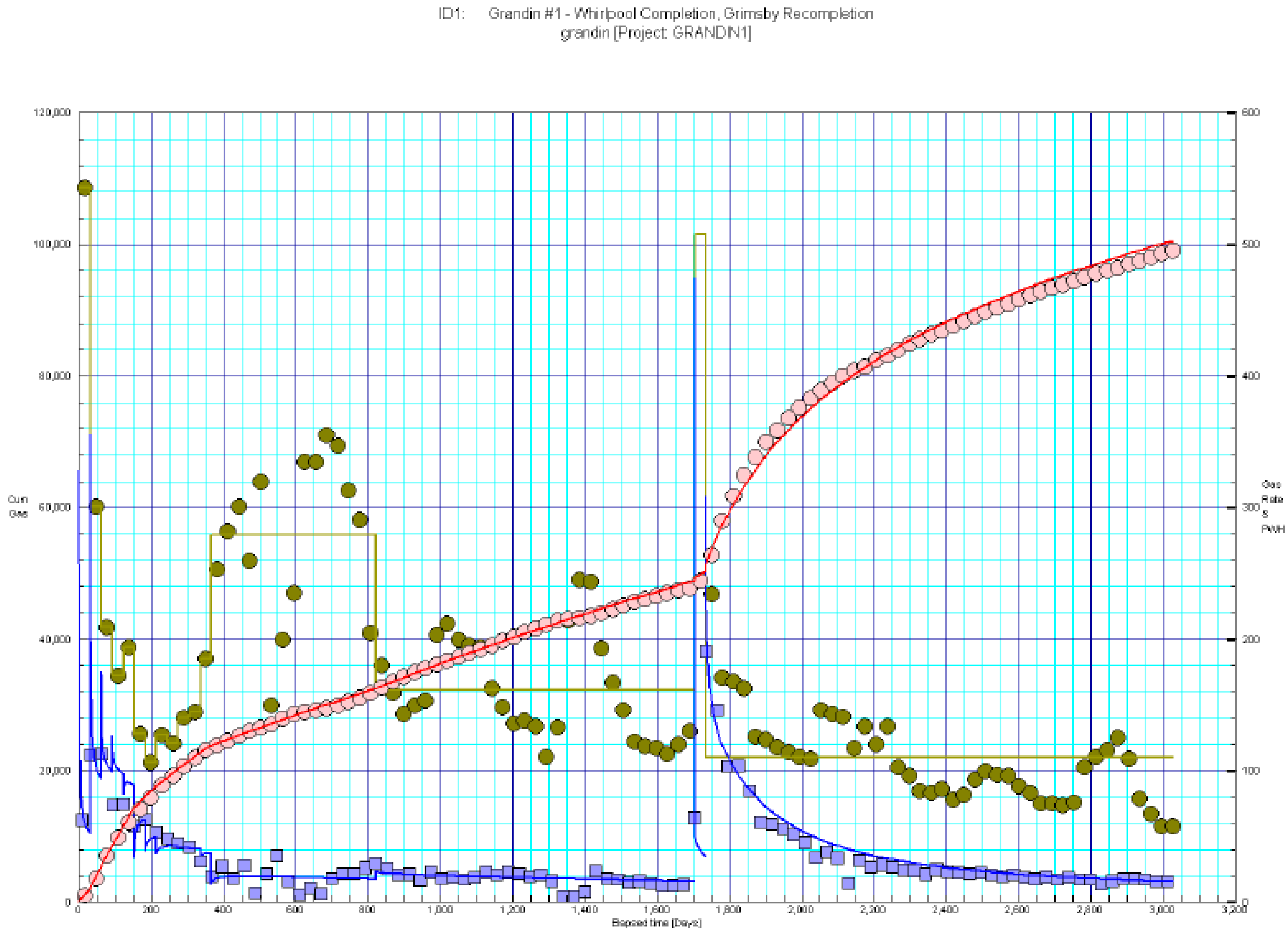

Figure 18 – History Match for Area 13

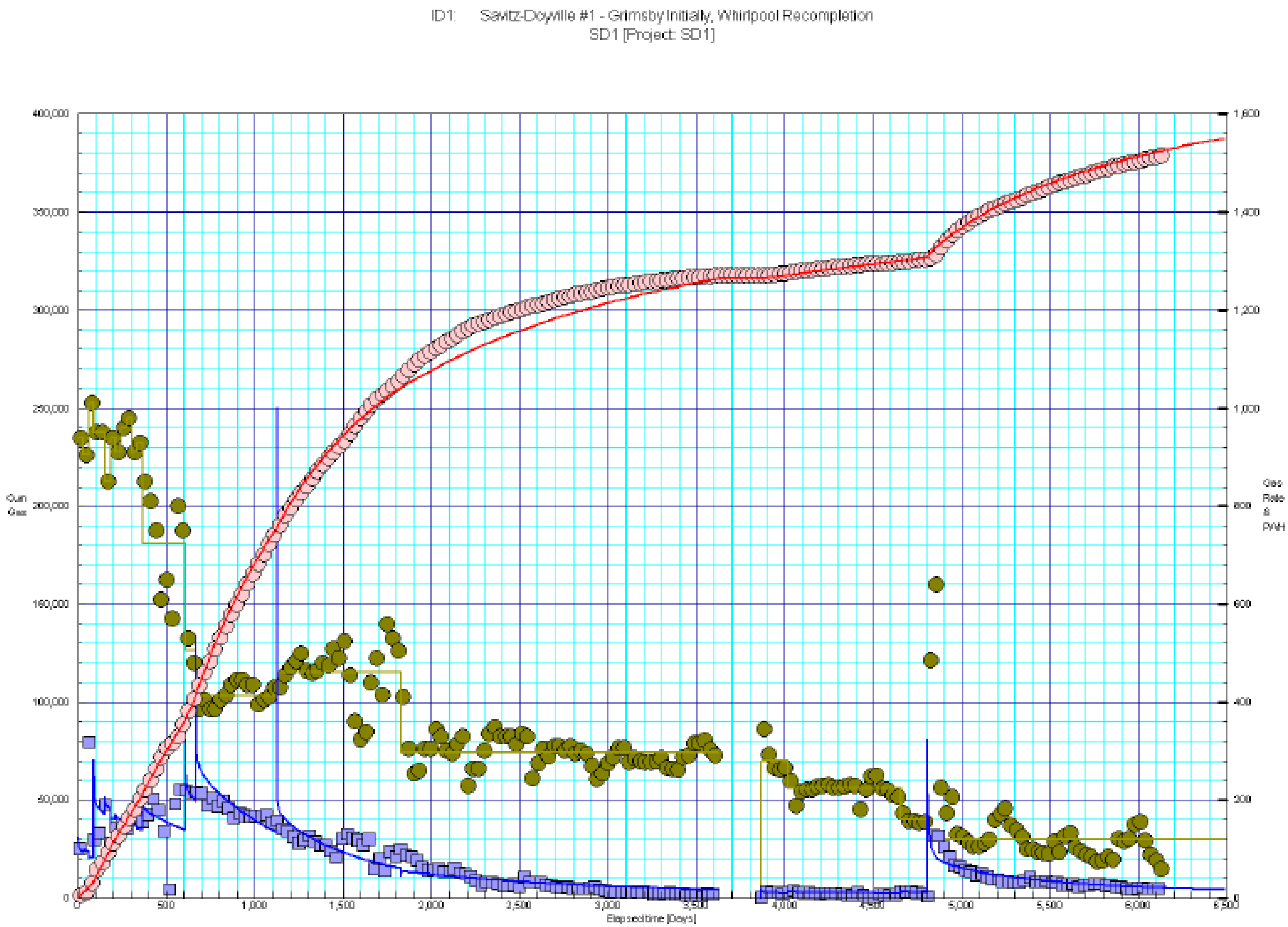

Figure 19 – History Match for Area 14

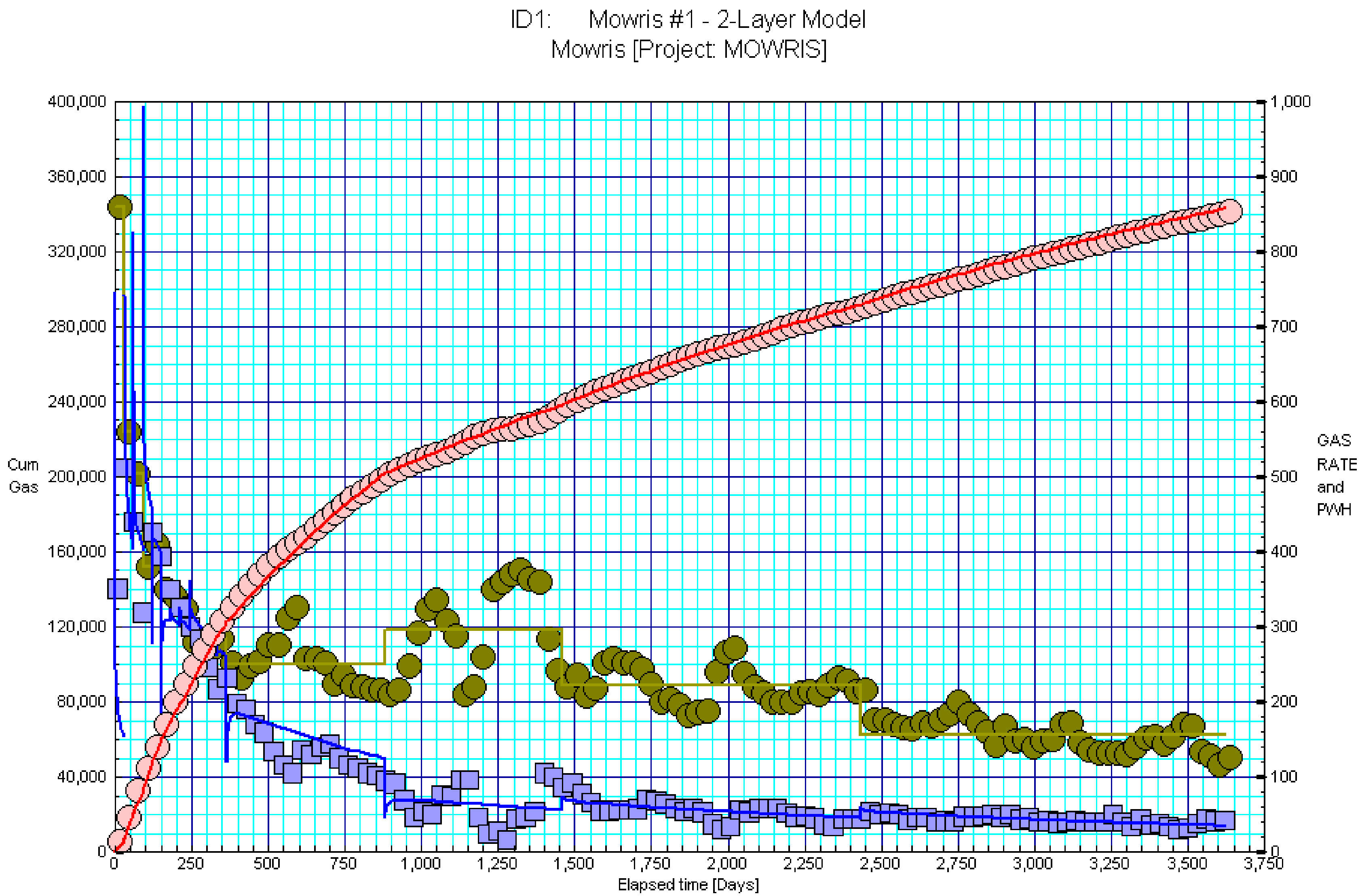

Figure 20 – History Match for Area 15

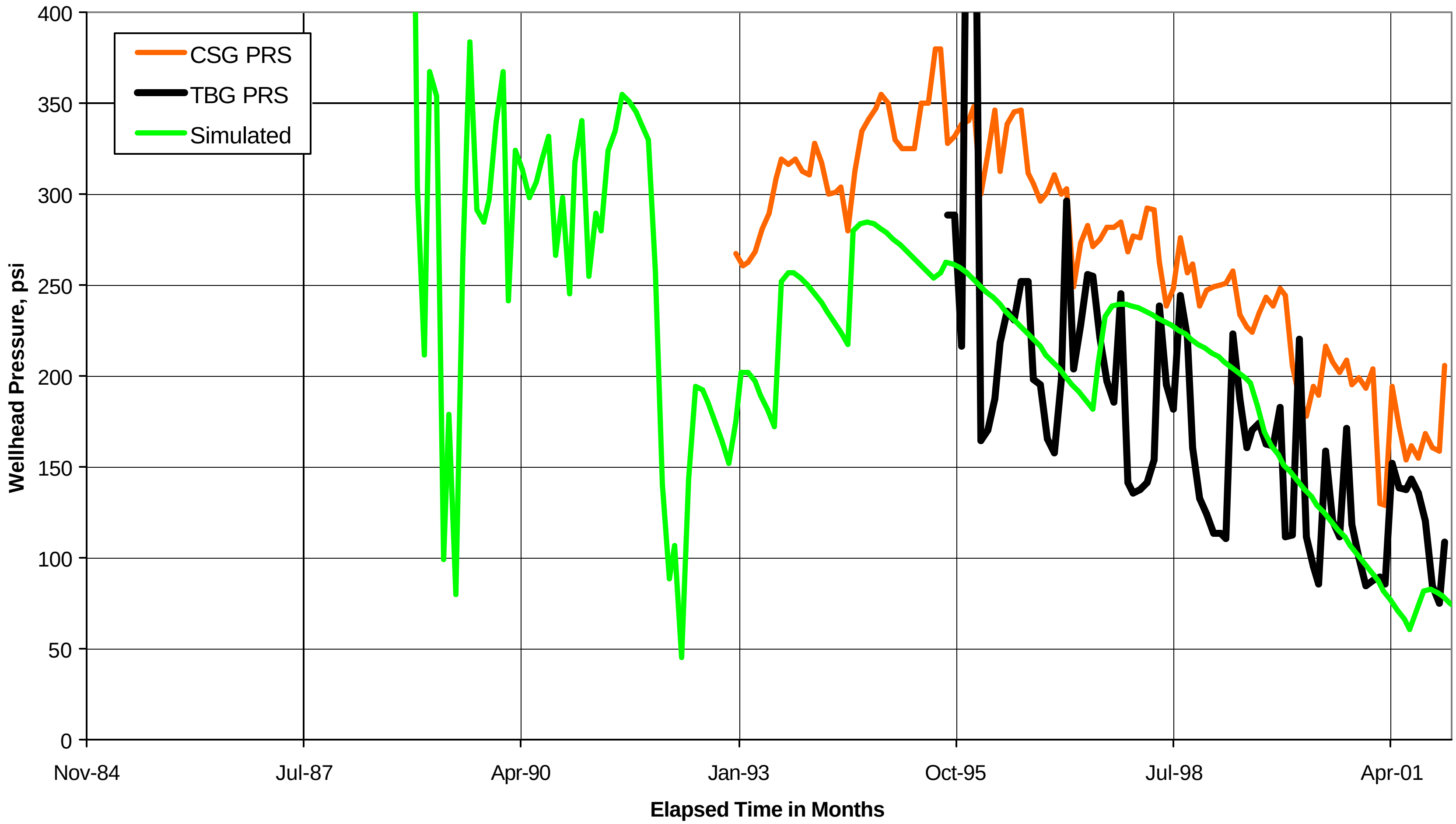

Figure 21 – Comparison of Simulated Wellhead Pressure to Historical Wellhead Pressure

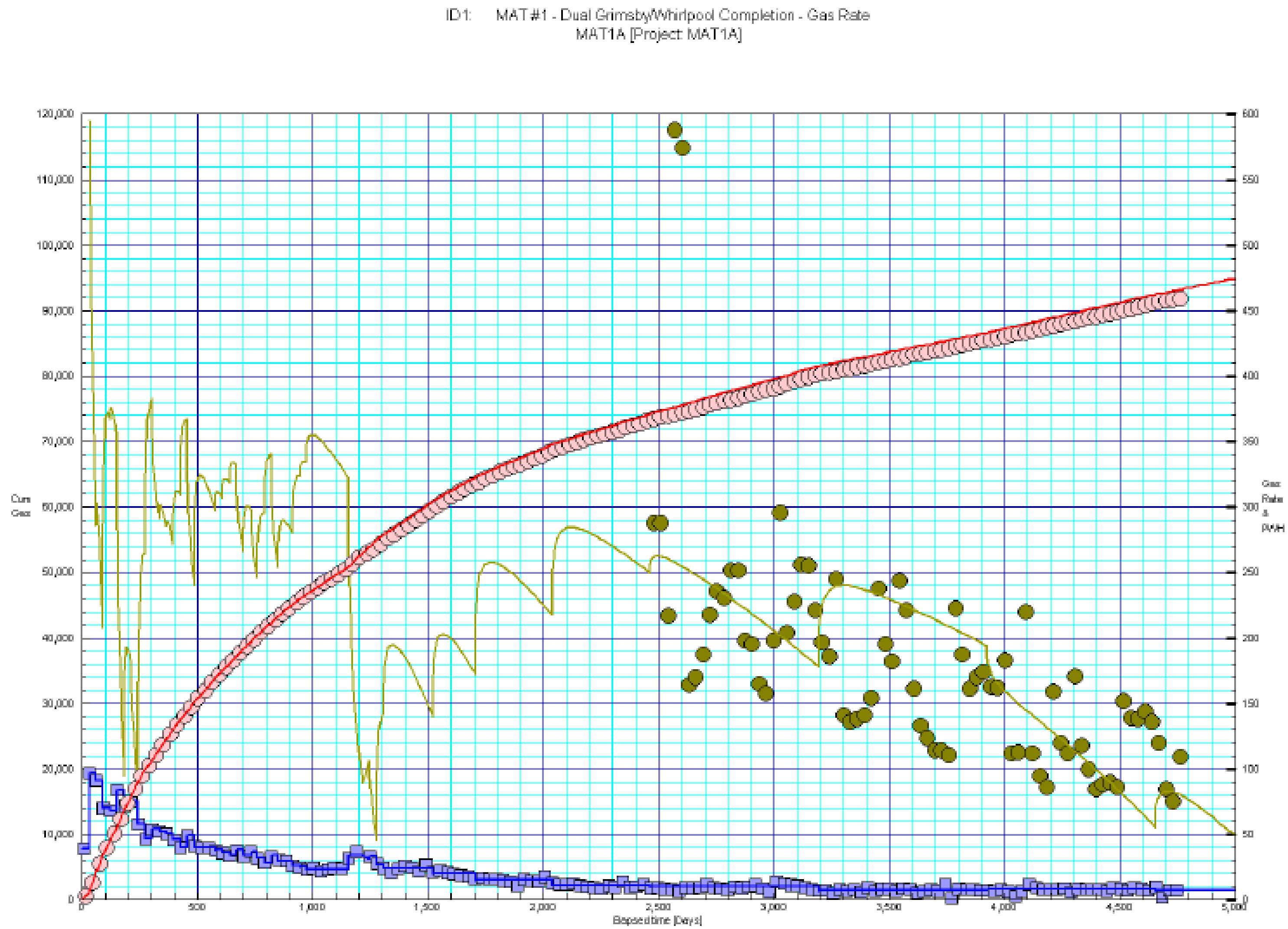

Figure 22 – History Match for Area 16

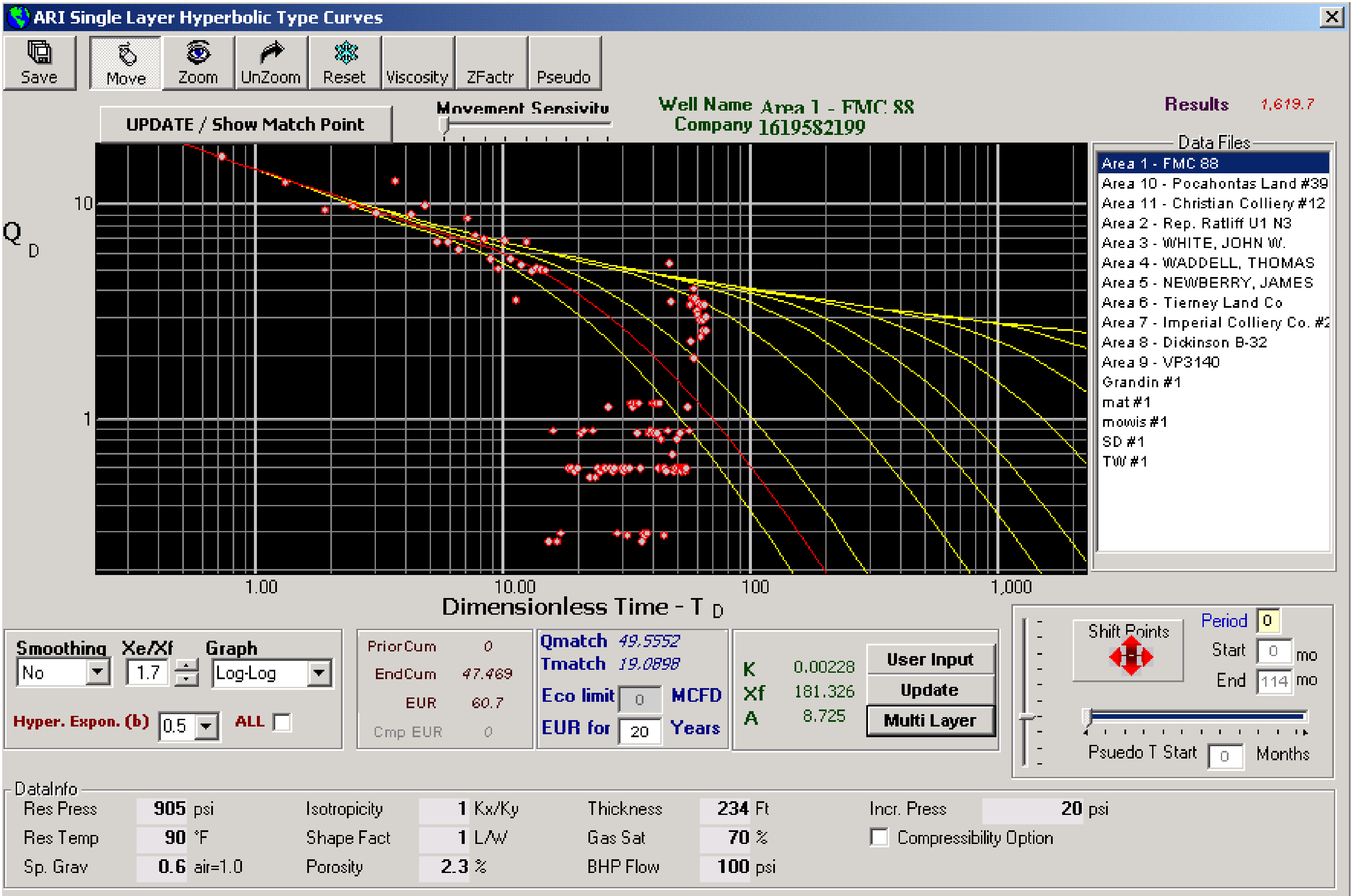

Figure 23 – Area 1 Single Layer Type Curve Match

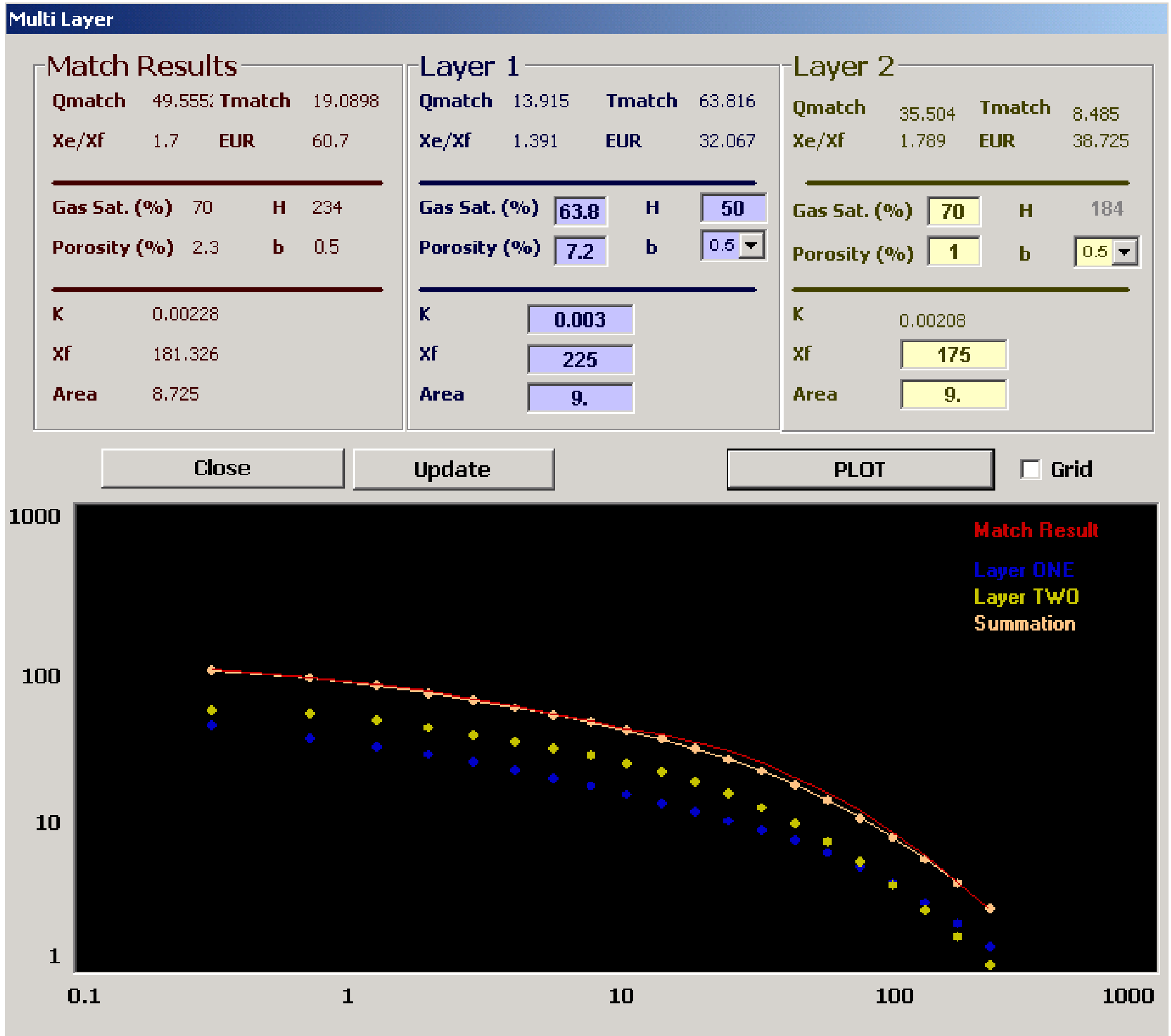

Figure 24 – Area 1 Multiple Layer Type Curve Match Results

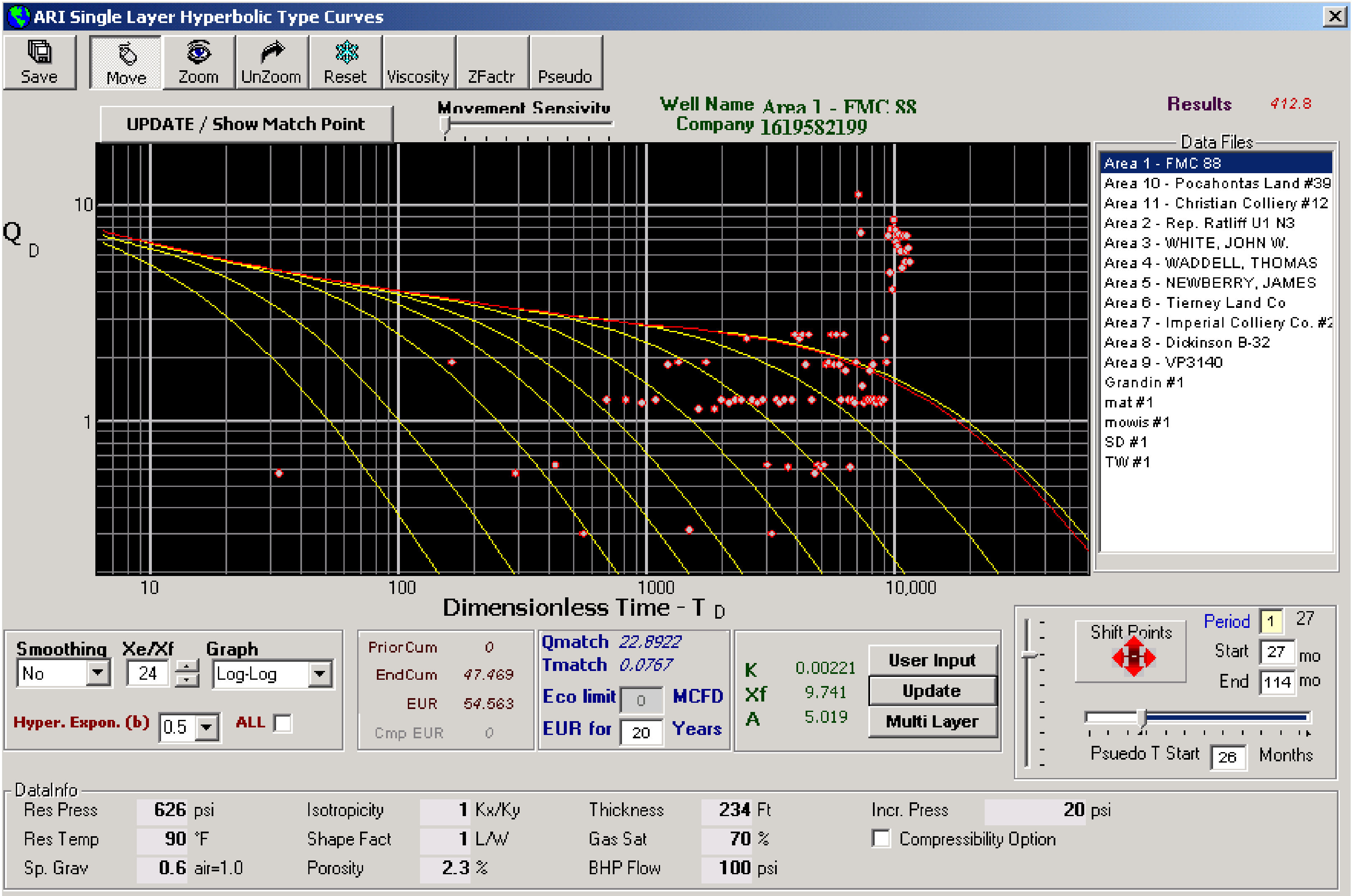

Figure 25 – Area 1 Restart Single Layer Type Curve Match

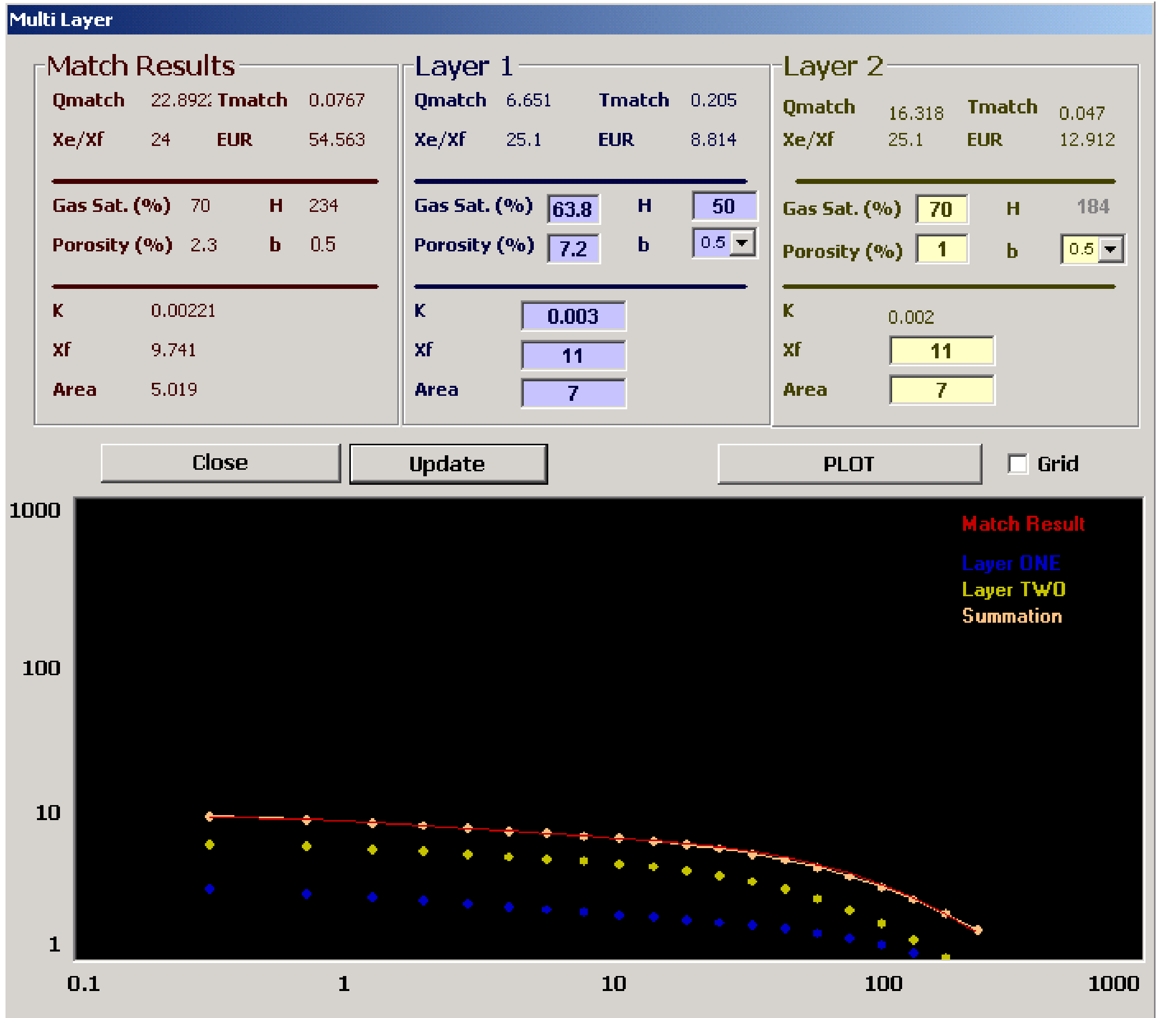

Figure 26 – Area 1 Restart Multiple Layer Type Curve Match Results

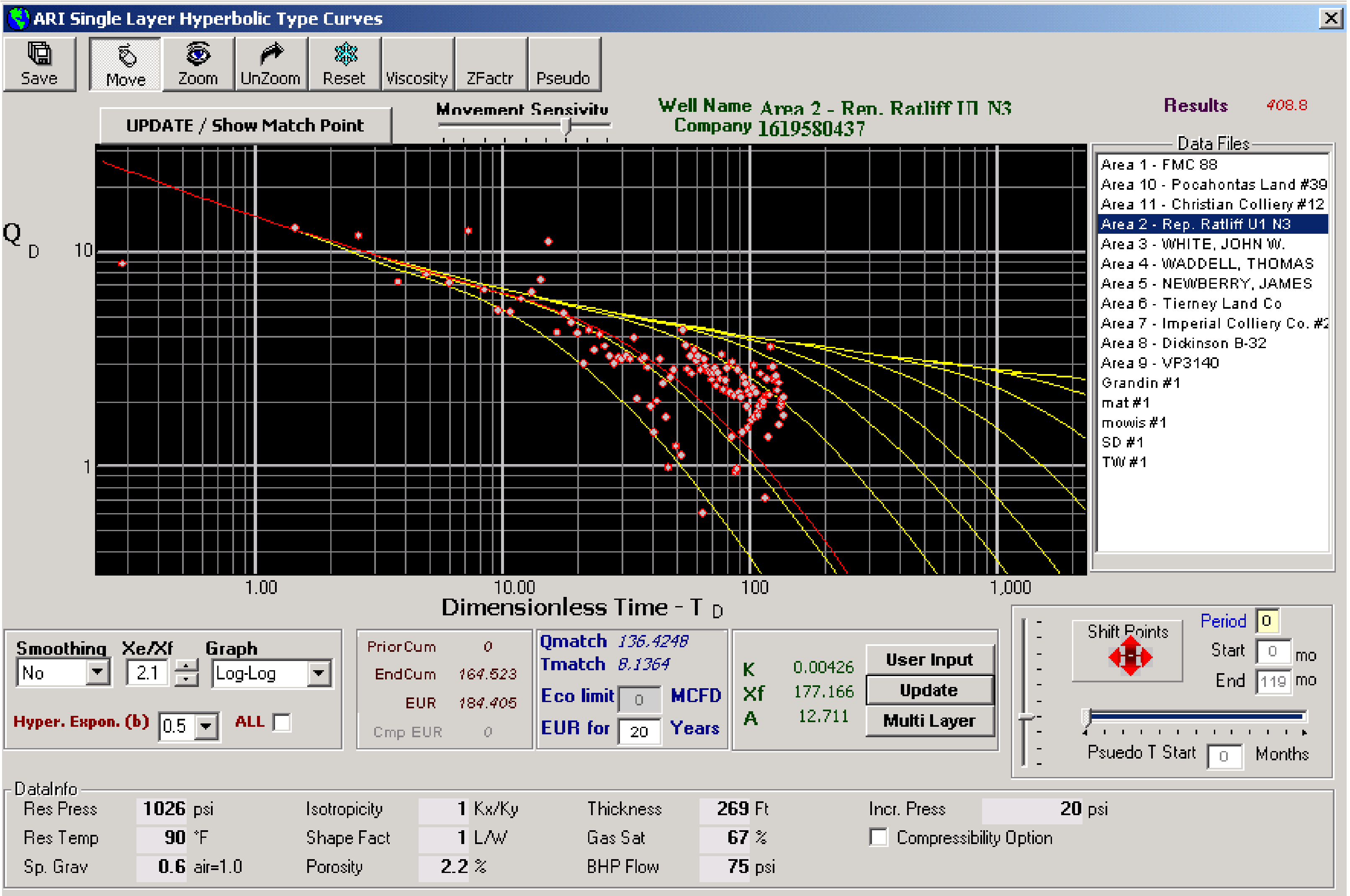

Figure 27 – Area 2 Single Layer Type Curve Match

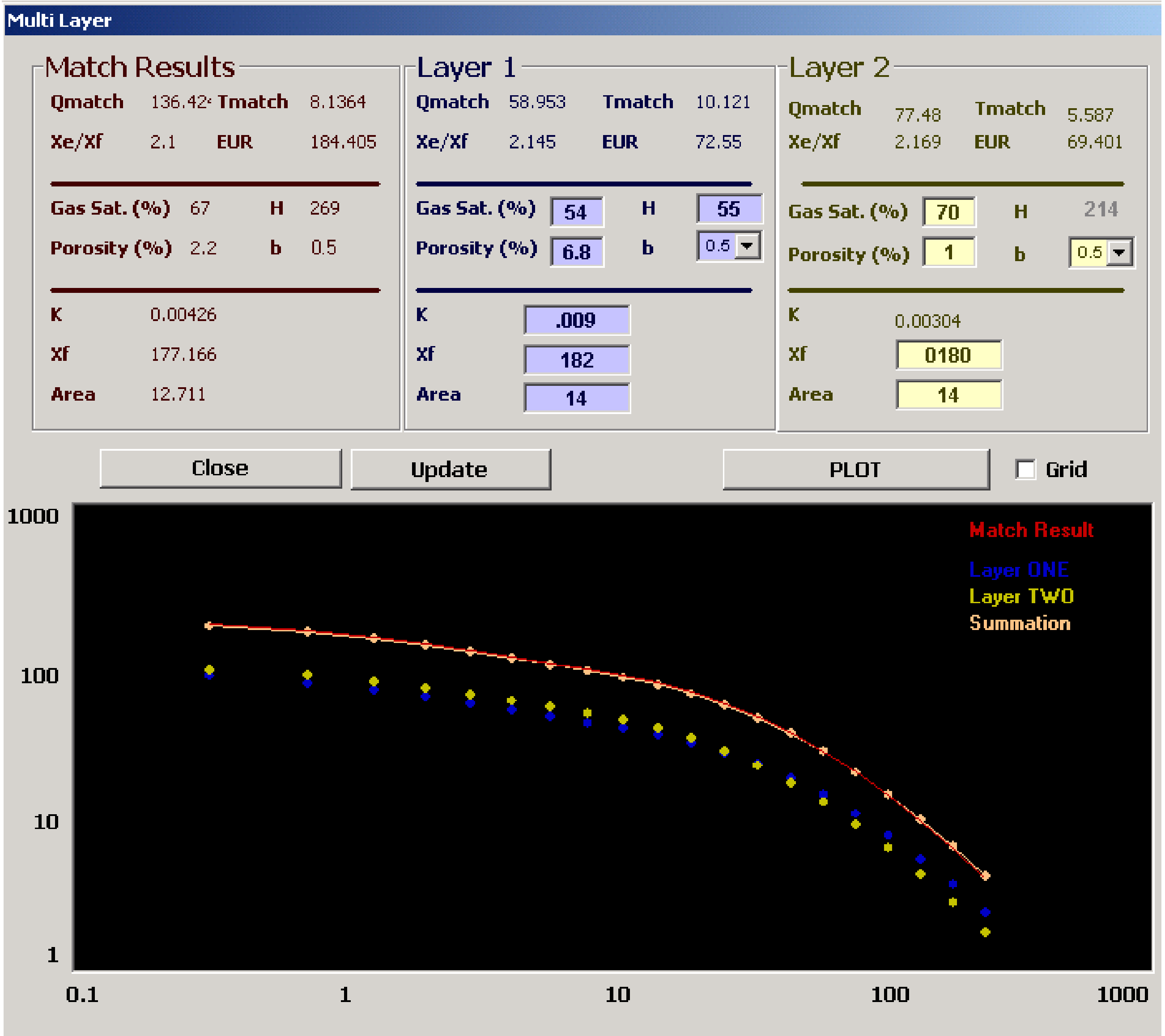

Figure 28 – Area 2 Multiple Layer Type Curve Match Results

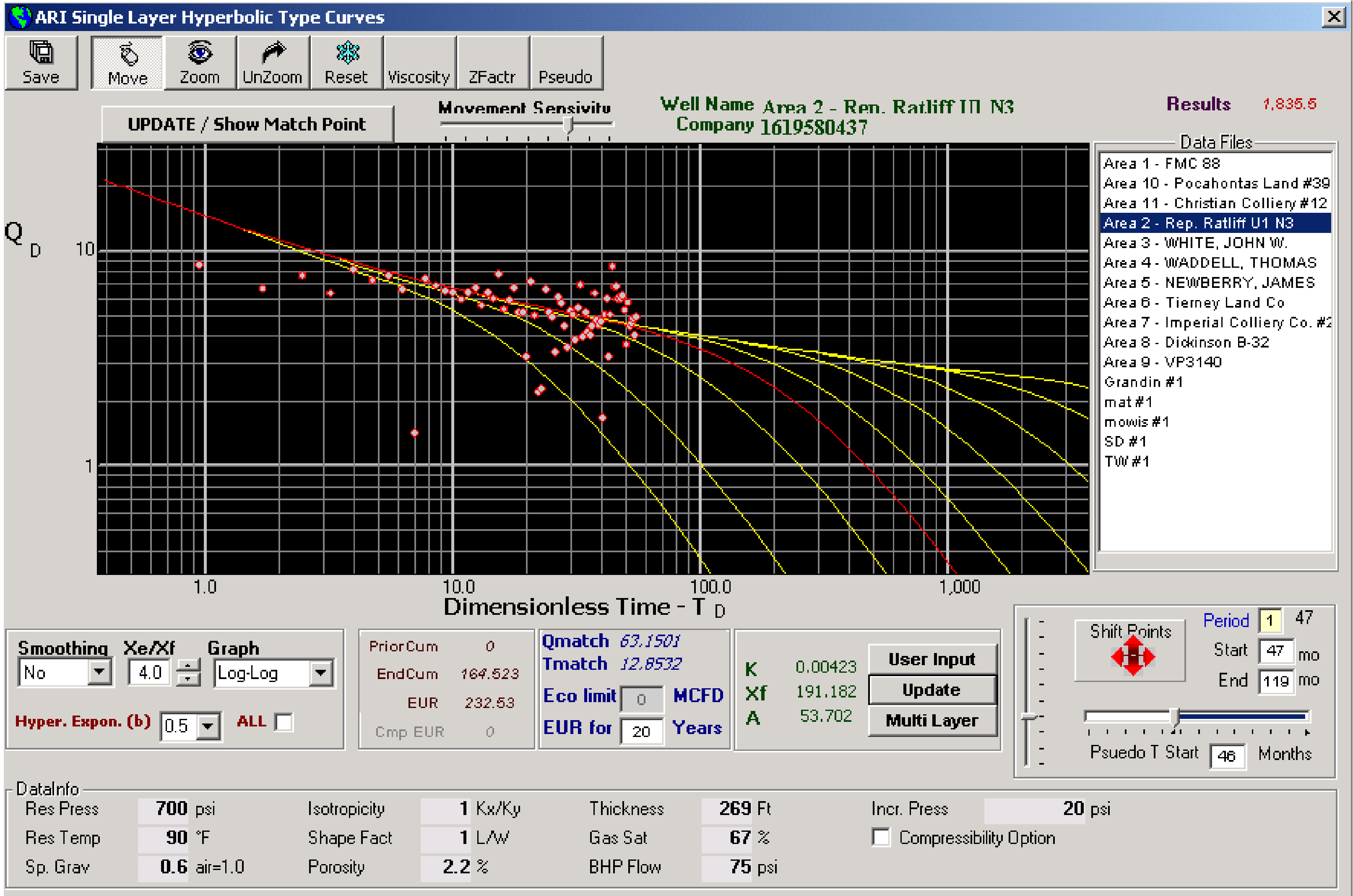

Figure 29 – Area 2 Restart Single Layer Type Curve Match

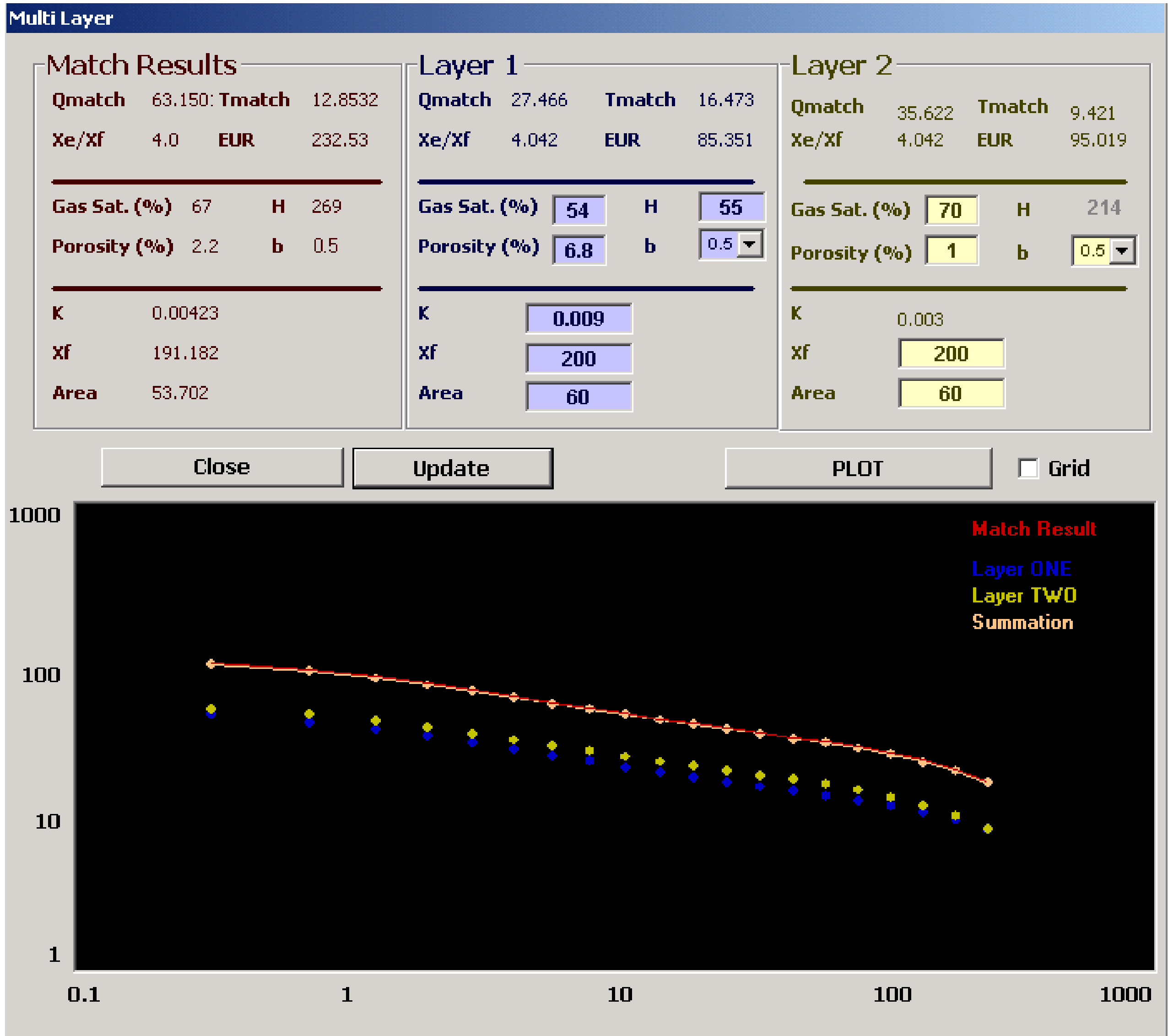

Figure 30 – Area 2 Restart Multiple Layer Type Curve Match Results

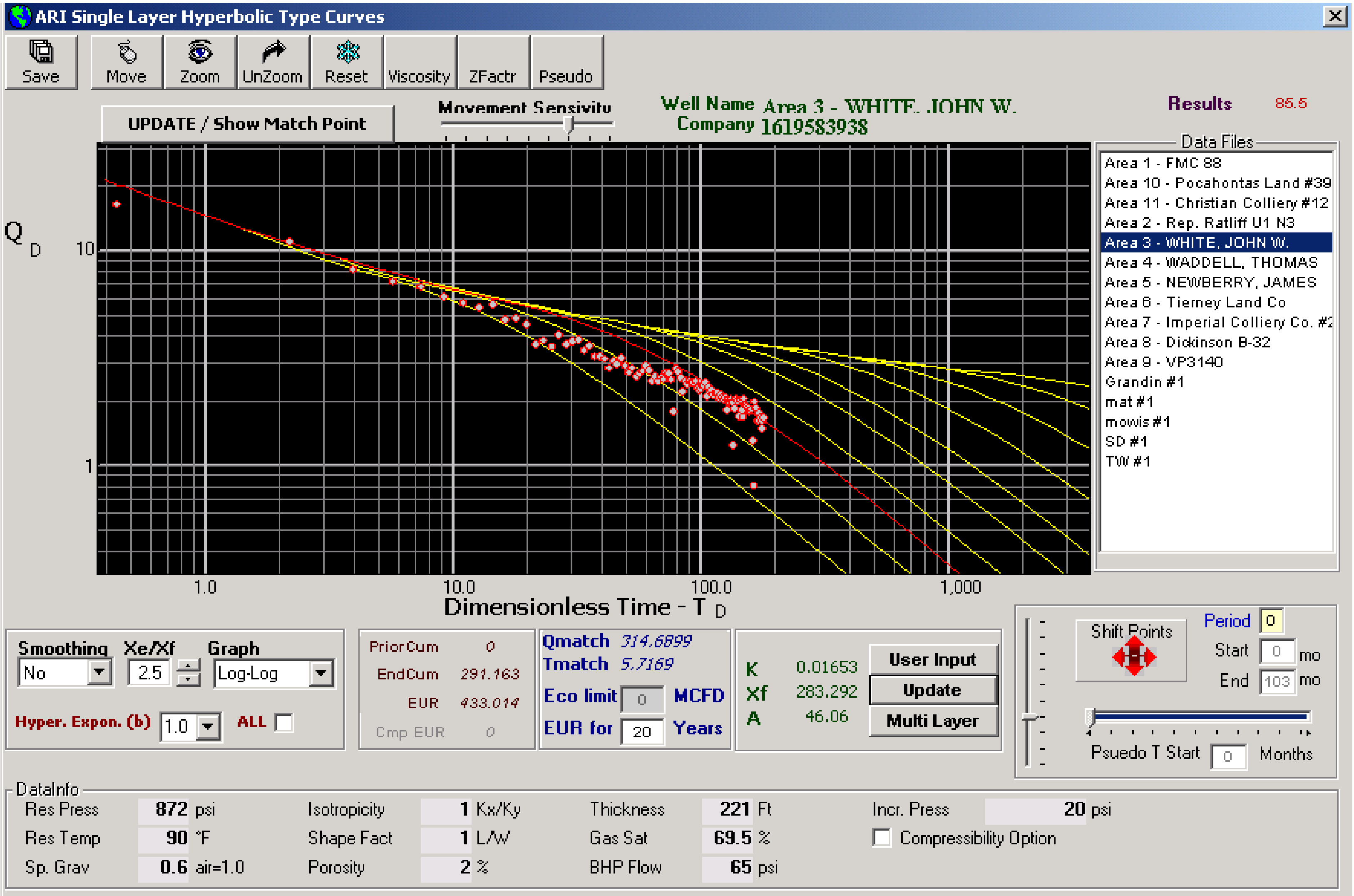

Figure 31 – Area 3 Single Layer Type Curve Match

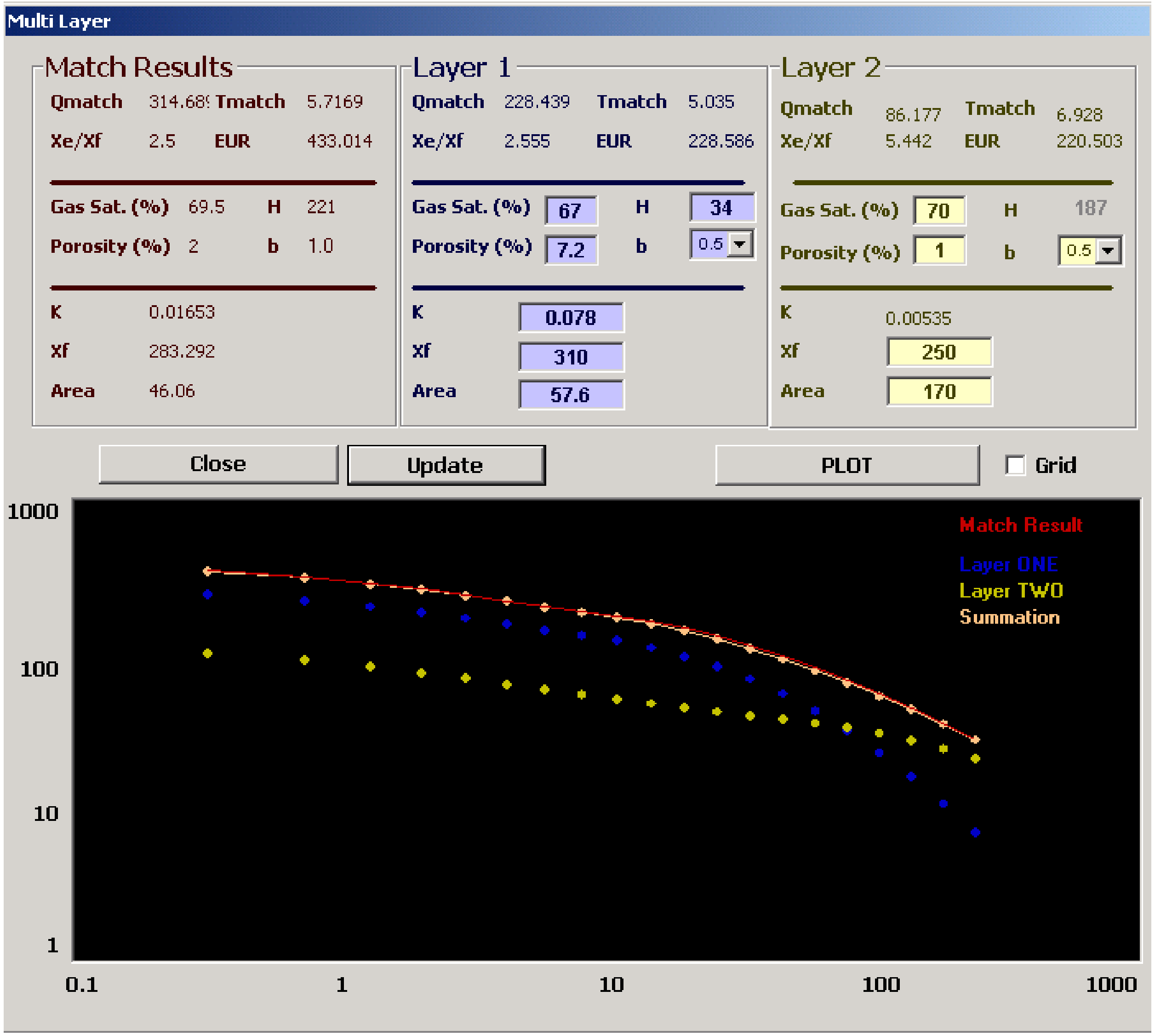

Figure 32 – Area 3 Multiple Layer Type Curve Match Results

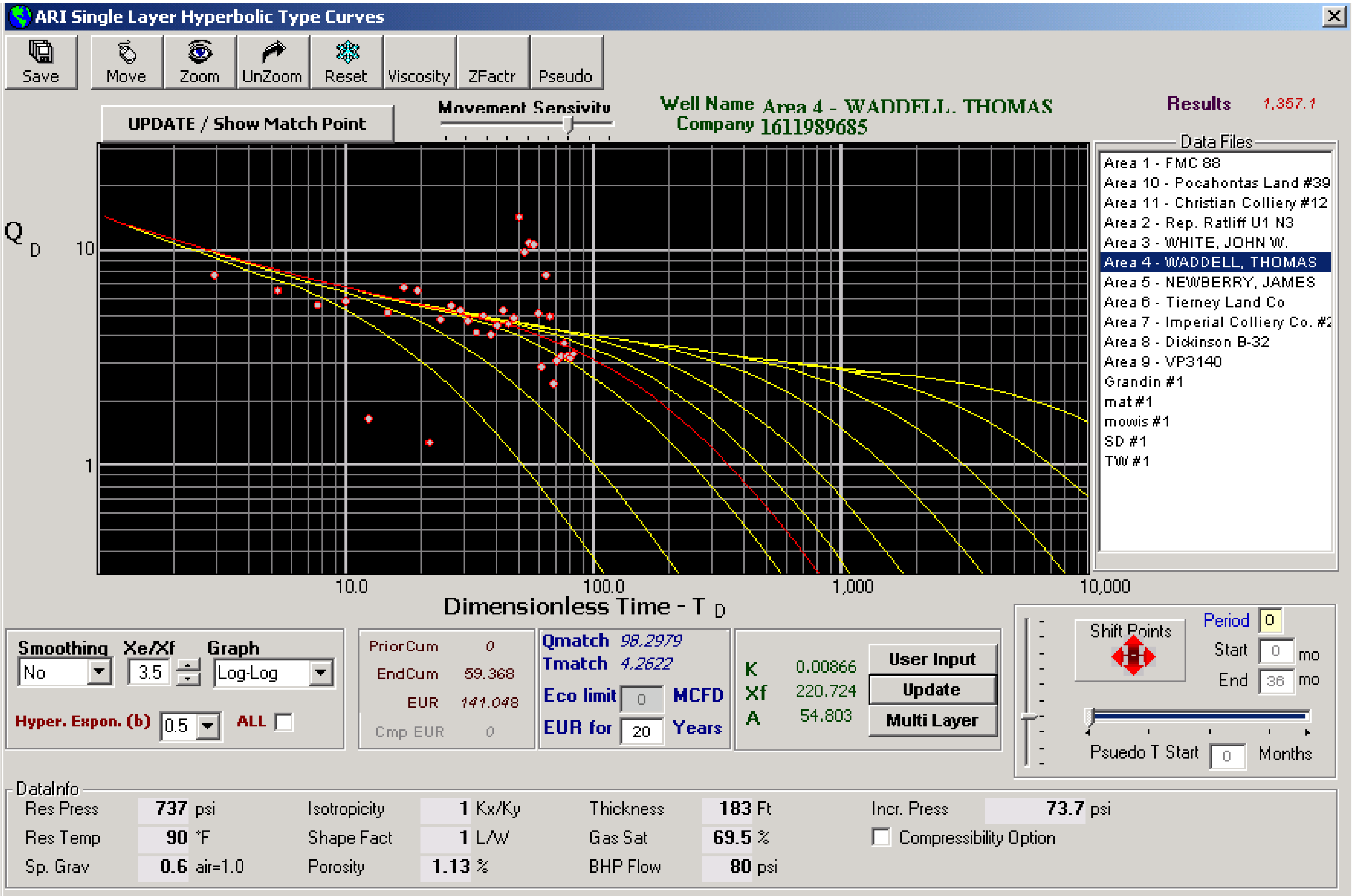

Figure 33 – Area 4 Single Layer Type Curve Match

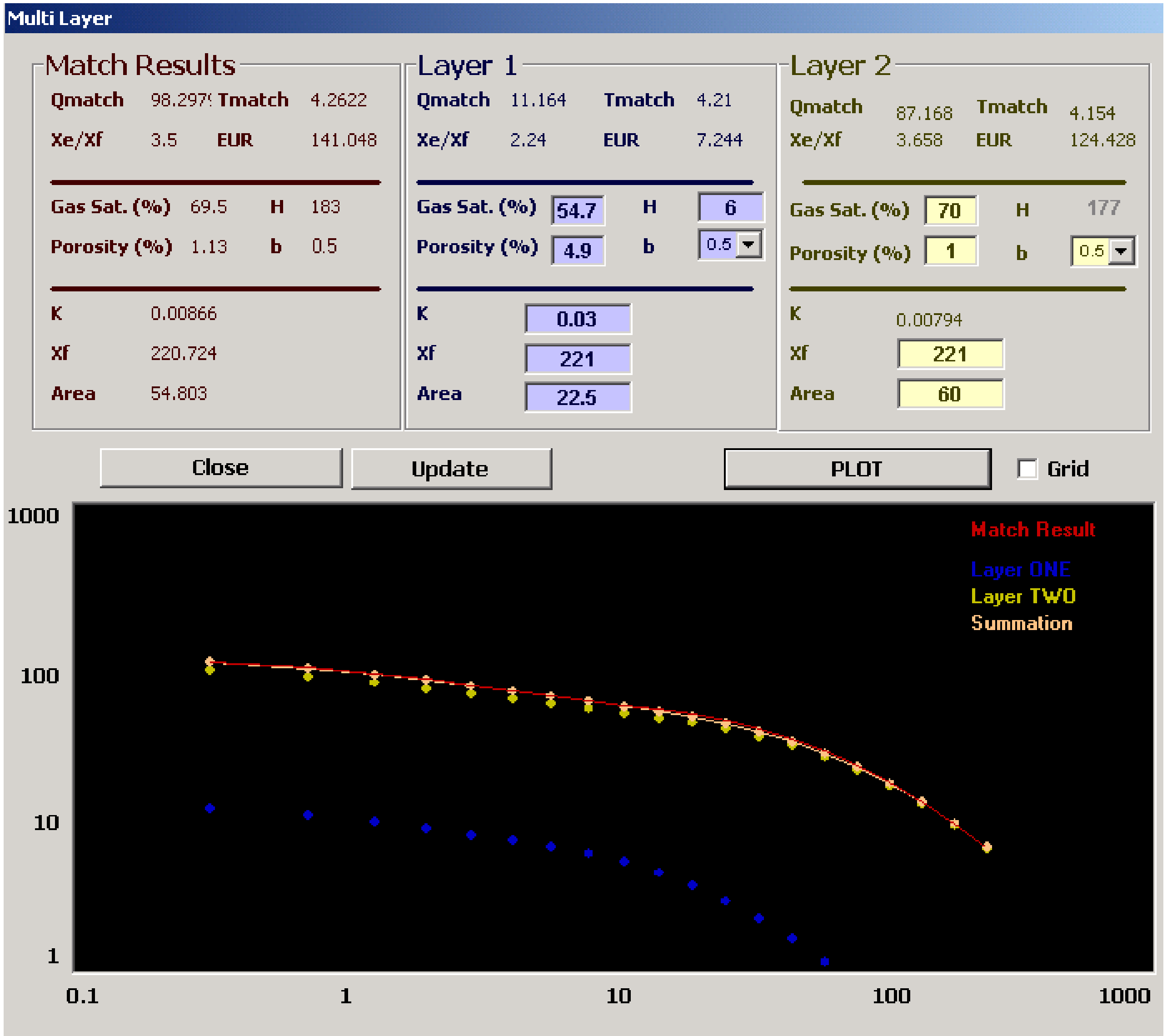

Figure 34 – Area 4 Multiple Layer Type Curve Match Results

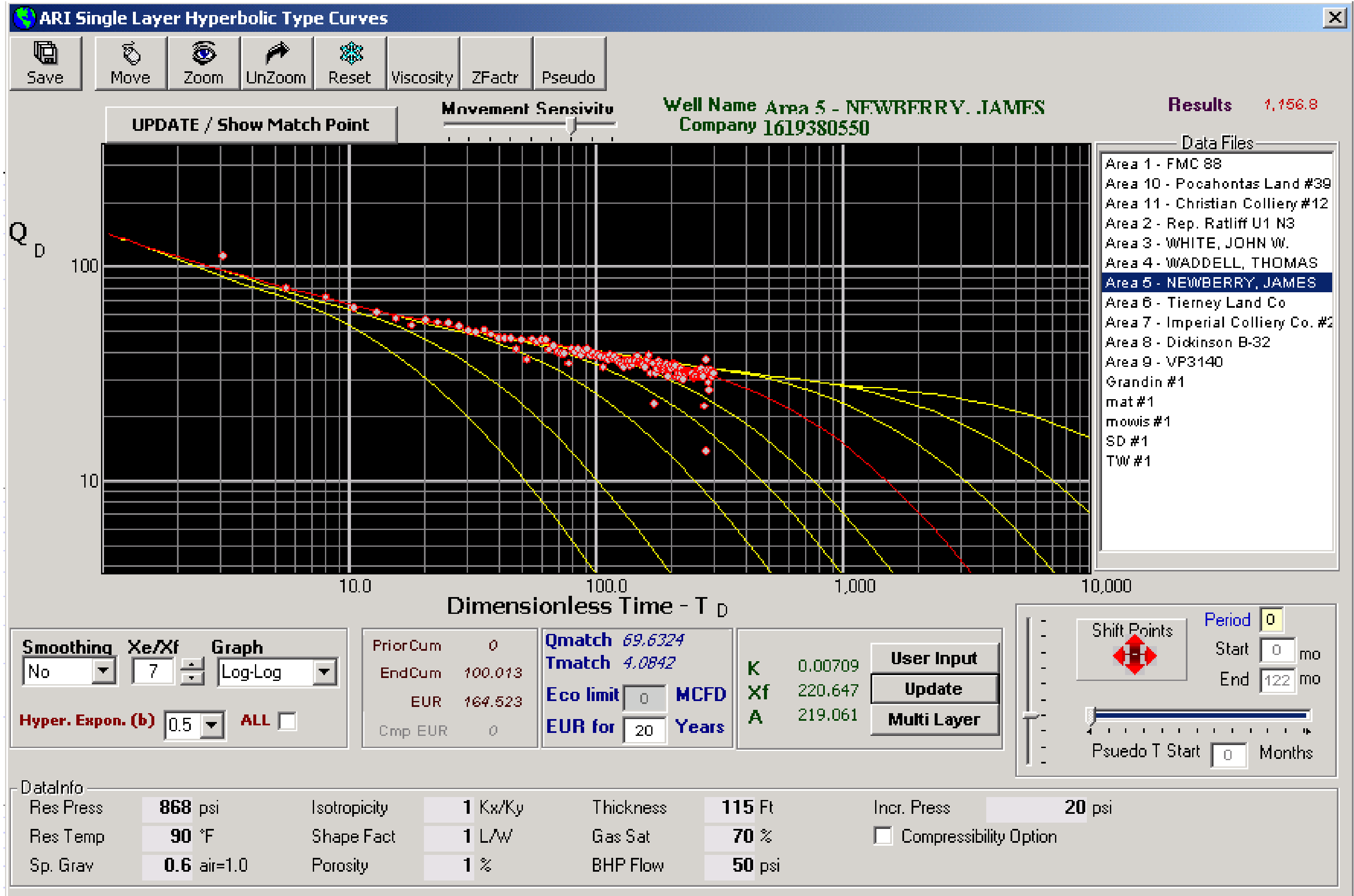

Figure 35 – Area 5 Single Layer Type Curve Match

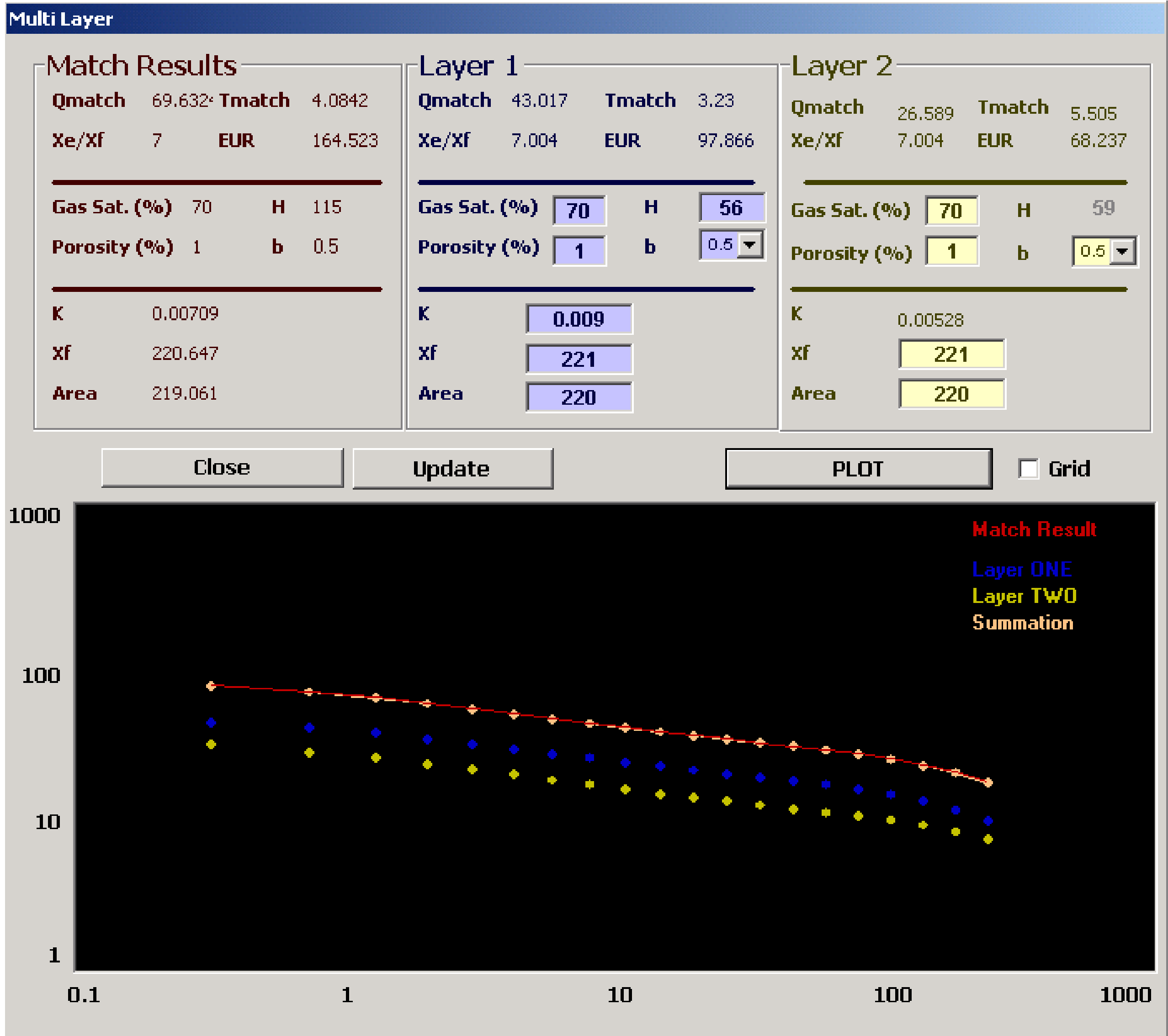

Figure 36 – Area 5 Multiple Layer Type Curve Match Results

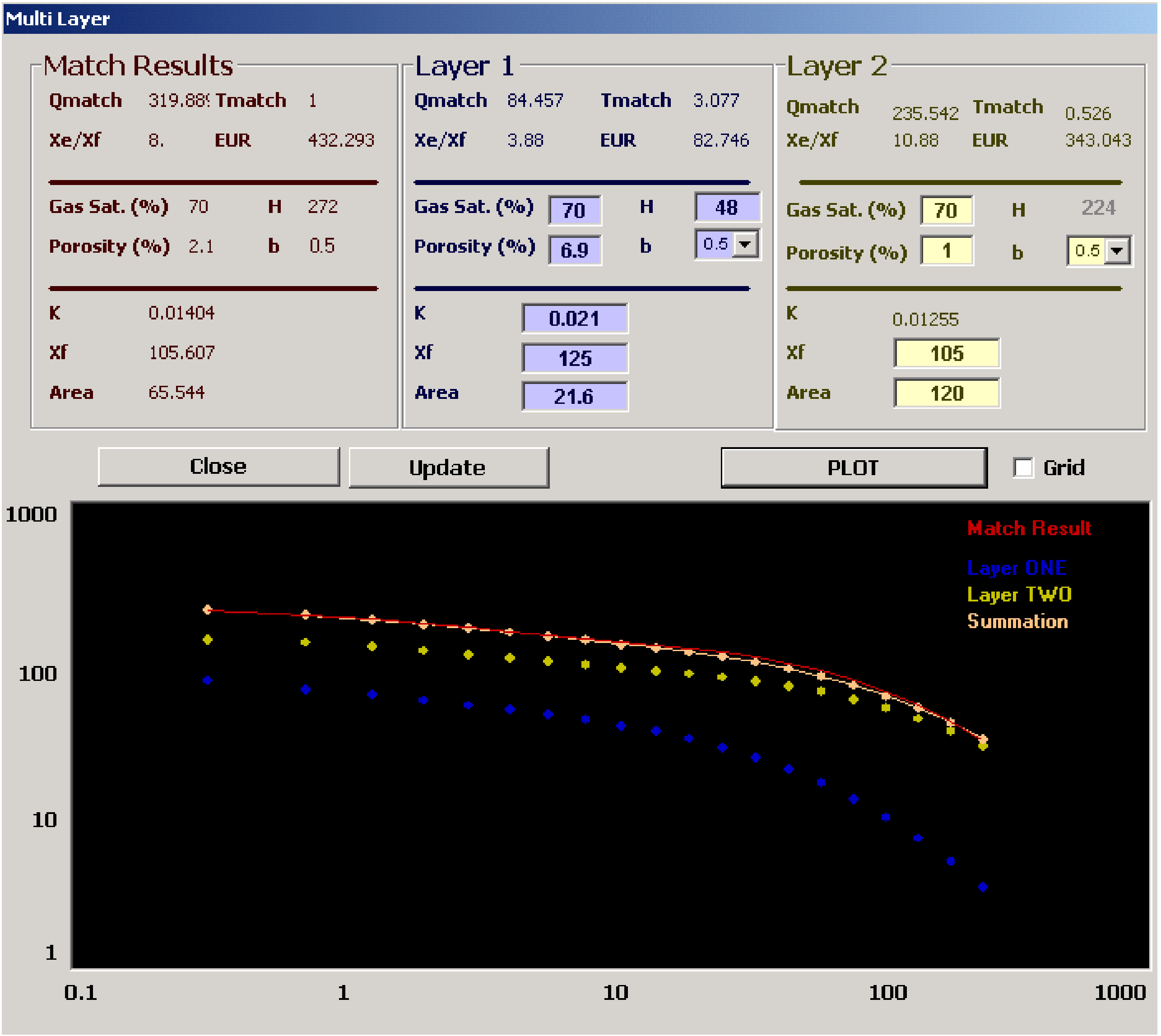

Figure 37 – Area 6 Single Layer Type Curve Match

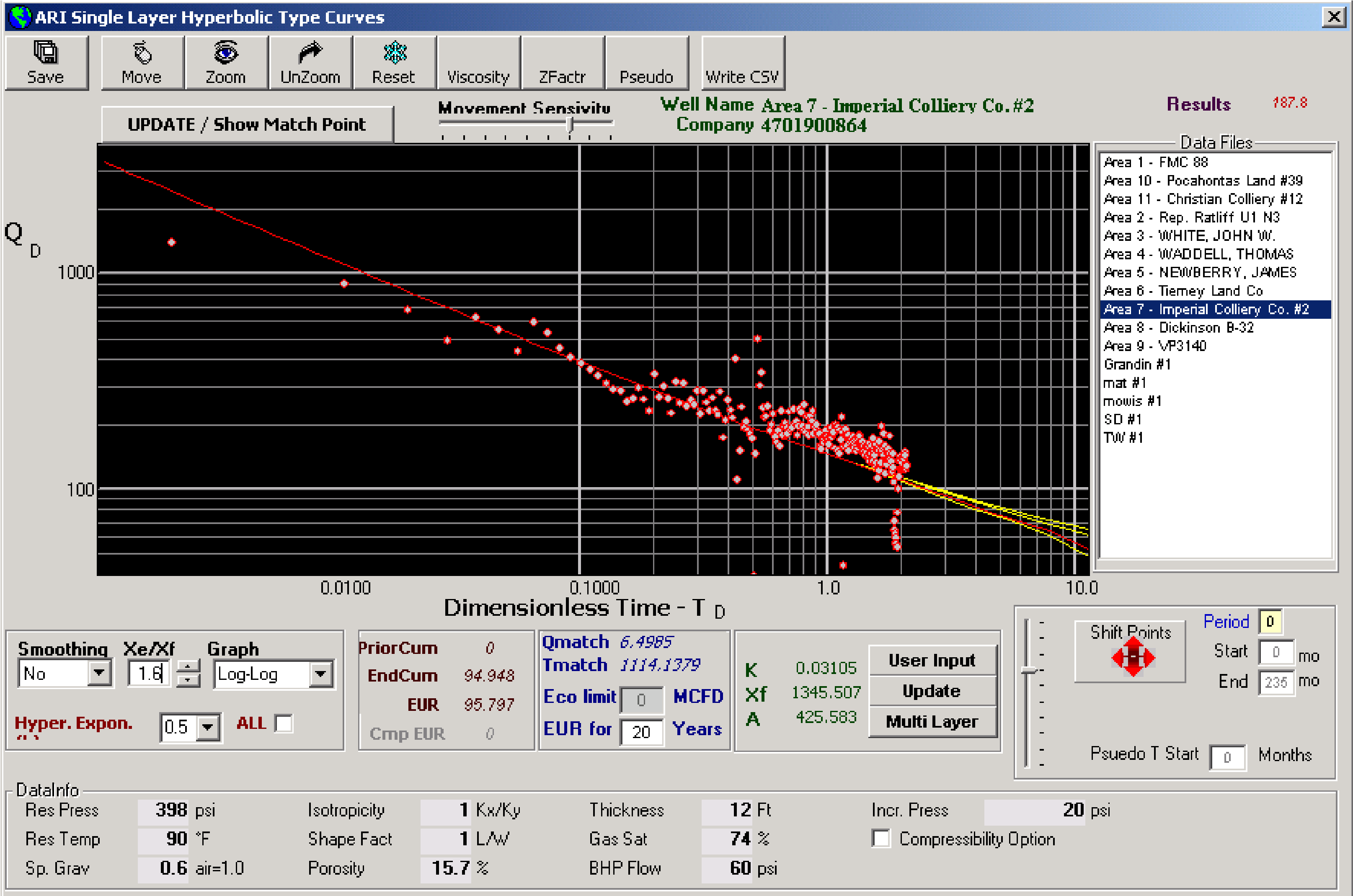

Figure 38 – Area 6 Multiple Layer Type Curve Match Results

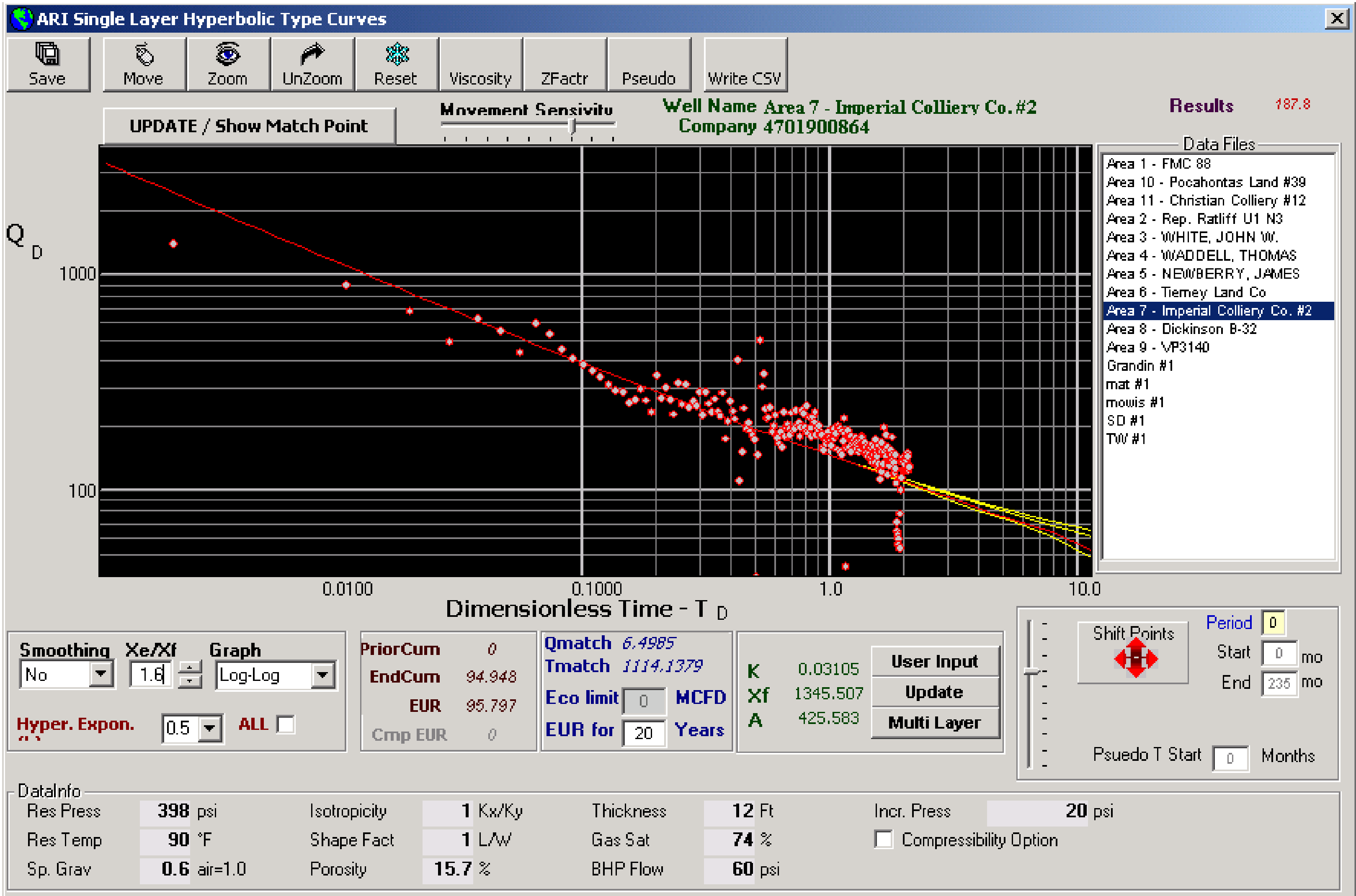

Figure 39 – Area 7 Single Layer Type Curve Match

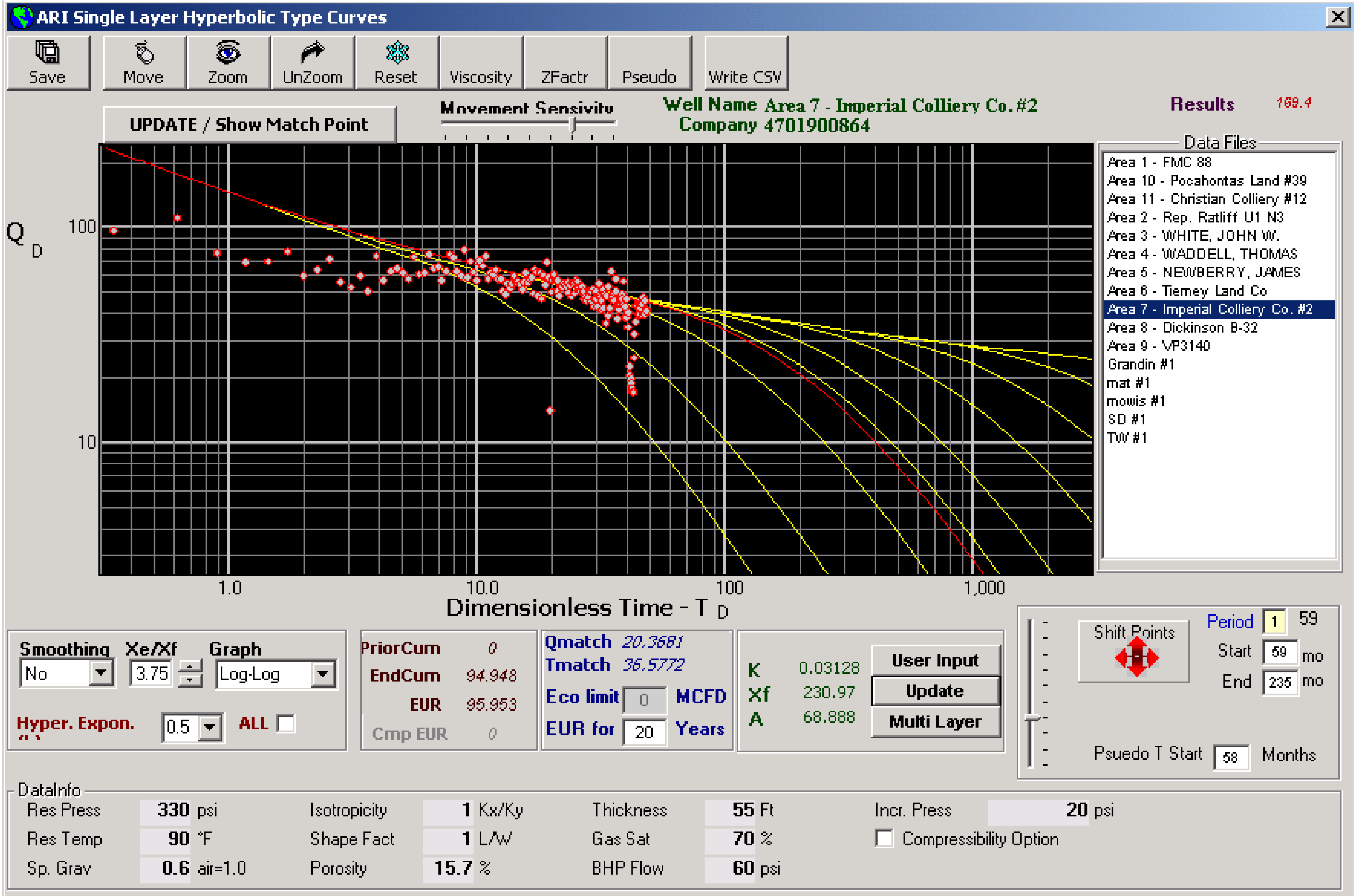

Figure 40 – Area 7 Restart Single Layer Type Curve Match

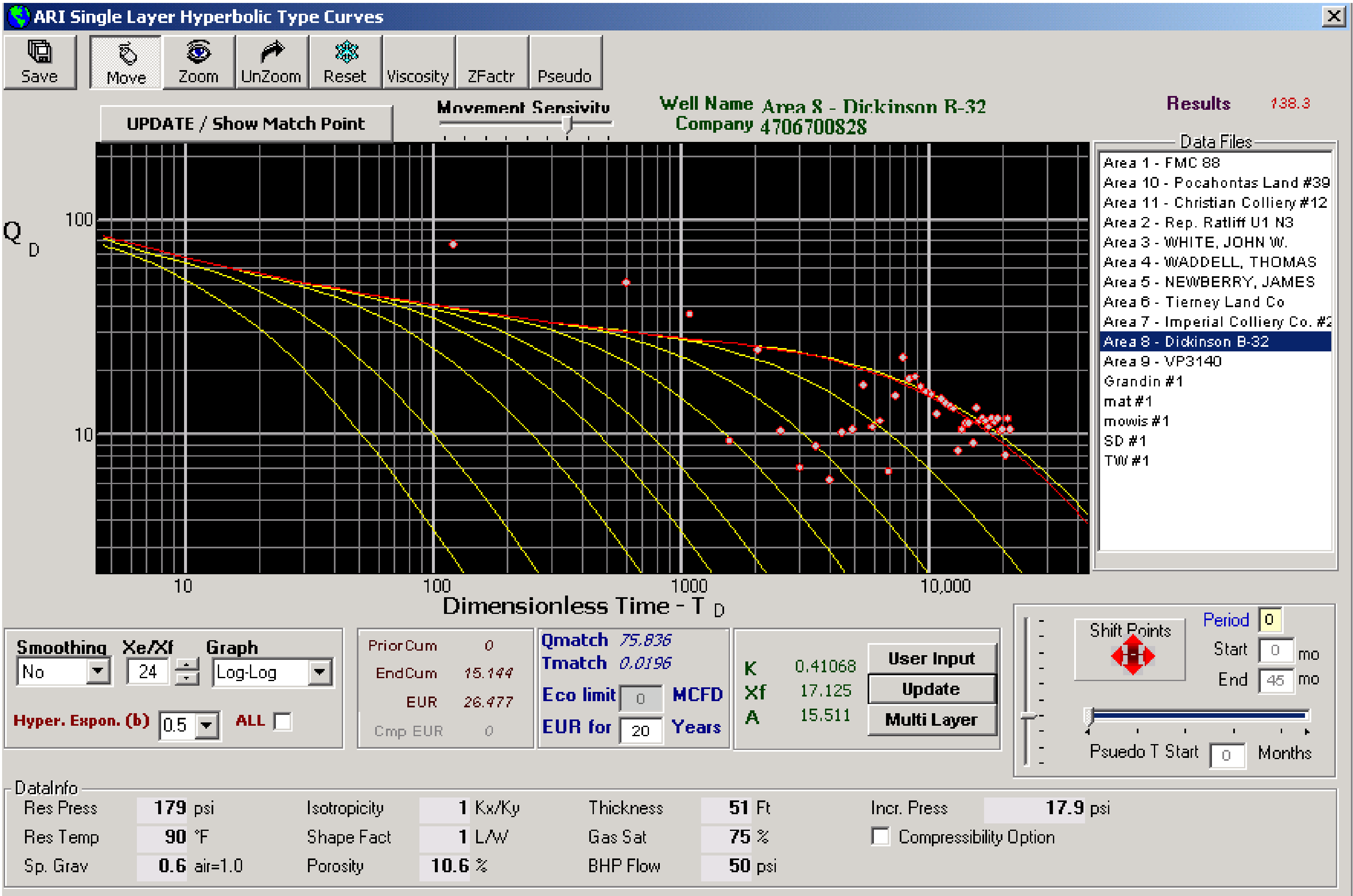

Figure 41 – Area 8 Single Layer Type Curve Match

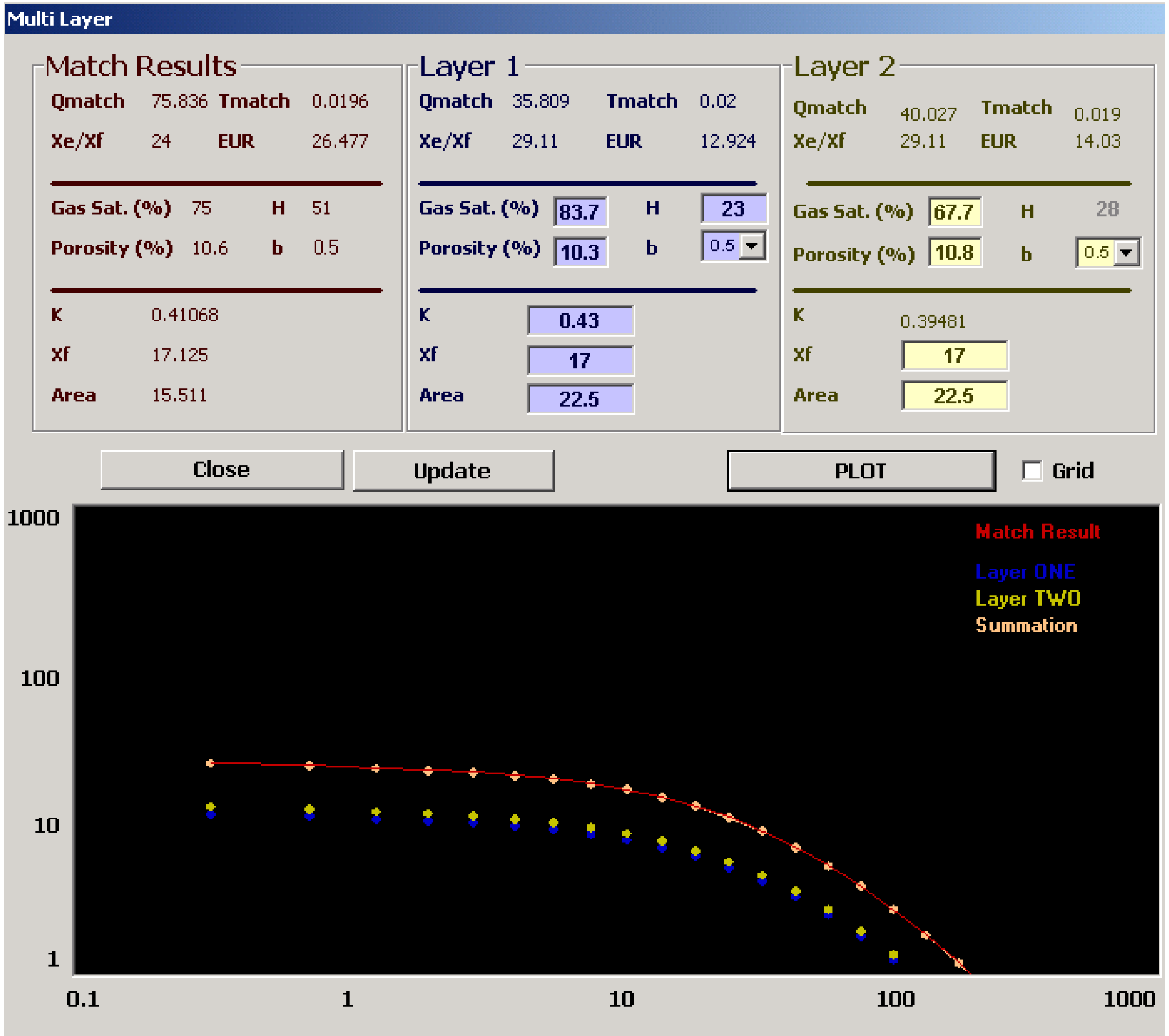

Figure 42 – Area 8 Multiple Layer Type Curve Match Results

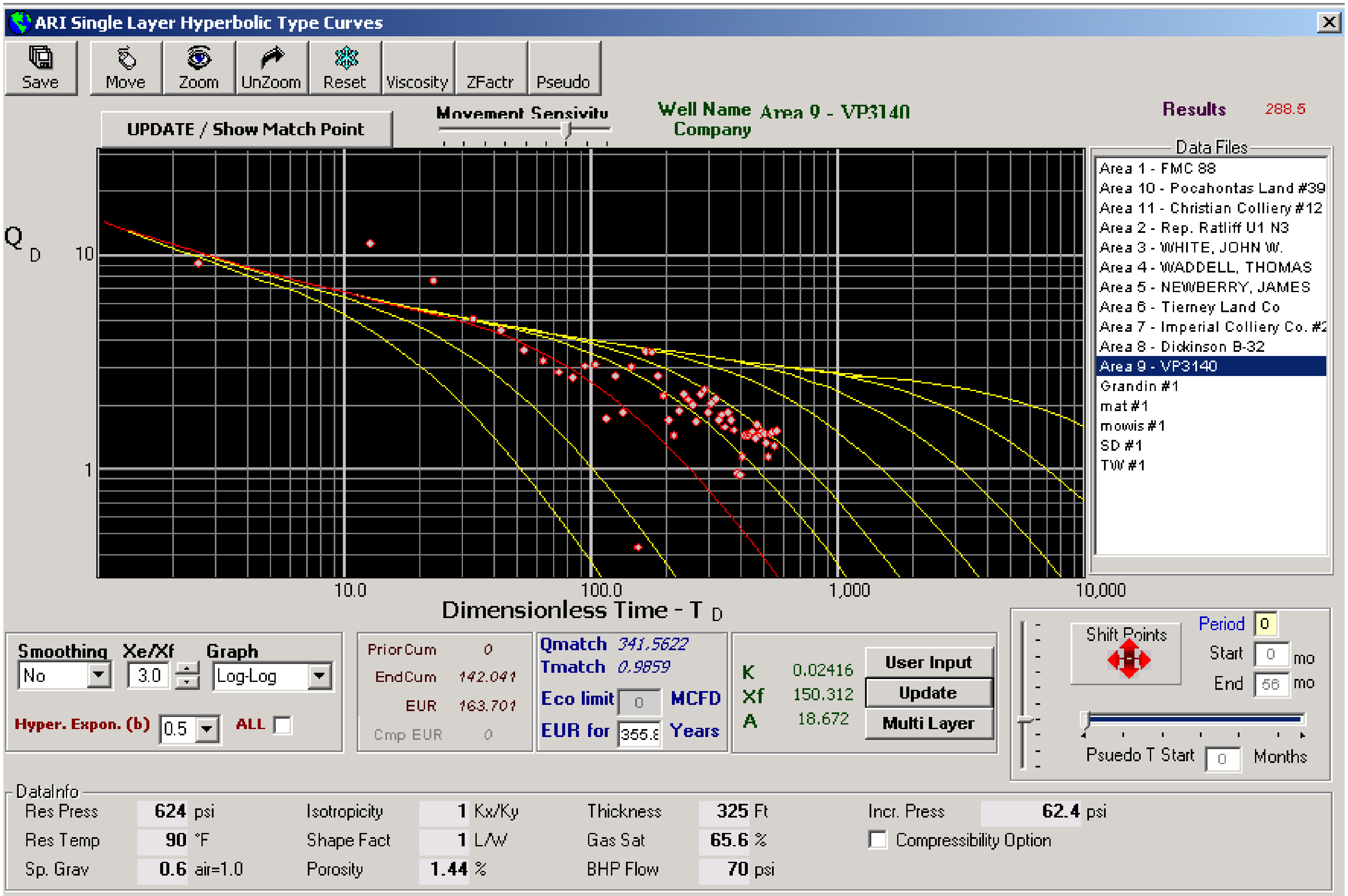

Figure 43 – Area 9 Single Layer Type Curve Match

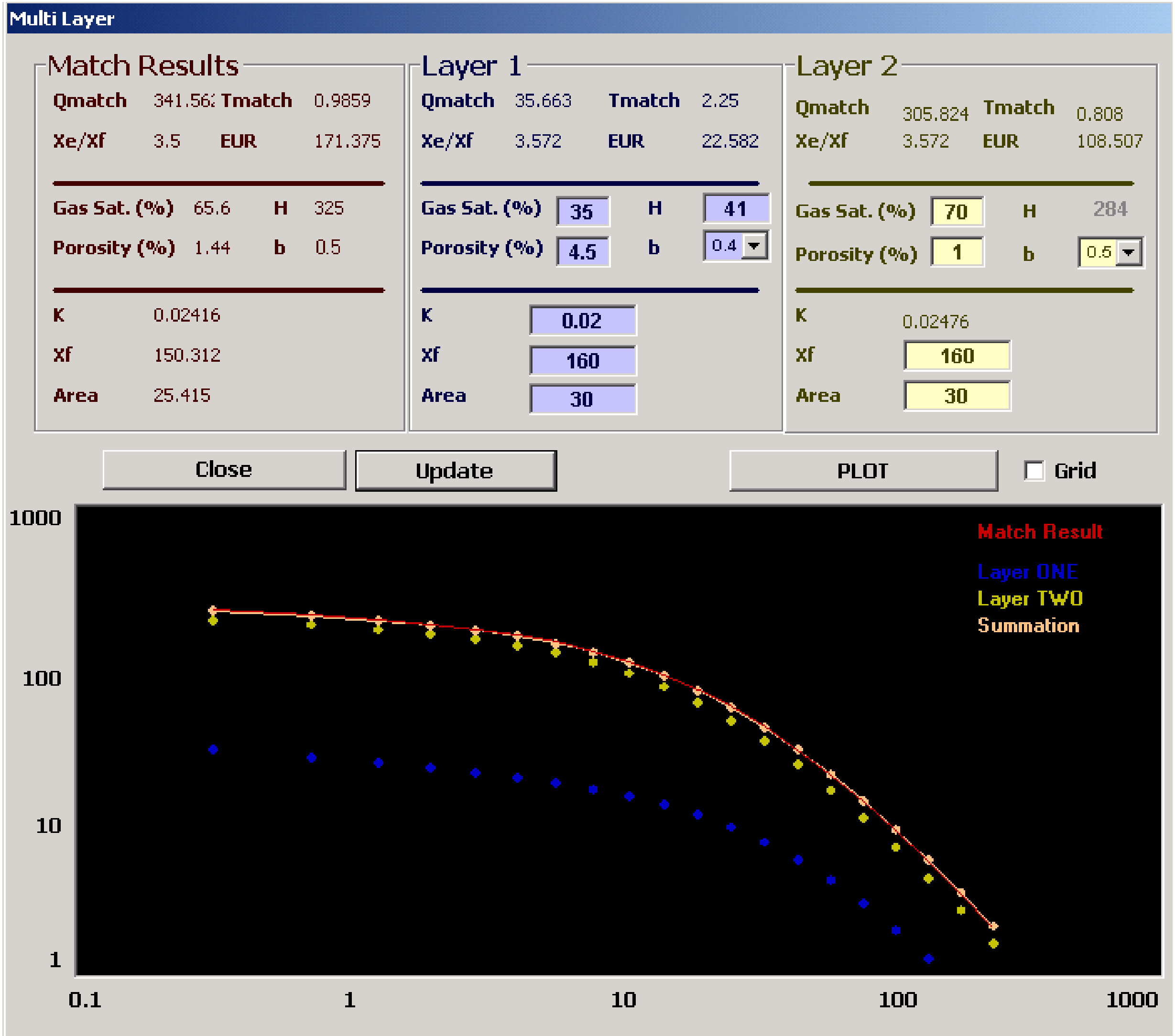

Figure 44 – Area 9 Multiple Layer Type Curve Match Results

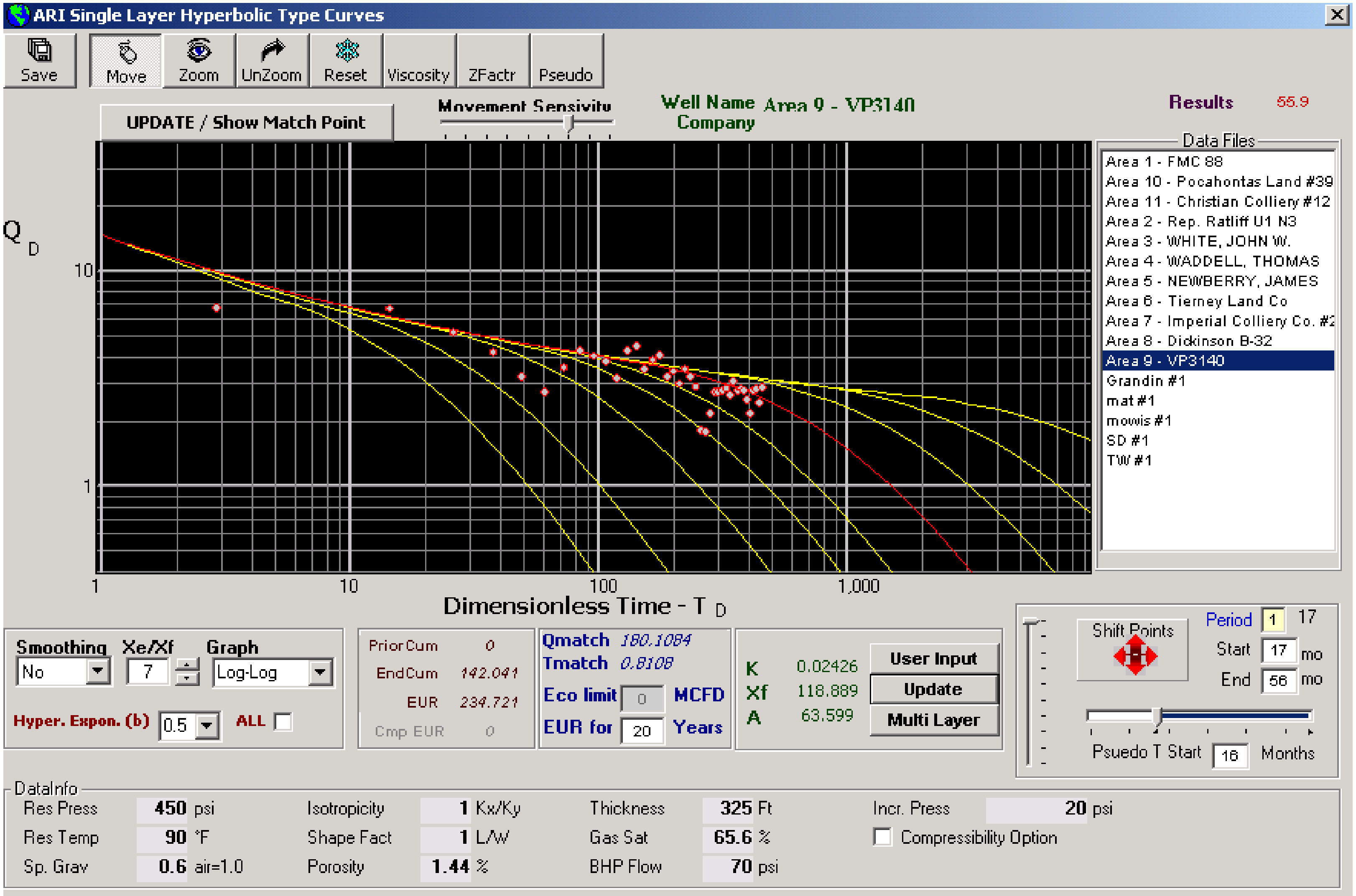

Figure 45 – Area 9 Restart Single Layer Type Curve Match

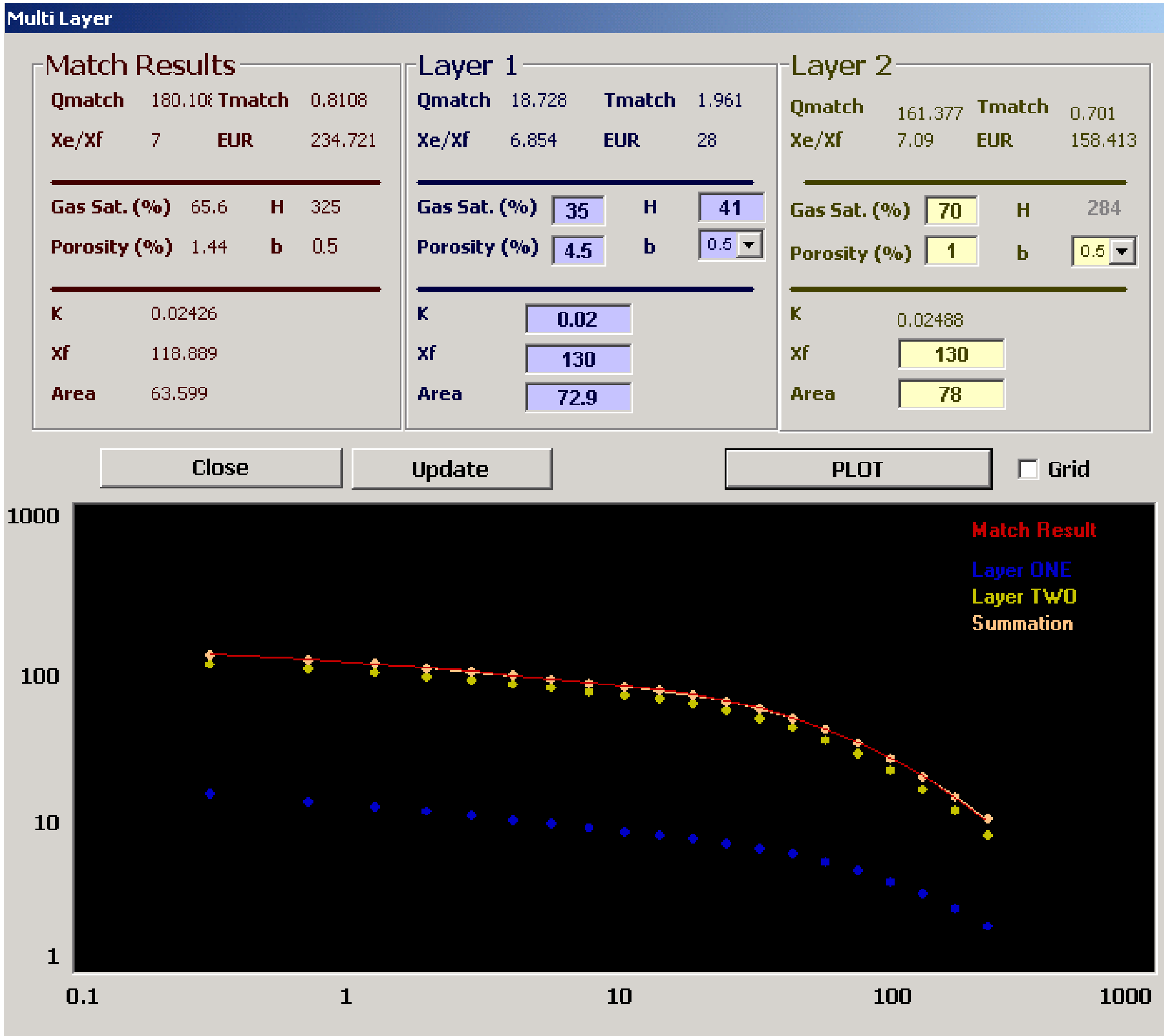

Figure 46 – Area 9 Restart Multiple Layer Type Curve Match Results

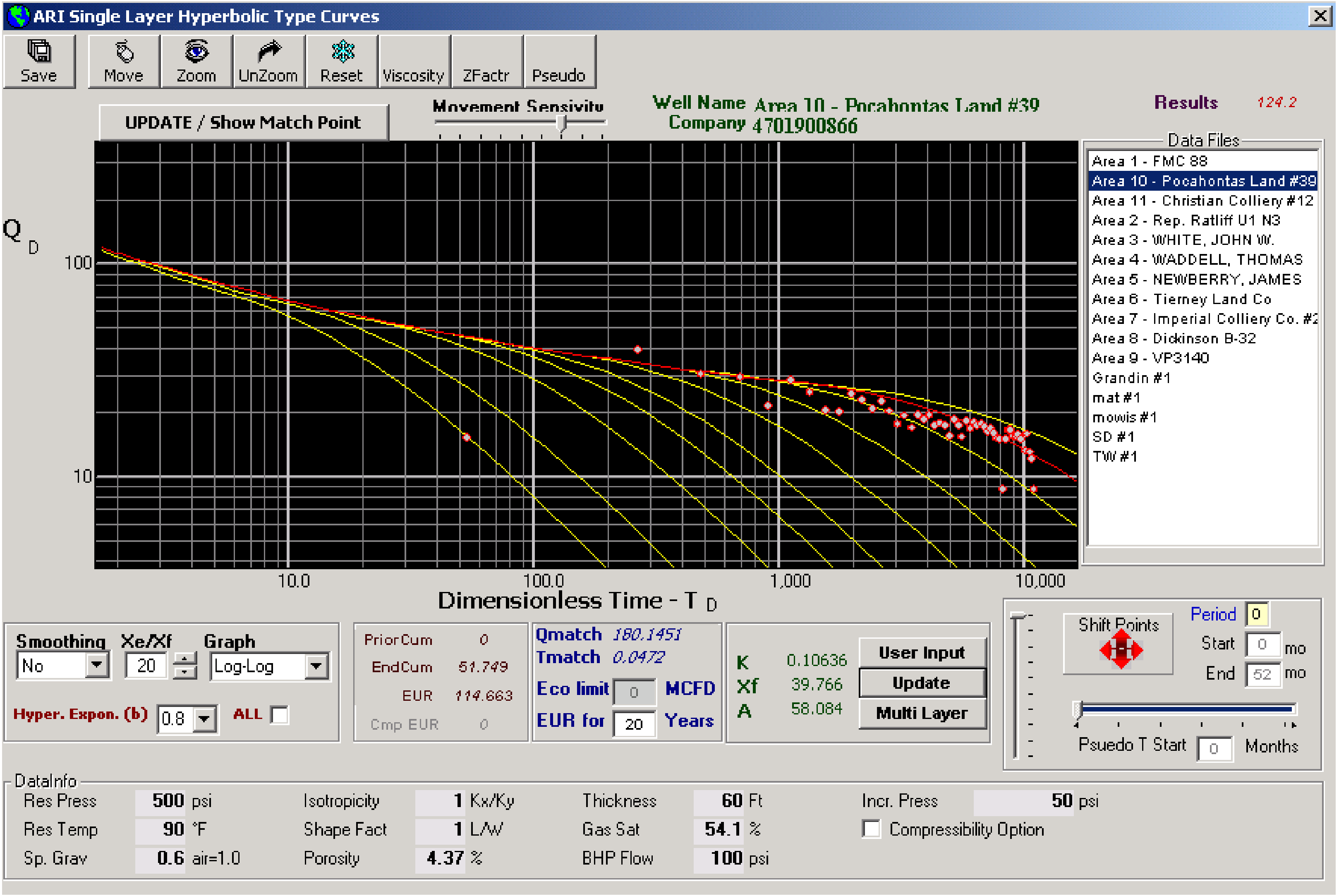

Figure 47 – Area 10 Single Layer Type Curve Match

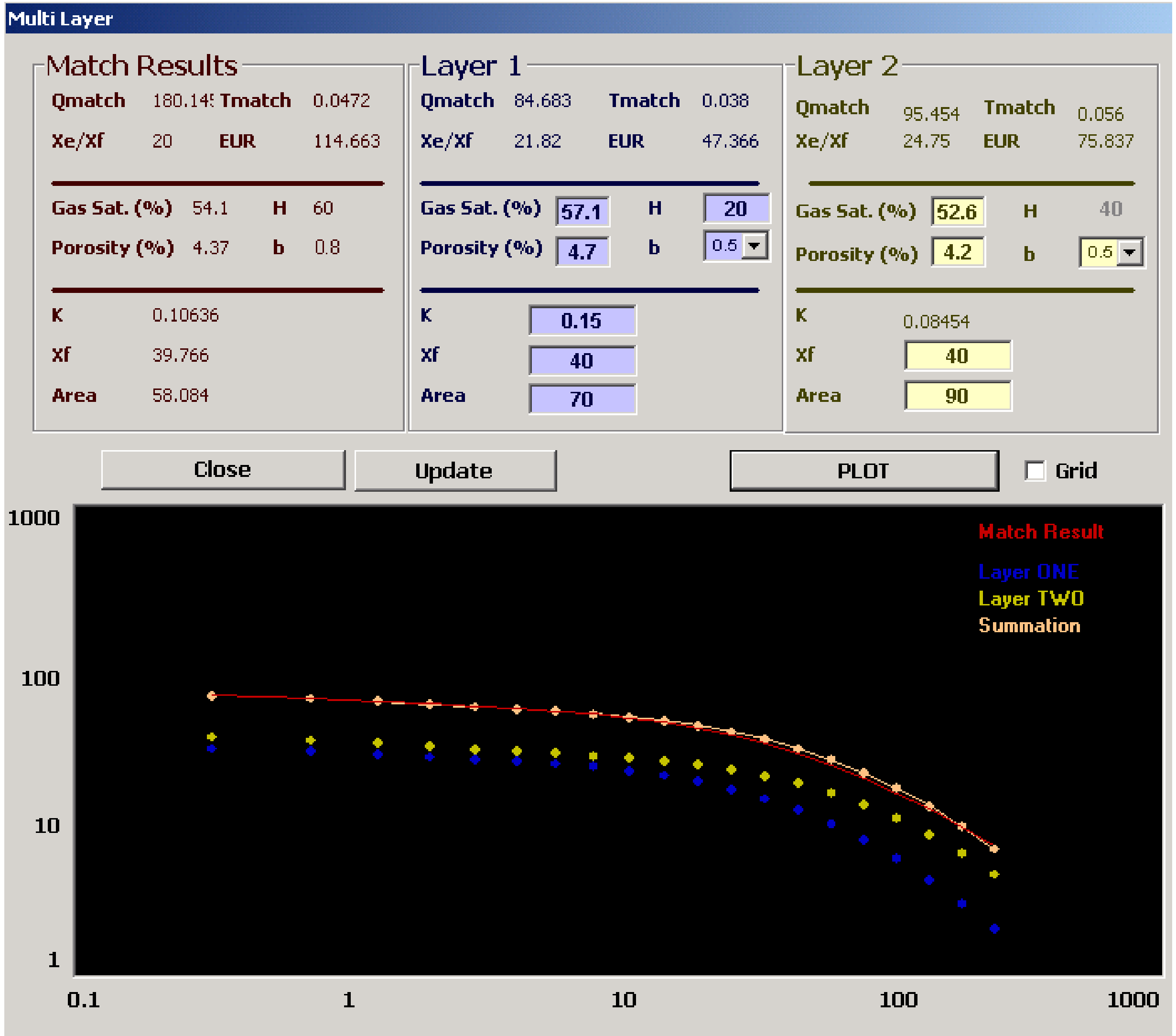

Figure 48 – Area 10 Multiple Layer Type Curve Match Results

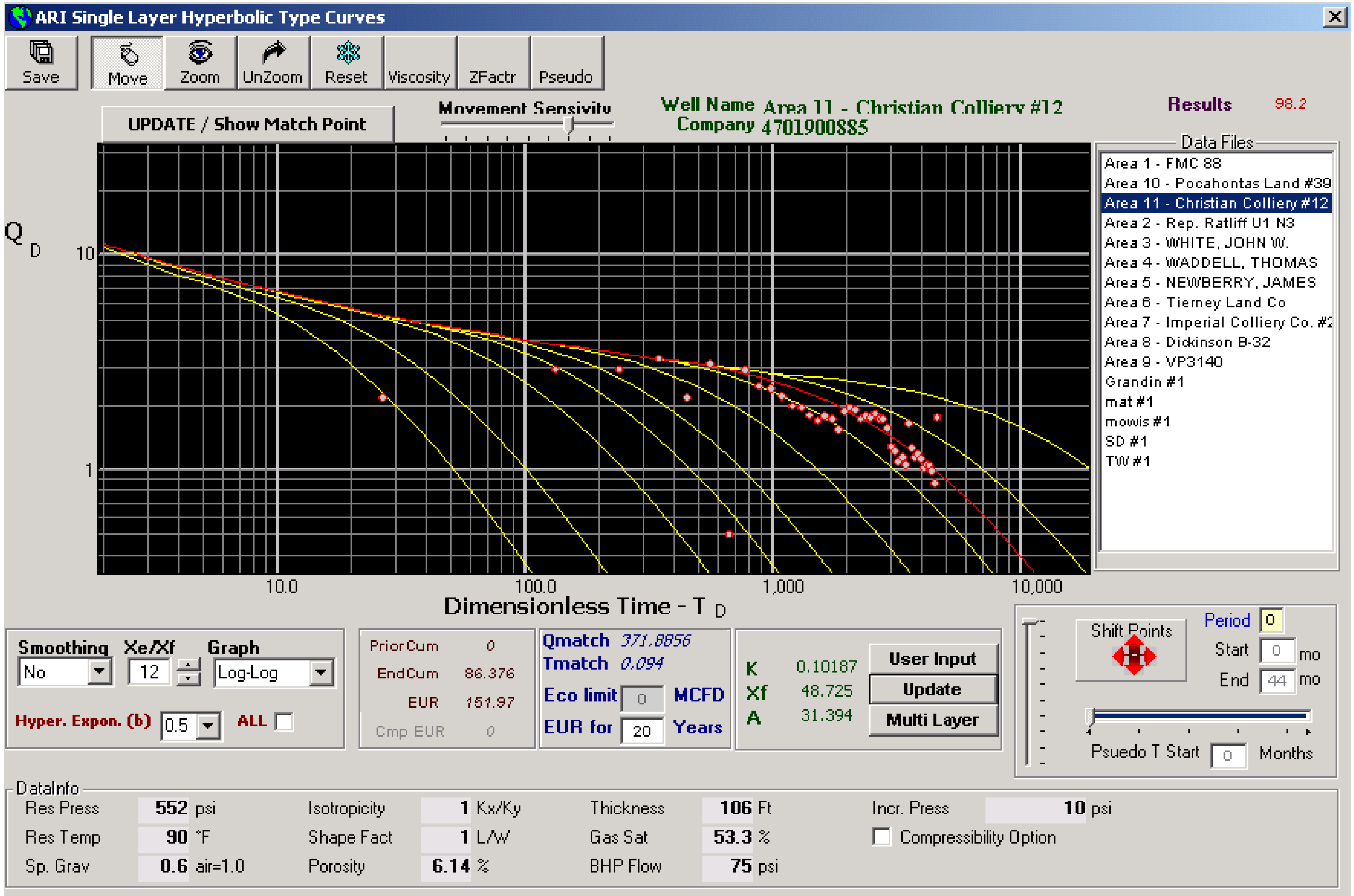

Figure 49 – Area 11 Single Layer Type Curve Match

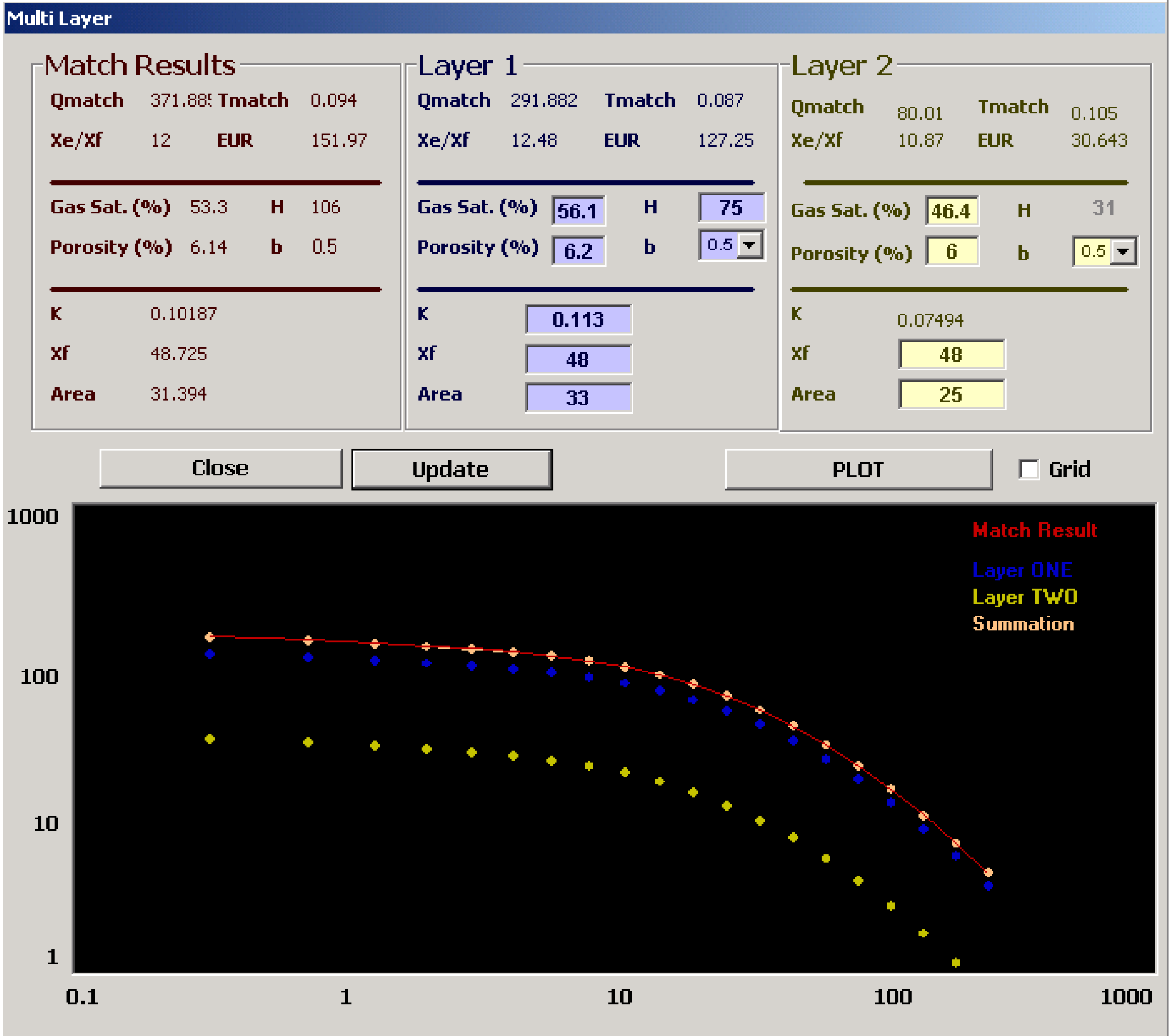

Figure 50 – Area 11 Multiple Layer Type Curve Match Results

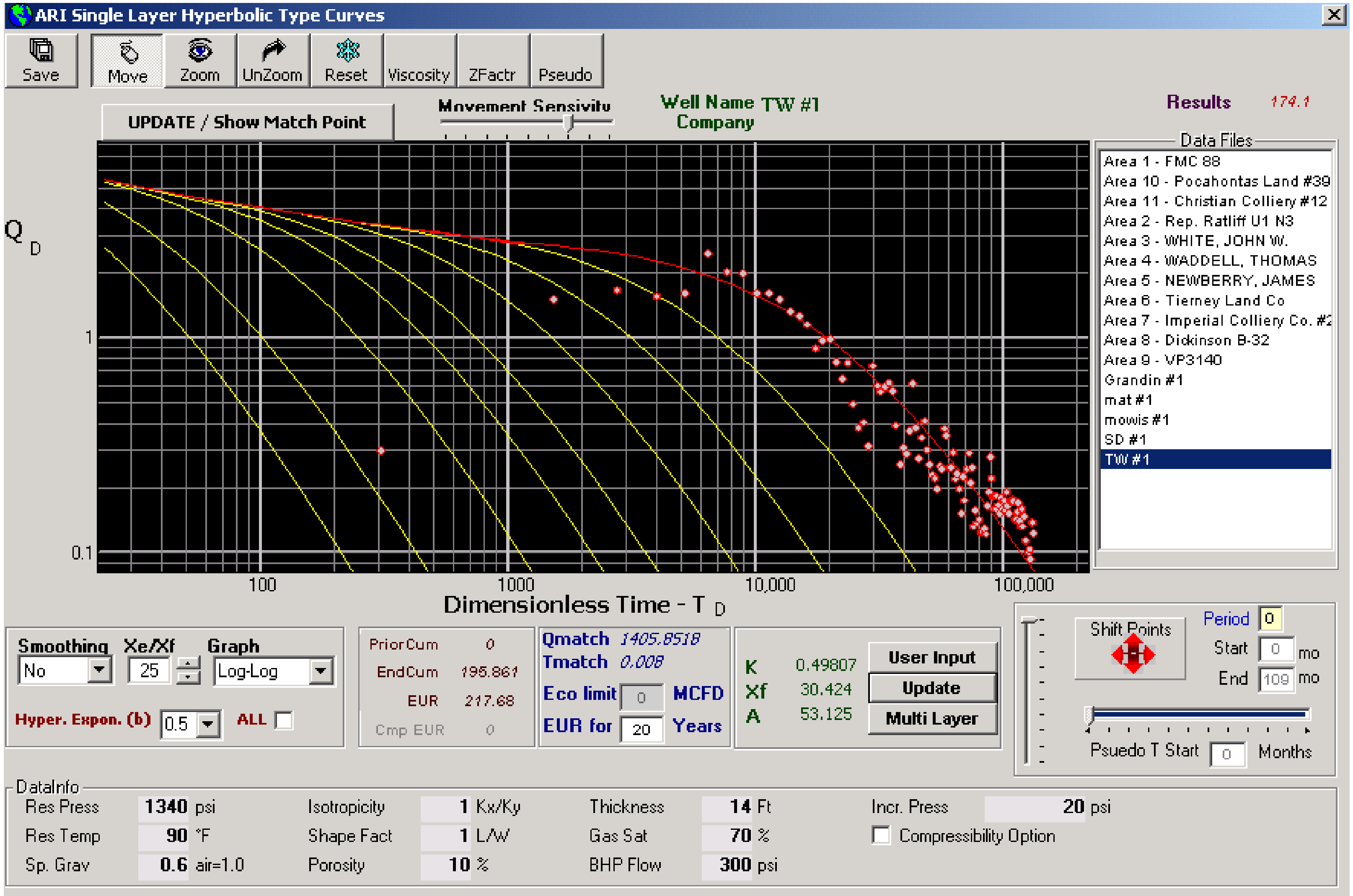

Figure 51 – Area 12 Single Layer Type Curve Match

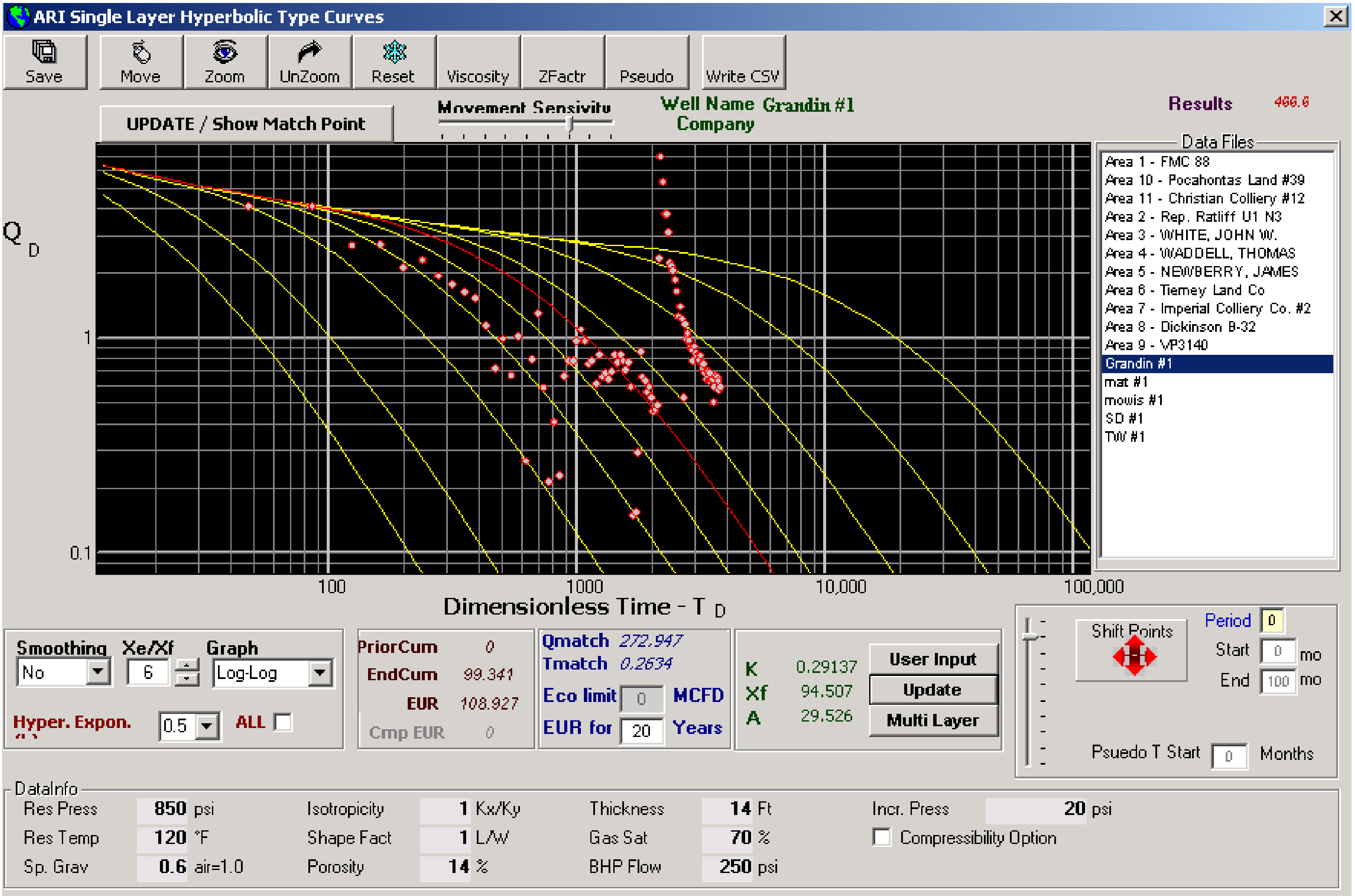

Figure 52 – Area 13 Single Layer Type Curve Match

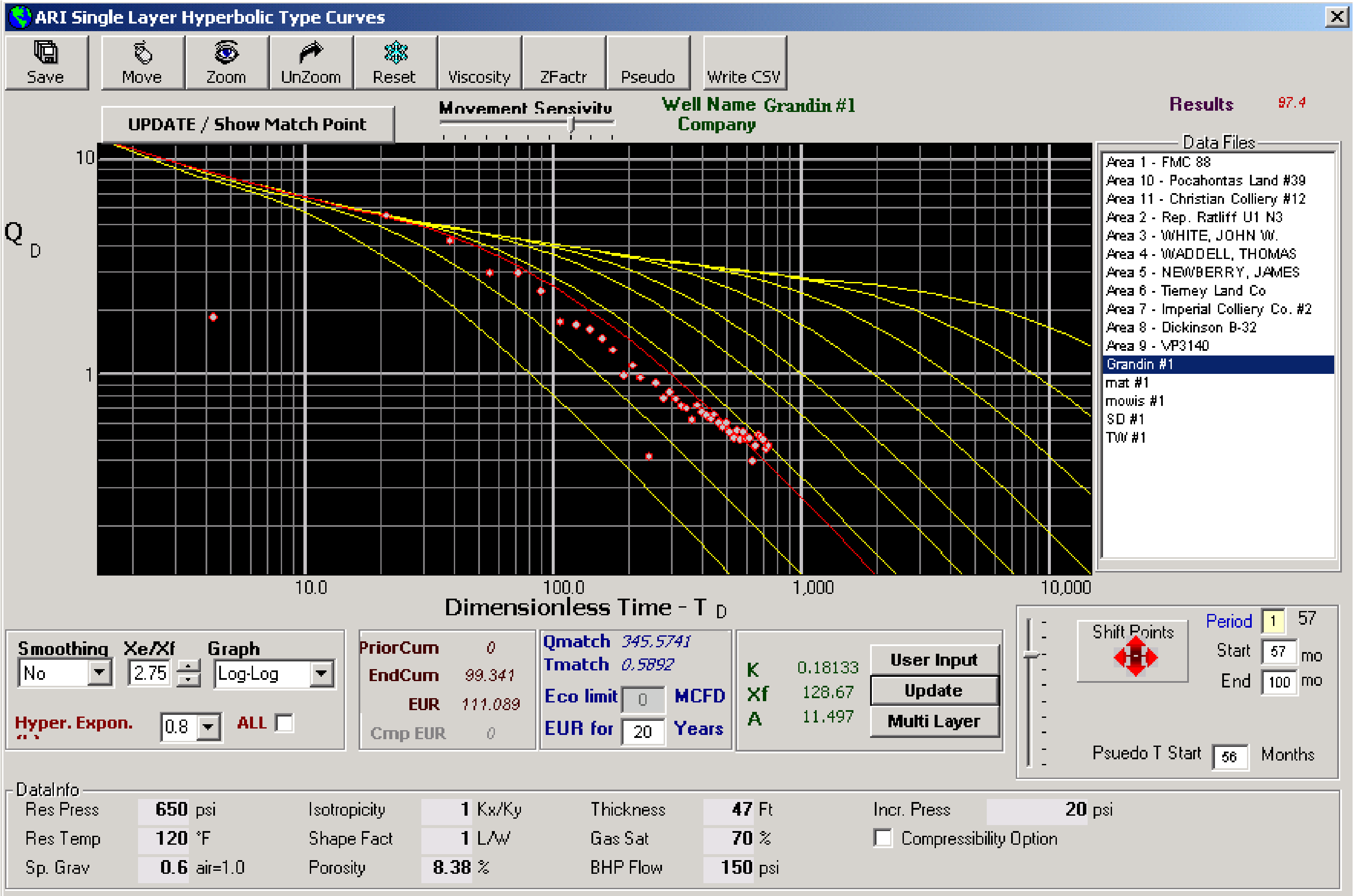

Figure 53 – Area 13 Restart Single Layer Type Curve Match

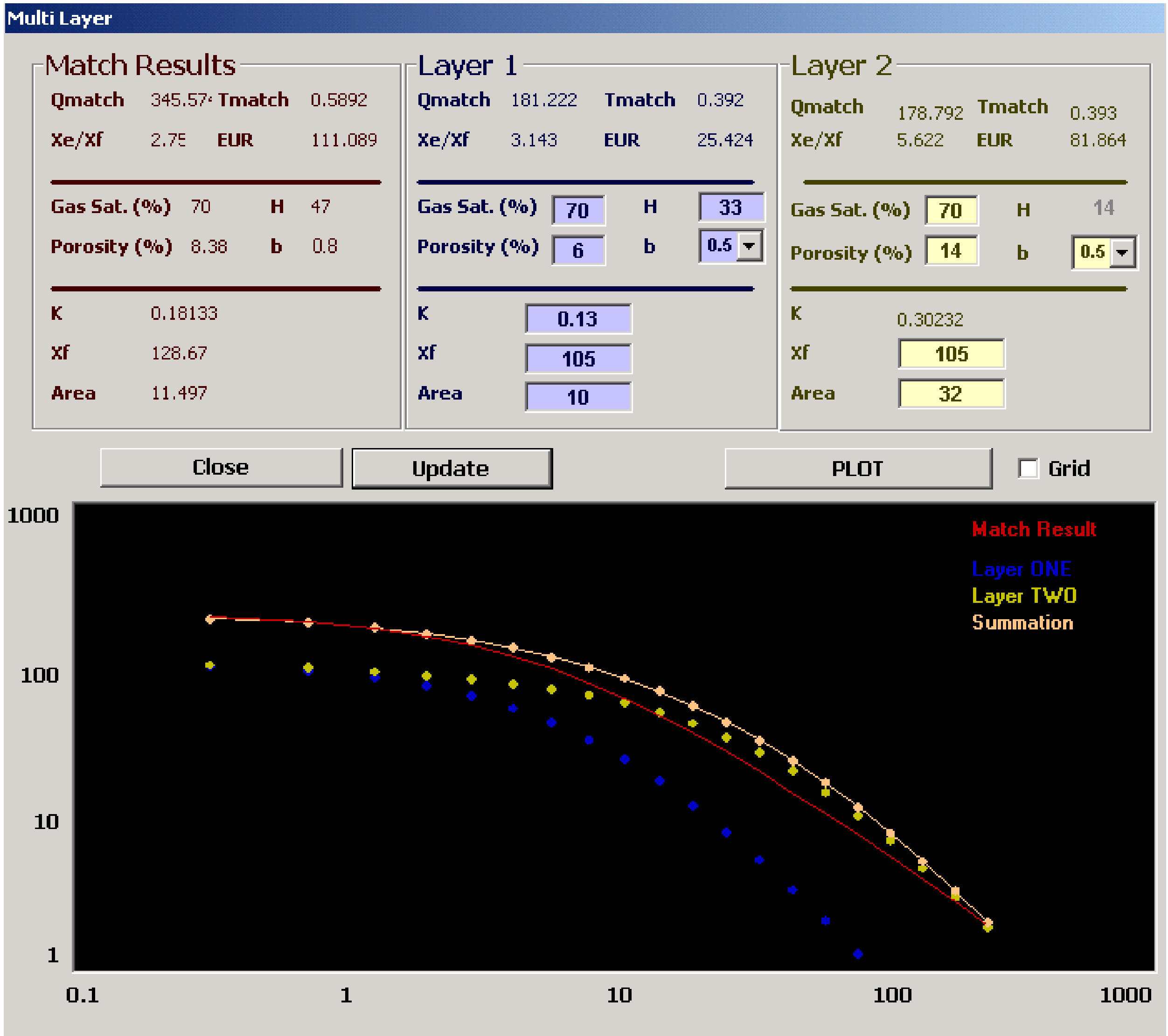

Figure 54 – Area 13 Restart Multiple Layer Type Curve Match Results

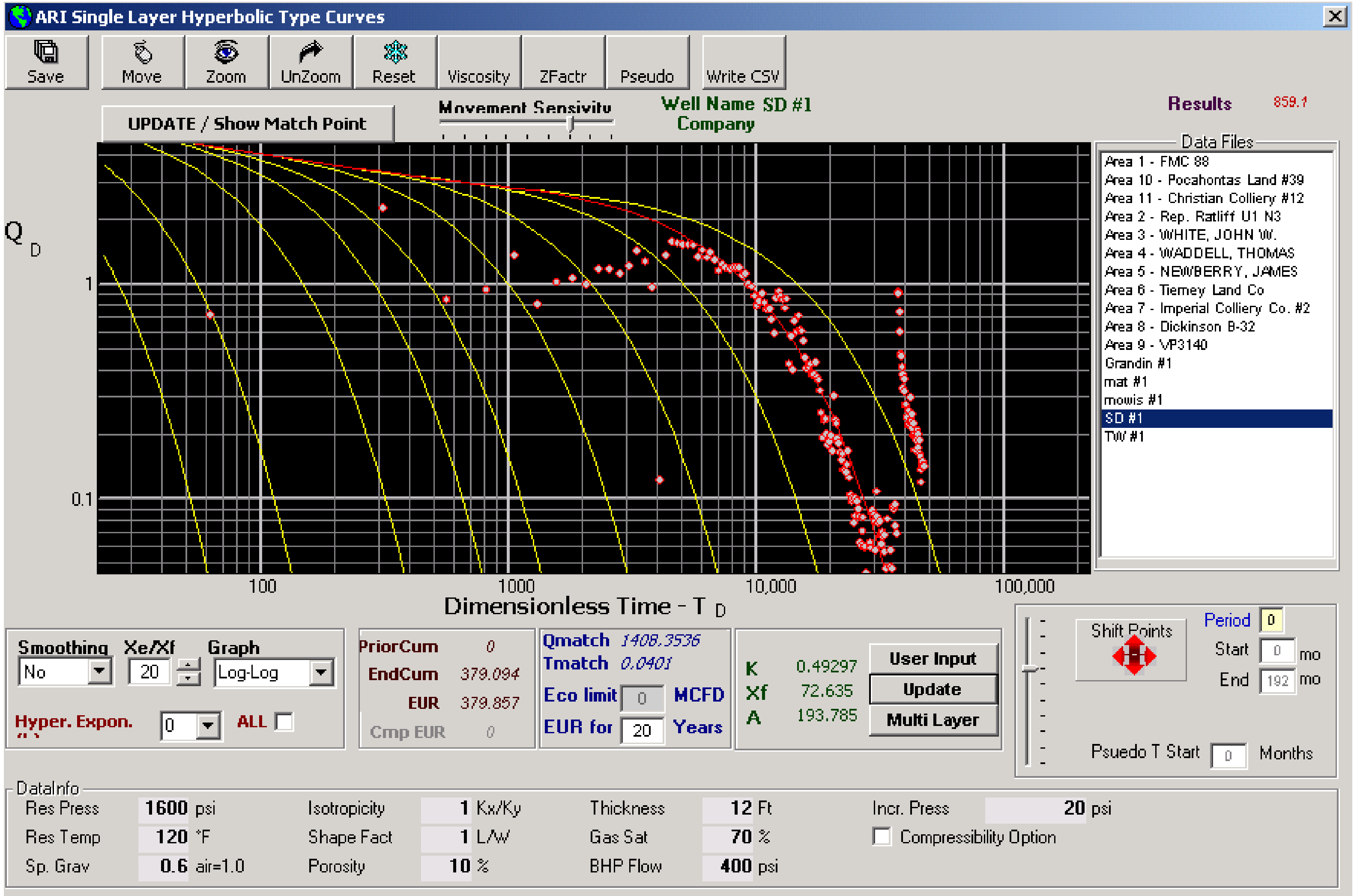

Figure 55 – Area 14 Single Layer Type Curve Match

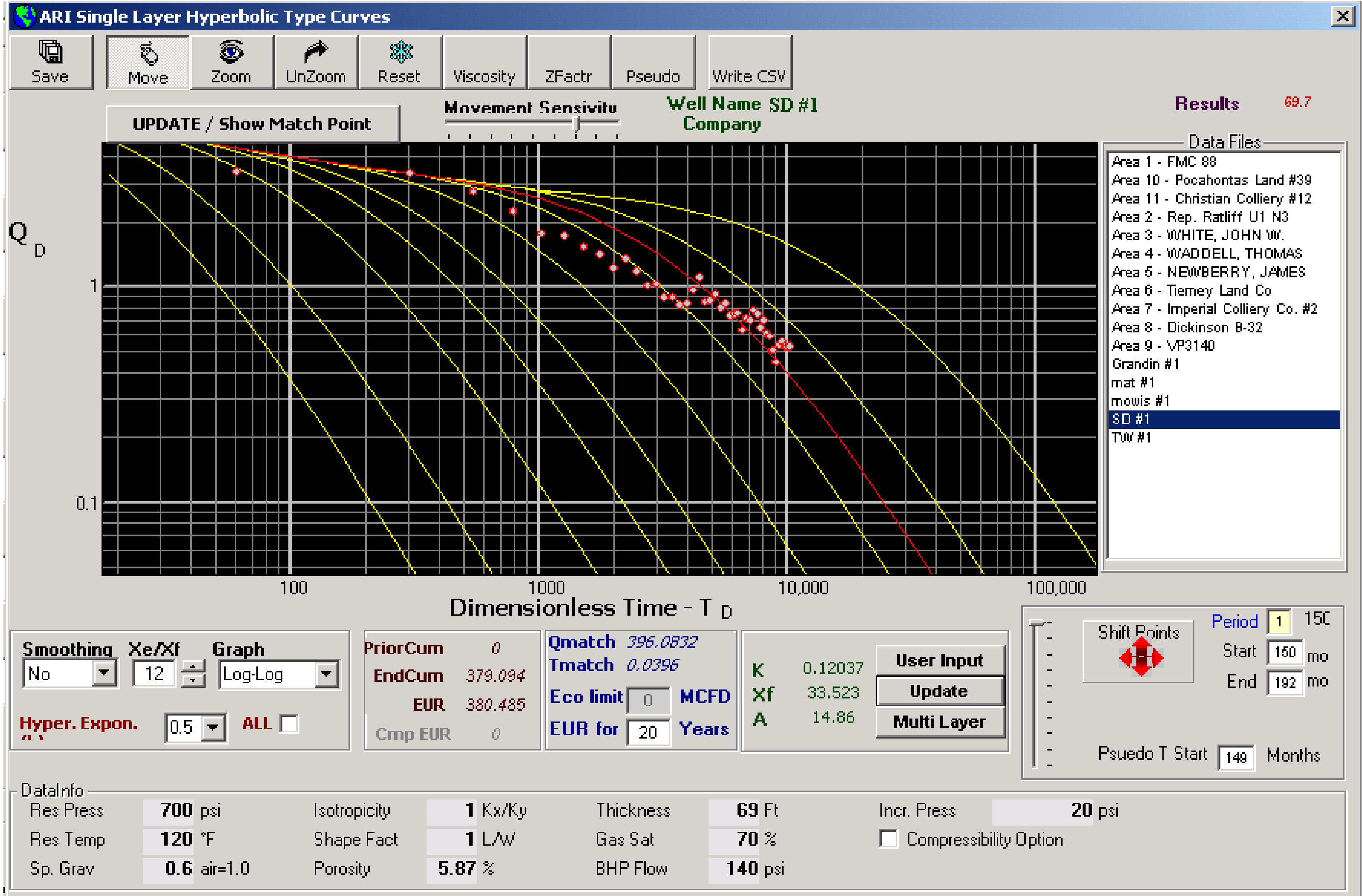

Figure 56 – Area 14 Restart Single Layer Type Curve Match

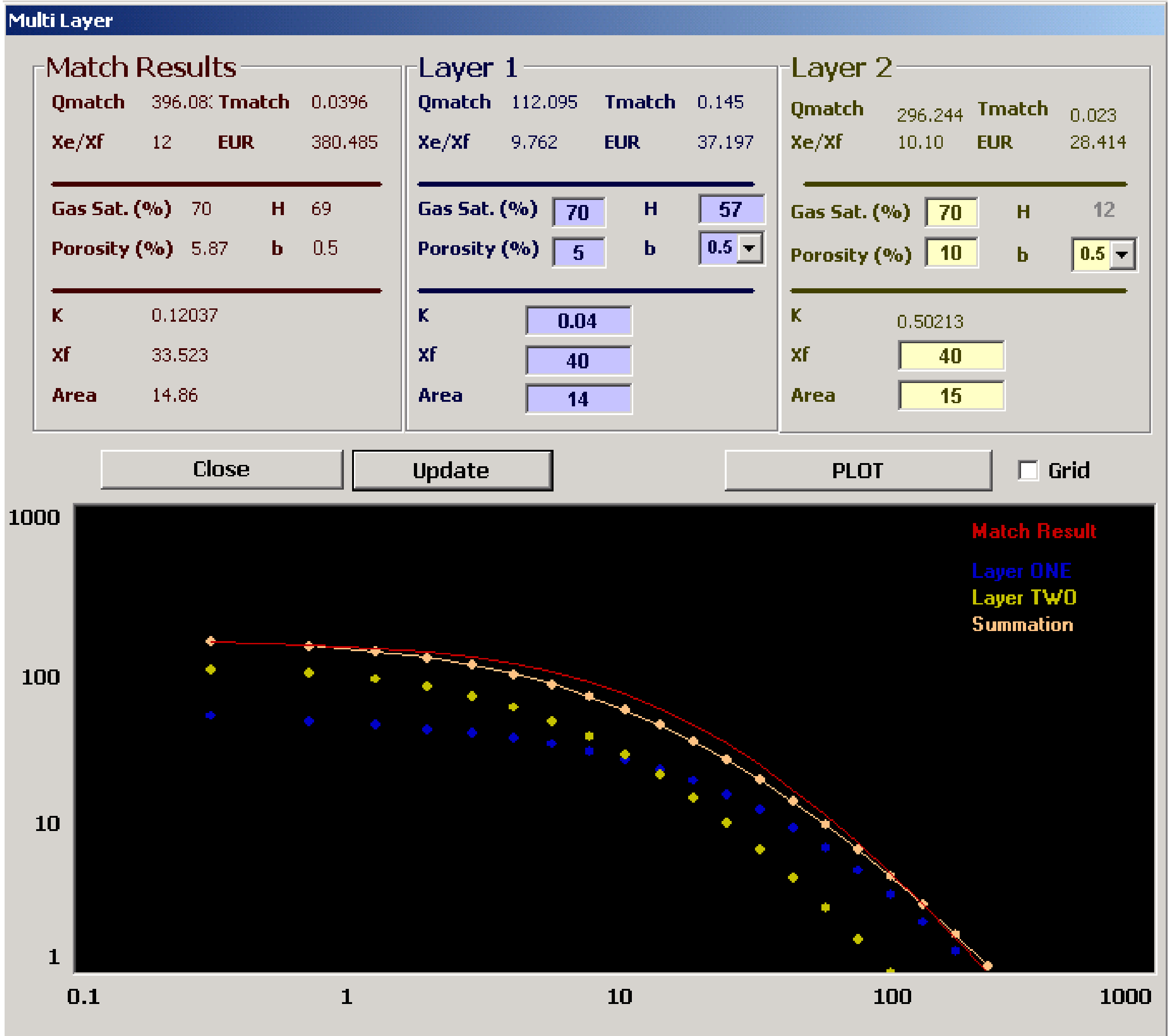

Figure 57 – Area 15 Restart Multiple Layer Type Curve Match Results

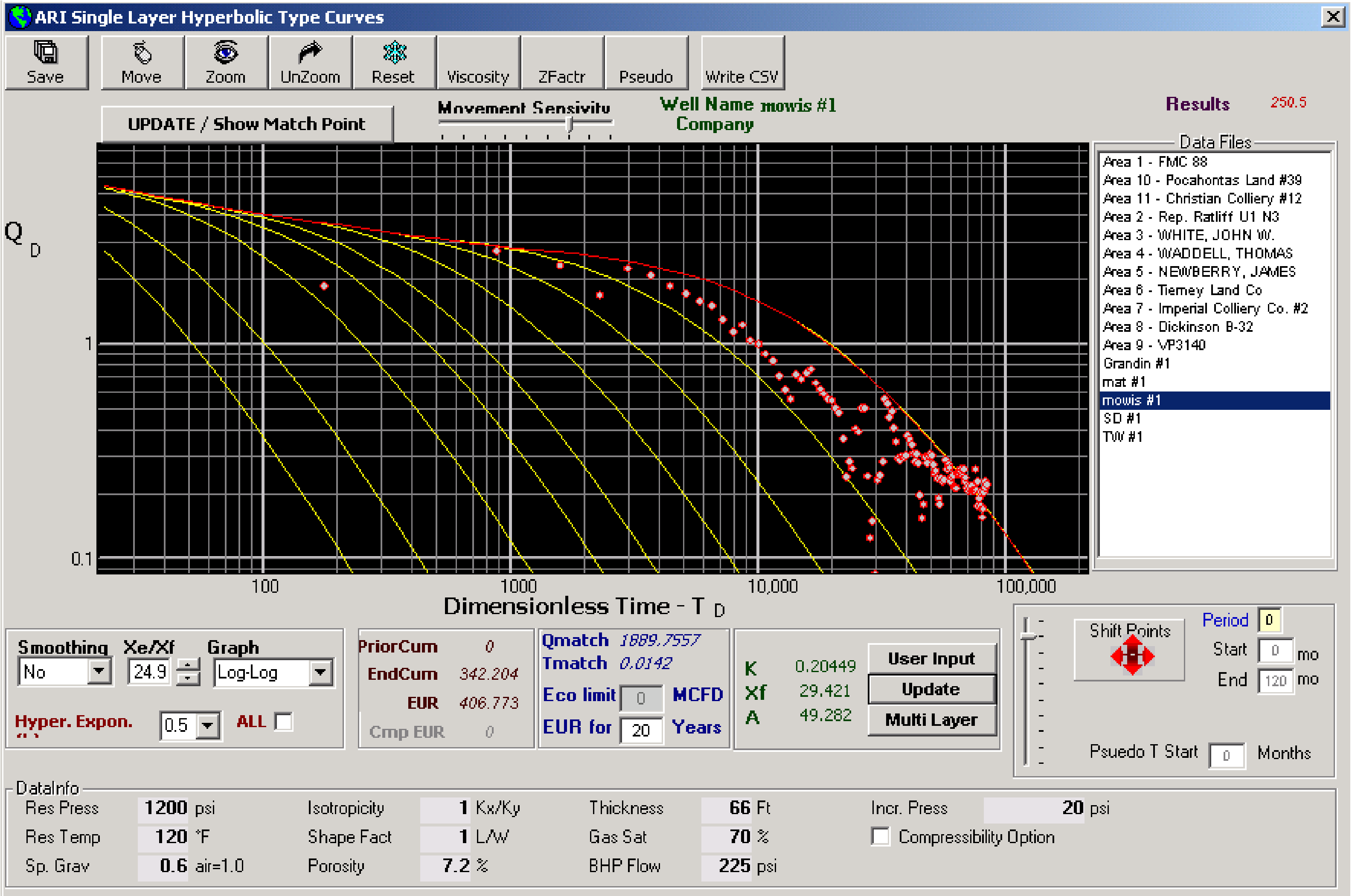

Figure 58 – Area 15 Single Layer Type Curve Match

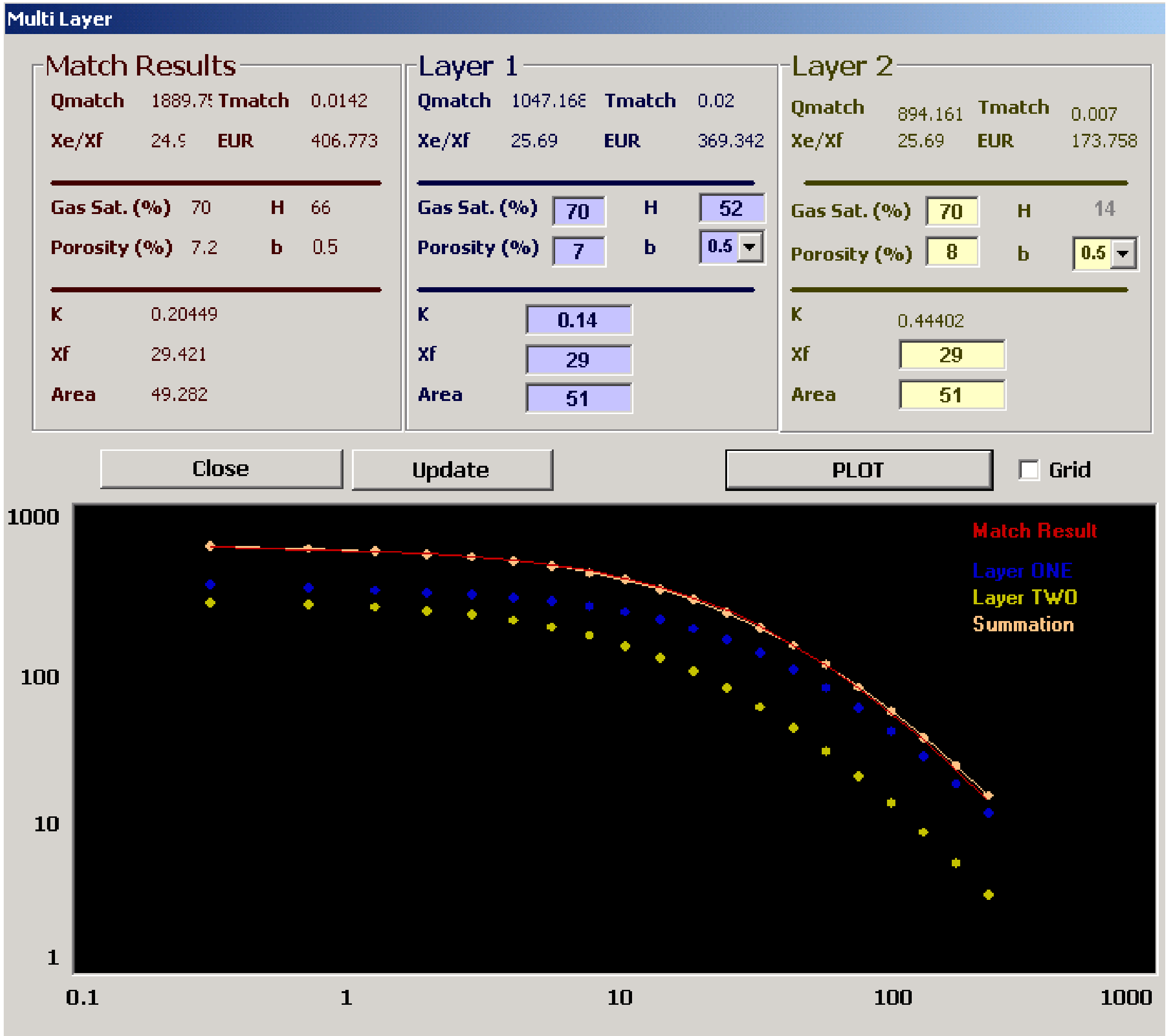

Figure 59 – Area 15 Multiple Layer Type Curve Match Results

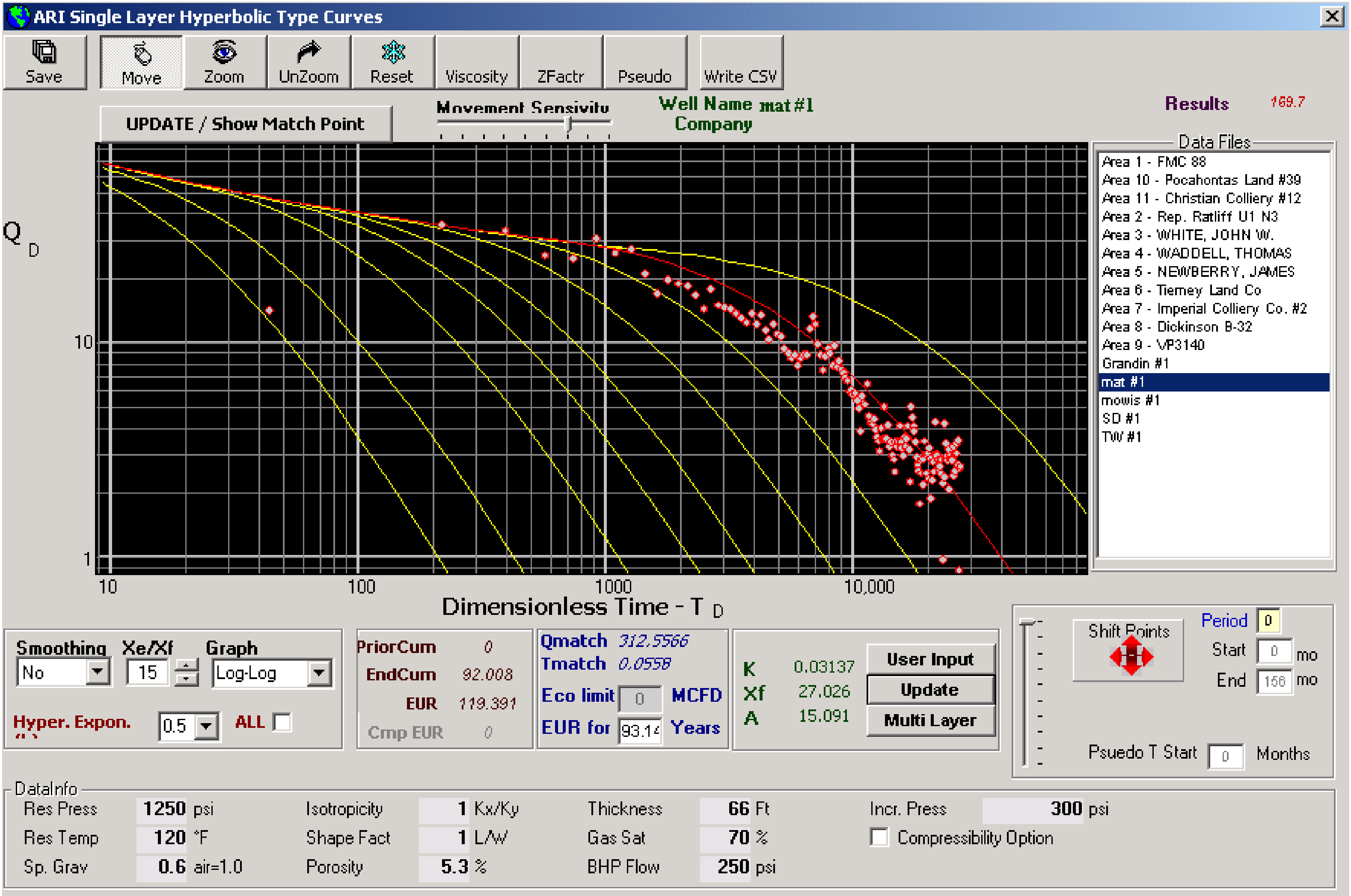

Figure 60 – Area 16 Single Layer Type Curve Match

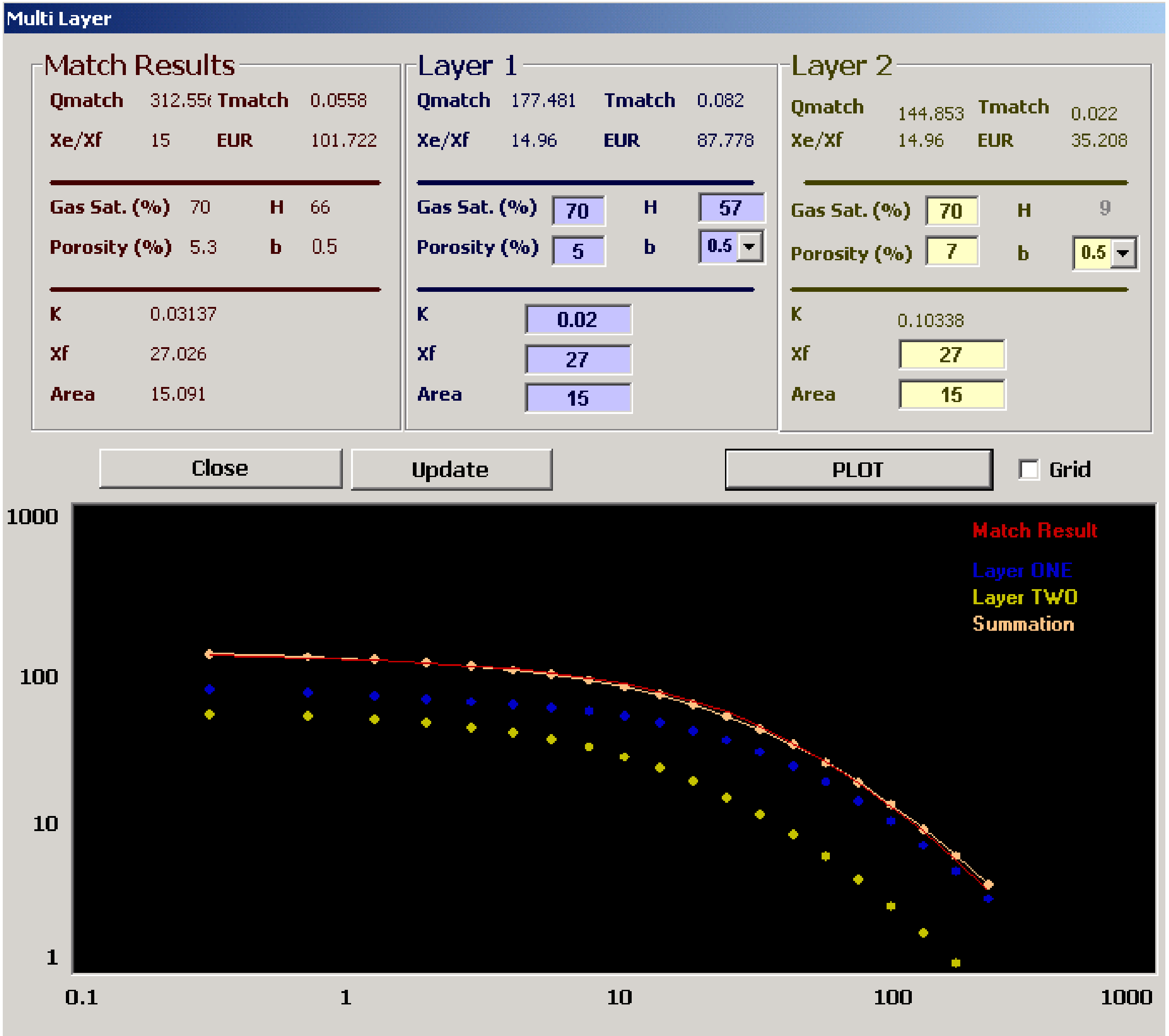

Figure 61 – Area 16 Multiple Layer Type Curve Match Results