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COMPARISON OF THE TORIS RECOVERY AND ECONOMIC MODEL TO RESULTS OF STEAM, GAS DISPLACEMENT, AND POLYMER TERTIARY INCENTIVE PROGRAM PROJECTS

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Comparison of the TORIS Recovery and Economic Model to Results of Steam, Gas Displacement, and Polymer Tertiary Incentive Program Projects

By R. A. Welch and J. F. Pautz

Abstract

The U.S. Department of Energy (DOE) has distributed enhanced oil recovery (EOR) computer predictive models to assist industry in identifying potential targets for advanced oil recovery projects. These predictive models are also used by DOE as part of a larger computer model that assesses the potential of EOR and other advanced oil recovery methods considering varying government policy options. Although these predictive models have been compared to the results of field projects and finite difference reservoir simulators, the quantitative accuracy of the EOR predictive models previously has not been determined. The information used in this study to quantify the accuracy is based on oil production information submitted to DOE by EOR project operators as part of the DOE Tertiary Incentive Program (TIP) of 1978. A statistically significant number of projects using steam recovery, miscible gas displacement, and polymer flood processes have sufficient field data that they can be compared to the results of the predictive models.

The results indicate the predicted oil production of the DOE Steam Flood Predictive Model (SFPM) is conservative compared to reported field production. The statistical confidence in the accuracy of the estimated oil production is reasonable considering this is a simplified model. Estimates of confidence at the 50% level are made for the SFPM for different degrees of engineering adjustments to the data. The DOE CO_2 Miscible Gas Predictive Model (CO2PM) is very conservative if only tertiary oil recoveries are considered and moderately optimistic if all remaining oil is considered by the model. Confidence limits were estimated for the CO2PM. The estimated oil production from the DOE Polymer Flood Predictive Model (PFPM) was very optimistic relative to reported oil production. The combination of widely scattered results and few projects prevented an estimate of confidence levels for the PFPM.

The reported field results used in this comparison study were not without problems. Inappropriate reservoir parameters and reported project areas are suspected for some of the projects used in this study. Unfortunately, it is impossible to tell which projects have miss-reported reservoir parameters. Therefore, the broad confidence ranges are overly pessimistic.

Summary of Results

Three DOE EOR predictive models that are part of the DOE Bartlesville Project Office (BPO) Tertiary Oil Recovery Information System (TORIS) were compared to field results from DOE TIP projects. These comparisons to actual field results verified the predictive ability of these EOR computer models. The SFPM outperformed the CO2PM and PFPM models turning out quite acceptable results. The SFPM underpredicted aggregate production by 19 to 33% using various interpretations of project descriptions.

For individual projects, there was a 50% confidence that the actual production for an individual project would be between 41 and 228% of that predicted. The miscible gas flood model assumes only tertiary oil recovery and ignores remaining mobile oil when it is used by the larger TORIS Recovery and Economic Model. This assumption that a gas displacement project starts at residual oil saturation severely underpredicted production response by about 85% for the aggregate of all the gas displacement tests with sufficient data to be used in the study. When the model was adjusted to account for remaining mobile oil, the model overpredicted oil production by about 45% above the aggregate oil production of the gas TIP projects. The range of values included in the 50% confidence level for the tertiary case was very large and unacceptable. When the mobile oil was included, there is a 50% confidence that the actual oil production falls between 39 to 368% of the oil production predicted by the model. The PFPM turned in the worst results. It overpredicted aggregate project production by about 400%. A confidence interval could not be determined for individual polymer projects. In general, the predictive models did a much better job of predicting aggregated oil production for a group of projects than they did for individual projects.

Background

The first attempt to systematically estimate the United States potential for EOR was made by the National Petroleum Council (NPC) in 1976.[1] The methodology used consisted of (1) screening a data base of 245 known reservoirs in

California, Texas, and Louisiana (with remaining oil in place representing 35 to 40% of that in known fields in the U.S.) to determine the most suitable EOR process to be applied; (2) estimating recovery based on prior field experience and expert consensus on residual oil saturation, and displacement and sweep efficiencies; (3) performing cost estimation on each recovery process; and (4) determining the economics of each project. Refinements in reservoir information, the recovery estimating models, and the economic models were pursued before the next NPC EOR study. The DOE had EOR computer models developed that could make reasonable estimates of oil recovery and with sufficient operating information the economics for reservoir wide projects could be estimated. These computer models were complex enough to estimate sensitivities to reservoir parameters and changing petroleum economics but simple enough to be run on a "Super Mini" computer in a few minutes per project (reservoir).

In 1982, the NPC started another EOR potential study.[2] This landmark effort included many industry experts organized in EOR process specific committees. These committees tested and refined the computer predictive models and the reservoir data they were provided to estimate the domestic EOR potential. Project development strategies, cost functions, expected recoveries, and the logic of the models were developed, thoroughly reviewed, and tested by leading EOR industry experts. The results of this effort were a suite of EOR predictive models and a larger integrated system using reservoir data and preprocessor programs with these models to analyze the domestic oil resource. The larger system has become the DOE TORIS Recovery and Economic Model. The individual simplified EOR predictive models were subsequently documented and published by DOE in 1986.[3-7]

Model refinements and testing have continued. Assessing the reliability and accuracy of individual predictive models by comparing the predicted results to field project results and finite difference simulation has shown that the models are less than prefect but reasonable.[8] Unfortunately, results of prior studies have been qualitative and have not estimated a confidence limit for the models because of limited information on EOR projects.

Another DOE program that was initiated about the same time the TORIS Model was conceived was the Tertiary Incentive Program of 1978. This program promoted the development of EOR projects and pilots through certification with the DOE and partial cost reimbursement. Projects were certified based on OMB No. 38-R0445 initial report forms submitted to the DOE. Each year after 1980, TIP operators have been requested to return a completed "Annual Report for Enhanced Oil Recovery Incentive Program," form FE-748. This annual update requests the operator to tabulate monthly fluid injection and production rates and indicate changes in key reservoir parameters used to describe a project. The information from these annual reports is maintained in the Enhanced Oil Recovery Project Database at the BPO. Since completing a form FE-748 is voluntary, numerous operators stopped reporting after the initial certification. The number of completed reports continues to decrease because many of the original projects have been terminated, completed, changed, were never started, or are not reporting. Approximately 50 projects have provided 10 years of production data, and roughly 100 have more than 3 years of data.

This study uses the TIP projects' results to quantify the accuracy of three of the EOR process models; Steam (SFPM), Miscible Gas (CO2PM), and Polymer (PFPM). Pre-processor portions of the TORIS Economic and Recovery Model were used to prepare and validate data from the TIP projects. Three changes were made that differentiate this work from a "typical" TORIS model run: (1) historical average wellhead oil prices were used, (2) the model did not screen the projects for EOR process type, and (3) there was no minimum target oil volume for a project.

A TORIS model compatible run involves the use of two pre-processor programs, DEFLT and ROBL, and the predictive models. All are FORTRAN coded programs executed on the MicroVAX™ system at the National Institute for Petroleum and Energy Research (NIPER). Project level data are retrieved from the DOE's EOR Project Database maintained by NIPER personnel. This database contains specific information such as reservoir rock and fluid properties, production and injection data, and essential data that describe the EOR projects. DEFLT reviews the project data and checks it for internal inconsistencies. If data critical to the model are missing or unknown, DEFLT will suggest, or provide in some cases, a replacement value. The output from DEFLT is passed to ROBL, a process specific program that converts the NPC flat file format to the input format required by the model. ROBL also provides cost structure information and pattern development timing used in the economic portion of the input data. Figure 1 shows the general flow of input data through the portion of the TORIS Recovery and Economic model used in this study.

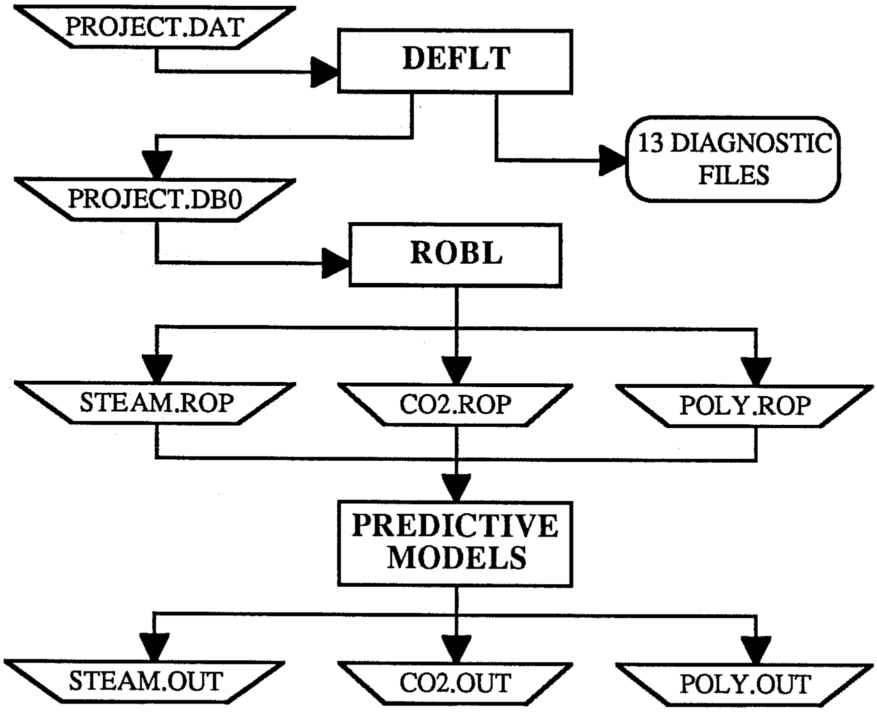

Fig. 1 Input data flow through the TORIS Recovery and Economic Model.

The basic approach of this comparative study was to apply increasing levels of engineering judgment to improve upon the project descriptions taken from the database. The first priority was to determine appropriate target oil volumes. Second, injection well counts were modified to approximate actual conditions. Third, the model was provided with actual fluid injection rates rather than accepting default rates determined by the models themselves. In the case of the miscible projects, additional accounting for mobile oil and swept zone oil saturations were addressed. One other important sensitivity that was not performed because of time constraints was to alter the model projected pattern development timing schemes to more accurately reflect ongoing field operations.

Most of the data describing the TIP projects originated from the OMB No. 38-R0445 initial report forms. The forms were submitted to the DOE and the information was entered into the DOE project database. In many cases, the yearly update forms, FE-748, contained different and/or contradictory information from that found in the initial reports. During preparation of the project description, the FE-748 data were considered current and generally more accurate when the data input file was being prepared. The data retrieved from the DOE EOR Project Database were checked during the review process for accuracy, and upon discovery of errors, corrections were made to the input data sets used in this study. The corrections included omissions, data that could not be substantiated, and common errors that were either transcription or typographical in nature. The changes were made to basic reservoir properties and to reported production and injection data. (A common and easily detected error in the production and injection data was that the operators submitted monthly totals instead of an average monthly rate.)

The model results were compared to gross oil production reported by the TIP project operators. It was assumed that all produced oil for the thermal projects was the result of steaming operations, even though some operators reported incremental oil production. The miscible and polymer projects were also compared to gross produced oil because many times incremental production was not reported, the data was unavailable, or the accuracy was in question.

Acknowledgments

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Development of Methods for Comparison

The comparative study began with 17 steamflood TIP projects that were selected because they appeared to have the most complete project descriptions. It was felt that this completeness would provide the best opportunity for meaningful results. In addition, a small group of projects was initially chosen because of the ease of handling in determining the methodology that would be applied to evaluate the TORIS predictive models. The study began with thermal projects because steamflooding probably has the greatest short-term future potential, and the model has been debugged and used extensively. The 17 steamflood projects chosen are shown in Table 1.

A review of the DOE project files revealed that three of the projects, SF109, SF228, and SF236, were never implemented. Therefore, the number of projects in the sampling was reduced to 14, of which 13 were located in California and one in Wyoming. The Gomaa[9] predictive routine was used exclusively in all thermal model runs.

Model Runs

The approach employed in this comparative study was to provide the model with the best project descriptions possible. Five cases were constructed, each one hopefully more accurate than the previous, and each employing greater engineering judgment. The subsequent model results were then compared to the reported production and/or injection data. However, only Case I represents a "typical" NPC (referring to the 1984 National Petroleum Council Study) compatible model run. That is, changes in the input data were made only to achieve a reasonable original-oil-in-place (OOIP) match and then run through the preprocessors. Normally, once the DEFLT results were accepted, no changes were made to the data. In this study, Cases II - V required deliberate and manual intervention to change the data either before or after DEFLT to systematically apply engineering judgment to improve the project description. The assumptions used in the five cases are described as follows:

Table 1
Steam Projects Used To Develop Methodology

Project No.	Field	Formation	Operator
SF019	Midway Sunset	Potter	Unocal
SF022	Casper Creek South	Tensleep	Unocal
SF026	Midway Sunset	Tulare Sand	Unocal
SF030	Guadalupe	Sisquoc	Unocal
SF091	Cat Canyon	Sisquoc	Chevron
SF100	Midway Sunset	Monarch	Chevron
SF107	Midway Sunset	Webster	Chevron
SF109	Midway Sunset	Miocene	Chevron
SF158	Midway Sunset	Upper Miocene	Santa Fe
SF186	Midway Sunset	Reef Ridge	Santa Fe
SF228	Casper Creek South	Tensleep	Unocal
SF236	Midway Sunset	Reef Ridge	Gen Am Oil of Texas
SF242	McKittrick	Tulare Sand	Chevron
SF345	Midway Sunset	Potter	Sun/Arco
SF407	Midway Sunset	7A Sand	Santa Fe
SF414	Poso Creek	Etchegoin	Elf Aquitaine
SF422	Kern River	Kern River	Chevron

Case I: Revise any volumetric parameter, either a reported value or a value supplied by DEFLT, within reason (normally ±10%) to generate OOIP volumes that agree within ± 3% of the reported values. If a reasonable change could not produce the desired effect, it was assumed that the reported OOIP volume was an error and the calculated value was substituted. All subsequent remaining-oil-in-place (ROIP) volumes calculated by DEFLT were left unchanged for this case.

Case II: Revise the calculated ROIP, if necessary, by making whatever reasonable changes necessary to the volumetric parameters to achieve agreement within ± 3% of the reported values. Generally, porosity, net thickness, and oil saturation were changed. ROIP is the same value as the Initial-Oil-In-Place (IOIP) used in the SFPM—the volume of oil in place at the start of the project.

Case III: Revise the calculated ROIP, if necessary, by changing only the drainage area to achieve agreement within ± 3% of the reported values. This case assumed that the drainage area was the volumetric variable most likely to be inaccurate - all other volumetric parameters were assumed to be correct.

Case IV: Same as Case III except change pattern size, number of patterns, and pattern development timing for those projects with enough information to warrant a different project description that reasonable engineering judgment could support.

Case V: Same as Case II except provide the model with actual steam injection rates rather than allowing the model to determine the rates. The first year average steam injection values were used wherever possible.

After several preliminary runs with the project data, it became apparent that some of the volumetric parameter data and OOIP/ROIP volumes reported for the projects were not internally consistent. For most projects, there was insufficient information in the files to determine whether the volumetric parameters, the hydrocarbon volumes, or both, were incorrect. Another check generated ROIP by reducing the OOIP by the cumulative production which further contributed to the inconsistencies of the data in many cases. These types of problems became commonplace and repetitive throughout this study and resolving them became one of the most important issues in the project descriptions.

Case I

Case I represented the typical TORIS run where reasonable changes to the data were made during the DEFLT data checking process. After that, the data were not altered. The aggregate calculated OOIP volume was 273.28 MMstb compared to 396.36 MMstb reported by the project operators. The resulting aggregate ROIP calculated by SFPM was 243.18 MMstb compared to a reported 338.83 MMstb. The calculated volumes were 69 and 72% of the reported values for OOIP and ROIP, respectively. Some of the projects did not report an OOIP or ROIP and the total calculated/reported (c/r) ratios reflect only those projects with complete data. Five of the projects, after revisions were made to their input data, still had calculated/reported OOIP's ranging from 52 to 115%. Table 2 summarizes the results for each project.

The execution of this group of projects by the SFPM showed that their predicted oil recovery ranged from 27 to 492% of that reported. The aggregate predicted oil production of the 14 projects is 71% of the reported production. Given the quality of the OOIP and ROIP agreement, the large variance in the oil production of individual projects was not surprising. The predicted to reported (p/r) aggregate ratios for water production and steam injection were 46 and 98%, respectively. The predicted and reported oil recovery, and the oil and water production and steam injection p/r ratios for each project, are presented in Table 3.

The projects were sorted by oil production p/r ratio. The shaded rows were those projects whose oil production p/r ratios were ± 30% of a perfect match.

Case II

The target oil (IOIP or ROIP) volume was more important to the SFPM than the OOIP, therefore, it was critical to obtain a good match between the reported ROIP and the calculated IOIP. In Case II, volumetric parameters were modified to obtain an ROIP match that was ±3% of the reported value. This assumed that the ROIP was more accurate than the rock and fluid property data. With reasonable changes to the input data, a total c/r ratio of 99% for the projects was obtained. The model generated an

Table 2
Summary of OOIP and ROIP Revisions

	OOIP			ROIP		
	Calc	Reported	c/r ratio	Calc	Reported	c/r ratio
SF019	16.36	16.40	0.998	12.41	11.60	1.070
SF022	40.02	58.00	0.690	33.73	55.00	0.613
SF026	14.64	14.70	0.996	14.26	13.98	1.020
SF030	39.08	62.40	0.626	38.26	50.00	0.765
SF091	8.43	11.00	0.766	6.69	10.26	0.652
SF100	12.30	12.30	1.000	11.80	10.00	1.180
SF107	36.45	37.00	0.985	35.11	33.60	1.045
SF158	5.55	7.20	0.771	4.70	7.05	0.666
SF186	1.30	1.31	0.992	1.11	n/a	n/a
SF242	8.02	8.00	1.003	7.29	7.00	1.041
SF345	82.38	n/a	n/a	72.65	n/a	n/a
SF407	4.10	4.15	0.988	4.00	3.54	1.131
SF414	4.47	3.90	1.146	4.38	3.80	1.152
SF422	82.56	160.00	0.516	70.56	133.00	0.531
total(all)=	355.66	n/a		316.95	n/a	
total=	273.28	396.36		243.18	338.83	
c/r=	0.689			0.718		

Table 3
Case I Predicted Production and Injection for 14 Projects

	Oil Production, mb		predicted/reported (p/r) Production		Injection
	Model	Reported	Oil	Water	Steam
SF414	193	706	0.273	0.201	0.366
SF030	2,467	7,167	0.344	0.681	1.168
SF422	10,152	23,666	0.429	0.261	0.527
SF242	1,617	2,934	0.551	0.157	0.485
SF019	1,101	1,541	0.714	1.670	4.846
SF345	16,728	23,067	0.725	0.887	1.423
SF100	1,725	1,917	0.900	0.623	0.569
SF107	5,701	5,912	0.964	1.337	1.042
SF186	376	275	1.365	0.933	1.683
SF158	1,141	736	1.551	2.023	0.966
SF407	1,583	701	2.258	5.838	9.744
SF022	4,410	1,689	2.611	0.387	6.373
SF091	692	207	3.338	2.479	1.662
SF026	2,131	433	4.921	2.471	9.507
Total =	50,017	70,951			
p/r =	0.705				
mean=			1.496	1.425	2.883

Shaded area is ± 30% of a perfect match.

aggregate oil production p/r ratio of 99% and the individual project ratios ranged from 23 to 609%. Total water production and steam injection p/r ratios for the projects were 40% and 96%, respectively. The total ratios for oil production and steam injection are excellent, but once again the individual projects exhibit a large variance. The total water production p/r ratio is not good but this parameter was probably one of the most difficult production values to report with any accuracy. The individual project results are shown in Table 4.

Case III

Case III matches the ROIP but assumes that all volumetric data, either reported by the TIP project operator or supplied by DEFLT, was correct except the drainage area. There were two exceptions, SF022 and SF026. There was sufficient information in the project files to modify the pattern size and number of patterns when the data was reviewed. The resulting aggregate ROIP c/r ratio for all projects was 107% and the aggregate oil production p/r ratio was 79%, indicating that on the whole, modifying only the drainage area did not improve the results. The model results are shown in Table 5.

Case IV

In this case, the project description and/or pattern development timing for seven projects was changed. Projects SF022 and SF026, which were modified in Case III by changing the pattern size and the number of patterns, were further modified. SF022 was fully developed in the first two years of operation and SF026 in the first year. Projects SF030, SF158, and SF407 were changed to develop all their patterns in the first year. These changes were made because the yearly well count data for these projects indicated they were fully developed early in their project life and their well counts remained constant over time. The SFPM normally stages the timing of pattern development over ten to twenty years. SF414's development occurred over the first three years. SF107 was unique in that its formation dip angle was 53°. The area was adjusted from 104 surface acres to 173 acres to compensate for the formation dip angle. The resulting aggregate ROIP c/r ratio for Case IV after making these changes was 102% and the aggregate oil production p/r ratio was 91%.

The project development timing change in SF022 yielded an excellent p/r ratio for oil production of 96%, but the ROIP c/r ratio was

Table 4
Case II Predicted Production and Injection for 14 Projects

	Oil Production, mb		predicted/reported (p/r) Production		Injection
	Model	Reported	Oil	Water	Steam
SF414	164	706	0.232	0.173	0.366
SF030	3,227	7,167	0.450	0.641	1.168
SF242	1,557	2,934	0.531	0.159	0.485
SF019	1,010	1,541	0.655	1.696	2.423
SF100	1,347	1,917	0.703	0.671	0.569
SF345	16,728	23,067	0.725	0.887	1.423
SF107	5,349	5,912	0.905	1.360	1.042
SF422	25,090	23,666	1.060	0.178	0.503
SF186	376	275	1.365	0.933	1.683
SF407	1,433	701	2.044	5.929	9.744
SF158	1,752	736	2.381	1.756	0.966
SF026	2,131	433	4.921	2.471	4.527
SF022	8,741	1,689	5.175	0.312	4.552
SF091	1,263	207	6.093	1.911	1.662
total =	70,168	70,951			
p/r =	0.989				
mean=			1.946	1.363	2.222

Shaded area is ± 30% of a perfect match.

Table 5
Case III Predicted Production and Injection for 14 Projects

	Oil Production, mb		predicted/reported (p/r) Production		Injection
	Model	Reported	Oil	Water	Steam
SF414	193	706	0.273	0.171	0.366
SF030	3,343	7,167	0.466	0.935	1.601
SF242	1,617	2,934	0.551	0.157	0.485
SF100	1,258	1,917	0.656	0.454	0.415
SF019	1,046	1,541	0.679	1.555	2.264
SF022	1,210	1,689	0.716	0.106	1.248
SF345	16,728	23,067	0.725	0.887	1.423
SF422	19,666	23,666	0.831	0.506	1.021
SF107	5,349	5,912	0.905	1.360	1.042
SF186	376	275	1.365	0.933	1.683
SF407	1,511	701	2.156	5.882	9.744
SF158	1,667	736	2.266	2.951	1.409
SF026	1,114	433	2.573	0.692	1.440
SF091	1,038	207	5.008	3.717	2.494
total =	56,116	70,951			
p/r =	0.791				
mean=			1.369	1.450	1.903

Shaded area is ± 30% of a perfect match.

17%. The p/r ratio for SF026 worsened going from 257 to 537%. Little change was observed in SF030 even though the acreage was reduced significantly. Bringing all the patterns on in the first year made up for the target oil decrease. The changes to SF158 and SF407 resulted in the model further over predicting oil production. The change to SF414, however, helped the model results by increasing the p/r ratio from 23 and 27% in Cases II and III, respectively, to 136%, a significant improvement. Changing the area in SF107 to correct for the dip angle did not help, taking the p/r ratio from a respectable 91% to 168%. The results are presented in Table 6.

Case V

This case was a refinement of Case II by supplying the model with actual steam injection rates rather than letting the model determine them. In most cases, the average (bcwepd, cold water equivalent) first year steam rates were used. Several of the projects did not have complete data for the first year so the best average of early time injection data was used. The aggregate total production p/r ratio decreased from 0.989 to 0.882 but the range of the individual project p/r ratios, 2.9 to 338%, was an improvement when compared to Case II (23 - 609%). Steam injection p/r ratios for all projects also decreased, from 96 to 83%, but once again, the range improved from Case II's 37 - 974% to 87 - 218%. Water production total was 37% of the reported volume. The individual project values are presented in Table 7.

The best results from all five cases revealed seven projects whose oil production p/r ratio agreed within ±30% of a perfect match. Three projects, SF107, SF345, and SF422 appeared in four of the five cases. Based on ROIP volume these projects ranked 5th, 2nd, and 1st in terms of size. Based on the mean p/r values, the SFPM overpredicted oil and water recovery and steam injection for every sensitivity case performed. The one exception was water production in Case V. No other trends emerged when the model results were sorted against any key reservoir property. Major project description changes, based on re-interpretation of the data, helped some projects and hurt others. Most of the projects did not differentiate between total and incremental oil production or there was no incremental production cited at all. For those

Table 6
Case IV Predicted Production and Injection for 14 Projects

	Oil Production, mb		predicted/reported (p/r)		
			Production		Injection
	Model	Reported	Oil	Water	Steam
SF030	3,563	7,167	0.497	0.794	1.423
SF242	1,617	2,934	0.551	0.157	0.485
SF100	1,258	1,917	0.656	0.454	0.415
SF019	1,046	1,541	0.679	1.555	2.264
SF345	16,728	23,067	0.725	0.887	1.423
SF422	19,666	23,666	0.831	0.506	1.021
SF022	1,619	1,689	0.958	0.138	1.872
SF414	960	706	1.359	0.710	1.756
SF186	376	275	1.365	0.933	1.683
SF107	9,950	5,912	1.683	2.308	1.803
SF407	1,788	701	2.551	7.192	11.862
SF158	2,525	736	3.432	4.152	2.007
SF091	1,038	207	5.008	3.717	2.494
SF026	2,325	433	5.369	1.363	4.033
total =	64,459	70,951			
p/r =	0.908				
mean=			1.833	1.776	2.467

Shaded area is ± 30% of a perfect match.

Table 7
Case V Predicted Production and Injection for 14 Projects

	Oil Production, mb		predicted/reported (p/r)		
			Production		Injection
	Model	Reported	Oil	Water	Steam
SF407	20	701	0.029	0.894	1.297
SF019	123	1,541	0.080	0.676	0.869
SF030	2,439	7,167	0.340	0.581	1.022
SF414	366	706	0.518	0.291	1.001
SF345	13,741	23,067	0.596	0.745	1.185
SF026	288	433	0.665	0.535	0.922
SF242	2,115	2,934	0.721	0.379	1.071
SF107	5,217	5,912	0.882	1.289	0.994
SF022	1,570	1,589	0.929	0.110	1.346
SF100	1,900	1,917	0.991	0.911	0.778
SF422	27,306	23,566	1.154	0.232	0.614
SF186	494	275	1.793	1.200	2.178
SF091	543	207	2.620	1.151	0.889
SF158	2,487	736	3.380	2.292	1.294
total =	62,563	70,951			
p/r =	0.882				
mean=			1.050	0.806	1.104

Shaded area is ± 30% of a perfect match.

projects that did report separate incremental production, very little was gained when the model results were compared to the incremental production.

Ten of the projects were expansions or continuations of previous or ongoing tertiary operations. Existing well counts changed through infill drilling, converting producers to injectors or vice-versa, replacing wells, or repairing wells. Four projects that could be identified as new, i.e., apparent undeveloped acreage with no prior tertiary operations, did not fare any better than the total project group as a whole. Two of those projects (SF019 and SF100) agreed fairly well, and the other two (SF091 and SF407) did not. One would expect new projects to be the least subject to errors in description and/or production and injection data.

Case I represented an NPC compatible TORIS screening run, i.e. start with the project level data, run it through DEFLT making reasonable changes, send the data to ROBL for formatting changes, append the cost structure information for the economic routines, and then run the SFPM. Other than attempts to match the OOIP, the data and the resulting ROIP was not changed. Almost half of the projects' OOIP and ROIP predicted volumes did not agree well with the reported data. The total oil recovery, 71% p/r, reflected the low hydrocarbon in place numbers.

Cases II - V were designed to improve the model's predictive ability. The input data was changed after DEFLT to provide the best project descriptions possible to the SFPM. Even though an excellent match to ROIP was obtained in Case II and the aggregate oil recovery p/r was 99%, the large variance in project level results were not much better than Case I. This suggested that the data provided by the operators was either inaccurate or the proper data was not supplied to adequately describe the projects. Further "subjective improvements" to selected project descriptions in Cases III and IV did not help. Case V improved on the variance range of the individual projects for oil production and steam injection rate, even though the aggregate totals for both parameters suffered somewhat.

The results of the 14-project steamflood comparison indicated that after matching the ROIP, an excellent agreement between oil recovery predicted by the model and reported results for the aggregate of the projects was achieved. Unfortunately, a similar conclusion at the project level could not be made. The variation between the predicted and reported oil production for individual projects varied from 3 - 609% (for all five cases) which indicated that the SFPM had a problem estimating oil production for an individual project.

Case V generated the best overall results even though Case II reported a 99% p/r ratio of total production. The total oil production p/r of 88% was very good, ROIP was almost a perfect match, and the mean p/r ratio for oil was 1.05. The range of oil production p/r ratios could have been better, but two projects grossly underpredicted oil production which affected the upper limit of the range. Water production and steam injection mean ratios were quite acceptable, particularly water as shown in Table 7. Quantifying the inaccuracy in estimating oil production was a principle goal of the study.

Statistical Approach

The statistical analysis is based on an evaluation of the ratio of the predicted oil production to reported oil production (p/r). The approach generally follows standard methods for estimating confidence levels with one exception. This exception relates to the skewed distribution of p/r data. It is not normal—values of p/r are not equally distributed on each side of the mean value. The lowest value for p/r was 0.06 while the highest value was over 6—many multiples of the mean. Since an underlying assumption to estimating confidence levels from z-tables and t-tables is that the data is distributed like a normal bell curve, direct analysis of the data was not appropriate. To solve this problem, an index or non-parametric method can be used. Although an index can distort results, an index is recommended over non-parametric methods if a suitable index can be found.[10]

The Chi-squared goodness-of-fit test was used to determine how well the p/r distribution compares to the normal bell curve. Levone[11] suggests that a Chi-squared value above 0.2 indicates a good fit. The Chi squared values for the unindexed p/r results were near or below 0.2. After evaluating a number of potential indexes, the natural logarithmic function, ln, was selected because it caused the least distortion of the data. Using ln (p/r) for the statistical analysis and then reverting the results back to p/r allows estimating the confidence in the accuracy of the models.

Chi-squared was calculated for the distribution of ln(p/r) for the confidence ranges reported in this study. They were all significantly above the 0.2 recommended by Levone.

The term confidence for the purposes of this report means the range of values that the actual oil production will fall between. The confidence limit is the degree or level of confidence. So a 50% confidence limit of 70 to 130% indicates that the actual production has a 50% chance of falling between 70 and 130% of the production estimated by the model. A p/r ratio of 100% would be a perfect match.

The results, presented in the Table 8, along with other key parameters, show a 50% confidence that actual production is approximately one-half to one and three-quarters of the estimated production for a specific project.

Accuracy of the Models

Steamflood (SFPM) Displacement Process

The selected subset of steam projects suggested that a larger selection of steamflood projects would improve the estimated accuracy of the SFPM. A larger group, which included the previous fourteen projects, supported the apparent trend that the SFPM model was under predicting aggregate production. Forty-six projects, taken from a total of 151 known TIP steam projects, represented the remaining thermal projects that met the criteria for this comparison study. The other 105 projects were excluded because they did not have a minimum of three years production, insufficient data for a project description was available, the project was never implemented, or there were uncorrectable inconsistencies in the data. The TIP project number, field name, formation, and operator name for the 46 projects are tabulated in Appendix A.

Based on the previous results, only two model runs were performed on this larger group. They are analogous to Cases II and V, matching ROIP and supplying actual steam injection rates, respectively. The results are summarized in Table 9.

The results of Case I were included to report the OOIP and ROIP volume ratios after attempting to match the OOIP. The larger group was in better agreement with ROIP after adjusting OOIP but, the ROIP needed adjustment to reasonably describe the project. Comparing the small sample results in Table 8 to the larger sample in Table 9 after ROIP consistency was addressed, the Case II results show a significant reduction in the total p/r (81% from 99%) but the mean oil production ratio improved (1.27 from 1.95). The 50% confidence interval shifted about 30 points to higher values. Case V, where actual first year average steam rates were input to the model, also generated worse statistics compared to the smaller group, particularly when comparing the total production ratio. Case V for both sample groups was an attempt to fine tune the project descriptions, so the poorer total oil production and broader confidence range were unexpected. Instead of using the first year average steam rates, a weighted average value taken over the life of the project might have improved prediction. Generally early steam rates tended to be low because rates have not stabilized for most projects which is consistent with the underpredicted results shown.

To better understand the effect of sampling, another grouping of projects for Case II was analyzed. By removing the original fourteen projects from the larger group, a third sample containing 32 projects was generated. The results for all three sample groups are shown in Table 10.

The sensitivity analysis shows that the original sample of fourteen projects were biased toward a better estimate of the aggregate oil production (99%) than a large sample would have predicted. The thirty-two projects sample

Table 8
Confidence Limits for Cases I-V for 14 Projects

Case	Percent of total reported volume OOIP, %	ROIP, %	Percent of total reported production, p/r, %	Mean oil production, p/r	50% Confidence Level Proj Prod falls between limits of predicted, %
I	69	72	71	1.50	52 to 174
II	n/a	99	99	1.95	41 to 162
III	n/a	107	79	1.37	57 to 172
IV	n/a	102	91	1.83	43 to 132
V	n/a	99	88	1.05	65 to 381

Table 9
Confidence Limits on 46 Steam Projects

Case	Percent of total reported volume OOIP, %	ROIP, %	Percent of total reported production, p/r, %	Mean oil production, p/r	50% Confidence Level Proj Prod falls between limits of predicted, %
I	90	85	n/a	n/a	n/a
II	n/a	99	81	1.27	69 to 208
V	n/a	99	67	0.90	80 to 377

Table 10
SFPM Sensitivity of Confidence Limit to Number of Projects

Case	Sample Population, n	Percent of total reported production, p/r	Mean oil production, p/r	50% Confidence Level Proj Prod falls between limits of predicted, %
II	14	99	1.95	41 to 162
II	32	72	0.91	86 to 228
II	46	81	1.27	69 to 208

indicated a under prediction basis and a broader range in the confidence limit than either the full sample or the 14 project sample. The statistics for the full forty-six project sample fall between the smaller samples as would be expected as the size of the sample increases. The forty-six project sample indicates that the SFPM under predicts oil production by about 20%. Using the combined statistics of 20% underprediction and a range of 70 to 200% for 50% confidence, the results indicate that the estimated oil production from the SFPM falls between 56% and 160% of the actual production.

Miscible Gas (CO2PM) Displacement Process

The Miscible Gas Predictive Model (CO2PM) was evaluated with thirty-four TIP projects out of a possible total of one hundred and nineteen. Fifty-six of the projects had less than three years of production data. Another twenty-eight projects had miscellaneous problems such as no CO_2 injection, unsuccessful projects due to tertiary injectant moving out of zone, projects that were never implemented, etc. Originally, thirty-five projects were selected but one of them possessed unusual fluid properties for a miscible gas displacement project (u = 160 cp. and API gravity = 17°) so, it was eliminated from consideration. The projects chosen are described in the appendix A.

Building on the experience from the SFPM runs, the first priority was to match the reported project ROIP to the ROIP calculated by the model (or IOIP) from the reported volumetric data to insure internal consistency. The ROIP was calculated from the oleic phase saturation in the CO2PM which is based on the residual oil saturation to water (S_{orw}). However, the Project Database contains minimal, information on S_{orw} (coded as SWZOS) and the model used the default value of 0.2. This conservative value for S_{orw} yielded a total ROIP of 1,457 MB, which represented only 33% of the 4,464 MB calculated from the reported volumetric data. The current oil saturation values that were passed to ROBL from the original project data were not used as residual saturations. The ROBL program substituted 0.2. Technically, this was a correct assumption because current and residual saturations were not necessarily the same. Another important use of S_{orw}, along with the connate water saturation (S_{cw}), was to set the relative permeability saturation endpoints.

The range of current oil saturations reported for the projects was 0.32 to 0.77. Obviously, many of these projects possessed mobile oil from incomplete primary or secondary process. The CO2PM allowed mobile oil to be included in the form of an oil cut (f_o) parameter, but normally ROBL defaulted f_o to 0.001 because it assumed the model was to be run in tertiary mode. The Project Database did not contain data on oil cut parameters either so now there were two problems; no residual oil saturations from which to base the tertiary project and no project level information on the mobile oil saturation above the S_{orw}. Updating the S_{orw} would not be sufficient to approximate the true target oil so a method was needed to include mobile oil in the description. For the purpose of this study, a pseudo oil cut curve was constructed to estimate apparent oil cuts to account for the mobile oil. This technique was applied to all of the projects.

Producing oil cuts were calculated for each project from their first year fluid production data. These values were input to the model and their corresponding oil saturations were determined by the CO2PM. A pseudo oil cut vs. oil saturation plot, based on the thirty-five projects, was constructed by plotting the producing f_o against the model derived S_o. After curve fitting the data points (figure 2), apparent f_o values were calculated from each projects' actual S_o. The apparent f_o values were substituted for the producing f_o values in the input data sets. The resulting model runs produced oil saturations and ROIP's much closer to those initially reported —a total ROIP of 4,084 MB, or 92% of the reported value from volumetrics. However, the total ROIP calculated from project volumetrics was 21% greater than the reported total ROIP. Also, nine of the thirty-four projects volumetric ROIP exceeded their reported OOIP. In order to keep as many miscible gas projects as possible for statistical purposes, the assumption was made that the volumetric data was correct and all projects were retained. A summary of the values used in these calculations are presented in the Appendix B.

The model's estimated oil production for these two Cases were vastly different. Case I, which used the default S_{orw} of 0.2, produced only 12% of the total production reported. Case II, which also used the default value of S_{orw} but adjusted f_o to allow for mobile oil, generated 180% of the total reported production. The predicted to reported (p/r) ratios of production for the individual projects ranged from 0.009 to 0.531 and 0.118 to 7.54 for Cases I and II, respectively. Case III improved upon Case II by adjusting the injector well count to closely match the actual

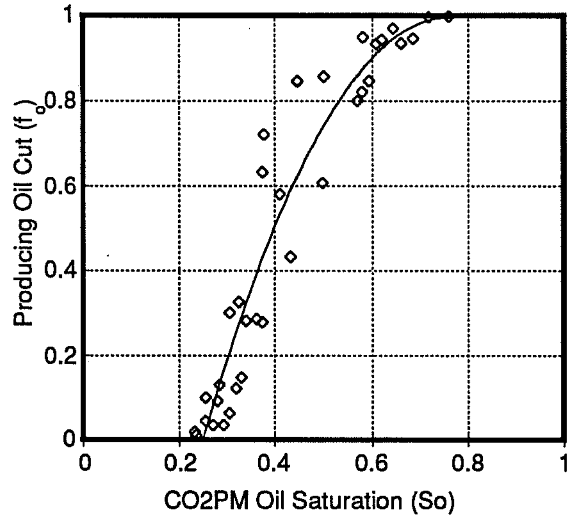

Fig. 2 Estimation of apparent f_o.

injection well count in the project description. Taken directly from the Project Database with only minor changes, Case II projected 3,320 injection wells, or 39% of the total 8,466 injection wells for all projects from 1981 to 1992. With manual intervention to the input data set, the Case III model run projected 9,021, or 107% of the actual injection well count. The effect on oil production, however, was minimal. Total predicted oil production was 182% of the total reported and the range of p/r was 0.120 to 7.56. One final refinement to the project descriptions, Case IV, provided actual CO_2 injection rates. Actual average first year carbon dioxide injection rates were supplied to the model and this improved the total produced oil p/r ratio to 145%. The range of individual project ratios widened from 0.017 to 10.44. A summary of the results is presented in Table 11.

The impact of actual S_{orw} values on the model results piqued our curiosity and a search of public sector information[12-22] was undertaken to acquire S_{orw} data for these projects. This data was obtained outside the Project Database, and does not represent the methods used in the NPC study or normal TORIS model runs. However, the predictive capability of the CO2PM was the object of this comparative study and providing the model with critical and selective information to test the model was warranted. Oil saturation data were found on twenty-nine of the thirty-four projects but in many cases the distinction between S_{orw} and current oil saturation was unknown; the other five projects retained the default value. Case V used these oil saturations

Table 11
Confidence Limits for Case I-V for Gas Displacement Projects

Case	Percent of reported volume ROIP, %	Percent of total reported production, p/r, %	Mean oil production, p/r	50% Confidence Level Proj prod falls between limits of predicted, %
I	33	12	0.136	572 to 2,888
II	92	180	2.188	33 to 138
III	92	182	2.303	32 to 131
IV	92	145	1.947	39 to 368
V	92	19	0.248	359 to 2,159

but the results did not show a significant improvement over Case I. Case V was intended to demonstrate that with approximate S_{orw} data, the model had the ability to predict reasonable production volumes for the aggregated projects. The results, however, suggested that the CO2PM, running in a strictly tertiary process mode continued to severely under predict actual field results. When mobile oil was introduced to approximate the correct target oil volume, the model overpredicted production compared to reported field production. Unfortunately, without S_{orw} and f_o, the ability to predict an accurate tertiary production response separate from remaining primary or secondary operations is unattainable. In addition, the impact on oil production response because of incorrect relative permeability endpoint saturation and fractional flow mobility was not been determined.

The thermal model production was compared to gross oil production because all production was assumed to have been a direct result of steaming operations, i.e. the oil was unproducible without steam. The miscible flood model runs have been compared to gross oil production as well. This was because some operators did not report incremental response and some admitted that they did not know what portion of the gross, if any, should be allocated to incremental production. When compared to reported incremental tertiary production, the model results for Cases I and V once again underestimated oil production relative to actual production. The predicted total oil production as a percentage of reported total incremental production was 27 and 26%, respectively. For Cases II, III, and IV, each employing mobile oil, the total p/r ratio was 258, 261, and 208%, respectively.

Polymer Flood (PFPM) Displacement Process

The Polymer Flood study began with forty-eight potential projects identified from the DOE Project files. Twenty-seven of these were located in the Project Database and 17 of those projects had sufficient reservoir and/or production data to be included in this study. One project, SF270, was eliminated because of problems with data input accuracy leaving a total of 16. These projects are described in Appendix A. The quality of the OOIP and ROIP raw data for the polymer projects was quite good and required much less modification than the thermal or miscible project data.

With only minor changes to the project descriptions, the volumetric ROIP total volume of 428,768 MB, which represented 13 of the 16 projects, was 105% of the total reported ROIP. Four of the projects were not included in the analysis of ROIP because neither OOIP nor ROIP was reported for them. However, these projects were included in the study by accepting their calculated ROIP from volumetric parameters. The injection well count balance was also quite good. The TIP operators reported 1,383 active injectors for all projects from 1981 to 1992 as compared to the models projected 1,187 injectors. Surprisingly, with this favorable matching, the total oil production predicted by the model was 74,767 Mb or 363% of aggregated oil production reported. The range of predicted to reported (p/r) production was also large varying from 9 to 1,035%.

Table 12
Confidence Limits for Case II & V for Polymer Flood Projects

Case	Percent of reported volume ROIP, %	Percent of total reported production, p/r, %	Mean oil production, p/r	50% Confidence Level Proj Prod falls between limits of predicted, %
II	105	363	3.191	n/a
V	105	442	4.347	n/a

Refining the project description by using actual polymer/water injection rate from first year averages resulted in the model overpredicting production even more. Total production was 90,920 MB or 442% of actual. The individual projects p/r ratios ranged from 86 to 1,077%. This was the first instance where every project except one was overpredicted by the model. The Polymer Flood results are summarized in Table 12.

Because of the extremely high over prediction of production by the PFPM, statistical analysis was not appropriate.

Problems Identified in the Coding

Although the models have been reviewed and checked by numerous experts, this study identified some problems in the coding that caused operational problems. These errors generally do not have a significant effect on the estimated oil production and are discussed in Appendix C.

Conclusions

Given the limitations inherent in the predictive models, the results of this study indicate the DOE steamflood model does a good job of predicting aggregated oil production for a random selection of projects—in the range of 80% of the actual oil production. A confidence limit for an aggregate oil production for a group of projects was not estimated. For an individual steam project, the mean predicted oil production varied significantly ranging from 90% to 200%. The range of the 50% confidence limit is roughly 70 to 210% of the calculated oil production. These statistics can be used with steamflood model results to indicate the accuracy of the estimated oil production for an individual project.

The miscible gas model severely under predicts production in the tertiary mode when the default values for the TORIS model are used. When more accurate project descriptions are used that includes the mobile oil, the mean oil production is roughly twice the actual production. The range of the 50% confidence limit is 30% to 140% when default values are used for CO_2 injection rates. The use of expected or actual gas injection rates does not help the accuracy of the predictions made by the miscible gas model. When the default injection rates are used, the confidence levels can be used to estimate the accuracy of the estimated oil for an individual project.

The polymer model grossly over predicts oil production for most projects. The mean predicted oil production for the sample of TIP projects was 3 to 4.5 times the reported oil production. The aggregated production for seventeen projects was roughly overpredicted by the same level as the mean. The large variance did not allow confidence levels to be estimated for this model.

Additional project descriptions and improved project descriptions would improve the reliability of the results of this study. This work will be updated from time to time attempting to improve upon the confidence levels and intervals as more and better information on projects is available. The models themselves can be further refined and the method developed can be used to assess the improvements in the models. Whether the study be regional, state, or national, the TORIS models are a valuable predictive tool and coupled with the other features of TORIS it is the only tool available to perform screening, predicting, and economic studies in an integrated package.

Limitations

The limitations of this study fall into two categories: the TORIS model and the project data. The TORIS predictive models are not sophisticated numerical simulators; they are analytical models that were calibrated against one or two simulation studies. Because they are analytical models, they must deal with average reservoir properties, constant pressures, idealized conditions, and events that normally would change with time. Basically they are static black box analyzers trying to mimic very dynamic and complex processes, so the moderate confidence in the oil production estimates is reasonable.

It would be easy to point to the models and blame them for the moderate confidence in the estimating ability of the three predictive models, however the large variance and apparent random results suggest problems with at least some of the reported project descriptions. The concern is that the TIP project description is different than the project implemented and therefore the production and injection data is not appropriately matched.

The quality of the project data is also a limitation. There were too many specific problems to mention but some of the more flagrant inconsistencies were:

1) OOIP and ROIP values inconsistent with the volumetric data.
2) Reported production greater than the OOIP and/or the ROIP.
3) Production reflective of an entire field when the TIP project is only a fraction of the field total.
4) Fluid saturations that totaled more than one pore volume.

Efforts were made to minimize the effect by eliminating projects with irreconcilable inconsistencies but the need for a large, random sample of projects to have significant statistic results required that projects with marginally consistent data be included. The results of this study supported the general conclusion that aggregated production estimates from the SFPM and CO2PM are reasonable but these results are not as accurate at the individual project level. This implies that data errors in larger projects were less significant or that reporting errors off-set each other.

Recommendations

Further refinement of the project descriptions seems appropriate. The following specific suggestions would be a good starting point:

1) Review the well count, pattern area, and pattern timing development of each project and adjust each to match actual conditions as well as possible. Many of the thermal projects are ongoing so, well additions and well shut-in's are part of their current operations. A better description of the project dynamics may produce a better match.
2) Calculate project life weighted average injection rates rather than using first year averages as was done in this study.
3) Review the public sector literature to improve the project descriptions. Outside information was used in the miscible gas sensitivity run using published residual oil saturations. Additional information on projects might confirm or refute the limitations of the data.
4) Consider contacting the operator(s) of seven to ten projects and request their aid to scrutinize in every detail the project descriptions used in this study.
5) This study did not perform sensitivity analysis using the SUPRI, Jones, or Intercomp predictive algorithms for the thermal projects. Previous studies[8] have shown the Gomaa routine to be best suited for the California thermal projects and the Intercomp routines are better for projects outside California. Since the method and data have been developed, routines other than Gomaa could be evaluated.

The results for the PFPM indicate that it grossly over estimates oil production. Refinements to this model should be considered.

The data set developed for the SFPM and the methodology developed should allow confident evaluation of refinements in this model. Since steam processes produce the most EOR oil, potential refinements to this model should be tested. In addition, a method for estimating the confidence in the aggregated oil production for steam should be explored.

The accuracy of the oil production estimates were the main consideration in this study. Although this is not independent of the economics, the ability of the models to be a go no-go economic screen was not evaluated.

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APPENDIX A: PROJECTS USED IN THE STUDY

Table A-1
Steam Projects

Project No.	Field Name	Reservoir or Formation Name	Operator	State
SF016	McKittrick	Amnicola/Tulare	Unocal/Chevron	CA
SF017	***Belridge North***	***Tulare***	***Unocal***	***CA***
SF018	Midway Sunset	Potter/Reef Ridge	Unocal	CA
SF019	***Midway Sunset***	***Potter Sand***	***Unocal***	***CA***
SF022	***Casper Creek So.***	***Tensleep***	***Unocal***	***WY***
SF026	***Midway Sunset***	***Tulare Sand***	***Unocal***	***CA***
SF030	***Guadalupe***	***Sisquoc***	***Unocal***	***CA***
SF091	***Cat Canyon***	***Sisquoc***	***Chevron***	***CA***
SF092	Kern Front	Chanac (Sec 27)	Chevron	CA
SF096	***Coalinga***	***Temblor (Sec 13D Phase 2)***	***Chevron***	***CA***
SF097	Coalinga	Temblor (Sec 13D - Phase 3)	Chevron	CA
SF098	Coalinga	Temblor (Sec 25 - Phase 1)	Chevron	CA
SF099	Midway Sunset	Monarch (Sec 26C- Phase II)	Chevron	CA
SF100	***Midway Sunset***	***Monarch***	***Chevron***	***CA***
SF101	Midway Sunset	Monarch (Sec 26C, U 10-10)	Chevron	CA
SF107	***Midway Sunset***	***Webster***	***Chevron***	***CA***
SF108	Midway Sunset	Potter (Sec 15A - Phase 1 and 2)	Chevron	CA
SF110	Cymric	Amnicola	Chevron	CA
SF111	Coalinga	Temblor (Sec 25 - Phase 2)	Chevron	CA
SF112	Kern River	Kern River Series (Sec 3 Phase 3)	Chevron	CA
SF120	Kern River	Kern River Series (KCL 39 - Phase 2)	Chevron	CA
SF121	Kern River	Kern River Series (China Grade) Davis Fee	Chevron	CA
SF122	Kern River	Kern River Series (China Grade) MC II	Chevron	CA
SF123	Kern River	Kern River Series (Sec 4)	Chevron	CA
SF124	Kern River	Kern River Series (MC I)	Chevron	CA
SF125	Kern River	Kern River Series (China Grade) American Naptha	Chevron	CA
SF126	Midway Sunset	Monarch (Sec 26C - Phase 1)	Unocal	CA
SF127	Cymric	Amnicola/Tulare	Chevron	CA
SF141	San Ardo	Aurignac (Monterey Co)	Mobil	CA
SF156B	Kern River	Kern River Series	Santa Fe	CA
SF158	***Midway Sunset***	***Upper Miocene***	***Santa Fe***	***CA***
SF164	Wilmington	Tar Zone (D1 Sand)	Champlin Petroleum	CA
SF184	Coalinga	Temblor (J, JV, G)	Santa Fe	CA
SF185	Coalinga	Temblor (J, JV) CMS Lease	Santa Fe	CA
SF186	***Midway Sunset***	***Reef Ridge***	***Santa Fe***	***CA***
SF187	Coalinga	Temblor (H, J, JV) Penn-Zier Lease	Santa Fe	CA
SF195	San Ardo	Lombardi (Monterey Co)	Mobil	CA

Table A-1 (continued)
Steam Projects

Project No.	Field Name	Reservoir or Formation Name	Operator	State
SF241	***Edison***	***116-Y18 (Chanac)***	***Chevron***	***CA***
SF242	***McKittrick***	***Tulare Sand***	***Chevron***	***CA***
SF243	McKittrick	Amnicola	Chevron	CA
SF247	McKittrick	Tulare/Amnicola Sand	Chevron	CA
SF251	Coalinga	Temblor (Sec 25D - Phase 3)	Chevron	CA
SF325	Midway Sunset	Monarch/Reef Ridge	Gen. American Oil of Texas	CA
SF341	Midway Sunset	Potter/Tulare (W&S Div Fee)	Sun/Arco	CA
SF343	Midway Sunset	Potter (Sec 15)	Sun/Arco	CA
SF345	***Midway Sunset***	***Potter***	***Sun/Arco***	***CA***
SF346	Cymric	Tulare Tar	Sun/Unocal	CA
SF370	Midway Sunset	Monarch (Sec 26 pilot)	Chevron	CA
SF371	Midway Sunset	Monarch (10-10, Maricopa Fee)	Chevron	CA
SF407	***Midway Sunset***	***7A Sand Pool***	***Santa Fe***	***CA***
SF414	***Poso Creek***	***Etchegoin Series***	***Elf Aquitaine***	***CA***
SF422	***Kern River***	***Kern River***	***Chevron***	***CA***

Projects in bold/italics font are the original 17 projects used to develop the methodology

Table A-2
Miscible Gas Displacement Projects

Project No.	Field Name	Reservoir or Formation Name	Operator	State
SF011	Tinsley Field	Perry	Pennzoil	MS
SF023	W Poison Spider	Cody-Phayles	Unocal	WY
SF041	Kelly-Snyder	Canyon Reef	Chevron	TX
SF059	Maljamar Field	Grayburg/SA	Conoco	NM
SF082	N. Farnsworth		Dorchester Enhanced Recovery Co	TX
SF083	N. Hansford		Dorchester Enhanced Recovery Co	TX
SF084	Hansford	Marmaton	Dorchester Enhanced Recovery Co	TX
SF117	Fordoche	Wilcox 12	Sun E&P	LA
SF118	Fordoche	Wilcox 8	Sun E&P	LA
SF131	East Binger	Marchand	Phillips	OK
SF135	Ford Geraldine	Ramsey/Delaware	Conoco	TX
SF136	South Pass Blk 61	Upper M RAAO, 2,3	Arco	LA
SF137	South Pass Blk 61	Middle M RBB	Arco	LA
SF138	South Pass Blk 61	Upper M RBB	Arco	LA
SF139	South Pass Blk 61	Middle M RAAO, 2,3	Arco	LA
SF140	Garber Field	Crews	Arco	OK
SF148	NE Purdy Field	Springer	Cities Service	OK
SF155	Welch Field	San Andres	Cities Service	TX
SF168	Rose City Field	Hackberry	GR Brown	TX

Table A-2 (continued)
Miscible Gas Displacement Projects

Project No.	Field Name	Reservoir or Formation Name	Operator	State
SF169	Bridger Lake Unit	Dakota A&C	Phillips	UT/WY
SF171	Fairway Unit	James Lime	Hunt Oil	TX
SF175	Dillinger Ranch Unit	Minnelusa	Tenneco	WY
SF194	McElroy	San Andres	Southland Royalty	TX
SF219	Seminole	San Andres	Amerada Hess	TX
SF222	TwoFreds	Delaware	HNG Fossil Fuels Co	TX
SF238	Alvord Field	Caddo Conglomerate	Amer Trader	TX
SF279	Headlee Devonian North	Devonian	Mobil	TX
SF305	Wasson (Willard Unit)	San Andres	Arco	TX
SF309	EVWBSSU	Sims Sand	Arco	OK
SF312	Lick Creek	Meakin	Phillips	OK
SF340	Painter Field	Nugget	Chevron	WY
SF380	GMK South	San Andres (Northrup)	Mobil	TX
SF381	GMK South	San Andres (Braddock)	Mobil	TX
SF382	GMK South	San Andres (May)	Mobil	TX
SF383	GMK South	San Andres (H&J)	Mobil	TX

Table A-3
Polymer Projects

Project No.	Field Name	Reservoir or Formation Name	Operator	State
SF005	Old Lisbon	Pettit Lime	Tenneco	LA
SF037	North Burbank	N Burbank	Phillips Pet Co	OK
SF055	Stephens Co Regular	Caddo Limestone	Sun E&P	TX
SF160	Stephens Co Regular	Caddo Limestone	Sun E&P	TX
SF196	Gumbo Ridge Unit	Tyler B	Milestone Pet Inc	MT
SF206	Deadman Creek Unit	Minnelusa B	Milestone/Meridian	WY
SF234	Hitts Lake	Paluxy	Sun E&P	TX
SF235	Lanyard D Sand Unit	Muddy D	MGF Oil Corp	CO
SF270	Westbrook	Clearfork	American Petrofina	TX
SF308	Kummerfeld	Minnelusa	Terra Resources Inc	WY
SF350	Robertson	Glorieta/Clearfork	Samedan Oil Corp	TX
SF372	Hewitt	Hewitt Sands	Hales Oil Interests	OK
SF391	Cement	Fortuna	Mobil	OK
SF395	Red River Bull Bayou	Paluxy	Sun E&P	LA
SF396	Sadle Ridge	Mesaverde 5th Bench	Belco Pet Corp	WY
SF413	Kuehne Ranch Unit	Minnelusa	Samedan Oil Corp	WY
SF421	Upper Valley	Timpoweap Kaibab	Tenneco	UT

APPENDIX B: MISCIBLE GAS MOBILE OIL CALCULATIONS

Table B-1

Determination of Apparent F_o from Oil Cut vs Oil Saturation Curve Fit

	Original Data			x,y pairs for curve fit		Calc Fo for
	Soi	So	Δ So	Producing F_O fr fluid data	Resulting S_O fr model	given So fr curve fit
SF011	-1	0.500	n/a	0.064	0.305	0.739
SF059	-1	0.550	n/a	0.019	0.233	0.829
SF140	0.700	-1	n/a	0.012	0.236	0.983
SF148	0.820	0.466	0.354	0.123	0.319	0.667
SF309	0.900	0.530	0.370	0.035	0.293	0.795
SF168	0.680	0.340	0.340	0.947	0.685	0.323
SF238	-1	0.770	n/a	0.326	0.325	0.995
SF082	0.800	0.560	0.240	0.433	0.433	0.845
SF380	0.758	0.700	0.058	0.800	0.570	0.983
SF381	0.758	0.700	0.058	0.821	0.580	0.983
SF382	0.760	0.700	0.060	0.607	0.499	0.983
SF383	0.758	0.700	0.058	0.847	0.594	0.983
SF135	-1	0.390	n/a	0.044	0.255	0.475
SF084	-1	-1	n/a	0.935	0.660	-1
SF083	0.620	0.399	0.221	0.036	0.270	0.500
SF041	-1	0.781	n/a	0.101	0.256	0.994
SF194	0.621	0.530	0.091	0.279	0.375	0.795
SF219	0.840	0.537	0.303	0.282	0.341	0.807
SF222	0.567	-1	n/a	0.288	0.363	0.855
SF305	0.810	0.552	0.258	0.093	0.280	0.832
SF155	0.730	0.470	0.260	0.148	0.330	0.676
SF175	0.800	0.320	0.480	0.131	0.284	0.258
SF023	-1	0.560	n/a	0.950	0.581	0.845
SF312	-1	-1	n/a	-1	-1	-1
SF117	-1	0.526	n/a	0.633	0.375	0.788
SF118	-1	0.530	n/a	0.997	0.718	0.795
SF136	0.780	0.750	0.030	0.971	0.644	0.996
SF137	0.780	0.750	0.030	0.943	0.620	0.996
SF138	0.780	0.750	0.030	0.934	0.609	0.996
SF139	0.780	0.750	0.030	0.858	0.502	0.996
SF171	0.704	0.481	0.223	0.301	0.306	0.700
SF169	0.748	0.606	0.142	0.581	0.411	0.907
SF279	-1	-1	n/a	0.722	0.378	-1
SF340	0.800	0.737	0.063	0.847	0.447	0.994
SF131	0.750	-1	n/a	0.999	0.760	0.996

removed SF312 (μ=160 cp, API = 17°)

No value denoted by "-1"

APPENDIX C: POTENTIAL CORRECTIONS IN THE MODEL CODING

Problems Pertaining to DEFLT and ROBL

The Vasquez and Beggs[1] correlations for dissolved gas (SGOR and R_S) and formation volume factor (FVF) in DEFLT were functions of temperature, pressure, API oil gravity, and gas gravity. The gas gravity term was corrected to surface separator conditions of 100 psig. Two assumptions used in the calculation of the corrected Separator Gas Gravity (SGG) were not consistent with those found in the steam food predictive model (SFPM). First, separator temperature conditions were neither consistent within DEFLT (there were several places where SGG may be calculated) or to the SFPM. In DEFLT, separator temperatures of 60 and 70 degrees were used in different places and in SFPM the formation temperature was used. Second, initialized SGG values, SGG_i, were corrected for temperature and pressure and yields SGG. SGG_i values were relative to air gravity (= 1.0), and DEFLT and SFPM used values of 1.0 and 0.8, respectively. One would normally expect a lower value (< 1.0) at initial conditions. DEFLT used SGG in the calculation of SGOR and the initial FVF (IFVF).

The solution gas oil ratio, R_S, was calculated in DEFLT and passed to the models for calculation of the current FVF (CFVF). DEFLT used two correlations, one a function of depth and another of pressure, for the 1st and 2nd default values, respectively, when R_S was not provided in the input data. We recommend using the Vasquez and Beggs correlation as the first default value because it is a more rigorous calculation based on temperature, pressure, API oil gravity, and SGG.

An error was discovered in the calculation of the IFVF and was traced to the Vasquez and Beggs correlation in DEFLT. Two regression analysis correlations for FVF were presented to represent the range of API oil gravities. API gravities .GT. and .LE. 30 had unique solutions differing by their curve fitting constants. Those constants in DEFLT were switched. DEFLT used the IFVF for the OOIP volume checking routine only; it did not pass the IFVF to the predictive models. Because of coding problems (see discussion of pressure calculations in the SFPM), it was simpler for the purposes of this study, and only for the thermal projects, to input a low value for IFVF such as 1.05 rvb/stb. The CFVF calculation by the SFPM used the regression constants correctly. However, the CFVF calculation included an R_S value calculated in DEFLT based on a pressure that may be abnormally high.

Hydrocarbon pore volume calculations required a conversion constant to change units from cubic feet (CF) to barrels (bbl). DEFLT used "7758" as the conversion factor to calculate OOIP and the model used "7759.17" (43,560 cf / 5.614 cf/bbl) to calculate IOIP. Neither value was incorrect, but this subtle difference can create confusion when setting up spreadsheets or hand calculating OOIP and IOIP.

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1. Vasquez, M.E. and Beggs, H.D., Correlations for Fluid Physical Property Prediction, *Journal of Petroleum Technology*, June, 1980, pp. 968-970.

When S_{oi} was not supplied, DEFLT would back calculate S_{oi} from the other volumetric parameters and the reported OOIP. Considering the internal inconsistencies inherent in the data, sometimes this calculation of S_{oi} yielded values greater than one. DEFLT did not check the calculated S_{oi} to see if the value was between zero and one and it further did not check to see if S_{oi} was less than the current oil saturation.

When the current oil saturation (S_{oc}) was unknown and entered as "-1" in the input data set and there was no primary production reported, ROBL defaulted S_{oc} to 0.6. In some instances, S_{oc} was greater than the initial oil saturation, S_{oi}, and all other volumetric parameters being equal, the IOIP would be greater than the OOIP. ROBL apparently did not check the oil saturations to prevent this problem. A quick and easy fix to this problem was to insure that all projects had some primary production, if only 10 bbls. This did not significantly impact the IOIP, and DEFLT then back calculated S_{oc} from the IOIP (OOIP less primary production).

There was considerable confusion in ROBL as to the distinction between well spacing and pattern spacing and the order of priority regarding the determination of pattern size. When the variable CDARY(3), well spacing, was provided as input to ROBL, the "default/calculate pattern size" code in ROBL would set pattern spacing equal to well spacing. Fortunately, well spacing was rarely, if ever, supplied, and to make sure the problem was eliminated CDARY(3) was set to zero in ROBL's code. Since pattern size was not an input variable, it was determined by ROBL from the well count. Originally, the order of calculation was from the producer well count, then from the average total well count, then from the injector well count. Since the pattern assumed for all the models is an inverted 5-spot it seemed reasonable that pattern size should be determined from the injector well count first, followed by the average total well count, and then by the producer well count. This change was incorporated in all of the model runs performed in this study. The one exception was the thermal projects. Most of the steam projects did not report an injection well count because there were no waterflood operations prior to steaming. In this case, the thermal projects' pattern size should be determined from the producing well count.

The miscible gas section of ROBL was passing porosity to the model as a whole number instead of a fraction and all OOIP and IOIP volumes were in error by two orders of magnitude. This error was corrected.

The producer to injector ratio for projects whose development of approximately ten patterns or less was too high. The algorithm responsible for these calculations was not reviewed and the impact on the model's revenue and cost streams was not determined. This problem was encountered with all three of the models run in this study.

Problems Encountered with the Models

SFPM

Many steam projects were unique in that they have very low initial and current pressures–many times 100 psi or less. DEFLT recalculated all input pressures that were less than or equal to (.LE.) 100 psi. The calculated pressures were based on depth and pressure gradient and for most steam projects the resulting pressures were high relative to their actual initial and current pressures. An attempt was made to change the pressure constraint in DEFLT to .LE. 40 psi, allowing all but very low actual field pressures to be honored, but sometimes strange results were obtained (e.g., R_s > SGOR in some cases). There was not enough time to fully resolve the issue at this time and the coding logic was left unchanged.

CO2PM

The default fluid injection rate (QRES) used by the model was based on a fraction of the hydrocarbon pore volume in reservoir barrel (rvb) units. However, the model multiplied (corrected?) QRES by the water formation volume factor (B_W). The actual code taken directly from the program looks like this:

```
C   DEFAULT FOR QRES (0.1 HCPV PER YEAR)

IF(QRES.LE 0.005)QRES=0.1*(1.0-SWCN)*BW*(7758.0*AREA*THICK*POROS)/365.0
```

Subsequently, the produced fluid volumes, Q_{oil}, Q_{CO2}, and Q_{wat}, which were calculated from QRES and were corrected to stock conditions using their respective formation volume factors, were apparently in error by the magnitude of B_w calculated for each project. An examination of the program code to determine why B_w was used in this calculation was not performed because of time constraints.

The model checks a project's revenue and cost streams and allows only one year of negative cash flow to determine when the economic limit has been reached. The miscible gas model, when used in the tertiary mode, usually exhibited a small initial oil response with large initial capital investments and were being stopped early, generally after the first year of the project. For the purposes of this study the economic limit constraint was removed so that the production projection could be reviewed regardless of the economics.

PFPM

The Polymer Flood model calculates OOIP from 1- S_{cw} and the IOIP from 1- S_{wi}. On several occasions, S_{cw} was greater than S_{wi} because the water saturations were determined from different assumptions, e.g. S_{cw} defaulted to 0.3 and S_{wi} may have been calculated in ROBL from Soi = 0.75 (or any value greater than 0.7). When this happened the IOIP was greater than the OOIP. The PFPM apparently did not check the OOIP and IOIP for directional consistency.

Just as in the CO2PM, the PFPM model checks a project's revenue and cost streams and allows only one year of negative cash flow to determine when the economic limit has been reached. For the purposes of this study the economic limit constraint was removed so that the production projection could be reviewed regardless of the economics.