KANSAS GEOLOGICAL SURVEY
OPEN-FILE REPORT 2002-68

RESERVOIR SIMULATION OF WELLINGTON WEST FIELD,
SUMNER COUNTY, KANSAS,
TO DESIGN AN EFFECTIVE WATERFLOOD
(DOE Contract #IND 27960)

by

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Alan P. Byrnes

Disclaimer

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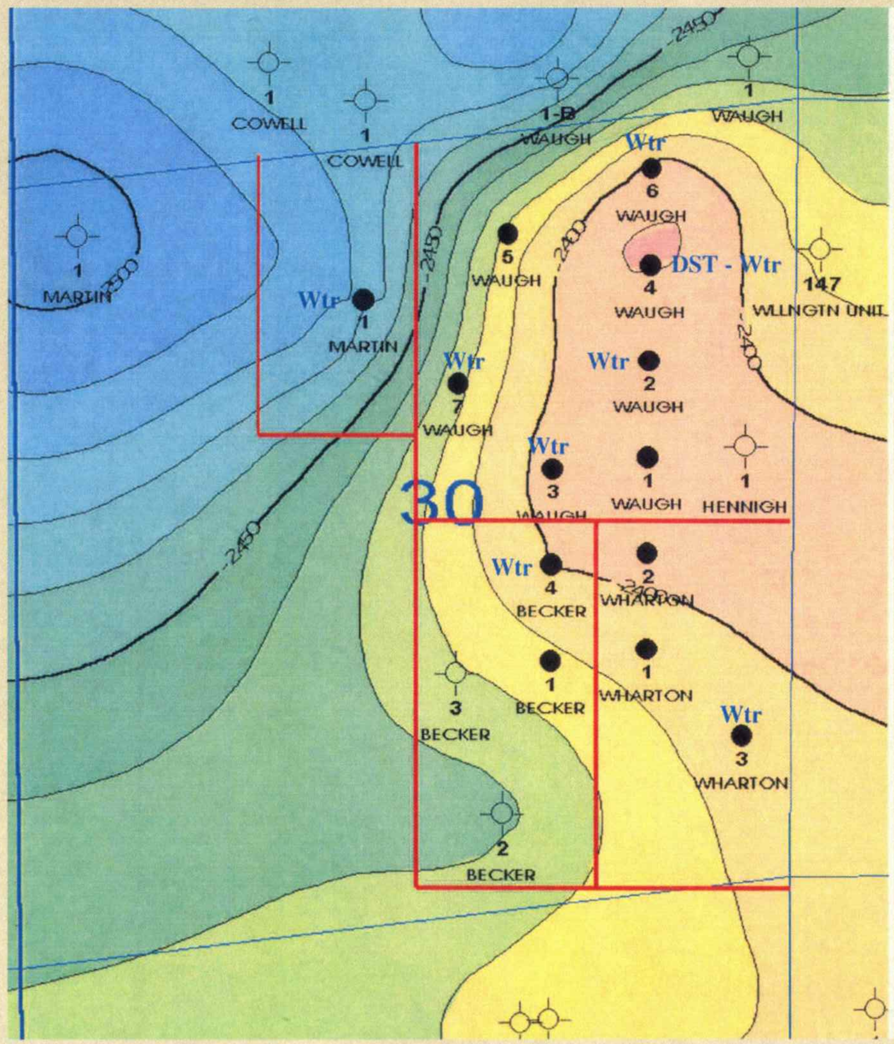
Wellington West Field – Sumner County, KS

Well locations and lease boundaries



Lease boundaries marked by red lines

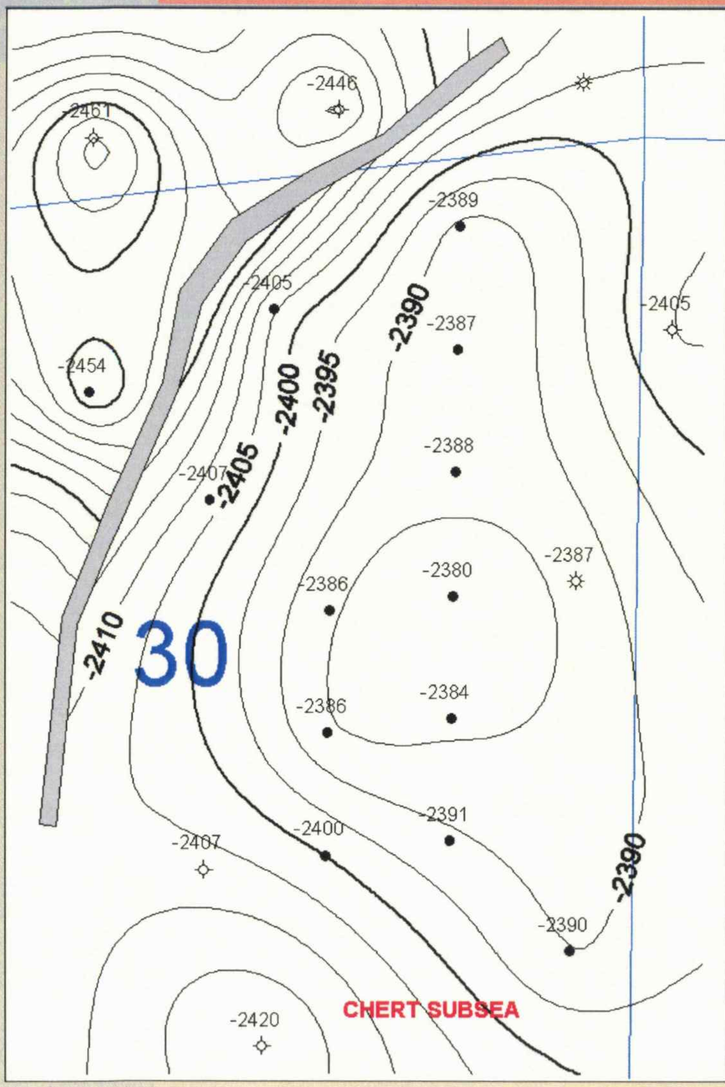
Model Construct
Geologic layering of the reservoir

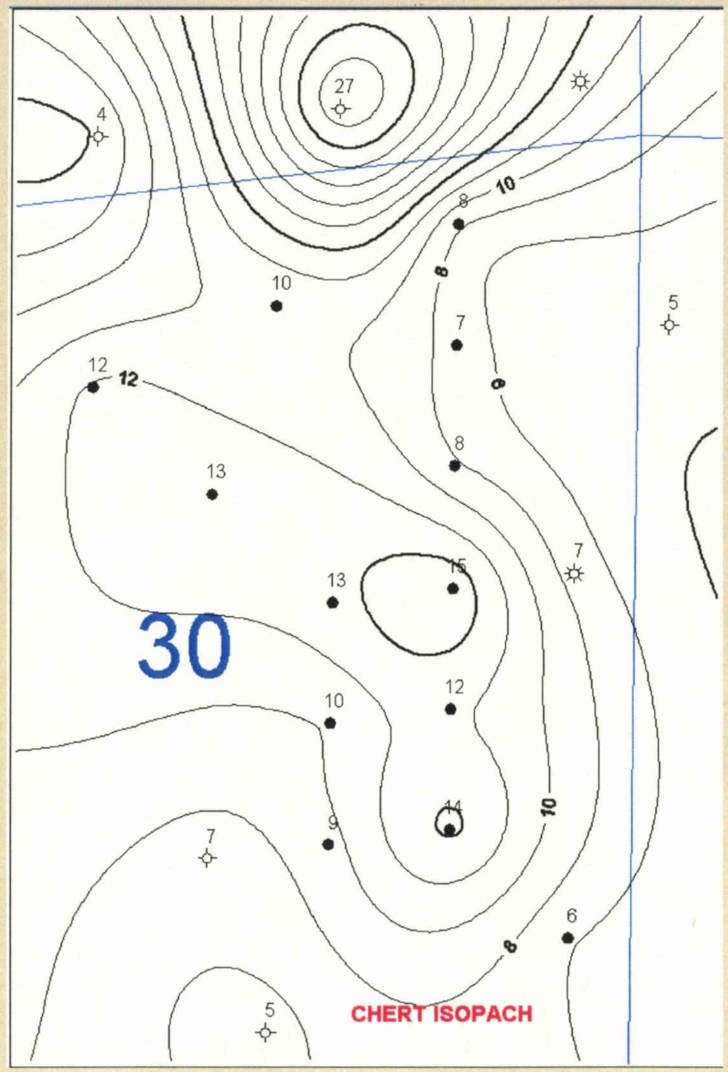
- Layers identified (top to bottom)
  - Chert – low permeability*
  - Argillaceous dolomite – permeability barrier* (from core plug measurements)
  - Dolomite
  - Limy Dolomite
- Layers modeled – 4 layer model
  - Dolomite Layer 1
  - Dolomite Layer 2
  - Dolomite Layer 3
  - Limy Dolomite

The dolomite reservoir was modeled as 3 layers in the simulation study.

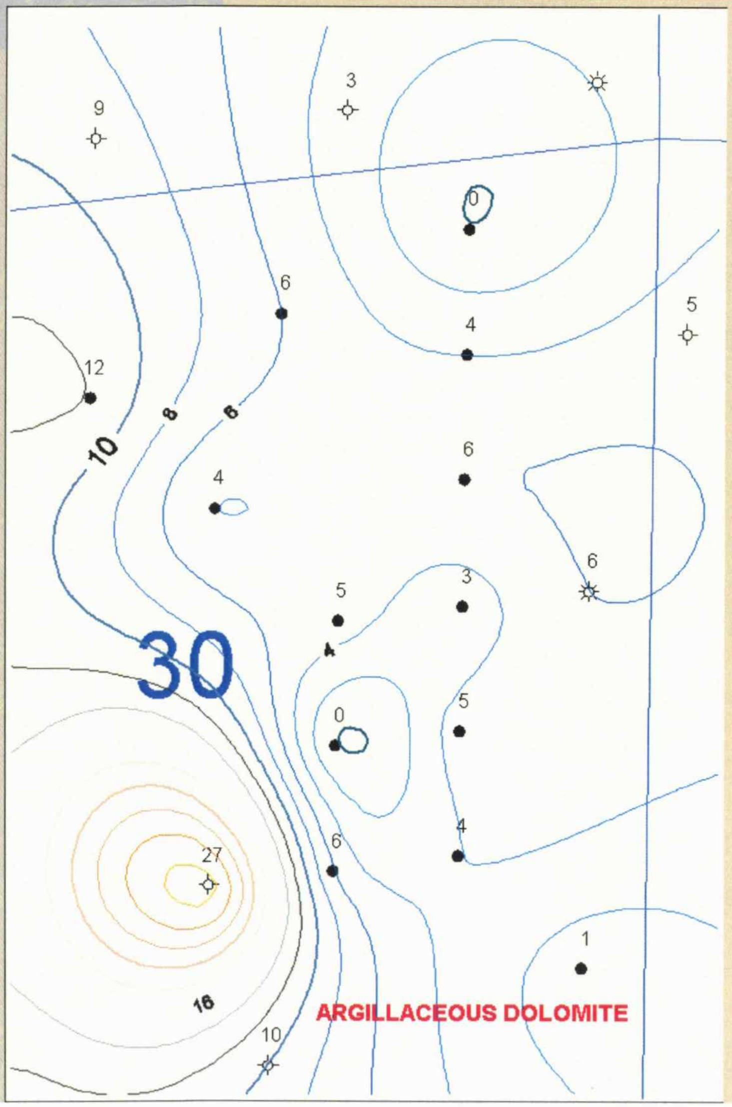
*Core analysis on plugs from well in a neighboring field

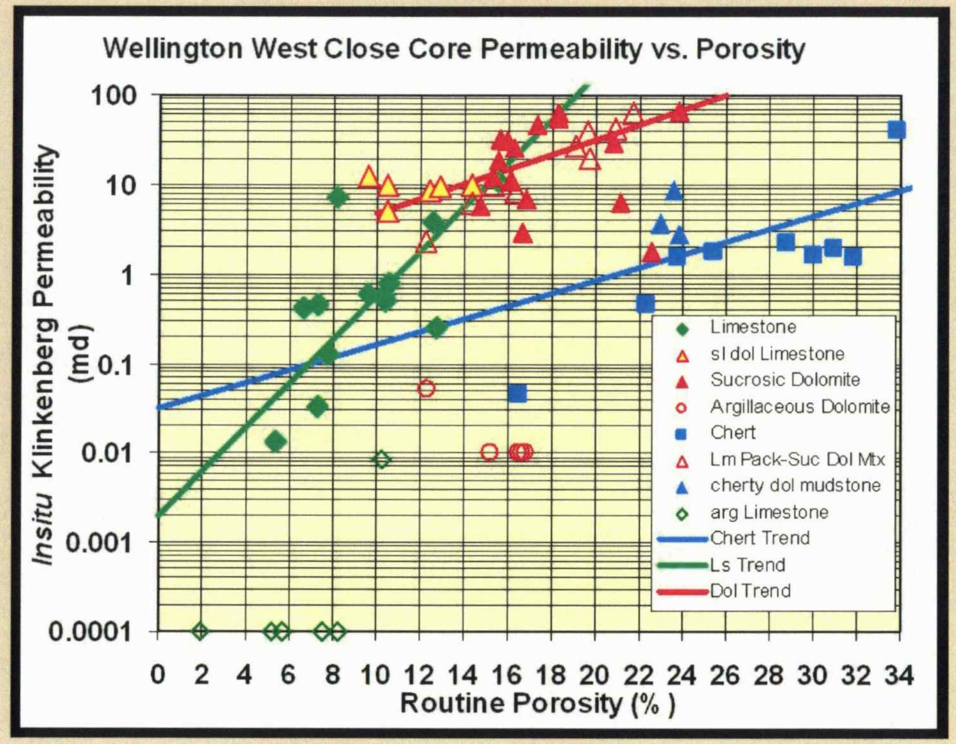
Top layer - Chert





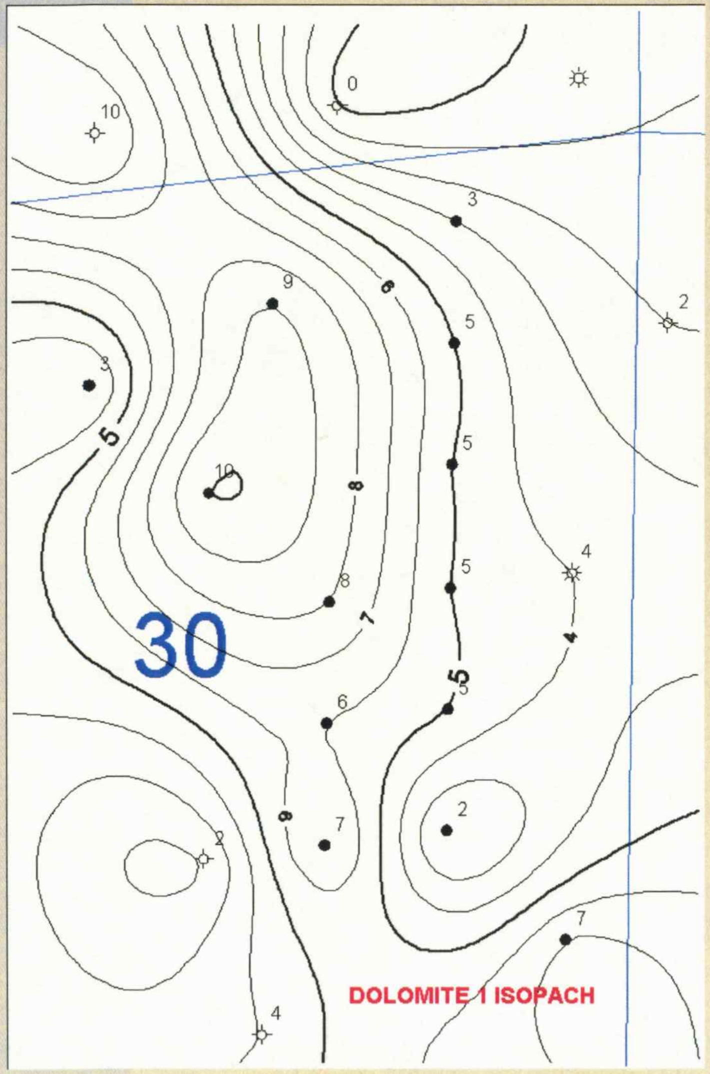
Argillaceous dolomite

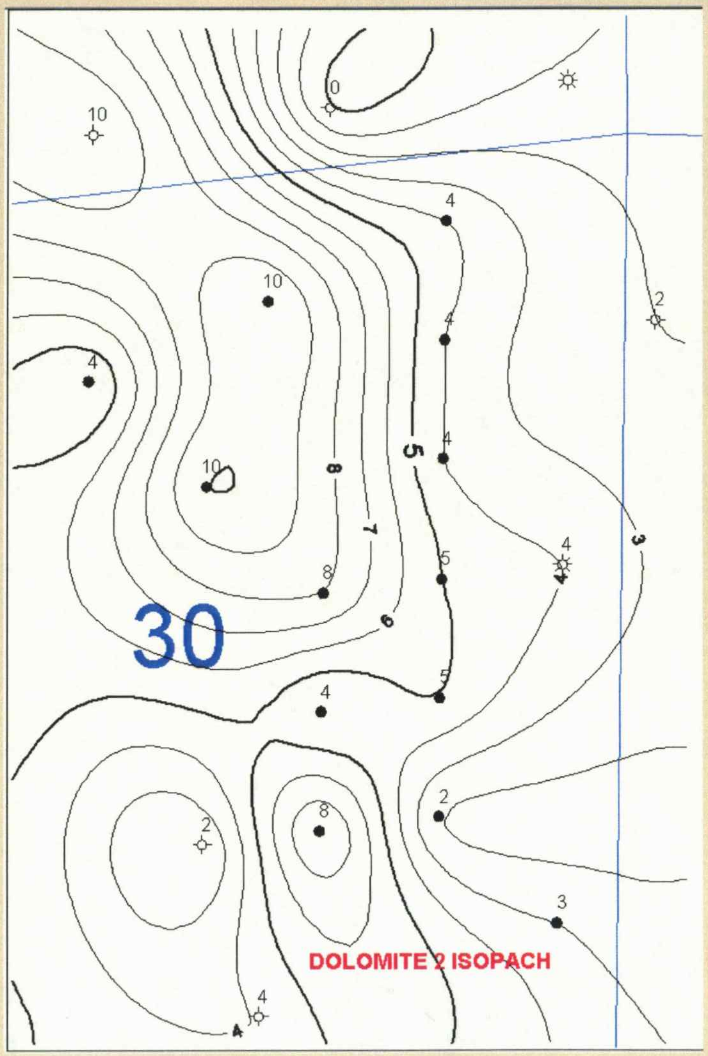




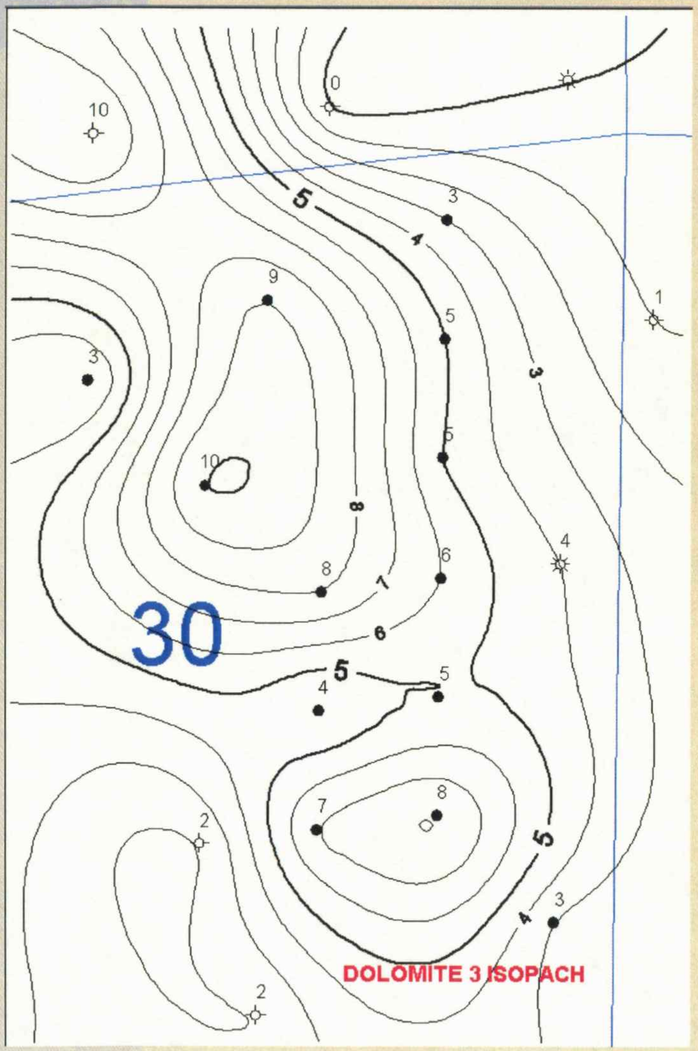
Core plug analyses (red circles) indicate that permeability in Argillaceous dolomite is so low that it is reasonable to consider it as a permeability barrier.

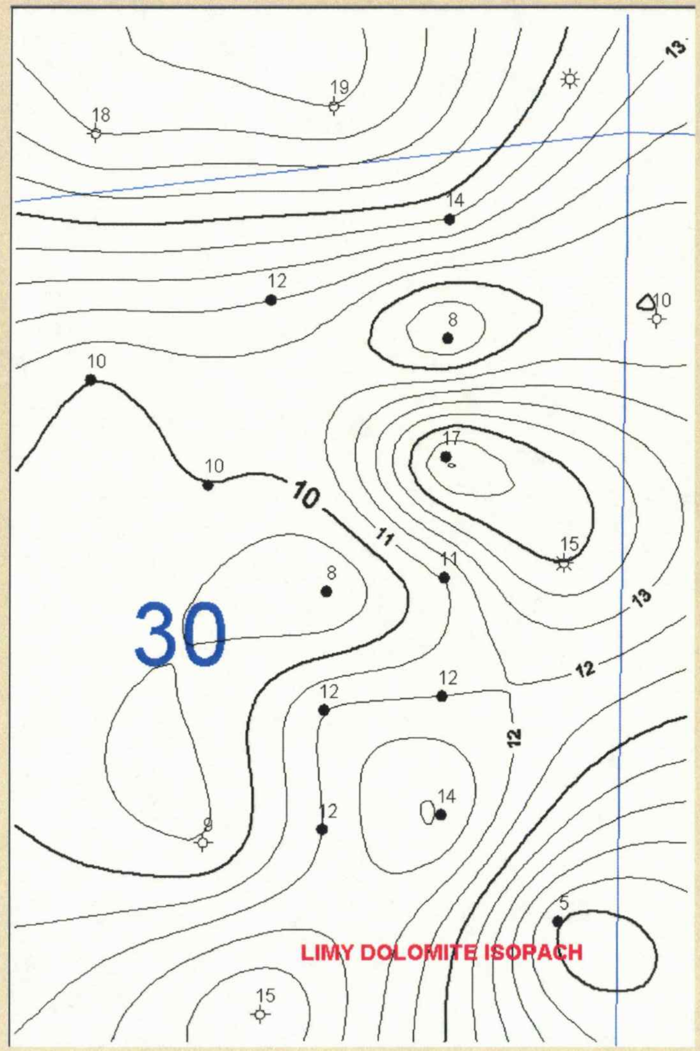
Isopach of dolomite layers 1 & 2





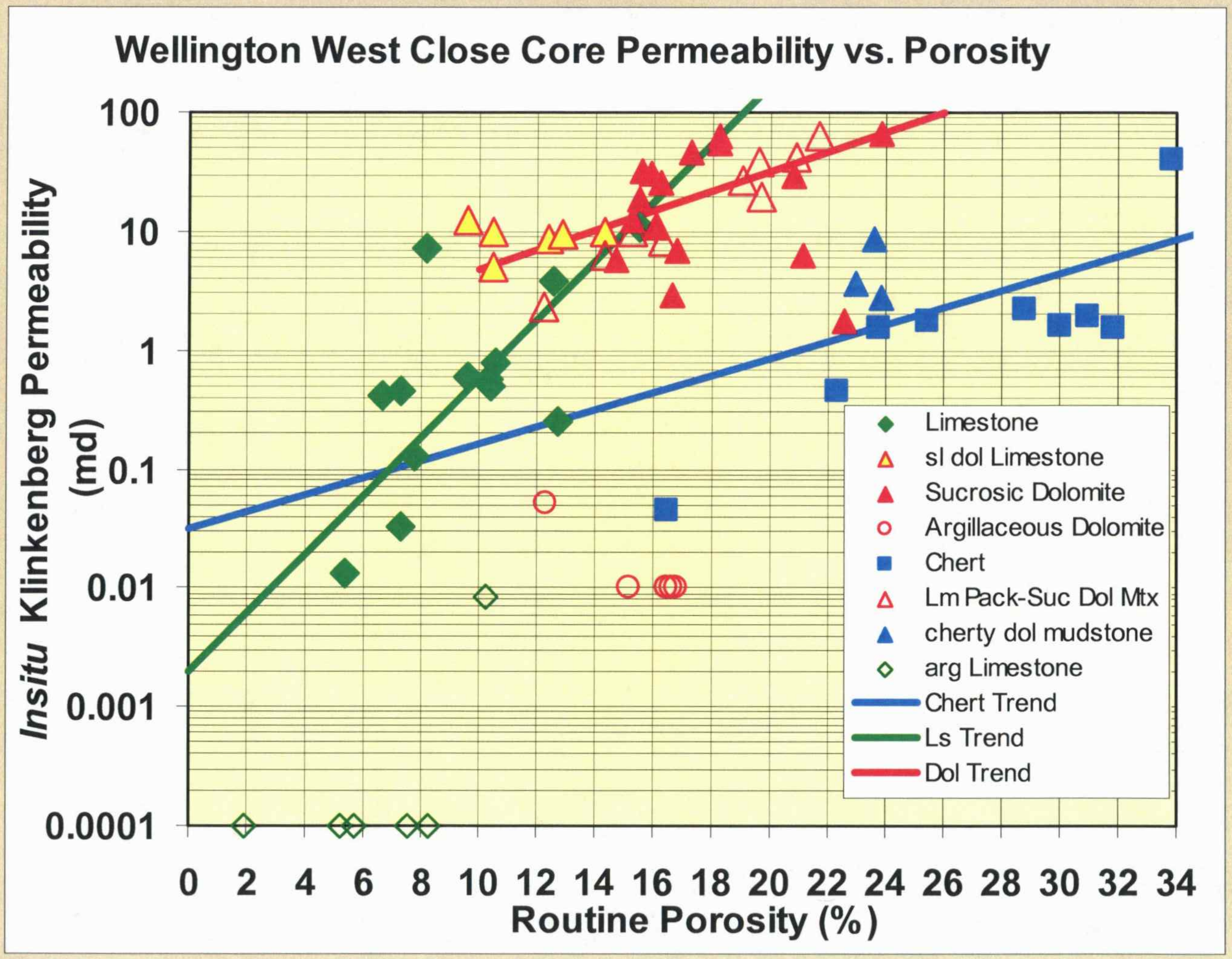
Isopach of dolomite 3 and Limy dolomite





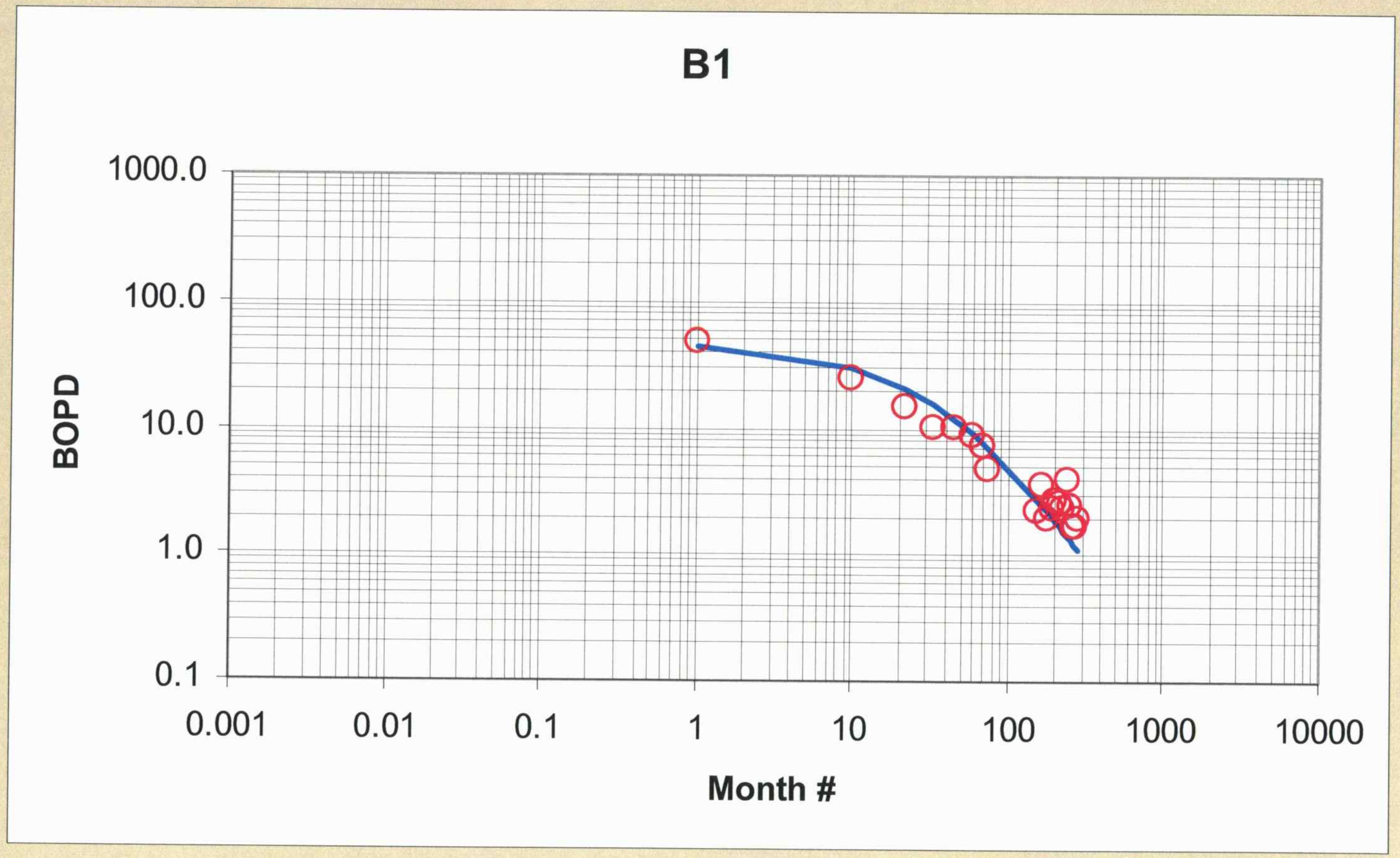
Core analysis

No core was available from Wellington west field. Core from an adjacent Mississippian field was used for routine and special analyses. Different permeability-porosity trends were visible for different rock types. The primary reservoir is represented by the dolomitic trend.

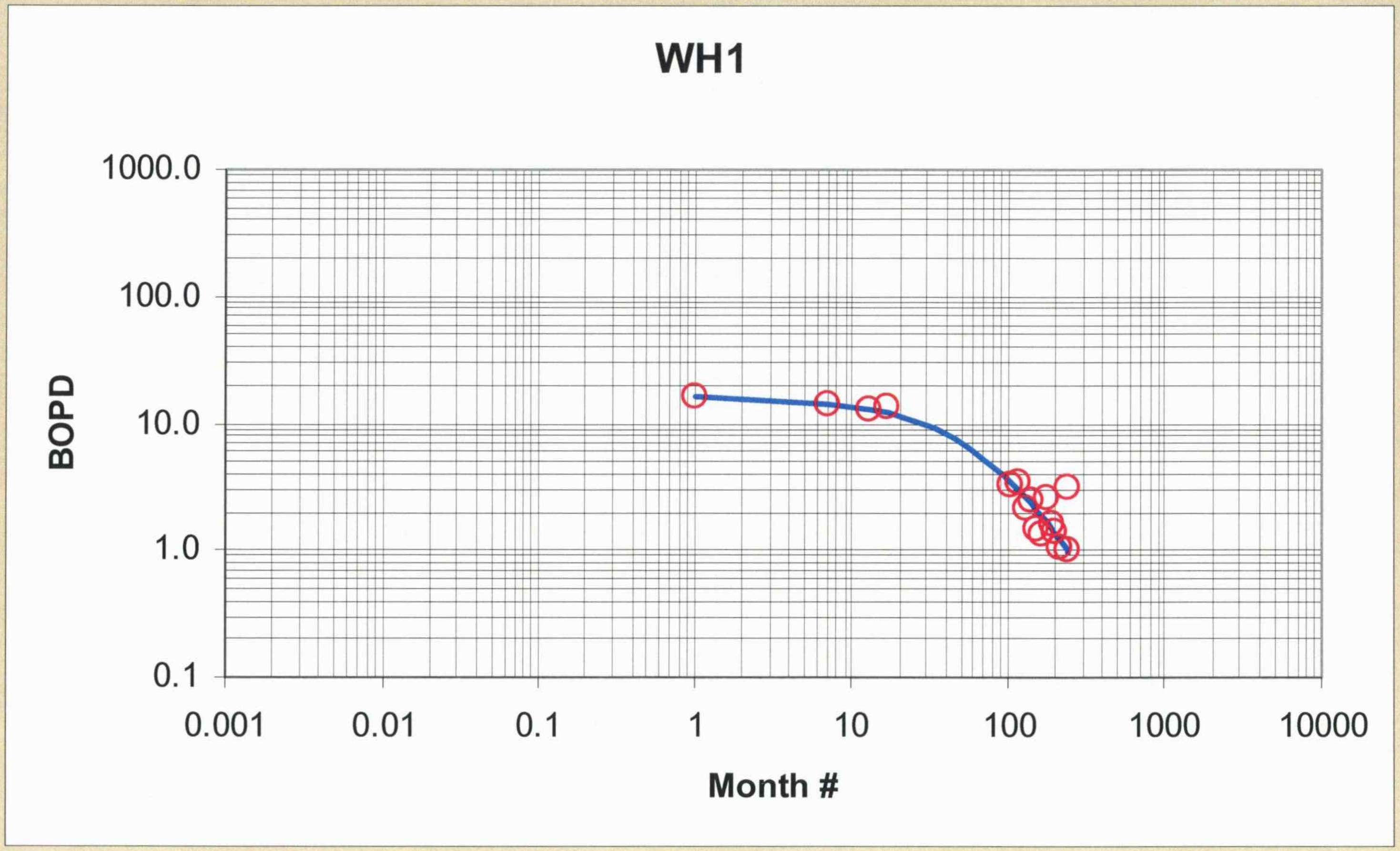


Decline Curve Analysis
Well Becker #1

Limited production data was available. For most wells, initial oil production rates were available along with annual well test results from 1989. Decline curve analysis was used to estimate the annual average oil rates for the years for which no data was available



Decline Curve Analysis
Well Wharton #1



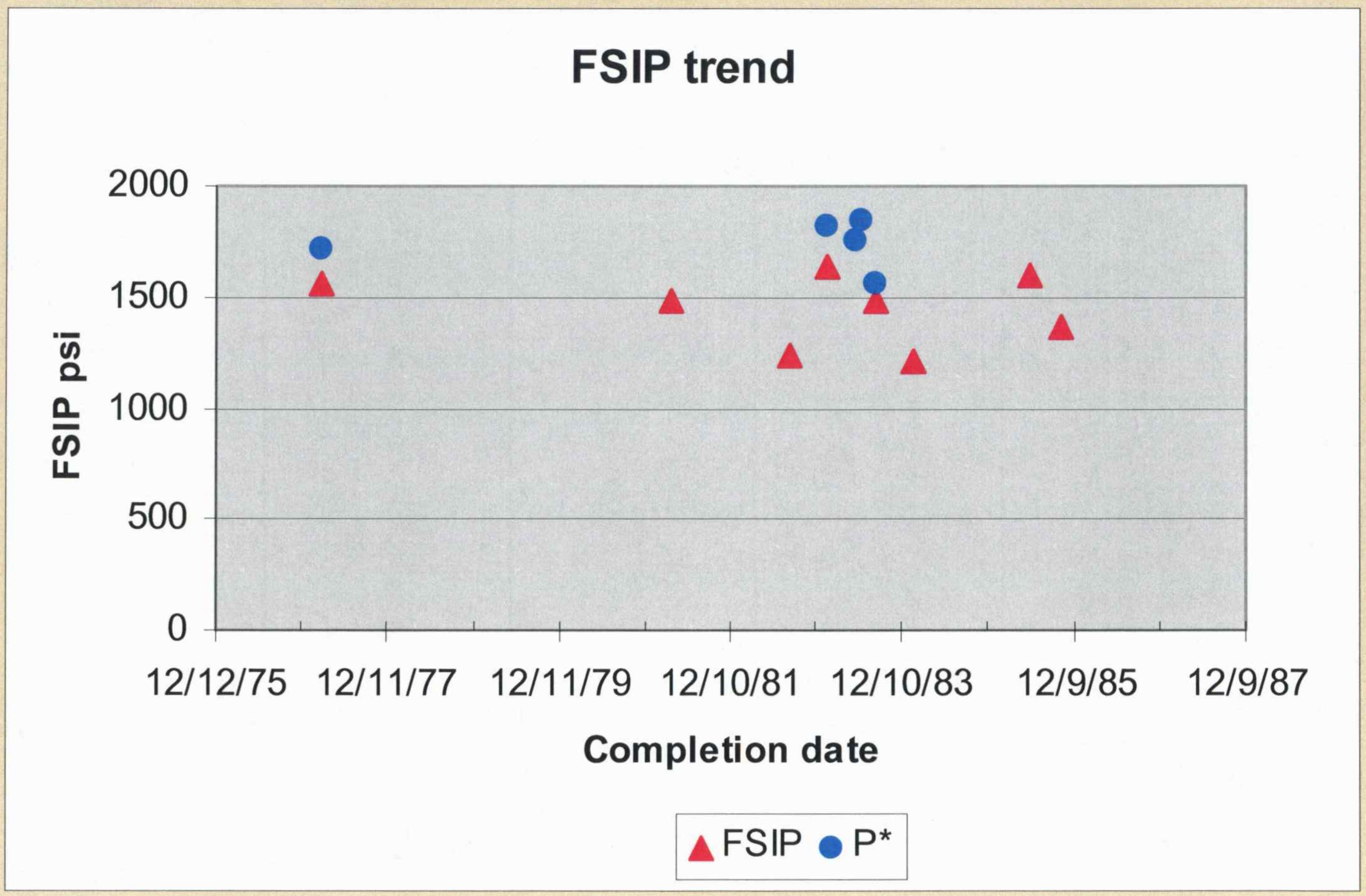
Well level production history

Year	M1 Oil	M1 Wtr	WH3 Oil	WH3 Wtr	WH2 Oil	WH2 Wtr	WH1 Oil	WH1 Wtr	W5 Oil	W5 Wtr	W4 Oil	W4 Wtr	W3 Oil	W3 Wtr	W2 Oil	W2 Wtr (fr W4)
1977																
1978																
1979																
1980																
1981							3848.0									
1982					2112.2		4506.6									
1983					4672.6		3359.4		2994.3		1767.8		1418.976		5631.4	
1984					2845.9		2782.0		6929.8		4636.7		2631.926		7195.8	
1985	204.0		1743.9		2142.7		2330.9		5741.1		4057.2		1863.283		5898.6	
1986	702.0		2176.4		1607.0		1973.2		4819.4		3577.0		1375.666		4906.6	
1987	692.0		2538.3		1252.6		1685.8		4092.3		3175.1		1049.595		4133.4	
1988	676.7		2003.3		998.6		1452.1		3510.0		2835.5		822.2654		3520.5	
1989	720.0	2880.0	1503.5	3006.9	1202.8	3608.3	1202.8	2405.5	4088.0	1387.0	1022.0	2628.0	547.5	5657.5	2299.5	5913.0
1990	501.1	2282.7	759.1	1973.7	1214.6	1821.9	1275.3	3279.4	2117.0	2628.0	2920.0	4380.0	474.5	6460.5	1825.0	2737.5
1991	490.7	3761.7	1543.7	5072.0	617.5	2469.9	793.9	4498.7	2755.8	6916.8	3102.5	8376.8	511	8249	1460.0	3942.0
1992	527.6	4044.9	1201.2	4805.0	843.4	3373.7	907.3	2888.1	2701.0	5706.2	1216.7	8516.7			1606.0	11242.0
1993	503.6	3860.9	1231.9	3762.2	1298.4	3029.7	532.7	2463.7	1825.0	6205.0	2445.5	11059.5			1423.5	6437.6
1994	458.8	3517.5	418.4	1954.1	1686.1	3349.6	498.6	1994.2	2357.3	6676.5	1822.0	6329.7			1861.5	6467.1
1995	422.4	3238.7	267.6	1070.4	883.1	1792.9	963.3	4388.6	1460.0	4380.0	1576.8	7183.2			1460.0	6651.1
1996	302.2	2316.6	714.8	2294.9	1128.6	3385.9	601.9	2407.7	1715.5	5219.5	1387.0	7373.0			1204.5	6402.9
1997	297.9	2283.7	674.8	5103.2	844.5	2428.4	505.1	3131.4	1825.0	8614.0	609.6	6314.5			1525.7	15805.2
1998	251.0	1924.2	468.7	3544.5	841.9	4647.5	385.9	2392.5	1219.1	9741.9	613.2	8037.3			2131.6	27939.2
1999	322.3	2471.3	0.0	0.0	880.0	4857.6	0.0	0.0	912.5	9136.0	613.2	7884.0			2135.3	27453.2
2000	332.5	2548.9	450.9	3341.2	1392.3	4176.9	369.7	1254.7	741.0	3376.3	693.5	3376.3			1660.8	8085.2
2001	54.3	416.6	454.3	4122.9	1046.0	5268.1	1161.2	3560.9	388.8	1764.0	450.0	2241.0			388.8	1936.2

Well level oil production histories were estimated from lease production volumes and decline curve analysis. No water production data was available till 1989. The annual oil production (of some of the wells) is shown in green while the water production is shown in blue. These production rates were input to the reservoir simulator.

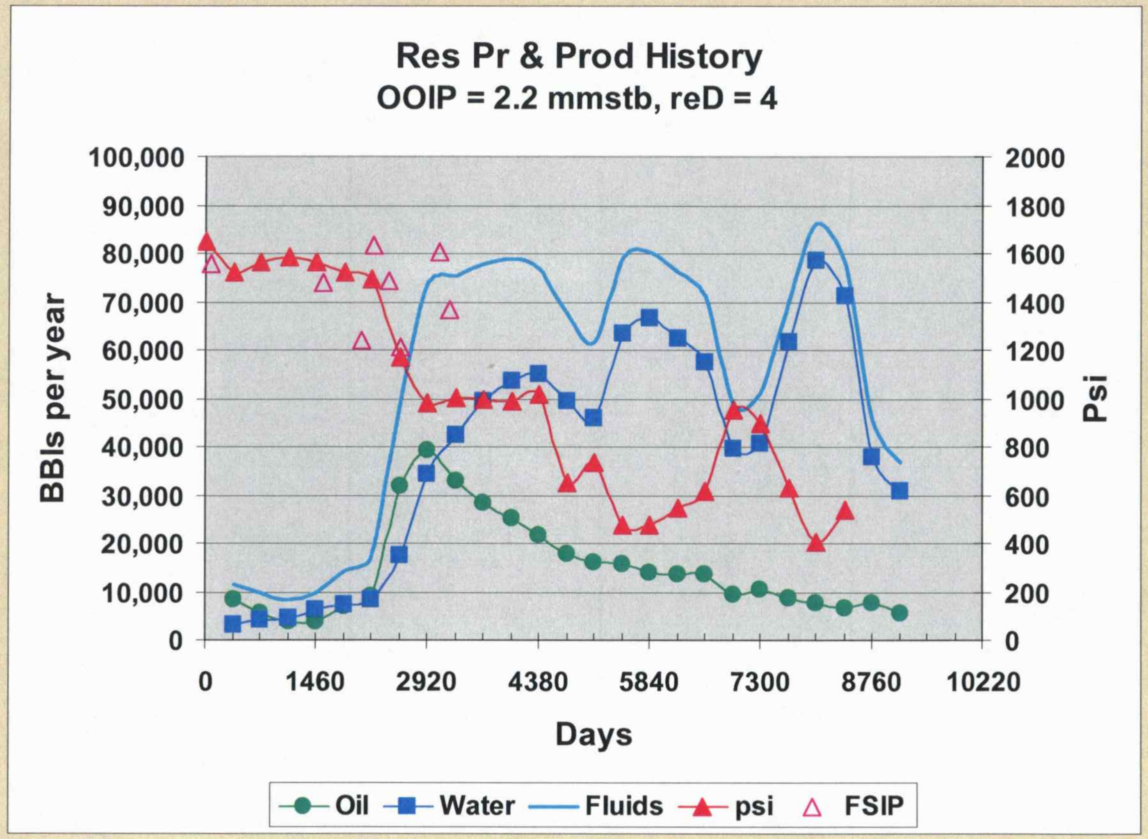
DST Analysis

DST data was available for 5 wells in the field. The initial reservoir pressure (Pi) was calculated from these tests and these values compared well with the shut-in pressures recorded in the scout cards.



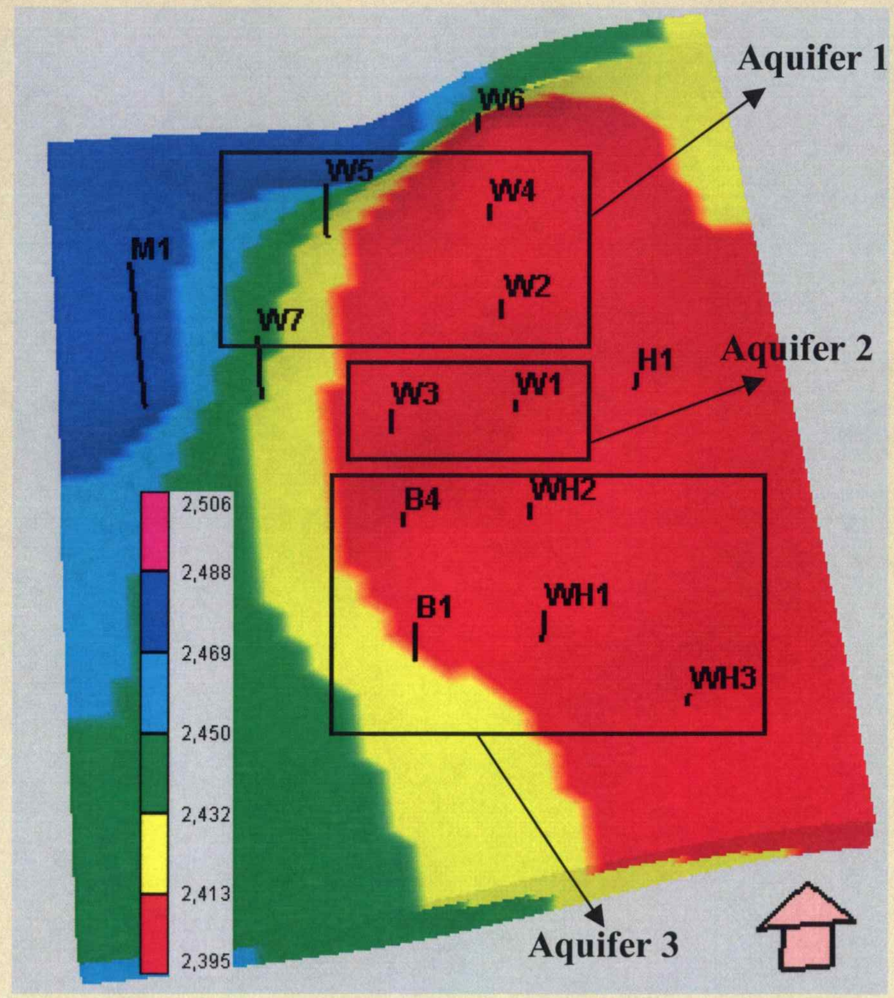
Material Balance Studies

Material balance (MB) calculations were carried out to confirm the reservoir drive mechanism and to estimate the volume of OOIP. Currently, producing wells are operating under pumped off conditions. Missing water production data was estimated by assuming water production to linearly increase from zero to the barrel test rate in 1989. The MB calculations indicate that a weak bottom water drive operates below most of the reservoir. Also, it provided an estimate of the OOIP (2.2 MMSTB) given the starting reservoir pressure and the current pumped off operating conditions. The MB OOIP estimate resulted in fine tuning the original reservoir geo-model. The pressure history, back calculated from MB, and marked in red triangles was found in conformance with the limited FSIP data (from DST) that was available.



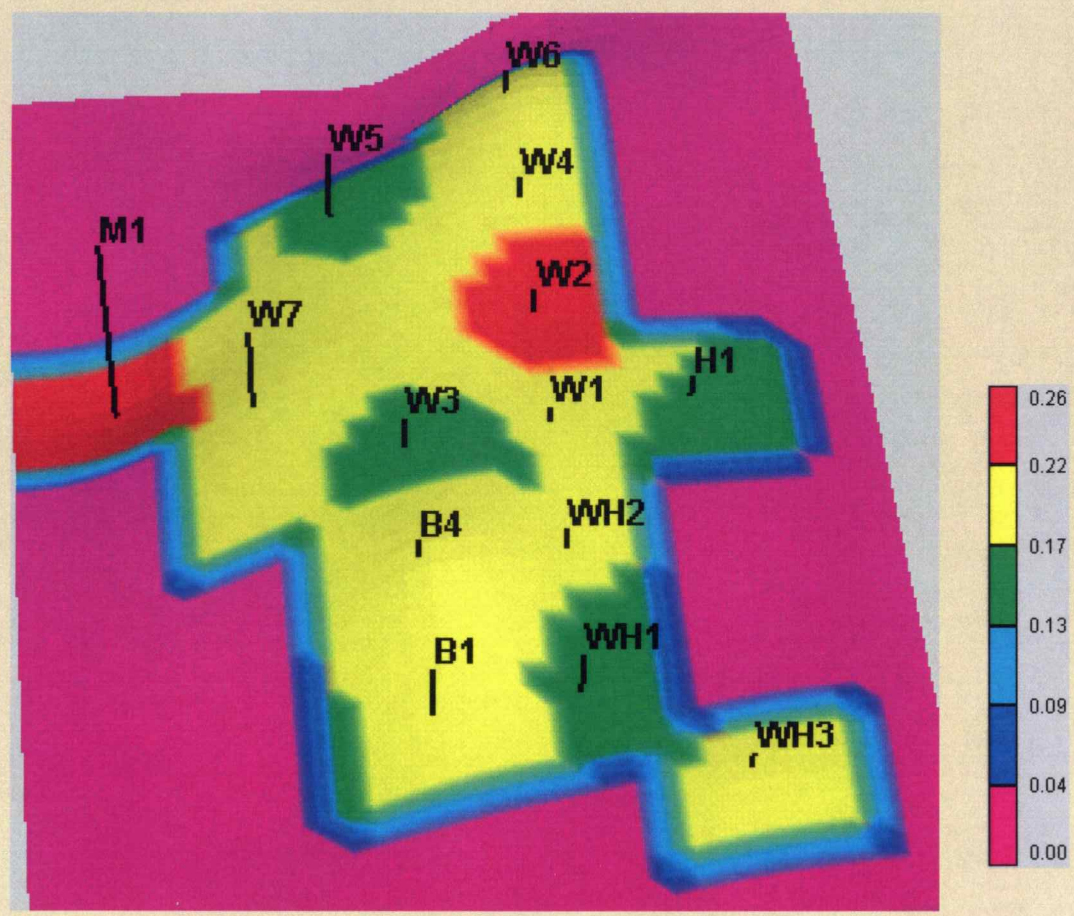
Reservoir model – Input to simulator
Structure map and aquifers

Wells W3 and W1 have been shut-in for almost a decade. Recent fluid-level measurements in these wells indicate that the bottom hole pressure is close to 1500 psi (close to initial reservoir pressure). This indicates that these 2 wells are charged by strong bottom water drives in contrast to rest of the field where all wells are producing under pumped off conditions and with near constant water production volumes. Thus, 3 separate aquifers were decribed in the reservoir model that was simulated. Aquifers 1 and 3 are weak aquifers while Aquifer 2 has been defined as a strong one.



Reservoir model – Input to simulator

Porosity map



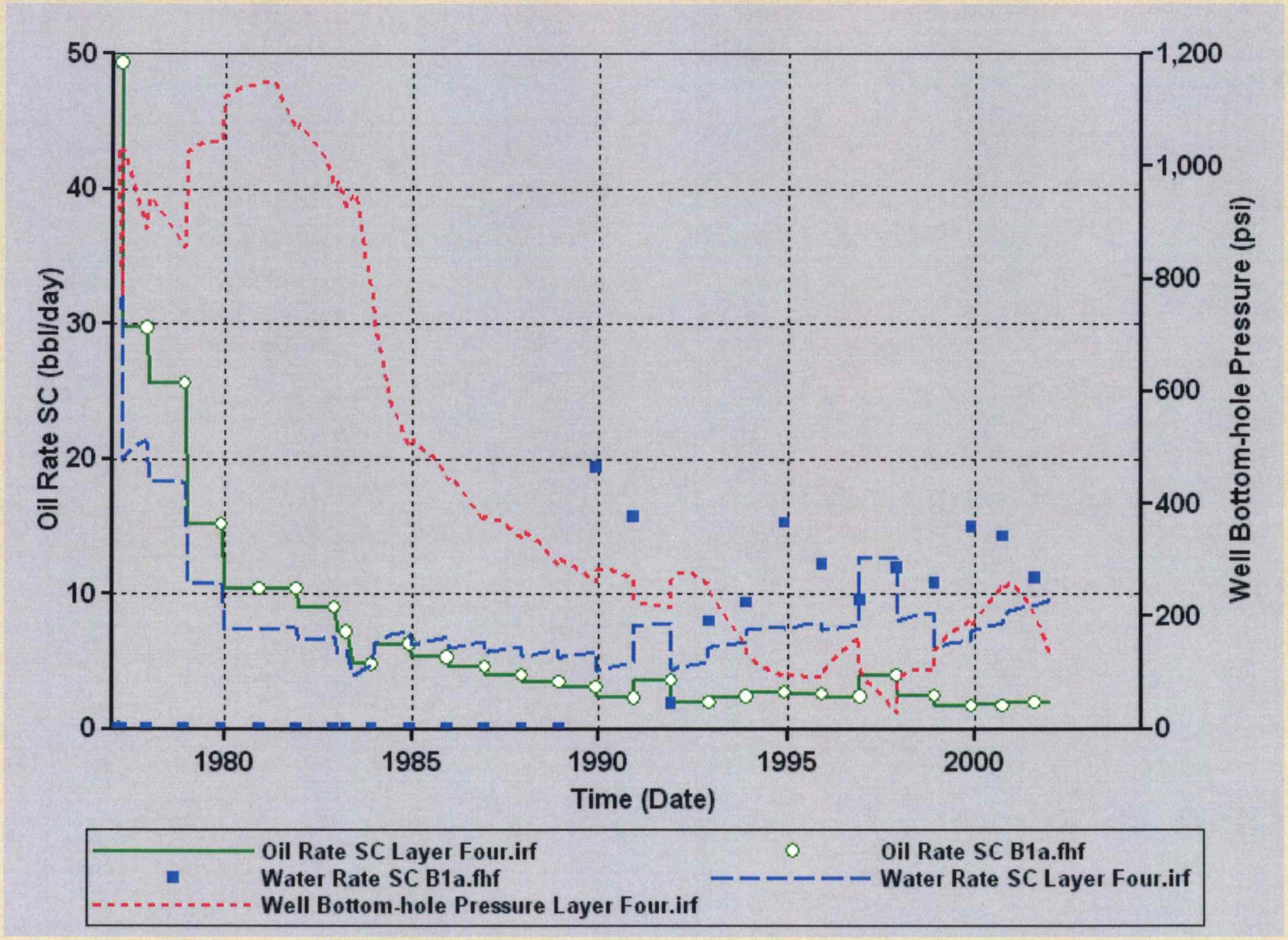
Reservoir model
History match

- Input
  - Well oil production history (Qo)
  - Minimum flowing bottom hole pressure (FBHP) = 30 psi
- Outputs
  - Water production rate (Qw)
  - FBHP required to match oil production history
- Match details
  - Permeability, capillary pressure and relative permeability fine tuned during history matching.

NOTE: In the succeeding slides, showing the final matches at the well level, the oil and water production histories are shown by green circles and blue squares. The simulation output of oil and water production are shown by green and blue lines. The simulated bottom-hole flowing pressure is shown by broken red line. Water production history was unavailable before 1989.

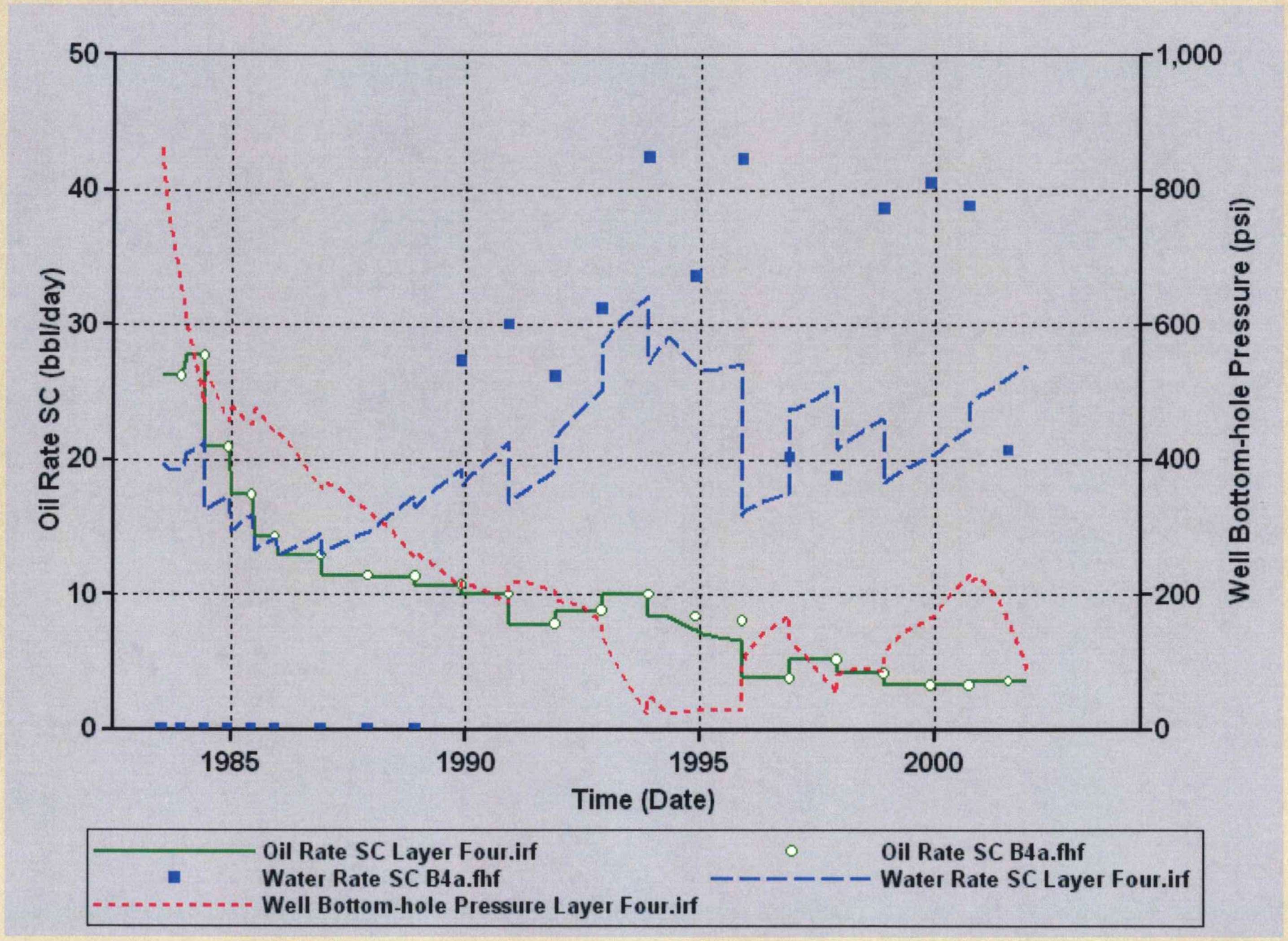
History matches

Becker #1 (B1)



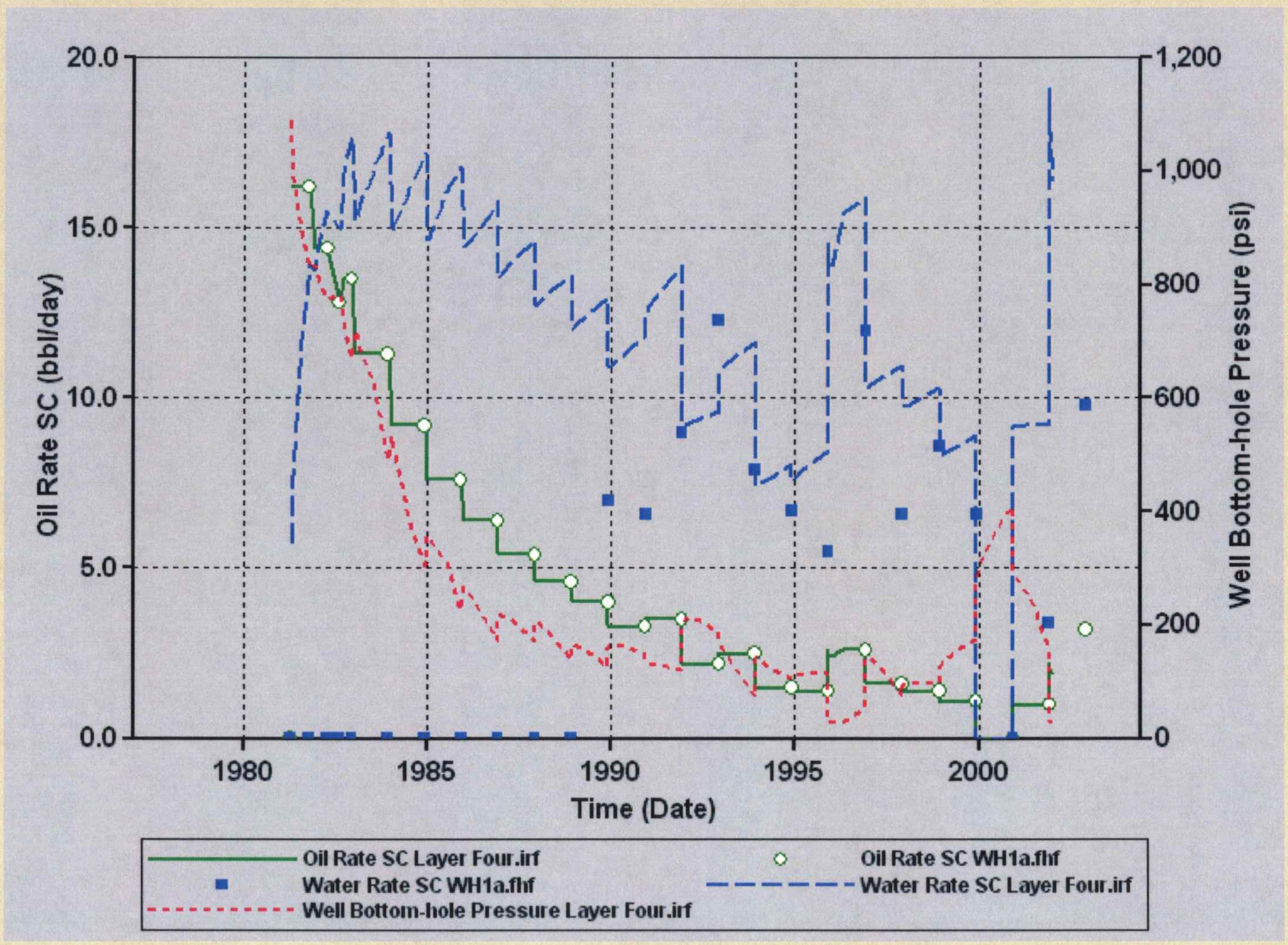
History matches

Becker #4 (B4)



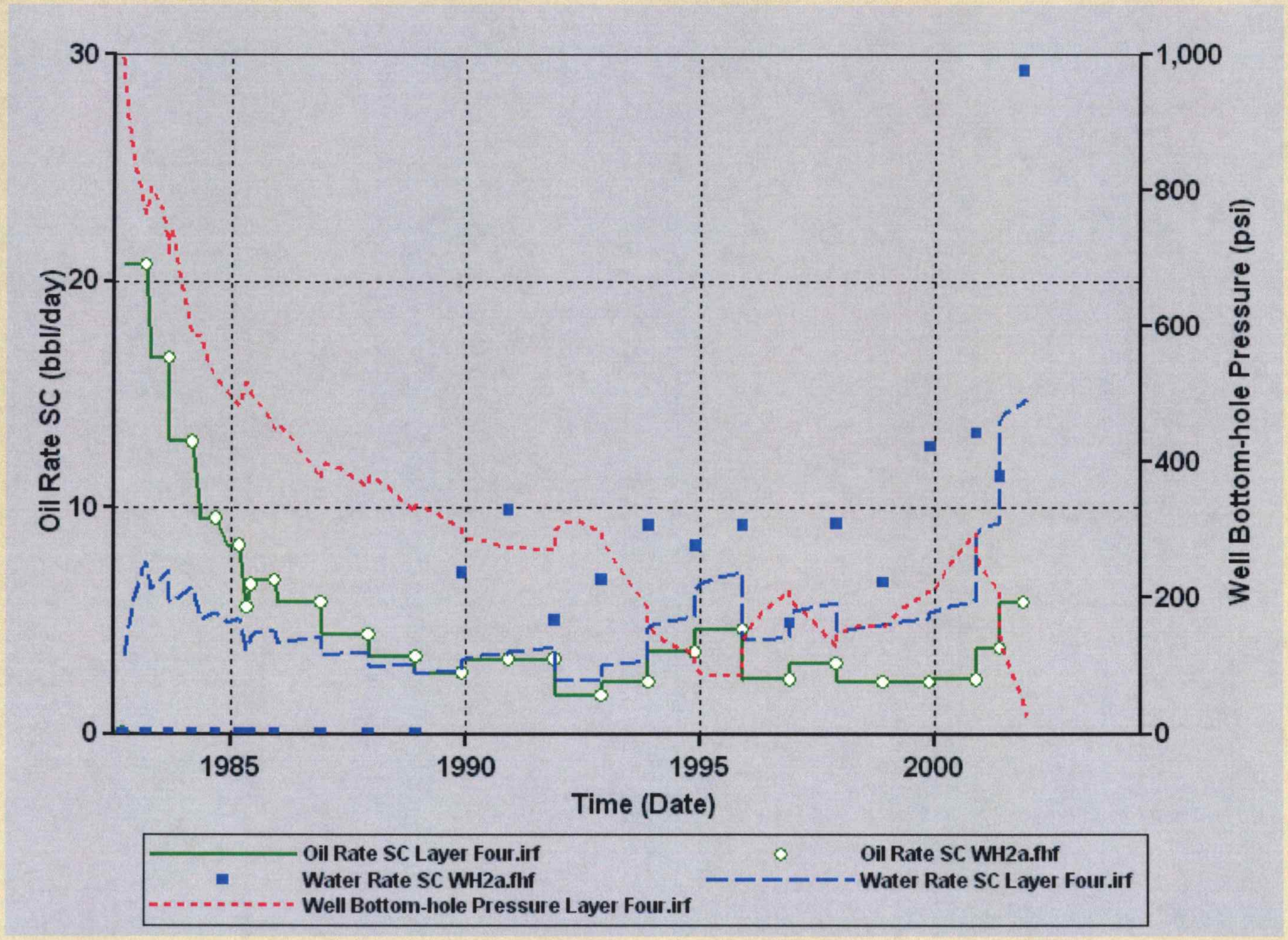
History matches

Wharton #1 (WH1)



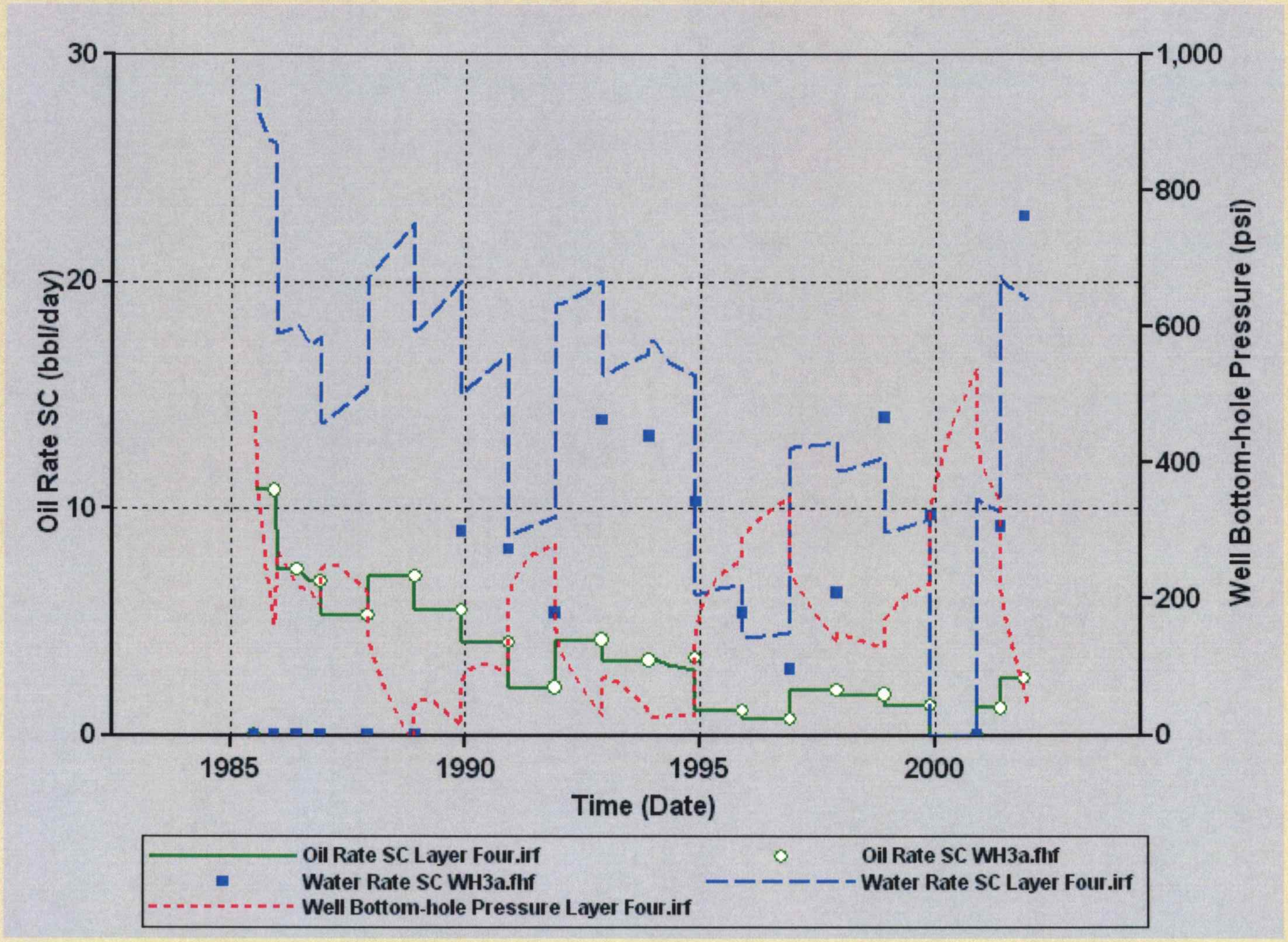
History matches

Wharton #2 (WH2)



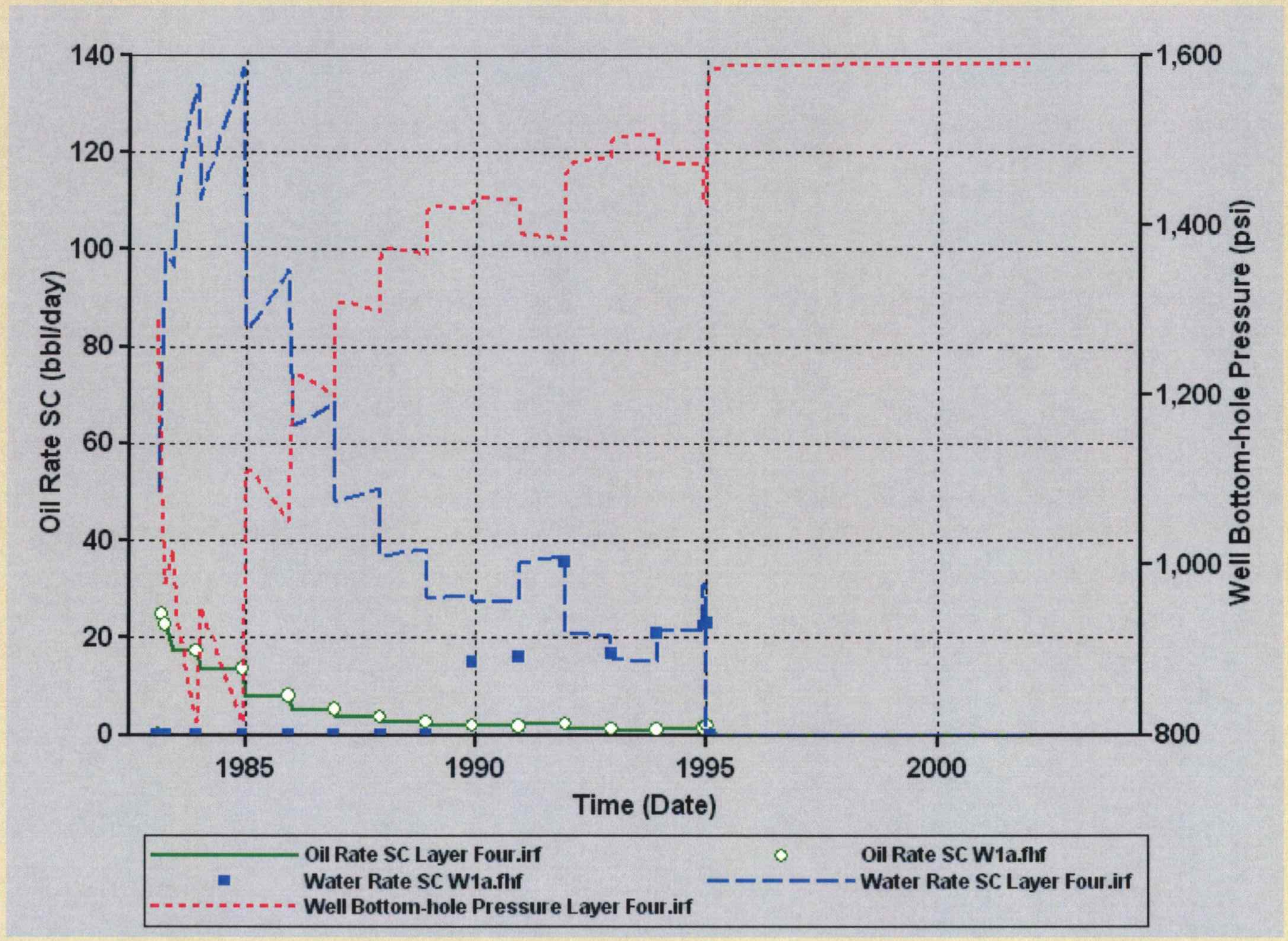
History matches

Wharton #3 (WH3)



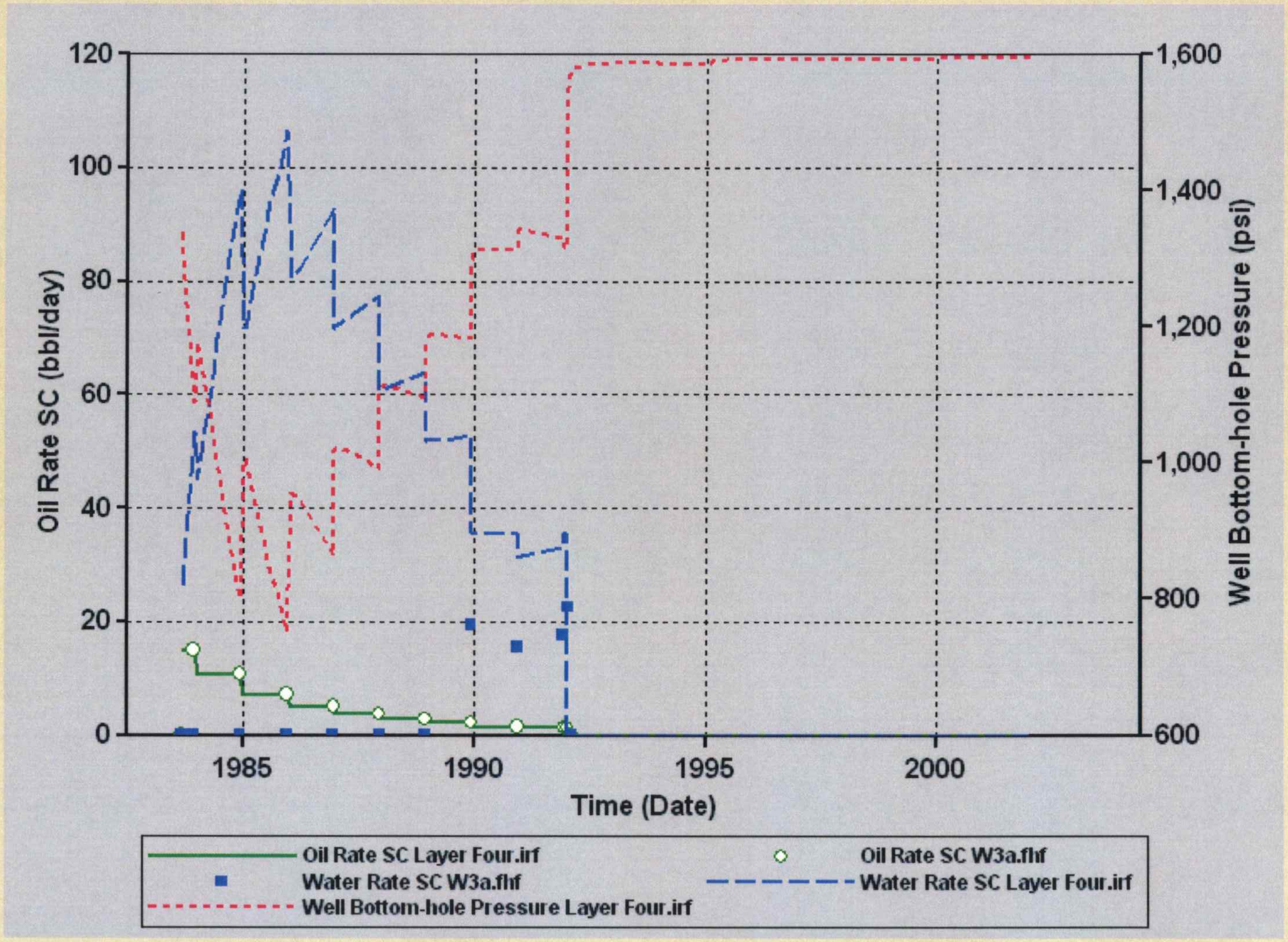
History matches

Waugh #1 (W1)



History matches

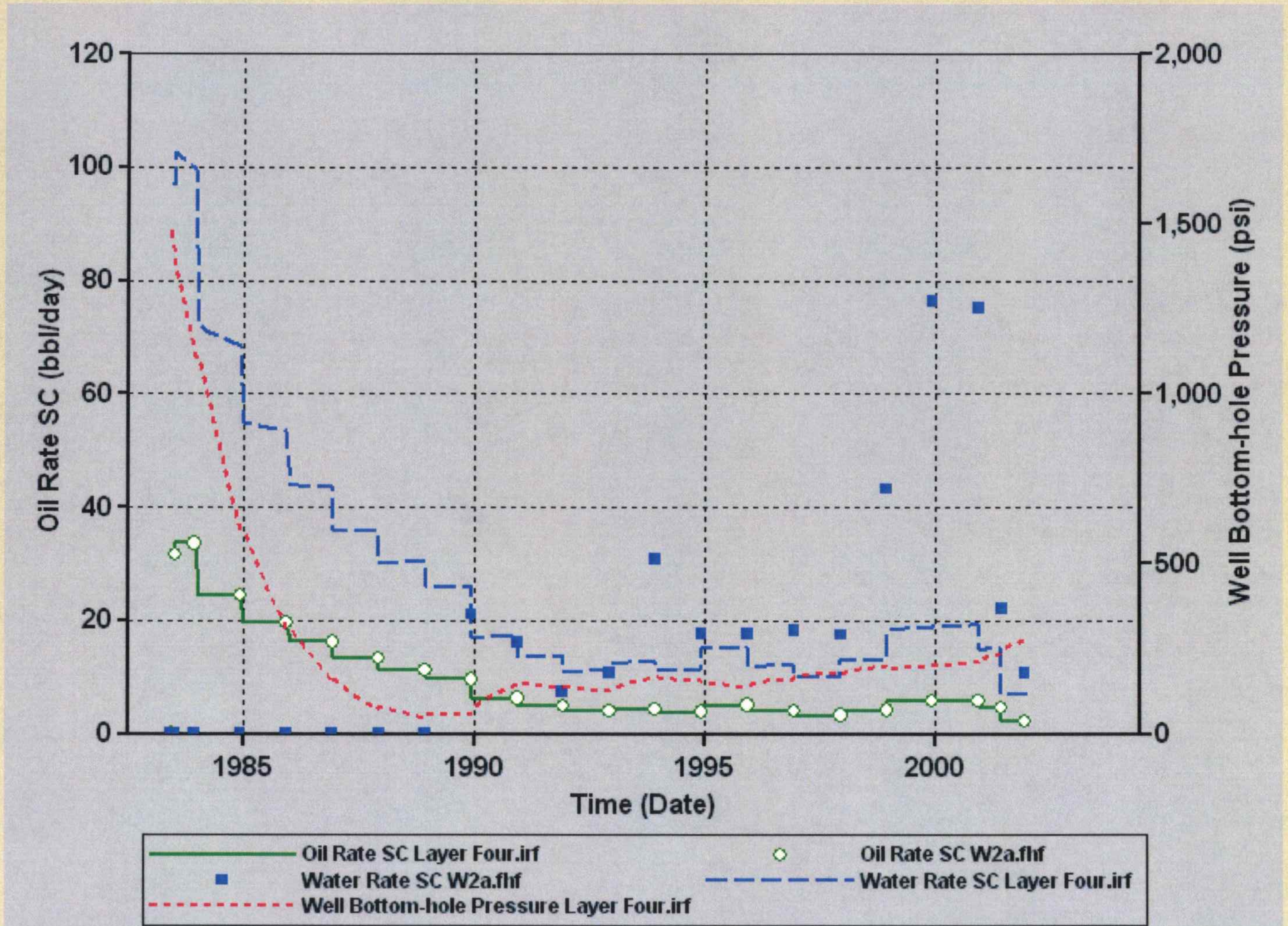
Waugh #3 (W3)



History matches

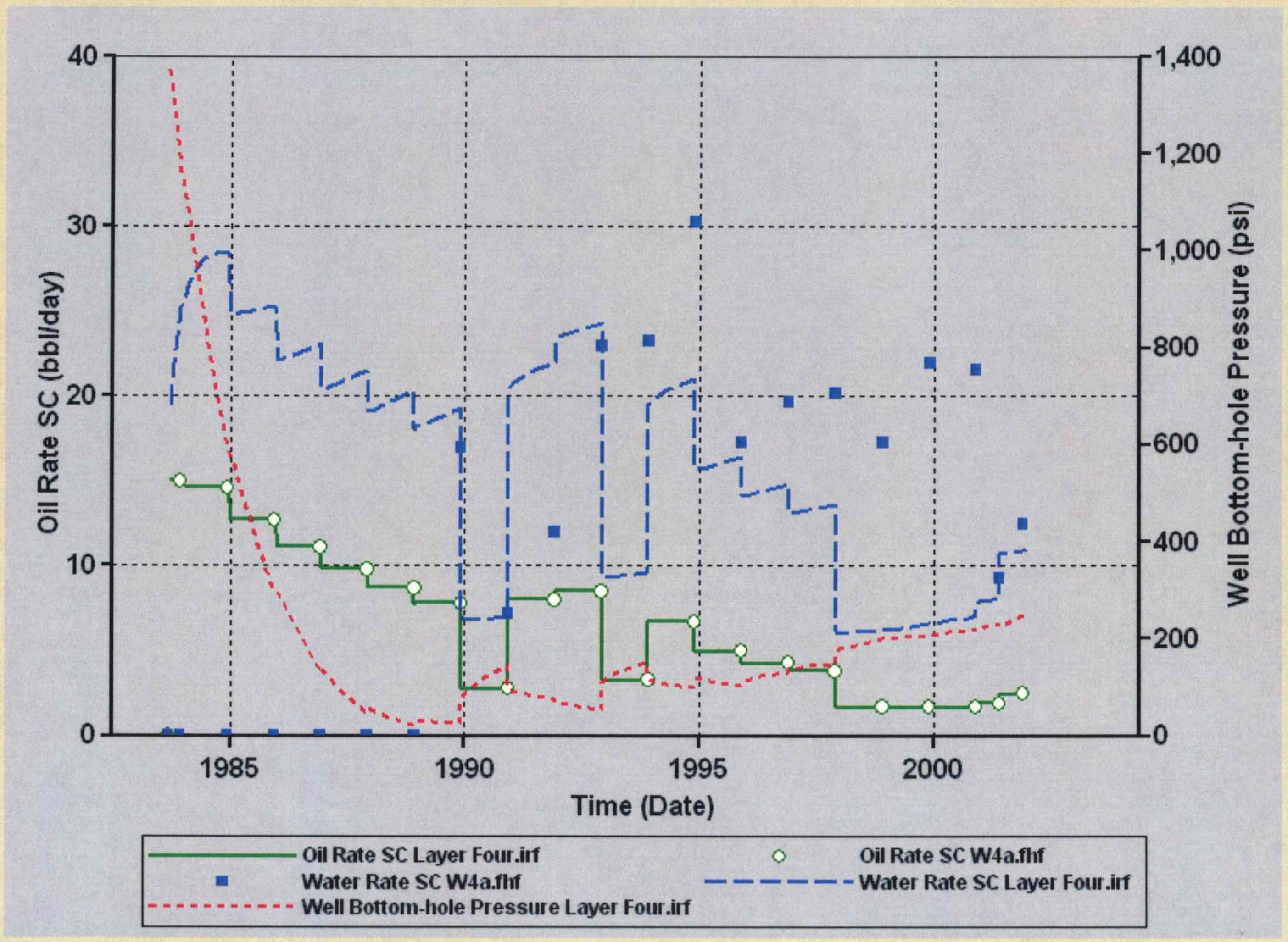
Waugh #2 (W2)

WOR of W4 used to recreate water production history as no water data was available for W2.



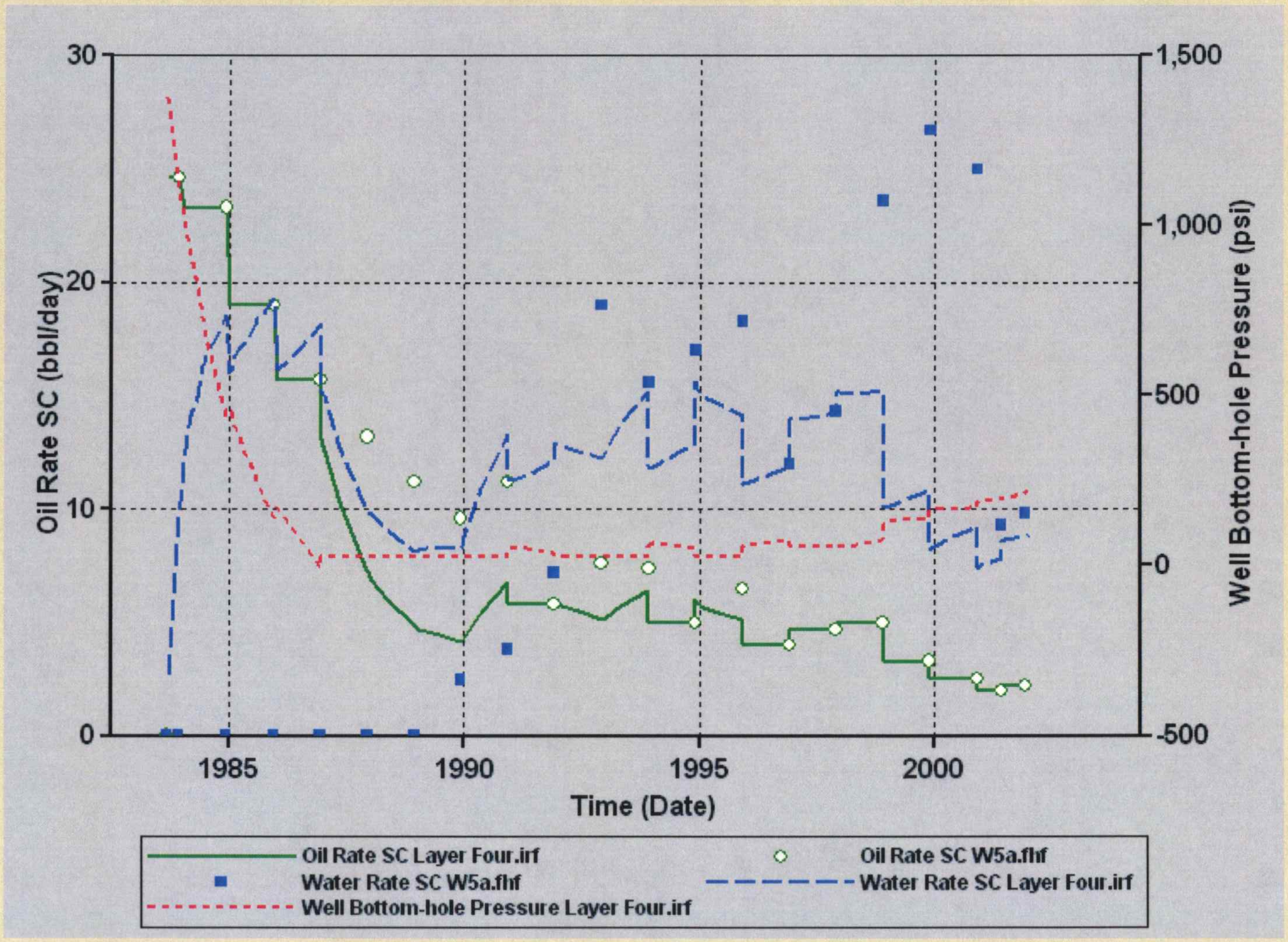
History matches

Waugh #4 (W4)



History matches

Waugh #5 (W5)



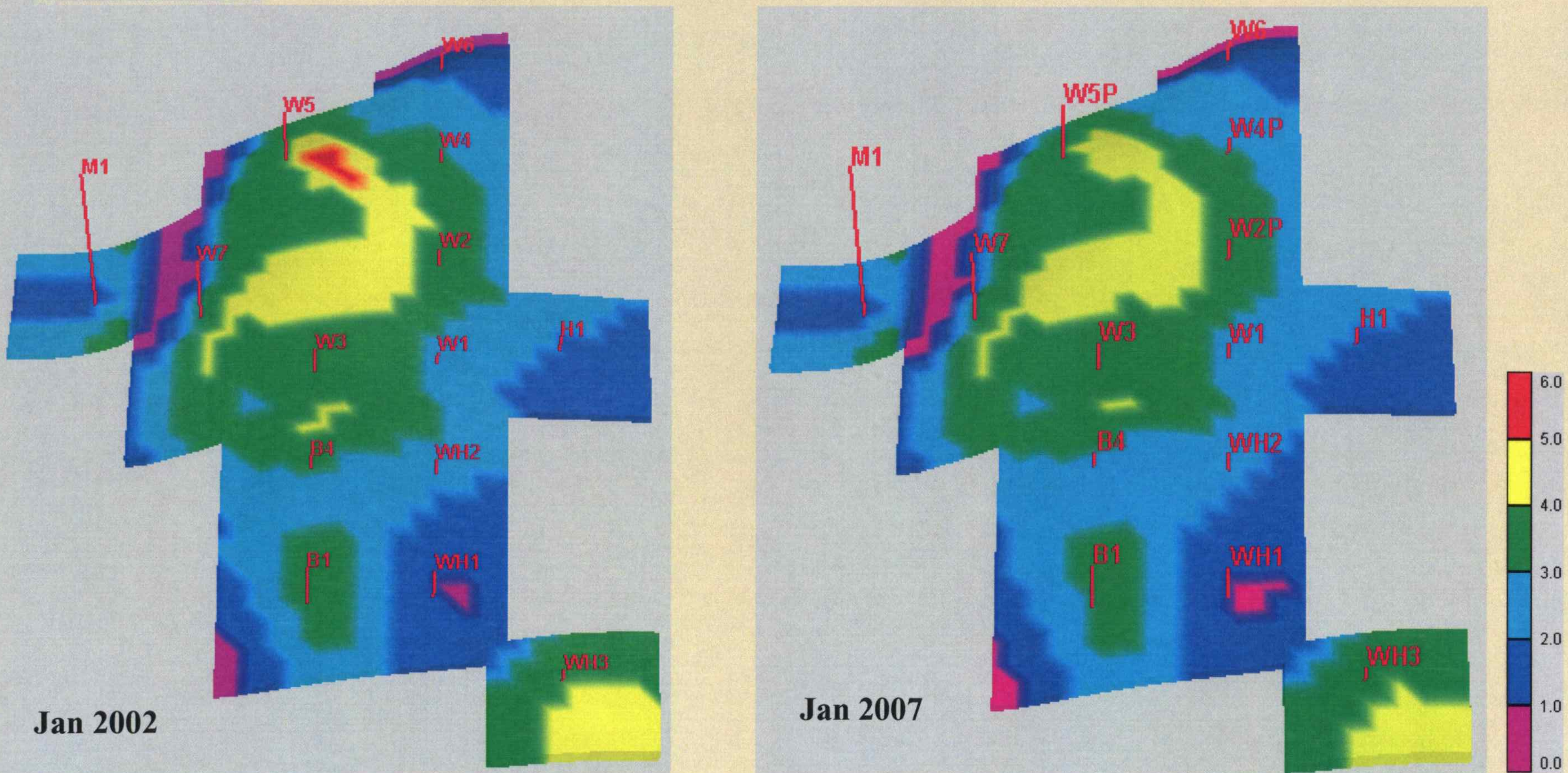
Data limitations

Related to reservoir characterization

- No cores available from Wellington West field proper
- Few resistivity logs available
  - No reliable data to map initial S_w
  - Initial S_w mapped using capillary pressure data - measured on core plugs from neighboring field
- No water production data available before 1989
- Oil production data often missing before 1989
  - Missing oil production data estimated from decline curves
- History of fluid columns in producing wells not available
- No PVT data was available

Base Case – Layer 1 (Output after history match)

Remaining So-ft @ Jan 2002 & Jan 2007



Shown are the oil saturation-feet (residual) as of Jan 2002 and Jan 2007 if the field was produced as it is, that is, without implementing any water injection. The maps also locate the pocket of residual oil. Left as it is, there will be some recovery of the residual oil by 2007.

Base Case – Layer 2

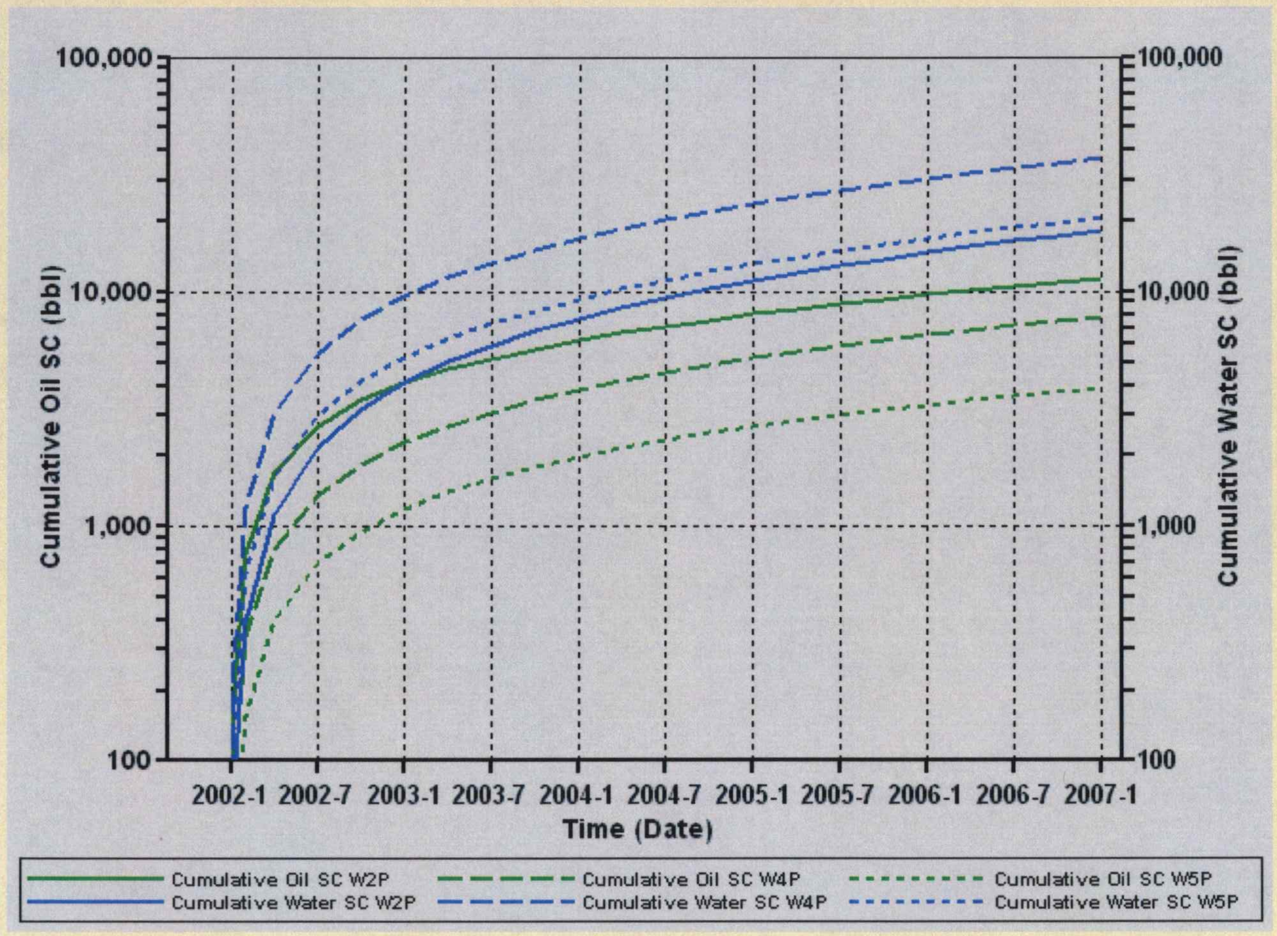
Remaining So-ft @ Jan 2002 & Jan 2007

Shown are the saturation-feet of residual oil in Layer 2. There is hardly any residual reserve in Layer 3 as of Jan 2002. As of Jan 2002, layer 1 has the maximum amount of residual oil. Left as it is, there will be little recovery of the remaining reserves from layer 2 after 5 years of production.

Cumulative recovery

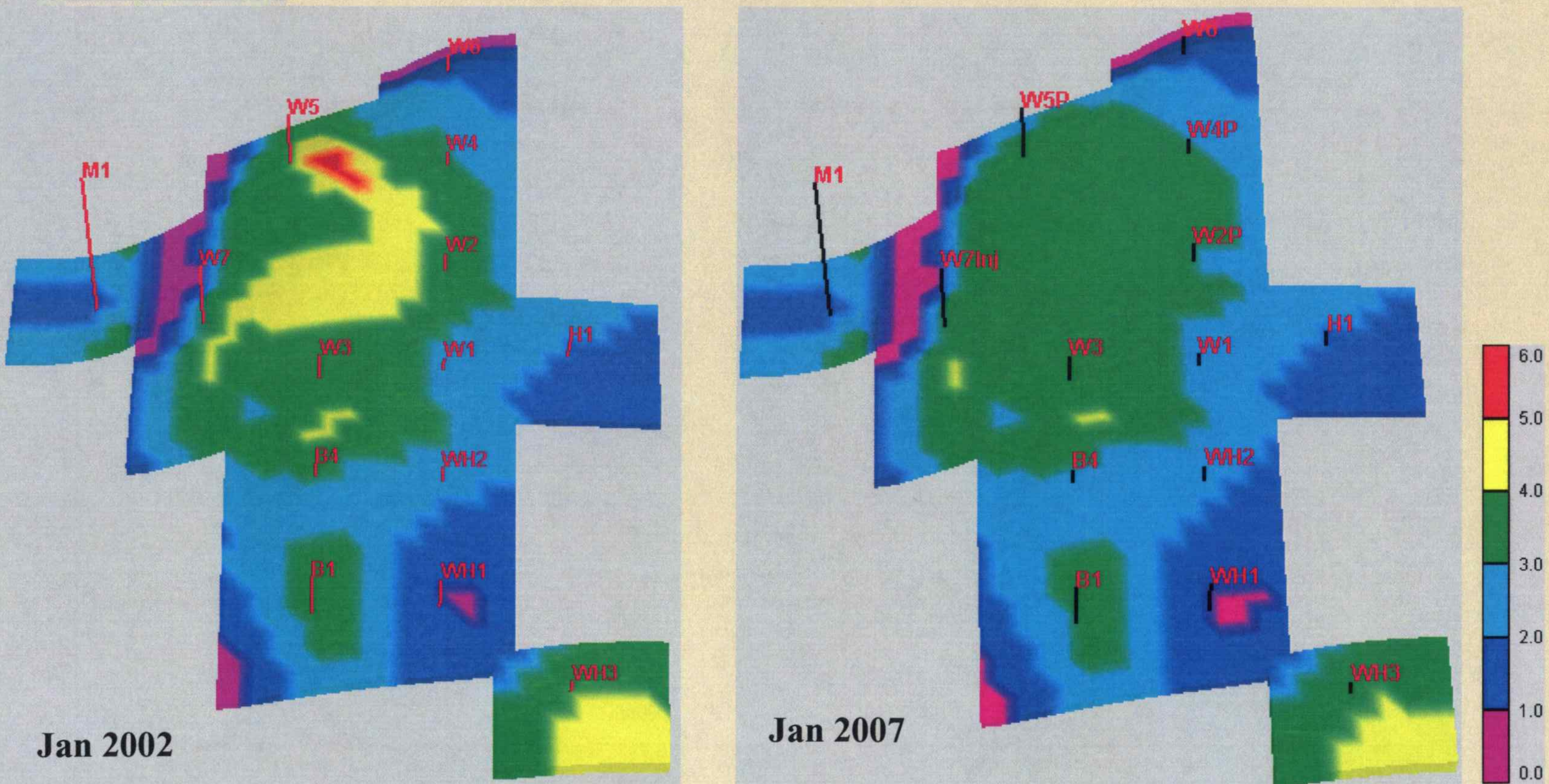
Base Case - Jan 2002 to Jan 2007

The plot shows the cumulative production estimated from the wells W2 (W2P), W4 (W4P), and W5 (W5P) from Jan 2002 to Jan 2007 if production was to go on as it is currently, that is, without the implementation of any water injection in the field.



Inject water in Layer 1 at W7 – **Slide A1**

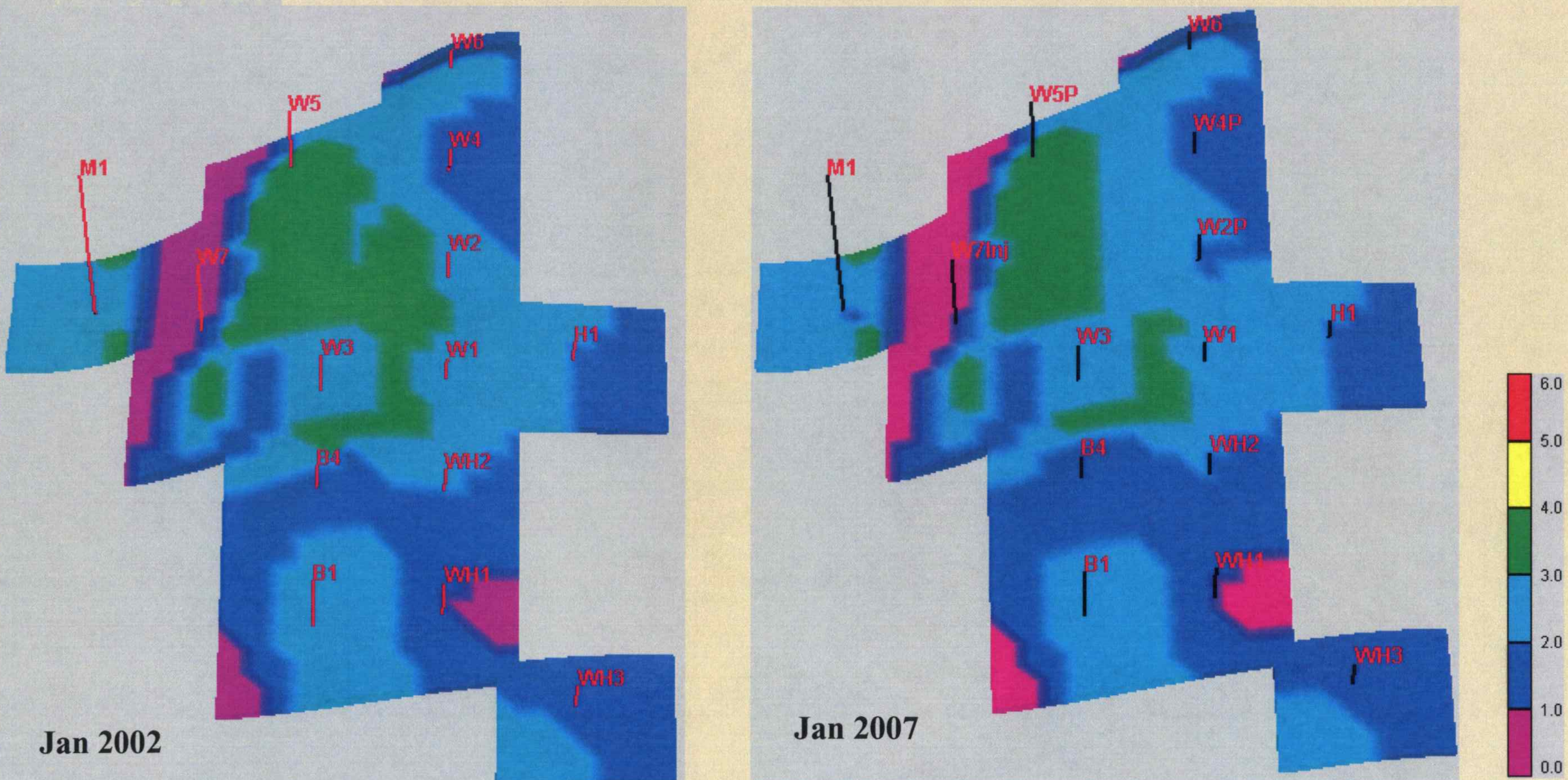
Remaining So-ft D1 @ Jan 2002 & Jan 2007



A significant portion of the residual oil (as of Jan 2002) is recovered from Layer 1 if W7, currently the water disposal well, is converted into an injector. In W7, water is injected into Layer 1 only and in volumes such that the bottom hole pressure is maintained below fracture pressure (assuming fracture gradient of 0.5 psi/ft) at 1500 psi.

Inject water in Layer 1 at W7 – **Slide A2**

Remaining So-ft D2 @ Jan 2002 & Jan 2007

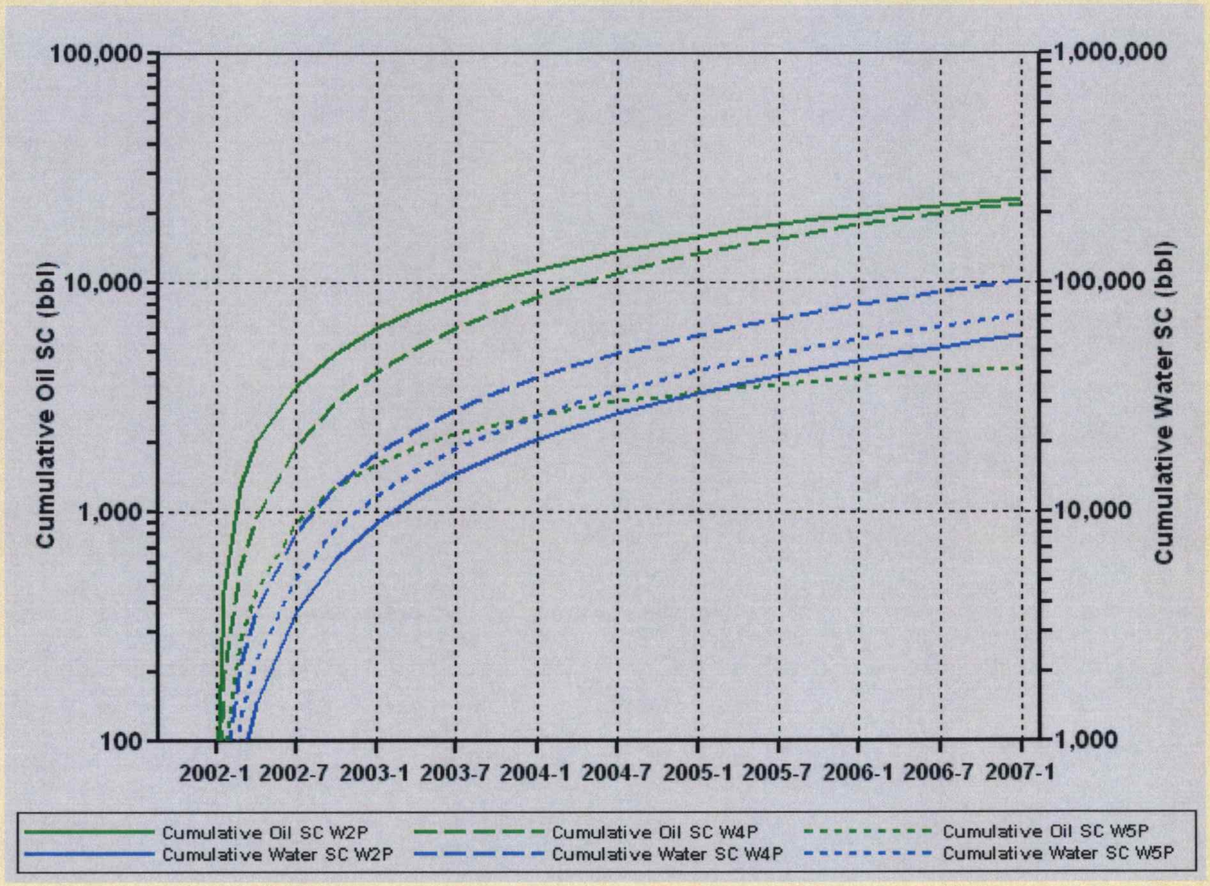


A significant portion of the residual oil (as of Jan 2002) is recovered from Layer 2 if W7, currently the water disposal well, is converted into an injector. At W7, water is injected into Layer 1 only and in volumes such that the bottom hole pressure is maintained below fracture pressure (assuming fracture gradient of 0.5 psi/ft) at 1500 psi.

Cumulative recovery

Inject in D1 @ W7 - Jan 2002 to Jan 2007

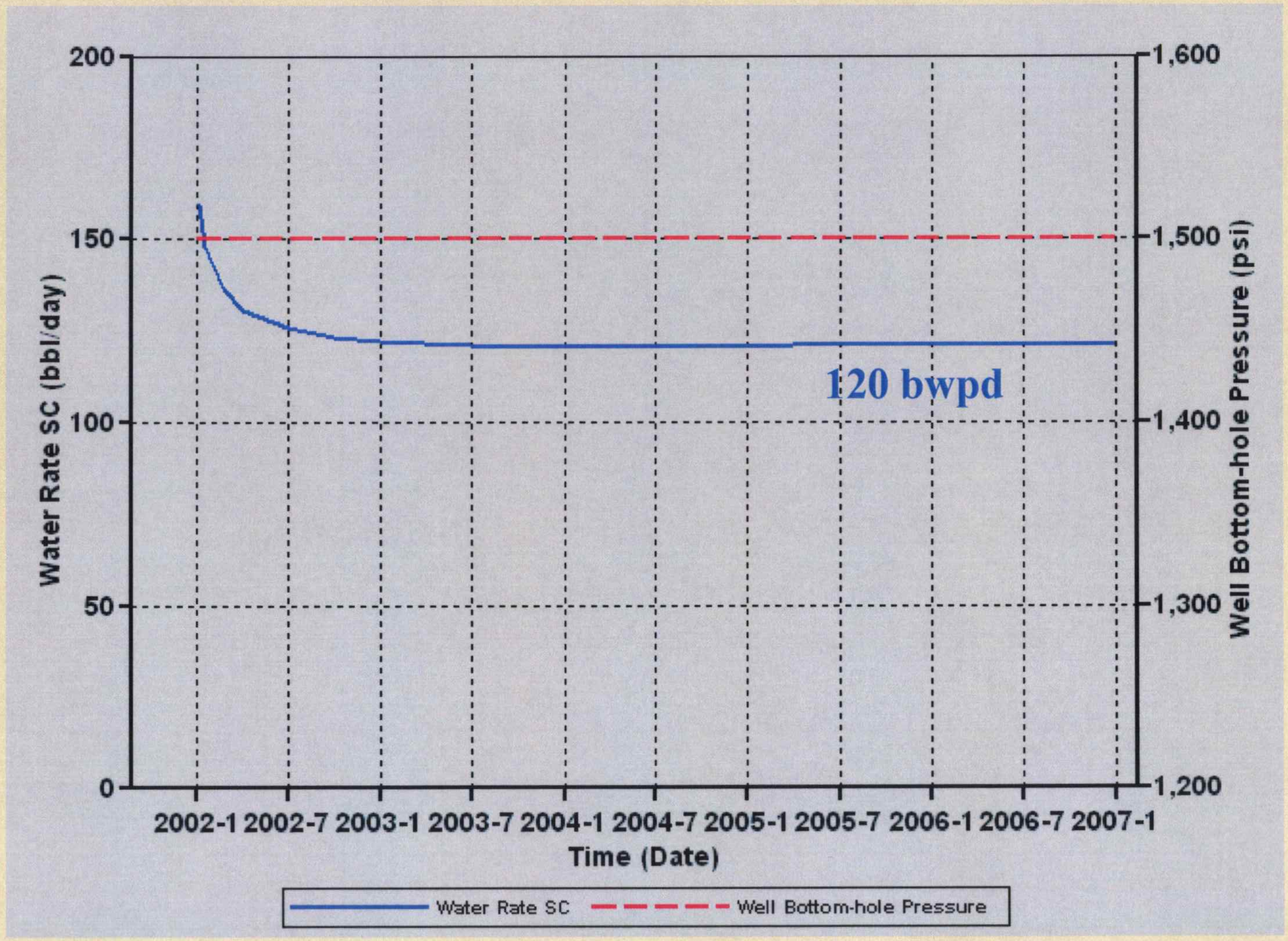
The plot shows the cumulative production estimated from the wells W2 (W2P), W4 (W4P), and W5 (W5P) from Jan 2002 to Jan 2007 if W7 was converted into an injector and water was injected such that BHP was maintained at 1500 psi. Water is injected only in layer 1 at W7.



Injection volumes

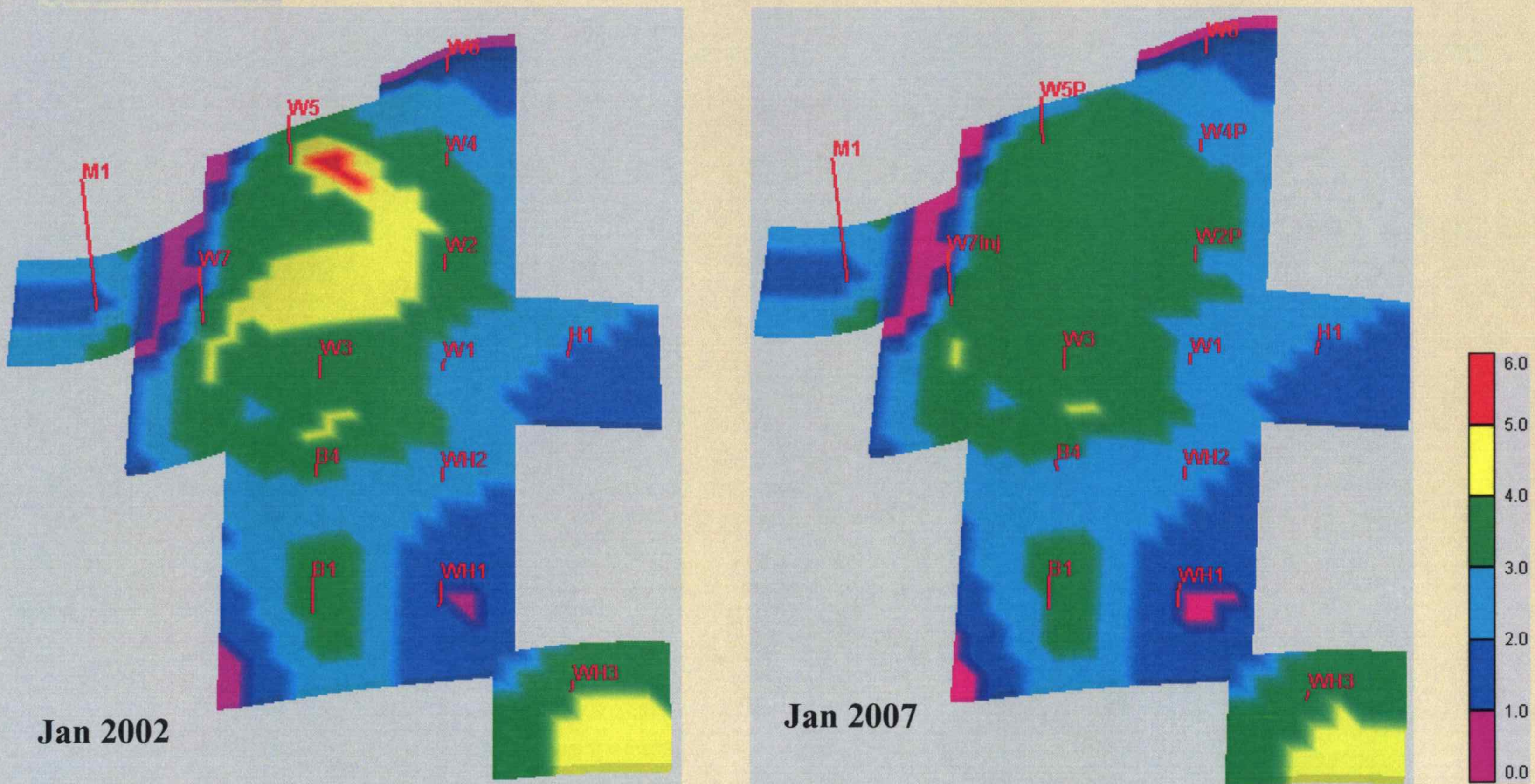
Inject in D1 @ W7 - Jan 2002 to Jan 2007

The plot shows that about 120 barrels/d of water need to be injected in W7 (into Layer 1) in order to maintain a BHP of 1500 psi.



Inject water in Layers 1&2 at W7 – **Slide B1**

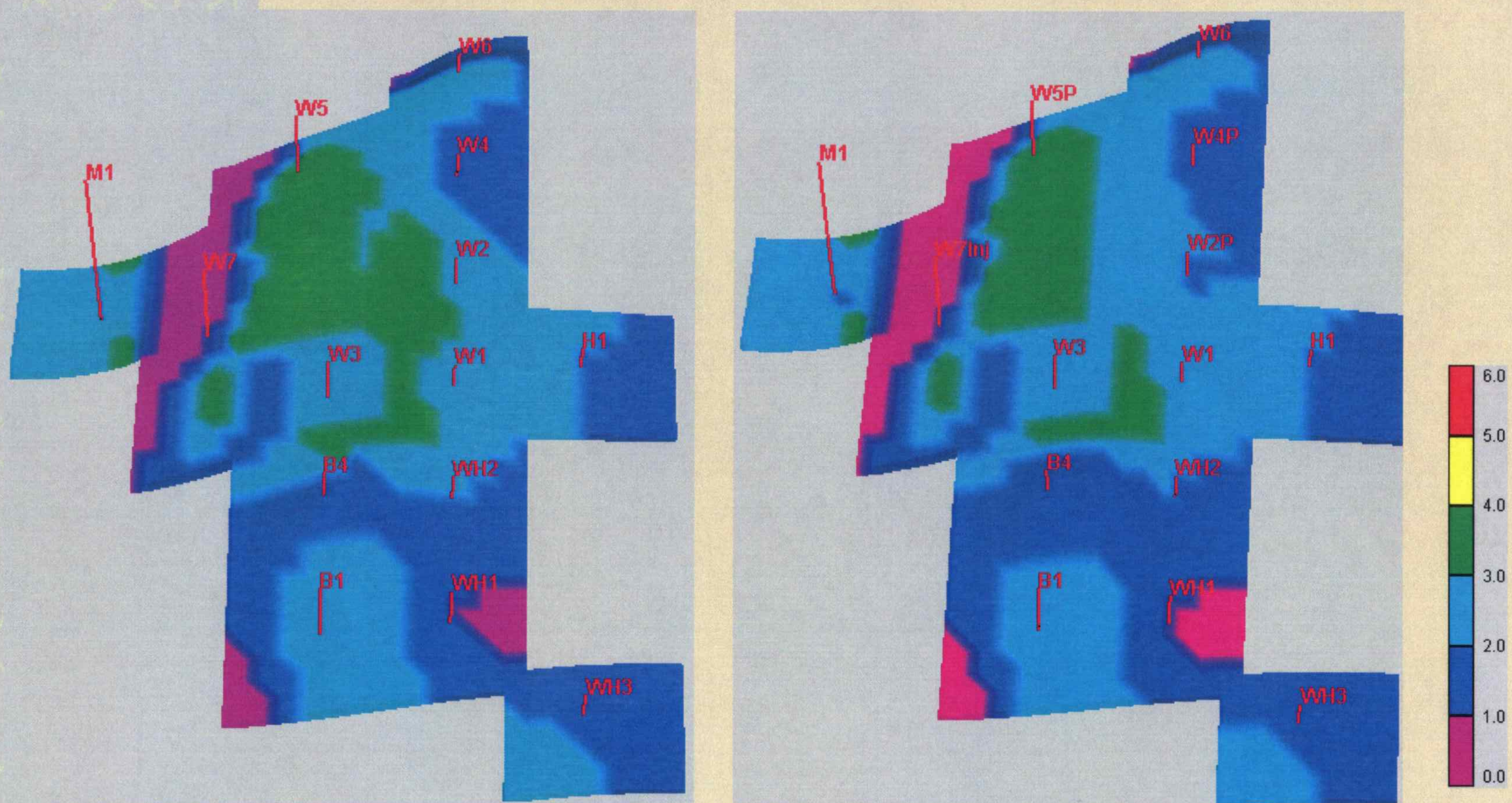
Remaining So-ft D1 @ Jan 2002 & Jan 2007



Shown above is the recovery of residual reserves from layer 1 if water is injected into layers 1 and 2 at W7 keeping a constant BHP of 1500 psi. In a relative sense, there is no significant incremental recovery by injecting into layers 1 and 2 at W7 as compared to injecting into layer 1 only. (Compare with Slide A1).

Inject water in Layers 1&2 at W7 – **Slide B2**

Remaining So-ft D2 @ Jan 2002 & Jan 2007

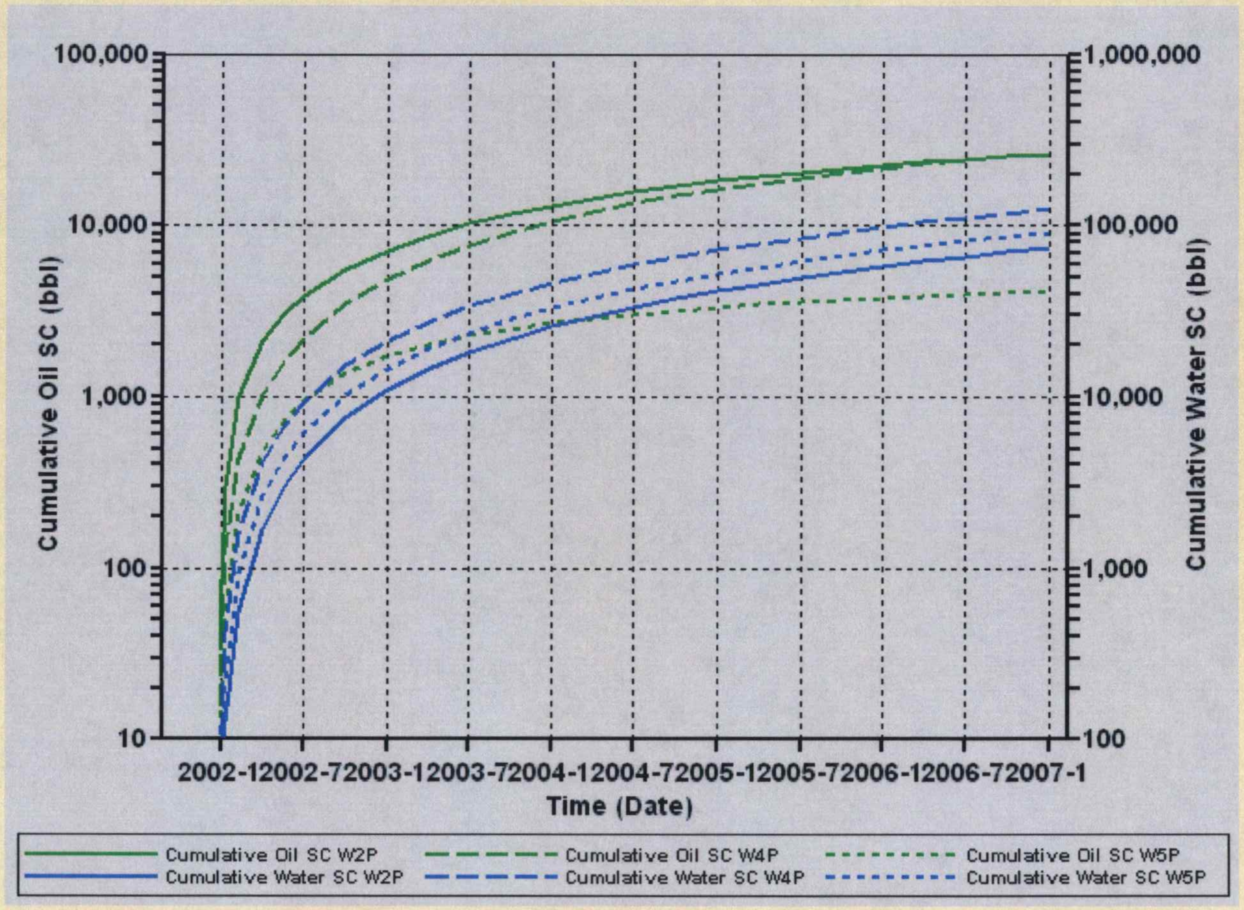


Shown above is the recovery of residual reserves from layer 2 if water is injected into layers 1 and 2 at W7 keeping a constant BHP of 1500 psi. In a relative sense, there is no significant incremental recovery by injecting into layers 1 and 2 at W7 as compared to injecting into layer 1 only. (Compare with Slide A2)

Cumulative recovery

Inject in D1&D2 @ W7 - Jan 2002 to Jan 2007

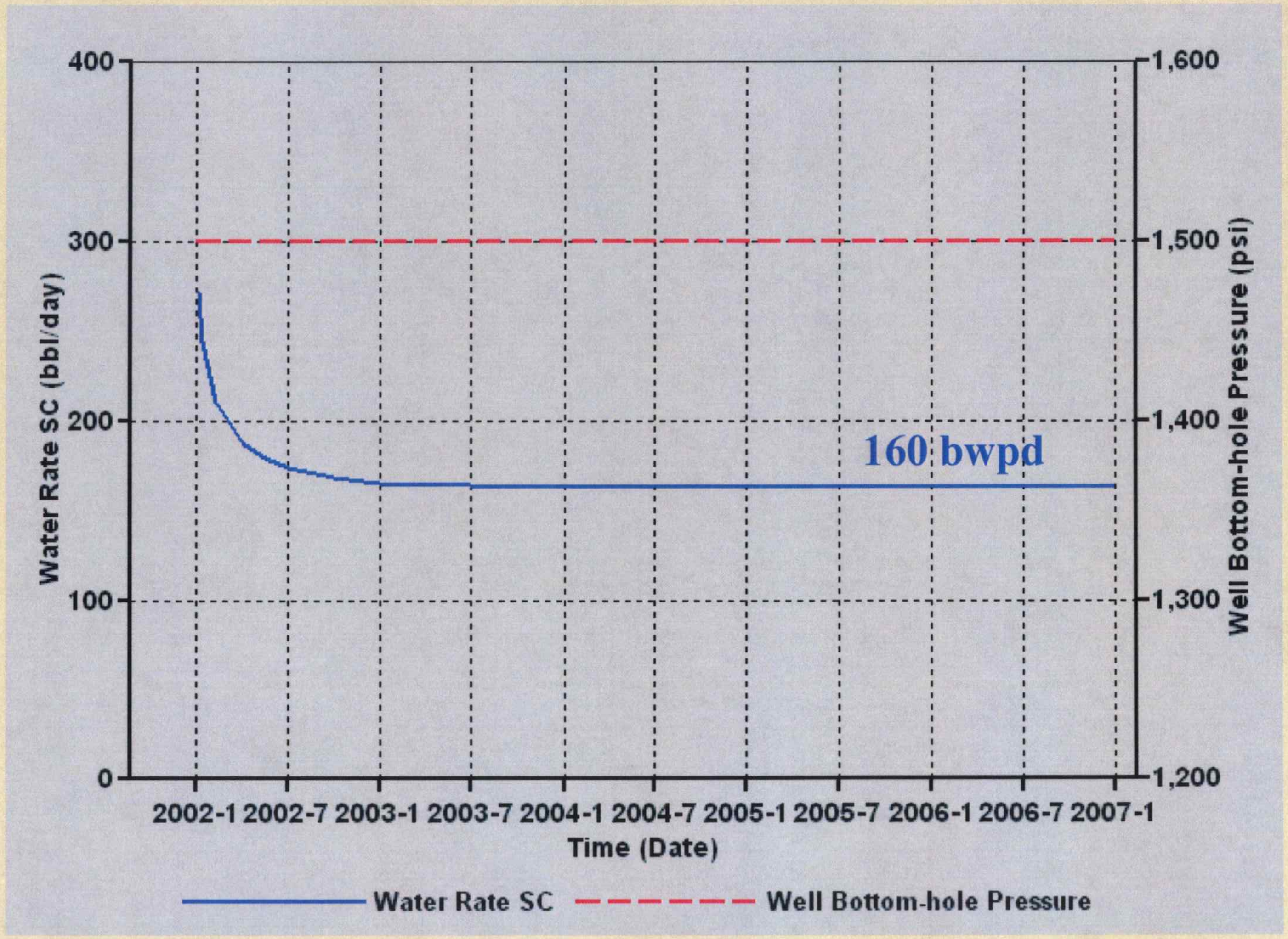
The plot shows the cumulative production estimated from the wells W2 (W2P), W4 (W4P), and W5 (W5P) from Jan 2002 to Jan 2007 if W7 was converted into an injector and water was injected such that BHP was maintained at 1500 psi. Water is injected in layers 1 and 2 at W7.



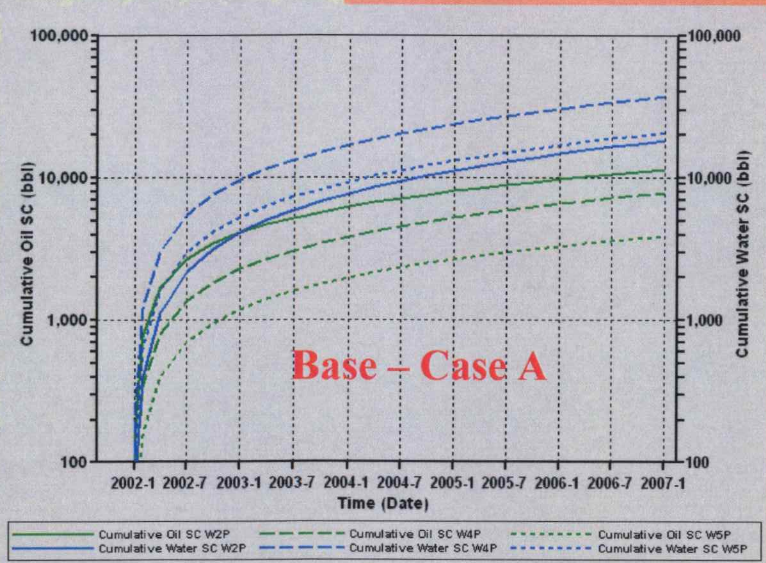
Injection volumes

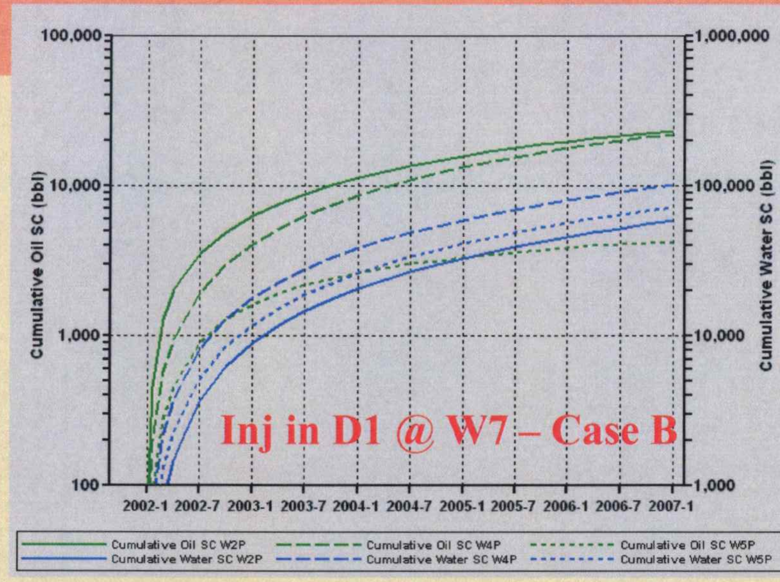
Inject in D1 & D2 @ W7 - Jan 2002 to Jan 2007

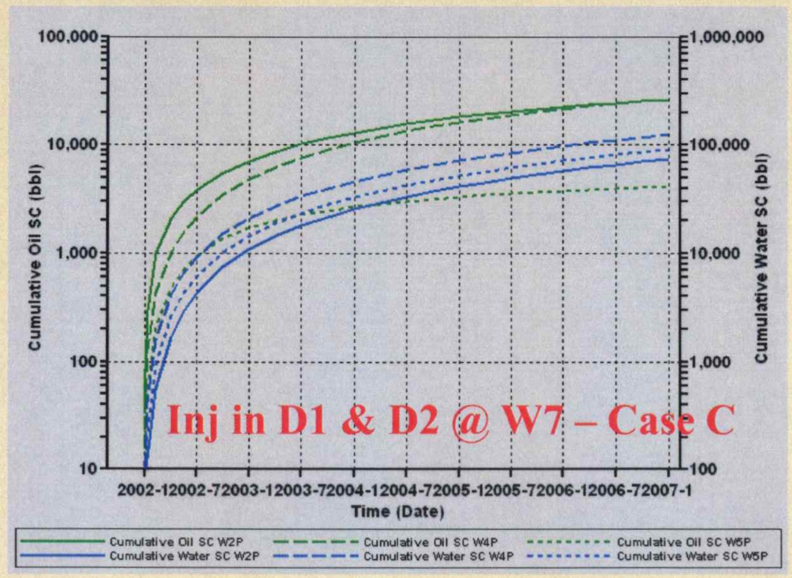
The plot shows that about 160 barrels/d of water need to be injected in W7 (into Layers 1 and 2) in order to maintain a BHP of 1500 psi.



Comparison of cumulative production - Jan 2002 to Jan 2007







Estimated oil and water production under 3 scenarios are compared. In Case A – production continues without implementation of any water injection. In Case B – water is injected into layer 1 at W7 at 1500 psi BHP. In Case C – water is injected into layers 1 and 2 at W7 at BHP = 1500 psi.

Production comparison – Oil volumes

Jan 2002 to Jan 2007

Case	After 5 yrs Cum W2P stb	After 5 yrs Cum W4P stb	After 5 yrs Cum W5P stb	After 5 yrs Total cum stb
Base	11286	7824	3903	23013
Inj W7 in D1	23276	22013	4262	49551
Inj W7 in D1 & D2	26341	26341	4107	56789

The Operator chose to implement Case B – convert W7 into a water injector and inject water into layer 1 only and keeping the BHP close to 1500 psi.

Currently, field implementation of water injection is in progress at Wellington West field.