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Development and Management of a Large Gas Field by a Computer Simulation

By

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ABSTRACT

This paper discusses the application of an integrated gas-field simulation system to evaluate deliverability designs and operating strategies. The system simultaneously considers the three interacting pressure drops one encounters in a gas gathering system[1].

Thus the actual backpressures and deliverability as a function of the movement of gas through the entire piping system are obtained. This integrated approach to gathering system design and field development allows rapid evaluation of the various alternates.

The operating system simulated is a large, middle-aged gas producing property located in Alberta, Canada. The primary study area consists of the property owned by Saskatchewan Power Corporation. However, due to the extent of the producing horizon, the study area included property not owned but adjacent to the property owned by Saskatchewan Power Corporation. The objectives of the study are to evaluate the feasibility and economics of maintaining the peak deliverability at contract demand for a period of ten years in the future and the development of a field operating strategy to minimize required investment and minimize or eliminate gas drainage across lease boundaries. The results of these objectives are presented. Additionally a comparison technique for various deliverability design alternates is presented. Finally, a discussion of the installation and utility of the integrated system on a small computer is included.

References and illustrations at end of paper.

INTRODUCTION

It has long been recognized that gas well deliverability is a function of the three pressure drops, in the reservoir, in the production string and in the surface piping and compressor configuration. Actual gas well deliverability and, consequently, total field deliverability can be computed only when all three pressure drops are considered simultaneously. Because each of the pressure drops is associated with a different flow system, three different simulation equations are involved. To perform rigorous compression studies, reservoir studies or gas gathering system design, one must integrate these three simulation segments in such a manner that the flows and pressures balance at each node in a multiwell gathering system.

The standard approach to gathering system compression studies does not account for interwell interference and its effect on a well's deliverability. At best the standard approach includes a backpressure curve connected to a piping network system. While all the wells are being produced at a constant rate, that is, making their contract obligation, this approach does not introduce large errors. More often, individual well rates do fluctuate for various reasons, and many systems are produced by floating part of the wells and choking others. Thus in the course of a performance prediction many of the wells are floating on the system in order to meet total contract obligation. When this occurs, the deliverability of each well must be updated according to the transient pressures, and the appropriate backpressure of each well must be used at all times during the prediction. One shortcoming of the older approach to design studies is that a steady-state backpressure curve fixes the drainage radius of a well and, when used over long prediction period (10 to 20 years), can introduce large errors in the determination of compression location and timing. Further, the standard approach does not readily permit the evaluation of infill drilling as an alternate for gas-field deliverability enhancement.

The rigorous approach to compression studies considers all the reservoir, piping and compression data in a single package to describe the total system in a continuous fashion from the reservoir to the mainline. Consequently, single-point compression, block compression, wellhead compression, infill drilling and combinations of these are easily evaluated while considering the effects of interwell interference. Engineers can rigorously and efficiently study many different planning alternatives.

The equations accounting for the three pressure drops considered in this system are:

Reservoir

$$\nabla Kh \nabla \Phi - Q = \not{0}h \frac{\partial \rho}{\partial t} \qquad (1)$$

where

Kh = permeability thickness
ρ = gas density
Q = production rate
$\not{0}h$ = porosity thickness
t = time
Φ = real gas potential

Flow Lines

$$Q = \frac{C\,T_b}{P_b} \left[\frac{(P_2^2 - P_1^2)d^5}{GT_a\, LZ_a\, f} \right]^{.5} \qquad (2)$$

where

C = units constant
T_b = base temperature
P_b = base pressure
P_1 = downstream pressure
P_2 = upstream pressure
G = gas gravity
T_a = average operating temperature
L = length of line segment
Z_a = average compressibility
d = pipe segment diameter
Q = flow rate
f = friction factor

Production String

$$Q = 200 \left[\frac{d^5}{GT_a\, Z_a\, fX} (P_2^2 - e^S P_1^2) \frac{S}{e^S - 1} \right]^{0.5}, \ldots \qquad (3)$$

where

f = friction factor
X = depth
S = $0.0375\ G\ X/T_a Z_a$

THE FIELD STUDY

The study area is that portion of the Medicine Hat Gas Field owned by the Saskatchewan Power Corporation, and some immediately adjacent property which affects gas migration.

This area of the field has reached middle age with over one-third of the original reserves of 650 BCF having been produced. The field is shallow, has a low permeability and drilled on a one well per section spacing.

The study area covers some ten townships in area and includes 205 wells at present with a development potential up to 285 wells. The average gathering pressure has been held at 240 psig for the last three years.

Previous estimates indicate that over $5,000,000 capital investment will be required to maintain field deliverability during the next ten years. In order to evaluate these earlier estimates and to optimize the development of the field, a study was carried out using a two dimensional transient gas model complete with a surface network simulator. The gas reservoir system enables determination of long term forecasts of field deliverability under various design alternates each with associated expenditures. This allows the construction of various feasible alternates which balance new wells and additional equipment from which to choose both a strategical and economical deliverability design.

The first step was to obtain a reservoir description by matching the past field performance. The study area was overlayed with a computing grid of 24 x 17 (see Figure 1). The block dimensions are one mile square. Early tests indicate that little space truncation occurs using these dimensions as long as the production term is handled implicitly. The initial permeability distribution and individual well skin factors were calculated from previous pressure buildup data. The initial porosity-thickness distribution was derived from existing cores and logs.

Early history matching runs indicated that considerable changes were required in the porosity-thickness data in the Northwest quadrant with relatively fewer changes in the permeability data. This early adjusted data was then processed using an automatic history match program[2]. This program optimized the unknown parameters within a specified range of uncertainty. It was found that only a few runs were required to achieve a suitable match. Figures 2 and 3 and Table 1 indicate an example of the degree of accuracy attained.

Several features were required in order that the program include all the characteristics of the actual system being simulated. These include:

1) The allocation of production from year to year is set by the average daily production for the field. The individual well production is prorated according to the available deliverability of the well. Exceptions to this area the wells bordering another producers property where considerable drainage has occurred. The wells bordering this property are produced at a 100% load factors in practice and are simulated in the model to produce in the same manner.

2) A special routine which calculates the amount of gas migrating across the boundary of a specified drainage area. This routine includes variable geometry.

3) A field recovery factor calculation is computed as a function of time. This provides information for long term economics as well as comparison of design alternates.

4) A calculation to provide regional averages is included in the program. This provides the average bottom hole and gathering pressures for regions of the field produced through various legs of the gathering system. These averages aid in determining the impact of block compression on field performance.

Using this reservoir management system various alternates including when and how many additional wells and horsepower will be required were evaluated. The information from this array of alternates allow the evaluation of the most economical combinations.

The several alternates consist of subsets of two overall strategies, Case I and Case II.

Case I considers the addition of block compression in the field. This was to be added at two locations as indicated in Figure 4.

Case II considers the addition of compression at the central station. All compression was added at a central site located five miles east of the field.

Seventeen runs of various length were required to develop the design curves for the feasibility portion of the study (an example shown in Figure 5). This provides three feasible schemes for Case I and two feasible schemes for Case II. Also plotted on Figure 5 is a forecast of requirements made subsequent to the study initiation. The gas requirements are substantially different than the requirements set forth a few months earlier. These differences reflect management's assessment of the market conditions and serve to illustrate the need for a responsible resource planning tool. Several additional schemes for both cases were simulated from the data provided by the feasibility runs.

Data from the initial computer runs also provided a means of estimating the average annual deliverability for the plotted peak flows. It was observed that the average production at the initial decline when the field was producing at 100% load factor, was about 80% of the difference in the peak flows for the beginning and ending of the year. This reduced to 66% in the final years of the field's production (see Figure 6). Figure 6 is a plot of annual production versus time for various schemes of development for both cases. The figure shows the greater the annual production obtained for the field compression the earlier the field is drilled out.

The alternate giving the largest annual production for Case II, central compression, is not as easily recognizable. Drilling the wells first gives a greater annual production during early years of the decline period, but is less than if compression were added first during the latter part of the decline period. There is little difference in the overall recovery for either alternate.

Central compression provides a more uniform gathering pressure across the field and creates an automatic proration system. This results in a reasonably uniform percent of recovery from the field regardless of the development scheme used. However, due to the reservoir heterogeneities, the field must be strategically operated under this alternate or large pressure gradients are formed across the field.

Field compression will provide the greatest percent recovery when wells are added before compression. With field compression, areas of the field are being drained more uniformly and with less sensitivity to operating strategy. This is similar to having a number of small fields where the automatic proration has less chance to be effective. This is indicated by the more pronounced difference in annual production with changing development schemes, as indicated by different count numbers. This fact along with the fact that when all wells are on decline, the system deliverability is an exponential decay function provides a basis for comparing various assign alternates.

The design alternate comparison technique involves a "count" system. The parameter generated is the present value of the compression added, divided by the present value of the wells drilled. Then lowest count number occurs when all the wells are drilled during the first few years of development and all the compression is added during the last few years of development. The highest count number occurs inversely when compression is added first. The count number can then be used with the "cost per MCF" of development to determine the optimum method.

Such a method is required to compare the output of various cases for development. Any method used must take into account the fluctuating percent of recovery from the field as well as capital and operating expenditures required for current and short term deliverability enhancement. Two methods were applied.

Annual Cost of Production

Historic costs were compiled for capital and operating expense. The whole system was studied so that the cost of gas at the discharge of the "Hatton Station" could be calculated.

A present value, discounted to 1970, is calculated for each case.

A value of gas was applied to the analysis. This allowed a comparison of profitability for each case and also an indication of when producing the field becomes uneconomical. This was found to be 1991 for both cases. The study was based on an abandonment date of 1999 because it was felt local conditions would warrant operation to this date.

Figure 7 is the present value, discounted to 1970, of the capital costs versus the count. The high capital cost occurs at low count numbers indicating that drilling wells first requires the greatest capital outlay. The varying recovery of gas for the cases has not been considered here.

Cost Per MCF

To take into account the varying percent of recovery from the field, a cost per Mcf was calculated for each case. The cost includes capital and operating expenses.

Figure 8 is a plot of cost per Mcf versus count. The figure indicates that the optimum case is the addition of compression first at the central station.

It is of interest to note that for Case I, field compression, the most economic case is drilling the wells first. Even through this alternate had the highest capital cost, the cost per Mcf is lowest because of a greater percent of recovery from the field.

Field Drainage

Considerable drainage has occurred along the west flank of the field. This was substantiated by the level of reservoir pressure encountered when these edge lease wells were drilled. An objective of the study was to quantify the net amount of drainage to date and to evaluate operating strategies which would minimize, if not eliminate, this drainage and if possible, make up the part or all of the past drainage. Figure 9 shows the historical cumulative net drainage and a prediction of this value for one operating strategy. This prediction shows that not only is all the past drainage made up but the value of cumulative net drainage reverses sign for this particular prediction case. Obviously the drainage is dependent on the operation of the adjacent property and the future drainage behavior will depend strongly on the manner in which this property is produced. However, with the current gas reservoir management system various operating conditions can be imposed on this property and the behavior of the net drainage evaluated.

Conclusions

1) These results clearly indicate that the optimum method of development is Case II (addition of compression at the central compressor station). The optimum scheme of development for this specific demand schedule is shown in Table 2.

2) The expenditures required to maintain deliverability are considerably less than earlier estimated of $5,000,000.

3) The study points out that a well production allocation system is required to assist pressure equalization. The computer runs indicated several low pressure areas developing in the field.

4) This initial analysis indicates that no more than 80 additional wells will be required to recover available gas in the field.

5) The study indicated that previous gas lost due to drainage would be recovered in the next ten years (see Figure 9). The assimilation of the large volume of operating data into a responsive system allows for rapid future updates and re-evaluation in the event of additional data or changing requirements.

6) The ability to predict at an early stage of the development of an abnormal pressure gradient across the field allows this fact to be accounted for and design alternates and producing strategies structured to minimize this gradient.

7) Clearly the ability to analyze such a large system and present alternates for evaluation affords management with the necessary information to answer the many "what if" alarming questions, and make timely decisions on large scale expenditures.

8) It is feasible to execute the gas reservoir management system on a small scale computer for short term operational problems stemming from large scale (many wells and surface equipment) reservoir systems.

Acknowledgements

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References

1. *"A Rigorous and Efficient Method for Gas Field Gathering System Design and Compression Studies"*, by J. R. Dempsey, J. K. Patterson, K. H. Coats, and J. P. Brill, presented at the Central Plains Regional Meeting of the Society of Petroleum Engineers of AIME, held in Amarillo, Texas, November 15 - 17, 1970.

2. *"A Practical Method for Determining Reservoir Description from Field Performance Data"*, by K. H. Coats, J. R. Dempsey, and J. H. Henderson, presented at the 43rd Annual Fall Meeting of the Society of Petroleum Engineers of AIME, held in Houston, Texas, September 29 - October 2, 1968.

APPENDIX A

Discussion of Installing a Large Integrated System on a Small Scale Computer

Saskatchewan Power Corporation's in-house computing facilities consist of a Ferranti-Packard 6000. The system has 24K words available for in-core programs and data. Because of the utility of the reservoir management system as a short term operational tool, it was desired to install the system tailored for the Many Islands reservoir on the FP6000.

From the start it was realized that the program instruction requirements would not cause any problems but rather the data requirements would. The original program was modified to accommodate the FORTRAN IV compiler differences and a small test case was executed. The results were good and as expected: Normal CPU execution time was 20 times slower, as compared to the CDC 6600, but no loss in accuracy was experineced. The in-core version of the program installed on the FP6000 would handle 50 wells and 100 surface pipelines.

However, a very large field, namely the Many Island Field, had to be studied, with a requirement for up to 300 wells and 400 surface lines. The pertinent data arrays were adjusted accordingly and the program was compiled in its virgin state to find out the gross core requirements. 50,000 words of memory would be required for an in-core execution. Only 25,000 words were available which represented the total core capacity of the FP6000 allowing for the executive program which takes the remaining 7,000 words.

Some sort of overlay technique had to be employed. Rewriting the program and tearing the algorithms was ruled out in order to preserve the efficiency of the simulation techniques employed. Furthermore, tailoring of the algorithms to the FP6000 would require the development of new techniques.

The program was not suitable for a program overlay since only one major subroutine is present.

The only alternative left was an overlay of individual arrays and/or groups of arrays. The program was methodically searched for programming areas of local data array demands. These arrays were isolated and marked as suitable for overlay. The converse, of course, was done also, isolating arrays of high demand throughout the program and groups of arrays appearing within arithmetic expression and input-output lists. An array use frequency tableau was developed in this manner.

The most logical and efficient manner of making these overlay arrays share the same memory locations would have been the use of the FORTRAN EQUIVALENCE facility. Unfortunately, most of the arrays of highest demand were two dimensional and those suitable for overlays were one dimensional. To compound the problem these high demand arrays were not suitable for overlaying amongst themselves. Some means had to be found to "equivalence" two dimensional and one dimensional arrays in the program's declarations (dimensions) portion and common areas and make it executable.

For all the overlay arrays, an appropriate random access file was constructed on the FP6000 drum permitting writing and reading of the pertinent data at the proper instances and as required by program execution.

The sharing of core locations of one and two dimensional arrays was accomplished by declaring one dimensional, one element arrays (the one dimensional arrays to be overlayed) in positions just preceding the two dimensional arrays. In effect, these one element arrays were dummies but had the proper names as required by the algorithms. By specifying these arrays in input lists and/or drum transfers, the body of the array is effectively moved into the core area of the succeeding two dimensional array. The FP6000 Fortran IV compiler permitted this since no checking occurs on exceeding dimension boundaries, e.g. DIMENSION A(1), B(25,10).

When array A is specified in an input or drum transfer list and in actual fact consists of 200 elements, these elements will overflow into array B. Any further reference to these elements throughout the program will still be made by naming array A. Any further overlaying of arrays of similar types was simply accomplished by the use of the Equivalence Statement.

Throughout the program all overlayed arrays had to be written to or read from the data drum file at precisely the proper location during execution of the program as the demand for these arrays arose. In case of program modifications, caution reigns supreme here.

It was realized that due to the relatively slow access time of the drum (15 milli-seconds average) the overall throughput time of the program would be prolonged considerably. In answer to that problem, a restart facility was built into the program. Long-range studies or history matching can be executed on a large scale computer external to the Corporation. The resulting outputs or status of the reservoir can then be transferred to an FP6000 tape which serves as the restart data for the modified program. Furthermore, after every time step the program can be suspended and the current status of the program and its core data dumped to tape as well as the current drum file, if so desired. This provides an option to either restart or continue a study at any time step without backing up to the initial restart point. In Figure 10 a system flow chart including the restart facility is shown.

TABLE 1 - COMPARISON OF PIPELINE MEASURED AND CALCULATED PRESSURES AND FLOWS

	PRESSURE (PSIG)		FLOW (MMCF/D)	
	Measured	Calculated	Measured	Calculated
Block Valve #1	240.9	242.	104.	107.
Block Valve 15-13-3	248.	250.1	45.1	48.5
Block Valve 2-14-2	245.6	246.7	46.7	56.9

Instantaneous Deliverability Test

(all wells wide open)

Measured Flow at Hatton Station	96.5 MMCF/D
Calculated Flow at Hatton Station	97.46 MMCF/D

TABLE 2

Additional compression, when required, should be added at the central compression station. The following is the most Economical method of development.

1972	add	1100 hp
1973	add	1100 hp
1976	drill	20 wells
1977	drill	45 wells
1979	add	3300 hp
1980	add	1100 hp
	and drill	15 wells

Total wells drilled	80
Total horsepower added	6600

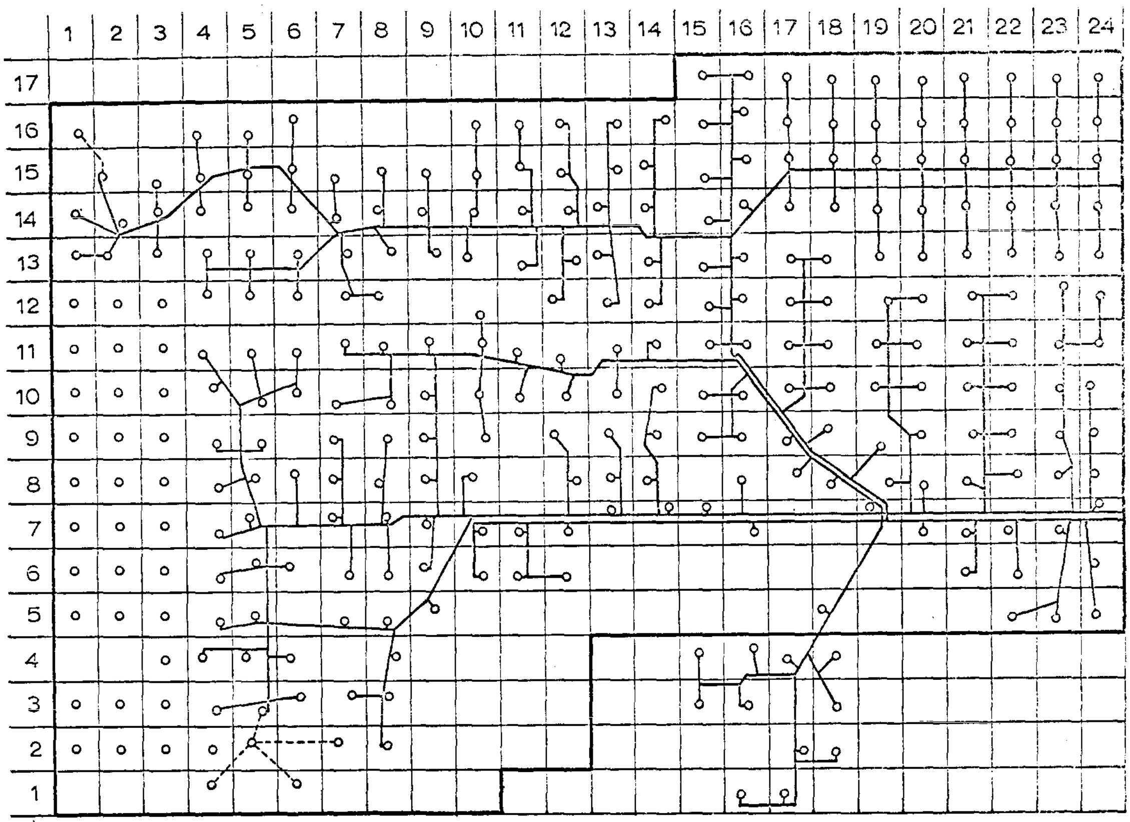

Fig. 1 - Computing grid and surface network.

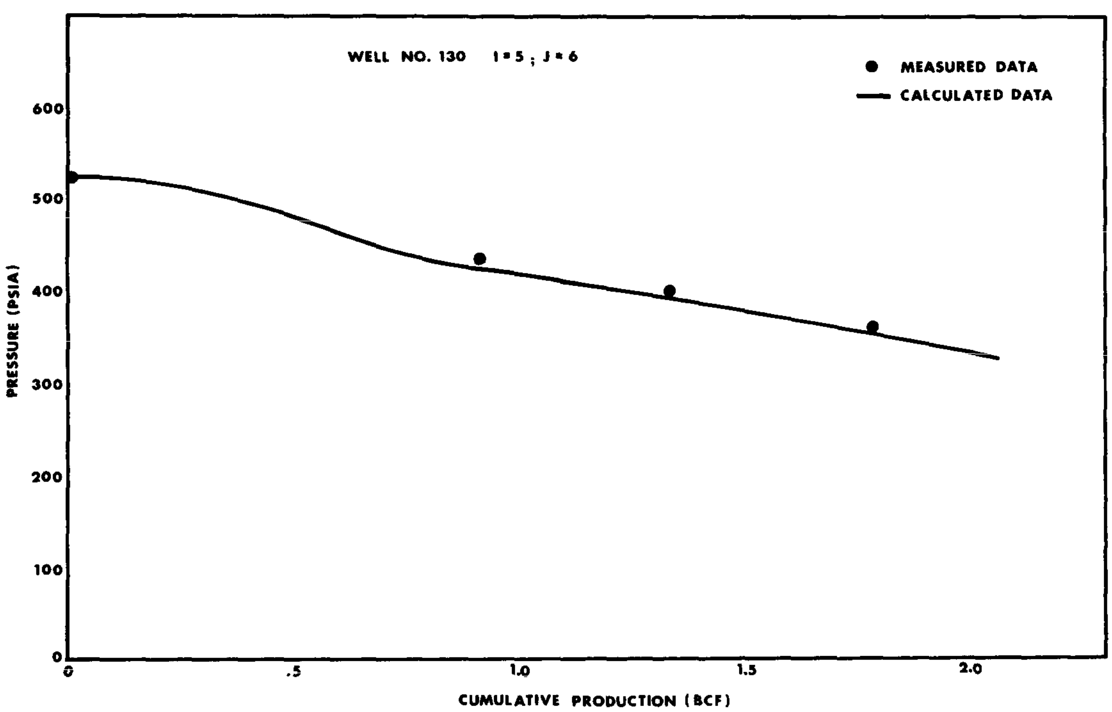

Fig. 2 - Example history match.

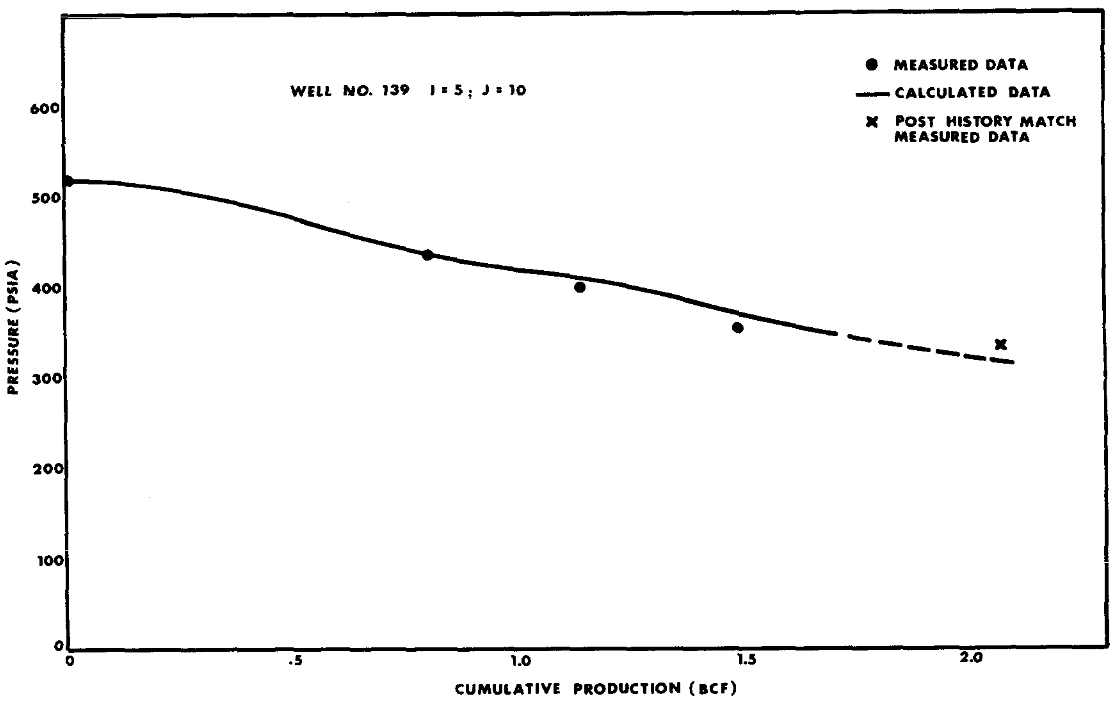

Fig. 3 - Example history match.

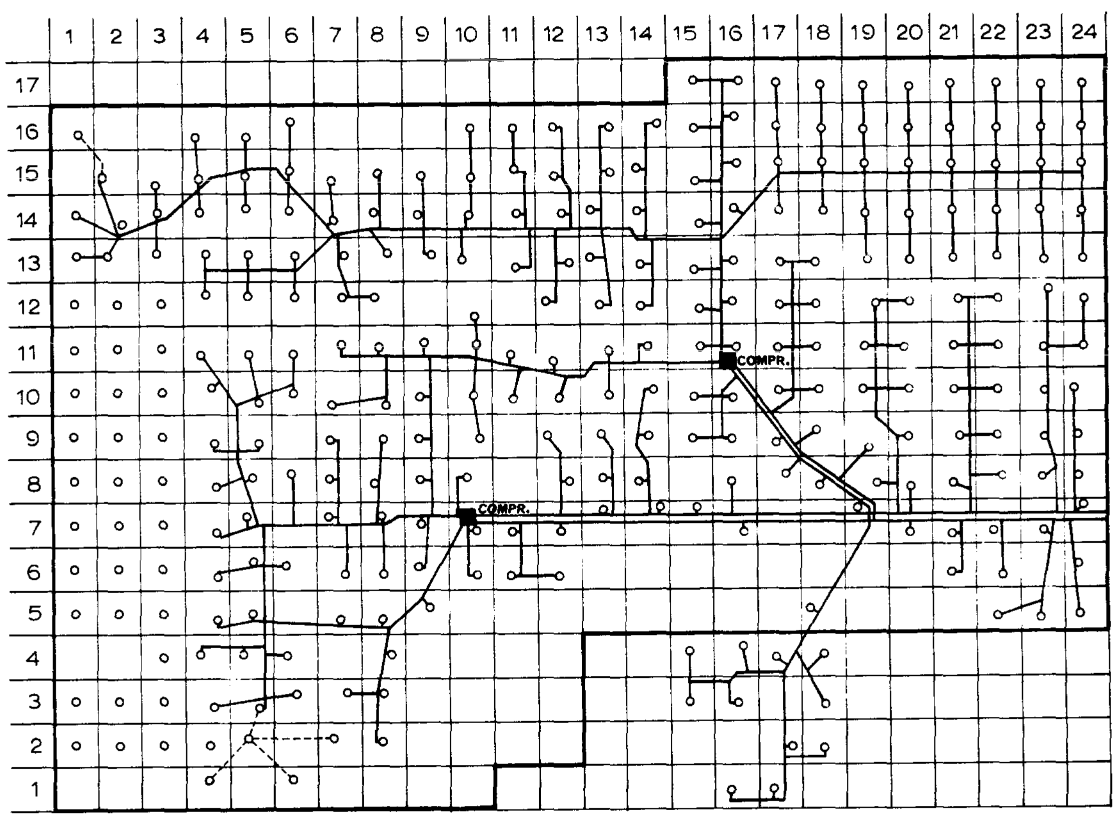

Fig. 4 - Computing grid and surface network.

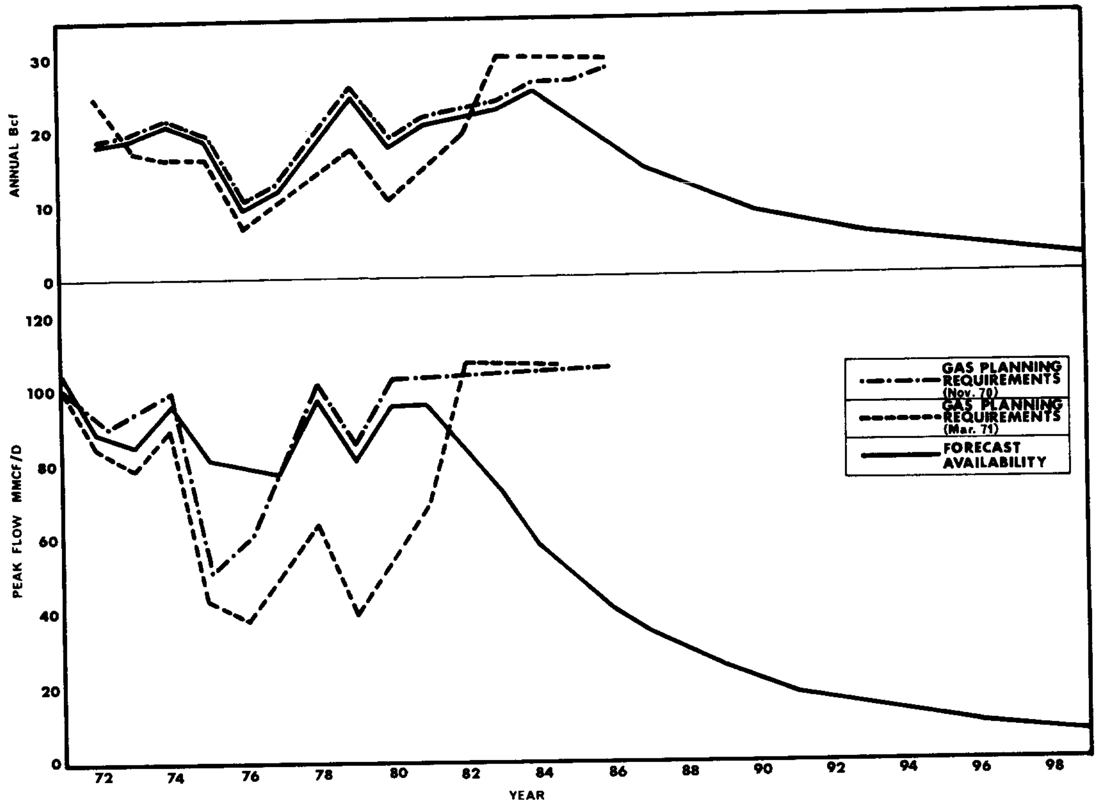

Fig. 5 - Projected flows and annuals for recommended development.

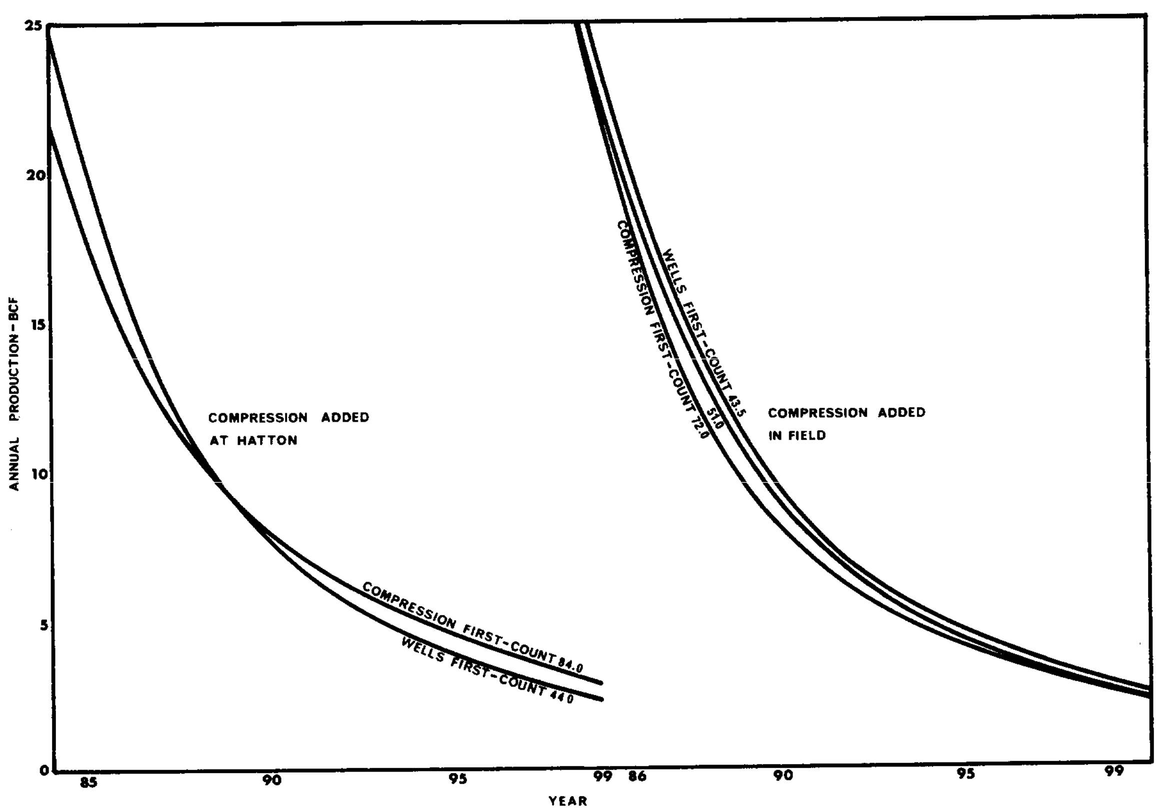

Fig. 6

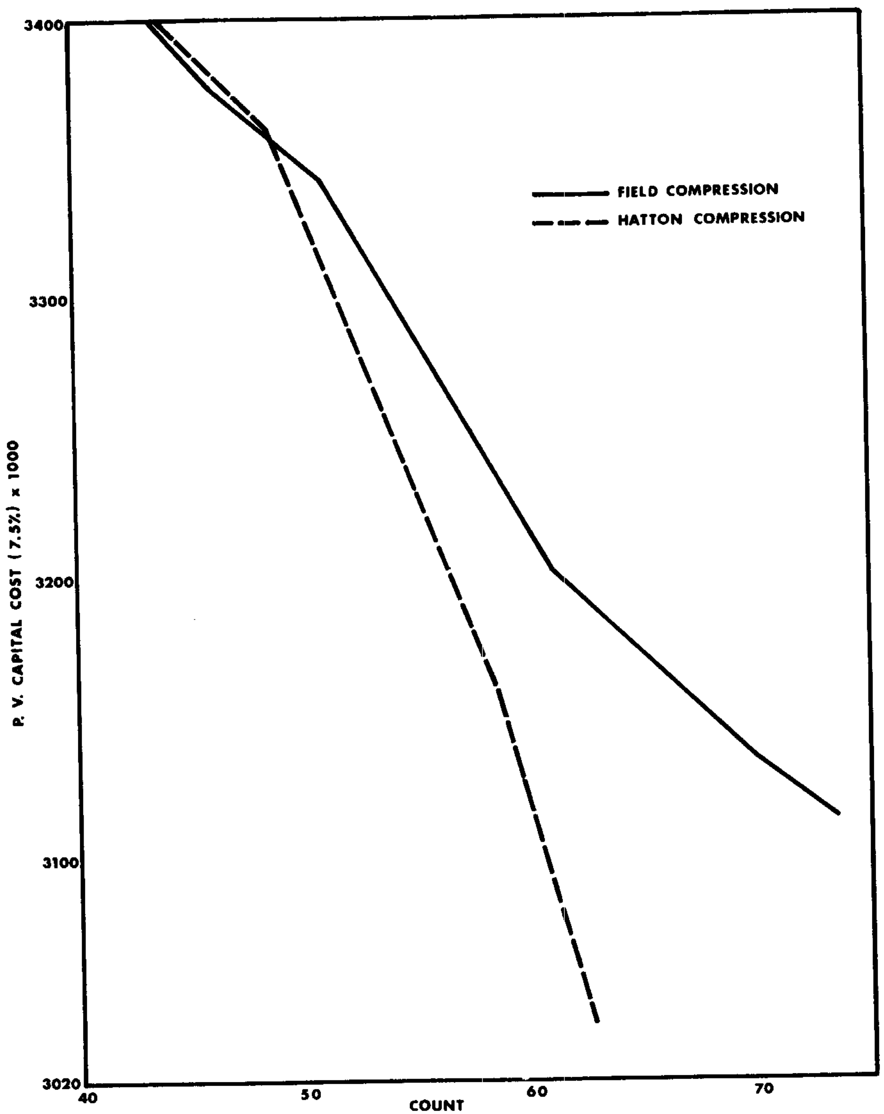

Fig. 7 - Comparison capital cost.

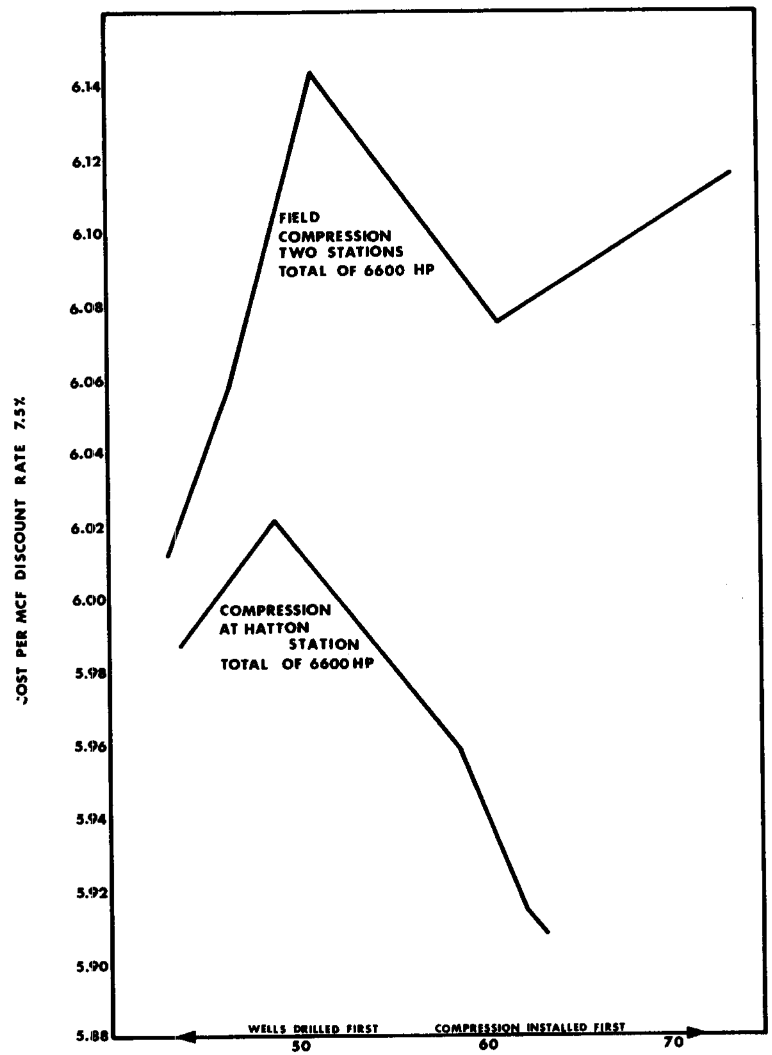

Fig. 8 - Count present value of installed HP over present value of wells drilled.

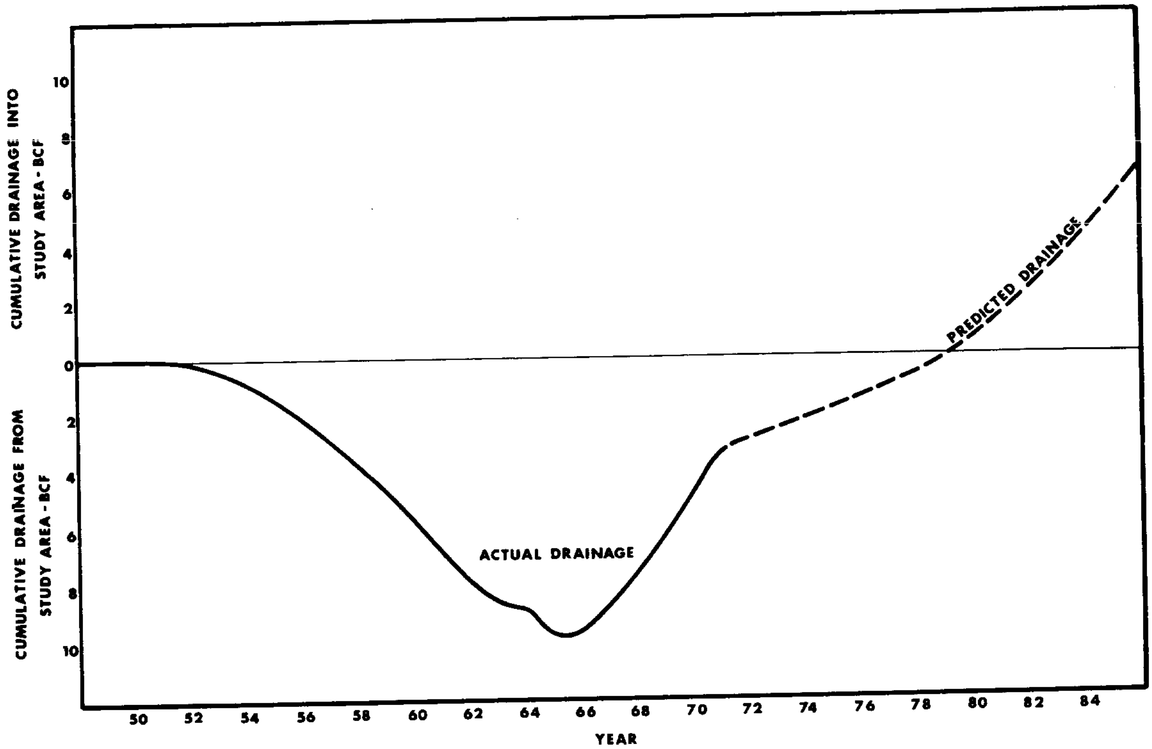

Fig. 9

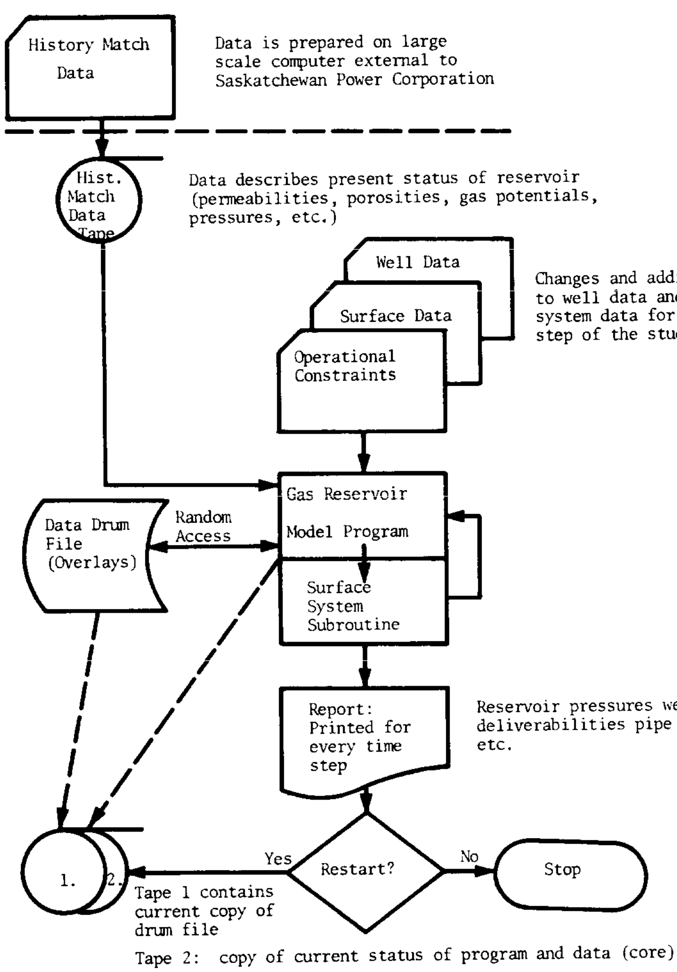

Fig. 10 - Gas reservoir management program, system flow chart.