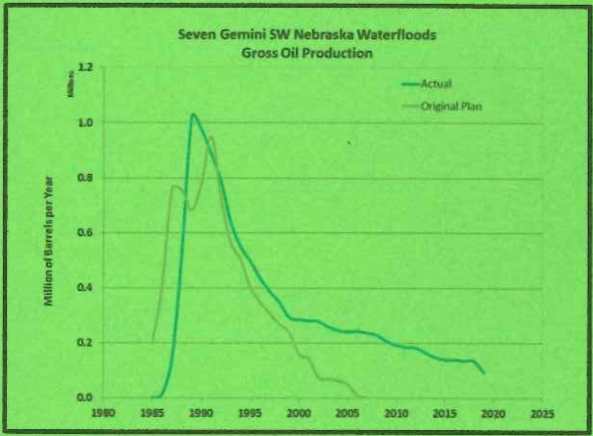

A Post-Mortem Review of Seven Gemini Southwest Nebraska Lansing-Kansas City Waterfloods

Acknowledgement

I would like to thank Mr. Mike Carr, President of Mica Energy and former President of Gemini Corporation (and my employer from 1985 to 1995, for which I have been unreservedly grateful) for allowing me the opportunity to prepare this paper. I would also like to thank Mr. Dan Blankenau, President of Great Plains Energy, for his review, research, suggestions, and support.

Disclosure

Earlier in my career, I worked for Mr. Carr and Gemini Corporation (and successors-in-interest Beard Oil Company and Sensor Oil and Gas), helping design and implement waterfloods in Southwest Nebraska. I may have, therefore, bias or opinion regarding both waterflood design and results thereof.

I also feel obligated to encourage readers to use judgement and caution in use of any observations in this paper which might influence future waterflood design or operation. Matters discussed in this paper may not have a relationship to other fields in other locations. Please perform your own studies (or retain qualified engineers to do so), and form your own opinions before making conclusions of future well and reservoir performance.

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A Post-Mortem Review of Seven Gemini Southwest Nebraska Lansing-Kansas City Waterfloods

Tim Busing, PE (retired)

1 Objectives

This paper presents a post-mortem review of seven waterfloods designed and implemented by Gemini Corporation (and its successors-in-interest) in the Lansing Kansas-City ("LKC") formation in Southwest Nebraska.

The projects described in this paper required significant effort by many people, took a number of years to complete, and had both significant cost and substantial returns. An after-project review is a normal part of transparent business conduct, and in any case may be of interest to participants and partners.

Observations made in this review may also influence or provide suggestions for future waterflood design and implementation.

2 Introduction

In the follow sections, the reader will see references to the pre-unit waterflood peformance forecasts for each of these seven fields. In a separate paper, I described a method of analogy using actual data from mature fields to predict waterflood response from a prospective Lansing-Kansas City waterflood. Each of these seven Gemini waterfloods is discussed in that paper, including an example of a new analog waterflood forecast. Those new forecasts, however, are not the topic of this paper, and are not shown in the following graphs.

Instead, in each of the following sections, pre-unit performance forecasts shown are those presented to Nebraska Oil and Gas Conservation Commission ("NOGCC") at the unitization hearing. In most cases, the forecast has been downloaded from the NOGCC website, and digitized for display on the following charts. In two cases, the Suess Unit and the Husker Unit, the original forecasts are not available on the NOGCC website. For those fields, images of the forecasts were obtained from historical files, and digitized. Digitizing the original images was necessary since the original source files are no longer available.

Other data used in this post-mortem may have been been obtained from the original waterflood feasibility studies (if available – see Table 3.1, below), but unitization exhibits from the NOGCC website (for example, hearing transcripts) have been prioritized whenever possible.

3 Summary

In the 1980's and 1990's, Gemini Corporation (and successors-in-interest Beard Oil Company and Sensor Oil and Gas) designed and implemented seven waterfloods in the Lansing Kansas-City ("LKC") formation in Southwest Nebraska. At the time of this paper, all of these waterfloods are very mature, and a retrospective analysis of their productive and financial performance can be made. The analysis is made on a 100% working interest ownership basis.

The waterfloods whose performance is recapped in this paper are:

- Gemini North Midway Unit
- Suess Unit
- Boevau Canyon Field Unit
- Husker Field Unit
- Bishop Field Unit
- Bush Creek Unit
- Driftwood Creek Unit

The most technically successful waterfloods were the sequence of five-spot LKC "F" zone waterfloods in adjacent fields in Hitchcock County, namely Bouvau Canyon, Husker, and Bishop. These fields, taken together, have been significant in size, recovery, and economic success.

The Suess Field in Red Willow County was smaller, different in waterflood implementation, but also very technically successful.

The most economically successful of this group of waterfloods was the Husker Unit, discussed below in section 4.4., although some of the relative success of Husker Unit is due to the relatively modest assumptions made for the pre-unit waterflood recovery forecast and for the original pre-unitization economics.

Waterfloods of Bush Creek and the Gemini North Midway Unit were marginally successful.

The Driftwood Creek Unit was the only waterflood in the group to miss its secondary recovery target (although Bush Creek and Gemini North Midway were late in reaching their recovery targets), and Driftwood was also the only field to fail to reach payout.

Additional data for this group of fields are shown on Table 3.1, which includes only pre-unit forecast volumes.

More detailed discussion of each field is included in section 4, below, including both production performance and economic performance.

Section 5 is a discussion of the collective performance of this group of fields. Actual outcomes are summarized for the group of fields in Table 5.1.

Finally, a few conclusions and recommendations for potential future waterfloods are shown in Section 6.

Table 3.1: Gemini Southwest Nebraska Lansing-Kansas City Waterfloods

	Gemini North Midway	Boevau Canyon	Husker	Bishop	Suess	Bush Creek	Driftwood Creek
NOGCC hearing date	3/3/1986	3/24/1987	6/30/1987	5/23/1989	8/22/1989	5/22/1990	9/28/1993
unit effective date	Apr-86	Apr-87	Jul-87	Jun-89	Sep-89	Jun-90	Oct-93
first injection month	Nov-86	Sep-87	Dec-87	Sep-89	Nov-89	Nov-90	Aug-95
production until date	1/1/1986	1/1/1987	1/1/1987	1/1/1989	1/1/1989	1/1/1990	7/1/1993
unit hearing oil rate	50	100	333	300	60	200	15
unit hearing reservoir pressure	100	150	200	200	200	300	200
NOGCC Case #	R-0633	R-0646	R-0648	R-0675	R-0677	R-0683	R-0730
# available wells	23	81	42	32	11	80	7
planned # producers	16	42	21	16	7	39	6
planned # injectors	7	39	24	21	5	41	4
injection pattern	irregular	5-spot	5-spot	5-spot	irregular	5-spot	irregular
planned installation cost $	400,000 [3]	2,800,000	960,000	960,000	577,000	3,000,000	420,000
reservoir volume gross ac. ft.	6,688	25,949	14,902	8,923	4,002	30,854	6,819
OOIP stb	3,879,000	16,185,412	11,091,445	5,295,839	3,165,530	18,036,338	4,032,931
producing zones	F	F	F	F	E	D (75%), F(25%)	C (42%), D(24%), E(34%)
Values Shown Below are Pre-Unit Forecast Recoveries:							
primary oil recovery	617,913	1,992,393	710,072	656,751	311,821	1,823,855	239,802
primary reserves	38,590	442,664	273,705	467,000	127,259	132,811	34,625
ultimate primary	656,503	2,435,057	983,777	1,123,751	439,080	1,956,666	274,427
estimated secondary	355,928	2,435,057	746,019	1,005,294	439,142	1,392,321	167,657
estimated primary + secondary	1,012,431	4,870,114	1,729,796	2,129,045	878,222	3,348,987	442,084
remaining combined reserves	394,518	2,877,721	1,019,724	1,472,292	566,401	1,511,280	202,282
planned secondary:primary	0.54	1.00	0.76	0.89	1.00	0.71	0.61
located in county	Red Willow	Hitchcock	Hitchcock	Hitchcock	Red Willow	Hitchcock	Hitchcock
have a report?		yes	yes		yes [1]	yes	
have an NOGCC transcript?		yes	yes	yes	yes	yes	yes
have an NOGCC data sheet?	yes	yes			yes	yes	yes
have an NOGCC decline curve?	yes	yes	yes [2]	yes	yes [2]	yes	yes

notes:

1	pre-unit report by R. S. Magnie; includes structure, zonation & reservoir volume, but no implementation plan or forecast recovery
2	decline curve apparently used for the NOGCC; not on NOGCC website, but found in a Beard Oil Co. May 1993 memo by Tim Busing
3	estimated capex

4 Discussion

4.1 Gemini North Midway Unit

Figure 4.1 (below) shows the waterflood response of the Gemini North Midway Unit ("GNMU").

The original waterflood response forecast was digitized from NOGCC exhibits. The original forecast was based on analog fields, but GNMU is one of the smaller waterfloods (compared to the analogs), is relatively elongated, and was thus designed with an irregular injection pattern. Additionally, it was directly offset by two pre-existing operating waterfloods.

LKC waterfloods are often characterized by very low reservoir energy (little or no free gas, low GOR, little or no water influx), and hence very rapid production decline, with (usually) very low pressures by the time waterfloods are initiated. The pronounced initial production increase seen in many LKC waterfloods is the quick response (rapid pressure increase) of a fluid-packed system to water injection. Any physical factors which may "waste" injection (off-pattern injection loss, loss of injection into less-production horizons, high-perm streaks or faults) will delay pressure buildup and delay production response. At GNMU, loss of injection off-pattern may be the cause of the "slower-than-analog" production buildup.

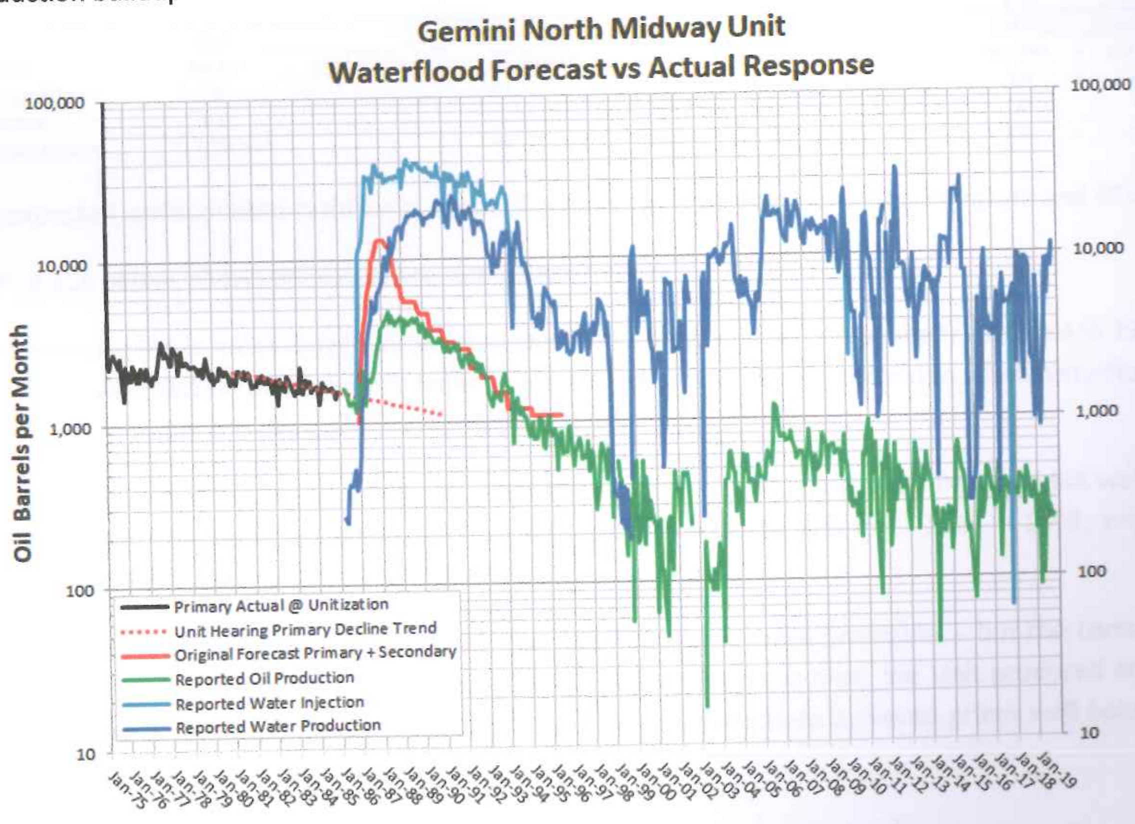

Figure 4.1: Gemini North Midway Unit Waterflood Forecast vs Actual Response

Later (from 1993 onward) the actual water injection rate was substantially reduced, likely due to tight cashflow, as shown on the following tables.

The pre-unitization cashflow is estimated as shown below, on Table 4.1.1. I could not find an original pre-unit cashflow, but the following should be a close approximation: it is based on the original primary plus secondary decline forecast and constant oil price appropriate for 1986. Opex and capex were based on costs quoted in the 1985 Boevau Canyon waterflood feasibility study.

Table 4.1.1: Gemini North Midway Unit Estimate of Originally-Proposed Waterflood Cashflow

Gemini North Midway Unit				Original not available; this cashflow is estimated, but matched to data reported at NOGCC hearing						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 5% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1985	0	0	0	0	0	0	0	0	0	0
1986	17,400	14,268	15.00	214,020	300,000	10,701	400,000	-496,681	-473,567	-473,567
1987	90,200	73,964	15.00	1,109,460	300,000	55,473	0	753,987	653,544	179,977
1988	128,200	105,124	15.00	1,576,860	300,000	78,843	0	1,198,017	944,020	1,123,997
1989	64,300	52,726	15.00	790,890	300,000	39,545	0	451,346	323,322	1,447,319
1990	48,300	39,606	15.00	594,090	300,000	29,705	0	264,386	172,175	1,619,494
1991	35,700	29,274	15.00	439,110	300,000	21,956	0	117,155	69,358	1,688,853
1992	10,850	8,897	15.00	133,455	300,000	6,673	0	-173,218	-93,227	1,595,626
	394,950	323,859		4,857,885	2,100,000	242,894	400,000	2,114,991	1,595,626	
						5%	10%	15%	20%	25%
NRI		0.82			CFBT	1,832,715	1,595,626	1,395,142	1,224,493	1,078,323
BFIT ROR		160.8%			disc invest	390,360	381,385	373,002	365,148	357,771
undisc prof/inv		5.3			P/I	4.7	4.2	3.7	3.4	3.0
undisc ROI		6.3			P/R	0	0	0	0	0
operating income		2,514,991			ROI	5.7	5.2	4.7	4.4	4.0

The expected undiscounted cashflow is about $2 million, with very attractive rate of return and ROI.

Table 4.1.2, below, shows the actual economic performance.

The producing life is much longer, although waterflood operations were essentially curtailed in 1993 as operations approached the economic limit. I've assumed a modest opex reduction when waterflooding was scaled back, but it is likely profitability was minimal from 1993-2003.

The oil price used in this analysis is the WTI marker price in Cushing, Oklahoma (from the EIA website), minus $3. On this basis, oil prices paid in Nebraska were below $20 from 1986 – 1999, with the exception of the "spike" to $21.50 in 1990, during the Gulf War.

However, when oil price increased in 2005, the GNMU became more profitable -- but the cumulative discounted cashflow from 1993 to present is very small. During this time, the Unit produced another 160,000 gross barrels of oil, but at little profit (unless opex reductions achieved prices well below the $200,000 per month I've assumed in this example).

Table 4.1.2: Gemini North Midway Unit Estimate of Actual Waterflood Cashflow

Gemini North Midway Unit				ACTUAL OIL RECOVERY & OIL PRICE; CAPEX unchanged; OPEX reverts to primary estimate						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 5% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1986	12,463	10,220	12.05	123,147	225,000	6,157	400,000	-508,010	-484,369	-484,369
1987	24,498	20,088	16.20	325,431	250,000	16,272	0	59,160	51,279	-433,090
1988	50,670	41,549	12.97	538,896	300,000	26,945	0	211,951	167,014	-266,076
1989	48,749	39,974	16.64	665,170	300,000	33,259	0	331,912	237,765	-28,311
1990	40,169	32,939	21.53	709,168	300,000	35,458	0	373,709	243,370	215,059
1991	32,480	26,634	18.54	493,787	300,000	24,689	0	169,098	100,110	315,169
1992	27,327	22,408	17.58	393,935	300,000	19,697	0	74,238	39,955	355,125
1993	18,386	15,077	15.43	232,631	300,000	11,632	0	-79,001	-38,653	316,471
1994	14,558	11,938	14.20	169,513	200,000	8,476	0	-38,962	-17,330	299,141
1995	10,341	8,480	15.43	130,841	200,000	6,542	0	-75,701	-30,611	268,530
1996	9,208	7,551	19.12	144,367	200,000	7,218	0	-62,852	-23,104	245,426
1997	7,767	6,369	17.61	112,157	200,000	5,608	0	-93,451	-31,230	214,196
1998	6,068	4,976	11.42	56,823	200,000	2,841	0	-146,018	-44,361	169,836
1999	3,305	2,710	16.34	44,283	200,000	2,214	0	-157,931	-43,618	126,218
2000	3,632	2,978	27.38	81,544	200,000	4,077	0	-122,533	-30,765	95,452
2001	2,350	1,927	22.98	44,282	200,000	2,214	0	-157,932	-36,048	59,404
2002	2,968	2,434	23.18	56,415	200,000	2,821	0	-146,406	-30,379	29,025
2003	1,092	895	28.08	25,144	200,000	1,257	0	-176,113	-33,222	-4,197
2004	4,293	3,520	38.51	135,565	200,000	6,778	0	-71,213	-12,212	-16,409
2005	5,157	4,229	53.64	226,830	200,000	11,341	0	15,488	2,415	-13,994
2006	8,599	7,051	63.05	444,577	200,000	22,229	0	222,348	31,513	17,518
2007	8,111	6,651	69.34	461,182	200,000	23,059	0	238,123	30,680	48,198
2008	7,046	5,778	96.67	558,532	200,000	27,927	0	330,606	38,724	86,922
2009	7,280	5,970	58.95	351,908	200,000	17,595	0	134,313	14,302	101,224
2010	4,699	3,853	76.48	294,691	200,000	14,735	0	79,957	7,740	108,964
2011	5,574	4,571	91.88	419,954	200,000	20,998	0	198,956	17,508	126,472
2012	4,680	3,838	91.05	349,413	200,000	17,471	0	131,943	10,556	137,027
2013	4,937	4,048	94.98	384,511	200,000	19,226	0	165,286	12,021	149,048
2014	2,752	2,257	90.17	203,481	200,000	10,174	0	-6,693	-443	148,606
2015	4,270	3,501	45.66	159,874	200,000	7,994	0	-48,120	-2,892	145,713
2016	3,670	3,009	40.29	121,249	200,000	6,062	0	-84,814	-4,634	141,079
2017	4,179	3,427	47.80	163,800	200,000	8,190	0	-44,390	-2,205	138,874
2018	4,263	3,496	62.23	217,535	200,000	10,877	0	6,658	301	139,175
2019	2,402	1,970	53.98	106,329	200,000	5,316	0	-98,987	-4,064	135,111
2020	0	0	62.00	0	0	0	0	0	0	135,111
	397,943	326,313		8,946,966	7,475,000	447,348	400,000	624,617	135,111	

				5%	10%	15%	20%	25%
NRI	0.82		CFBT	251,357	135,111	79,371	36,086	(3,915)
BFIT ROR	24.5%		disc invest	390,360	381,385	373,002	365,148	357,771
undisc prof/inv	1.6		P/I	0.6	0.4	0.2	0.1	0.0
undisc ROI	2.6		P/R	0	0	0	0	0
operating income	1,024,617		ROI	1.6	1.4	1.2	1.1	1.0

The overall result is that actual cumulative undiscounted cashflow was about $0.6 million, and cashflow discounted at 10% was about $0.15 million, with a BFIT ROR of about 24%, given the assumptions described above.

GNMU recovery matched plan, but after many years of operation. It did not make very much money, but did not lose money, either.

4.2 Boevau Canyon Field Unit

Figure 4.2 (below) shows the forecast and actual waterflood response of the Boevau Canyon Field Unit.

This field was the first of the Gemini pattern waterfloods. I recall that its design as a five spot pattern flood was influenced by the 1993 Exeter Dry Creek Field, located very nearby. But Boevau Canyon, even more than Dry Creek, seemed to be ideal for pattern waterflooding. Boevau Canyon had been more completely drilled during primary development than Dry Creek, and so only one newly drilled injector was needed to establish a field-wide 40-acre 5-spot pattern. Dry Creek, by comparison, required drilling 39 new injection wells to complete a 40-acre pattern.

Another positive factor for Boevau Canyon waterflood recovery was the fact that only one reservoir zone (the LKC "F") dominated Boevau Canyon production and subsequent injection, whereas Dry Creek was produced from five separate LKC horizons. A negative factor for Boevau Canyon was that relatively moe complete primary development also meant relatively greater percentile ultimate primary recovery, and a relatively smaller secondary target.

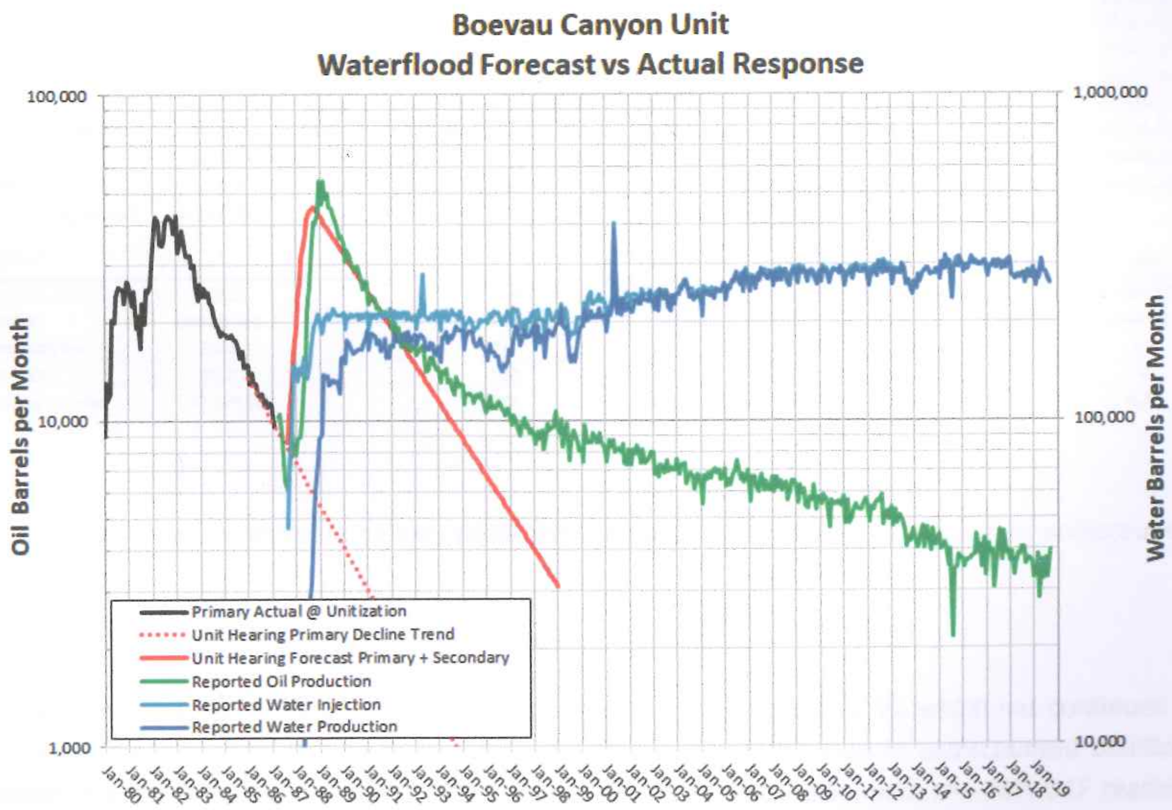

Figure 4.2: Boevau Canyon Field Unit Waterflood Forecast vs Actual Response

The original waterflood response forecast and primary decline were digitized from NOGCC unitization exhibits. Actual production performance was very similar for the first 5 years of waterflood, and better than forecast thereafter.

Better-than-forecast production performance should lead to better-than-forecast economics.

The original economic expectation is shown in Table 4.2.1, below, taken from the pre-unit waterflood feasibility study.

Table 4.2.1: Boevau Canyon Unit Originally-Proposed Waterflood Cashflow

Boevau Canyon Field Unit				Original from Feasibility Study						
Primary + Secondary Economics										
								undisc	disc	cum disc
	gross	net		net oil	direct	tax @	capex	cashflow	cashflow	cashflow
	oil	oil	$/bbl	revenue	opex	5%		BFIT	@10%	@10%
year	bbl	bbl		$	$	$	$	$	$	$
1985	197,059	160,603	25.00	4,015,077	720,000	200,754	2,800,000	294,323	280,626	280,626
1986	304,138	247,872	25.00	6,196,812	1,000,800	309,841	0	4,886,171	4,235,256	4,515,882
1987	565,044	460,511	25.00	11,512,772	1,000,800	575,639	0	9,936,333	7,829,687	12,345,569
1988	425,647	346,902	25.00	8,672,558	1,000,800	433,628	0	7,238,130	5,185,038	17,530,608
1989	337,119	274,752	25.00	6,868,800	1,000,800	343,440	0	5,524,560	3,597,747	21,128,354
1990	272,977	222,476	25.00	5,561,906	1,000,800	278,095	0	4,283,011	2,535,651	23,664,005
1991	228,826	186,493	25.00	4,662,330	1,000,800	233,116	0	3,428,413	1,845,188	25,509,193
1992	161,538	131,653	25.00	3,291,337	1,000,800	164,567	0	2,125,970	1,040,188	26,549,382
1993	153,600	125,184	25.00	3,129,600	1,000,800	156,480	0	1,972,320	877,283	27,426,664
1994	132,864	108,284	25.00	2,707,104	1,000,800	135,355	0	1,570,949	635,231	28,061,895
1995	114,927	93,666	25.00	2,341,638	1,000,800	117,082	0	1,223,756	449,854	28,511,749
1996	99,412	81,021	25.00	2,025,520	1,000,800	101,276	0	923,444	308,599	28,820,348
1997	85,992	70,083	25.00	1,752,087	1,000,800	87,604	0	663,683	201,628	29,021,977
1998	74,383	60,622	25.00	1,515,554	1,000,800	75,778	0	438,976	121,238	29,143,215
1999	64,341	52,438	25.00	1,310,948	1,000,800	65,547	0	244,600	61,413	29,204,628
	3,217,867	2,622,562		65,564,040	14,731,200	3,278,202	2,800,000	44,754,638	29,204,628	
						5%	10%	15%	20%	25%
NRI		0.815			CFBT	35,666,970	29,204,628	24,438,562	20,814,981	17,988,997
BFIT ROR		undefined			disc invest	2,732,520	2,669,695	2,611,013	2,556,039	2,504,396
undisc prof/inv		16.0			P/I	13.1	10.9	9.4	8.1	7.2
undisc ROI		17.0			P/R	0	0	0	0	0
operating income		47,554,638			ROI	14.1	11.9	10.4	9.1	8.2

The waterflood was expected to be very profitable, earning approximately $45 million in undiscounted cashflow.

The actual waterflood economics are shown in Table 4.3.2, below.

The Unit produced about 800,000 more barrels of oil, during a productive life which has continued to the current day. To date, the Unit has earned approximately $60 million in undiscounted cashflow. However, the cashflow discounted at 10% is lower than the original plan, with the 10% DCF reaching about $17 million versus $29 million in the original plan.

The lower discounted cashflow is due to lower actual oil price versus plan. For all the actual cashflow estimates in this paper, actual oil price has been estimated as the WTI Cushing spot price minus $3 per barrel. That estimated price first modestly exceeded the original plan of $25 constant price in calendar year 2000, and did not remain above $25 until 2003.

Table 4.2.2: Boevau Canyon Unit Estimate of Actual Waterflood Cashflow

Boevau Canyon Field Unit				ACTUAL OIL RECOVERY & OIL PRICE; OPEX and CAPEX unchanged and unescalated						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 5% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1987	73,835	60,176	16.20	974,844	750,600	48,742	2,800,000	-2,624,499	-2,502,361	-2,502,361
1988	266,347	217,073	12.97	2,815,434	1,000,800	140,772	0	1,673,863	1,450,878	-1,051,484
1989	538,685	439,028	16.64	7,305,430	1,000,800	365,272	0	5,939,359	4,680,129	3,628,646
1990	358,549	292,217	21.53	6,291,441	1,000,800	314,572	0	4,976,069	3,564,610	7,193,256
1991	271,073	220,924	18.54	4,095,940	1,000,800	204,797	0	2,890,343	1,882,272	9,075,527
1992	216,028	176,063	17.58	3,095,184	1,000,800	154,759	0	1,939,625	1,148,307	10,223,835
1993	186,768	152,216	15.43	2,348,692	1,000,800	117,435	0	1,230,457	662,238	10,886,072
1994	160,408	130,733	14.20	1,856,402	1,000,800	92,820	0	762,782	373,212	11,259,284
1995	142,169	115,868	15.43	1,787,839	1,000,800	89,392	0	697,647	310,312	11,569,596
1996	131,559	107,221	19.12	2,050,058	1,000,800	102,503	0	946,755	382,831	11,952,426
1997	116,855	95,237	17.61	1,677,120	1,000,800	83,856	0	592,464	217,791	12,170,217
1998	110,276	89,875	11.42	1,026,372	1,000,800	51,319	0	-25,747	-8,604	12,161,613
1999	107,372	87,508	16.34	1,429,884	1,000,800	71,494	0	357,589	108,637	12,270,250
2000	103,553	84,396	27.38	2,310,754	1,000,800	115,538	0	1,194,416	329,879	12,600,128
2001	96,587	78,718	22.98	1,808,949	1,000,800	90,447	0	717,701	180,198	12,780,326
2002	93,624	76,304	23.18	1,768,717	1,000,800	88,436	0	679,481	155,092	12,935,419
2003	85,774	69,906	28.08	1,962,955	1,000,800	98,148	0	864,007	179,283	13,114,701
2004	82,860	67,531	38.51	2,600,615	1,000,800	130,031	0	1,469,784	277,256	13,391,958
2005	79,908	65,125	53.64	3,493,306	1,000,800	174,665	0	2,317,841	397,483	13,789,441
2006	81,204	66,181	63.05	4,172,728	1,000,800	208,636	0	2,963,292	461,974	14,251,415
2007	76,610	62,437	69.34	4,329,392	1,000,800	216,470	0	3,112,122	441,069	14,692,484
2008	75,787	61,766	96.67	5,970,958	1,000,800	298,548	0	4,671,610	601,899	15,294,383
2009	70,009	57,057	58.95	3,363,530	1,000,800	168,176	0	2,194,553	257,046	15,551,429
2010	66,492	54,191	76.48	4,144,526	1,000,800	207,226	0	2,936,500	312,681	15,864,110
2011	64,041	52,193	91.88	4,795,531	1,000,800	239,777	0	3,554,954	344,123	16,208,233
2012	64,037	52,190	91.05	4,751,914	1,000,800	237,596	0	3,513,518	309,192	16,517,425
2013	57,176	46,598	94.98	4,425,920	1,000,800	221,296	0	3,203,824	256,308	16,773,733
2014	51,715	42,148	90.17	3,800,460	1,000,800	190,023	0	2,609,637	189,793	16,963,527
2015	45,147	36,795	45.66	1,680,051	1,000,800	84,003	0	595,248	39,356	17,002,883
2016	46,425	37,836	40.29	1,524,428	1,000,800	76,221	0	447,406	26,892	17,029,774
2017	47,133	38,413	47.80	1,836,160	1,000,800	91,808	0	743,552	40,629	17,070,403
2018	45,113	36,767	62.23	2,288,016	1,000,800	114,401	0	1,172,816	58,259	17,128,662
2019	31,238	25,459	53.98	1,374,381	1,000,800	68,719	0	304,862	13,767	17,142,429
2020	0	0	62.00	0	0	0	0	0	0	17,142,429
	4,044,357	3,296,151		99,157,932	32,776,200	4,957,897	2,800,000	58,623,835	17,142,429	

					5%	10%	15%	20%	25%
NRI	0.815			CFBT	28,486,548	17,142,429	11,955,570	9,096,557	7,263,944
BFIT ROR	120.3%			disc invest	2,732,520	2,669,695	2,611,013	2,556,039	2,504,396
undisc prof/inv	20.9			P/I	10.4	6.4	4.6	3.6	2.9
undisc ROI	21.9			P/R	0	0	0	0	0
operating income	61,423,835			ROI	11.4	7.4	5.6	4.6	3.9

I suspect cost reduction measures have been put in place given the many years of operation, but I don't have access actual operating costs. As a result, as noted earlier, opex has been held constant and unchanged from the original economic estimate.

Although the discounted profit has been lower than the original plan, Boevau Canyon has been a very profitable waterflood, with the estimated BFIT ROR for the project exceeding 120%.

4.3 Husker Field Unit

Figure 4.3 (below) shows the forecast and actual waterflood response of the Husker Field Unit. Husker is located immediately north of Boevau Canyon, and shares many similar characteristics. The flood pattern was also a regular 5 spot.

The original waterflood response forecast and primary decline were digitized from NOGCC unitization exhibits. The forecast primary + secondary peak is obviously lower than the actual primary production peak, and the forecast secondary:primary ratio was 0.76, lower than a common LKC waterflood expectation of 1:1. Although I was involved with the Husker waterflood design and forecast, I don't recall why this relatively conservative waterflood performance forecast was used for unitization.

Whatever the cause of the relatively conservative waterflood forecast, actual field waterflood performance was significantly better than the forecast predicts. Volumes reported at unitization, reflecting recovery after 1/1/1987, were remaining primary recovery of 274,000 barrels, and secondary recovery of 746,000 barrels, for a remaining recovery total of just over 1 million barrels. In fact, Husker has produced almost 2.5 million barrels through 3Q2019. Husker exceeded the 1 million barrel target in just over 4 years following unitization.

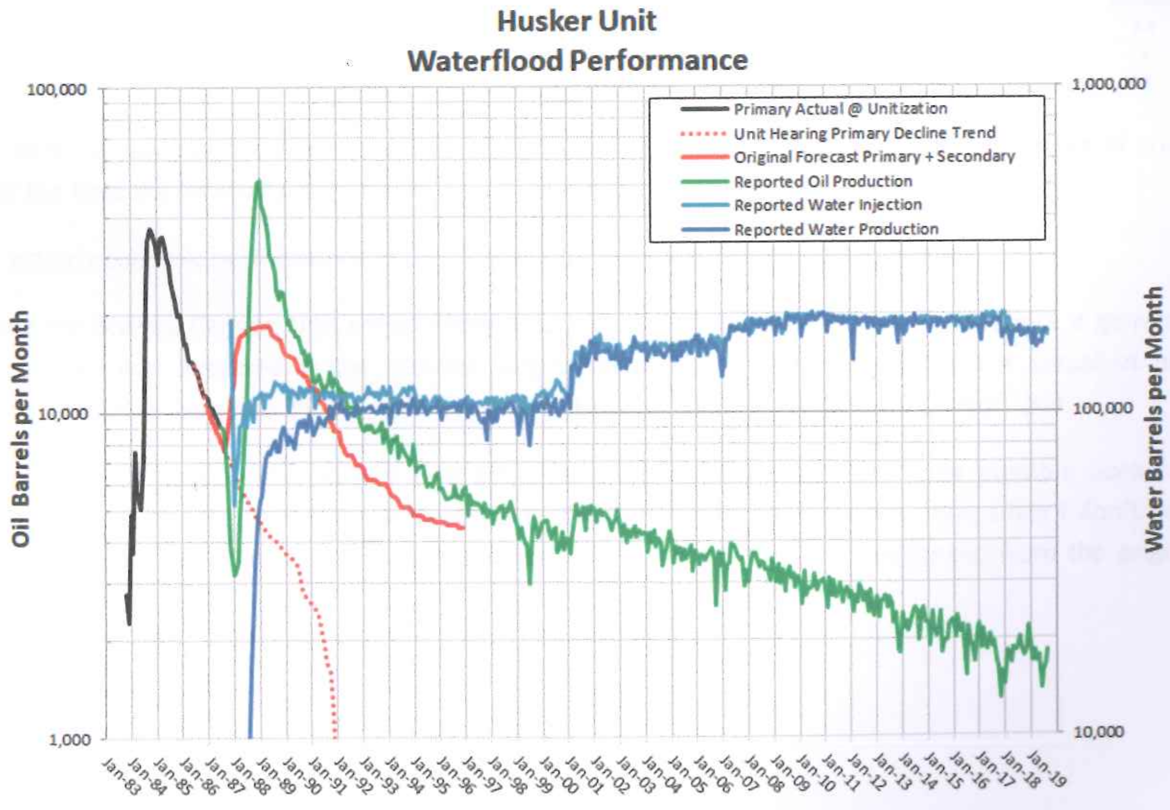

Figure 4.3: Husker Field Unit Waterflood Forecast vs Actual Response

The original estimate of Husker waterflood economic performance, taken from the waterflood feasibility study and presented at the unitization hearing, is shown on Table 4.4.1, below.

Table 4.3.1: Husker Unit Originally-Proposed Waterflood Cashflow

Husker Field Unit				Original from Feasibility Study						
Primary + Secondary Economics										
								undisc	disc	cum disc
	gross	net		net oil	direct	tax @	capex	cashflow	cashflow	cashflow
	oil	oil	$/bbl	revenue	opex	5%		BFIT	@10%	@10%
year	bbl	bbl		$	$	$	$	$	$	$
1986	83,280	69,122	12.85	888,223	280,000	44,411	0	563,812	537,573	537,573
1987	107,903	89,559	12.85	1,150,839	509,292	57,542	974,718	-390,713	-338,663	198,910
1988	200,848	166,704	12.85	2,142,144	597,168	107,107	0	1,437,869	1,133,020	1,331,930
1989	205,548	170,605	12.85	2,192,272	597,168	109,614	0	1,485,491	1,064,132	2,396,062
1990	163,104	135,376	12.85	1,739,586	597,168	86,979	0	1,055,438	687,331	3,083,393
1991	123,804	102,757	12.85	1,320,432	597,168	66,022	0	657,242	389,104	3,472,497
1992	93,244	77,393	12.85	994,494	657,168	49,725	0	287,601	154,788	3,627,285
1993	69,312	57,529	12.85	739,247	597,168	36,962	0	105,117	51,431	3,678,716
1994	61,368	50,935	12.85	654,520	597,168	32,726	0	24,626	10,954	3,689,670
	1,108,411	919,981		11,821,758	5,029,468	591,088	974,718	5,226,484	3,689,670	
						5%	10%	15%	20%	25%
NRI		0.83			CFBT	4,360,692	3,689,670	3,161,334	2,739,431	2,398,219
BFIT ROR		undefined			disc invest	905,931	844,870	790,373	741,493	697,451
undisc prof/inv		5.4			P/I	4.8	4.4	4.0	3.7	3.4
undisc ROI		6.4			P/R	0	0	0	0	0
operating income		6,201,202			ROI	5.8	5.4	5.0	4.7	4.4

The oil price assumed for this analysis was $13.50 ($12.85 per barrel after deducts), the price of crude oil at the time the forecasts were made.

The actual economic performance of the Husker Unit is shown on Table 4.4.2, below.

Unlike the Boevau Canyon Unit actual economics, oil price in the Husker actual economics is generally higher than was assumed in the pre-unit original economics. This helps make the actual vs plan economic comparison look much better for the Husker Unit than for the Boevau Canyon Unit.

A factor which would make Husker Unit actual economics even better would be possible opex cost reductions, which may have been achieved over the many years of operation. But, since I don't have that actual opex data, for this analysis opex has been held constant and unchanged from the original economic estimate.

Table 4.3.2: Husker Unit Estimate of Actual Waterflood Cashflow

Husker Field Unit				ACTUAL OIL RECOVERY & OIL PRICE; OPEX and CAPEX unchanged and unescalated						
Primary + Secondary Economics										
								undisc	disc	cum disc
	gross	net		net oil	direct	tax @	capex	cashflow	cashflow	cashflow
	oil	oil	$/bbl	revenue	opex	5%		BFIT	@10%	@10%
year	bbl	bbl		$	$	$	$	$	$	$
1987	40,369	33,506	16.20	542,802	298,584	27,140	974,718	-757,641	-722,382	-722,382
1988	214,985	178,438	12.97	2,314,335	597,168	115,717	0	1,601,450	1,388,112	665,730
1989	392,203	325,528	16.64	5,416,794	597,168	270,840	0	4,548,786	3,584,378	4,250,108
1990	206,184	171,133	21.53	3,684,487	597,168	184,224	0	2,903,095	2,079,634	6,329,742
1991	151,013	125,341	18.54	2,323,818	597,168	116,191	0	1,610,459	1,048,776	7,378,518
1992	129,725	107,672	17.58	1,892,869	657,168	94,643	0	1,141,058	675,535	8,054,053
1993	105,969	87,954	15.43	1,357,134	597,168	67,857	0	692,110	372,497	8,426,550
1994	91,910	76,285	14.20	1,083,251	597,168	54,163	0	431,921	211,329	8,637,878
1995	78,039	64,772	15.43	999,438	597,168	49,972	0	352,298	156,701	8,794,580
1996	67,349	55,900	19.12	1,068,802	597,168	53,440	0	418,194	169,101	8,963,681
1997	62,344	51,746	17.61	911,239	597,168	45,562	0	268,509	98,704	9,062,385
1998	59,304	49,222	11.42	562,119	597,168	28,106	0	-63,155	-21,105	9,041,280
1999	49,985	41,488	16.34	677,907	597,168	33,895	0	46,843	14,231	9,055,511
2000	50,662	42,049	27.38	1,151,314	597,168	57,566	0	496,581	137,148	9,192,658
2001	56,068	46,536	22.98	1,069,407	597,168	53,470	0	418,769	105,143	9,297,801
2002	57,381	47,626	23.18	1,103,976	597,168	55,199	0	451,609	103,080	9,400,882
2003	51,244	42,533	28.08	1,194,313	597,168	59,716	0	537,430	111,517	9,512,399
2004	47,586	39,496	38.51	1,521,006	597,168	76,050	0	847,787	159,924	9,672,324
2005	44,137	36,634	53.64	1,965,032	597,168	98,252	0	1,269,613	217,724	9,890,048
2006	42,086	34,931	63.05	2,202,424	597,168	110,121	0	1,495,134	233,090	10,123,137
2007	41,740	34,644	69.34	2,402,229	597,168	120,111	0	1,684,949	238,801	10,361,939
2008	40,574	33,676	96.67	3,255,500	597,168	162,775	0	2,495,557	321,532	10,683,471
2009	37,470	31,100	58.95	1,833,351	597,168	91,668	0	1,144,515	134,056	10,817,527
2010	35,198	29,214	76.48	2,234,313	597,168	111,716	0	1,525,429	162,429	10,979,956
2011	33,629	27,912	91.88	2,564,561	597,168	128,228	0	1,839,165	178,033	11,157,989
2012	31,687	26,300	91.05	2,394,634	597,168	119,732	0	1,677,734	147,642	11,305,631
2013	28,995	24,066	94.98	2,285,774	597,168	114,289	0	1,574,318	125,947	11,431,577
2014	27,653	22,952	90.17	2,069,581	597,168	103,479	0	1,368,934	99,560	11,531,137
2015	25,525	21,186	45.66	967,341	597,168	48,367	0	321,806	21,277	11,552,414
2016	24,316	20,182	40.29	813,144	597,168	40,657	0	175,319	10,538	11,562,951
2017	22,065	18,314	47.80	875,407	597,168	43,770	0	234,468	12,812	11,575,763
2018	21,953	18,221	62.23	1,133,892	597,168	56,695	0	480,030	23,845	11,599,608
2019	15,296	12,696	53.98	685,366	597,168	34,268	0	53,929	2,435	11,602,043
2020	0	0	62.00	0	0	0	0	0	0	11,602,043
	2,384,644	1,979,255		56,557,559	19,467,960	2,827,878	974,718	33,287,004	11,602,043	
						5%	10%	15%	20%	25%
NRI		0.83			CFBT	17,686,150	11,602,043	8,696,269	7,018,724	5,897,384
BFIT ROR		293.1%			disc invest	951,227	929,357	908,929	889,792	871,814
undisc prof/inv		34.2			P/I	18.6	12.5	9.6	7.9	6.8
undisc ROI		35.2			P/R	0	0	0	0	0
operating income		34,261,722			ROI	19.6	13.5	10.6	8.9	7.8

The Husker Unit has easily exceeded initial estimates of oil recovery and economic performance. Actual undiscounted and discounted cashflows were much higher, and all economic metrics are extremely attractive.

4.4 Bishop Field Unit

Figure 4.4 (below) shows the forecast and actual waterflood response of the Bishop Field Unit. The Bishop Field is located immediately north of the Husker Field, continuing the trend of fields beginning with Boevau Canyon. Bishop is similar in many ways to Husker and Boevau Canyon, and was also implemented as a regular 5 spot.

The original waterflood response forecast and primary decline were digitized from NOGCC exhibits. The forecast primary + secondary is similar to the Husker waterflood forecast in that the waterflood peak is noticeably lower than the actual primary production peak. The Bishop Field forecast secondary:primary ratio was 0.89, better than Husker at 0.76, but lower than Boevau Canyon at 1.0.

And, as with Husker, Bishop Field actual waterflood performance was significantly better than the forecast predicts. Volumes reported at unitization, reflecting recovery after 1/1/1989, were remaining primary recovery of 467,000 barrels, and secondary recovery 1,005,000 barrels, for a remaining recovery total of 1,472,000 barrels. In fact, after unitization Bishop has produced just under 2 million barrels through 3Q2019. Bishop exceeded the 1.47 million barrel target in 2005, 16 years following unitization.

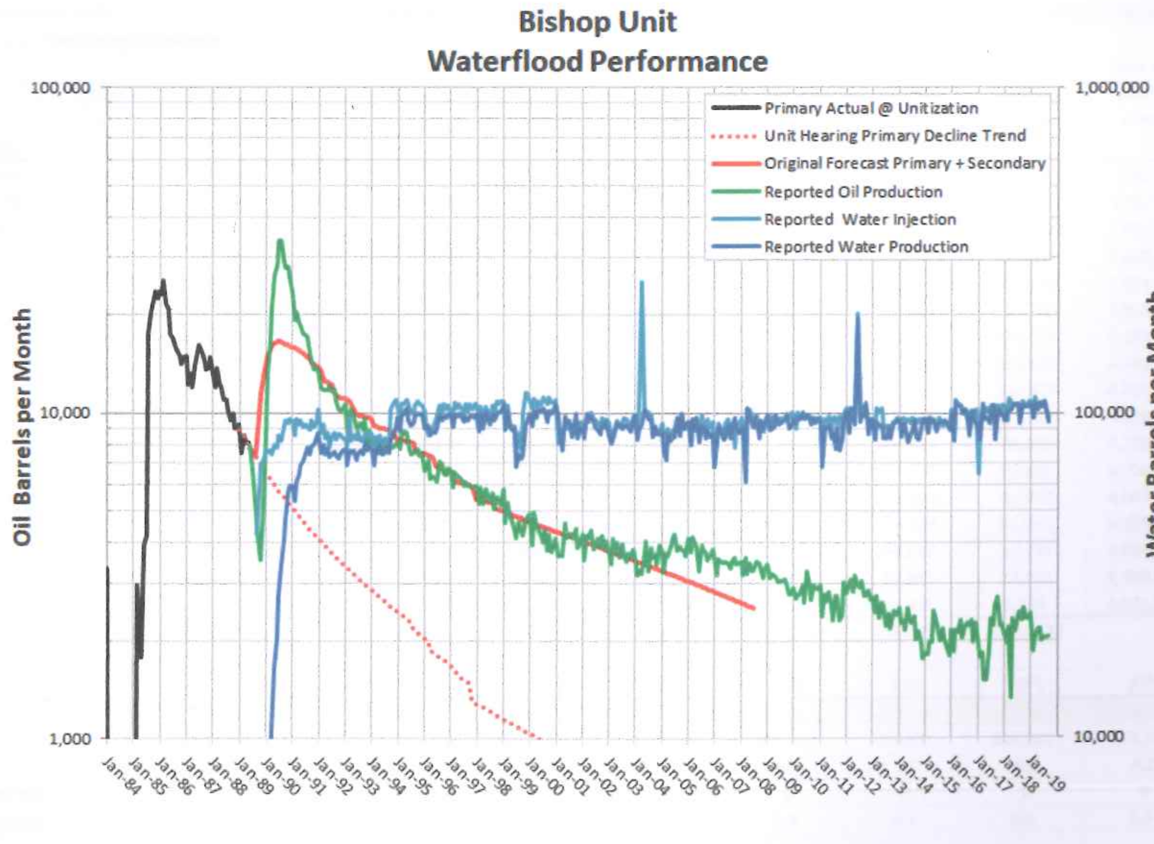

Figure 4.4: Bishop Field Unit Waterflood Forecast vs Actual Response

A comparison of Boevau Canyon, Husker and Bishop waterflood recovery is shown below in Table 4.4.1, where volumes shown are tabulated beginning at unitization, and through 3Q2019. This comparison shows that Bishop, although smaller, has exhibited higher recovery efficiency over waterflood life.

Table 4.4.1: Comparison of Bishop, Husker and Boevau Cumulative Production and Injection

	Cumulative Production	Cumulative Injection	Cum Oil / Cum Inj
Boevau Canyon	4,044,357	94,049,222	4.3%
Husker	2,384,644	57,206,139	4.2%
Bishop	1,977,486	34,540,223	5.7%

The pre-unitization cashflow is estimated as shown below, on Table 4.4.2. I could not find an original pre-unit cashflow, but the following should be a close approximation. It is based on the original primary plus secondary decline forecast, and constant oil price and capex quoted in the unitization hearing transcript. Opex was estimated based on costs quoted in the 1985 Boevau Canyon waterflood feasibility study. The resulting undiscounted cashflow matches the reported pre-unitization secondary-only target value of $6.9 million.

Table 4.4.2: Bishop Unit Estimate of Originally-Proposed Waterflood Cashflow

Bishop Field Unit				Original not available; this cashflow is estimated, but matched to data reported at NOGCC hearing						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 5% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1989	65,173	54,094	15.00	811,404	245,000	40,570	960,000	-434,166	-342,117	-342,117
1990	191,650	159,070	15.00	2,386,043	420,000	119,302	0	1,846,740	1,322,913	980,797
1991	180,450	149,774	15.00	2,246,603	420,000	112,330	0	1,714,272	1,116,382	2,097,178
1992	145,600	120,848	15.00	1,812,720	420,000	90,636	0	1,302,084	770,867	2,868,045
1993	122,400	101,592	15.00	1,523,880	420,000	76,194	0	1,027,686	553,106	3,421,151
1994	107,350	89,101	15.00	1,336,508	420,000	66,825	0	849,682	415,730	3,836,881
1995	95,600	79,348	15.00	1,190,220	420,000	59,511	0	710,709	316,121	4,153,002
1996	84,150	69,845	15.00	1,047,668	420,000	52,383	0	575,284	232,623	4,385,625
1997	73,350	60,881	15.00	913,208	420,000	45,660	0	447,547	164,519	4,550,143
1998	62,950	52,249	15.00	783,728	420,000	39,186	0	324,541	108,456	4,658,599
1999	57,900	48,057	15.00	720,855	420,000	36,043	0	264,812	80,451	4,739,050
2000	53,827	44,676	15.00	670,141	420,000	33,507	0	216,634	59,831	4,798,881
2001	50,329	41,773	15.00	626,602	420,000	31,330	0	175,271	44,007	4,842,887
2002	47,025	39,031	15.00	585,462	420,000	29,273	0	136,189	31,085	4,873,973
2003	43,893	36,431	15.00	546,470	420,000	27,324	0	99,147	20,573	4,894,546
2004	40,917	33,961	15.00	509,414	420,000	25,471	0	63,943	12,062	4,906,608
2005	38,081	31,607	15.00	474,109	420,000	23,705	0	30,404	5,214	4,911,822
	1,460,645	1,212,335		18,185,031	6,965,000	909,252	960,000	9,350,779	4,911,822	
						5%	10%	15%	20%	25%
NRI		0.83			CFBT	6,657,071	4,911,822	3,728,765	2,896,605	2,293,186
BFIT ROR		415.3%			disc invest	849,763	756,466	676,903	608,581	549,536
undisc prof/inv		9.7			P/I	7.8	6.5	5.5	4.8	4.2
undisc ROI		10.7			P/R	0	0	0	0	0
operating income		10,310,779			ROI	8.8	7.5	6.5	5.8	5.2

As with the Husker Unit, oil prices in these Bishop Unit actual waterflood economics are generally higher than was assumed in the pre-unit original economics.

Table 4.4.3: Bishop Unit Estimate of Actual Waterflood Cashflow

Bishop Field Unit				ACTUAL OIL RECOVERY & OIL PRICE; OPEX and CAPEX unchanged and unescalated						
Primary + Secondary Economics										
								undisc	disc	cum disc
	gross	net		net oil	direct	tax @	capex	cashflow	cashflow	cashflow
	oil	oil	$/bbl	revenue	opex	5%		BFIT	@10%	@10%
year	bbl	bbl		$	$	$	$	$	$	$
1989	37,013	30,721	16.64	511,194	245,000	25,560	960,000	-719,366	-566,850	-566,850
1990	293,301	243,440	21.53	5,241,260	420,000	262,063	0	4,559,197	3,265,983	2,699,133
1991	209,879	174,200	18.54	3,229,660	420,000	161,483	0	2,648,177	1,724,566	4,423,700
1992	137,811	114,383	17.58	2,010,855	420,000	100,543	0	1,490,313	882,303	5,306,002
1993	111,928	92,900	15.43	1,433,451	420,000	71,673	0	941,778	506,870	5,812,872
1994	94,215	78,198	14.20	1,110,418	420,000	55,521	0	634,897	310,641	6,123,512
1995	94,962	78,818	15.43	1,216,169	420,000	60,808	0	735,360	327,086	6,450,599
1996	79,396	65,899	19.12	1,259,983	420,000	62,999	0	776,984	314,182	6,764,781
1997	74,004	61,423	17.61	1,081,665	420,000	54,083	0	607,581	223,348	6,988,128
1998	66,212	54,956	11.42	627,597	420,000	31,380	0	176,217	58,889	7,047,017
1999	56,492	46,888	16.34	766,156	420,000	38,308	0	307,848	93,525	7,140,542
2000	51,054	42,375	27.38	1,160,223	420,000	58,011	0	682,211	188,416	7,328,958
2001	48,635	40,367	22.98	927,635	420,000	46,382	0	461,253	115,810	7,444,768
2002	48,307	40,095	23.18	929,398	420,000	46,470	0	462,928	105,664	7,550,432
2003	44,970	37,325	28.08	1,048,089	420,000	52,404	0	575,684	119,455	7,669,887
2004	42,709	35,448	38.51	1,365,121	420,000	68,256	0	876,865	165,410	7,835,297
2005	45,492	37,758	53.64	2,025,358	420,000	101,268	0	1,504,091	257,934	8,093,231
2006	45,549	37,806	63.05	2,383,647	420,000	119,182	0	1,844,465	287,550	8,380,781
2007	41,555	34,491	69.34	2,391,582	420,000	119,579	0	1,852,003	262,477	8,643,258
2008	40,308	33,456	96.67	3,234,157	420,000	161,708	0	2,652,449	341,747	8,985,005
2009	36,831	30,570	58.95	1,802,086	420,000	90,104	0	1,291,981	151,329	9,136,333
2010	34,401	28,553	76.48	2,183,720	420,000	109,186	0	1,654,534	176,176	9,312,510
2011	31,730	26,336	91.88	2,419,742	420,000	120,987	0	1,878,755	181,865	9,494,375
2012	34,814	28,896	91.05	2,630,946	420,000	131,547	0	2,079,399	182,989	9,677,363
2013	29,549	24,526	94.98	2,329,448	420,000	116,472	0	1,792,976	143,439	9,820,803
2014	26,540	22,028	90.17	1,986,283	420,000	99,314	0	1,466,969	106,690	9,927,492
2015	24,322	20,187	45.66	921,750	420,000	46,088	0	455,663	30,127	9,957,619
2016	25,825	21,435	40.29	863,606	420,000	43,180	0	400,426	24,068	9,981,687
2017	24,738	20,533	47.80	981,455	420,000	49,073	0	512,383	27,997	10,009,684
2018	26,261	21,797	62.23	1,356,404	420,000	67,820	0	868,584	43,146	10,052,831
2019	18,683	15,507	53.98	837,127	420,000	41,856	0	375,270	16,947	10,069,777
2020	0	0	62.00	0	0	0	0	0	0	10,069,777
	1,977,486	1,641,313		52,266,184	12,845,000	2,613,309	960,000	35,847,875	10,069,777	
						5%	10%	15%	20%	25%
NRI		0.83			CFBT	17,153,719	10,069,777	6,824,297	5,054,818	3,947,983
BFIT ROR		591.8%			disc invest	849,763	756,466	676,903	608,581	549,536
undisc prof/inv		37.3			P/I	20.2	13.3	10.1	8.3	7.2
undisc ROI		38.3			P/R	0	0	0	0	0
operating income		36,807,875			ROI	21.2	14.3	11.1	9.3	8.2

The Bishop Unit actual waterflood economics are much better than the pre-Unit forecast. The BFIT ROR is huge, due to low capex (since no drilling was required), and also due to sustained high oil production. The undiscounted and 10% discounted cumulative cashflows are much higher than had been forecast.

4.5 Bush Creek Unit

Figure 4.5 (below) shows the forecast and actual waterflood response of the Bush Creek Unit.

The Bush Creek Unit is located just east of the Boevau Canyon Field. It is of similar size and similar numbers of wells have been drilled, but unlike Boevau Canyon, Husker, and Bishop (all entirely LKC "F" fields), the Bush Creek field produces primarily from two reservoir units, the LKC lower "D" (comprising approximately 75% of the net acre feet) and the LKC "F".

The original waterflood response forecast and primary decline were digitized from NOGCC exhibits. The size of the originally forecast secondary recovery response appears larger than primary recovery, but that is mainly because Bush Creek was much older than Boevau Canyon and the others, having been first drilled in 1962. As a result, the primary recovery curve was "spread out" over a number of years. The quoted ultimate primary recovery for Bush Creek was about 1.9 million barrels, with only 130,000 barrels remaining on 1/1/90. The forecast ultimate secondary recovery was about 1.4 million barrels, for a secondary:primary recovery ratio of 0.74 (similar to the Husker Unit).

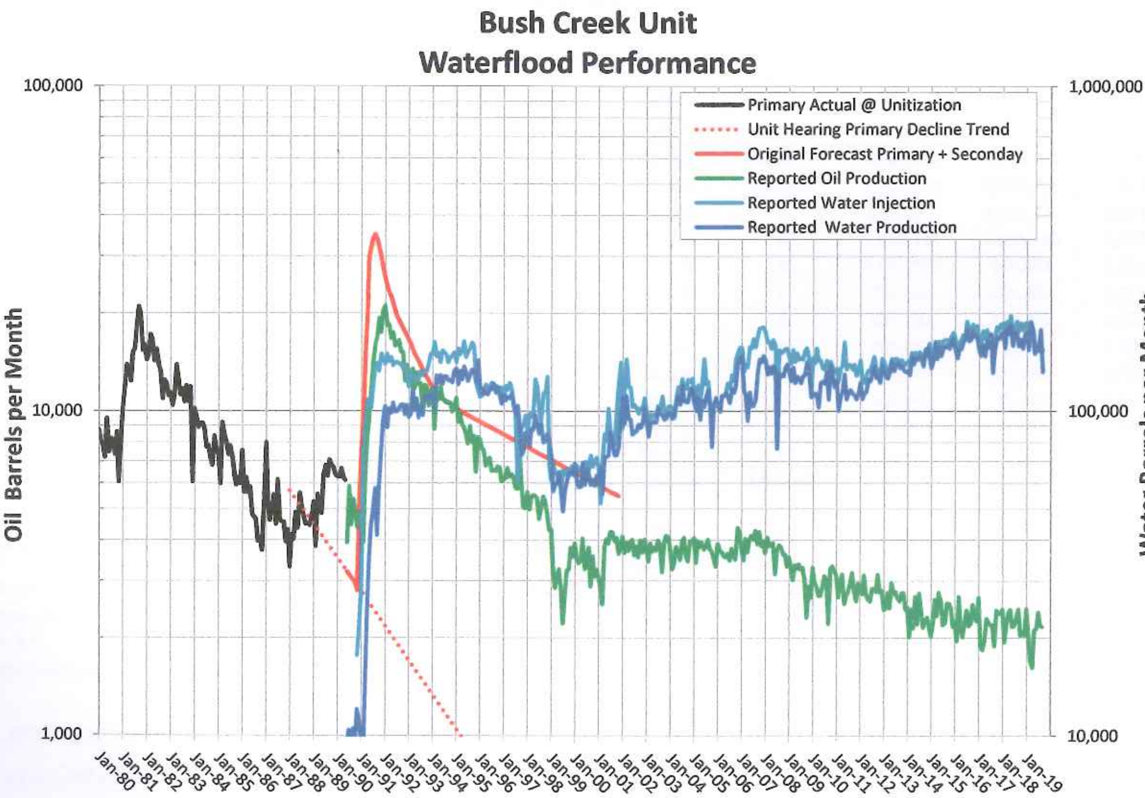

Figure 4.5: Bush Creek Unit Waterflood Forecast vs Actual Response

The actual waterflood response was poorer than the pre-unit forecast throughout waterflood life, although the shape of the actual response was similar. The largest deviations are seen between 1996 and 2007, and particularly between 1999 and 2002, when actual field injection rates were substantially reduced from the original plan.

Part of the reason Bush Creek waterflood response was below target was perhaps due to relatively lower injection than planned. The pre-unit forecast was based on 6,000 BWIPD (about 180,000 BWIPM). In fact, during 1992-1995, injection averaged about 140,000 BWIPM (77% of plan), and then was substantially reduced until 2007.

Bush Creek is also a multi-zone flood, as mentioned earlier. As a sensitivity, I found that reducing assumed injection to about 100,000 BWIPM from startup would result in a new revised analog forecast similar to early actual performance. Since actual injection was about 140,000 BWIPM, this could imply that about 30% of injected water was lost off-pattern, or perhaps that the LKC "F" horizon (about 25% of the total net pay) took its share of injection but did not respond.

The original economic expectation is shown in Table 4.5.1, below, taken from the pre-unit waterflood feasibility study.

Table 4.5.1: Bush Creek Field Unit Originally-Proposed Waterflood Cashflow

Bush Creek Field Unit				Original from Feasibility Study						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 6% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1990	38,016	31,249	18.00	562,485	840,000	33,749	2,200,000	-2,511,264	-2,394,397	-2,394,397
1991	312,576	256,937	18.00	4,624,874	840,000	277,492	800,000	2,707,382	2,346,716	-47,681
1992	252,168	207,282	18.00	3,731,078	840,000	223,865	0	2,667,213	2,101,726	2,054,045
1993	170,412	140,079	18.00	2,521,416	840,000	151,285	0	1,530,131	1,096,110	3,150,155
1994	133,584	109,806	18.00	1,976,509	840,000	118,591	0	1,017,918	662,897	3,813,052
1995	116,784	95,996	18.00	1,727,936	840,000	103,676	0	784,260	464,302	4,277,353
1996	103,116	84,761	18.00	1,525,704	840,000	91,542	0	594,162	319,781	4,597,134
1997	94,080	77,334	18.00	1,392,008	840,000	83,520	0	468,487	229,220	4,826,354
1998	84,912	69,798	18.00	1,256,358	840,000	75,381	0	340,976	151,665	4,978,020
1999	76,620	62,982	18.00	1,133,670	840,000	68,020	0	225,649	91,244	5,069,264
2000	68,016	55,909	18.00	1,006,365	840,000	60,382	0	105,983	38,959	5,108,223
2001	60,996	50,139	18.00	902,497	840,000	54,150	0	8,347	2,789	5,111,012
	1,511,280	1,242,272		22,360,899	10,080,000	1,341,654	3,000,000	7,939,245	5,111,012	
						5%	10%	15%	20%	25%
NRI		0.822			CFBT	6,326,425	5,111,012	4,172,374	3,432,107	2,837,664
BFIT ROR		90.3%			disc invest	2,890,523	2,791,045	2,700,210	2,616,897	2,540,173
undisc prof/inv		2.6			P/I	2.2	1.8	1.5	1.3	1.1
undisc ROI		3.6			P/R	0	0	0	0	0
operating income		10,939,245			ROI	3.2	2.8	2.5	2.3	2.1

The economics were less attractive than the neighboring fields, since capex and opex were similar to Boevau Canyon, but expected recovery was more similar to the smaller Husker and Bishop units. Still, the 10% discounted cashflow was expected to be about $5 million, with a BFIT ROR of about 90%.

The actual economic performance of the Bush Creek Field Unit is shown on Table 4.5.2, below. Oil price was lower than plan for 7 of the first 10 years of waterflood operations, and substantially lower in several of those years. And, as in some prior cases, for a field with marginal recovery, operating expenses become critical. However, in the economics shown below, I did not lower opex in years when oil price was low, and the Operator was likely making every attempt to control costs. I did not have the information to do so, and so held opex constant as previously assumed.

Table 4.5.2: Bush Creek Field Unit Estimate of Actual Waterflood Cashflow

Bush Creek Field Unit				ACTUAL OIL RECOVERY & OIL PRICE; OPEX and CAPEX unchanged and unescalated						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 6% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1990	33,769	27,758	21.53	597,632	490,000	35,858	2,200,000	-2,128,226	-2,029,184	-2,029,184
1991	148,607	122,155	18.54	2,264,753	840,000	135,885	800,000	488,868	423,743	-1,605,441
1992	197,261	162,149	17.58	2,850,571	840,000	171,034	0	1,839,537	1,449,529	-155,912
1993	143,358	117,840	15.43	1,818,275	840,000	109,097	0	869,179	622,637	466,725
1994	128,259	105,429	14.20	1,497,090	840,000	89,825	0	567,265	369,419	836,143
1995	104,864	86,198	15.43	1,330,038	840,000	79,802	0	410,236	242,870	1,079,014
1996	83,707	68,807	19.12	1,315,593	840,000	78,936	0	396,657	213,483	1,292,496
1997	73,367	60,308	17.61	1,062,018	840,000	63,721	0	158,297	77,451	1,369,947
1998	61,981	50,948	11.42	581,831	840,000	34,910	0	-293,079	-130,361	1,239,587
1999	38,327	31,505	16.34	514,788	840,000	30,887	0	-356,099	-143,993	1,095,594
2000	41,674	34,256	27.38	937,930	840,000	56,276	0	41,654	15,312	1,110,906
2001	44,177	36,313	22.98	834,484	840,000	50,069	0	-55,585	-18,576	1,092,331
2002	45,989	37,803	23.18	876,273	840,000	52,576	0	-16,304	-4,953	1,087,377
2003	45,538	37,432	28.08	1,051,097	840,000	63,066	0	148,031	40,884	1,128,261
2004	44,377	36,478	38.51	1,404,764	840,000	84,286	0	480,478	120,637	1,248,898
2005	45,035	37,019	53.64	1,985,687	840,000	119,141	0	1,026,546	234,310	1,483,209
2006	44,931	36,933	63.05	2,328,643	840,000	139,719	0	1,348,925	279,904	1,763,112
2007	47,324	38,900	69.34	2,697,349	840,000	161,841	0	1,695,508	319,836	2,082,948
2008	44,402	36,498	96.67	3,528,305	840,000	211,698	0	2,476,606	424,710	2,507,658
2009	37,303	30,663	58.95	1,807,588	840,000	108,455	0	859,132	133,938	2,641,596
2010	35,568	29,237	76.48	2,236,038	840,000	134,162	0	1,261,876	178,841	2,820,437
2011	34,397	28,274	91.88	2,597,846	840,000	155,871	0	1,601,975	206,402	3,026,838
2012	33,741	27,735	91.05	2,525,281	840,000	151,517	0	1,533,764	179,648	3,206,487
2013	31,823	26,159	94.98	2,484,535	840,000	149,072	0	1,495,463	159,238	3,365,725
2014	28,064	23,069	90.17	2,080,096	840,000	124,806	0	1,115,291	107,961	3,473,686
2015	28,748	23,631	45.66	1,078,985	840,000	64,739	0	174,246	15,334	3,489,020
2016	27,169	22,333	40.29	899,793	840,000	53,988	0	5,806	464	3,489,484
2017	26,377	21,682	47.80	1,036,395	840,000	62,184	0	134,211	9,761	3,499,245
2018	26,693	21,942	62.23	1,365,429	840,000	81,926	0	443,503	29,323	3,528,568
2019	18,852	15,496	53.98	836,557	840,000	50,193	0	-53,636	-3,224	3,525,344
2020	0	0	62.00	0	0	0	0	0	0	3,525,344
	1,745,682	1,434,951		48,425,664	24,850,000	2,905,540	3,000,000	17,670,124	3,525,344	

					5%	10%	15%	20%	25%
NRI	0.822			CFBT	7,463,579	3,525,344	1,814,451	967,541	488,182
BFIT ROR	34.1%			disc invest	2,890,523	2,791,045	2,700,210	2,616,897	2,540,173
undisc prof/inv	5.9			P/I	2.6	1.3	0.7	0.4	0.2
undisc ROI	6.9			P/R	0	0	0	0	0
operating income	20,670,124			ROI	3.6	2.3	1.7	1.4	1.2

Gross oil production eventually surpassed the original expectation, but it took until Aug-2011 (21 years) to do so. Oil prices eventually surpassed the original plan assumption of $18 flat oil price, but it took the oil price surge in 2005-2015 to make substantial impacts on cashflow.

The result is that the Bush Creek Unit waterflood was a modest recovery and financial success. Total recovery fell short of the original plan every year, but sustained long enough to exceed the original forecast total. Undiscounted cashflow was much higher thanks to a period of high oil price, but 10% discounted cashflow was $3.5 million, approaching the original target of $5.1 million.

4.6 Suess Field Unit

Figure 4.6 (below) shows the forecast and actual waterflood response of the Suess Field Unit

Because the field was described with an interpreted oil-water contact, injection wells were located with the intent of achieving gravity-stabilized displacement updip toward producers nearer the top of the moderate structural relief.

The original waterflood response forecast and primary decline were digitized from NOGCC unitization exhibits. Compared to many other waterfloods in the region, Suess waterflood performance was in the middle of the pack in terms of injection efficiency (fluid production rate / injection rate), but much better in terms of oil cut (oil cut vs injection volume). The excellent oil cut performance, much better than assumed for the forecast, is likely why the actual field waterflood response exceeded the forecast for 30 years.

A possible interpretation is that while single zone waterfloods are more likely to do well than multi-zone floods, and regular waterflood patterns more likely to do well than irregular patterns, gravity stabilized waterfloods may be the most attractive of all. During waterflood design, we speculated Suess waterflood displacement might be gravity stabilized.

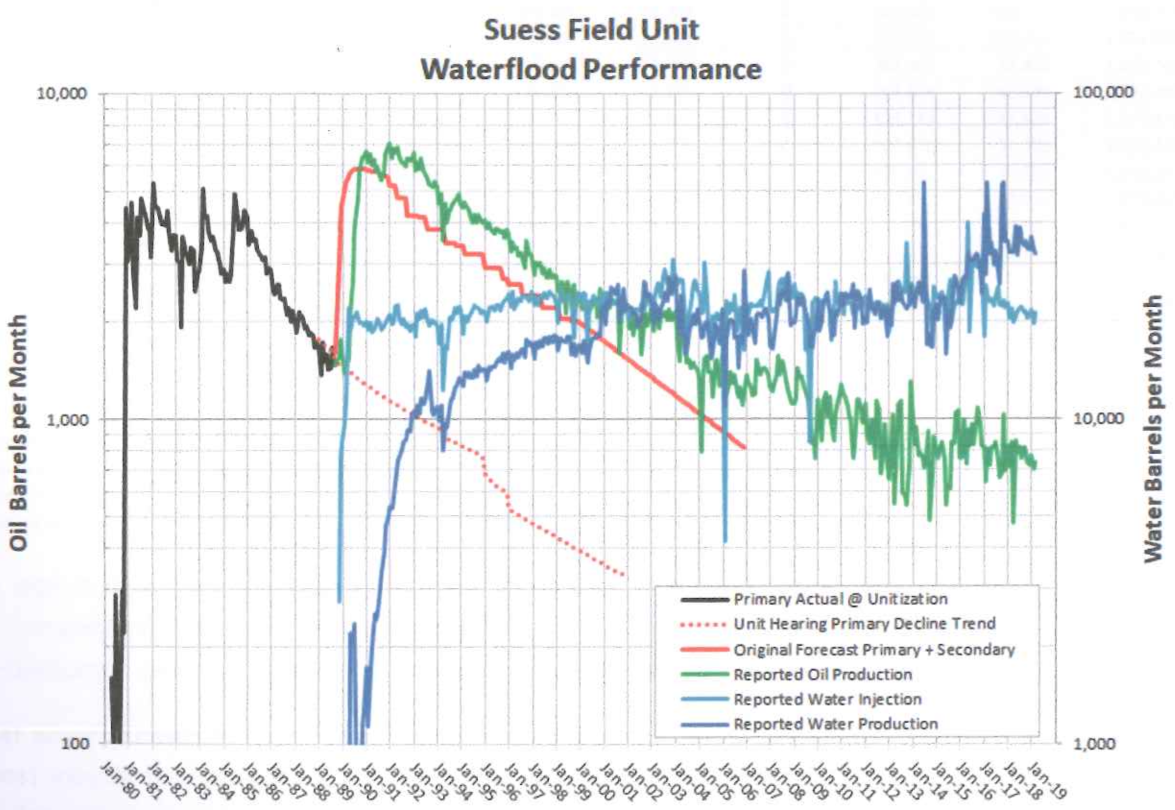

Figure 4.6: Suess Field Unit Waterflood Forecast vs Actual Response

In terms of economic performance, the Suess Unit is a special case.

The original Unit economics are estimated below, in Table 4.6.1. In this case, I also could not find an original cashflow, but a transcript of unitization testimony is posted on the NOGCC website, and provides key metrics to allow matching the following cashflow:

Table 4.6.1: Suess Unit Estimate of Originally-Proposed Waterflood Cashflow

Suess Unit				Original not available; this cashflow is estimated, but matched to data reported at NOGCC hearing						
Primary + Secondary Economics										
								undisc	disc	cum disc
	gross	net		net oil	direct	tax @	capex	cashflow	cashflow	cashflow
	oil	oil	$/bbl	revenue	opex	5%		BFIT	@10%	@10%
year	bbl	bbl		$	$	$	$	$	$	$
1985	0	0	0	0	0	0	0	0	0	0
1986	0	0	16.00	0	0	0	0	0	0	0
1987	0	0	16.00	0	0	0	0	0	0	0
1988	0	0	16.00	0	0	0	0	0	0	0
1989	10,300	8,549	16.00	136,784	45,000	6,839	600,000	-515,055	-491,086	-491,086
1990	66,850	55,486	16.00	887,768	180,000	44,388	0	663,380	575,007	83,921
1991	68,385	56,760	16.00	908,153	180,000	45,408	0	682,745	537,993	621,914
1992	57,150	47,435	16.00	758,952	180,000	37,948	0	541,004	387,549	1,009,463
1993	48,300	40,089	16.00	641,424	180,000	32,071	0	429,353	279,606	1,289,070
1994	42,700	35,441	16.00	567,056	180,000	28,353	0	358,703	212,361	1,501,431
1995	38,800	32,204	16.00	515,264	180,000	25,763	0	309,501	166,575	1,668,006
1996	34,200	28,386	16.00	454,176	180,000	22,709	0	251,467	123,037	1,791,043
1997	30,200	25,066	16.00	401,056	180,000	20,053	0	201,003	89,406	1,880,449
1998	27,400	22,742	16.00	363,872	180,000	18,194	0	165,678	66,994	1,947,443
1999	24,550	20,377	16.00	326,024	180,000	16,301	0	129,723	47,686	1,995,129
2000	22,401	18,593	16.00	297,490	180,000	14,875	0	102,616	34,292	2,029,421
2001	19,700	16,351	16.00	261,612	180,000	13,081	0	68,531	20,820	2,050,241
2002	17,324	14,379	16.00	230,061	180,000	11,503	0	38,558	10,649	2,060,890
2003	15,235	12,645	16.00	202,315	180,000	10,116	0	12,199	3,063	2,063,953
2004	13,397	11,120	16.00	177,915	180,000	8,896	0	-10,981	-2,506	2,061,447
2005	11,781	9,779	16.00	156,458	180,000	7,823	0	-31,365	-6,508	2,054,939
2006	10,361	8,599	16.00	137,588	180,000	6,879	0	-49,291	-9,298	2,045,640
	559,034	463,998		7,423,968	3,105,000	371,198	600,000	3,347,769	2,045,640	
						5%	10%	15%	20%	25%
NRI		0.83			CFBT	2,589,443	2,045,640	1,645,291	1,343,053	1,109,593
BFIT ROR		122.0%			disc invest	585,540	572,078	559,503	547,723	536,656
undisc prof/inv		5.6			P/I	4.4	3.6	2.9	2.5	2.1
undisc ROI		6.6			P/R	0	0	0	0	0
operating income		3,947,769			ROI	5.4	4.6	3.9	3.5	3.1

The expected primary + secondary recovery is reported in the unitization hearing transcript, as are the $16 constant oil price, and approximately $0.6 million capex. The results, above, match the recorded pre-unitization secondary target value of $2.5 million undiscounted cashflow.

What wasn't known at the time of the unitization hearing was that the First Gulf War would occur at almost exactly the same time that the Suess Unit would reach peak production. The result of the invasion of Kuwait and subsequent war increased, although briefly, oil prices from about $17 per barrel to over $40 per barrel, with the peak occurring in 3Q1990. Suess production peaked at the same time.

In one month, October, 1990, Suess production had increased from an initial 60 BOPD to over 200 BOPD, and held that average for over 3 years. Oil prices increased from $17 per day to over $40 per day. The entire Suess Unit waterflood investment of approximately $600,000 was paid out in about 4 months of incremental production.

The following Table 4.6.2 shows the estimated actual economic performance of the Suess Field Unit.

Table 4.6.2: Suess Unit Estimate of Actual Waterflood Cashflow

Suess Unit				ACTUAL OIL RECOVERY & OIL PRICE; OPEX and CAPEX unchanged and unescalated						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 5% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1989	6,262	5,197	16.64	86,486	45,000	4,324	600,000	-562,839	-536,646	-536,646
1990	41,949	34,818	21.53	749,624	180,000	37,481	0	532,143	461,253	-75,392
1991	73,346	60,877	18.54	1,128,663	180,000	56,433	0	892,230	703,064	627,672
1992	77,114	64,005	17.58	1,125,201	180,000	56,260	0	888,941	636,793	1,264,466
1993	68,681	57,005	15.43	879,591	180,000	43,980	0	655,611	426,952	1,691,418
1994	54,483	45,221	14.20	642,137	180,000	32,107	0	430,030	254,589	1,946,006
1995	51,430	42,687	15.43	658,659	180,000	32,933	0	445,726	239,892	2,185,898
1996	45,871	38,073	19.12	727,954	180,000	36,398	0	511,557	250,293	2,436,191
1997	39,566	32,840	17.61	578,309	180,000	28,915	0	369,393	164,305	2,600,496
1998	34,402	28,554	11.42	326,083	180,000	16,304	0	129,779	52,477	2,652,974
1999	29,508	24,492	16.34	400,193	180,000	20,010	0	200,184	73,588	2,726,561
2000	27,343	22,695	27.38	621,381	180,000	31,069	0	410,312	137,119	2,863,680
2001	26,706	22,166	22.98	509,374	180,000	25,469	0	303,906	92,327	2,956,008
2002	23,635	19,617	23.18	454,723	180,000	22,736	0	251,987	69,595	3,025,602
2003	24,675	20,480	28.08	575,085	180,000	28,754	0	366,331	91,977	3,117,580
2004	19,855	16,480	38.51	634,631	180,000	31,732	0	422,900	96,527	3,214,107
2005	16,144	13,400	53.64	718,750	180,000	35,938	0	502,813	104,334	3,318,441
2006	15,228	12,639	63.05	796,904	180,000	39,845	0	577,059	108,855	3,427,296
2007	16,261	13,497	69.34	935,856	180,000	46,793	0	709,064	121,596	3,548,893
2008	15,749	13,072	96.67	1,263,638	180,000	63,182	0	1,020,456	159,088	3,707,980
2009	13,481	11,189	58.95	659,605	180,000	32,980	0	446,625	63,298	3,771,279
2010	12,653	10,502	76.48	803,192	180,000	40,160	0	583,033	75,119	3,846,398
2011	12,607	10,464	91.88	961,415	180,000	48,071	0	733,344	85,896	3,932,294
2012	10,900	9,047	91.05	823,729	180,000	41,186	0	602,543	64,159	3,996,453
2013	9,929	8,241	94.98	782,737	180,000	39,137	0	563,600	54,557	4,051,010
2014	9,678	8,033	90.17	724,312	180,000	36,216	0	508,097	44,713	4,095,723
2015	9,513	7,896	45.66	360,522	180,000	18,026	0	162,496	13,000	4,108,723
2016	10,594	8,793	40.29	354,271	180,000	17,714	0	156,557	11,386	4,120,109
2017	9,253	7,680	47.80	367,104	180,000	18,355	0	168,748	11,157	4,131,266
2018	9,114	7,565	62.23	470,746	180,000	23,537	0	267,209	16,061	4,147,327
2019	5,898	4,895	53.98	264,271	180,000	13,214	0	71,057	3,883	4,151,209
2020	0	0	62.00	0	0	0	0	0	0	4,151,209
	821,828	682,117		20,385,147	5,445,000	1,019,257	600,000	13,320,890	4,151,209	

				5%	10%	15%	20%	25%
NRI	0.83		CFBT	6,854,010	4,151,209	2,829,531	2,085,037	1,614,332
BFIT ROR	118.0%		disc invest	585,540	572,078	559,503	547,723	536,656
undisc prof/inv	22.2		P/I	11.7	7.3	5.1	3.8	3.0
undisc ROI	23.2		P/R	0	0	0	0	0
operating income	13,920,890		ROI	12.7	8.3	6.1	4.8	4.0

Actual recovery was 50% higher than the pre-unit forecast. Undiscounted cashflow was $10 million higher than the pre-unit forecast, and 10% discounted cashflow was doubled.

4.7 Driftwood Creek Unit

Figure 4.7 (below) shows the forecast and actual waterflood response of the Driftwood Creek Unit.

The Driftwood Creek Unit produces from three reservoir units, the LKC "C", "D", and "E", comprising 42%, 24%, and 34% of the mapped reservoir volume respectively. The field is relatively small, resulting in an irregular flood pattern, with no fully confined producing wells.

The original waterflood response forecast and primary decline were digitized from NOGCC unitization exhibits. The original waterflood forecast was relatively modest, with a forecast secondary:primary ratio of 0.61, and remaining reserves (from 7/1/93) of 34,625 barrels (remaining primary) plus 167,657 barrels (secondary), for total remaining reserves of 202,282 barrels.

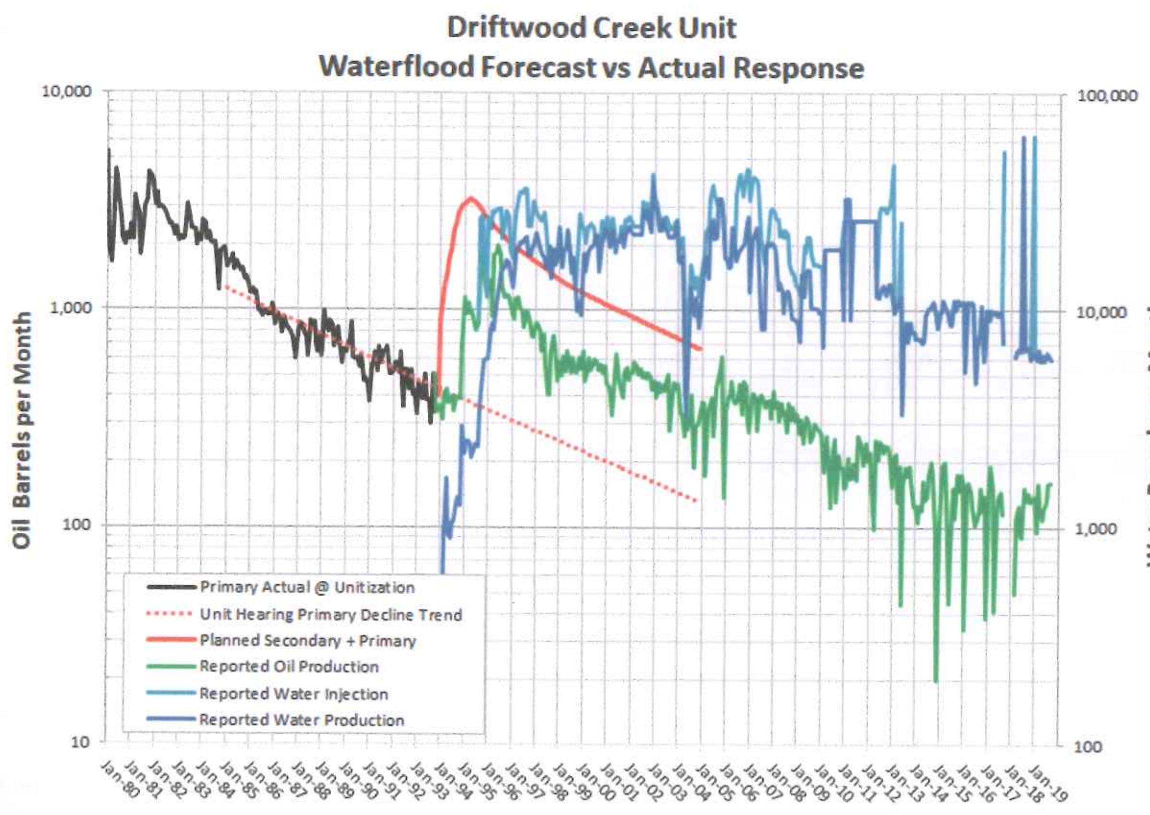

Figure 4.7: Driftwood Creek Unit Waterflood Forecast vs Actual Response

The actual waterflood response was poorer than the forecast throughout waterflood life. The actual total recovery from 1/1/93 through 9/1/2019 was 130,435 barrels, or about 65% of plan. The reason for the poor response is likely due to both poor pattern conformance, due to the limited numbers of wells and irregular injection well spacing, and to the multiple target waterflood horizons .

The initial actual production increase wasn't do to rapid waterflood response (it was prior to injection startup), but rather due to re-entry of three TA'd wells, which were briefly produced before conversion to injection.

Driftwood Creek is the only Gemini waterflood to fail to achieve its primary + secondary recovery target (although Gemini North Midway and Bush Creek were very slow to reach their forecast recovery).

The original Driftwood Creek Unit waterflood economics are estimated below, in Table 4.7.1. In this case, I also could not find an original cashflow, but a transcript of unitization testimony is posted on the NOGCC website, and the following cashflow is matched to key results.

Table 4.7.1: Driftwood Creek Unit Estimate of Originally-Proposed Waterflood Cashflow

Driftwood Creek Unit				Original not available; this cashflow is estimated, but matched to data reported at NOGCC hearing						
Primary + Secondary Economics										
								undisc	disc	cum disc
	gross	net		net oil	direct	tax @	capex	cashflow	cashflow	cashflow
	oil	oil	$/bbl	revenue	opex	5%		BFIT	@10%	@10%
year	bbl	bbl		$	$	$	$	$	$	$
1993	1,281	1,050	18.00	18,908	30,000	945	120,000	-132,038	-125,893	-125,893
1994	24,250	19,885	18.00	357,930	120,000	17,897	300,000	-79,967	-69,314	-195,207
1995	36,475	29,910	18.00	538,371	120,000	26,919	0	391,452	308,459	113,252
1996	27,700	22,714	18.00	408,852	120,000	20,443	0	268,409	192,275	305,527
1997	22,080	18,106	18.00	325,901	120,000	16,295	0	189,606	123,477	429,004
1998	18,450	15,129	18.00	272,322	120,000	13,616	0	138,706	82,117	511,121
1999	15,515	12,722	18.00	229,001	120,000	11,450	0	97,551	52,503	563,624
2000	13,619	11,167	18.00	201,014	120,000	10,051	0	70,964	34,721	598,345
2001	12,086	9,911	18.00	178,395	120,000	8,920	0	49,475	22,006	620,351
2002	10,726	8,796	18.00	158,321	120,000	7,916	0	30,405	12,295	632,646
2003	9,519	7,806	18.00	140,506	120,000	7,025	0	13,481	4,955	637,601
2004	8,448	6,928	18.00	124,695	120,000	6,235	0	-1,539	-514	637,087
	200,150	164,123		2,954,216	1,350,000	147,711	420,000	1,036,506	637,087	
						5%	10%	15%	20%	25%
NRI		0.82			CFBT	807,150	637,087	508,162	408,527	330,231
BFIT ROR		88.5%			disc invest	395,937	374,451	355,163	337,762	321,994
undisc prof/inv		2.5			P/I	2.0	1.7	1.4	1.2	1.0
undisc ROI		3.5			P/R	0	0	0	0	0
operating income		1,456,506			ROI	3.0	2.7	2.4	2.2	2.0

As mentioned above, the original waterflood recovery estimate was modest, and so the original economics were also modest, with undiscounted cashflow of approximately $1 million, and 10% discounted cashflow of approximately $600,000.

The actual economic performance of the Driftwood Creek Unit waterflood is shown on Table 4.7.2, below. Oil price was modestly lower than plan for 6 of the first 7 years of waterflood operations. After that, actual oil prices were above plan, but actual oil recovery in those years was not as planned, so the overall impact of later-year improved oil price was not substantial.

In recent years (2015 onward) these economics suggest the unit may have been losing money. As with other cases described earlier, I think it is likely that aggressive operating expense cost-cutting has been implemented to allow continued operation of the Unit. I've not included those impacts in this cashflow, since I don't have data showing the size of any cost reductions. However, annual cashflow would remain small even with the most aggressive cost cutting, and the overall Unit actual cashflow would not be substantial.

Table 4.7.2: Driftwood Creek Unit Estimate of Actual Waterflood Cashflow

Driftwood Creek Unit				ACTUAL OIL RECOVERY & OIL PRICE; CAPEX unchanged; OPEX reverts to primary estimate						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	$/bbl	net oil revenue $	direct opex $	tax @ 5% $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1993	1,192	977	15.43	15,082	30,000	754	120,000	-135,672	-129,358	-129,358
1994	4,896	4,015	14.20	57,009	120,000	2,850	300,000	-365,841	-317,106	-446,464
1995	13,902	11,400	15.43	175,896	120,000	8,795	0	47,102	37,115	-409,349
1996	16,953	13,901	19.12	265,796	120,000	13,290	0	132,506	94,921	-314,428
1997	11,328	9,289	17.61	163,579	120,000	8,179	0	35,400	23,053	-291,374
1998	7,925	6,499	11.42	74,213	120,000	3,711	0	-49,498	-29,304	-320,678
1999	6,780	5,560	16.34	90,844	120,000	4,542	0	-33,698	-18,137	-338,815
2000	6,691	5,487	27.38	150,224	120,000	7,511	0	22,712	11,113	-327,702
2001	5,642	4,626	22.98	106,316	120,000	5,316	0	-19,000	-8,451	-336,154
2002	6,148	5,041	23.18	116,859	120,000	5,843	0	-8,984	-3,633	-339,786
2003	5,190	4,256	28.08	119,503	120,000	5,975	0	-6,472	-2,379	-342,166
2004	3,846	3,154	38.51	121,450	120,000	6,072	0	-4,623	-1,545	-343,710
2005	4,503	3,692	53.64	198,064	120,000	9,903	0	68,160	20,707	-323,003
2006	4,793	3,930	63.05	247,803	120,000	12,390	0	115,413	31,875	-291,128
2007	4,385	3,596	69.34	249,326	120,000	12,466	0	116,860	29,341	-261,787
2008	4,159	3,410	96.67	329,681	120,000	16,484	0	193,197	44,098	-217,690
2009	3,479	2,853	58.95	168,171	120,000	8,409	0	39,763	8,251	-209,439
2010	2,457	2,015	76.48	154,087	120,000	7,704	0	26,383	4,977	-204,462
2011	2,398	1,966	91.88	180,669	120,000	9,033	0	51,636	8,855	-195,607
2012	2,540	2,083	91.05	189,639	120,000	9,482	0	60,157	9,378	-186,229
2013	1,950	1,599	94.98	151,873	120,000	7,594	0	24,279	3,441	-182,788
2014	1,581	1,296	90.17	116,898	120,000	5,845	0	-8,947	-1,153	-183,940
2015	1,654	1,356	45.66	61,928	120,000	3,096	0	-61,169	-7,165	-191,105
2016	1,521	1,247	40.29	50,250	120,000	2,513	0	-72,262	-7,695	-198,800
2017	1,095	898	47.80	42,920	120,000	2,146	0	-79,226	-7,669	-206,469
2018	1,163	954	62.23	59,346	120,000	2,967	0	-63,621	-5,599	-212,067
2019	1,195	980	53.98	52,899	120,000	2,645	0	-69,746	-5,580	-217,647
2020	0	0	62.00	0	0	0	0	0	0	-217,647
	129,366	106,080		3,710,324	3,150,000	185,516	420,000	-45,192	-217,647	

			5%	10%	15%	20%	25%
NRI	0.82	CFBT	(142,738)	(217,647)	(258,509)	(277,094)	(283,232)
BFIT ROR	#NUM!	disc invest	395,937	374,451	355,163	337,762	321,994
undisc prof/inv	-0.1	P/I	-0.4	-0.6	-0.7	-0.8	-0.9
undisc ROI	0.9	P/R	0	0	0	0	0
operating income	374,808	ROI	0.6	0.4	0.3	0.2	0.1

It appears, then, that Driftwood Creek is the only Gemini LKC waterflood which failed to meet its primary plus secondary recovery targets, and is the only one to lose money.

Fortunately, Driftwood Creek was also the smallest of the Gemini LKC waterfloods, so the impacts of these shortfalls were less onerous.

5 Combined Waterflood Results

The combined recovery results for the seven Gemini waterfloods in the Lansing Kansas-City ("LKC") formation in Southwest Nebraska are shown in Table 5.1, below.

Table 5.1: Gemini Southwest Nebraska Lansing-Kansas City Waterfloods

	Gemini Seven Waterfloods	Gemini North Midway	Boevau Canyon	Husker	Bishop	Suess	Bush Creek	Driftwood Creek
Unitization Date	-	Apr-86	Apr-87	Jul-87	Jun-89	Sep-89	Jun-90	Oct-93
date for remaining reserves	-	01/01/86	01/01/87	01/01/87	01/01/89	01/01/89	01/01/90	07/01/93
primary recovery @ date	6,352,607	617,913	1,992,393	710,072	656,751	311,821	1,823,855	239,802
remaining primary reserves	1,516,654	38,590	442,664	273,705	467,000	127,259	132,811	34,625
ultimate primary	7,869,261	656,503	2,435,057	983,777	1,123,751	439,080	1,956,666	274,427
estimated secondary	6,541,418	355,928	2,435,057	746,019	1,005,294	439,142	1,392,321	167,657
estimated primary + secondary	14,410,679	1,012,431	4,870,114	1,729,796	2,129,045	878,222	3,348,987	442,084
remaining combined reserves	8,058,072	394,518	2,877,721	1,019,724	1,472,294	566,401	1,525,132	202,282
secondary:primary	0.83	0.54	1.00	0.76	0.89	1.00	0.71	0.61
pre-unit additional recovery	182,029	4,286	31,370	59,864	41,542	12,326	31,572	1,069
P + S reserves @ unit formation	7,876,043	390,232	2,846,351	959,860	1,430,752	554,075	1,493,560	201,213
actual unit recovery	11,502,057	397,943	4,044,357	2,384,644	1,977,486	822,579	1,745,682	129,366
actual vs plan	146%	102%	142%	248%	138%	148%	117%	64%
exceeded plan recovery	-	Oct-17	Aug-01	Sep-91	Aug-03	Feb-01	Feb-11	N/A
years to exceed plan	-	31.5	14.3	4.2	14.2	11.4	20.7	N/A
recovery 10 years after unitization	7,022,606	282,203	2,376,066	1,509,805	1,224,082	513,264	1,031,856	85,330
% achieved in 10 years	87%	72%	83%	148%	83%	91%	68%	42%

The seven waterfloods had a combined pre-flood expectation of approximately 8 million barrels of additional primary plus secondary oil recovery.

The combined fields have achieved about 11.5 million barrels of additional recovery to date (through 3Q2019), a realization of about 150%.

A simple chart of actual versus plan gross oil production is shown in Figure 5.1, below.

On a combined basis, the comparison of actual production versus planned production is good. Although production ramp-up was somewhat later than plan, production growth was rapid, peak production was slightly above plan (exceeding 1 million barrels per year), and combined production has continued for about 15 years beyond the originally-planned completion.

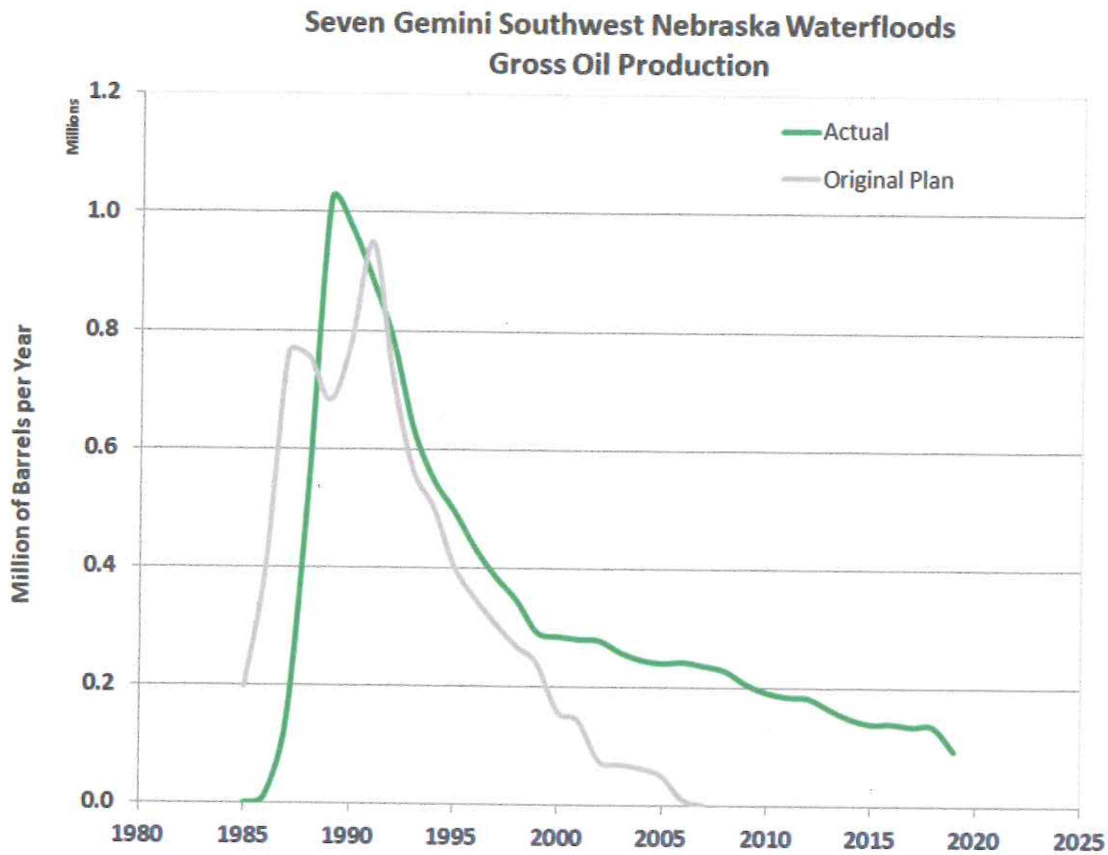

Figure 5.1: Actual versus Plan Gross Oil Production for the Combined Gemini Waterfloods

The combined economic performance of the combined waterfloods is shown on the following figures.

Gemini Seven Waterfloods				Original Cashflows: Sum of GNMU, Boevau, Husker, Bishop, Bush Creek, Driftwood, Suess						
Primary + Secondary Economics										
year	gross oil bbl	net oil bbl	weighted average $/bbl	net oil revenue $	direct opex $	tax $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1985	197,059	161,588	25.00	4,039,710	720,000	200,754	2,800,000	318,956	304,112	304,112
1986	404,818	331,951	22.03	7,314,212	1,580,800	364,953	400,000	4,968,459	4,306,581	4,610,694
1987	763,147	625,781	22.07	13,811,611	1,810,092	688,654	974,718	10,338,148	8,146,312	12,757,005
1988	754,695	618,850	20.03	12,393,960	1,897,968	619,578	0	9,876,414	7,074,975	19,831,980
1989	682,440	559,601	19.26	10,778,488	2,187,968	540,007	1,560,000	6,490,513	4,226,802	24,058,782
1990	780,897	640,336	18.24	11,678,491	3,337,968	592,219	2,200,000	5,548,304	3,284,736	27,343,519
1991	949,741	778,788	18.16	14,143,253	3,337,968	756,324	800,000	9,248,961	4,977,835	32,321,354
1992	720,550	590,851	18.07	10,674,043	3,397,968	573,413	0	6,702,662	3,279,459	35,600,812
1993	565,305	463,550	18.42	8,538,135	3,067,968	453,938	120,000	4,896,229	2,177,830	37,778,642
1994	502,116	411,735	18.38	7,568,066	3,157,968	399,746	300,000	3,710,352	1,500,322	39,278,964
1995	402,586	330,121	19.07	6,294,306	2,560,800	332,951	0	3,400,555	1,250,048	40,529,012
1996	348,578	285,834	19.05	5,444,915	2,560,800	288,353	0	2,595,762	867,459	41,396,471
1997	305,702	250,676	19.03	4,769,159	2,560,800	253,133	0	1,955,226	594,003	41,990,474
1998	268,095	219,838	19.01	4,178,501	2,560,800	222,155	0	1,395,546	385,428	42,375,902
1999	238,926	195,919	18.93	3,708,081	2,560,800	197,362	0	949,920	238,503	42,614,404
2000	157,863	129,447	16.69	2,160,020	1,560,000	118,814	0	481,206	109,836	42,724,240
2001	143,112	117,351	16.66	1,955,404	1,560,000	107,480	0	287,924	59,745	42,783,985
2002	75,075	61,562	15.66	963,769	720,000	48,692	0	195,077	36,799	42,820,783
2003	68,647	56,291	15.63	880,047	720,000	44,465	0	115,582	19,821	42,840,604
2004	62,762	51,465	15.61	803,544	720,000	40,601	0	42,943	6,695	42,847,299
2005	49,863	40,887	15.24	622,970	600,000	31,528	0	-8,558	-1,213	42,846,086
2006	10,361	8,496	16.00	135,931	180,000	6,879	0	-50,949	-6,564	42,839,522
	8,452,337	6,930,916		132,856,615	43,360,668	6,881,999	9,154,718	73,459,230	42,839,522	

				5%	10%	15%	20%	25%
NRI	0.82		CFBT	55,063,438	42,839,522	34,349,450	28,227,805	23,671,576
BFIT ROR	undefined		disc invest	7,752,354	6,708,091	5,912,962	5,295,231	4,806,477
undisc prof/inv	8.0		P/I	7.1	6.4	5.8	5.3	4.9
undisc ROI	9.0		P/R	0	0	0	0	0
operating income	82,613,948		ROI	8.1	7.4	6.8	6.3	5.9

Figure 5.2: Estimate of Originally Planned Cashflow for the Combined Gemini Waterfloods

The originally planned combined undiscounted cashflow was approximately $75 million, while the 10% discounted combined cashflow was about $45 million. Total capital investments were about $9 million, leading to a ROI exceeding 8.

The estimated actual combined cashflows are shown on Table 5.3, below.

The estimate of actual combined cashflow exceeds $150 million. The estimate of 10% discounted cashflow is just above $40 million. Operation expenses for the projects exceeded $100 million, while taxes required about $15 million. The estimated BFIT ROR is about 130%, and ROI exceeds 10.

Gemini Seven Waterfloods

Primary + Secondary Economics

Actual Cashflows: Sum of GNMU, Boevau, Husker, Bishop, Bush Creek, Driftwood, Suess

year	gross oil bbl	net oil bbl	weighted average $/bbl	net oil revenue $	direct opex $	tax $	capex $	undisc cashflow BFIT $	disc cashflow @10% $	cum disc cashflow @10% $
1986	12,463	10,220	12.05	123,147	225,000	6,157	400,000	-508,010	-484,369	-484,369
1987	138,702	113,736	16.20	1,842,517	1,299,184	92,154	3,774,718	-3,323,538	-2,880,791	-3,365,159
1988	532,002	436,242	12.97	5,658,054	1,897,968	283,433	0	3,476,653	2,739,552	-625,607
1989	1,022,912	838,788	16.64	13,957,430	2,187,968	699,254	1,560,000	9,510,208	6,812,643	6,187,036
1990	973,921	798,615	21.53	17,194,186	2,987,968	869,657	2,200,000	11,136,561	7,252,438	13,439,473
1991	886,398	726,846	18.54	13,475,732	3,337,968	699,479	800,000	8,638,285	5,114,083	18,553,556
1992	785,266	643,918	17.58	11,320,081	3,397,968	596,937	0	7,325,176	3,942,445	22,496,001
1993	636,282	521,751	15.43	8,050,622	3,367,968	422,426	120,000	4,140,228	2,025,719	24,521,720
1994	548,729	449,958	14.20	6,389,400	3,357,968	335,762	300,000	2,395,671	1,065,588	25,587,307
1995	495,707	406,480	15.43	6,271,982	3,357,968	328,244	0	2,585,770	1,045,585	26,632,892
1996	434,043	355,915	19.12	6,805,100	3,357,968	354,784	0	3,092,348	1,136,751	27,769,643
1997	385,231	315,889	17.61	5,562,813	3,357,968	289,924	0	1,914,920	639,933	28,409,577
1998	346,168	283,858	11.42	3,241,656	3,357,968	168,570	0	-284,883	-86,548	28,323,029
1999	291,769	239,251	16.34	3,909,354	3,357,968	201,351	0	350,036	96,674	28,419,703
2000	284,609	233,379	27.38	6,389,927	3,357,968	330,048	0	2,701,912	678,387	29,098,089
2001	280,165	229,735	22.98	5,279,317	3,357,968	273,367	0	1,647,982	376,154	29,474,244
2002	278,052	228,003	23.18	5,285,101	3,357,968	274,081	0	1,653,053	343,010	29,817,254
2003	258,483	211,956	28.08	5,951,726	3,357,968	309,320	0	2,284,438	430,931	30,248,185
2004	245,526	201,331	38.51	7,753,269	3,357,968	403,205	0	3,992,096	684,599	30,932,784
2005	240,376	197,108	53.64	10,572,890	3,357,968	550,508	0	6,664,414	1,038,974	31,971,757
2006	242,390	198,760	63.05	12,531,805	3,357,968	652,123	0	8,521,715	1,207,750	33,179,507
2007	235,986	193,509	69.34	13,417,881	3,357,968	700,319	0	9,359,594	1,205,908	34,385,415
2008	228,025	186,981	96.67	18,075,405	3,357,968	942,322	0	13,775,115	1,613,466	35,998,881
2009	205,853	168,799	58.95	9,950,728	3,357,968	517,388	0	6,075,372	646,911	36,645,793
2010	191,468	157,004	76.48	12,007,648	3,357,968	624,889	0	8,024,791	776,807	37,422,599
2011	184,376	151,188	91.88	13,891,183	3,357,968	722,964	0	9,810,250	863,310	38,285,909
2012	182,399	149,567	91.05	13,618,092	3,357,968	708,531	0	9,551,593	764,134	39,050,043
2013	164,359	134,774	94.98	12,800,871	3,357,968	667,085	0	8,775,817	638,247	39,688,290
2014	147,983	121,346	90.17	10,941,774	3,357,968	569,857	0	7,013,950	463,736	40,152,027
2015	139,179	114,127	45.66	5,211,029	3,357,968	272,312	0	1,580,748	95,012	40,247,039
2016	139,520	114,406	40.29	4,609,434	3,357,968	240,335	0	1,011,131	55,250	40,302,288
2017	134,840	110,569	47.80	5,285,189	3,357,968	275,526	0	1,651,695	82,047	40,384,335
2018	134,560	110,339	62.23	6,866,408	3,357,968	358,223	0	3,150,218	142,259	40,526,594
2019	93,564	76,722	53.98	4,141,799	3,357,968	216,212	0	567,619	23,302	40,549,896
2020										
	11,501,306	9,431,071		288,383,549	106,009,160	14,956,745	9,154,718	158,262,926	40,549,896	

			5%	10%	15%	20%	25%
NRI	0.82	CFBT	72,022,699	40,549,896	26,584,027	19,138,282	14,547,765
BFIT ROR	134.2%	disc invest	7,873,226	6,869,231	6,067,688	5,417,063	4,881,118
undisc prof/inv	17.3	P/I	9.1	5.9	4.4	3.5	3.0
undisc ROI	18.3	P/R	0	0	0	0	0
operating income	167,417,644	ROI	10.1	6.9	5.4	4.5	4.0

Figure 5.3: Estimate of Actual Cashflow for the Combined Gemini Waterfloods

The figure shows how economically significant this group of projects have been, and also how profitable.

Figure 5.4, below, is a simple chart representing the planned versus actual combined cashflows.

Oil price is a large part of the story, since actual vs plan production was relatively similar (recall Figure 5.1).

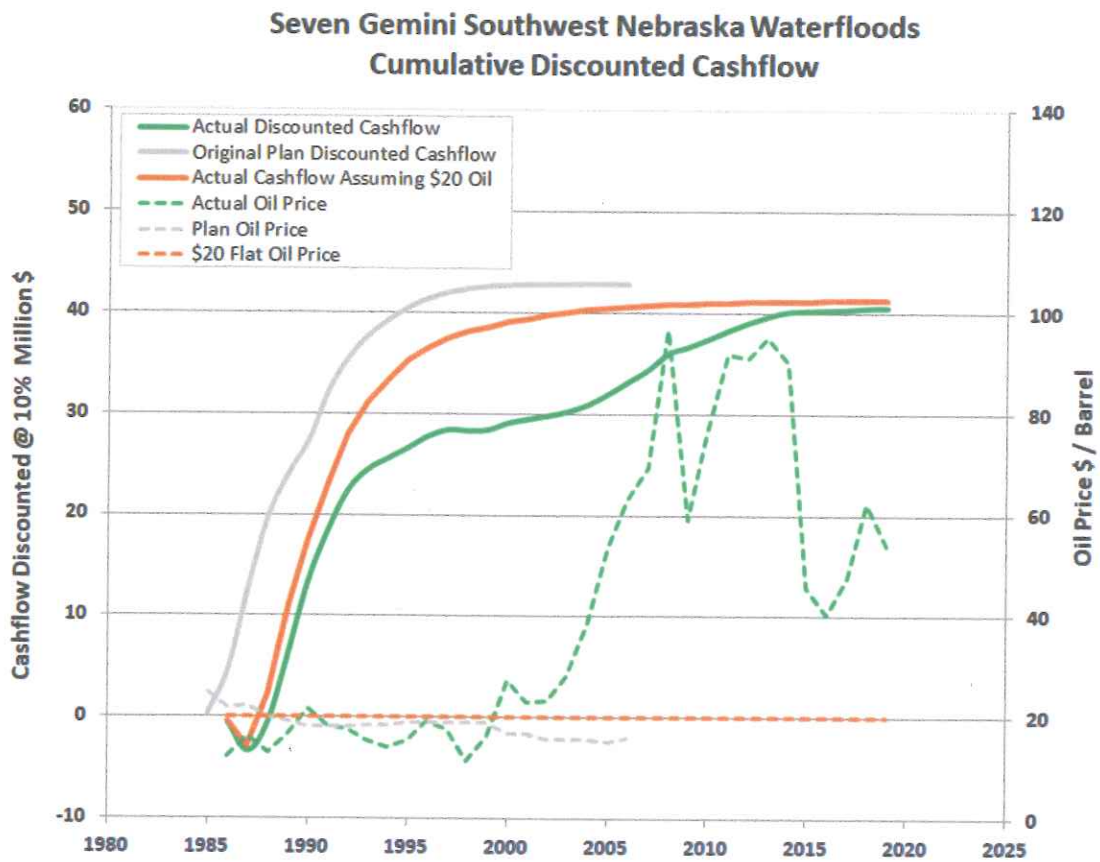

Figure 5.4: Comparison of Planned vs Actual Estimated Combined Cashflows

The figure shows that actual 10% discounted cashflow, in green, was about $30+ million at 2005, when the original combined discounted cashflow, in grey, was planned to be about $40+ million. After 2005, continued production and profit substantially closed the gap between actual and plan.

Oil prices are also shown on Figure 5.4 using dashed lines of the same color as the cashflows. Plan oil prices were constant for each field, and averaged about $20 per barrel. I've used production volume weighting to compute the average prices, creating the minor fluctuation shown for the original plan oil price. The actual oil price (shown as a green dashed line) was lower-than-plan throughout the 1990's, adversely impacting actual cashflow. Much higher oil prices from 2000 onward helped sustain profitability and allowed continued production and profit.

The orange lines on the plot represent a recalculated actual cashflow for which the production volumes were actual, but actual oil price was replaced by a $20 flat price. For this cashflow, I also assumed a cap on opex equivalent to $10 / barrel. Most of the fields would otherwise have been uneconomic in late life, whereas we know they continued to produce.

What the $20 flat price cashflow shows is that actual cashflow would have been moderately below original plan cashflow through 2005, but not as seriously as if calculated with actual oil price.

6 Observations and Conclusions

- The production and economic performances of the seven Gemini Southwest Nebraska Lansing-Kansas City waterfloods were, in general, very good.
- The most technically successful waterfloods were the sequence of five-spot LKC "F" zone waterfloods in adjacent fields in Hitchcock County, namely Boevau Canyon, Husker, and Bishop. These fields, taken together, produced over 8.4 million barrels after unitization, versus combined plan volumes of approximately 5.2 million barrels.
- The Suess Field in Red Willow County was smaller, multi-zone, and not a pattern waterflood, but nevertheless very technically successful, producing over 820,000 barrels after unitization versus the plan volume of about 555,000.
- The most economically successful of this group of waterfloods was the Husker Unit, which achieved a 10% discounted cashflow of $11.6 million versus the planned 10% discounted cashflow of $3.7 million. Some of the relative success of Husker Unit is due to the relatively modest assumptions made for the pre-unit waterflood recovery forecast, and thus the pre-unit economics.
- Waterfloods of Bush Creek and the Gemini North Midway Unit were marginally successful. Although each reached their waterflood recovery target, doing so took many years. Bush Creek made about 70% of the originally planned 10% discounted cashflow, while GNMU made less than 10% of the originally planned 10% discounted cashflow.
- The Driftwood Creek Unit was the only waterflood in the group to miss its secondary recovery target (although Bush Creek and Gemini North Midway were late in reaching their recovery targets), and Driftwood was also the only field to fail to reach payout. Fortunately, Driftwood Creek was also the smallest of the Gemini LKC waterfloods, so the impacts of these shortfalls were less onerous.

In retrospect, opportunities for improvement might have included the following.

- Several of the units (Boevau Canyon, Bush Creek, Driftwood Creek) achieved initial waterflood response slowly than originally expected, either due to delay of the unitization hearing or delay injection startup (likely due to delay in drilling or converting injection wells). Additional consideration of startup timing would help ensure credible forecasts.
- Different risking of waterflood response might have been applied to fields with 5-spot patterns and single flood horizon versus fields with irregular patterns or multiple waterflood zones.
- Additional consideration of capex phasing and/or operational flexibility might be helpful in fields with higher perceived recovery risk, or during time periods of higher oil price uncertainty.