Reservoir Simulation of 12-Section Graskell Area – Chase/Council Grove Reservoir Systems

Kansas Geological Survey

Open File Report No. – 2006-26

Authors:

Saibal Bhattacharya

Martin K. Dubois

Alan P. Byrnes

1.0 Introduction

The Hugoton and Panoma gas fields (Figure 1), North America's largest, produce from 13 fourth-order marine-nonmarine sedimentary cycles of the Wolfcampian Chase and Council Grove Groups, respectively. A fine-layered cellular geomodel was constructed for these fields using a four step workflow: 1) define lithofacies in core and correlate to wireline log curves and geologic variables (depositional environment and relative cycle-position), 2) train a neural network and predict lithofacies at non-cored wells, 3) populate a 3D cellular model with lithofacies using stochastic methods, and 4) populate the model with petrophysical properties and fluid saturations using facies-specific equations based on core data. The fine-scale model was upscaled to 25 layers for simulation. A 12-Section area, named Graskell in this report, was extracted from the field-wide model and used in simulation studies described below.

2.0 Objective

The objective of this study was to validate the above-mentioned geomodel by simulating the production/pressure performance of Hugoton Parent, Hugoton Infill, and Council Grove wells located in select multi-section areas, such as the Graskell, in the Hugoton field. The reservoir geomodel was developed using an automated facies recognition technique and applying facies-specific capillary pressure curves developed by integrating available core data. The intent of this exercise is, therefore, to evaluate the robustness of this geomodel by comparing how close the simulator-calculated pressure/production performances of individual wells match with respective histories with minimum modifications to the geomodel. The focus is not to obtain exact matches of pressure/production histories at individual wells with localized model modifications. Computer Modeling Group's (CMG's) IMEX simulator was used in this study.

The process of geomodel validation can be approached by answering the following set of questions:

a) Given the storage and permeability distribution in the model, can Chase Parent & Infill and Council Grove wells match their respective production histories and in the process undergo a pressure decline along historic trends?

b) Upon production and pressure history matching, what is the simulator-calculated shut-in pressure at a hypothetical Council Grove well as of January 1978?

c) How good a match is attained between simulator-calculated layer-pressures with RFT layer-pressures at Eliot A6 in the study area?

This report details the simulation studies carried out at Graskell area, which includes Sections 1, 2, 11, 12, 35, and 36 in Township 28S, Range 35W and Sections 5, 6, 7, 8, 31, and 32 in Township 28S, Range 34W. The location of the Graskell simulation area within the context of the Hugoton-Panoma fields is shown in Figure 1 while Figure 2 shows the study area bordered by broken green line.

3.0 Model Inputs

3.1 Graskell area layout

The Graskell area is situated in the east-central portion (Figure 1) of the Hugoton-Panoma field area directly inside the downdip margin of the Panoma field. The gas column is continuous from the top of the Chase to the upper most zones in the Council Grove. However, only one well in the simulation area was completed in any zone below the A1_LM, the uppermost marine carbonate in the Council Grove, yet the cumulative gas produced per Council Grove (Panoma) is nearly 1 BCF gas. Zones with the most original gas in place are the Ft Riley, Towanda, lower Ft Riley, Wreford, Krider, and A1_LM in order of importance.

3.2 Static model

The workflow used in building the static model for the Flower area simulation (Bhattacharya et al. 2005) was used for the Graskell study. A 70-square mile, 806,000 fine cellular model was constructed in Petrel and populated with lithofacies, permeability X, Y, and Z, and water saturation for two free water levels (FWL), 75 feet and 100 feet below the base of perforations in the Council Grove. The two lowest zones in the Council Grove were not modeled since they are well below the gas/water contact. Lithofacies at node wells were predicted at node wells using the Geomod 3 version of trained neural networks. A smaller 12 square-mile area (Figure 3) was extracted from the model and the 180 layer fine model was upscaled to 23 layers, one per zone for the Chase and Council Grove (through the B5_LM) using the same upscaling method as for the Flower model (Figure 4). For porosity and water saturation the upscaling was volume-weighted arithmetic average, while Petrel's tensor upscaling using PSK solver was utilized for estimating X and Y direction permeability. Permeability Z was calculated using a function of lithofacies and permeability XY.

Free water level (Figure 5) is the most significant variable in determining water saturations in portions of the reservoir system that are low in the gas column such as in the Council Grove layers. As in the Flower model, the FWL was arbitrarily moved down 25 feet from the originally estimated FWL to allow the model to have higher gas saturations in the upper Council Grove. This provided for a better correspondence between original-gas-in-place (OGIP) volumes charging the model (Figure 6) and cumulative gas produced from Panoma wells, under the assumption that all Panoma Gas withdrawal is restricted to the Council Grove interval (Tables 9.4.1 and 9.4.2). However, this assumption is contrary with pressure data and simulation results that suggest that there is likely to have been communication in both directions.

3.3 Engineering Model

The 23-layer geomodel was exported to the reservoir simulator – Computer Modeling Group's IMEX. Each layer in this 23-layer model coincided with a formation- or member-level stratigraphic interval in the Chase and Council Grove system. Each layer represents a half-cycle of marine/non-marine sedimentary cycle. In most cases, the model layer closely approximates the RFT intervals at wells in and around the study area. Grid cells dimensions were set at 660 ft by 660 ft for all layers.

Figure 7 lists the basic PVT properties input for simulation.

3.4 Permeability Modeling

One Council Grove core (Alexander D2 in Section 29, Township 27 South, Range 35 West, Grant County, Kansas) was available in the vicinity of the study area. No cores representing the Chase formations were available. Log-porosity and permeability estimated using facies-specific correlations were compared with corresponding values obtained from whole cores in all CG layers and Wreford to obtain layer-specific permeability multiplier (Figure 8). A multiplier of 1.0 was used for shale layers. Most of permeability multipliers in the non-shale layers were in the vicinity of 3.0. Thus, absent Chase core data, a permeability multiplier of 3.0 was assumed for all non-shale Chase layers.

3.5 Reservoir Pressure

The first recorded surface shut-in (SI) pressures (soon after completion) at the Chase Parent wells in the area studied varied between 400 to 432 psi (Figure 9) with the pressure at the two earliest wells being 406 psi and 432 psi. Surface shut-in pressures were converted to bottom-hole shut-in pressures. The bottom-hole shut-in pressures corresponding to the average and median surface shut-in pressures were 445 and 448 psi. Given the variation in the recorded shut-in pressures at the initial wells, a starting

reservoir pressure of 440 psi was assumed in this study. Thus, the reservoir model in the simulator was initialized using a starting pressure of 440 psi resulting in a charge of 170.61 bcf gas (Figure 10) as OGIP with Fort Riley and Towanda being the major gas storage units with OGIPs of 43.9 and 29.9 bcf respectively.

3.6 Hydraulic Fractures

Most of the wells in the study area were drilled before 1950. Current records indicate that all wells were hydraulically fractured some time during their production life. However, the exact date on which each well was fractured is not available. Fracturing technology came in to use in the study area in the 1960s. In this study, it was assumed that wells were fractured as of January 1, 1960. Later infill/replacement wells drilled in the 1980s or later were assumed to be fractured upon completion.

However, there is no information or test data available which would enable one to estimate the physical characterization of these fractures. The intent of the fracturing was to enhance the well productivity. Lacking physical descriptions of hydraulic fractures, the enhanced well productivities were modeled in this study using the well productivity (ff) factor greater than 1 with the ff set to 1.0 for an un-fractured well. The ff value was modified at each well to match the post-1960 production.

3.7 Flow Constraints

Annual production data for individual wells were available for initial completion to 1966. From 1967 onwards, monthly production data were available for all the Chase wells in the study area. Regular tubing head flow and shut-in pressure data were available for all wells from 1967 onwards. Between 1952 and 1966, six-monthly cumulative production data was available for all Chase Parent wells. Only total cumulative production till 1951 was available for each Chase Parent well. Complete monthly production histories were available for Chase Infill and Council Grove wells.

In the simulator, all wells were flowed under rate constraints until May 2004. Thereafter, all wells were flowed under a constant bottom-hole pressure (BHP) of 14.7 psi till December 2006. The intent of changing from rate constraint to pressure constraints was to see if the simulator-calculated production rates from May 2004 to December 2006 followed the already established decline trends without showing production spikes (or signs of excess flow capacity). The well names and their abbreviated names used in the simulator model along with their starting dates, cumulative production, and initial perforation intervals are listed in Figures 11 and 12.

4.0 Reservoir Simulation Studies

Well operators confirm that each of these wells was hydraulically fractured during some point in its production life. However, the exact date when each well was fractured is unavailable. In the model, it was assumed that each well was fractured as of January 1, 1960 – the approximate time frame when fracturing came in vogue in the study area.

Because the wells were not fractured pre-1960, flow in this period was dominated by matrix. Also during this period, the well completions could not extend beyond the layers recorded in completion reports. Thus, the strategy employed in the designing the following set of simulation runs was to first try to match pre-1960 field production by adjusting matrix permeability through the application of different multipliers. It was only after obtaining a match with the historic production volumes prior to January 1, 1960, that other factors such as layers drained by the fractures and productivity gains from hydraulic fracturing were modified on a well-by-well basis to improve both the production and flowing pressure matches at each well.

The model used in this study was an 11-layer model with grid-cell sizes of 660 feet by 660 feet. A consistent set of legends was used to analyze the simulation results. The simulator-calculated production and bottom-hole flowing pressure are displayed in red and green lines while the historic production and well head flowing pressures (WHFPs) are displayed in blue and magenta. Hence, through this report, Chase

Parent wells will be referred as P, while Chase Infill wells will be referred as I, and Council Grove wells will be referred as G.

4.1 RUN 1

All P, I, and G wells were completed in the perforated intervals obtained from completion records. Hydraulic fractures were modeled using ff = 6.0 at all P wells as of January 1, 1960. The initial reservoir pressure was set at 440 psi and initial permeability multipliers (as described in Figure 8) were applied to each of pay (gas) layers. Figures 13 and 14 compare the simulator-calculated cumulative gas production with the historic volumes at the P wells. It appears that the simulator-calculated gas production matched or came close to matching the well history only at those P wells where completions (and therefore fractures) extended to L8 (Fort Riley). Simulator-calculated gas production fell short in every other Chase Parent (P) well. Figures 15 and 16 showed that simulator-calculated gas production fell significantly short at every Council Grove (G) well.

Simulation results from the initial run indicate that the current model is unable to deliver the recorded gas production from both P and G wells. Therefore, the next series of simulator runs (from Run 2 to Run 5) details model modifications necessary to match production histories at the P wells while Runs 6 to 8 revolve around model adjustments required to match G well production histories.

4.2 RUN 2

The well productivity as a result of hydraulic fracturing (as of January 1, 1960) was increased at all P wells using ff = 10.0, compared to ff = 6.0 in Run 1, while all other model parameters were left unchanged. Figures 17 and 18 show that the simulator-calculated gas production for P wells increased (slightly) over that obtained in Run 1 with the cumulative gas production at P wells not completed to L8 (Fort Riley) still falling short of historic volumes.

4.3 RUN 3

Hydraulic fracture completions were extended to L8 (Fort Riley) at all P wells where recorded perforations stopped short of L8. All other model parameters were left unchanged from Run 1 (such as ff = 6.0 for all P wells). Figures 19 and 20 showed that the simulator-calculated gas production increased at P wells that had previously not been perforated in L8. However, simulator-calculated cumulative gas production still fell short in some of these P wells where fracture completions were extended to L8.

4.4 RUN 4

As noted before, no Chase core was available from or near the Graskell study area. Nor was layer-specific DST carried out at any of the wells in or around the study area to calculate layer-specific permeability at the test well. Thus, permeability multipliers applied on permeability estimated by facies-specific equations at each of the Chase gas zones was arbitrary. There was no core- or DST-based permeability available to compare the permeability estimated by facies-specific equations for each Chase gas zone and to develop appropriate multipliers. Thus, an arbitrary multiplier of 3.0 was used for each Chase gas zone in the previous simulation models. Given the inability of the simulator-calculated gas production to match historic volumes at some of the P wells, an additional permeability multiplier of 2.0 (over an above the original multiplier of 3.0) was employed on two of the most productive Chase zones, i.e. L6 (Towanda) and L8 (Fort Riley) in this run. All other model parameters were left unchanged from Run 3.

Figures 21 and 22 summarize the results of Run 4. Simulator-calculated gas production matched or almost matched at all P wells except those located in the SW corner of the simulation area. For example, Higgenbotham (PHigB1) is located in the SW corner of the Graskell study area. This well is the second highest gas producer in the study area having produced 10 bcf of gas. However as per the current model, the OGIP (Figure 23 A) and permeability (Figure 23 B) distributions in the driver layers, such as L8 (Fort Riley) and L6 (Towanda), in the SW corner of the study area including the drainage

area of PHigB1 (Figure 23) are low compared to other regions of the Graskell study area. Figure 23 C shows that within the study area there are no wells with qualified logs in the south-western corner. Wells with qualified logs are located outside the study and at a considerable distance from the SW corner of the study area resulting perhaps in non-representative OGIP and permeability distributions being mapped in this section of the study area.

4.5 RUN 5

Permeability was adjusted (Kxy*6 over the initial multiplier, Figure 8) in L1 (Herrington) to match the estimated RFT layer pressure data. All other inputs were kept the same as in Run 4. Figures 24 and 25 display the simulator-calculated cumulative production and bottom-hole flowing pressure matched against historic production and well-head flowing pressures. Simulator-calculated gas production matched historic volumes at all but five wells namely, PHogB1, PMor1, PStan1 (all located at the SW corner of the study area), and PGoer1 and PEub1 located in the SE corner of the study area. Wells where a good production match was obtained also showed close matches between FTHP (historic flowing surface pressure) and FBHP (simulator-calculated bottom-hole flowing pressures) except in PDev where despite a production match the simulator-calculated FBHP fails to match the recorded FTHP match and shows flow capacity limitations in the well drainage area. It may be noted that PDev is also located in the SW corner of the study area. Thus, reasonable matches of production and pressure were obtained at seven out of 12 Chase Parent wells in the study area using the current geomodel.

Layer pressures from RFT tests were available from five wells in and around the study area. One of wells, Eliot A-6 (PEliot), was located within the study area. However, available RFT data shows significant variation (Figure 26) in recorded shut-in pressures within each of the pay layers in and around the study area. Figure 27 compares the RFT layer-pressure data recorded at Eliot A6 (as of December 2004) with the simulator-calculated grid-block pressure at the location of this well in the model and also shows the

degree of variation (in the "Comments" column) in recorded RFT layer pressures within a layer at different wells in and around the study area. RFT layer pressure data was recorded in L1 (Herrington), L4 (Winfield), L6 (Towanda), L8 (Fort Riley), L10 (Florence), and L11 (Wreford). The goodness of fit (or lack of it) between simulator-calculated layer-pressures and RFT layer-pressures should be considered in the context of discrepancies existing in reported RFT layer-pressure data and the fact that production and pressure histories have been matched in only seven out of 12 Chase Parent wells using the current geomodel.

The permeability and OGIP distributions in L1 (Herrington) are poorer than that in L6 (Towanda) in the current geomodel input to the simulator. However, RFT layer-pressure data indicate that L1 (Herrington) has produced an equal fraction of its storage as L6 (Towanda) despite having significantly lesser storage and flow capabilities because both L1 and L6 are assumed to have an initial pressure of 440 psi and have declined to 78 and 74 psi respectively as of December 2004. Discrepancies, such as these, exist in the RFT data and need to be resolved in order to match against simulator-calculated layer pressures.

4.6 RUN 6 & 7

Runs 6 to 8 were designed to identify modifications required on the geomodel in order to obtain history matches at the Council Grove (G) wells in the study area. The Kxy distribution in the Chase layers were kept the same as in Run 3 while a multiplier of 10 (over the initial multiplier, Figure 8) was used for the CG pay layers in Run 6. The ff denoting the productivity enhancement by hydraulic fracturing was set at 6.0 for all the G wells. Also, the fractures in the G wells were constrained to the perforated intervals. In Run 7, the Kxy in the Chase and the Council Grove pay layers were kept the same as Run 3 while the productivity enhanced due to hydraulic fracturing in G wells was increased by using ff = 10.0. Figures 28 and 29 compare the simulator-calculated cumulative production from the G wells. It is apparent from these figures that the simulator-

calculated gas production matches or is close to historic volumes at G wells in Run 6 while it remained significantly short of historic volumes in Run 7.

4.7 RUN 8

The Kxy in the Council Grove pay layers were the same as that obtained after the use of the original multipliers (Figure 8). However, the completions in the G wells were extended to L8 (Fort Riley) using ff = 6.0. Figures 30 and 31 compare the simulator-calculated cumulative production from the G wells with historic volumes and that obtained from Run 6. It is apparent from the above-mentioned figures that the simulator-calculated cumulative production at the G wells matches or is close to matching historic volumes at all but four wells, namely Stanley 3C (GStan3C), Eubank 4C (GEub4C), Davatz Gas Unit 2 (GDav2), and Higgenbotham 2A (GHigB2A). Of the above-mentioned wells, GEub4C, GDav2, and GHigB2A are located along the southern boundary of the study area which in the current model (Figure 25) has lower OGIP and tighter permeability distribution than other areas of the study area. GStan3C is located in the NE corner of the study area.

4.8 RUN 9

Fracture completions in the P wells were extended to L8 (Fort Riley) using ff = 6.0. Permeability multiplier of 2 (over the initial multiplier) was applied to L6 (Towanda) and L8 (Fort Riley) while that of 6 (over the initial multiplier) was applied to L1 (Herrington). A permeability multiplier of 10 (over the initial multiplier) was applied to all Council Grove pay layers. Simulator-calculated cumulative production matched historic volumes at majority of the P and G wells. Figure 32 shows the simulator-calculated pressure distributions as of January 1978, i.e., the time frame when most of the G wells were drilled in the modeled area. Figure 33 shows the simulator-calculated shut-in pressure stabilized to 400 psi, after 4 days of shut-in followed by a day of flow in January 1978, at a hypothetical G well (named CG SI) located at the center of the study area when its completions (ff = 6.0) were restricted to the Council Grove pay layers. Figure 34 plots the first recorded surface shut-in pressures at all the G wells drilled in the

study area. This plot clearly shows that the initial shut-in pressures recorded at newly drilled G wells in the late 1970s ranged between 150 psi to 210 psi, and thus the simulator-calculated shut-in pressure of 400 psi for a hypothetical G well is significantly higher than pressures characteristically recorded at G wells in the study area.

4.9 RUN 10

The input parameters for the P wells were left unchanged from Run 9. For the G wells, the fracture completions were extended to L8 (Fort Riley) using ff = 6.0 while the permeability distribution was the same as obtained after using the initial multipliers. Figures 35 and 36 show the production and pressure history matches obtained at the P wells. Simulator-calculated production matched historic volumes at all P wells except PHigB1. Good pressure matches were obtained at some of the P wells while for other the simulator-calculated BHFP followed the trend set by recorded THFPs. Presence of spikes in the simulator-calculated BHFP profiles at P wells where the simulator-calculated BHFP pressures did not match history may be indicative of low permeability prevailing in the driver pay zones in the current model. Also, production spikes are evident in some of the P wells when they are released from flow constraints after May 2004. Figures 37 and 38 compare the simulator-calculated production and bottom-hole flowing pressures with historic production volumes and recorded surface flowing pressures for the G wells. The simulator-calculated production matches the historic rates at all G wells. However, in most G wells, the simulator-calculated BHFPs are, despite showing spikes, close to and follow the trend of the recorded THFPs. Also, production spikes become visible in many G wells when released of flow constraints. Figure 39 and 40 show the history matches for cumulative production and flowing pressures for the Chase Infill (I) wells in the study area. The above figures show that the simulator-calculated production matches or is close to matching the historic volumes at most I wells except those located in the tight border areas along the south and south-western border of the study area. Also, many of I wells show spikes in the simulator-calculated flowing pressure profiles, which may indicate tight permeability present in the drainage areas of the affected wells in the current model. Production spikes are also evident (Figures 41 and 42) at most of the Chase Infill wells

when released of flow constraints in the simulator and this may indicate excess flow capacity. Figure 43 shows the location of the Chase Infill wells where the simulator-calculated production failed to match the historic volumes. Each of these I wells is located along the southern and southwestern border of the study area where the OGIP and permeability distribution in the driver layers (such as L6 and L8) are relatively lower than other areas within the same layers.

Figure 44 plots the shut-in pressure at a hypothetical Council Grove well (CG SI) that was completed in the simulator in January 1978. The CG SI well was flowed for one day before shut-in and recorded a stabilized shut-in pressure of 200 psi after four days. This simulator-calculated shut-in pressure is within the range of shut-in pressures recorded at G wells in the study area upon their completion in and around 1978.

Figure 45 tabulates the simulator-calculated layer pressures as of December 2004 at the location of the Eliot A6 (IElli5) well and compares them with corresponding layer-pressures recorded by RFT tests. The simulator-calculated layer pressure is close to that recorded by RFTs for L6 (Towanda) and L8 (Fort Riley) – the two driver zones in terms of storage and flow capacity in the study area. The approximate nature of these pressure matches have to be put in the context of the current geomodel which shows relatively low OGIP and tighter permeability distribution along the southern and southwestern borders of the study area, and therefore is inadequate for obtaining production/pressure history matches at P, G, and I wells located in these above-mentioned border areas. It is only after reasonable history matches have been obtained at all the wells in the study area that the exercise of matching simulator-calculated layer pressures at a specific location with RFT layer pressures can be carried out in order to validate the underlying geomodel. Also, operator feedback and presence of significant variations in pressures within a layer in and around the study area as evident from RFT data raises questions about how representative the RFT data is for comparison with simulator-calculated pressures.

4.10 RUN 11

The input permeability distribution for Chase and Council Grove layers is the same as Run 10. However, hydraulic fractures at the P wells were extended to L14 (B1 Shale) using ff = 6.0 while the G wells were completed to L8 (Fort Riley) using ff = 6.0. The production and pressure history matches for the P wells remained unchanged from Run 10. However, more prominent production spikes became visible when P wells were released of flow constraints. For the G wells, the simulator-calculated well production rates were similar to Run 10 with a slight reduction in production spikes at some of the wells when released from flow constraints. At the I wells, production spikes increased when wells released from flow constraints. The shut-in pressure at a hypothetical Council Grove well (located at the center of the study area) stabilized to 225 psi (Figure 46) upon completion after a 4 day shut-in followed by 1 day of flow. The simulator-calculated layer pressures from this run, at the location of Eliot A6, were compared with the RFT layer-pressures in Figure 47 and were found to be close to that obtained from Run 10.

5.0 Conclusions

a) The current geomodel for the Graskell study area has insufficient OGIP and permeability distribution along the southern and southwestern border areas to enable production history matches at Chase Parent, Chase Infill, and Council Grove wells located therein.

b) It is imperative that the underlying geomodel be modified to enable successful history matching (of production and pressure) at all wells within the study area.

c) For wells located in the study area and away from the southern or southwestern borders, the simulator-calculated production matches or is close to matching the historic volumes. The simulator-calculated (bottom-hole) flowing pressures are close to and follow the trends set by recorded (surface) flowing pressures particularly at wells where good production matches have been obtained.

d) Production spikes are visible at most wells when released of flow constraints despite production and pressure history matches indicating presence of excess flow capacity in the current model in the drainage areas of the corresponding wells.

e) Significant intra-layer variation in RFT pressures recorded in and around the study area has been observed leading to doubts about the accuracy and representativeness of RFT recordings.

f) Using the current geomodel, production and pressure history matches were obtained at majority of the wells outside the southern and southwestern border. Despite lack of history matches at border wells, the simulator-calculated layer-pressure at the Eliot A6 well is close (within 30 psi) to that recorded by RFT measurements for the two major driver zones in the study area, i.e. L6 (Towanda) and L8 (Fort Riley).

It is hoped that further refinement of the geomodel, particularly along the southern and southwestern borders, will help to attain history matches at these border wells and thereby lead to better layer-pressure matches.

References:

Bhattacharya, S., M. K. Dubois, and A. P. Byrnes, 2005, Reservoir simulation of 9-Section area around Flower A1 well – Chase/Council Grove Reservoir Systems, KGS-OFR 2005-54

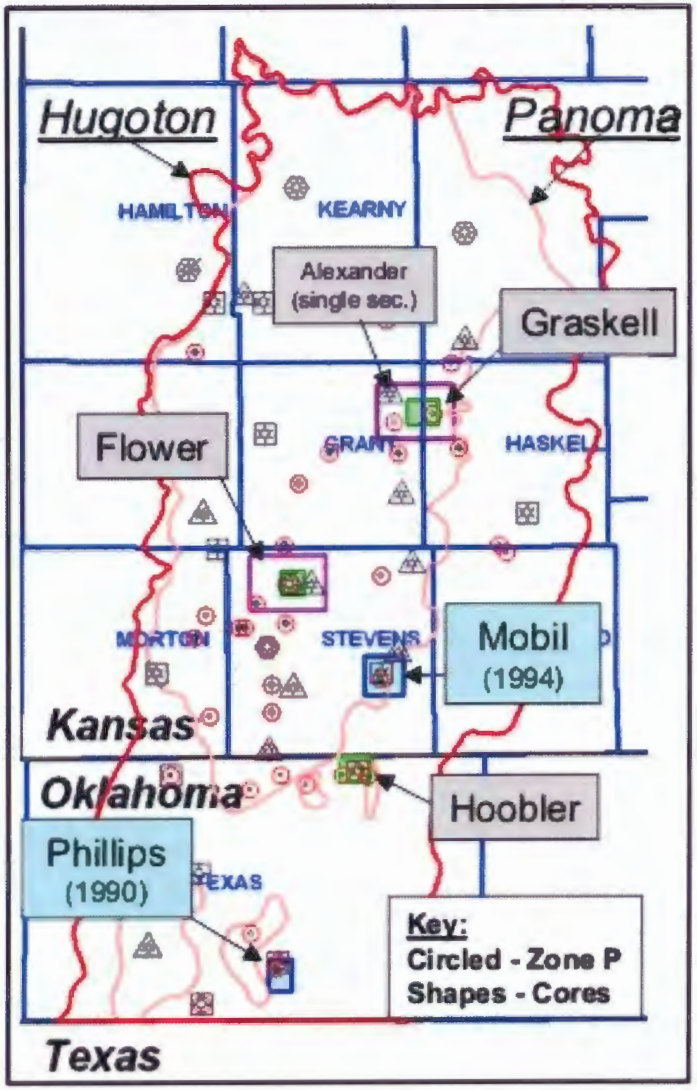

Hugoton
Panoma
HAMILTON
KEARNY
Alexander
(single sec.)
Graskell
Flower
GRANT
HASKEL
MORTON
STEVENS
Mobil
(1994)
Kansas
Oklahoma
Hoobler
Phillips
(1990)
TEXAS
Key:
Circled - Zone P
Shapes - Cores
Texas

Figure 1

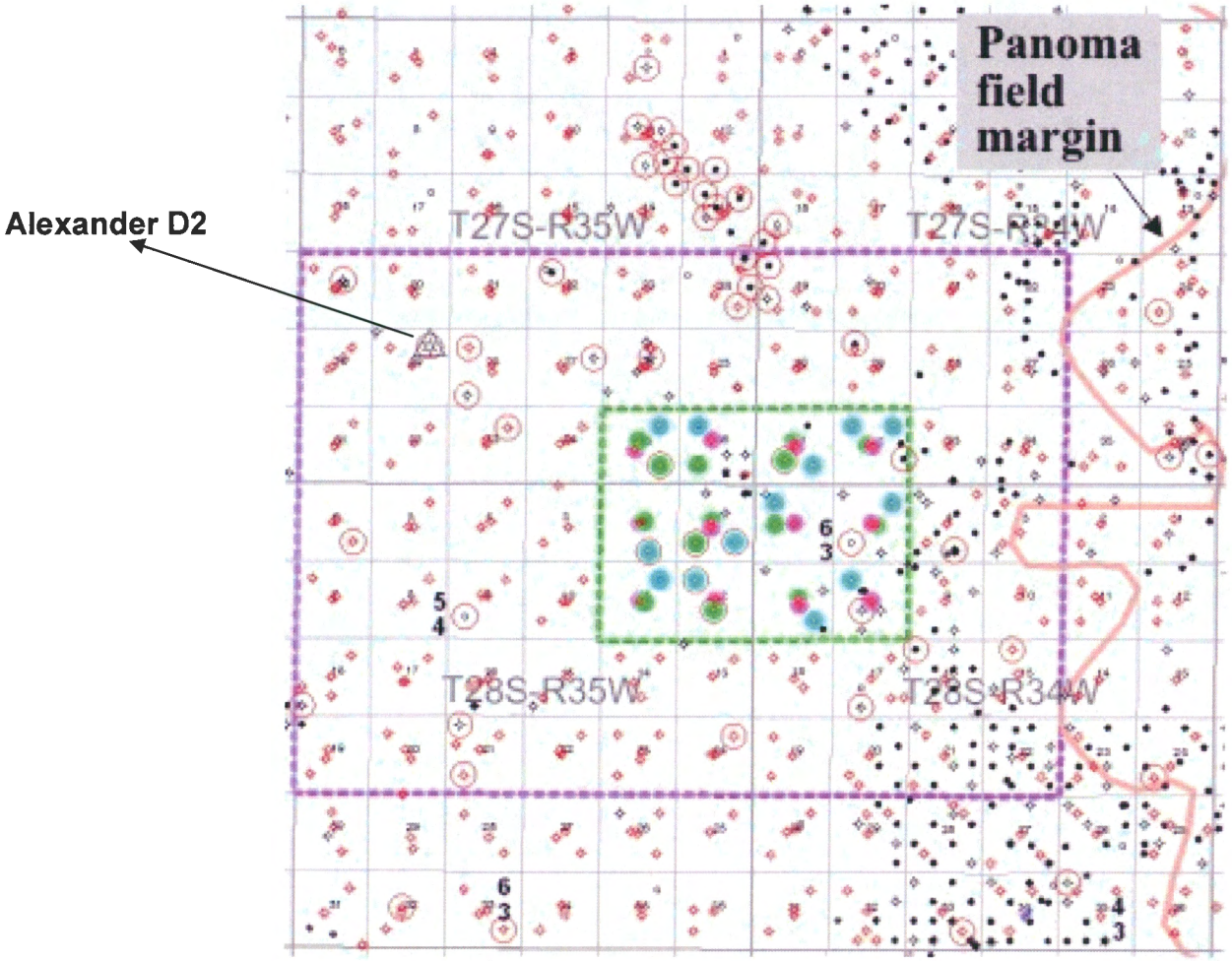
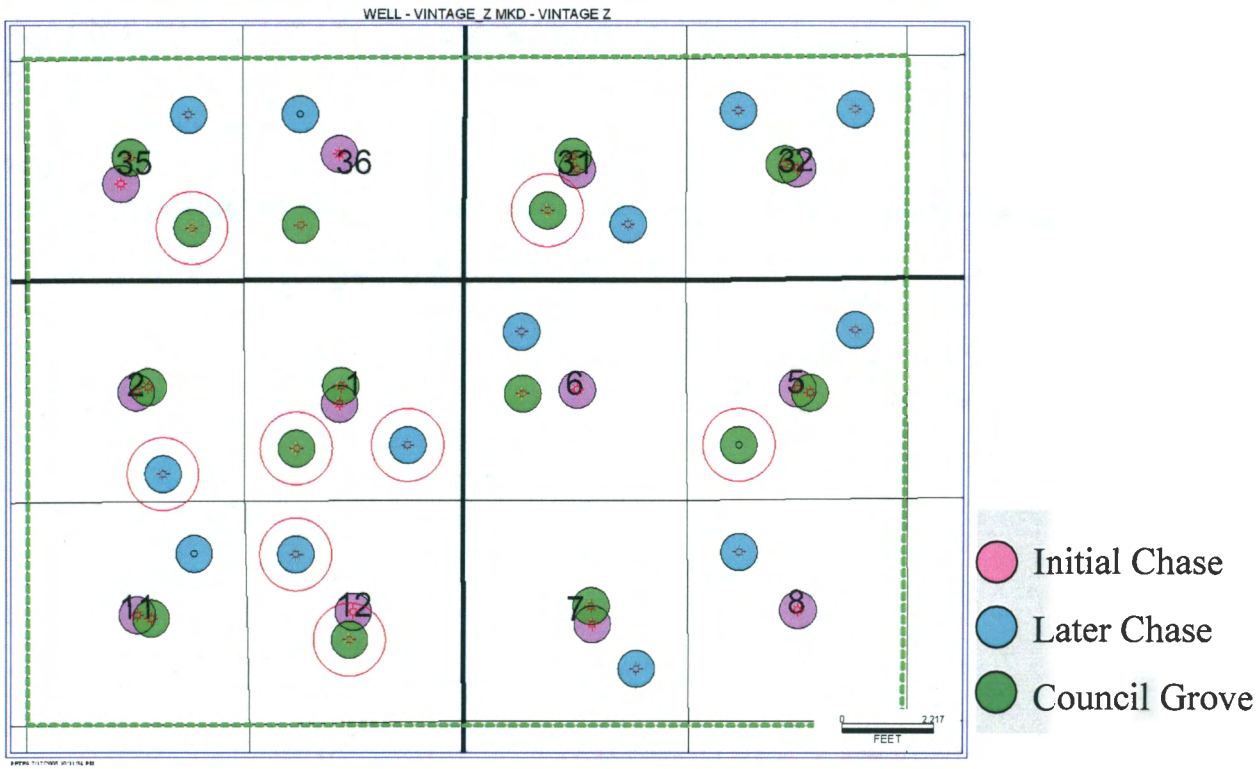

Panoma
field
margin
Alexander D2
T27S-R35W
T27S-R34W
T28S-R35W
T28S-R34W

Figure 2



Circled wells have qualified logs.

Figure 3

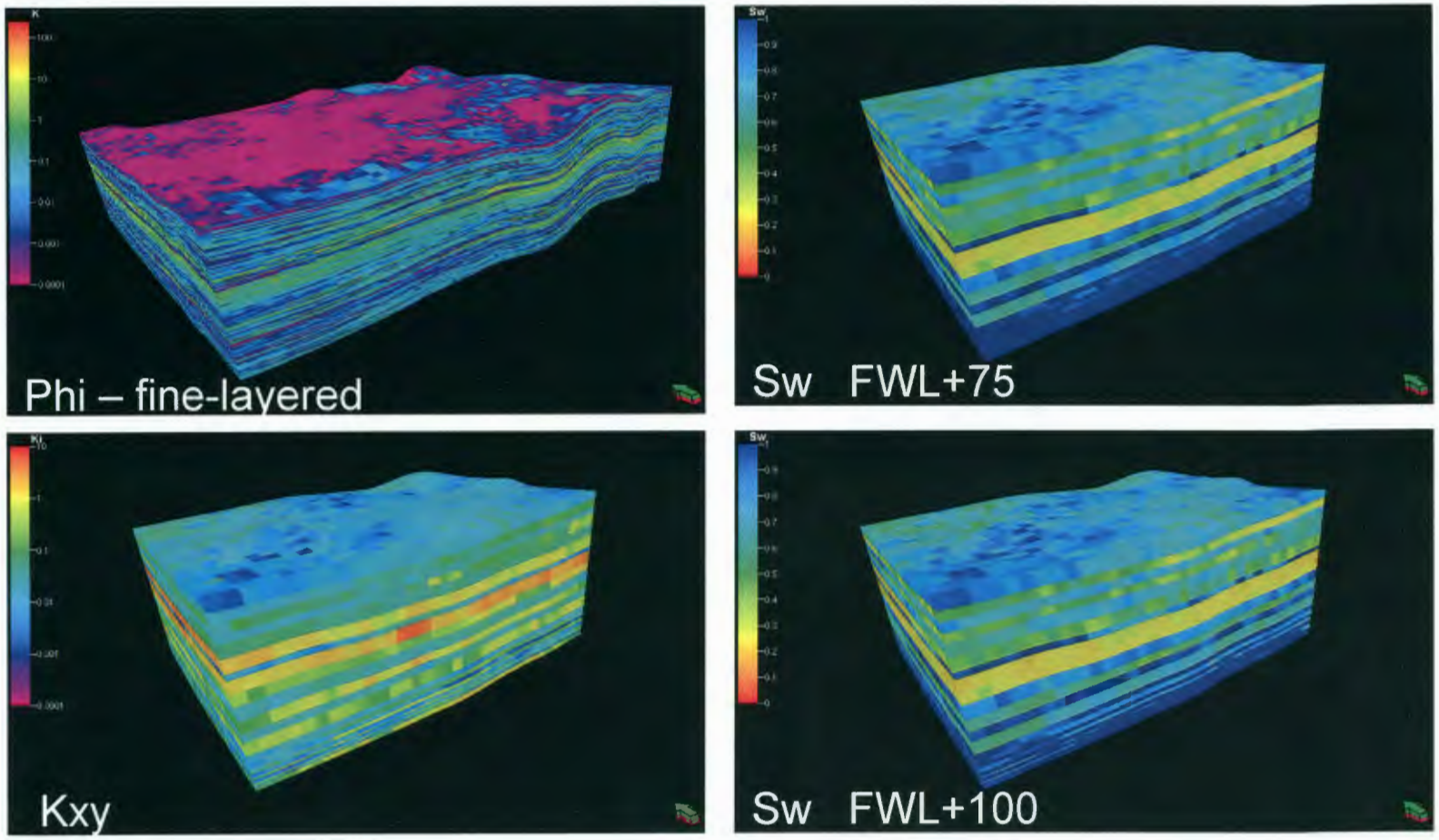


Figure 4

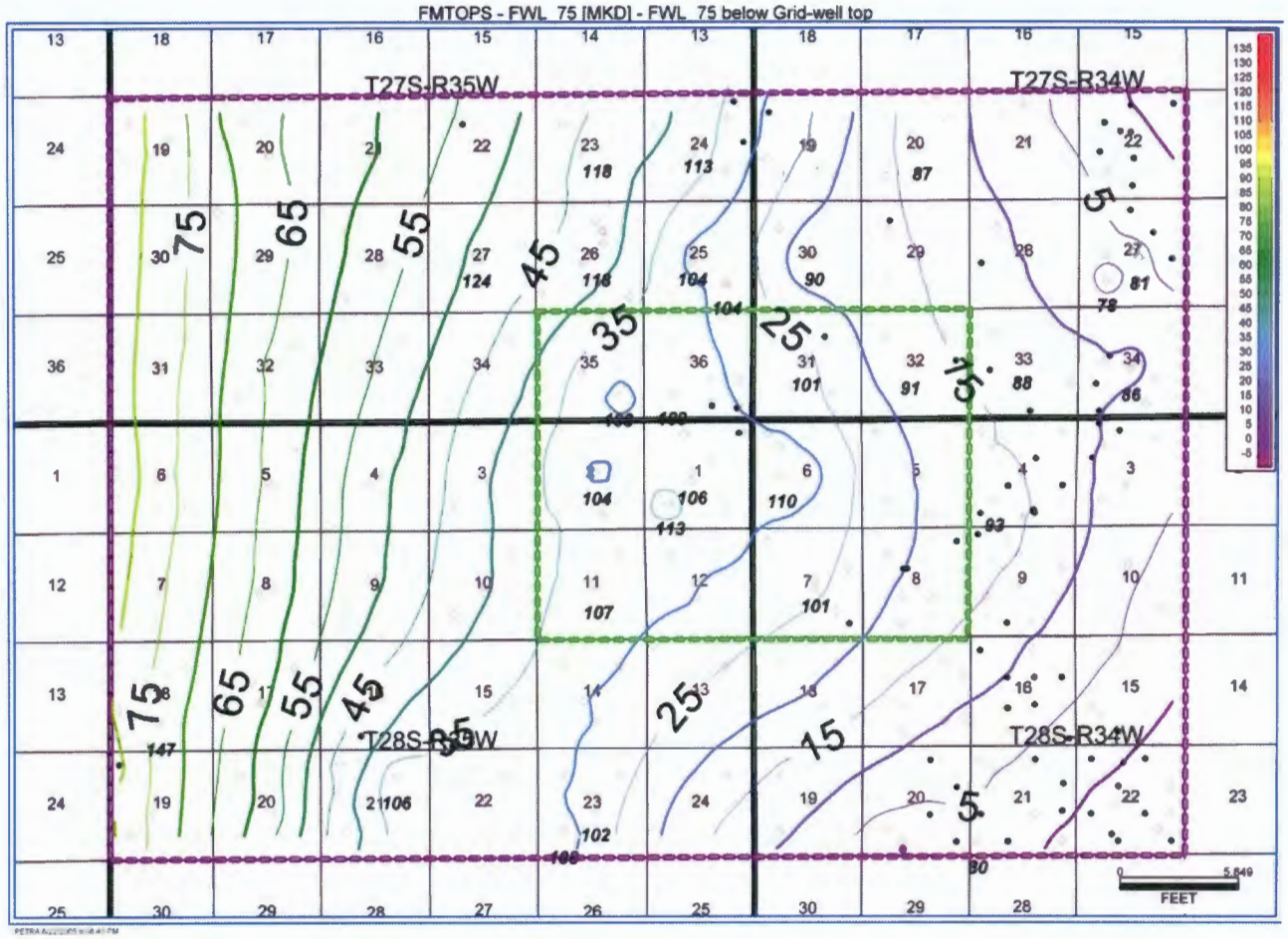

FMTOPS - FWL 75 [MKD] - FWL 75 below Grid-well top
T27S-R35W
T27S-R34W
T28S-R35W
T28S-R34W
FEET

Figure 9.4.5

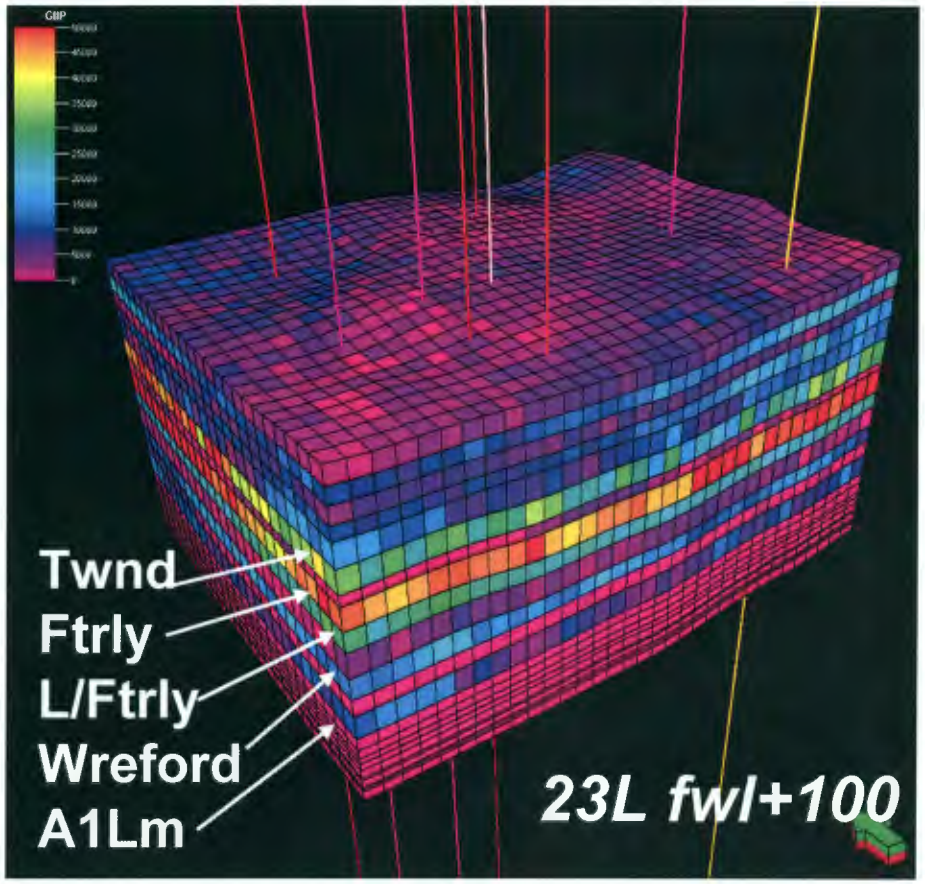


Figure 6

Assumed PVT properties:

Reference pressure	465	psi	
Rock compressibility	0.000002	1/psi	(assumed)
Reservoir temp	90	F	
Gas gravity (Air = 1.0)	0.715		
Water salinity	110,000	ppm	

Figure 7

Permeability Multiplier Applied to Layers

	Sample #	Log Phi	K md (trans)	Core Phi	Core K, md	Multi	Layer	Multiplier Used
HRNGTN							1	3.0
KRIDER							2	3.0
ODELL							3	1
WINF							4	3.0
GAGE							5	1
TWND							6	3.0
B/TWND							7	1
FTRLY							8	3.0
LFTRLY							9	3.0
B/FTRLY							10	1
WREFORD	7	0.10	0.11	0.09	0.15	1.38	11	1.4
A1_SH	3						12	1
A1_LM	23	0.11	0.18	0.08	0.71	3.93	13	3.9
B1_SH	2						14	1
B1_LM	10	0.07	0.04	0.06	0.17	4.29	15	4.3
B2_SH	0						16	1
B2_LM	8	0.09	0.14	0.08	0.40	2.87	17	2.9
B3_SH	1						18	1
B3_LM	0						19	3.0
B4_SH	4						20	1
B4_LM	3						21	3.0
B5_SH	0						22	1
B5_LM	13	0.12	3.20	0.10	4.65	1.45	23	1.5

Layers in Red – Chase, Layers in Blue - CG

Figure 8

Well	IP Date	Initial SIP, psi
1 Biggs	Dec-47	411
1 Cromer	Feb-47	412
1 DaVatz	Sep-51	400
1 Elliot	Oct-47	411
1 Fee	Dec-47	409
1 Goering	Dec-48	418
1 Higgenbotham	Nov-47	417
1 McMorran	Nov-47	413
1 Stanley	Dec-46	432
1 Stanley	Oct-47	411
1 Taton	Sep-51	411
C-1 Eubank	Dec-45	406

Avg SI pr, psi
413
Median pr, psi
411

Figure 9

Simulator OGIP and Production

Layer OGIP in Simulator Model

OGIP (bcf) in Sim at 440 psi = 170.61

Layer	bcf
1	3.6
2	12.1
3	3.6
4	9.2
5	9.3
6	29.9
7	2.9
8	43.9
9	17.8
10	2.6
11	17.6
12	1.5
13	12.9
14	0.2
15	1.3
16	0.03
17	0.9
18	0.07
19	0.4
20	0.5
21	0.07
22	0.04
23	0.2

Initial reservoir pressure = 440 psi.
Simulator calculated OGIP = 170.7 bcf

Cumulative Production from Chase Parent, CG, and Chase Infill wells vs. Simulator Calculated Total Production

Production as of May 2004

	bcf
Chase Parent	89.82
Chase Infill	8.38
Council G	10.91
Total Prod	109.11
Sim Prod	104.7

L6 and L8 are the driver zones in this study area

Figure 10

Chase Parent and Council Grove (CG) Wells in Study Area

Production, Perforation Intervals, & Cumulative Production

Chase Parent wells

	Well	Sim name	Prod Start	Perf Top	Perf Base	Cum Gas, mcf
1	Taton1	PTat1	1/1/1951	1	6	8,958,461
2	Stanley1	PStan1	1/1/1947	1	8	7,997,756
3	Stanley1 Oxy	PStanO	1/1/1948	1	8	7,049,501
4	McMoran1	PMor1	1/1/1948	1	8	10,786,642
5	Higginbotham 1	PHigB1	1/1/1948	1	8	10,188,790
6	Goering1	PGoer1	1/1/1949	1	7	8,117,999
7	Fee1	PFee1	1/1/1948	1	8	5,686,279
8	Eubanks1	PEub1	1/1/1946	1	6	7,744,731
9	Elliot1	PEliot	1/1/1948	1	6	4,696,387
10	DaVatz1	PDav	1/1/1951	1	6	5,722,071
11	Cromer1	PCrom	1/1/1947	1	8	5,924,928
12	BiggsA1	PBigs	1/1/1948	1	8	6,946,830

89,820,375

CG wells

	Well	Sim Name	Prod Start	Perf Top	Perf Base	Cum Gas, mcf
1	2 TATON GAS UNIT	GTat2	10/1/1980	8	13	1,144,835
2	3 C STANLEY	GStan3C	9/1/1985	8	14	863,418
3	2 STANLEY C	GStan2C	5/1/1978	8	14	288,828
4	2 STANLEY A	GStan2A	7/1/1978	8	14	889,403
5	2 MC MORRAN A	GMor2A	6/1/1978	8	14	986,529
6	2 HIGGENBOTHAM A	GHigB2A	5/1/1978	8	13	908,559
7	4 EUBANK C	GEub4C	10/1/1978	8	14	1,357,899
8	4 ELLIOTT	GElot4	10/1/1978	8	15	573,261
9	2 DAVATZ GAS UNIT	GDav2	8/1/1986	8	13	667,730
10	3 A CROMER	GCrom3A	4/1/1985	8	14	1,034,950
11	2 CROMER A	GCrom2A	5/1/1978	8	14	214,258
12	2 BIGGS A TWIN	GBigs2A	8/1/1978	8	14	176,747
13	BIGGS A 4	GBigs4A	6/1/1991	8	13	573,312
14	2 APPLEMAN-JACKSON-F	GApplJ2	3/1/1980	8	13	1,228,034

10,907,763

Figure 11

Chase Infill Wells in Study Area

Production, Perforation Intervals, and Cumulative Production

Chase Infill wells

	Well	Sim Name	Prod Start	Perf Top	Perf Base	Cum Gas
1	3-HI TATON GU	ITatn3	10/1/1993	1	10	774,838
2	Stanlee 4	IStan4	9/1/1990	1	10	970,395
3	3 STANLEY A	IStan3A	12/1/1992	1	8	644,102
4	3 MCMORRAN A	IMor3A	9/1/1988	1	8	733,055
5	A-3 HIGGENBOTHAM	IHig3A	5/1/1994	1	11	632,961
6	Goering 2	IGor2	4/1/1995	1	8	687,707
7	Fee 1-2	IFee	5/1/1994	1	8	421,043
8	Eubank 5	IEub5	11/1/1993	1	10	540,658
9	Elliot 5A	IElli5	11/1/1990	1	10	685,113
10	3 HI DAVATZ G.U.	IDav3	12/1/1988	1	8	672,062
11	Crommer 4A	ICrom4A	9/1/1990	1	11	870,452
12	BiggsA3	IBig3A	9/1/1990	1	11	747,619
						8,380,005

Figure 12

RUN 1: P, I, G - fractures constrained to perforated intervals

Initial K multipliers applied to gas zones, ff= 6, Pi = 440 psi

Match Chase Parent wells

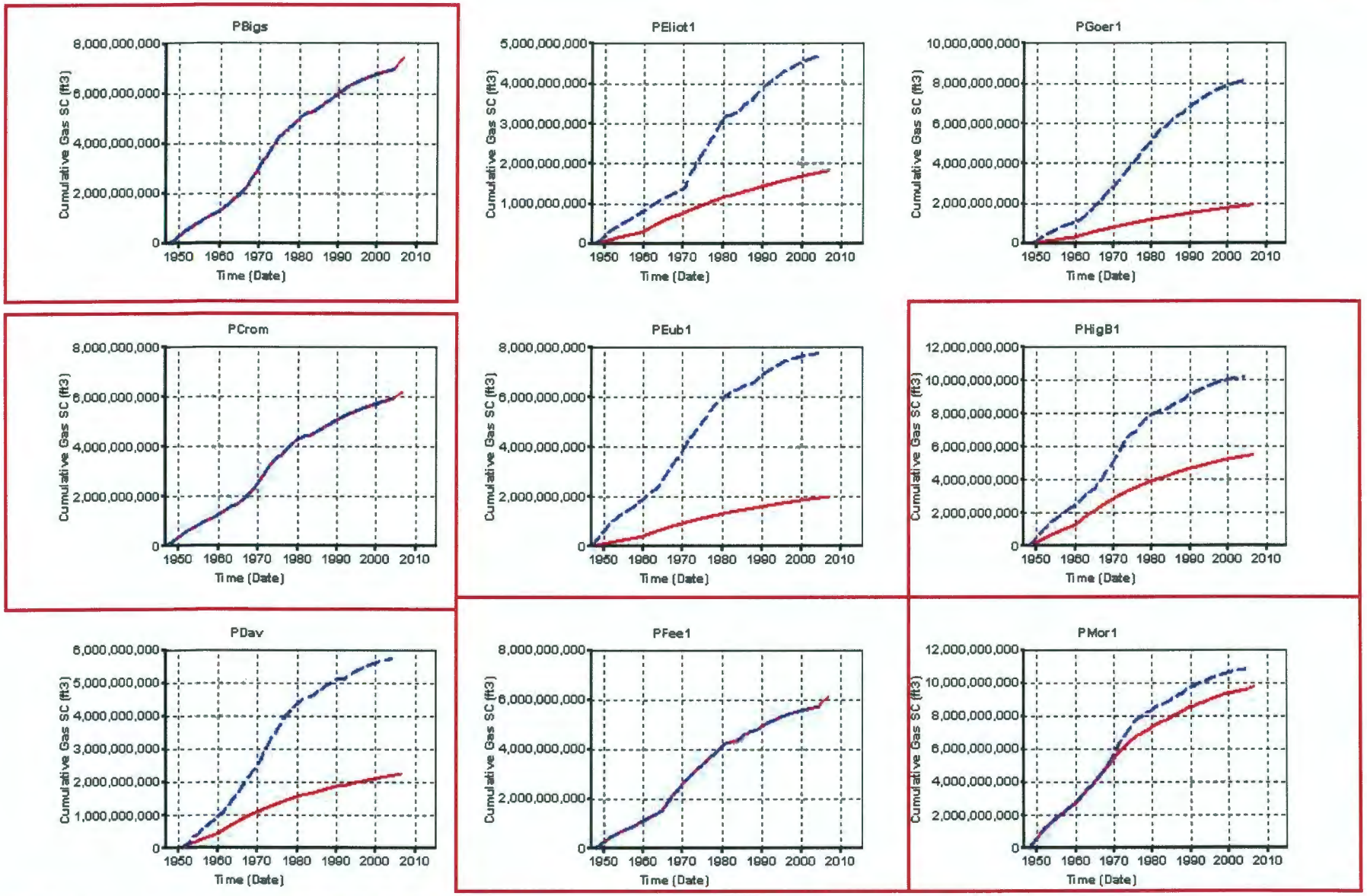
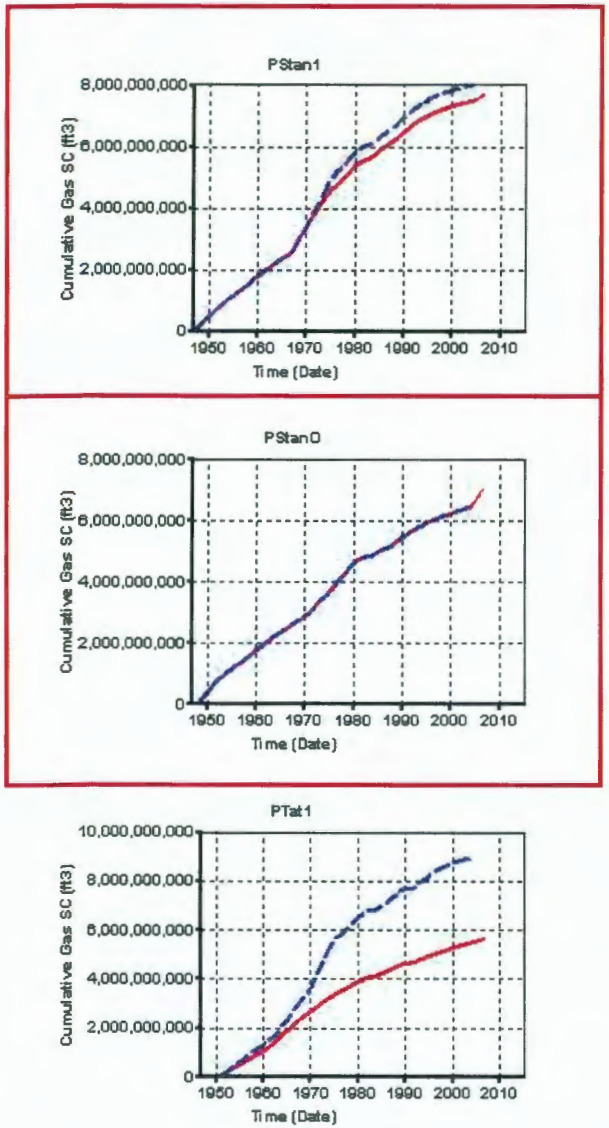


Figure 13 **Broken blue – Historic gas prod** **Red – Simulator calculated gas prod**

RUN 1: P, I, G - fractures constrained to perforated intervals

Initial K multipliers applied to gas zones, ff= 6, Pi = 440 psi

Match Chase Parent wells (Continued)



Gas production matched or come close to matching in Chase Parent wells where perforations (and hence the fractures) extend to Layer 8 (L8)

Well Completed in L8

Figure 14 **Broken blue – Historic gas prod** **Red – Simulator calculated gas prod**

RUN 1: P, I, G - fractures constrained to perforated intervals

Initial K multipliers applied to gas zones, ff= 6, Pi = 440 psi

Match Council Grove wells

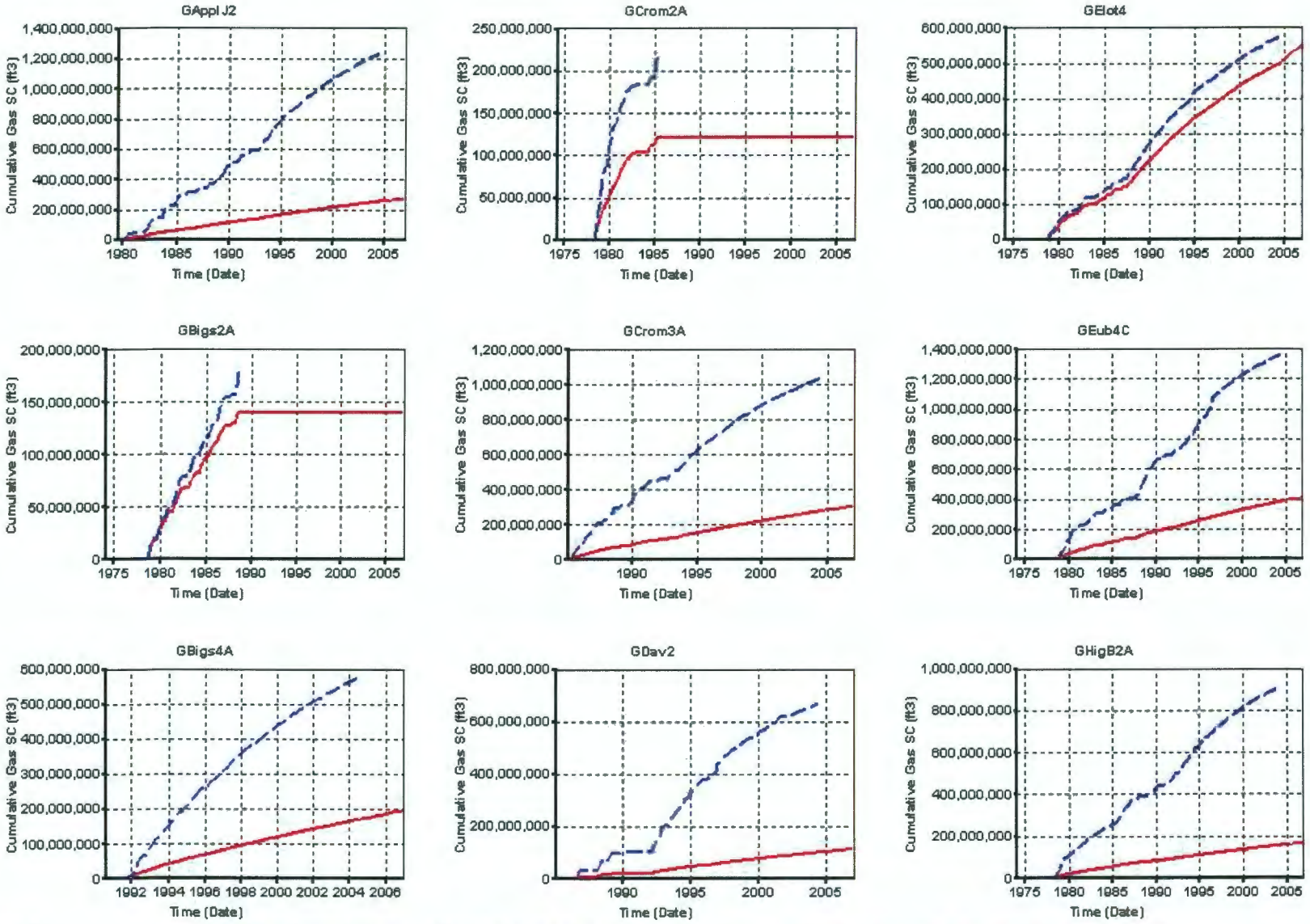
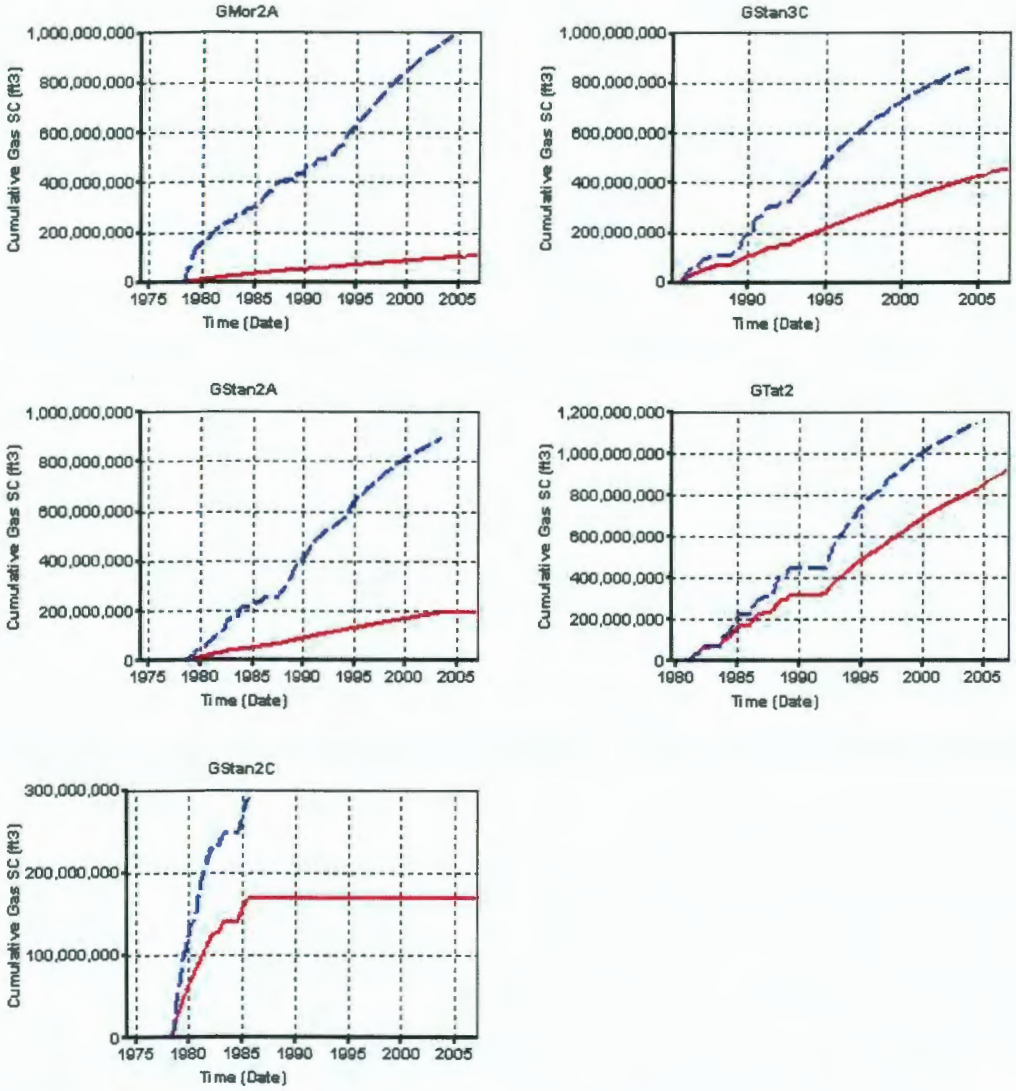


Figure 15 **Broken blue – Historic gas prod** **Red – Simulator calculated gas prod**

RUN 1: P, I, G - fractures constrained to perforated intervals
Initial K multipliers applied to gas zones, ff= 6, Pi = 440 psi

Match Council Grove wells

(Continued)



Simulator calculated gas production fell significantly short of historic production in every Council Grove well.

Figure 16 **Broken blue – Historic gas prod** **Red – Simulator calculated gas prod**

RUN 2: P, I, G - fractures constrained to perforated intervals

Initial K multipliers applied to gas zones, ff= 10, Pi = 440 psi

Match Chase Parent wells

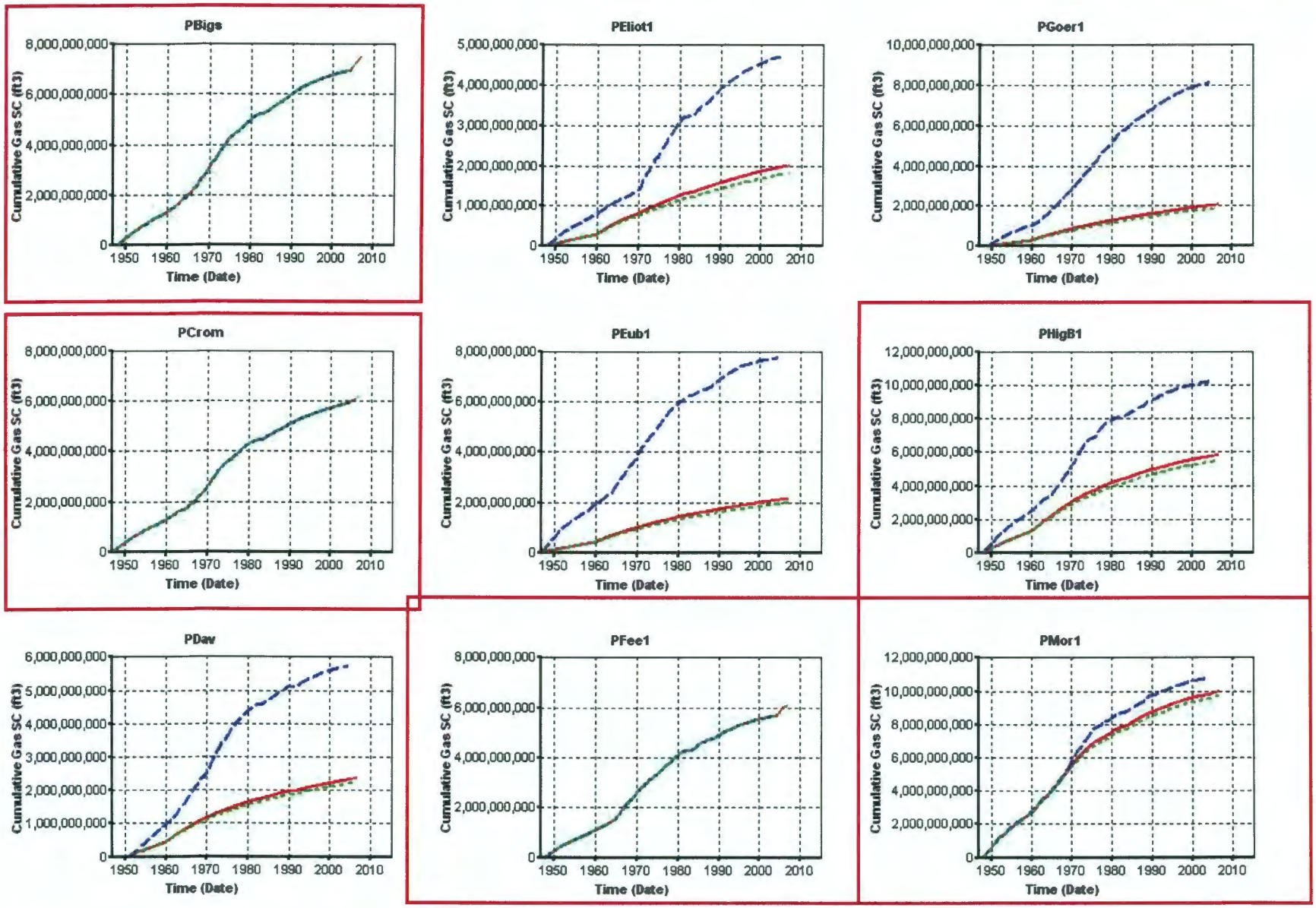


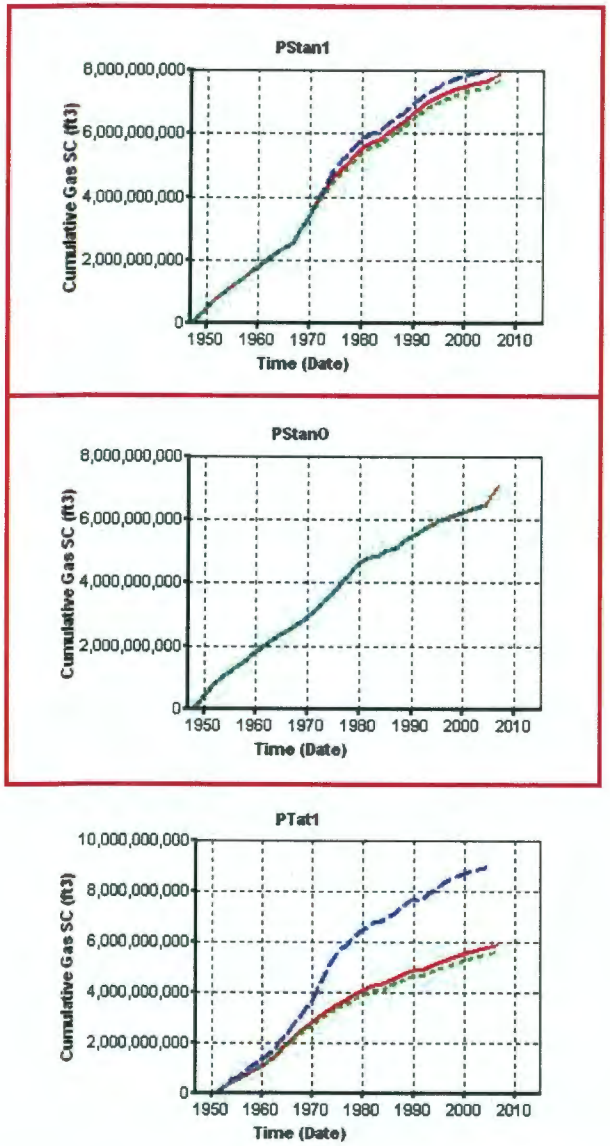
Figure 17

Broken blue – Historic gas prod, Red – Simulator calculated gas prod, Green – Results from Run 1

RUN 2: P, I, G - fractures constrained to perforated intervals

Initial K multipliers applied to gas zones, ff= 10, Pi = 440 psi

Match Chase Parent wells (Continued)



Gas production increased only slightly as compared to Run1. Simulator-calculated cumulative production rates in Chase parent wells not completed in L8 are significantly short of historic volumes.

Completed in L8

Figure 18

Broken blue – Historic gas prod, Red – Simulator calculated gas prod, Green – Results from Run 1

RUN 3: P&I - fractures extended to L8

Initial K multipliers applied to gas zones, ff= 6, Pi = 440 psi

Match Chase Parent wells

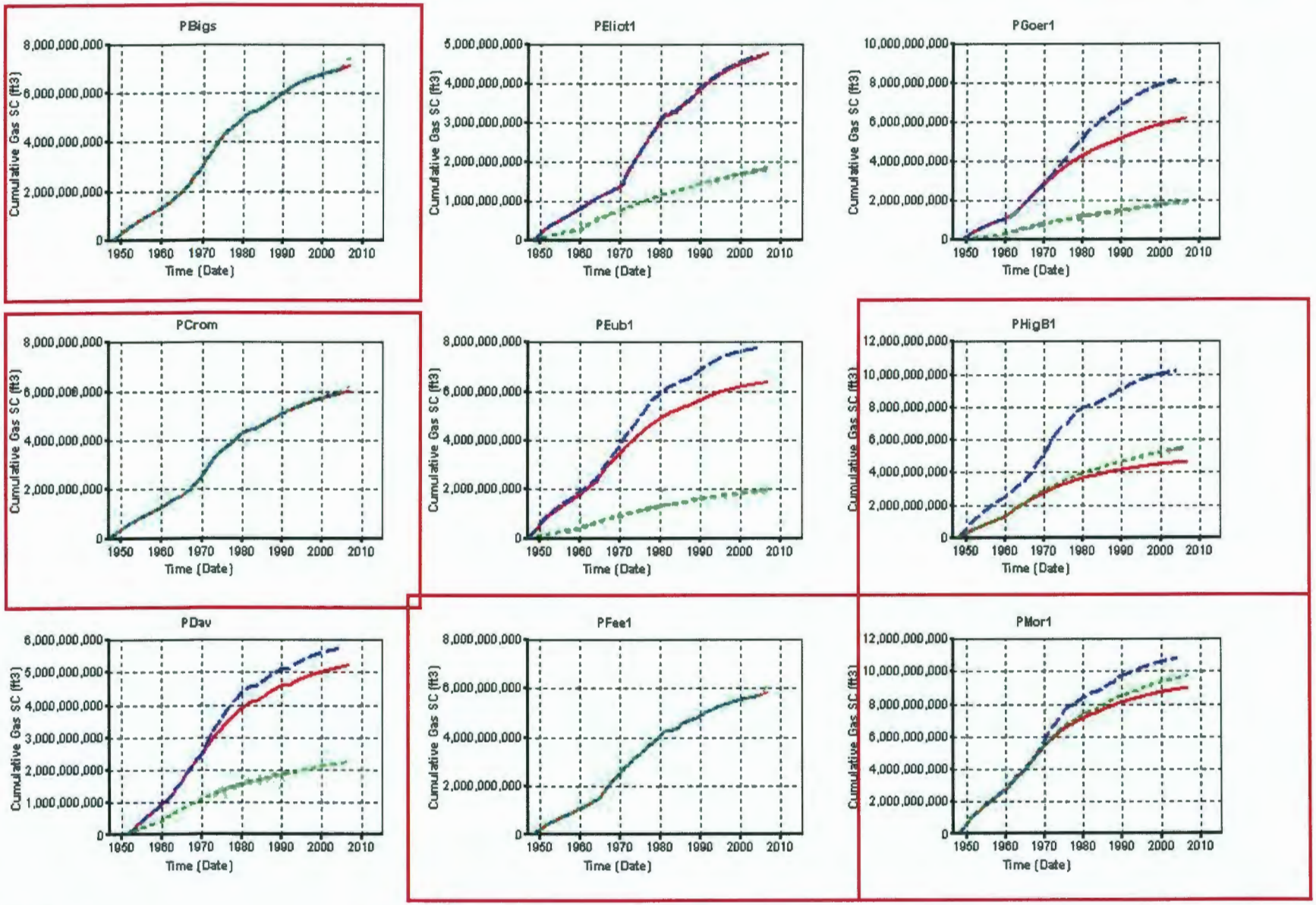


Figure 19

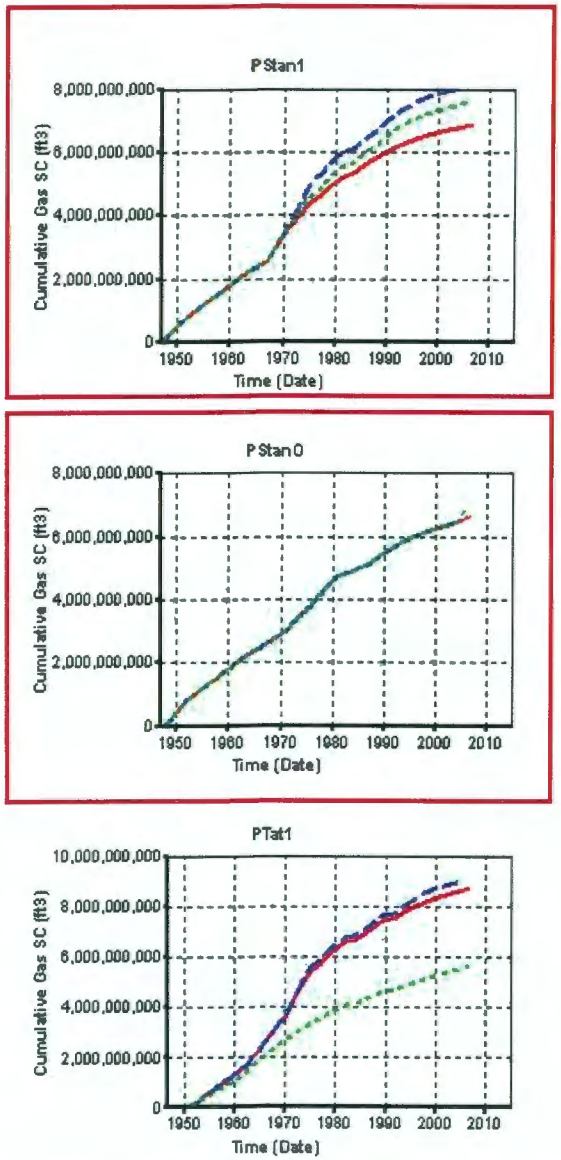
Broken blue – Historic gas prod, Red – Simulator calculated gas prod, Green – Results from Run 1

RUN 3: P&I - fractures extended to L8

Initial K multipliers applied to gas zones, ff= 6, Pi = 440 psi

Match Chase Parent wells

(Continued)



Gas production improved in wells that had not been perforated in L8. However, cumulative production is still short in some of these wells.

Completed in L8

Figure 20

Broken blue – Historic gas prod, Red – Simulator calculated gas prod, Green – Results from Run 1

RUN 4: **P&I - fractures extended to L8. K*2 in driver Chase zones are L6 & L8 (OGIP and K)**

K multiplier applied over and above initial multiplier of 3, ff = 6, Pi = 440 psi

Match Chase Parent wells

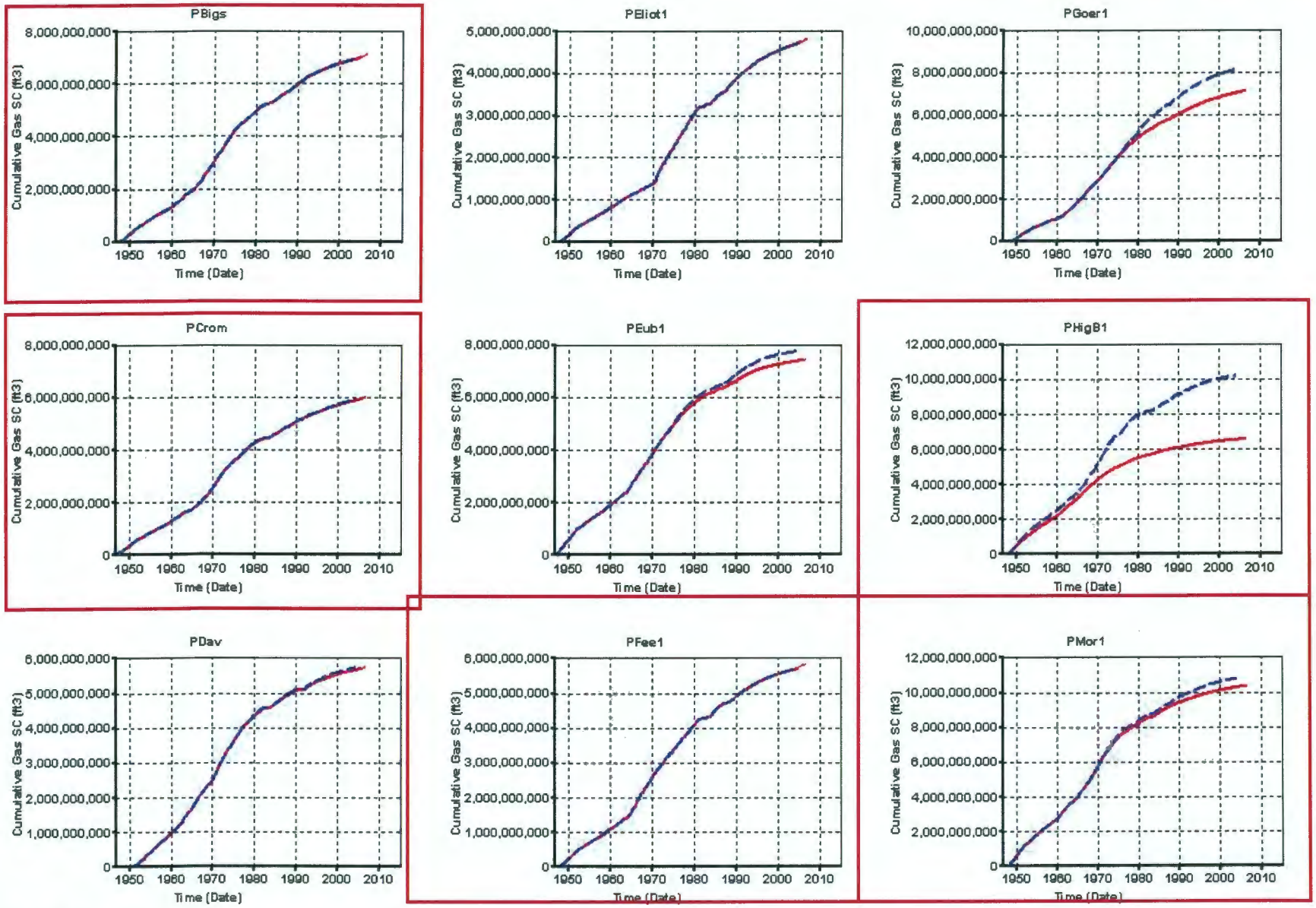


Figure 21

Broken blue – Historic gas prod

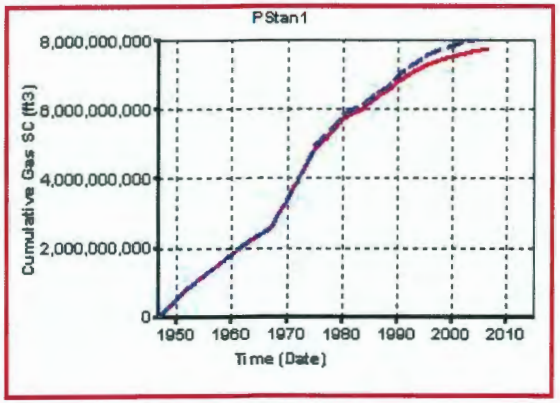
Red – Simulator calculated gas prod

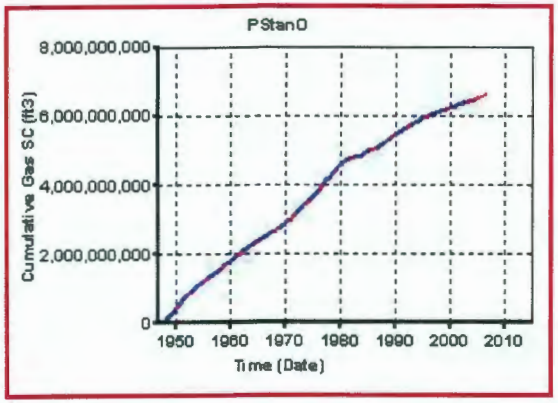
RUN 4: P&I - fractures extended to L8. K*2 in driver Chase zones are L6 & L8 (OGIP and K)

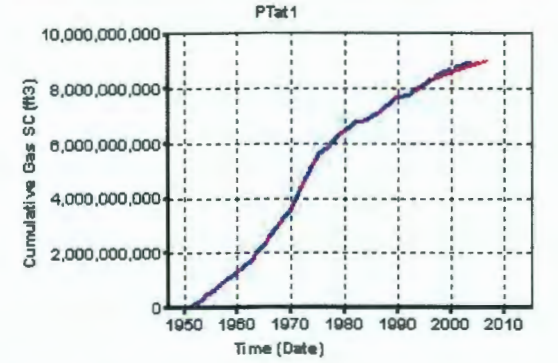
K multiplier applied over and above initial multiplier of 3, ff = 6, Pi = 440 psi

Match Chase Parent wells

(Continued)







Gas production matched or almost matched in all wells except those located in the SW corner of the simulation area.

Example: PHiggenbotham – located in the SW corner. This well is the second highest gas producer in the study area and has produced 10 bcf. However, the OGIP and K mapped in the drainage area of this well is low in the geomodel input to the simulator.

Within the study area there are no wells with qualified logs in the south-western corner. Wells with qualified logs are located outside the study and at a considerable distance from the SW corner of the study area resulting perhaps in non-representative OGIP and permeability distribution in this section of the study area.

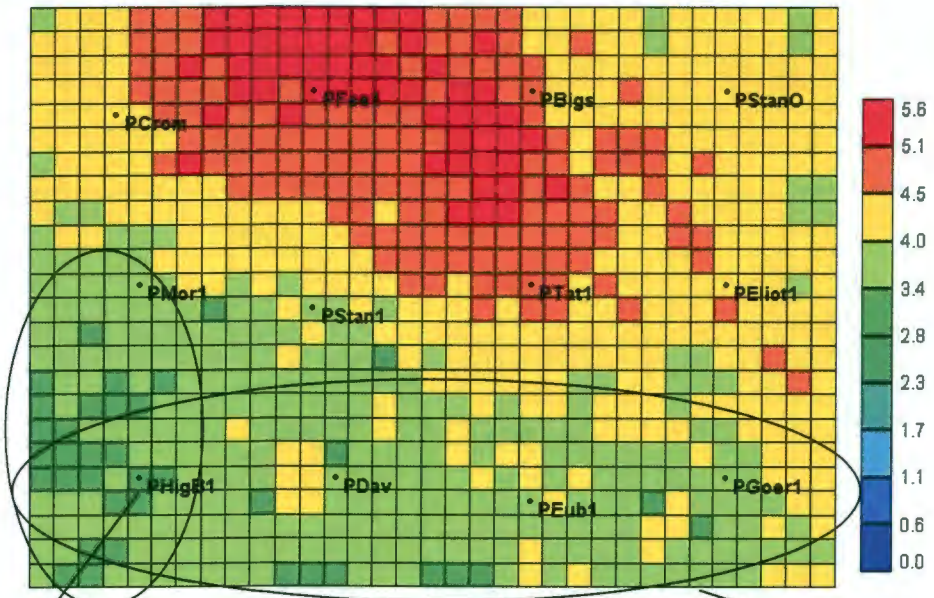
Well completed in L8

Figure 22

Broken blue – Historic gas prod

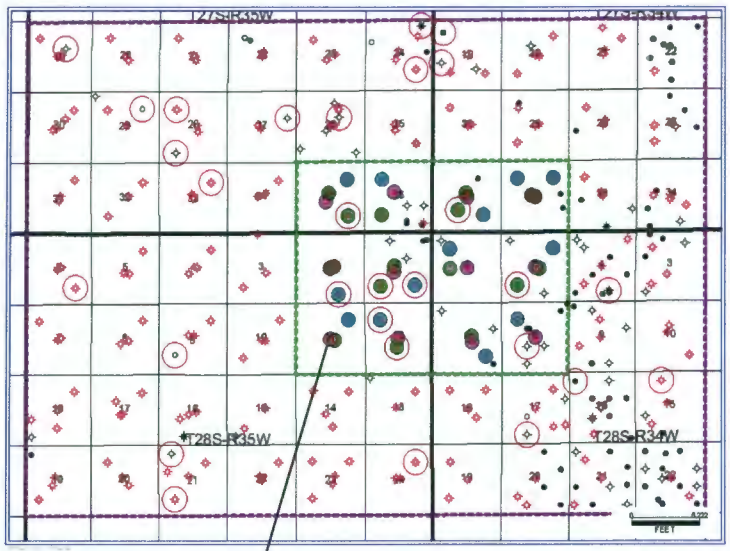
Red – Simulator calculated gas prod

A. Gas per unit area in L8 – 3/1/1952

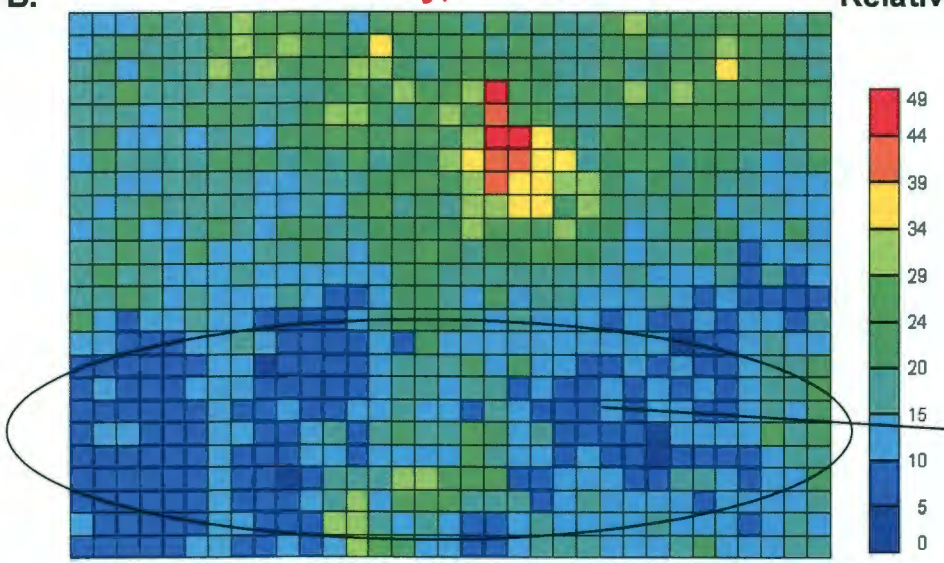


Higgenbotham

C.



B. Permeability, md distribution in L8



Relatively low OGIP

No wells with qualified logs in this section – SW corner of study area. Circled wells have qualified logs.

Relatively tighter permeability

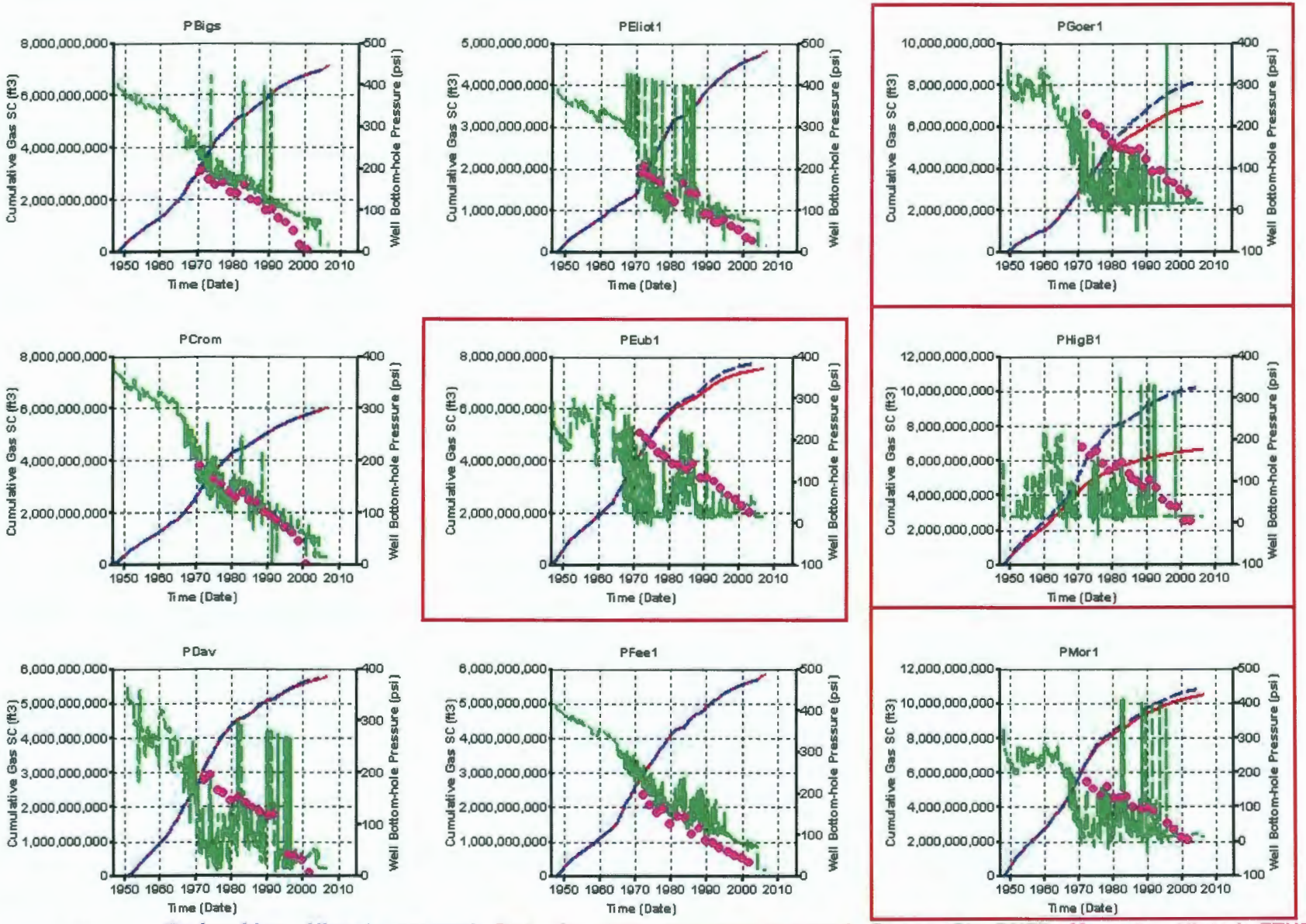
Chase Parent Production

Sim name	Cum Gas, mcf
PTat1	8,958,461
PStan1	7,997,756
PStanO	7,049,501
PMor1	10,786,642
PHigB1	10,188,790
PGoer1	8,117,999
PFee1	5,686,279
PEub1	7,744,731
PEliot	4,696,387
PDav	5,722,071
PCrom	5,924,928
PBigs	6,946,830

Figure 23

RUN 5: P&I - fractures extended to L8. K*2 in driver (in terms of OGIP & K) Chase zones, i.e., L6 & L8 Permeability adjusted in Chase zones (Kxy*6 in L1) to better match RFT layer pressures. Also, ff = 6, Pi = 440 psi

Match Chase Parent wells



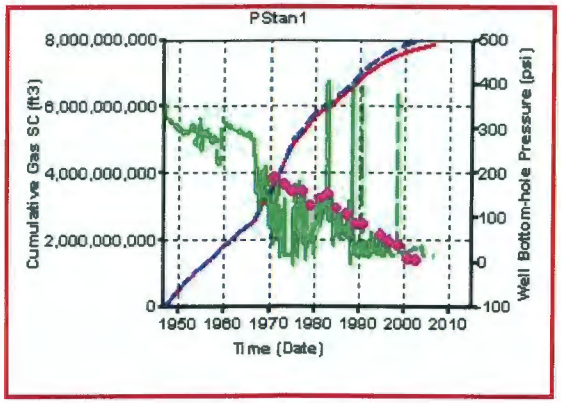
Broken blue – Historic gas prod **Red – Simulator calculated gas prod** **Green – Sim BHFP** **Magenta – Historic FTHP**

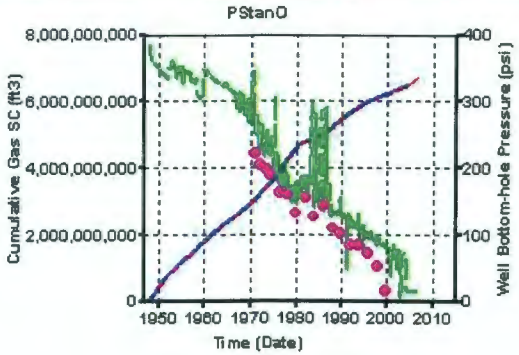
Figure 24

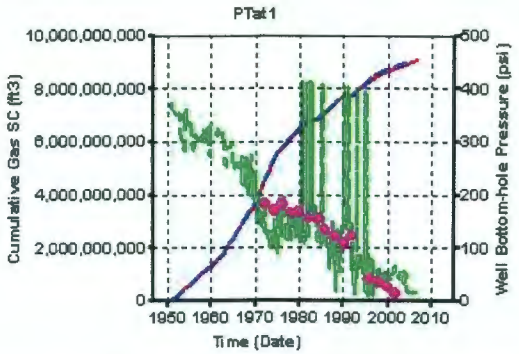
RUN 5: P&I - fractures extended to L8. K*2 in driver (in terms of OGIP & K) Chase zones, i.e., L6 & L8 Permeability adjusted in Chase zones (Kxy*6 in L1) to better match RFT layer pressures. Also, ff = 6, Pi = 440 psi

Match Chase Parent wells

(Continued)





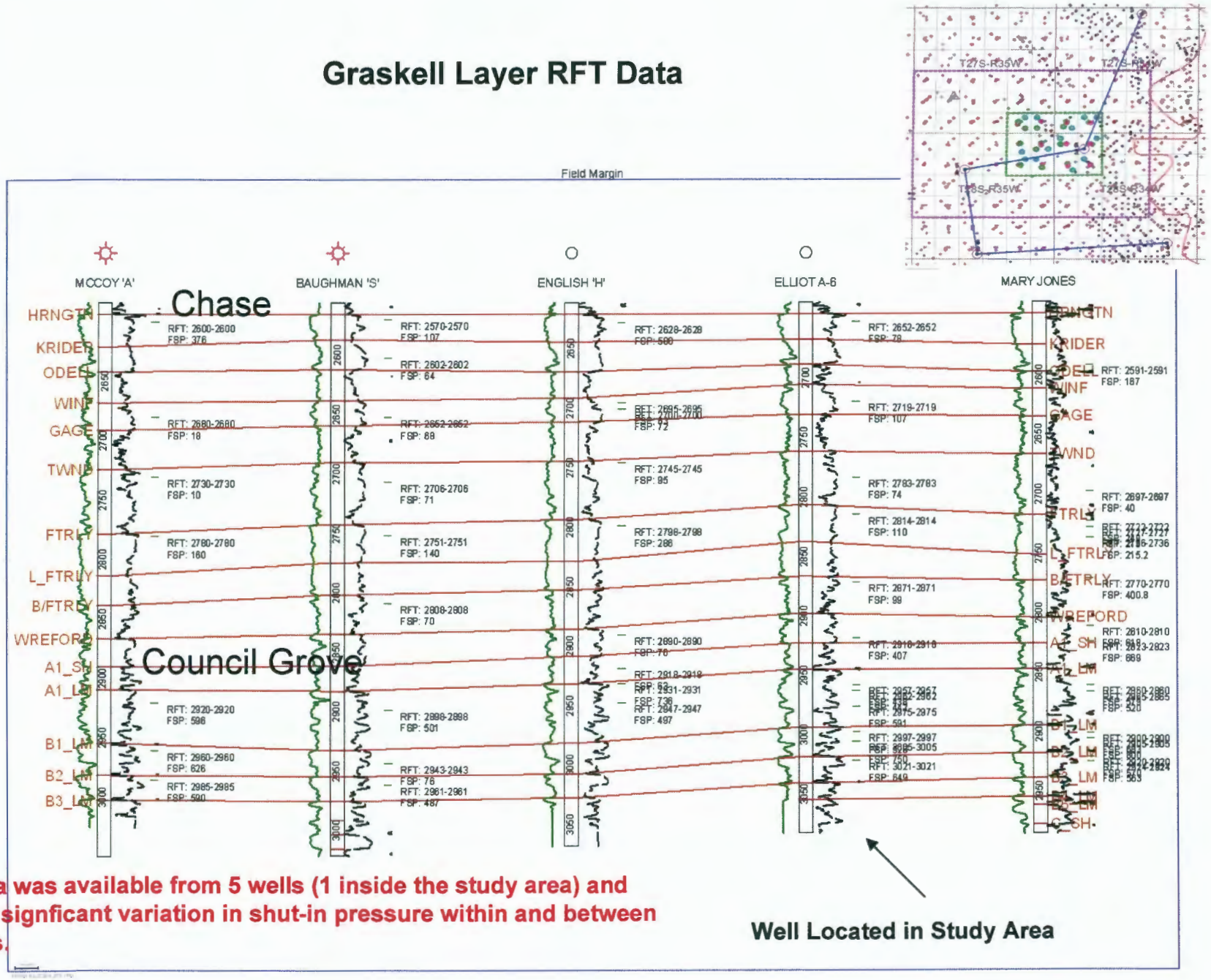


Gas production matched at all wells except those in the tight border areas.

Wells with good production matches also show close matched between FTHP (historic flowing surface pressure) and FBHP (simulator calculated bottom hole flowing pressures).

Figure 25 Broken blue – Historic gas prod Red – Simulator calculated gas prod Green – Sim BHFP Magenta – Historic FTHP

Graskell Layer RFT Data



RFT data was available from 5 wells (1 inside the study area) and showed signficant variation in shut-in pressure within and between intervals.

Figure 26

Simulator Calculated Pressure (Run 5) vs. Chase RFT data

Location Eliot A6 well - Dec 2004

Formation	Layer	Simulator, psi	RFT, psi	Best Guess, psi	*COMMENTS*
HRNGTN	1	420	78	78	**may be low**; 107, 379, 500 in other wells
KRIDER	2	384	na	**300**	not tested; low k in area; 64, 167 in other wells
ODELL	3	383	na	400	Silt-shale; should be high
WINF	4	251	107	107	may be high; 18,68,72 in other wells
GAGE	5	181	na	400	Silt-shale; should be high
TWND	6	127	74	74	okay; 10, 40, 71, 95, in other wells
B/TWND	7	117	na	400	Silt-shale; should be high
FTRLY	8	89	110	110-200	may be low; 140, 160, 215, 286 in other wells
L/FTRLY	9	90	na	200-300	
FLRNC	10	300	99	99	70 in one other well, **mostly shale**
WREFORD	11	303	407	200	too high; 76 in one other well
A1_SH	12	362	na	400	Silt-shale; should be high

Appearance of discrepancy in the RFT layer-pressure data

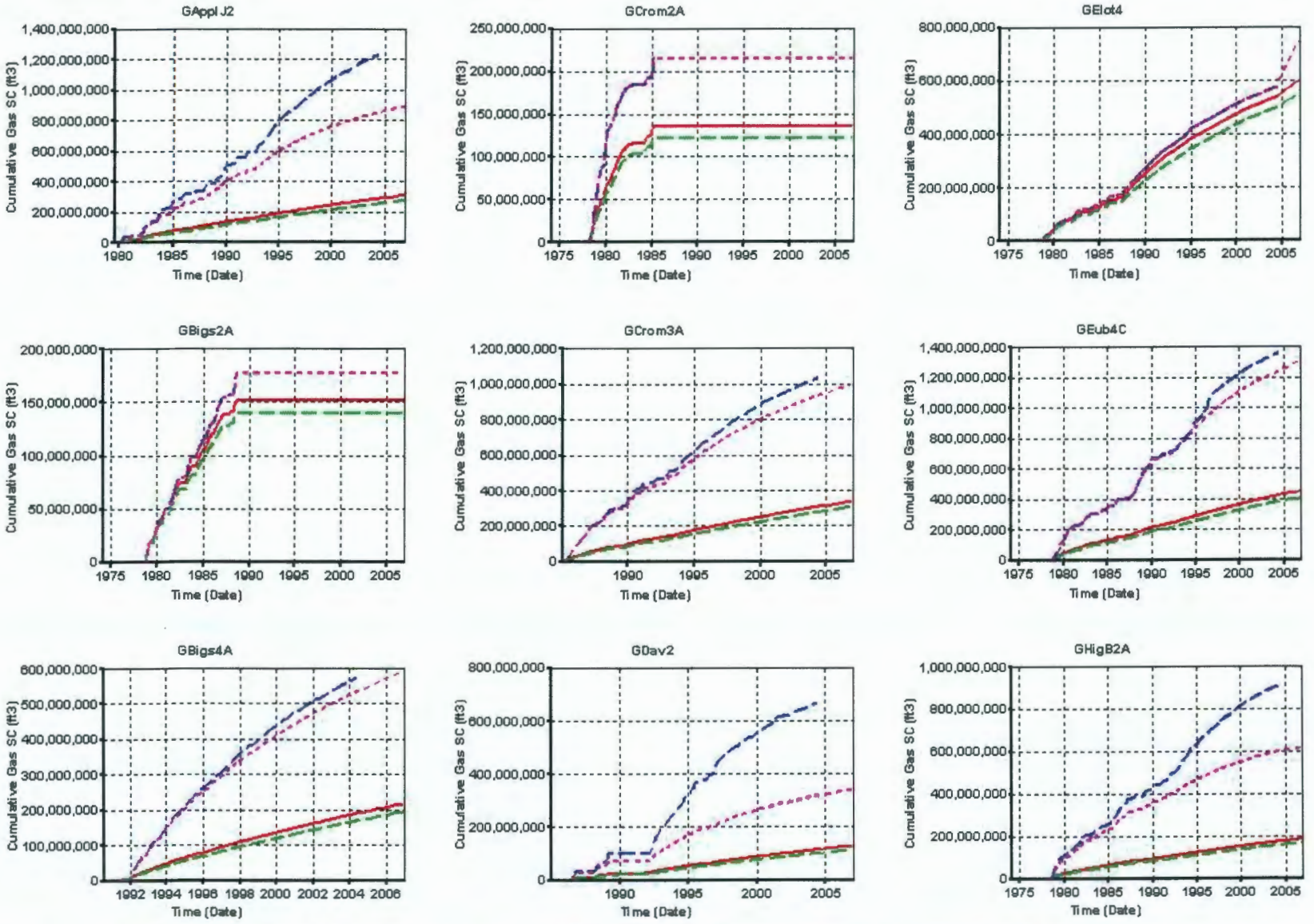
Figure 27

RUNS 6&7: Initial Kxy in Chase (as Run 3). Fractures constrained to perfs in CG. Pi = 440 psi.

Run 6 – K*10 (over initial multiplier) in CG pay & ff = 6.

Run 7 – Original K multiplier in CG pay & ff = 10

Match CG wells



Broken blue – Historic gas prod Red – Run 7 Green – Run 1 Magenta – Run 6

Figure 28

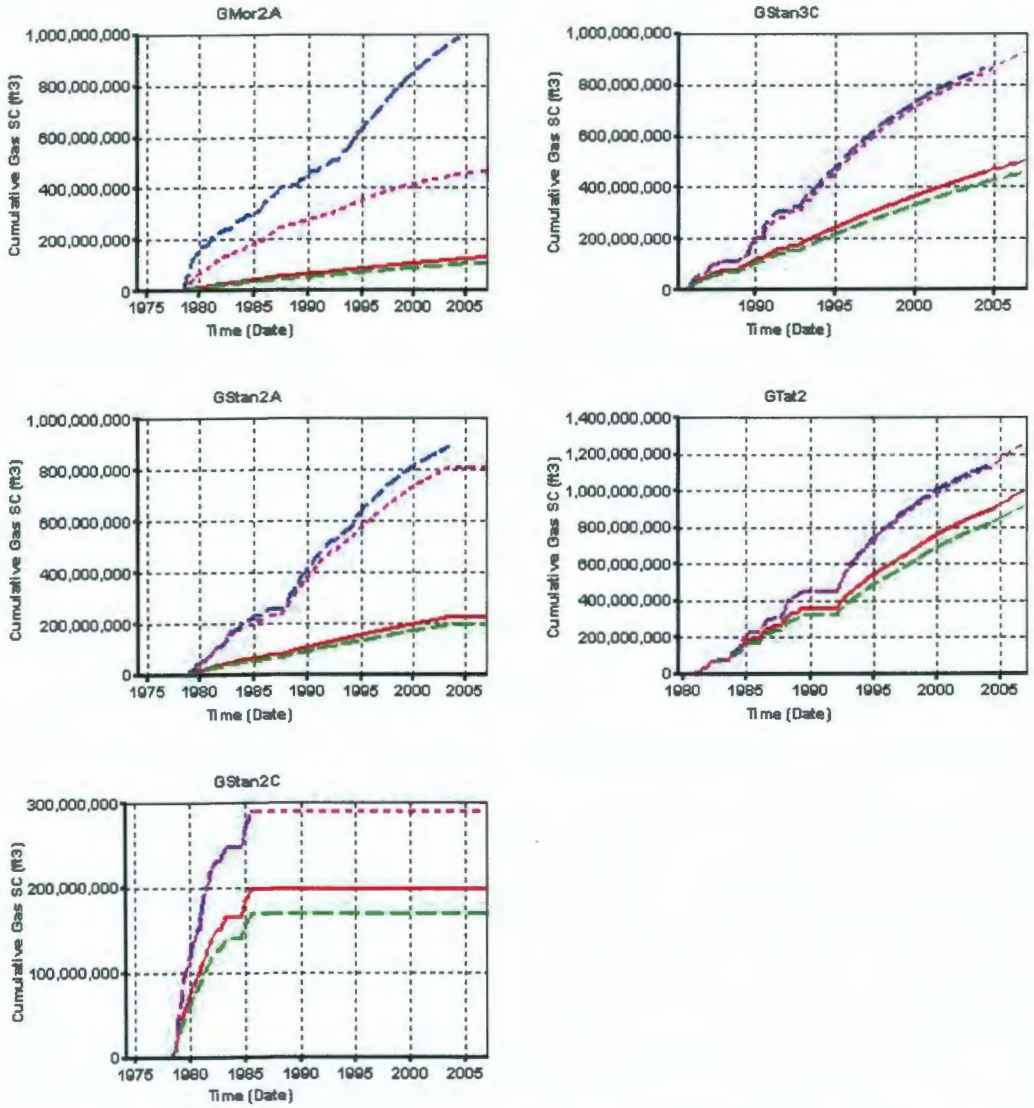
RUNS 6&7: Initial Kxy in Chase (as Run 3). Fractures constrained to perfs in CG. Pi = 440 psi.

Run 6 – K*10 (over initial multiplier) in CG pay & ff = 6.

Run 7 – Original K multiplier in CG pay & ff = 10

Match CG wells

(Continued)



Run 6 - Gas production matched or comes close to matching history in most Council Grove wells

Run 7 - Gas production increased slightly over base case (Run 1) but remained significantly short of history

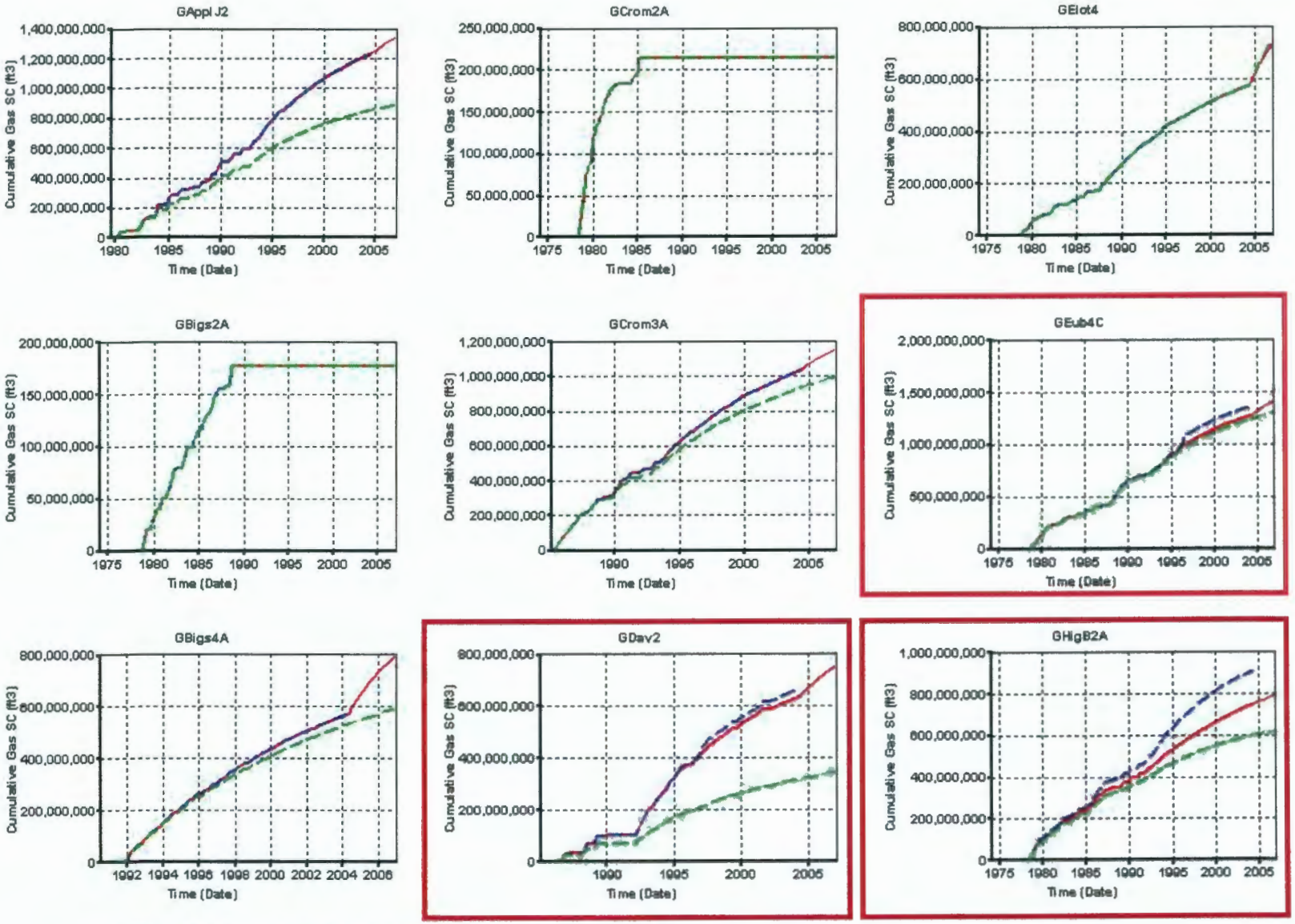
Figure 29

Broken blue – Historic gas prod Red – Run 7 Green – Run 1 Magenta – Run 6

RUN 8: CG fractures extended to L8, ff = 6. Original K multiplier in CG. Pi = 440 psi

Run 6 – K*10 (over initial multiplier) in CG pay & ff = 6

Match Council Grove wells



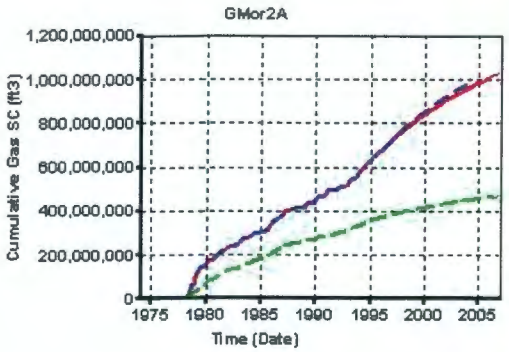
Broken blue – Historic gas prod **Red – Run 8** **Green – Run 6**

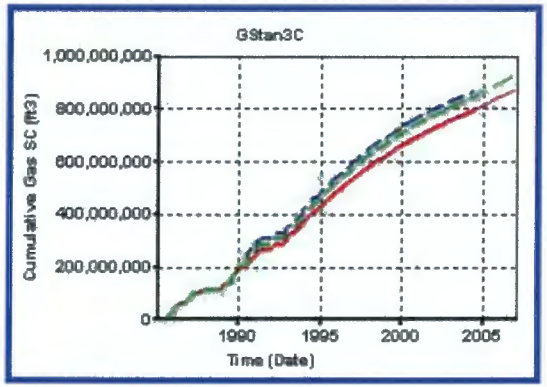
Figure 30

RUN 8: CG fractures extended to L8, ff = 6. Original K multiplier in CG. Pi = 440 psi

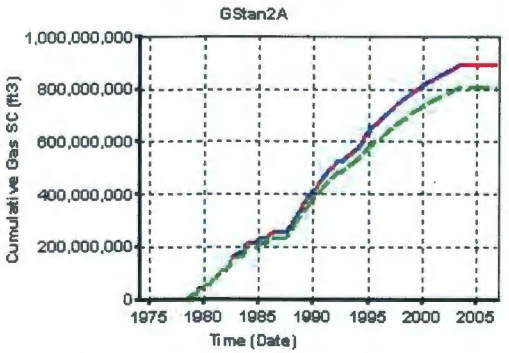
Run 6 – K*10 (over initial multiplier) in CG pay & ff = 6

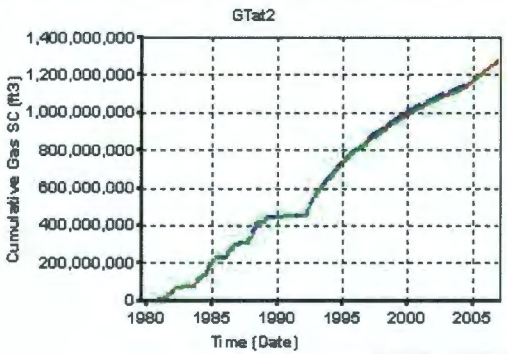
Match Council Grove wells



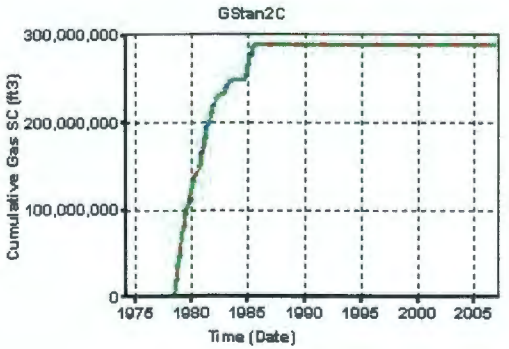


Wells in tight border areas





Well in NE corner of study area



Production matched at all Council Grove wells except 3 wells along the southern border and 1 well located in the NE corner of the study area.

Broken blue – Historic gas prod Red – Run 8 Green – Run 6

Figure 31

RUN 9: Chase Parent wells - Frac to L8 and ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1). Council Grove wells - K*10 in pay layers (over initial K multiplier) and ff =6

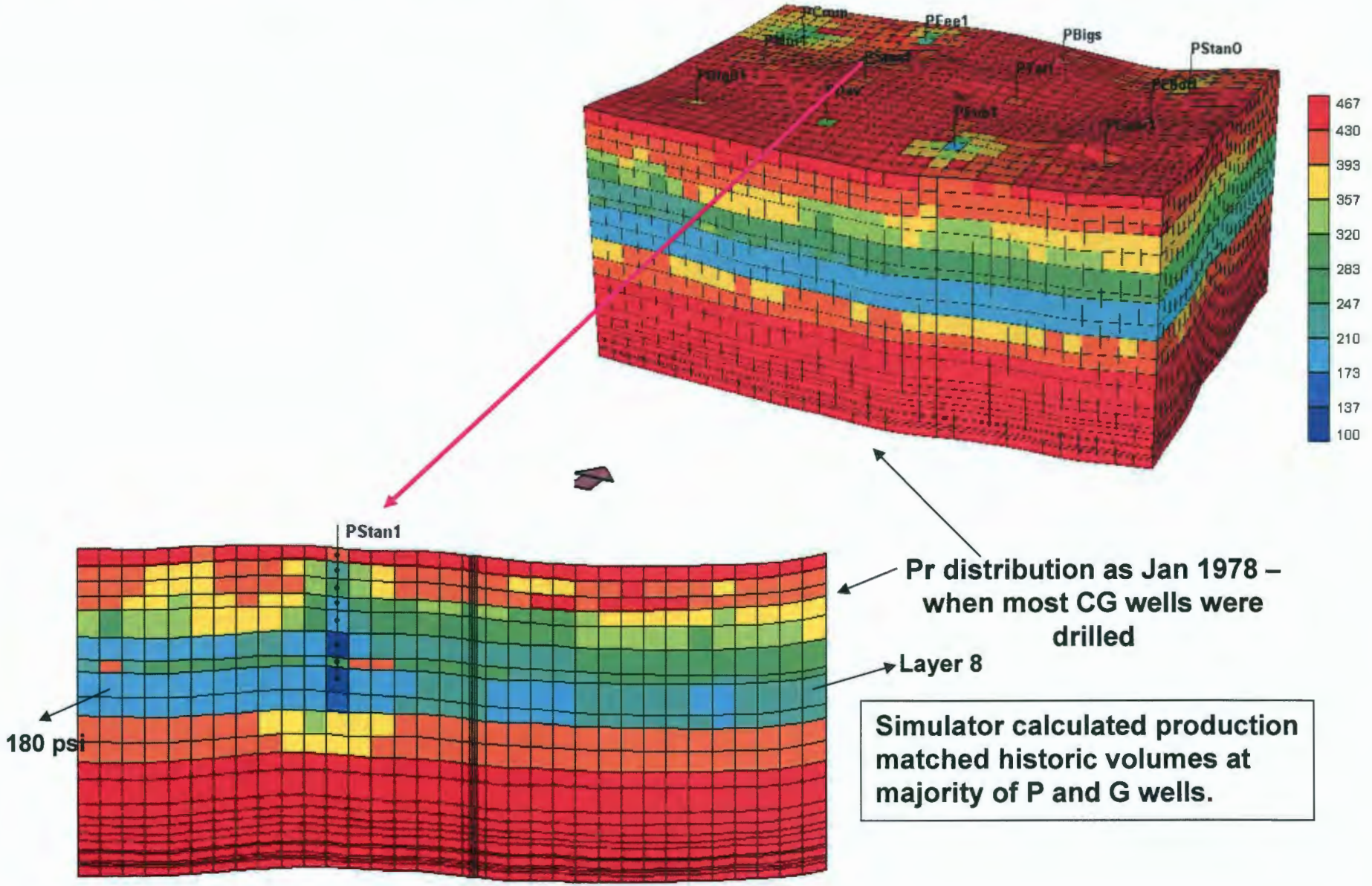
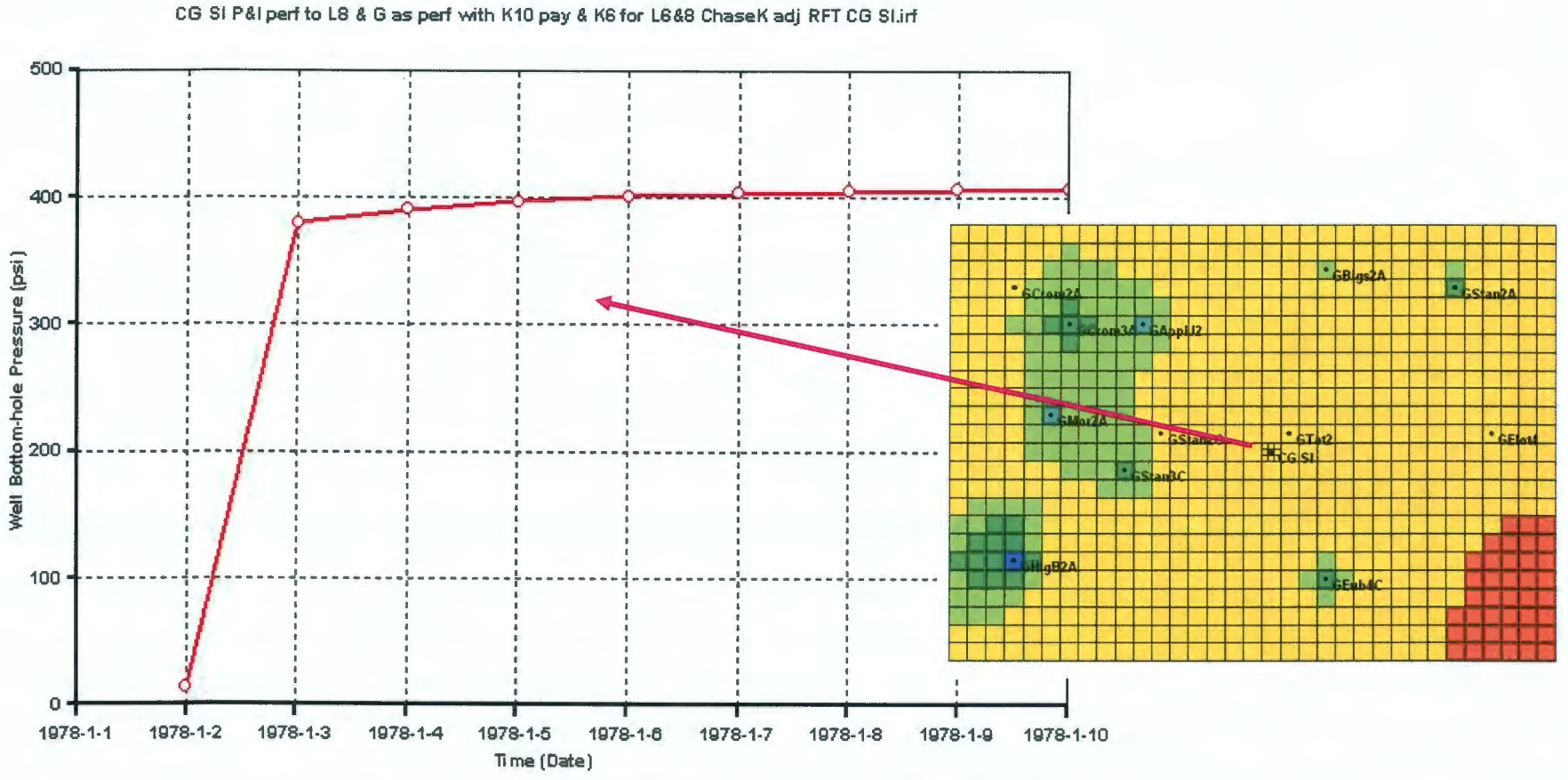


Figure 32

RUN 9: **Chase Parent wells - Frac to L8 and ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1). Council Grove wells - K*10 in pay layers (over initial K multiplier) and ff =6**

Bottom hole SI pressure at a hypothetical CG well as of January 2, 1978

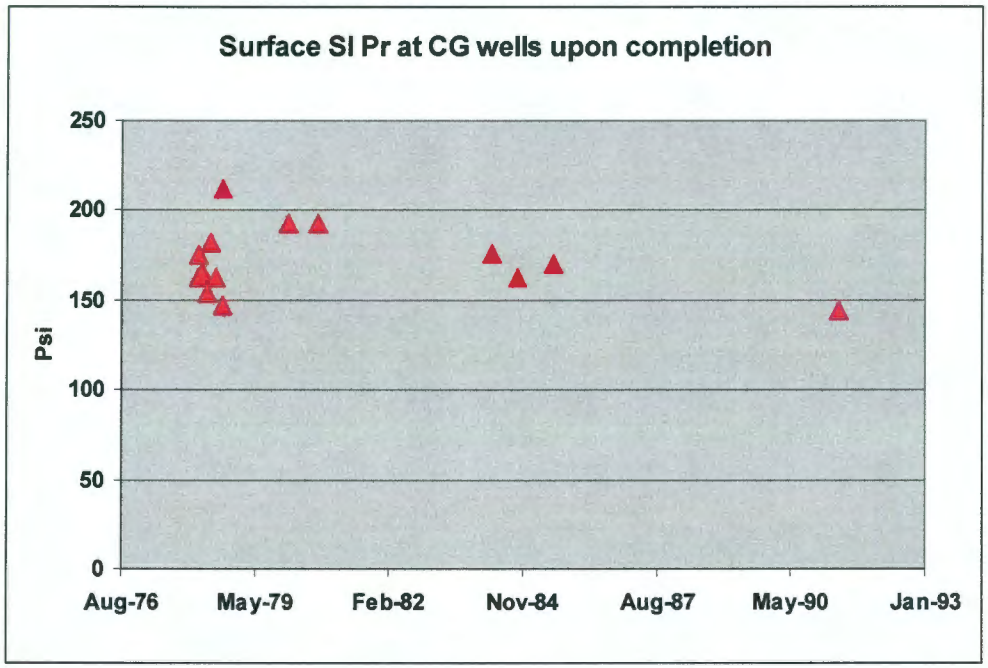


SI pressure stabilizes around 400 psi after 4 days

Figure 33

RUN 9: Chase Parent wells - Frac to L8 and ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1). Council Grove wells - K*10 in pay layers (over initial K multiplier) and ff =6

Historically recorded initial surface shut-in pressures at Council Grove wells



Simulator calculated SI pr at CG well as of January 1978 = 400 psi

Figure 34

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

Chase Parent well matches

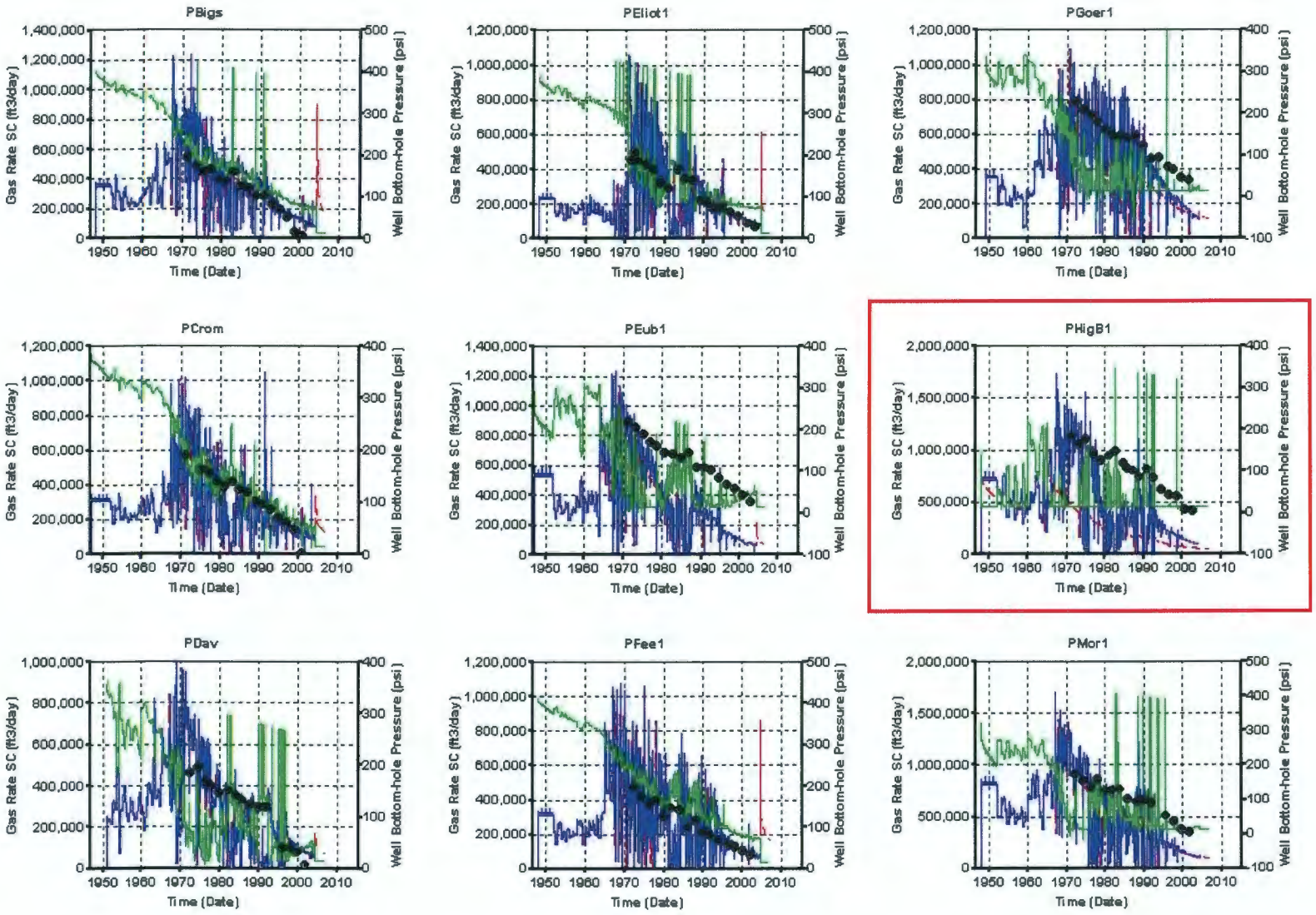
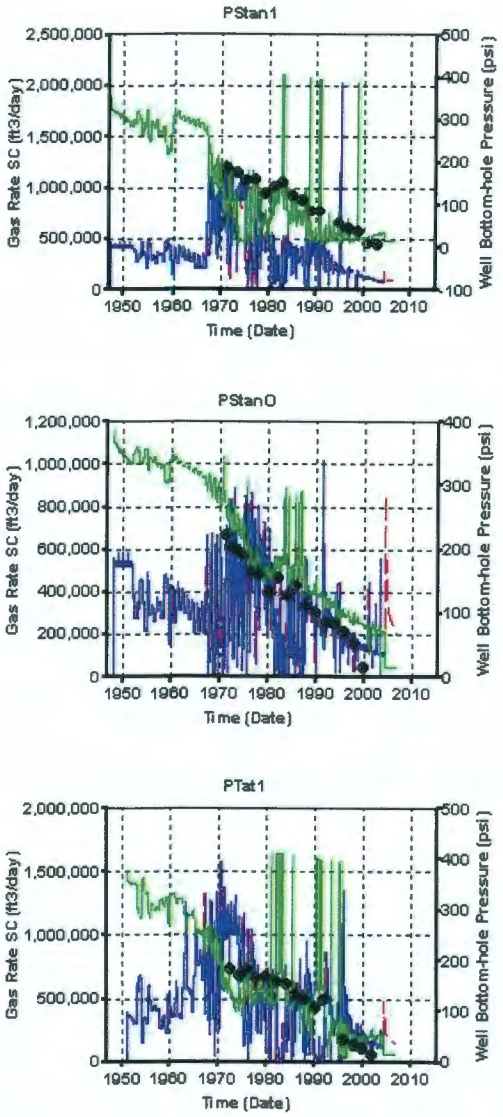


Figure 35

Red – Simulator calculated gas prod

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

Chase Parent well matches



Final History matches – CH P wells

Production matched at all but PHigB1.

Pressure matched at few wells.

Pressure spikes indicate tight K

Production spikes when released of flow constraints

Figure 36 **Blue – Historic gas prod** **Red – Simulator calculated gas prod** **Green – Sim BHFP** **Black – Historic FTHP**

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

Council Grove well matches

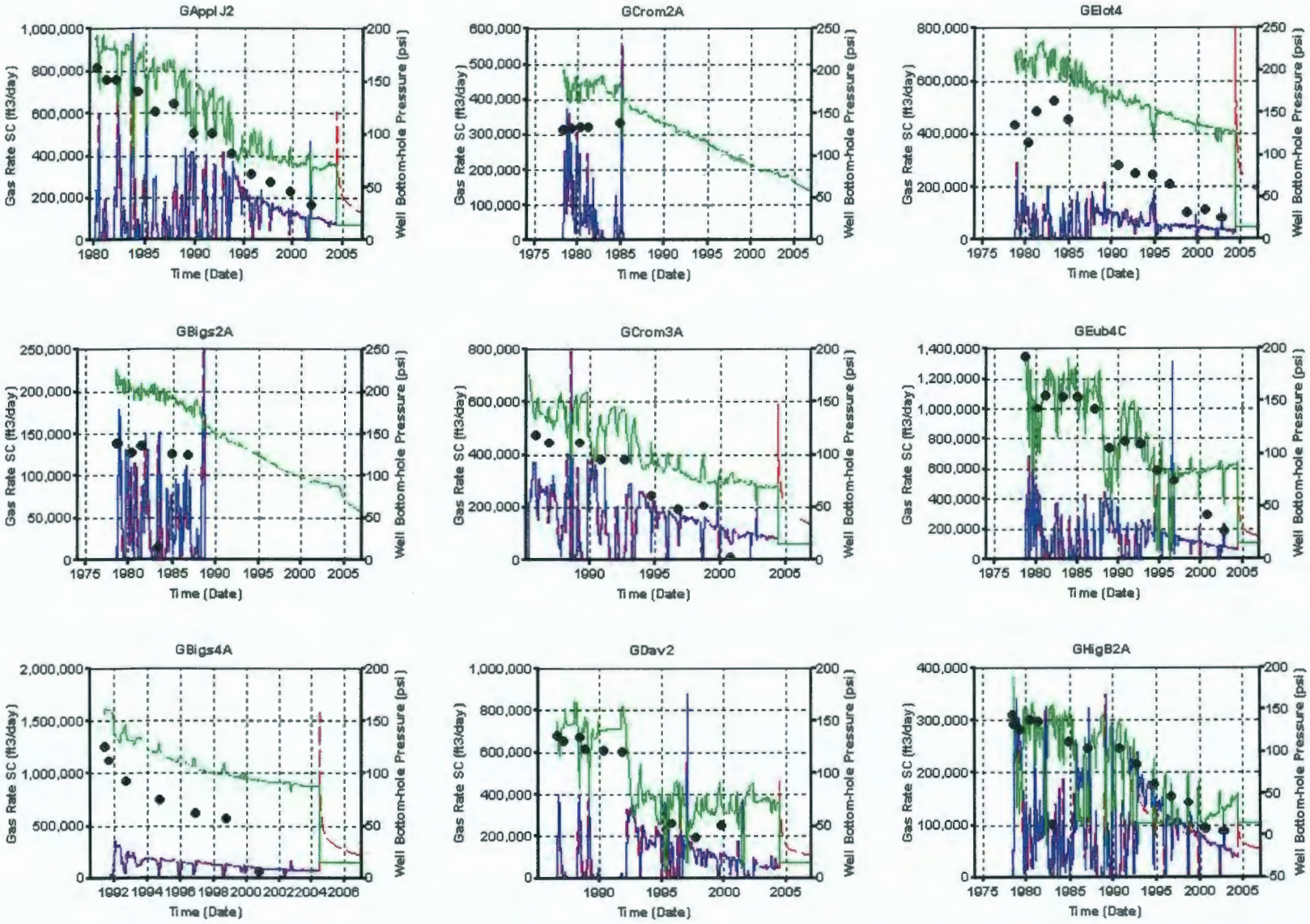
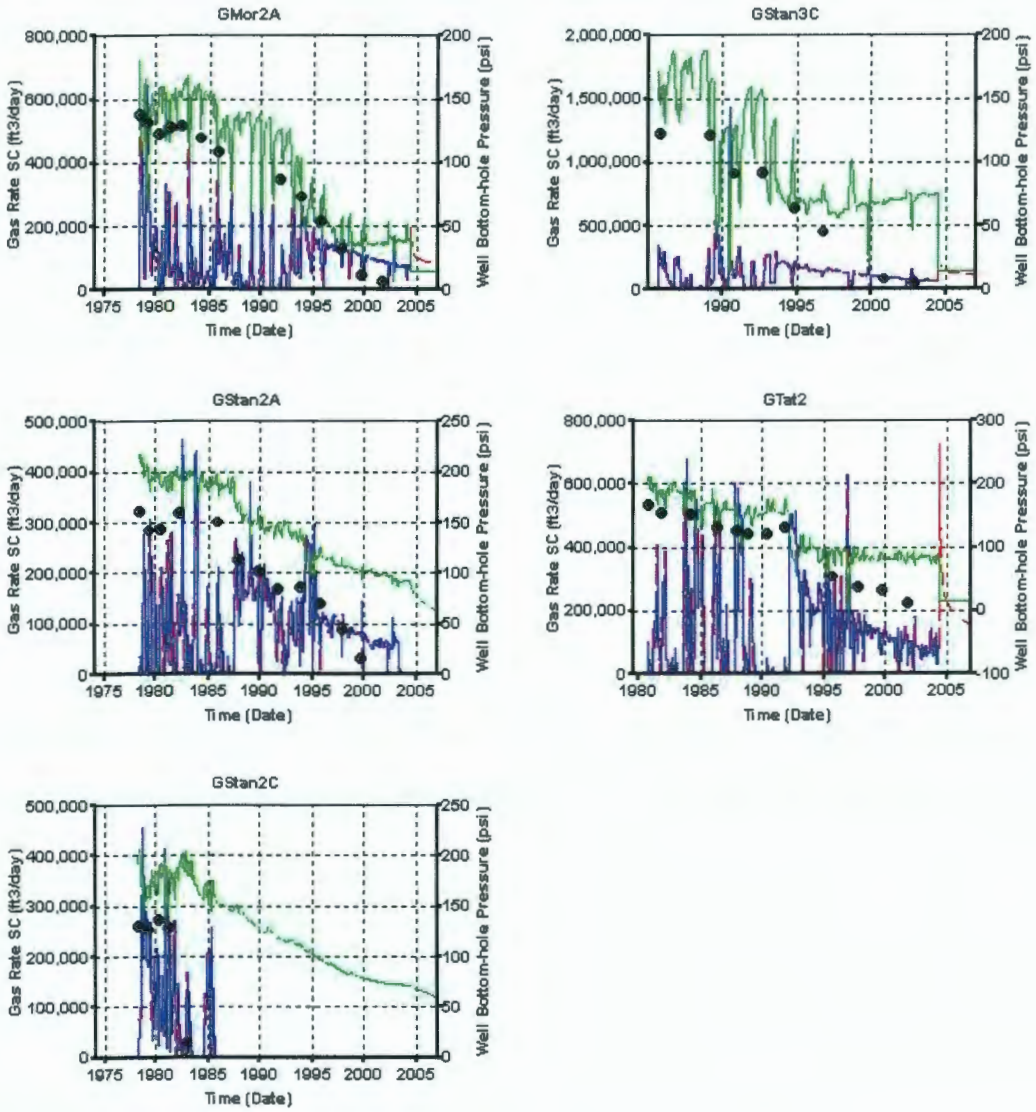


Figure 37

Red – Simulator calculated gas prod

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

Council Grove well matches



Final History matches – CG wells

Figure 38 Blue – Historic gas prod Red – Simulator calculated gas prod Green – Sim BHFP Black – Historic FTHP

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

Chase Infill well matches

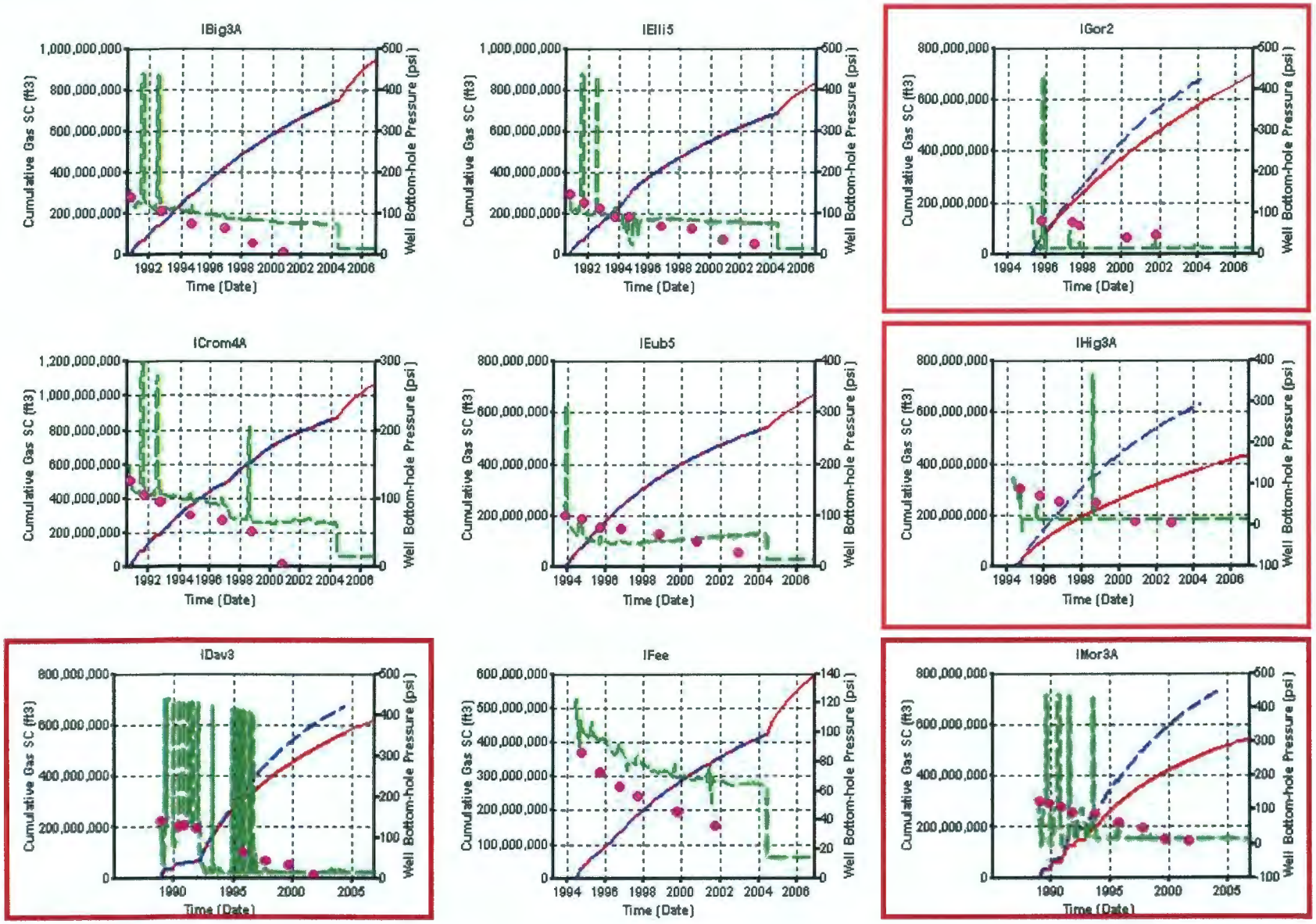
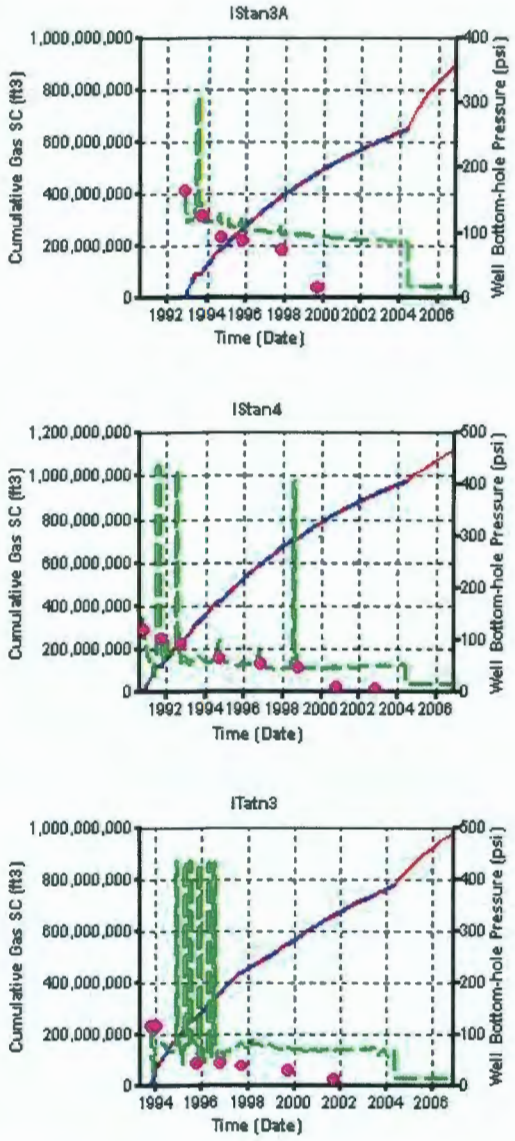


Figure 39

Red – Simulator calculated gas prod

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers



Chase Infill well matches (Continued)

Chase Infill wells

Production matched or close to matching in most wells except those in tight border areas.

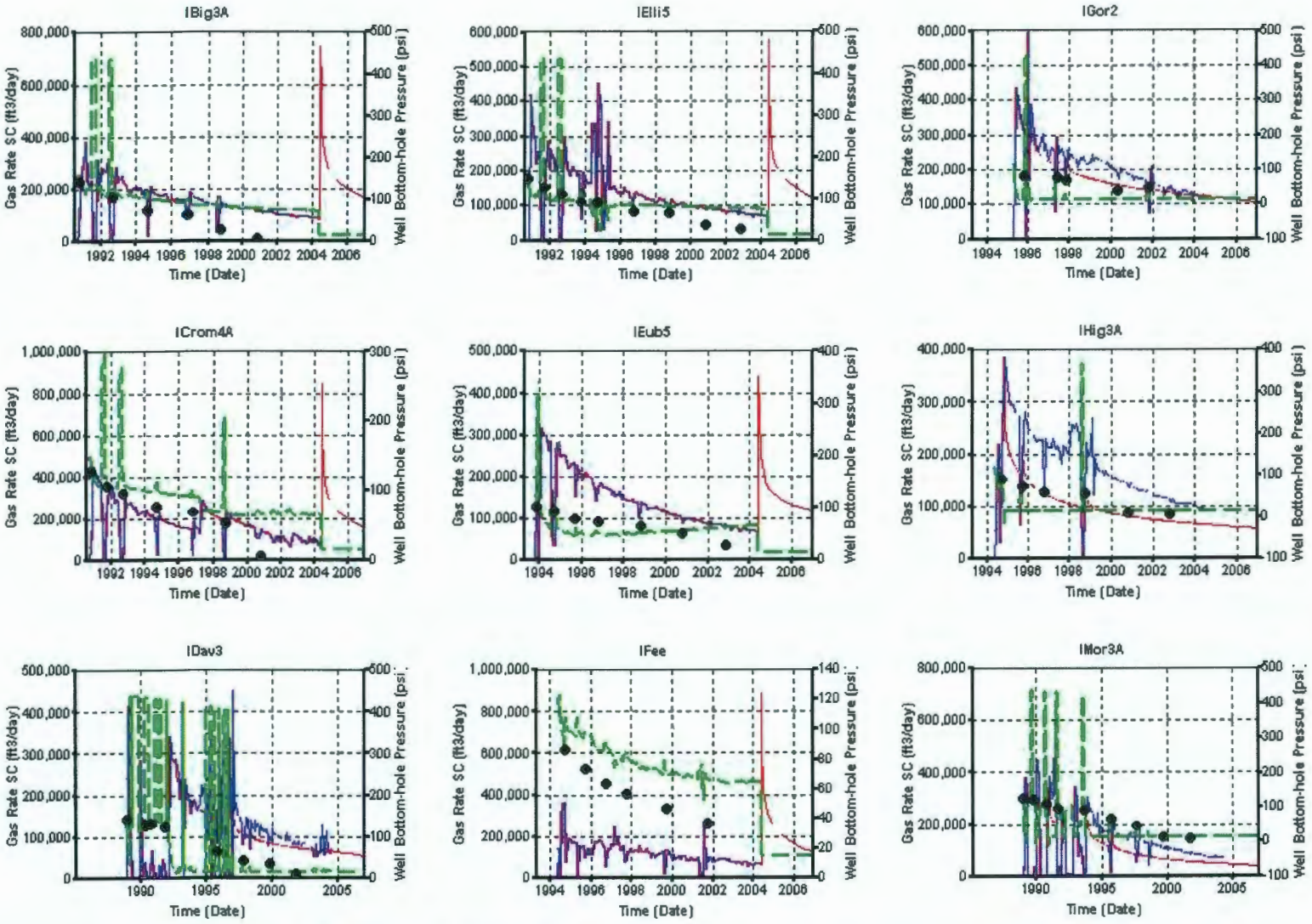
Bottom hole flowing pressure (spikes) indicative of perhaps tight permeability.

Figure 40

Broken blue – Historic gas prod Red – Simulator calculated gas prod Green – Sim BHFP Magenta – Historic FTHP

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

Chase Infill well matches

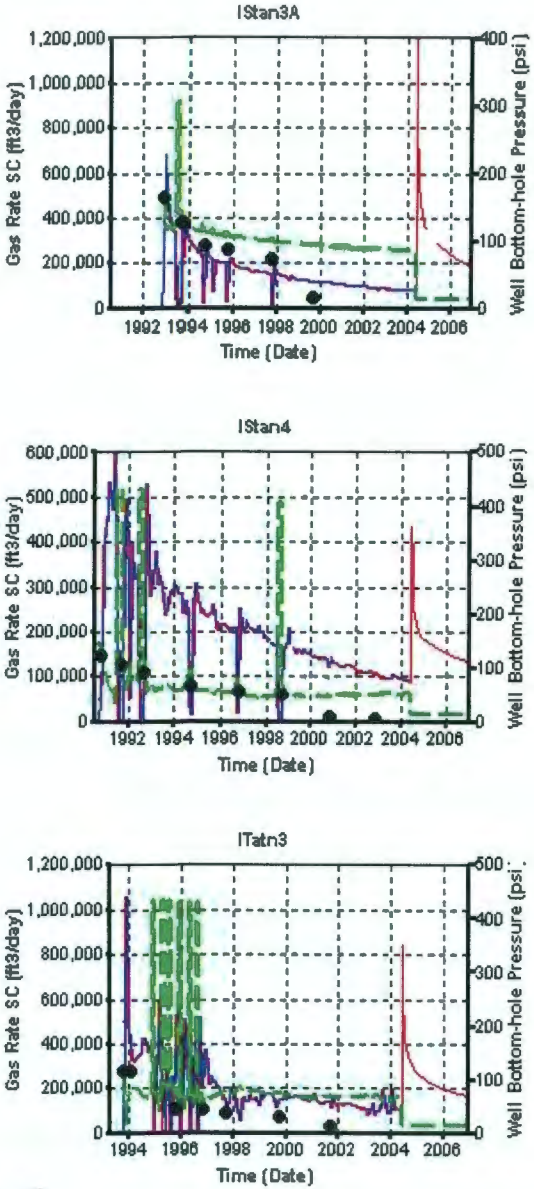


Production matched in most wells. However, production spikes visible in some wells.

Figure 41 **Blue – Historic gas prod** **Red – Simulator calculated gas prod** **Green – Sim BHFP** **Black – Historic FTHP**

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

Chase Infill well matches

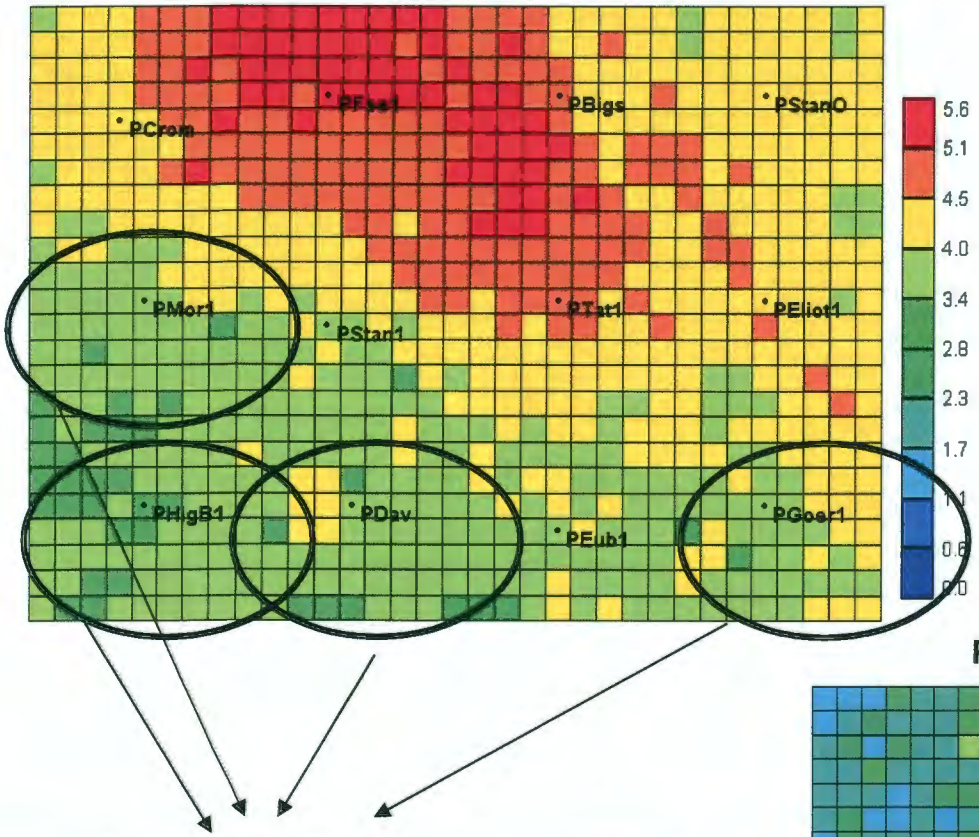


Production matched in most wells. Many wells do show a production spike when released from rate constraints indicating presence of excess flow capacity.

Red – Simulator calculated gas prod **Green – Sim BHFP** **Black – Historic FTHP**

Figure 42

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1 and K*100 in L5 & L7 (shale)) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers



Gas per unit area in L8 – 3/1/1952

Chase infill wells where simulator calculated production failed to match historic volumes. Location of these wells indicate relatively lower OGIP and permeability distribution in respective drainage areas.

Permeability, md distribution in L8

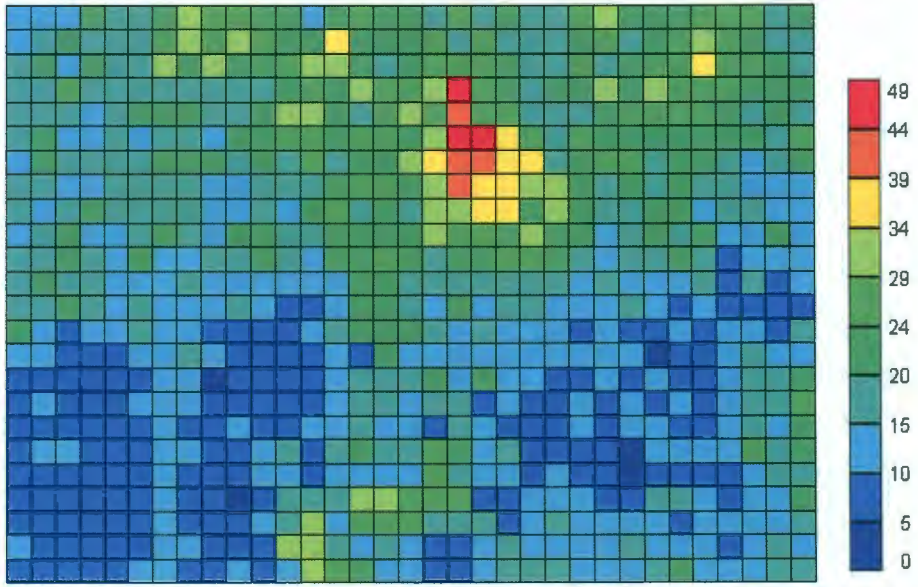
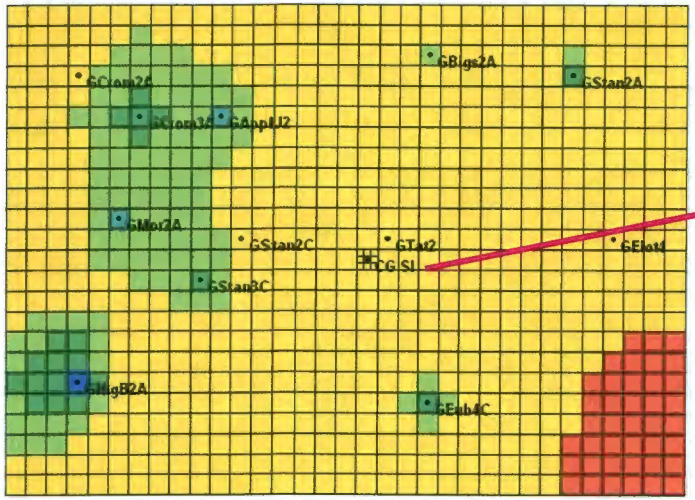
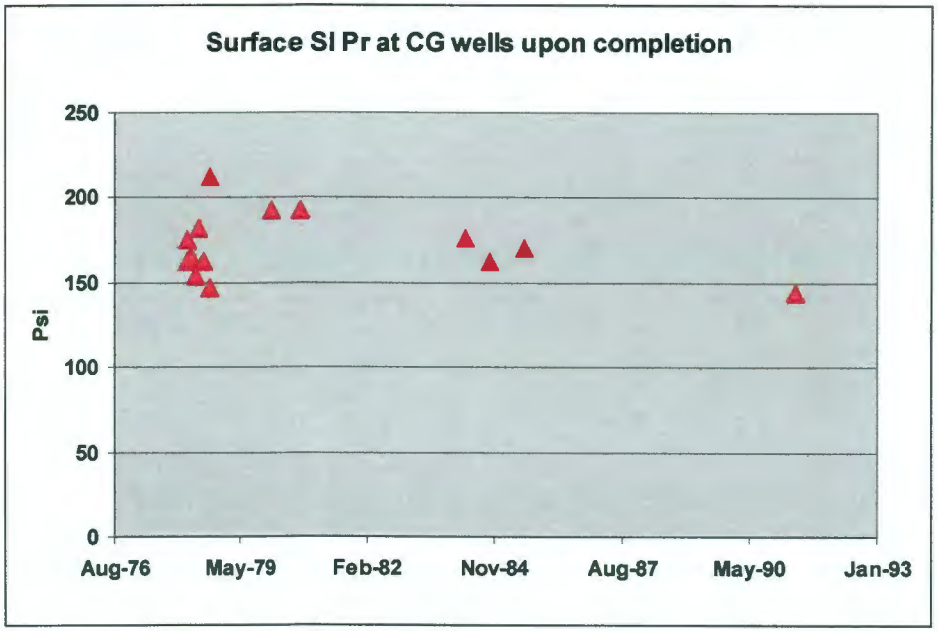


Figure 43

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers







Chase Parent wells - Gas production matched at all wells except those in the tight border areas.

Council Grove Wells - Production matched at all wells except those in tight border areas.

SI pr at hypothetical CG well in 1978 = 200 psi.

Figure 44

RUN 10: Chase Parent wells - Frac to L8, ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1 and K*100 in L5 & L7 (shale)) Council Grove wells – Frac extended to L8, ff = 6.0 and original K multipliers

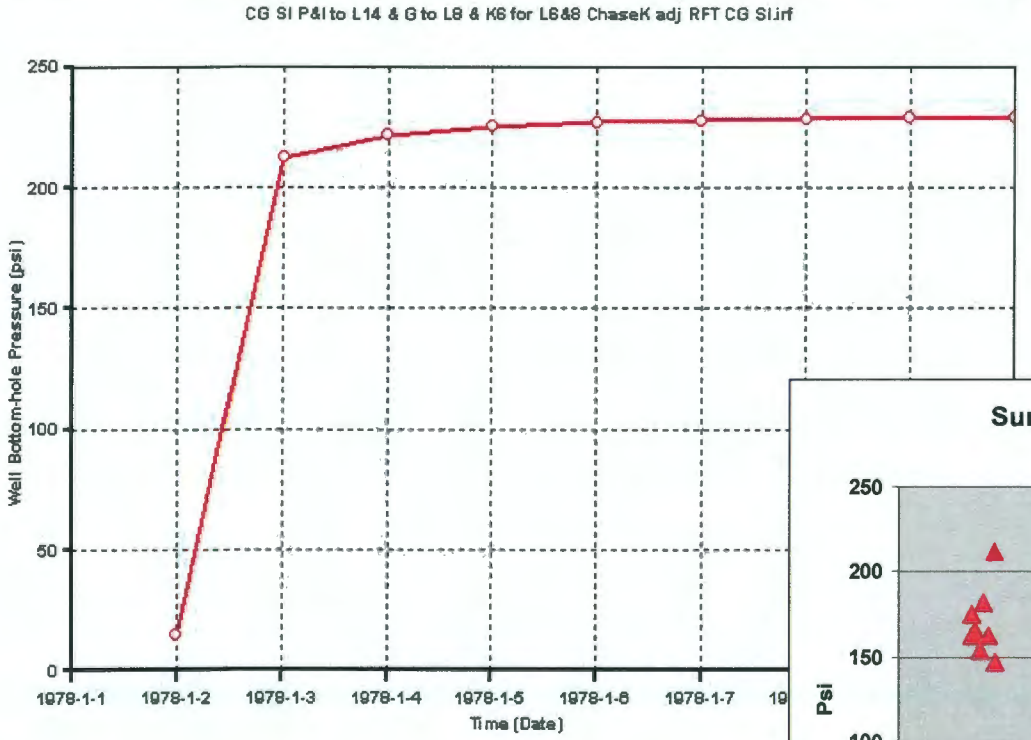
		Dec-04			
Formation	Layer #	Run 10 - PV Avg Pr	RFT, psi	Best Guess	*COMMENTS*
HRNGTN	1	397	78	78	May be low; 107, 379, 500 in other wells
KRIDER	2	326		300	Not tested; low k in area; 64, 167 in other wells
ODELL	3	339		400	Silt-shale; should be high
WINF	4	250	107	107	May be high; 18,68,72 in other wells
GAGE	5	225		400	Silt-shale; should be high
TWND	6	115	74	74	Okay; 10, 40, 71, 95, in other wells
B/TWND	7	149		400	Silt-shale; should be high
FTRLY	8	79	110	110-200	May be low; 140, 160, 215, 286 in other wells
L/FTRLY	9			200-300	
FLRNC	10	281	99	99	70 in one other well, mostly shale
WREFORD	11	285	407	200	Too high; 76 in one other well
A1_SH	12	314		400	Silt-shale; should be high
A1_LM	13	259	438	<100	Too high; tight test?
A1_LM	13		442	<100	Too high; tight test?
A1_LM	13		591	<100	Too high; tight test?
B1_SH	14			400	Silt-shale; should be high
B1_LM	15	410	526	Not perfd	Too high; tight test?
B1_LM	15		750	Not perfd	Too high; tight test?
	16			Not perfd	Silt-shale; should be high
B2_LM	17	434	649	Not perfd	Too high; tight test?

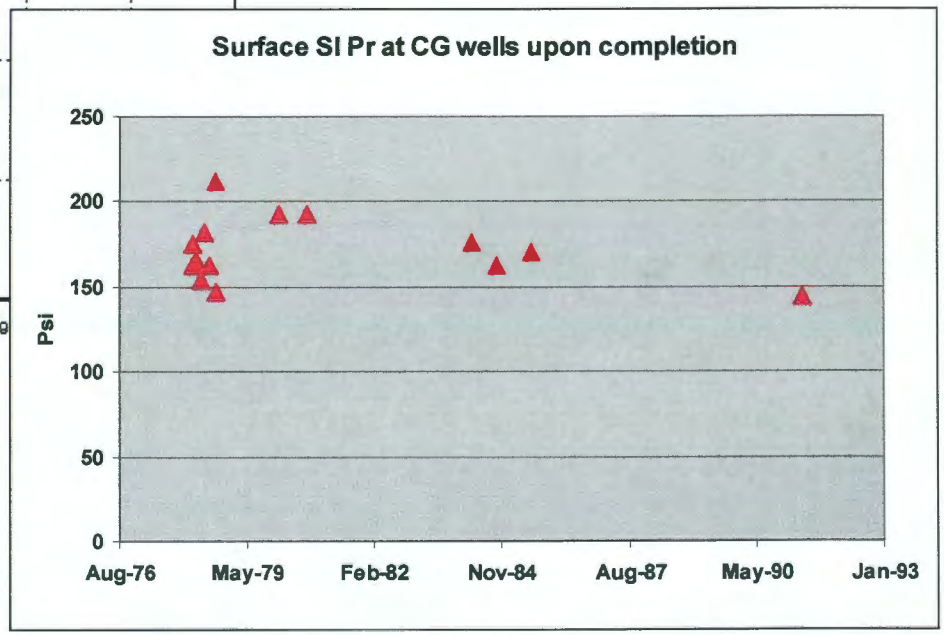
It is difficult to make a best estimate of layer pressure from RFT data as the date from the available 5 wells (1 within the study area and 4 from around the study area) show significant variation within each layers.

Figure 45

RUN 11: Chase parent wells - Frac to L14 and ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1). Council Grove wells – Frac extended to L8, ff = 6, and original K multipliers in pay.

Shut-in pressure at hypothetical Council Grove well – Jan 1978





Shut in pressure stabilizes around 225 psi and is close to that historically recorded at the surface when Council Grove wells came online in the study area.

Figure 46

RUN 11: Chase parent wells - Frac to L14 and ff = 6.0, K*2 in L6&8. Perm modifications in other Chase layers (K*6 in L1). Council Grove wells – Frac extended to L8, ff = 6, and original K multipliers in pay.

Comparison of Layer Pressures – Run 10 & 11 vs. RFT (best estimates)

		Dec-04	Dec-04			
Formation	Layer #	Run 10 - PV Avg Pr	Run 11 - PV Avg Pr	RFT, psi	Best Guess	*COMMENTS*
HRNGTN	1	397	400	78	78	May be low; 107, 379, 500 in other wells
KRIDER	2	326			300	Not tested; low k in area; 64, 167 in other wells
ODELL	3	339			400	Silt-shale; should be high
WINF	4	250	261	107	107	May be high; 18,68,72 in other wells
GAGE	5	225			400	Silt-shale; should be high
TWND	6	115	131	74	74	Okay; 10, 40, 71, 95, in other wells
B/TWND	7	149			400	Silt-shale; should be high
FTRLY	8	79	89	110	110-200	May be low; 140, 160, 215, 286 in other wells
L/FTRLY	9				200-300	
FLRNC	10	281	234	99	99	70 in one other well, mostly shale
WREFORD	11	285	225	407	200	Too high; 76 in one other well
A1_SH	12	314			400	Silt-shale; should be high
A1_LM	13	259	149	438	<100	Too high; tight test?
A1_LM	13			442	<100	Too high; tight test?
A1_LM	13			591	<100	Too high; tight test?
B1_SH	14				400	Silt-shale; should be high
B1_LM	15	410		526	Not perfd	Too high; tight test?
B1_LM	15			750	Not perfd	Too high; tight test?
	16				Not perfd	Silt-shale; should be high
B2_LM	17	434		649	Not perfd	Too high; tight test?

Figure 47