Reservoir Management Decision Making in Presence of Uncertainty: A Progress Report

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Abstract

Reservoir decisions must be made in the face of much uncertainty. One of the biggest sources of uncertainty is the reservoir volume, defined by subsurfaces, and architecture, defined by facies and petrophysical property distributions. This uncertainty is unavoidable given the sparse well data and difficulty in accurately relating geophysical measurements to reservoir-scale heterogeneities. Our goal is to make reservoir management decisions, such as choosing the number and location of production wells, in a manner that is robust with respect to the inherent uncertainty in reservoir volume and architecture.

Uncertainty in the static reservoir volume and architecture may be quantified by geostatistical methods. This uncertainty may then be transferred to uncertainty in reservoir production response by processing multiple realizations through a flow simulator. Optimal decisions may be made, which maximize expected profitability. Although computer intensive, the "full approach" of considering multiple realizations and multiple production scenarios should lead to improved decisions. A case study is documented here that illustrates the benefit.

This report summarizes work-in-progress directed toward the Ph.D. of Paulo Cruz. Publication of the full Ph.D. dissertation and all related details is expected in mid-2000.

KEYWORDS: well planning, geostatistical simulation, development planning

Uncertainty in Reservoir Forecasting

Petroleum exploration and production require huge investments and are inherently risky activities. Decisions regarding investment in exploration and production activities depend on our forecast of future hydrocarbon production. Uncertainty is present in such production forecasts due to our ignorance in the reservoir volume, distribution of internal heterogeneities, fluid properties, behavior of the rock and fluid when subjected to external stimuli, and the future prices of the product.

Reservoirs are under hundreds or thousands feet of rock and water (in the offshore case) and cannot be directly seen or measured accurately. The reservoirs can only be modeled and, then, only by making important decisions on the spatial distribution of rock and fluid properties borrowing from known nearby or analogous reservoirs. These decisions on the behavior of the reservoir away from available well data can be incorrect.

Seismic data give reasonable information about reservoir boundaries, but the resolution of seismic is much larger than the internal heterogeneities. The correlation between the geophysical measurements and rock and fluid properties are subject to error. Historical production data including well tests provide additional large scale information; however, individual well production data is subject to error and the inverse relationship to rock and fluid properties is difficult and ill-posed.

Flow simulation provides a rigorous approach to predict reservoir behavior; however, the equations and software used for flow simuation consider data without any error or uncertainty and give a single deterministic response. But the equations and numerical solution schemes themselves have approximations, assumptions and errors that increase the uncertainty and unreliability in the forecasts.

Future prices of oil and gas are uncertain, which further increases uncertainty in revenue forecasts.

Reservoir Decision Making

In the petroleum industry, exploration and production are done in sequence. First, exploration finds a promising geologic structure making use of seismic responses and knowledge of the sedimentary basin. Then, it is necessary to drill a well in order to prove the existence of a hydrocarbon reservoir. When the first exploratory well succeeds in finding hydrocarbon, depending on the field size, other exploratory wells must be drilled to delimit the deposit. After that, a development plan is generated to provide the necessary data for the production cash flow analysis. If the company decides to invest in that project, the development plan is implemented and hydrocarbon is produced.

There are at least three different types of decisions involved in this process: (1) the decision of drilling a exploratory well or not, (2) the technical decision of the best development plan and (3) the business decision of investing in the project or not. Each decision has a different risk type and magnitude.

Many risks can be analyzed with a decision table which relates alternative actions to various outcomes. Estimates of the probabilities attached to each outcome are necessary. Expected Monetary Values (EMV's) can be calculated from the decision table and make choices made to maximize profit. EMV analysis involves multiplying financial outcomes by probabilities and summing the products to get a "risk-weighted" financial estimate. The time value of money must be accounted for in the alternatives because money received in the later in the future is worth less than right now. Discounted cash flow is used to calculate the present value of each alternative. In addition, each organization may have a different assessment of the consequences for losses or gains, i.e. different desires for financial gains and the aversion to losses. A utility function can be built to translate monetary values to utility values. We can substitute the utilities for dollars in the decision table, and calculate "expected utility values" or EUV's, instead of EMV's. An EUV table thus combines risk, expressed as probabilities, with risk aversion, expressed by the utility function.

Exploration decisions are very risky. Most exploratory wells are dry or non-commercial, resulting in substantial losses. The risk varies from well to well. The successful exploratory wells must ultimately pay for the dry holes. In order to evaluate the EMV of an exploration well, we need the probability of a dry hole and its complement, the probability of a producer and the possible outcomes. A regional "success ratio" is a useful starting point for estimating the dry hole probability. Success ratio represents the proportion of the overall exploratory wells that were successful in a specific region. The outcome of a dry hole is just the cost of drilling the well, but the outcome of the producer is, actually, a probability distribution because there is a spectrum of sizes of the field that might be discovered. The production curves for each size can be estimated directly by "analogous" reservoirs, or by modeling rock and fluid geometries and properties and then using a flow simulator. Normally each field size is associated to only one production curve, but it could be related to a probability distribution of curves too, due to the uncertainty on the modeled parameters.

In a petroleum company, *Reservoir Management* plans and controls reservoir production. The main products of this activity are the development and the workover plans. A development plan determines the number, type and location of additional wells while a workover plan determines the operations to be done for improving production in existing wells. Both plans present the rig work schedule and the curves for injection and production fluids. With this, and data about the costs of wells, facilities, pipelines and operating expenses, a cash flow analysis can be done. The plans for producing the fields and the associated cash flows are the basis for huge investments in the petroleum business. Any improvement in the plans represents large improvements to a companies revenue. In this research the focus is on the development plan as representative of a reservoir management decision. Nevertheless, the procedures introduced here may be adapted for workover decisions too.

Once the development plan is defined, there are techniques to transfer certain types of uncertainty in the data to the production forecasts, generating a probability distribution of production curves. A good way to do that is by using geostatistical realizations. It is widely accepted that stochastic geostatistical simulations can provide several equiprobable images (realizations) of a reservoir, all of them respecting the available data from wells and seismic. These different realizations are themselves a measure of the geological model uncertainty. For each realization a flow simulator is run and a production curve is obtained, using the number, location, type and start production time of the wells as defined in the plan. The difference in the production curves provides a measure of the uncertainty in the forecasts. Since the realizations are equiprobable, all the production curves have the same probability. The expected monetary value of the project thus is just the arithmetic mean of the discounted cash flow calculated over each curve. This canbe used to guide the business decision of investing or not in a particular project and to rank alternative projects.

There remains the question as to how can we determine the best reservoir development plan in the presence of uncertainty? This research is intended to provide some answers to this question. This research considers the uncertainty in the geological model due to sparse sampling of the reservoir, which is by far the most important source of uncertainty in the geological model. Future work could address the other uncertainties mentioned in the preceeding section.

The "Full Approach"

In some cases, a development plan consists of an estimate of the necessary number and type of wells, the initial production/injection rates and the production rate decline based on "analogous reservoirs". It is possible to work with the best and worst value for each parameter, obtaining ranges for the total production/injection curves, instead of only one deterministic curve, but the decision about the number, type and location of the wells does not take into account any uncertainty.

When reservoir data is available, a better and more "conventional" approach consists of building a deterministic (no uncertainty) model of the reservoir structure and properties. This may be done by traditional geological modeling, by kriging, or by generating just one stochastic realization. Then, different numbers of wells and well configurations are considered. A flow simulator is run for each possible alternative to generate the respective production/injection curves. A cash flow analysis is performed and the alternative that leads to the maximum profit is chosen. Notwithstanding the simplicity of this approach, it does not guarantee that the decision is "optimal" or "robust" with respect to the unavoidable uncertainty in the reservoir structure and heterogeneity.

An alternative approach, called here the "full approach", can be considered to define the development plan taking into account the uncertainty of the geological model due to the sparse sampling. The steps of the full approach:

1. Generate several realizations of the reservoir structure and petrophysical properties: $l = 1, ..., L$. Each reservoir model l is a complete specification of all static properties such as geometry, porosity and absolute permeability, as well as the fluid properties such as PVT (Pressure, Volume, Temperature) curves and relative permeability curves. Each realization may have an associated probability of occurring $f_l, l = 1, ..., L$. Stochastic simulations using geostatistical tools can be performed to generate different equiprobable realizations of the reservoir; however the set of realizations may include sensitivity studies on average parameters, continuity of shales, aquifer strength, relative permeability, etc., that would give reduced probability for to realizations.

2. Enumerate all possible reservoir management scenarios: $s = 1, ..., S$. Each scenario is a complete specification of one possible solution for the problem. For example, one scenario could be the number of wells, their locations, completion intervals, surface facilities and so on. The total number of scenarios S could be in the hundreds. The scenarios may be identified by inspecting the L realizations.

3. Establish a quantitative measure of profit to be maximized P. The measure of profit will increase with increased hydrocarbon production and will decrease as more wells and facilities are required. It depends on the related costs, hydrocarbon prices and taxes. A good unit to measure the profit is the present value of the discounted cash flow.

4. Calculate the profit for each scenario and each realization: $P_{s,l}, s = 1, ..., S; l = 1, ..., L$. The fluid production and injection curves are obtained by running a flow simulator and the defined quantitative measure of profit is applied over the scenario specifications and curves for each situation (s and l).

5. Determine the optimal scenario s^* by some type of L-optimal profit. In the simplest case this will be based on expected values $E\{P_s\} = \sum_{l=1}^{L} F_l \cdot P_{s,l}$. The optimal scenario s^* is such that $E\{P_{s^*}\}$ is maximum.

Case Study

The best scenario from the full approach takes into account the uncertainty in the geological model, but is it better than the decision resulting from applying the conventional approach? In order to quantify the "goodness" of the full approach, we must compare the results of making decisions both ways with "true" reservoir results. That is not possible in practice since only one development plan can be implemented and there is no access to the true reality of the reservoir distribution. Moreover, we must consider multiple "true" reservoirs because, by chance, the "conventional" or "full" method could appear better in one particular case.

A very large case study was undertaken to demonstrate the value of considering uncertainty in reservoir decision making. This case study is on summarized below; complete details are included in the upcoming Ph.D. dissertation. The methodology of the case study consisted of the following steps:

- *Create* a large number of realistic true reservoirs: fifty different true reservoirs were created using stochastic methods that *are not* used again for decision making. These true reservoirs provide the source of data provide a measure of the profitability of different development decisions. Care was taken to ensure fairness in checking the "conventional" and "full" methods.

- *Sample* the true reservoirs to obtain well and seismic data. The same data is available to both methods.

- *Construct* a conventional reservoir model and L geostatistical reservoir models for each true reservoir. In our example, we construct $L = 20$ geostatistical realizations for each true reservoir, thus, we have 1000 geostatistical realizations, 50 true reservoirs, and 50 conventional reservoir models.

- *Enumerate* a number of development scenarios for each true reservoir. For this case study, 77 different scenarios were identified for each reservoir (11 different numbers of wells and 7 different configurations). The specific number of wells varied between the true reservoirs to account for the variable OIP of each reservoir.

- *Run* many many different flow simulations to permit selection of the optimal scenario by the "conventional" and "full" methods.

- *Compare* the results of the "conventional" and "full" methods using the actual flow performance of the chosen development plans. Access to the true reservoir permits this comparison whereas it would be impossible in practice.

The reservoir volumes, productivities and lithologies represent medium size offshore reservoirs with sandstone/shale lithology. No faults or fractures were considered and only vertical producer wells were used in the scenarios. In spite of the limitations and assumptions inherent in this case study, the comparison is fair and illustrative. In all cases, the limited sample data were used for modeling. Statistics and additional information from the true reservoirs were **never** used in the conventional or geostatistical modeling.

A discounted measure of profit (expressed in terms of oil volume) is considered. A discount rate of 7.5% was used. Fluid properties, well conditions, and shut-in criteria were chosen to be realistic.

Results

Four methods are summarized below: (1) conventional approach with a reservoir model built by kriging, (2) conventional approach using the first geostatistical realization, (3) the full approach using the expected value of profit (mean) as the selection criteria, and (4) the full approach using the scenario that comes up the most (mode) as the selection criteria.

For each case, the defined measure of profit (P) was evaluated and recorded. In the full approach (using several stochastic realizations) we calculated the mean P over all the realizations for each scenario. The true responses tell us the *real* best scenarios. The response from the conventional reservoir model and geostatistical simulations tell us an estimate of the best scenario with the full approach (mean over all realizations) and conventional approach (realization 1 - as an example of just one realization - and kriged model).

To compare the approaches we need to compare the true responses of the best scenarios determined with each approach. For reservoir 1, for example, the best scenario determined with the full approach (seven wells and configuration number six with a true P value of $4,040,776m^3$ of oil) is slightly better than the best scenario determined with the realization 1 (seven wells and configuration number 3 with a true P value of $4,005,707m^3$ of oil) and it is much better than the best scenario determined with the kriged model (seven wells and configuration number 5 with a true P value of $3,843,33m^3$ of oil). With none of the approaches, though, the true best scenario was determinded, which would be eight wells and configuration number two with $P = 4,055,313m^3$ of oil, but it is important to remember that in real cases the true reservoir is unknown. We are only verifying if the full approach leads to better decisions than the conventional approach or not. The best scenario determined with the full approach was better than the one determined with realization 1, but the realization could have been any of the other nineteen. Actually to compare the approaches we need to calculate the expected value of the conventional approach using only one realization. This is done by taking the mean over the true responses of the best scenario decided with each realization. For reservoir 1, for example, the expected value of the conventional approach using only one realization was $P = 3,969,062m^3$ of oil, which is worse than the result with realization 1. But these results are valid only for reservoir 1; for a different reservoir the conventional approach can lead to better decisions. To compare the approaches more reliably we need more statistics. That is why we applied the approaches to fifty different reservoirs.

Figure 2 presents a table with the P results and comparisons between the approaches for the fifty reservoirs. In the table, conv_1 stands for conventional approach - one realization and conv_k for conventional approach-kriging. The columns "% $\geq$ conv_1" present the number of realizations (in percentage) for which the full approach led to a decision better than or equal to the decision using only that realization for the same reservoir. For example, if the best scenarios determined with two of the twenty realizations have greater true P than the scenario determined with the full approach, the "% $\geq$ conv_1" is 10.0 ($\frac{2}{20} \cdot 100$). The columns "% gt conv_1" present the number of realizations (in percentage) for which the full approach was better (only) than conv_1. The columns "full - conv_1" and "full - conv_k" present the difference in profit (P) between the full and conventional approaches. A negative value means that the conventional approach is better than the full one.

The results indicate that in average:

- Any of the versions of the full approach is better than any of the versions of the conventional approach.
- The conventional approach-one realization leads to better decisions than the conventional approach-kriging.
- The full approach-mean leads to better decisions than the full approach-mode.
- The full approach-mean led to decisions better than or equal to those obtained using just one realization for 70% of the realizations.
- The full approach-mean led to better decisions than the conventional approach- one realization for 64% of the reservoirs.
- The full approach-mean led to better decision than the conventional approach- kriging for 72% of the reservoirs.
- The average gain per reservoir in using the full approach-mean over the conventional approach-one realization was $64,000 m^3$ of oil.
- The average gain per reservoir in using the full approach-mean over the conventional approach-kriging was $166,000 m^3$ of oil.

The difference between the average number of true reservoirs for which the full approach-mean led to a decision better than or equal to the decison using only that realization (70%) and the average number of reservoirs for which the difference in profit between the full approach-mean and the conventional approach-one realization was positive (64%) is explained by the fact that some realizations led to the same decision than the full approach (25%).

The improvement of the full approach over the conventional approach is unambiguous. The dollar value of the full approach is also significant - in the millions of dollars (discounted to current dollars).

Future Work

Future work is progressing in a number of areas. One avenue of research is to improve the CPU speed of the full approach. Considering 20 (or more) geostatistical realizations multiplies the flow simulation effort considerably. There are a number of ways to improve the CPU speed including pre-screening the realizations. Another avenue of research is to devise better approaches to select well locations, that is, to reduce the number of scenarios that must be considered. In addition to improving on the full approach, there are a number of research avenues open to use multiple realizations to make other exploration and reservoir management decisions.

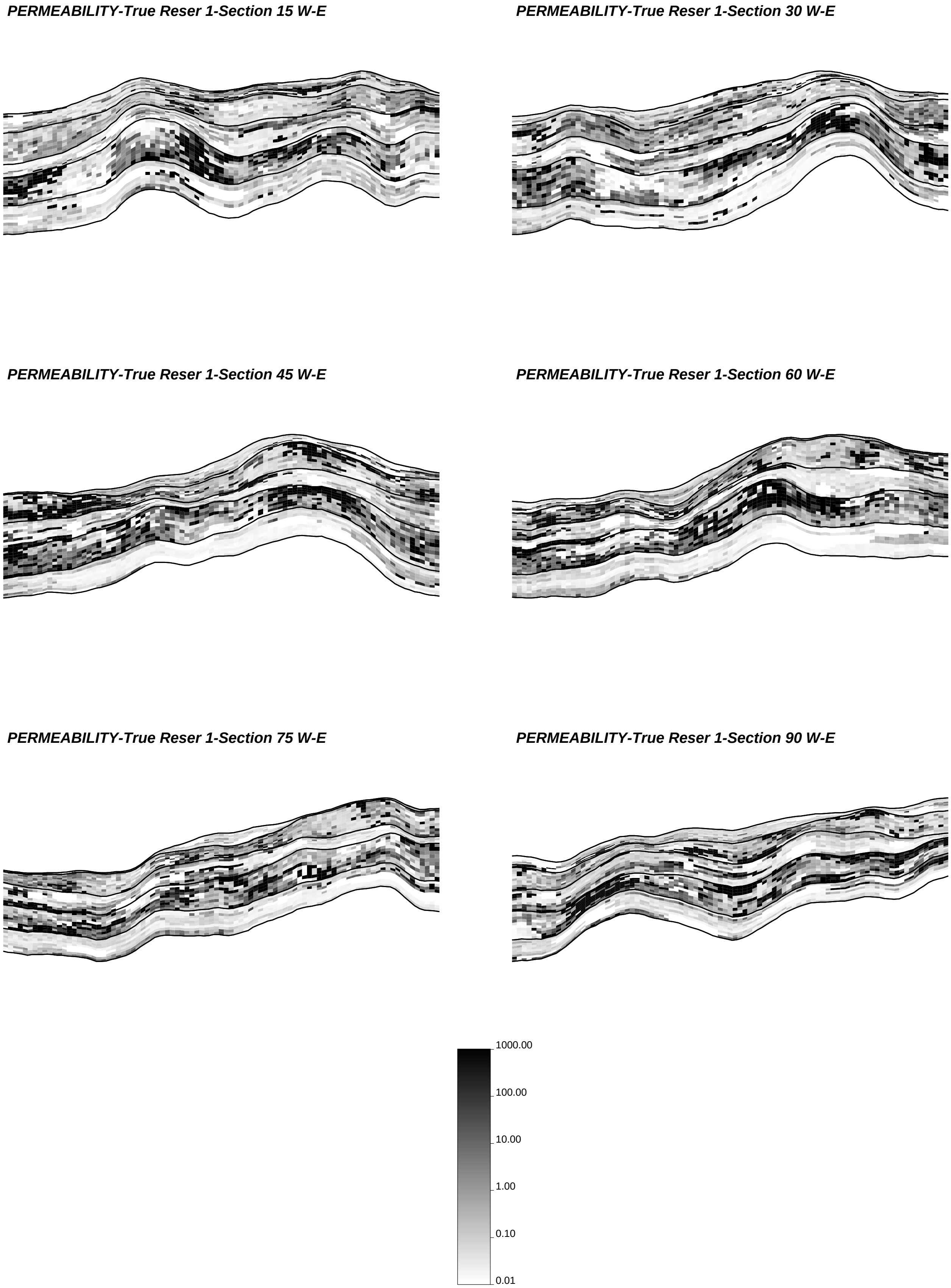

Figure 1: Cross-sections of permeability in the top fige laters of the first true reservoir.

TABLE 1 - Comparison between the approaches

Re ser voir	Conv_1	Conv_k	Full_Mean					Full_Mode				
	PV (1000m3)	PV (1000m3)	PV (1000m3)	% >= Conv_1	% > Conv_1	Full-Conv_1 (1000m3)	Full-Conv_k (1000m3)	PV (1000m3)	% >= Conv_1	% > Conv_1	Full-Conv_1 (1000m3)	Full-Conv_k (1000m3)
1	3969	3843	4041	100%	65%	72	197	4041	100%	65%	72	197
2	2288	2775	2545	95%	80%	257	-230	2120	50%	25%	-168	-655
3	4143	4301	4301	100%	65%	158	0	4301	100%	65%	158	0
4	5554	4838	5556	55%	25%	2	718	5556	55%	25%	2	718
5	4483	4574	4725	100%	100%	243	152	4523	70%	50%	40	-51
6	2712	2647	2659	50%	20%	-53	13	2659	50%	20%	-53	13
7	8497	8410	8678	100%	80%	181	268	8678	100%	80%	181	268
8	2655	2350	2814	95%	75%	159	464	2814	95%	75%	159	464
9	5514	5613	5894	95%	75%	380	281	5894	95%	75%	380	281
10	2418	2280	2325	45%	20%	-93	45	2325	45%	20%	-93	45
11	4009	3588	4384	80%	65%	375	796	4460	100%	80%	451	872
12	2288	2459	2459	95%	80%	171	0	2459	95%	80%	171	0
13	10195	10034	10220	45%	30%	24	186	10388	85%	55%	193	354
14	4766	4890	4828	85%	70%	63	-62	4651	25%	5%	-115	-239
15	7144	7422	7300	75%	60%	156	-121	7300	75%	60%	156	-121
16	6124	6374	6041	50%	15%	-83	-333	6041	50%	15%	-83	-333
17	4730	4726	4919	85%	70%	189	193	4620	35%	15%	-111	-106
18	1909	1925	2020	100%	55%	111	95	2020	100%	55%	111	95
19	7924	7699	7895	60%	35%	-29	196	7895	60%	35%	-29	196
20	6312	6420	6420	100%	30%	108	0	6420	100%	30%	108	0
21	2034	1453	2347	100%	80%	313	894	2347	100%	80%	313	894
22	3164	2868	3453	100%	70%	290	586	3453	100%	70%	290	586
23	3883	3531	4146	85%	80%	263	615	3542	25%	10%	-341	11
24	3826	3982	3705	25%	5%	-121	-277	3944	100%	65%	119	-38
25	3119	2859	3351	100%	70%	232	493	3351	100%	70%	232	493
26	8481	8734	8309	50%	35%	-171	-425	8819	100%	80%	338	84
27	6536	6081	6571	60%	35%	35	490	6571	60%	35%	35	490
28	4062	4063	3876	15%	5%	-186	-187	3984	50%	35%	-78	-79
29	4791	5242	5242	100%	75%	451	0	5242	100%	75%	451	0
30	5938	5927	6188	100%	85%	249	261	6097	70%	40%	158	170
31	4579	4550	4581	45%	35%	2	31	4065	15%	0%	-514	-485
32	3118	2803	3210	60%	60%	91	407	3181	60%	30%	63	379
33	3137	2982	3027	55%	30%	-110	44	3027	55%	30%	-110	44
34	8291	8116	7759	15%	0%	-532	-357	8337	65%	40%	46	221
35	2935	3106	2997	65%	50%	63	-108	2703	30%	10%	-232	-403
36	9253	9617	9143	50%	15%	-110	-474	9143	50%	15%	-110	-474
37	3286	3188	3246	45%	25%	-41	58	3246	45%	25%	-41	58
38	5923	6106	6139	100%	75%	215	33	6139	100%	75%	215	33
39	4557	4244	4440	25%	10%	-117	196	4440	25%	10%	-117	196
40	8625	8223	8879	100%	70%	255	656	8879	100%	70%	255	656
41	1007	985	852	30%	0%	-155	-133	852	30%	0%	-155	-133
42	7463	6336	7686	65%	50%	223	1351	7862	100%	70%	398	1526
43	11326	10142	11199	40%	35%	-128	1057	10914	10%	0%	-412	773
44	3147	3836	3108	80%	0%	-39	-728	3108	80%	0%	-39	-728
45	8529	8404	8468	65%	20%	-60	64	8468	65%	20%	-60	64
46	2722	2468	2816	75%	30%	94	348	2816	75%	30%	94	348
47	12188	12204	11815	35%	10%	-373	-389	11815	35%	10%	-373	-389
48	8208	7468	7543	20%	0%	-666	74	8427	60%	35%	219	958
49	6876	6692	7682	100%	85%	806	991	6784	60%	40%	-92	92
50	1771	1909	1791	60%	15%	20	-118	1791	60%	15%	20	-118
TOTAL	260409	255284	263592	3475	2270	3183	8307	262509	3410	2015	2101	7226
MEAN	5208	5106	5272	70%	45%	64	166	5250	68%	40%	42	145

% Reservoirs with (Full_mean - Conv_1) > 0 =	64%
% Reservoirs with (Full_mode - Conv_1) > 0 =	58%

% Reservoirs with (Full_mean - Conv_k) > 0 =	72%
% Reservoirs with (Full_mode - Conv_k) > 0 =	70%

Figure 2: Table of case stduy results.