Development of a Natural Gas Systems Analysis Model (GSAM)

Annual Technical Report
Contract Year Seven

For:

U.S. Department of Energy
Federal Energy Technology Center
Morgantown, West Virginia
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By:

ICF Consulting, Inc.
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EXECUTIVE SUMMARY

This report summarizes work over the past twelve months on DOE Contract DE-AC21-92MC28138, Development of a Natural Gas Systems Analysis Model (GSAM). The products developed under this project directly support the Federal Energy Technology Center (FETC) in carrying out its natural gas R&D mission.

GSAM development has been ongoing for the past six years. The major development programs completed during the past year include:

- Produced programmer's guides for Reservoir Performance Module, Storage Reservoir Performance Module, Exploration and Production Module, and Demand and Integrating Module;
- Designed and implemented Federal land leasing/development model into GSAM;
- Updated offshore database to include Eastern Gulf of Mexico and Atlantic Offshore undiscovered fields;
- Developed and implemented water-depth specific drilling cost model for offshore wells;
- Enhanced tight reservoir model to improve deliverability calculations from hydraulically fractured reservoirs and incorporated consistency with horizontal well computations;
- Updated Storage Reservoir Performance Module (SRPM) database consistent with published data from American Gas Association (AGA) and Energy Information Administration (EIA);
- Redesigned numerical model of the SRPM to produce consistent data entry of injection/extraction program for the Annual Demand and Integrating Module;
- Modified exploration drilling algorithm to improve accuracy of GSAM predictions for exploration wells drilled;
- Modified breakeven drilling cost formulation in project selection criteria to incorporate selection based on profitability and not production;
- Implemented USGS reserve growth function into Exploration and Production Module;
- Implemented issue-specific environmental cost model into Exploration and Production Module;
- Updated database and mathematical model of Industrial Demand Module to account detailed information on boilers, cogeneration/nonutility generation, process heat, and feedstock;
- Updated GSAM annual model to take into account variation of wholesale-to-retail markups with respect to time, weather influence, and heat rate variation by vintage; and
- Modified cost file in Production and Accounting Module to account for regional cost variation consistent with the cost files in Reservoir Performance Module.

I. INTRODUCTION

This report provides an overview of the activities to date and schedule for future testing, validation, and authorized enhancements of Natural Gas Systems Analysis Model (GSAM) under the Department of Energy (DOE) contract DE-AC21-92MC28138. The goal of this report is to inform DOE managers of progress in model development and to provide a benchmark for ongoing and future research.

Section II of the report provides a detailed discussion on the major GSAM development programs performed and completed during the period of performance, July 1, 1998 to September 30, 1999. Key improvements in the new GSAM version are summarized in Section III.

II. GSAM DEVELOPMENT

GSAM research over the past year has substantially enhanced the accuracy, credibility, and scope of the system. This section documents the recent results and continuing efforts for GSAM development.

A. GSAM DOCUMENTATION

1. Background

Programmer's guides for GSAM main modules were produced to provide detailed descriptions of all major subroutines and main variables of the computer code. General logical flowcharts of the subroutines are also presented in the guides to provide overall picture of interactions between the subroutines. A standard structure of routine explanation is applied in every programmer's guide. The explanation is started with a brief description or main purpose of the routine, lists of input and output files read and created, and lists of invoked/child and calling/parent routines. In some of the guides, interactions between the routine itself and its parent and child routines are presented in the form of graphical flowchart. The explanation is then proceeded with step by step description of computer code in the subroutine where each step delegates a section of related code. Between steps, if a certain section of code needs further explanation, a "Note" is inserted with relevant explanation.

2. Programmer's Guide for Reservoir Performance (RP) Module

The first edition of programmer's guide for RP Module was released in March 1999. The guide is divided into four main sections:

- Summary Write-up section explains the background of the guide and structure of the documentation

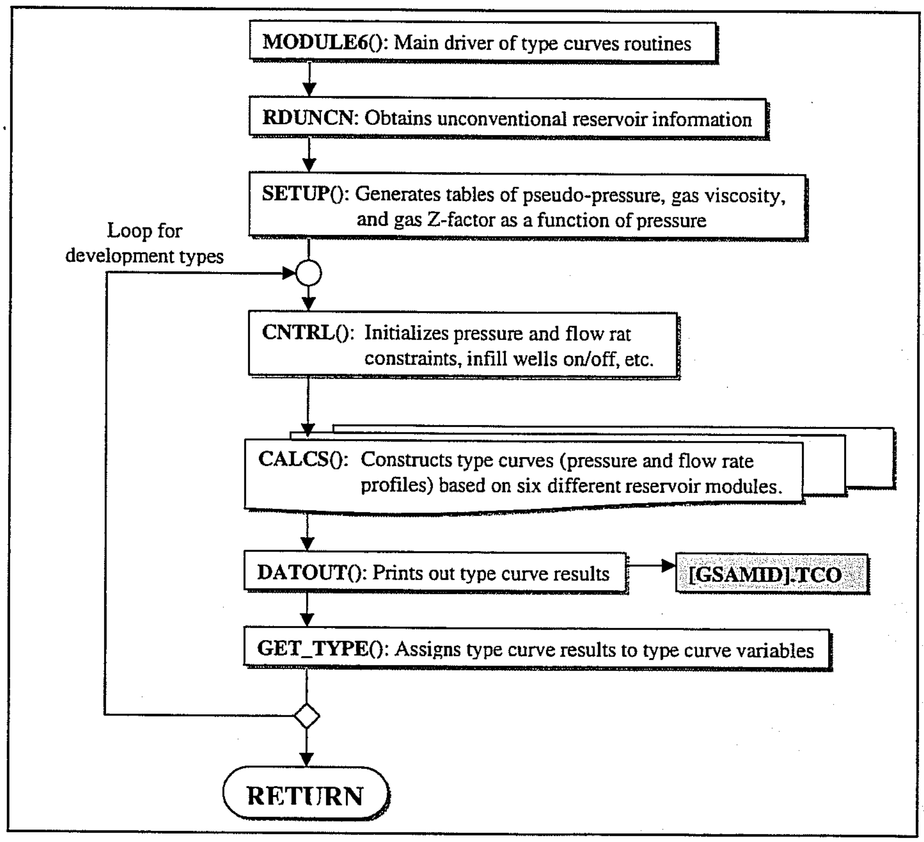
- Data Dictionary section provides description of all main variables and indicates the header files (FORTRAN files that hold global variable declarations and definitions) for the variables. Table II-1 shows part of "Data Dictionary" of the RP programmer's guide

- Flow Charts section presents logical flow of subroutines of the RP module. Sample of flowchart for subroutine MODULE6() is shown in Figure II-1

Table II-1: Example of "Data Dictionary" from RP Programmer's Guide

Variable Name	Location	Description
aatcf	Cashflow.h	Annual After Tax Cash Flo
acprod	Gsamvar.h	Estimated Total Production Area
Qg	Type5.h	Gas Production Rate per Well
wlspac	Gsamvar.h	Well Spacing

Figure II-1: Sample of Flowchart from RP Programmer's Guide



- Program section groups the subroutines (one main RP program and 85 RP subroutines) into eight subsections based on their basic functionality. The sub-sections are Main RP Program, Reading Routines, Data Setup Routines, Type Curve Routines, Rock and Fluid Properties Routines, Costing Routines, Writing Routines, and Miscellaneous Routines. Figure II-2 is an example of "Program" section which is part of subroutine FRICTN() from subsection "Type Curve Routines".

Figure II-2: Example of "Program Section" from RP Programmer's Guide

SUB-PROGRAM FRICTN()

LOCATION: MODULE6D.FOR

MAIN THEME: This routine calculates Moody friction factor using Colebrook White correlation. Newton-Raphson procedure is utilized to solve the non-linear equation

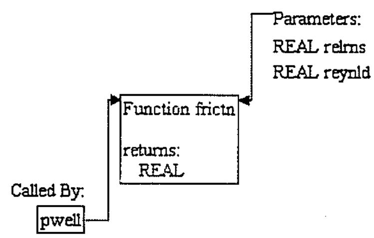
CALLS: None

CALLED BY: PWELL() (in file MODULE6B.FOR)
Calculates bottomhole pressure, wellhead pressure, or flow rate based on the difference between well head pressure and botto hole pressure of the well using Smith's formula

READS: None

CREATES: None

ROUTINE INTERACTIONS:



Step 1: **Name and parameters of the sub-program are declared.**

Note: Name of the sub-program is FRICTN() and the parameters passe to this sub-program are as follows:

Input Parameters:
- *Reynld* Reynold numbe
- *RelRns* Relative roughness

Output Parameter:
- *Frictn* Moody friction facto

```
FUNCTION Frictn (Reynld, RelRns)
```

Step 2: **Friction factor of 1 is returned if Reynold number is less than 64.**

```
If (Reynld .lt. 64.) then
        Frictn = 1.
        Return
End If
```

3. Programmer's Guide for Storage Reservoir Performance Module (SRPM)

The first edition of programmer's guide for SRPM was released in June 1999. The structure of the documentation is similar with the RP programmer's guide with enhancements in "Data Dictionary" and "Program" sections. The guide also incorporates one additional "I/O Files Dictionary" section. The "Data Dictionary" section of the SRPM programmer's guide does not only describe the main variables and show their locations in the header files, but it also gives units of the variables and provides a cross reference for each variable. The variable cross-reference can provide a quick way to visit each use of variables in the SRPM code. Table II-2 shows part of "Data Dictionary" of the SRPM programmer's guide.

Table II-2: Example of "Data Dictionary" from RP Programmer's Guide

Variable Name	Description	Cross Reference		
		Process	File Name	Line Number(s)
absrns	Absolute roughness of pipe (in)	Declared in	TYPE4.H	1
		Assigned in	TYP_CRV.FOR	23
		Assigned in	SETVAR.FOR	8
		Called b	PWELL.FOR	9
		Called b	TYP_CRV.FOR	25
		Called b	SETVAR.FOR	1
acprod	Well drainage area (acres)	Declared in	GSAMVAR.H	100, 129
		Assigned in	RD_STOR.FOR	96, 97, 106, 118, 126, 140, 166, 169
		Called b	RD_STOR.FOR	107, 109, 119, 124, 131, 144, 152, 168, 170
		Called b	CONVERT.FOR	46
		Called b	STORPERF.FOR	477

The computer code in the "Program" section is now listed with line number. Note that this is not a FORTRAN line number and should not be referred to branching statements in the code. The purpose of the line number is only for variable cross-referencing as discussed in "Data Dictionary" section. Figure II-3 shows an example of code listing from subroutine RD_STOR() of "Reading Routines" section. It can be seen that by looking at both Table II-2 and Figure II-3, one can quickly find where the assignments and implementations of variable *acprod* in the code.

The "I/O Files Dictionary" section provides the following information:

- Brief description of input and output (I/O) files of the SRPM
- Relative location of the files in the main directory of the SRPM
- Type of I/O file: I=Input file, O=Output file, Req=Required File, Opt=Optional File
- Name of subroutine that creates or reads the I/O file

Table II-3 shows part of "Data Dictionary" of the SRPM programmer's guide.

Figure II-3: Example of "Program Section" from SRPM Programmer's Guide

Step 13 **Drainage area *acprod* (acres) and well spacing *wlspac* (acres) calculations.**

Note: First *acprod* is set to *acrelim* if value for *acrelim* is greater than zero or it is set to *acretot.*

```
      acprod = acrelim
      if (acprod.le.0.1) acprod = acretot
```

Note: If *dbwells* is not available, *wlspac* is set to data of well spacings based on regional average assigned in file *DWLSPAC.DAT.* Return *icode=5* if well spacing data is not found in file *DWLSPAC.DAT.* If *acprod* is not available, *acprod* is set equal to four times the average well spacing. *dbwells* is then calculated based on *acprod* and *wlspac.*

```
      if (dbwells.le.0.0) then
        icount = 0
        call clook2(gsamid(1:2),regname,n_tot_reg,icount)
        if (icount.eq.0) then
          icode = 5
          return
        endif
        wlspac = min_well(icount)
        if (acprod.le.0.0) acprod = wlspac*4.0
        dbwells = acprod/wlspac
```

Note: If value of *dbwells* is available, *wlspac* is calculated based on *acprod* and *dbwells.* For potential/undeveloped storage, values of *acprod* and *wlspac* are modified if permeability is greater than 200 md and number of wells is greater than 200. Calculations are based on data in file *DWLSPAC.DAT.*

```
      else
        wlspac = acprod/dbwells
        if (statin.eq.1.and.permi.ge.200.and.dbwells.gt.200) then
          icount = 0
          call clook2(gsamid(1:2),regname,n_tot_reg,icount)
          if (icount.eq.0) then
            icode = 5
            return
          endif
          wlspac = min_well(icount)
          if (acprod.le.0.0) acprod = wlspac*4.0
          dbwells = acprod/wlspac
        endif
      endif
```

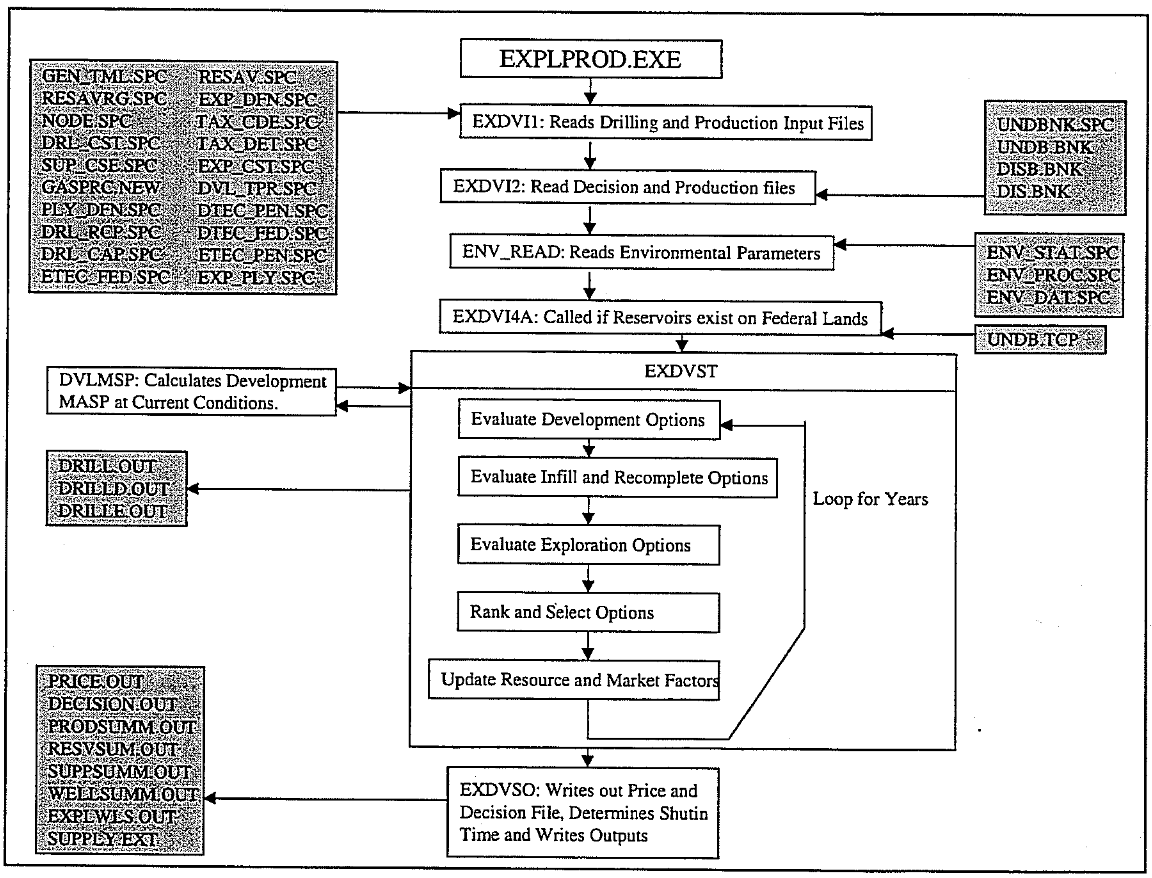
Table II-3: Example of "Data Dictionary" from SRPM Programmer's Guide

File Name	Location	Type*	Read/Write in	Descriptio
*.ADJ	[MAIN] \[DIR]	O, Opt	STORPERF	One output file for each reservoir database in input file REGIONS.DAT that is generated to report adjusted reservoir properties.
*.ERR	[MAIN] \[DIR]	O	STORPERF	One output file for each reservoir database in input file REGIONS.DAT that is generated to report error/action messages.
*.PRD	[MAIN]\[DIR]	O, Opt	WRT_TCP()	One output file for each reservoir database in input file REGIONS.DAT that contains summary of rates, cumulative production, and pressures.

4. Programmer's Guide for Exploration and Production (E&P) Module

Programmer's guide for E&P module was first released in January 1999. Based on three E&P programs (ENV_WRTE.EXE, MAKEBIN.EXE, and EXPLPROD.EXE), the document is coherently structured with important routines (over and above the three E&P programs) separated by labeled tabs. The write-up within each tab contains the main routine (for which the tab is specified) and may also contain other subroutines which it calls. To assist in locating the different subroutines (in case there is more than one within a tab), a table of contents has been provided in each tab. A general flowchart for main program EXPLPROD.EXE is provided in the guide (Figure II-4). The basic structure for the explanation of the "Program" section discussed in the background is also implemented in the E&P programmer's guide.

Figure II-4: Flowchart of EXPLPROD.EXE from E&P Programmer's Guide



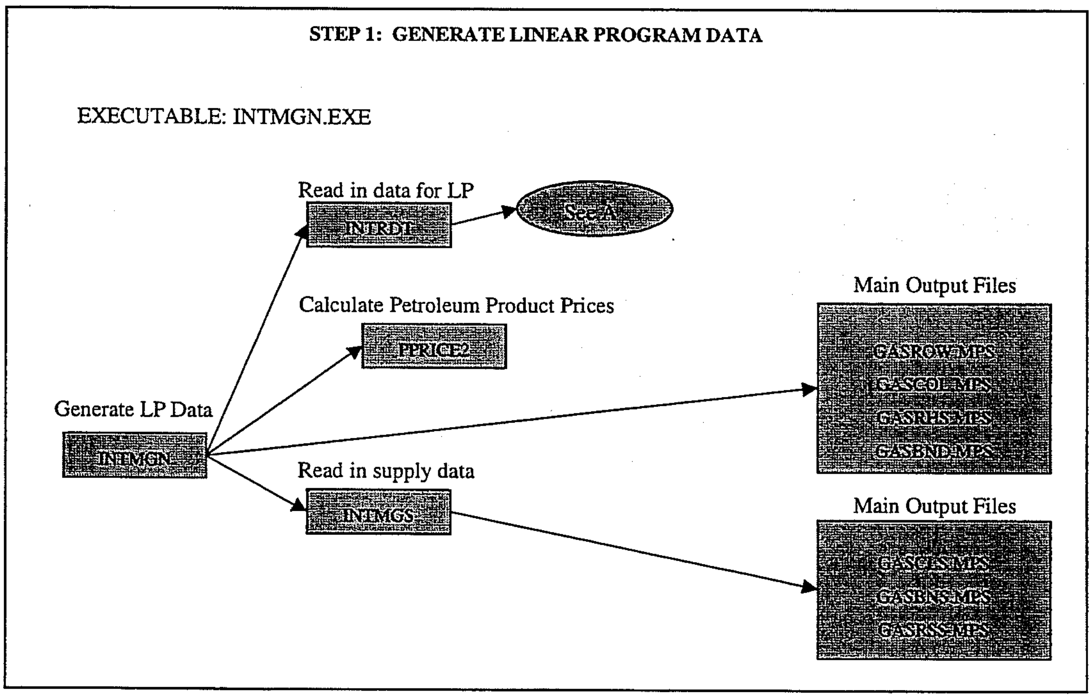
5. Programmer's Guide for Demand and Integrating (D&I) Module

The first edition of programmer's guide for D&I module was released in February 1999. The structure of the documentation is based on three main programs (INTMGN.EXE, INTRPT.EXE, and INTRVS.EXE) and is very much similar with the structure in the E&P programmer's guide. Flowchart section in the D&I programmer's guide is organized in four sequential steps:

- Step 1: Generate Linear Program Data
- Step 2: Consolidate Linear Program Data and Run Linear Program Solver
- Step 3: Read Linear Program Solution and Produce output Reports
- Step 4: Read Linear Program Solution and Produce Supply Gas Price

Figure II-5 shows flowchart for Step 1 from the D&I programmer's guide.

Figure II-5: Flowchart of STEP 1 from D&I Programmer's Guide



B. FEDERAL LAND LEASING/DEVELOPMENT MODELING

1. Background

The Federal Government is currently the largest owner of oil and gas resource in the United States. Of these resources, a large percentage is restricted from use and production based upon governmental policy, specifically moratoriums imposed on drilling/production in the OCS areas, and leasing and development permitting delays on onshore areas. If these restrictions were eased or removed, a large portion of the resource on Federally owned lands could be produced. As a result, the actions that the government could potentially take with respect to these resources can have a vast impact in all aspects of the oil and gas industry. With these factors in mind, the Department of Energy (DOE) asked ICF Consulting to update GSAM, to incorporate Federal land leasing activities, and provide impacts on production, reserves, cashflow and related employment levels.

In the previous annual report, it was noted that several changes had already been made to the GSAM model with respect to Federal resource. One of these changes was to look into independent research, which described the distribution of discovered reservoirs between Federal and Private lands. Once these assessments were made they were incorporated into the model database. These changes also included assessing all gas resources on all undiscovered plays as being either Federal or Private. The calculation behind this assumed that each reservoir had a Federal and Private portion. This method was effective in judging the overall impact of changes in Federal policy but was not as precise on a more intricate level. To improve the precision overall, since the last annual report, ICF Consulting decided to go one step further in the division of plays as being either Private or Federal land. Instead of assessing a fraction of each reservoir as Federal land, this new adjustment created EITHER Federal OR Private reservoir in a play ensuring the total resource in the play was accordingly split between Federal and Private. This change in play status allows ICF Consulting to track results by Federal and Private properties separately.

2. Splitting Up Federal/Private Land in GSAM Databases (Resource Module)

A FORTRAN program (FEDRES2.EXE) was developed and used to split GSAM undiscovered database into Federal and Private databases. The splitting process is performed to calculate number of accumulations (NRR) in each field size class (FSC) based on average recoverable reserve fraction of Federal land in the corresponding play. In GSAM, a play in the undiscovered resource is defined as a group of 13 field size classes (FSC 5 to FSC 17). The following steps are carried out for every play in the GSAM undiscovered databases to split the NRR of each FSC:

1. Read reservoir properties and NRR of 13 FSC records (of one play) from undiscovered GSAM database (*.GSM). Based on play level recovery factor obtained from play average property file (AVG.*), calculate average and total reserves of each FSC in the play. Table 4 shows USGS play "2212" in San Juan region (GSAM region 09) from GSAM database file UNDISC.GSM. Notice that each FSC record is indicated by 11-digit GSAMID.

2. Read play level Federal fraction obtained from play definition file (PLY_DFN.TXT). For the example in Step 1, the corresponding undiscovered Federal fraction fro PLY_DFN.TXT is 0.5.

3. Apply the Federal fraction to the total of NRR in each FSC to get the first estimate of NRR for Federal land and Private land. First, calculate the Federal NRR by taking the integer part of the product of Federal fraction and total NRR. The Private NRR is then set to the remaining NRR in the FSC. Using the calculated FSC average reserves (Table II-4), calculate FSC and total Federal and Private reserves. Table II-5 shows NRRs and reserves of Federal and Private lands. The bottom row of Table II-5 is the calculated Federal and Private reserve fractions. Notice that the calculated Federal fraction (0.32) is different with the data obtained from PLY-DFN.TXT (0.5). This results from rounding of NRR into an integer.

4. Adjust the Federal and Private NRRs of each FSC by subtracting or adding one accumulation from the NRRs to get the best possible estimate of Federal and Private NRRs. The adjustment is done by calculating Federal reserve fractions of 8192 combinations (i.e. 2^{13}) for every play, and select one combination that gives the closest Federal fraction to the data read from PLY_DFN.TXT (which in this case is 0.5). Table II-6 shows the final NRR splitting calculation that gives smallest deviation between calculated and expected Federal fractions (within 2% error).

Table II-4: FSC Data and Calculated Reserves of an Undiscovered Play

GSAM ID	FSC	NRR	Avg. Reserve (BCF)	Total Reserve (BCF)
09112212005	5	9	4.5	40.5
09112212006	6	5	9.0	45.0
09112212007	7	3	18.0	54.0
09112212008	8	2	36.0	72.0
09112212009	9	1	72.0	72.0
09112212010	10	0	144.0	0.0
09112212011	11	0	288.0	0.0
09112212012	12	0	576.0	0.0
09112212013	13	0	1152.0	0.0
09112212014	14	0	2304.0	0.0
09112212015	15	0	4608.0	0.0
09112212016	16	0	9216.0	0.0
09112212017	17	0	18432.0	0.0
Total for play "2212"		20		283.5

Table II-5: First Estimate of Federal NRR and Private NRR (Federal Fraction=0.5)

FSC	NRR	Federal NRR	Private NRR	Federal Reserve (BCF)	Private Reserve (BCF)
5	9	4	5	18.0	22.5
6	5	2	3	18.0	27.0
7	3	1	2	18.0	36.0
8	2	1	1	36.0	36.0
9	1	0	1	0.0	72.0
10	0	0	0	0.0	0.0
11	0	0	0	0.0	0.0
12	0	0	0	0.0	0.0
13	0	0	0	0.0	0.0
14	0	0	0	0.0	0.0
15	0	0	0	0.0	0.0
16	0	0	0	0.0	0.0
17	0	0	0	0.0	0.0
Total	20	8	12	90.0	193.5

Calculated Reserve Fraction	0.32	0.68
Correct Reserve Fraction	0.50	0.50

Table II-6: Final Estimate of Federal NRR and Private NRR (Federal Fraction=0.5)

FSC	Federal			Private		
	GSAM ID	NRR	Reserve (BCF)	GSAM ID	NRR	Reserve (BCF)
5	09112212F005	5	22.5	09112212P005	4	18.0
6	09112212F006	3	27.0	09112212P006	2	18.0
7	09112212F007	1	18.0	09112212P007	2	36.0
8	09112212F008	2	72.0	09112212P008	0	0.0
9	09112212F009	0	0.0	09112212P009	1	72.0
10	09112212F010	0	0.0	09112212P010	0	0.0
11	09112212F011	0	0.0	09112212P011	0	0.0
12	09112212F012	0	0.0	09112212P012	0	0.0
13	09112212F013	0	0.0	09112212P013	0	0.0
14	09112212F014	0	0.0	09112212P014	0	0.0
15	09112212F015	0	0.0	09112212P015	0	0.0
16	09112212F016	0	0.0	09112212P016	0	0.0
17	09112212F017	0	0.0	09112212P017	0	0.0
Total		11	139.5		9	144.0

Calculated Reserve Fraction	0.49	0.51
Correct Reserve Fraction	0.50	0.50

5. Create two GSAM database files, one for Federal land and one for Private land, and store the final NRR values with the same reservoir properties as in the original GSAM database. I these two files a letter "F" for Federal portion or "P" for Private portion is inserted after the 8th character of the original GSAMID (see Table II-6). For UNDISC.GSM, the Federal land database file will be named UNDISCF.GSM and the Private land database file will be named UNDISCP.GSM. In the case when there is no Private land is found in the original database (e.g. UNDOFF.GSM for undiscovered offshore GSAM database), zero size Private land database will be created. This file should not be used in any GSAM run.

3. Regional Reserve Availability Curve (RESAV.SPC) (E&P Module)

As an integral part of Federal/Private land modeling, a new specification file (RESAV.SPC) was added to the E&P module to control undiscovered reserve availability in relation with effective penetration rates of exploration drilling. The file stores regional reserve availability percentage of each resource type for Federal and Private lands as a function of time. The format of each region in the RESAV.SPC file is as follows:

• Header line	Region Name
• Column 1 (9 characters)	Resource Type
• Column 2	Year
• Column 3	Federal Land Reserve Availability (%)
• Column 4	Private Land Reserve Availability (%)
• Index for end of regional data	"**`End all     -1`**"

Figure II-6 is an example of regional Federal and Private reserve availability data. The implementation of reserve availability function in E&P module will be addressed in the Federal land modeling section.

Figure II-6: Reserve Availability Data for Texas Gulf Coast

```
Texas Gulf Coast
Conv      1993   5.0   5.0
Lin Flow 1993   5.0   5.0
W Drive  1993   5.0   5.0
Conv      1995   7.0   7.0
Lin Flow 1995   7.0   7.0
W Drive  1995   7.0   7.0
Conv      2000  10.0  10.0
Lin Flow 2000  15.0  15.0
W Drive  2000  20.0  20.0
Conv      2005  25.0  25.0
Lin Flow 2005  25.0  25.0
W Drive  2005  30.0  30.0
Conv      2010  55.0  55.0
Lin Flow 2010  40.0  40.0
W Drive  2010  35.0  35.0
Conv      2015  75.0  75.0
Lin Flow 2015  55.0  55.0
W Drive  2015  56.0  56.0
Conv      2020 100.0 100.0
Lin Flow 2020  80.0  80.0
W Drive  2020  80.0  80.0
End all    -1
```

4. Development and Exploration Technology Incremental Penetration Rates for Federal Lands (DTEC_FED.SPC and ETEC_FED.SPC) (E&P Module)

For the purpose of controlling penetration rates of current and advanced technologies for development and exploration drilling in Federal lands, two new specification files were added to the E&P module. The specification file DTEC_FED.SPC stores current and advanced technology incremental penetration rates as a function of time for development drilling program and ETEC_FED.SPC specifies similar information for exploration drilling program. The two files use the same three-column format where the first column specifies the year (all years should be specified), the second column specifies incremental current technology penetration rate (in percentage), and the third column specifies incremental advanced technology penetration rate (in percentage). Figure II-7 shows the contents of DTEC_FED.SPC file. The use of the two files in the E&P module will be discussed in the Federal land modeling section.

Figure II-7: Reserve Availability Data for Texas Gulf Coast

```
Federal Lands Technology Penetration Increaments For DEVELOPMENT TECHNOLOGY
NOTE: Values Should be Specified for all the years
Year  Curr. Tech. Increment     Adv. Tech. Increment
1993        0                        0
1994        0                        0
1995        0                        0
1996        0                        0
1997        0                        0
1998        0                        0
1999        0                        0
2000        0                        0
2001        0                        0
2002        0                        0
2003        0                        0
2004        0                        0
2005        0                        0
2006        0                        0
2007        0                        0
2008        0                        0
2009        0                        0
2010        0                        0
2011        0                        0
2012        0                        0
2013        0                        0
2014        0                        0
2015        0                        0
2016        0                        0
2017        0                        0
2019        0                        0
2020        0                        0
```

5. Enhancing GSAM for Modeling Federal Lands

Several changes have been made in the modeling side of GSAM to incorporate the changes in GSAM database and data specification, and to enhance development and exploration logic for Federal and Private lands. The first step in the enhancement of GSAM for modeling Federal land leasing/ development was the following two modifications related to the play definition file (PLY_DFN.SPC):

- Play ID (first column of PLY_DFN.SPC file) conversion from 4-digit into 5-digit. A character "F" for Federal portion of the play or "P" for Private portion of the play was appended to the original play ID. This modification increases number of plays in the PLY_DFN.SPC because one play in the original file could become two plays, one for Federal land and another for Private land.

- Modification in dimensioning of array variables related to number of plays and GSAMID. Size of these variables was increased to reflect the increase in number of plays in the PLY_DFN.SPC file and the change in GSAMID from 11-digit to 12-digit. Maximu allowable number of plays in the E&P module currently is 1538.

The second step was code modifications for the purpose of implementing Federal land leasing and development modeling into the GSAM modules. Code modification for the Reservoir Performance module is quite minimal. Several minor alterations (due to GSAMID conversion from 11-digit to 12 digit) were performed which include read/write formatting modifications to subroutines for reading the GSAM database, reading specification file PLY_DFN.SPC, and writing RP outputs. Minor modifications were also done to miscellaneous subroutines that have access to GSAMID variables (e.g. table look-up subroutines that compare two play IDs).

Major code modification was implemented in the Exploration and Production module. Several modifications to development and exploration algorithms were implemented on top of the basic changes as applied in the RP module. The calculation of undiscovered resource availability is modified to incorporate reserve availability rates specified in new specification file RESAV.SPC. The reserve availability rates are utilized in E&P module as multipliers to the existing exploration technology penetration rate defined in specification file ETEC_PEN.SPC. Product of exploration technology penetration rate and reserve availability rate is used to control how much Federal/Private undiscovered resource is available to be discovered at the prescribed year. Since the RESAV.SPC can provide different availability rates between Federal and Private reserves, it gives GSAM the ability and flexibility to control the proportion of exploration activities in Federal and Private lands.

Rates of technology penetration obtained from DTEC_PEN.SPC and ETEC_PEN.SPC files were modified to incorporate incremental technology penetration rates from DTEC_FED.SPC and ETEC_FED.SPC. Incremental penetration rate of development technology from DTEC_FED.SPC is added to the penetration rate from DTEC_PEN.SPC if a development project is situated in Federal lands. Similarly, incremental penetration rate from ETEC_FED.SPC is added to the penetration rate fro ETEC_PEN.SPC for exploration projects in Federal lands. These modifications enable GSAM to differentiate the current and advanced technology penetration rates for development and exploration drilling between Federal and Private lands. Currently, the incremental technology penetration rates in DTEC_FED.SPC and ETEC_FED.SPC files are set to zero assuming similarity between technology penetration rates in both Federal and Private lands. Whenever data for technology penetration rates in Federal lands become available, GSAM can provide more precise analysis in the activity and impact of exploration and development drilling in Federal lands.

Similar to the Reservoir Performance module, only minor changes were made to the Production and Accounting module. The same concept as in the RP module was applied in modifying several subroutines and variable declarations due to changes in number of plays and number of characters for

GSAMID and play ID. In addition, one index ("0" or "1") was appended to input file OUTPUT.OPT to control calculation and output file generation related only to Federal lands. An index of "1" is specified if the P&A run is dedicated only for Federal lands. Setting the index to "1" will skip all cost calculations and economic reporting procedure for Private lands. An index of "0" has to be specified if overall pro forma cashflow calculations and aggregations are required. Two logical statements were added to the P&A model to skip the cost calculations in the Private lands. One logical statement was placed in the exploration economic calculations to skip exploration wells in Private lands (read from exploration well data file EXPLWLS.OUT) and another logical statement was placed within development project decision loop, to skip projects in Private lands.

6. Chapter Summary

Modifications in database and computer code were exercised to incorporate Federal land leasing and development modeling in GSAM. Several new specification files were added to enable GSAM to control exploration and development drilling activities in Federal lands. Incorporating the Federal land leasing and development modeling in GSAM can provide a very precise look at the impact of changing Federal policies on the oil and gas industry.

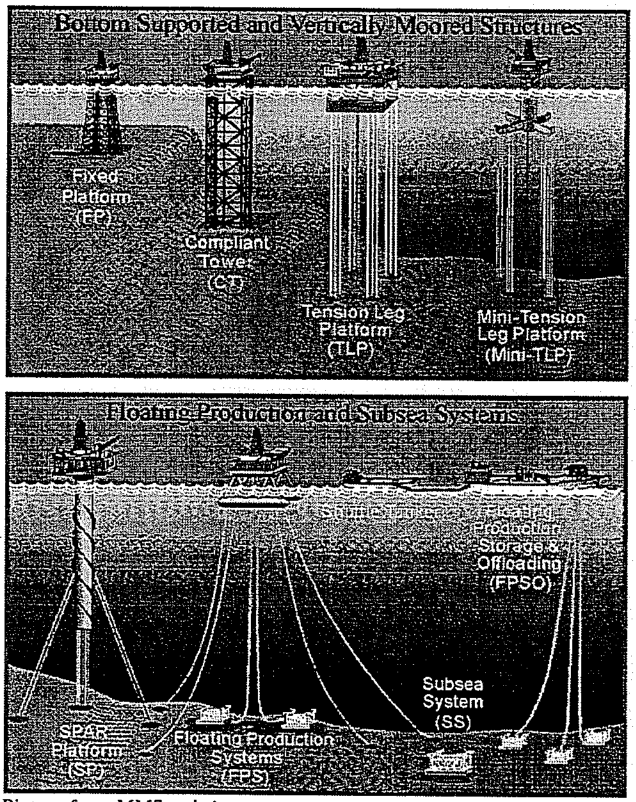
C. *Offshore Database and Drilling Cost Modeling Updates*

1. Background

When GSAM was originally developed, the vast majority, if not all, of the offshore drilling reservoirs that were in use or contemplated for use were in shallow water. Since that time, deepwater drilling has become a large and increasingly growing portion of the offshore drilling in use. A proble that arises from the growing deepwater drilling is that GSAM, because of the drilling costing algorithms at its inception, was not equipped to accurately model the exploration, drilling, and platform costs associated with deepwater development. GSAM models deepwater drilling in the same exact manner that it models shallow drilling. The result is that for deepwater drilling, GSAM did not fairly represent the drilling costs. Recent studies by the Minerals Management Service (MMS) and other industry associations have resulted in an increased understanding of the technology and necessary costs related to deepwater drilling. These are evaluated explicitly as a function of water depth. This has provided pertinent information for improving GSAM's offshore database and drilling costing algorithms.

Deepwater drilling holds many costs that are not relevant to shallow drilling. One of the new cost components associated with deepwater drilling as compared to stationary sites, i.e. sites where it is possible to drive the drilling platform's pylons into the seabed, is that deepwater drilling sites cannot have pylons driven into the seabed because of the prohibitive costs of building such a structure. Deepwater drilling sites also have to compete with conflicting currents, drastic changes in water temperature, and much stronger and more pervasive storms that make a stationary deepwater platform all but impossible. Furthermore, at incremental depth changes, the technology, which can be used for one deepwater drilling site, is not necessarily valid at another relatively shallower sites (see Figure II-8).

Figure II-8: Deepwater Development Systems



Picture from MMS website

Another difference between deepwater drilling and shallow/stationary drilling platforms is that, if needed, many deepwater drilling rigs can be moved between sites depending upon the current cost of drilling and other market factors. GSAM in its current design is now capable of modeling these factors and more in its updated calculation of offshore drilling costs.

2. Eastern Gulf of Mexico and Atlantic Offshore Database (Resource Module)

Historically, the GSAM model has regarded the offshore area of the Gulf of Mexico as containing only two regions; Eastern and Western. Conversely the MMS has three planning regions in the same area; Eastern, Western, and Central. In descriptions of the areas, the GSAM western region corresponds with the MMS western region and the GSAM eastern region corresponds with the central MMS region. The reason that GSAM has not taken noticed of or included the MMS eastern region is that there is a presidential moratorium on leases in this area, consequently it was judged to be unimportant in the drilling and production of gas. This has recently changed because of the realization that there are several areas, which are exempt from the moratorium, based upon when the decision was made on their leases. These areas include Pensacola, King's Peak, and Destin Dome (see Table II-7) as well as the lease sale 181 area which is currently scheduled for December 2001. While not all of these areas are producing, for various reasons including environmental concerns, they all do have the capability to produce. As a result, they do need to be included as an area in GSAM in case projections need to be made concerning their use. Since these needs had to be addressed, the model was adjusted and the GSAM Gulf of Mexico regions was named in the same manner as the MMS. Conversely, there is the probability that there are some undiscovered regions present in the Eastern Gulf of Mexico and the current presidential moratorium has prevented their discovery. In an attempt to ensure complete accuracy, two projected undiscovered plays (one shallow and one deep) were placed in the model and given appropriate characteristics including resource distributions (Table II-8).

The Atlantic Offshore area suffers from many of the same restrictions as the Gulf of Mexico East region. The Atlantic offshore also has a presidential moratorium on future leasing, similar to the eastern Gulf of Mexico region. However, a lease in the Mid-Atlantic area exists from prior to the imposition of moratorium. This lease area is called Manteo and its development is pending the completion of environmental impact assessments. However, once again similar to the eastern Gulf of Mexico, the possibility exists for the use and production from this site. As a result, GSAM has been equipped to recognize the Atlantic Offshore area and its possibilities with respect to drilling, production, etc. To assist in the modeling of undiscovered offshore areas in the Atlantic we have placed a projected mid depth undiscovered play into the Atlantic Offshore area (Table II-9).

Table II-7: Three Discovered Fields in Eastern Gulf of Mexico

Category	Pensacola	Destin Dome	King's Peak
Status	Developed	Explored, ready for development	Explored, ready for development
Field Size	Estimated 50 MMcf	Scenario 1: Estimated 670 Bcf Scenario 2: Estimated 2 Tcf	Estimated 750 Bcf
Production Rate	Estimated 5 MMcf/da	Scenario 1: 300 MMcf/da for the field Scenario 2: 450 MMcf/da for the field	Not known
Number of wells	1	Scenario 1: 12 Scenario 2: 21	7
Well Depth	15,000 feet	22,000 feet	20,000 feet
Water Depth	300 feet	300 feet	6,000 feet
Completion type	sub-sea satellite well	riser to platform	sub-sea satellite well, no platform
Distance to platform for tie-in	12 miles	Unknown	estimated 20 miles
Distance to shore	20 miles	20 miles	Unknown
Development start date	Not Applicable	1999	1999
Production start date	1999	2000	2000

Scenario 1: Limited development of Destin Dome
Scenario 2: Full-scale development of Destin Dome

Table II-8: Undiscovered Fields in Eastern Gulf of Mexico

Location	Field Size Class	Area (acre)	Net Pay (ft)	Permeability (md)	Porosity (fraction)	Depth (ft)	Water Depth (ft)	Number of Accumulations	Estimated Recoverable Reserve (BCF)
Shallow	05	341.8	30.0	800	0.3	15000	300	1	5.0
	07	723.6	50.3	800	0.3	15000	300	1	17.9
Deep	07	166.5	83.9	800	0.3	20000	5000	1	16.8
	08	301.7	108.7	800	0.3	20000	5000	2	39.35
	09	490.2	140.8	800	0.3	20000	5000	2	82.8
	11	806.8	236.3	800	0.3	20000	5000	1	228.7
	12	1458.0	306.1	800	0.3	20000	5000	1	535.5

Table II-9: Manteo Field (Undiscovered) in Atlantic Offshore

Field Size Class	Area (acre)	Net Pay (ft)	Permeability (md)	Porosity (fraction)	Depth (ft)	Water Depth (ft)	Number of Accumulations	Estimated Recoverable Reserve (BCF)
15	11273.3	399.2	800	0.3	15000	2130	1	3500

3. Offshore Drilling Cost Modeling Updates (RP, E&P, and P&A Modules)

Drilling cost in GSAM (onshore and offshore) was calculated using a set of polynomial equations based on polynomial regressions of regional cost versus depth data from 1997 Joint Association Survey (JAS) on Drilling Costs. No differentiation was considered between onshore and offshore drilling costs as both of the costs were assumed to be the same at the same well depth. In other words, water depth was not a factor in offshore drilling cost calculations.

Based on recent studies by Mineral Management Service (MMS) and other industry associations, GSAM drilling cost formulation is modified to incorporate water-depth specific technology and drilling cost for offshore wells. In the new formulation, offshore drilling cost is calculated based on the summation of two drilling cost functions; well depth cost function and water depth cost function (Figure II-9).

For the purpose of incorporating the new offshore drilling cost formulation in GSAM, some data specification and code modifications are implemented. Play definition file PLY_DFN.SPC is modified by adding one column that provides information on average water depth of undiscovered plays. Appropriate routines in the RP, E&P, and P&A modules are modified by updating the reading format of PLY_DFN.SPC file and adding variables to store the water depth data. The following routines are also modified to incorporate offshore drilling cost formulation:

- UNITCOST, unit cost subroutine (RP module)
- DRLCST, drilling cost subroutine (E&P module)
- UNITCOST, unit cost subroutine (P&A module)
- PRODACCT, main program (P&A module)

Logical statements are added to these routines to control drilling cost calculation. The new offshore drilling cost equation is utilized for wells with positive water depth (offshore wells) and the original drilling cost formulation is utilized otherwise.

Figure II-9: Offshore Drilling Cost Equation in US$

$$\mathit{Well\ depth\ cost} = -2x10^{-7}\,D^3 + 0.0402\,D^2 - 227.64\,D$$

$$\mathit{Water\ depth\ cost} = \begin{cases} 1350\,WD + 2.09x10^6 & \text{for } WD < 3000\,ft \\ 135\,WD + 6.86x10^6 & \text{for } WD \geq 3000\,ft \end{cases}$$

$$\mathit{Offshore\ drilling\ cost} = \mathit{Well\ depth\ cost} + \mathit{Water\ depth\ cost}$$

where :

$D = \mathit{Well\ depth\,(ft)}$

$WD = \mathit{Water\ depth\,(ft)}$

4. Chapter Summary

GSAM definition of Gulf of Mexico regions has been updated and is consistent with MMS description of western, central, and eastern Gulf of Mexico areas. A new GSAM database (EGOMDU.GSM) was developed for discovered plays in the eastern Gulf of Mexico. GSAM offshore database (UNDOFFF.GSM) was modified to include undiscovered plays in the eastern Gulf of Mexico and Atlantic Offshore regions. Offshore drilling cost formulation was developed and implemented in GSAM modules. Modifications in offshore database and drilling cost modeling maintain the consistency of GSAM database and contribute to more accurate GSAM predictions.

D. TIGHT RESERVOIR TYPE-CURVE MODELING UPDATE

1. Background

GSAM models tight reservoirs based on linear flow concept due to the fact that most of these reservoirs are produced through either hydraulically fractured well (vertical well) or horizontal well. In Reservoir Performance (RP) module, type curve (production rate and/or pressure as a function of time) for hydraulically fractured wells is generated by means of pressure drop calculation for a well with a finite conductivity fracture. The RP module handles the horizontal wells the same way as in the hydraulically fractured wells. In this case, the type curve is constructed by first transforming horizontal well properties into equivalent fractured well properties. The transformation yields equivalent hydraulically fractured well properties such as effective drainage area, fracture half-length, effective wellbore radius, and fracture conductivity. These properties are then used as a basis for constructing the type curve for the horizontal well.

In the previous GSAM version, there was inconsistency observed between gas production in hydraulically fractured and horizontal wells. For equivalent reservoir properties and operating conditions, gas production from horizontal wells was found to be unrealistically higher (about twice higher) than that from fractured wells. Debugging the RP module code led to the conclusion that the doubling effect in the horizontal wells was caused by inconsistency in transformation formulations. Equivalent skin factor was unnecessarily calculated and included in the transformation from horizontal well to hydraulically fractured well. The equivalent skin factor should not be included in the transformation because it has already been captured in variable effective wellbore radius. Including the equivalent skin factor together with the effective wellbore radius will double the production from the horizontal wells. This problem was resolved by setting equivalent skin factor equals to zero. In addition, effective wellbore radius equation for hydraulically fractured wells was updated using the same method used for horizontal wells. The later modification is implemented to maintain consistency between the horizontal and hydraulically fractured wells.

2. Horizontal Well to Hydraulically Fractured Well Transformation (RP Module)

As discussed earlier, four equivalent fracture properties need to be computed in the transformation from horizontal well to the hydraulically fractured well. The first property is the <u>effective drainage area</u> of a horizontal well. Since the penetration length of a horizontal well is much longer than that of a vertical well, under the same operating conditions, a horizontal well will drain more area than a vertical well. The effective drainage area of a horizontal well is calculated based on average horizontal well drainage area of two methods offered by Joshi[1] (see Figure II-10 (b) and (c)). The proposed method was implemented in GSAM to modify effective well spacing calculation in subroutine CONVERT() of the RP module.

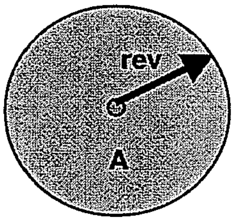
For the second property, <u>equivalent fracture conductivity</u>, a horizontal well is transformed to hydraulically fractured well with an infinite conductivity fracture. In GSAM, infinite conductivity fracture is modeled with dimensionless fracture conductivity (fracture conductivity divided by permeability and fracture half-length) of 100,000.

<u>Equivalent fracture half-length</u> and <u>effective wellbore radius</u> for a horizontal well are calculated using Joshi's method. These two properties are function of length of horizontal section of the well, drainage area, ratio of horizontal and vertical direction permeability, reservoir thickness, and wellbore radius. Figure II-11 shows formulation for equivalent fracture half-length and effective wellbore radius.

[1] Joshi, S.D., "Horizontal Well Technology", PennWell Publishing Company, 1991

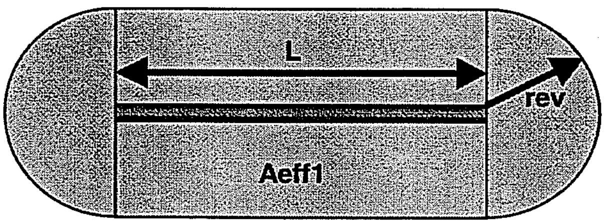
Figure II-10: Effective Drainage Area of Horizontal Wells

(a) Drainage Area of a Vertical Well



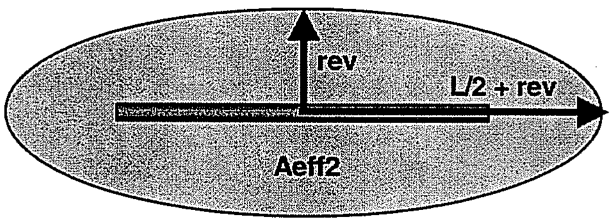
$$rev = \sqrt{\frac{A(435460)}{\pi}}$$

(b) Drainage Area of a Horizontal Well (Method 1)



$$Aeff1 = A + \frac{(L)(2)(rev)}{43560}$$

(c) Drainage Area of a Horizontal Well (Method 2)



$$Aeff2 = \frac{\pi(0.5L + rev)rev}{43560}$$

$$Aeff = 0.5(Aeff1 + Aeff2)$$

where:

Aeff = *effective drainage area for horizontal wells (acre)*

A = *drainage area of vertical well (acre)*

L = *length of horizontal well section (ft)*

Figure II-11: Effective Wellbore Radius and Fracture Half-Length for Horizontal Wells

$$rweff = \frac{(rev)(0.5L)}{\left[a + \sqrt{a^2 - (0.5L)^2}\right]\left[\beta h / (2rw)\right]^{\beta h / L}}$$

$$xf = rweff / 0.5$$

where :

$$a = 0.5L\left[0.5 + \sqrt{0.25 + (2rev / L)^4}\right]^{0.5}$$

$$rev = \sqrt{\frac{Aeff(435460)}{\pi}}$$

$$\beta = \sqrt{k_h / k_v}$$

$rweff$ = effective wellbore radius (ft)

xf = fracture half length (ft)

L = length of horizontal well section (ft)

h = reservoir thickness (ft)

rw = wellbore radius (ft)

$Aeff$ = effective drainage area (acre)

k_h = horizontal permeability (md)

k_v = vertical permeability (md)

As mentioned earlier, effective wellbore radius equation for fractured well was also modified to maintain consistency between hydraulically fractured well and horizontal well. The effective wellbore radius as a function of fracture half-length and dimensionless fracture conductivity is determined using a set of equations shown in Figure II-12. The updated effective wellbore equation and the transformation equations are implemented in CALCOF() and CONVLV() subroutines of the RP module.

To validate the updated RP module, several test runs were conducted. For example, a test run was performed to check whether the hydraulically fractured well model collapses to a conventional reservoir model (vertical well with no fracture in conventional reservoir) for a small fracture half-length. For these runs, the fracture half-length is set to a small number (one foot), permeability is set to 0.001 md (tight reservoir), and all other properties and operating conditions for the two runs are set equal to each other. Recovery efficiencies after one year of production from the two runs are very close to each other (0.062% for the fractured model and 0.058% for the conventional model) suggesting that the fractured model behaves like the horizontal model for small fracture half-lengths.

Figure II-12: Effective Wellbore Radius of Hydraulically Fractured Wells

rweff = (xf) (rw/xf)	
where :	
rw/xf = 0.1864(Fcd) + 0.0138	for Fcd ≤ 1
rw/xf = 0.087(Fcd) + 0.111	for 1 < Fcd ≤ 2
rw/xf = 0.035(Fcd) + 0.215	for 2 < Fcd ≤ 5
rw/xf = 0.008(Fcd) + 0.35	for 5 < Fcd ≤ 10
rw/xf = 0.002(Fcd) + 0.41	for 10 < Fcd ≤ 30
rw/xf = 0.00003(Fcd) + 4691	for 30 < Fcd ≤ 1000
rw/xf = 0.5	for Fcd > 1000
rweff = effective wellbore radius (ft)	
Fcd = Dimensionless fracture conductivity	

3. Chapter Summary

The hydraulically fractured well and horizontal well models in tight reservoirs (linear flow model) in the Reservoir Performance model has been modified. The updated RP module eliminates the doubling effect (production from horizontal wells is twice the production from hydraulically fractured wells) in the previous version of the RP module. The fractured well model has been verified with the conventional model. The validation runs showed that the fractured well model collapses to the conventional well model for small fracture half-lengths.

E. *STORAGE RESERVOIR PERFORMANCE MODULE (SRPM) VERSION 1999*

1. Background

The SRPM model uses reservoir level properties presented by the American Gas Association (AGA) to determine the characteristics of underground gas storage in the United States. One of the important characteristic, which concerned the development and the accuracy of the model, is working gas capacity. It is known that the AGA storage reservoir information does not cover all existing storage reservoirs because the AGA collects information only from volunteers. The AGA survey captures about 90 percent of the gas storage in Eastern Consuming Region and about 96 percent of the storage in Western Consuming Region of the U.S. Therefore, the working gas capacity from the AGA is expected to be lower than the anticipated value. Energy Information Administration (EIA), on the other hand, collects storage reservoir information from all storage operators and hence is expected to provide more accurate working gas capacity estimation. To determine the accuracy of working gas capacity obtained from the AGA, a comparison with the EIA data was made. When the data was compared, it was realized that there were several significant differences in the data of the AGA as compared to that of the EIA. The EIA data recorded a larger working gas and number of sites for the Depleted Gas/Oil fields. Additionally, AGA Salt Cavern Storage data was low for all categories when compared to the EIA data. The Aquifer storage numbers were roughly similar for both sets of data (see Table II-10). These differences are significant enough that it was felt that there should be an attempt to adjust the AGA data on working gas capacity by adding more sites to the database.

Table II-10: Number of Sites and Working Gas Capacity from EIA and AGA based on their 1997 Releases

	Depleted Gas/Oil Field				Aquifer Storage				Salt Cavern Storage			
State	EIA Number of Sites	AGA Number of Sites	EIA Working Gas MMcf	AGA Working Gas MMcf	EIA Number of Sites	AGA Number of Sites	EIA Working Gas MMcf	AGA Working Gas MMcf	EIA Number of Sites	AGA Number of Sites	EIA Working Gas MMcf	AGA Working Gas MMcf
Alabama	0		0		0		0		1		2,000	
Arkansas	3	4	20,000	7,043	0	0	0	0	0	0	0	0
California	10	9	222,000	212,679	0	0	0	0	0	0	0	0
Colorado	9	8	52,000	37,984	0	0	0	0	0	0	0	0
Iowa	0	0	0	0	4	8	74,000	60,092	0	0	0	0
Illinois	12	8	47,000	44,346	17	19	200,000	219,172	0	0	0	0
Indiana	18	15	19,000	17,282	10	7	22,000	5,019	0	1	0	9
Kansas	18	14	107,000	87,176	0	0	0	0	1	0	2,000	0
Kentucky	22	15	107,000	57,762	2	1	6,000	254	0	0	0	0
Louisiana	8	7	273,000	173,103	0	0	0	0	5	0	17,000	0
Maryland	1	1	15,000	15,301	0	0	0	0	0	0	0	0
Michigan	45	45	632,000	492,421	0	0	0	0	2	2	2,000	208
Minnesota	0	0	0	0	1	1	2,000	2,100	0	0	0	0
Missouri	0		0		1		10,000		0		0	
Mississippi	4		36,000		0		0		3		20,000	
Montan	5	5	208,000	55,201	0	0	0	0	0	0	0	0
Nebraska	1	2	8,000	42,498	0	0	0	0	0	0	0	0
New Mexico	2	2	64,000	12,478	1	0	8,000	0	0	0	0	0
New York	21	19	82,000	59,388	0	0	0	0	1	0	0	0
Ohio	23	22	206,000	192,093	0	0	0	0	0	0	0	0
Oklahoma	13	12	157,000	134,889	0	0	0	0	0	0	0	0
Oregon	1		7,000		0		0		0		0	
Pennsylvania	60	51	378,000	369,503	0	0	0	0	0	0	0	0
Tennessee	1		1,000		0		0		0		0	
Texas	22	16	373,000	145,048	0	0	0	0	13	2	70,000	13,662
Utah	2	1	51,000	46,250	2	2	9,000	948	0	0	0	0
Virginia	1		1,000		0		0		1		0	
Washington	0	0	0	0	1	1	15,000	15,100	0	0	0	0
West Virginia	36	31	192,000	182,342	0	0	0	0	0	0	0	0
Wyoming	5	5	41,000	28,187	1	1	4,000	836	0	0	0	0
Total	343	292	3,299,000	2,412,974	40	40	350,000	303,521	27	5	113,000	13,879

Reservoir level working gas capacity as an input to the SRPM model is used as a basis to adjust reservoir properties such as permeability and skin factor. The reservoir property adjustment, to match the working gas capacity and deliverability values in SRPM, is required because both working gas capacity and seasonal average deliverability are input parameters for Demand and Integrating (D&I) module of GSAM. Without this adjustment, storage data for D&I module is incomplete and supply/demand equilibrium will be unrealistic. In some instances, however, the property adjustment process fails to bring the working gas capacity to the value given in the database. The calculated working gas capacities in these reservoirs are less than that the value in the database. This problem was resolved in SRPM by adding more reservoirs in the corresponding state where the reservoir resides.

In the previous SRPM model, there were some modeling aspects that required modifications. The reservoir property adjustment procedure was not structured and the numerical method to search for permeability and skin factor values was not very stable. In addition, the model was designed for fixed five-day time step size. This limitation created inconsistency between output data of the SRPM and injection/extraction programs implemented in the D&I module. For example, an extraction period of 31 days in the D&I module could not be modeled with exactly 31 days because any number of steps in the SRPM simulation will never yield 31 days (it would yield 30 days rather). Absolute open flow (AOF) potential was defined as flow rate at the end of one year of extraction or injection which is not consistent with assumptions used to construct gas storage type curves. Based on these observations, it was found necessary to modify the computer model with better structure and stable numerical method for reservoir property adjustment procedure, more flexibility in time step sizes, and consistent methodology in AOF calculations.

2. Database Updates

The decision of adding more reservoir sites in SRPM database is dictated by the difference between EIA and AGA working gas capacities. In the regions where working gas capacity from the AGA is higher than that from the EIA, no site is added to the SRPM database even if the AGA reports less number of reservoir sites. In one instance (Arkansas) where there were a greater number of sites in the AGA data but a smaller working gas value, a site was added to compensate for working gas shortfall. In all, based on the difference between EIA and AGA number of sites, 83 new reservoir sites were added.

The next step in updating the SRPM database is trial and error process involving SRPM runs and adding more sites to the database. The trial and error is performed to match working gas capacity fro SRPM run with the one from the database. Seventeen more sites were added in this process that brought the total working gas capacity from the SRPM run close to the total working gas in the database. However, working gas capacities for aquifer sites in Kentucky and salt cavern sites in Michigan are still below the targeted values. To meet the targeted values we would have needed to add at least ten sites per state. We will update the reservoir databases for salt cavern and aquifers in the next fiscal year.

A comparison between the updated AGA data and the EIA data is shown in Table II-11. Overall, we found that the new additions greatly improved the AGA working gas capacity. In the region of depleted gas/oil fields, the new additions bring the total working gas capacity from about 73% to about 90% of the total EIA working gas capacity. The updated total working gas capacities in aquifer and salt cavern storage are very close to that from the EIA.

Table II-11: Number of Sites and Working Gas Capacity (EIA and Current SRPM Data)

	Depleted Gas/Oil Field				Aquifer Storage				Salt Cavern Storage			
State	EIA Number of Sites	SRPM Number of Sites	EIA Working Gas MMcf	SRPM Working Gas MMcf	EIA Number of Sites	SRPM Number of Sites	EIA Working Gas MMcf	SRPM Working Gas MMcf	EIA Number of Sites	SRPM Number of Sites	EIA Working Gas MMcf	SRPM Working Gas MMcf
Alabama	0	0	0	0	0	0	0	0	1	1	2,000	2,000
Arkansas	3	6	20,000	19,044	0	0	0	0	0	0	0	0
California	10	10	222,000	221,711	0	0	0	0	0	0	0	0
Colorado	9	10	52,000	52,121	0	0	0	0	0	0	0	0
Iowa	0	0	0	0	4	9	74,000	73,516	0	0	0	0
Illinois	12	12	47,000	46,877	17	19	200,000	219,172	0	0	0	0
Indiana	18	18	19,000	18,966	10	15	22,000	21,420	0	1	0	9
Kansas	18	18	107,000	106,344	0	0	0	0	1	1	2,000	2,000
Kentucky	22	22	107,000	108,003	2	2	6,000	969	0	0	0	0
Louisiana	8	9	273,000	272,673	0	0	0	0	5	5	17,000	17,000
Maryland	1	1	15,000	15,301	0	0	0	0	0	0	0	0
Michigan	45	45	632,000	492,421	0	0	0	0	2	3	2,000	448
Minnesota	0	0	0	0	1	1	2,000	2,100	0	0	0	0
Missouri	0	0	0	0	1	1	10,000	10,000	0	0	0	0
Mississippi	4	4	36,000	36,000	0	0	0	0	3	3	20,000	20,000
Montan	5	5	208,000	55,201	0	0	0	0	0	0	0	0
Nebraska	1	2	8,000	42,498	0	0	0	0	0	0	0	0
New Mexico	2	2	64,000	12,478	1	2	8,000	8,000	0	0	0	0
New York	21	22	82,000	82,388	0	0	0	0	1	0	0	0
Ohio	23	23	206,000	205,488	0	0	0	0	0	0	0	0
Oklahoma	13	13	157,000	154,951	0	0	0	0	0	0	0	0
Oregon	1	1	7,000	7,000	0	0	0	0	0	0	0	0
Pennsylvania	60	60	378,000	379,518	0	0	0	0	0	0	0	0
Tennessee	1	1	1,000	1,000	0	0	0	0	0	0	0	0
Texas	22	29	373,000	372,555	0	0	0	0	13	13	70,000	69,774
Utah	2	2	51,000	51,454	2	2	9,000	948	0	0	0	0
Virginia	1	1	1,000	1,000	0	0	0	0	1	0	0	0
Washington	0	0	0	0	1	1	15,000	15,100	0	0	0	0
West Virginia	36	36	192,000	189,486	0	0	0	0	0	0	0	0
Wyoming	5	5	41,000	28,187	1	1	4,000	836	0	0	0	0
Total	343	357	3,299,000	2,972,664	40	53	350,000	352,061	27	27	113,000	111,231

3. Modeling Updates

Reservoir property adjustment in SRPM was restructured. The adjustment procedure for each storage reservoir is started with skin factor adjustment and followed with permeability adjustment. Bisection iteration method was implemented between -15 and +15 for skin factor and between 0.001 md and 10,000 md for permeability. Bisection method was chosen to ensure that the adjusted skin factor and permeability are within the ranges specified and was found to be stable for all storage reservoirs in the SRPM database.

The SRPM model was modified to handle variable time step sizes. Simulation using one-day time step size is now possible which enables the SRPM to output data on a daily basis.

Subroutine CALCOF() for AOF calculation in the previous SRPM model was removed. Inconsistency in time step sizes between AOF calculation and type curve construction was resolved by including AOF calculation in subroutine SOLVER() parallel with the type-curve flow rate and pressure calculations. The AOF is calculated using the gas flow rate subroutine, RATE1(), with a constraint of sandface pressure of 14.7 psia. Since the same subroutine is also utilized in type curve construction, the modeling of AOF is now consistent with flow rate calculation for the type curve.

4. Chapter Summary

Altogether, 100 new storage reservoirs were added to the SRPM database. These new additions were generated based on differences in number of reservoirs reported in the AGA and the EIA. Working gas capacity data from EIA was used as a basis for the database modification because the information collected by the EIA covers more storage reservoirs than that from the AGA.

Some modeling aspects were modified to provide the SRPM with better procedure for reservoir property adjustment, more flexibility in time step sizes, and consistent methodology in AOF calculations.

Salt cavern storage in the SRPM is still modeled as a conventional reservoir. The modeling of salt cavern storage needs to be changed and the database should be consistent with the new model. We foresee these implementations to be undertaken in the next fiscal year.

F. EXPLORATION DRILLING ALGORITHM UPDATE

1. Background

To determine the accuracy of GSAM predictions of exploration wells drilled, we have utilized a comparison between GSAM calculations and the Joint Association Survey (JAS) data. Historically, the number of exploration wells that GSAM has predicted has been much lower than the published JAS number of wells. In an attempt to remedy the differences, we have adjusted the exploration drilling algorithms (based on literature review and conversation with other consultants) so that we can produce a better prediction of the number of exploration wells drilled.

2. Successful Exploration Drilling Assumption (E&P Module)

In the previous Exploration and Production (E&P) module, it was assumed that each successful exploration drilling effort finds three accumulations (in one undiscovered field): one accumulation in the current field size class (FSC) and two accumulations in smaller FSCs. Using this assumption, if the success rate for exploration is 100%, each accumulation explored corresponds to one-third exploration wells. Note that number of accumulations explored at any given time is calculated based on probability of finding accumulations specified in file EXP_DFN.SPC and the remaining undiscovered accumulations in that year.

This assumption is found to be optimistic and causing number of exploration wells to be lower than expected. The very first attempt to solve the exploration drilling issue was to redefine the assumption of successful exploration drilling utilized in the E&P module. In the new algorithm, one successful exploration drilling effort is assumed to find only one accumulation or for success rate of 100%, each accumulation explored represents one exploration well. The new exploration drilling assumption was implemented in the E&P module. The new GSAM model (with new successful exploration drilling assumption) improves the number of exploration well prediction significantly.

3. Chapter Summary

Previous assumption of successful exploration drilling was found to be optimistic. New assumption for successful exploration drilling was implemented to the E&P module of GSAM which improved number of exploration wells drilled.

G. MODIFICATION TO PROJECT SELECTION CRITERIA

1. Background

Previously, the project selection criterion used in the Exploration and Production (E&P) module ranked the projects on the basis of minimum acceptable supply price (MASP). This method of project selection is acceptable in most cases since the project that has the lowest MASP would probably be the most profitable. However, it was realized that in many cases the assumption of lower MASP resulting in greater profitability is not necessarily true. The MASP calculation does not take into account the effect of drilling rig availability or capacity (specified in file DRL_RCP.SPC) in the region where the project is located. Therefore, a project with low MASP but located in a region with shortage in drilling rig capacity should not be given a high rank unless the project is still economic by adding cost associated in transporting rig capacity from another region. To take into account this realization, the model was adjusted in such a manner that a criterion based on drilling rig availability is included in the project selection process.

2. Breakeven Drilling Cost Factor Formulation (E&P Module)

In earlier version of GSAM, a criterion based on drilling rig availability was already implemented in the E&P module in the form of breakeven drilling cost factor (BDCF). The BDCF is defined as the fraction of full drilling cost at which MASP equals to supply price (see Figure II-13). In this figure, the x-axis is drilling cost factor (drilling cost divided by full drilling cost) where DCF_V is variable drilling cost factor, DCF_F is full drilling cost factor (equals to 1), DCF_T is full drilling cost plus cost of transporting rig capacity divided by full drilling cost. The y-axis is the MASP. The BDCF formulation in the E&P module, however, was not consistent with the aforementioned definition and it always resulted in drilling cost factor (i.e. BDCF) higher than the factor to transport rig capacity to the region (DCF_T). This is the reason why BDCF in the previous version of E&P module did not have significant role in the project selection process.

The equation for breakeven drilling cost factor that is consistent with the relations between drilling cost factors and MASPs as shown in Figure II-13 was reformulated. The new equation (Figure II-14) is used to calculate BDCF of all projects. The projects are then ranked based on both MASP and BDCF. The BDCF is also used to determine the actual drilling cost realized and to control utilization and movement of the regional rig capacities.

Figure II-13: MASP vs Breakeven Drilling Cost Factor

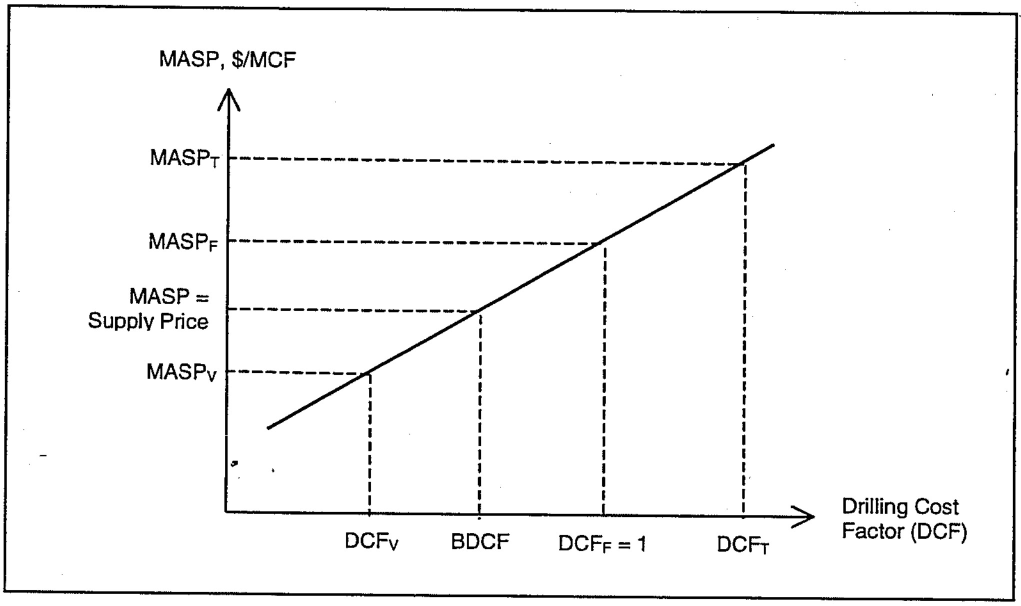


Figure II-14: Breakeven Drilling Cost Factor Equation

$$BDCF = \left[\frac{Supply\ Price - MASP_V}{MASP_F - MASP_V}\right](DCF_F - DCF_V) + DCF_V$$

3. Chapter Summary

Consistent breakeven drilling cost factor (BDCF) formulation was developed and implemented in the E&P module. The projects are now ranked based on both MASP and BDCF. The BDCF is instrumental in controlling utilization and movement of the regional rig capacities especially when there are shortages in regional rig capacities.

H. Regional Reserve Growth Function

1. Background

Historically, the regional reserve growth function has been used as a calibration tool for the E&P module of GSAM. This was done mainly as a result of inadequate access data, which could be used to properly calibrate the growth function. The original data for the reserve growth function was put into place in a manner, which was believed to be a reasonable projection of the reserve growth. This data was then manipulated to alter the reserve availability by region and thereby production.

Recently, studies have been done and information has been released which gives fairly accurate projections of the regional reserve growth function throughout the United States. The majority of the information from these studies has been released through the United States Geological Survey (USGS). Table II-12 shows an example of reserve growth function in the Gulf Coast. With this new information, it is now possible to accurately calibrate the regional reserve growth function in the E&P module. While this calibration will remove some of the flexibility from the calibration of the model as a whole, it should make the specific pieces of the model, which relate to the reserve growth function, have a greater degree of precision.

Table II-12: Reserve Growth Function in Gulf Coast

Year	Reserve Growth Rate
1993	27%
1994	34%
1995	40%
1996	42%
1997	45%
1998	47%
1999	49%
2000	50%
2001	52%
2002	54%
...	...

2. Database Update (E&P Module)

Prior to incorporating regional reserve growth functions into the E&P module, the available data must first be segmented into pieces, which then becomes suitable for assimilation into the module. The first step of this process is to determine the annual reserve growth rate. The annual reserve growth rate was calculated by taking the cumulative reserve growth values for each year and dividing them by the total projected reserve growth reserves for that region. The resulting value for each year is a percentage of the total projected gas. This percentage reflects the cumulative reserve growth for each year. The next step, which was needed to incorporate the USGS data into the E&P module, was cross-mapping the USGS region to the appropriate GSAM region. The proper disposition of the USGS data was determined by associating each GSAM region with a USGS region. The division of regions that was used is shown in Table II-13.

Once this conversion was made, it was fairly simple to transfer the reserve growth rate that had previously been calculated for the USGS regions to the corresponding GSAM regions. For those regions, which did not have corresponding USGS regions, i.e. Gulf of Mexico, Atlantic Offshore, etc., the average USGS growth rate for the lower forty-eight states was used.

When we had determined the values to be used for all the GSAM regions, the specification file RESAVRG.SPC was updated to reflect the more accurate growth rates. Example of entries (for Texas Gulf Coast) in the RESAVRG.SPC file is shown in Table II-14. When placing the values into the file, the percentages were uniformly distributed across the resource types present in each region. For example, if the reserve growth rate for Appalachia was thirty-two percent in 1995 then the growth rates for conventional, tight, and unconventional gas in Appalachia in 1995 were all thirty-two percent. Once the calibrated values were placed into RESAVRG.SPC they were not changed in any way.

Table II-13: GSAM to USGS Region Crosswalk and Reserve Growth Reserves for Lower 48

GSAM Region	USGS Region	Reserve Growth Reserve (TCF)
Alaska	Alaska	32.0
Pacific Onshore	Pacific Coast	13.5
San Juan	Colorado Plateau, Basin, and Range	11.8
Rockies Foreland	Rocky Mountains and Northern Great Plains	19.2
Williston		
Permian Basin	West Texas and Eastern New Mexico	51.2
Mid-Continent	Mid-Continent	88.3
Mid-West		
Arkla-East Texas	Gulf Coast	102.4
Texas Gulf Coast		
South Louisiana		
MAFALA Onshore		
Appalachia	Eastern	3.7
	Total (Lower 48)	322.1

Table II-14: Entries for Texas Gulf Coast in Specification File RESAVRG.SPC

Resource Type	Year	Previous Reserve Growth Rate	Updated Reserve Growth Rate
Conventional	1993	3%	27%
Linear Flow	1993	3%	27%
Water Drive	1993	3%	27%
Conventional	1995	8%	40%
Linear Flow	1995	8%	40%
Water Drive	1995	8%	40%
Conventional	2000	12%	50%
Linear Flow	2000	12%	50%
Water Drive	2000	12%	50%
Conventional	2005	17%	57%
Linear Flow	2005	17%	57%
Water Drive	2005	17%	57%
Conventional	2010	28%	60%
Linear Flow	2010	38%	60%
Water Drive	2010	38%	60%
Conventional	2015	53%	64%
Linear Flow	2015	51%	64%
Water Drive	2015	51%	64%
Conventional	2020	82%	67%
Linear Flow	2020	82%	67%
Water Drive	2020	82%	67%

3. Chapter Summary

In the past, the regional reserve growth function of the E&P module was not completely accurate because of insufficient data. New information from the USGS has given us the chance to properly calibrate the growth function. The USGS data was cross-mapped onto GSAM regions and the annual growth rate was placed into the specification file RESAVRG.SPC for both specific regions and the United States as a whole. The current values reflect the exact projections of the USGS for the regional reserve growth rate through the year of 2020.

I. Issue-Specific Environmental Modeling

1. Background

In its assessment of environmental costs, GSAM is capable of analyzing forty to fifty technology and regulatory issues, which result in or affect environmental compliance costs. This method is very effective at providing a broad-spectrum assessment of the environmental costs associated with oil and gas resource development in each region. Recently, we modified GSAM to treat different reservoirs located in a state or region separately. When the model assesses each of the issues behind the environmental costs, it determines state average for these costs. This method is ideal for costs, which apply to most or all of the reservoir sites in a state. Unfortunately, there are some issues, which are specifically a function of one or two categories of parameters related to a field, and do not affect the other fields present in a state. As a result, the environmental costs can be adversely calculated for these issues, being calculated on a state average. Recent studies by both external and internal departments have allowed us to accurately gauge the specific costs associated with some of the issues that are highly dependent on the characteristic of a field, such as depth, resource type, etc. Since these problems had the possibility to affect the outcome of a models' calculation, it was decided to address those issues which could have an adverse impact on the calculation of environmental costs if they were calculated in a state average method.

2. Onshore Drilling Waste Management Cost (E&P Module)

Previously, the cost for onshore drilling waste was assessed on a state level average. It was felt that large variation in well depth for different fields in a state necessitated creating a field-specific calculation was ideal. The manner in which the new calculation was done rested on the average depth of the drilling and the sum of the values of four scenarios, which predicted costs. The calculations took into account the depth of the well, the type of hydraulic injection, if any, used, the cost of disposal, either off or onsite, and several other factors such as whether the waste needed to be treated, etc. When combined, these new calculations served to greatly magnify the precision of the environmental costs appropriate to each drilling site.

3. Hydraulic Fracturing Cost (E&P Module)

Many types of reservoirs, particularly coalbed methane reservoirs, utilize hydraulic fracturing to increase the ease with which gas can be extracted from the reservoirs. Recent litigation by environmental groups has raised the possibility that this action may need to be regulated by the Environmental Protection Agency as UIC under the Safe Drinking Water Act. This regulation has the ability to increase compliance costs, since studies and reports will have to be done before hydraulic fracturing could begin. As this cost is specifically associated with wells that are hydraulically fractured, it was decided that the GSAM Environmental costing model needed to be updated to include field-specific incremental costs for hydraulic fracturing. Several simulation runs were conducted to determine the formula to be used in the calculation of the increment hydraulic fracture environmental compliance cost. The table below displays the prominent considerations as applied to the environmental costs. This table presents the base cost, what percentage of the cost applies to each site type, the year where the costs apply, the depth costs apply to and which states the costs apply to.

Table II-15: Constraints for Hydraulic Fracturing Cost

Parameter	Value
Hydraulic fracturing base cost (US$)	67300
Percentage applies to conventional reservoirs	30
Percentage applies to tight reservoirs	100
Percentage applies to radial flow reservoirs	0
Percentage applies to linear flow reservoirs	100
Percentage applies to water drive reservoirs	0
Percentage applies to coalbed methane reservoirs	100
Applies to years higher than	2002
Applies to wells having depth less than (ft)	99999
Applies to states	Alabama Onshore, Montana

J. Industrial Demand Model

1. Background

The following is a description of a new Industrial Demand Module in GSAM which takes into account more detailed information than in the previous Industrial Module. The purpose of this work is to provide an industrial component which shows more variation in response to other factors that change in GSAM. In addition, such a model will presumably model the actual demand in this sector more closely.

We model the demand in this sector by considering the following four subsectors:

1. Boilers,
2. Cogeneration/Nonutility Generation (NUGS),
3. Process Heat, and
4. Feedstock.

We have made use of two plant level Access data bases: the boiler data base and the NUGS data base that we describe in the next section; see Section 4 for details on Access modules used to convert these data to ASCII form for the industrial demand FORTRAN programs.

Lease and Plant use of gas in the industrial sector is also important but is taken into account in another part of GSAM [2]. According to GRI Projections [3], these four subsectors (plus Lease & Plant) account for approximately 99% of the industrial demand for gas. The remaining category, HVAC will not initially be modeled explicitly.

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[2] See for example, the program INTRPG.FOR in the Demand and Integrating module.
[3] GRI Baseline Projection of U. S. Energy Supply and Demand, 1997 Edition, "The Contribution of Technology," August, 1996, p. 55.

Table II-16: Natural Gas Consumption by Type of Service (Trillion BTU)

Subsector	1995	2000	2005	2010	2015
Boilers	2509	2605	2911	3183	3442
Cogeneration[4]	2079	2414	2619	2780	2910
Process Heat	3149	3462	3783	4064	4345
HVAC	105	113	124	134	141
Lease & Plant	1304	1334	1385	1491	1616
Feedstocks	382	802	839	871	908
TOTAL	9528	10730	11661	12523	13362

Table II-17: Natural Gas Consumption by Type of Service (% of Total)

Subsector	1995	2000	2005	2010	2015
Boilers	2509	2605	2911	3183	3442
Cogeneration[5]	2079	2414	2619	2780	2910
Process Heat	3149	3462	3783	4064	4345
HVAC	105	113	124	134	141
Lease & Plant	1304	1334	1385	1491	1616
Feedstocks	382	802	839	871	908
TOTAL	9528	10730	11661	12523	13362

2. Data

2.1. Databases for Boilers and NUGS Subsectors

The boiler database (after pruning some variables) consists of some 31 variables and 30,853 boilers. Those records have been filtered to eliminate boilers associated with the commercial sector and keeping just those records related to the groups that burn: gas or distillate fuel, gas or residual fuel, or gas only.

[4] The cogeneration figures shown here include cogeneration in both the industrial and electrical power generation sectors. The industrial share is approximately 50% which, for 1995 would make around 1000 TBtu and a total of about 8.5 TBtu. According to AEO99, p.130, their comprable number (for 1996) is 8.53 Tcf or 8.786 TBtu.

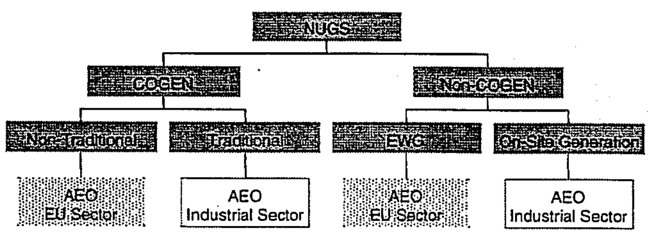
[5] The cogeneration figures shown here include cogeneration in both the industrial and electrical power generation sectors. The industrial share is approximately 50% which, for 1995 would make around 1000 TBtu and a total of about 8.5 TBtu. According to AEO99, p.130, their comprable number (for 1996) is 8.53 Tcf or 8.786 TBtu.

Table II-18: Boiler Database

Field Name	Description	Consolidation Scheme
ORIS Code	Unique Identifier	n/a
Coal Demand Region	IPM coal demand region code	n/a
Region Name	NERC Region	use region
Region Code		n/a
State Abbv		n/a
State Name		n/a
State Code		n/a
State Code No		n/a
CountyName		n/a
County Code		n/a
County Code No		n/a
CityName		n/a
City Code		n/a
PLANTID	Industrial Plant Numerical Identifier (may want to eliminate)	n/a
POINTID	Individual Boiler Indentier (may want to eliminate)	n/a
Efficienc	Boiler efficiency (Steam Btu out / Fuel Btu in)	weight by steam capacit
SCC 2x	Standard Classification Code (identifies boiler type, fuel type, end use)	n/a
SicV1	SIC code (2 digit)	n/a
SicNameV1	SIC name	n/a
NOx Base Rate	NOx emission rate (lb/mmbtu)	weight by steam capacit
SO2 Rate	SO2 emission rate (lb/mmbtu)	weight by steam capacit
CO2 Rate	CO2 emission rate (lb/mmbtu)	weight by steam capacit
IPMFuel	Major fuel type (GAS, OIL, etc)	included in consolidation
IPMFuel2	Actual subtype (resid, distillate, etc.)	included in consolidation
FuelCap	Boiler Firing Capacity (MMBtu/hr)	weight by steam capacit
SteamCap	Steam Capacity (MMBtu/hr)	weight by steam capacit
CapFac	Capacity Factor(percent of the year)	weight by steam capacit
New Steam Demand TBtu	Steam Demand (TBtu)	Total
NoxTons	Annual NOx Emission in (tons per year)	Total
CO2Tons	Annual CO2 Emission in (tons per year)	Total
Fueltype	flag for group	n/a

The NUGS database (after pruning some variables) consists of some 28 variables and 511 plants after eliminating those records associated with the commercial sector and following the scheme shown below.

Figure II-15: Breakdown of NUGS



Consequently, we apply a filter in reading in the database to only allow for plants that are either traditional cogen or on-site generation non-cogen (as well as not "commercial"). The set of variables with their descriptions appear below.

Table II-19: NUGS Database

Field Name	Description	Consolidation Scheme
RIDCODE	Unique Identifier	n/a
GEN_TYPE	COGEN or Not COGEN	n/a
TvsNT	Traditional or Non-traditional	n/a
Nonattain	Nonattainment designation (severe, etc.)	n/a
ST_abbv	State abbreviation	n/a
EEI_SIC	Edison Electric Institute SIC code (REF, CHEM, PAPR, etc.)	n/a
IPM_PF	IPM Primary Fuel/Generation Type	n/a
IPM_FUEL	IPM Primary Fuel Type Used	n/a
Input Firing Rate	Input firing rate MMBTU/hr.	summed
ipm_cap	IPM generation capacity M	summed
OnL_YEAR	Start Year	n/a
OffL_Year	Estimated End Year	n/a
Final_Nox_Rate	Final NOx Rate lbs./MmBTU	averaged
sox_est	SOx Estimate lbs./MmBTU	averaged
cap_fac	capacity factor	averaged
gen_MWh	Generation in Megawatt hours	summed
MMBtu_E	Estimated fuel usage in millions of BTU for Electricit	summed
Pwr/Ht	Power/Heat (useful BTU of Electricity/useful BTU of Steam)	averaged
MMBtuT	millions of BTU of fuel used for Thermal	summed
MMBtu_Fuel	millions of BTU of fuel used	summed
HeatRate	BTU per kWh	averaged
NetHeatRate	BTU per kWh ([Total fuel used – Fuel for steam]/kWh)	averaged
Sox_TonsR	SOx Tons Rate lbs./MmBTU	averaged
Nox_TonsR	NOx Tons Rate lbs./MmBTU	averaged
CO2_EmisRate	CO2 Emissions Rate lbs./MmBTU	averaged
CO2_MMtons	CO2 Emissions in Tons mm Metric Tons	summed
Secondary Fuel		n/a
EWG		n/a
fueltype	Flag for group	n/a

We distinguish the following groups within the Boiler and NUGS subsectors:

Table II-20: Designation of Subsectoral Demand

Subsector	Group	Fuels Burned	Size	Firm or Interruptible[6]
Boilers[7]	1	gas or distillate	small	interruptible
	2	gas or resid	small	interruptible
	3	gas only	small	firm
	4	gas or distillate	large	interruptible
	5	gas or resid	large	interruptible
	6	gas only	large	firm
NUGS[8]	1	gas or distillate	small	interruptible
	2	gas or resid	small	interruptible
	3	gas or distillate	large	interruptible
	4	gas or resid	large	interruptible

The point of these groups is to consolidate the data from individual plants and boilers into groups for eventual use in the Integrating LP. If this is not done, the number of combinations between individual plants/boilers, seasons, years, regions is too large from a computational point of view.

2.2. Databases for Process Heat and Feedstock Subsectors

In addition to the Boilers and NUGS databases, the new Industrial model also takes into account the data for the Process Heat and Feedstock subsectors; at this time, we only consider aggregate demand. These databases were derived from the GRI topical report, "1998 Industrial Trends Analysis", October 1998.

Since the GRI report used Census regions which do not exactly match with GSAM regions, the following crosswalking scheme was applied. For GSAM regions that were subunits of a Census Division, Process Heat or Feedstock demand was weighted in 1995 by industrial GRP in 1995. Thus, for example, since the Pacific Northwest region made up 22 percent of the industrial GRP in the Pacific it was given 22 percent of the Process heat or Feedstock demand for natural gas.

[6] Note that by "interruptible" we mean the ability to be interrupted since the associated plants/sites are dual fueled.
[7] These six groups comprised approximately 98% of the capacity from the boiler data base. The remaining 2% was divided between units that used coal and gas, other and gas, and it was not clear that using them would add much to the model.
[8] These four groups comprised approximately 98% of the capacity from the NUGS data base. The remaining 2% was divided between units that used coal and gas, other and gas, and it was not clear that using them would add much to the model.

The GRI report included explicit Process Heat demand numbers (although a corrected copy of the table needed to be sent). This report did not however, explicitly contain demand for natural gas in the Feedstock subsector. To overcome this deficiency, the demand data for this subsector was based on taking the a certain percentage of the total energy demand for feedstock in that region. These percentages for 1995 were derived from the national ratio of natural gas to total energy for the Feedstock subsector. The Feedstock total energy as well as the national percentages were derived from the GR report.

2.3. Regional Data

In addition to the two cross-sectional databases, we compiled the following cross-sectional, time series data which for use in determining elasticities and other parameters:

Table II-21: Sample of the Data Gathered for Computing Elasticities (For each GSAM region)

year	Industrial Sector Natural Gas Price ($/Mcf)	Industrial Sector Distillate Price ($/Mcf)	Industrial Sector Resid Price ($/Mcf)	Industrial Sector Consumption (Tcf)
1997				
1998				
.				
.				
.				
2020				

Forecast data from 1997 to 2020 were obtained for natural gas, distillate, and residual prices and consumption in the industrial sector. All price and consumption industrial data was derived from the AEO 1999 Supplement Tables published by the EIA.

The regional data in the AEO correspond to the US Census Bureau regional divisions of New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain, and Pacific. However, these regions do not necessarily correspond to GSAM divisions. The Pacific, Mountain, and South Atlantic Regions were broken up into the following GSAM regions:

U.S. Census Region	GSAM Region
Pacific	Pacific Northwest, California, Non-contiguous U.S.
Mountain	Mountain North, Mountain South
South Atlantic	South Atlantic, Florida

* Information for Hawaii and Alaska was excluded in the final analysis

The quantities consumed for natural gas, distillate, and residual were divided into the various GSAM regions according to the Industrial Gross State Product (GSP) forecasts, produced by the Bureau of Economic Analysis (BEA). For example, if California's industrial GSP comprises 75 percent of the Pacific region's industrial GSP for a given year, then California would consume 75 percent of the fuel utilized in the industrial sector in the Pacific region for that year. The fuel prices in the GSAM regions were assumed to be the same as the associated U.S. Census Division. Thus, the industrial price for distillate in California would be the same as the industrial distillate price for the Pacific region. The BEA Industrial GSP forecasts are given in five-year increments.

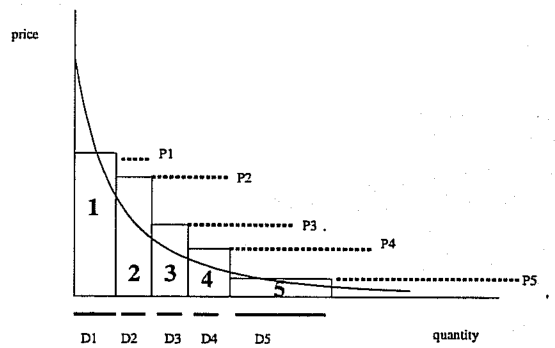
For this analysis, the ratios of each state's industrial GSP to its associated U.S. Census were calculated in five-year increments. The ratios of the intervening years were assumed to be the same as share of the previous five-year increment. Thus, California's share of industrial GSP in the Pacific region in 1998 would be the same as its share in 1995; its share in 2003 would be the same as its share in the year 2000 and so on.

3. Mathematical Formulations for the New Industrial Demand Module

3.1. Explanation of the Step-Function Approximation to the Demand Curves

Based on the boiler and NUGS data bases, we generated demand models for eventual use in the Integrating LP. However, in order to incoportate the demand curves into the LP, the Demand Module needs to take the demand curves and break them into blocks as shown below.

Figure II-16: Sample Discretization of a Demand Curve



In particular, using this example, the demand module first estimates the smooth curve shown below by sampling the demand at the prices $p_1, p_2, \ldots, p_5$ generating the associated demand levels

$D_1, (D_1 + D_2), \ldots, \left(\sum_{j=1}^{5} D_j\right)$. The LP then solves for the optimal demand levels based on matching supply and demand in addition to a host of other factors. Note that in the objective function, there are terms of the form $-\sum_{j=1}^{5} D_j * P_j$ which estimate the (negative of the) area under the demand curve which is part of the objective to be optimized. Also, since we are minimizing the objective function and since the prices are strictly decreasing, all of demand level D_j will be picked before selecting the next demand level D_{j+1}. This result is necessary in order for the step function approximation to operate properly.

3.2. Notation for New Variables

To account for the demand for gas in the four industrial subsectors under consideration, we define the following new notation:

Boilers

1. DBntjlg = seasonal boiler demand for gas in MMcf/day for region n, time t, group g, season l, segment j (g=1,2,4,5 dual-fuel demand)

2. DBntjg = annual boiler demand for gas in MMcf/day for region n, time t, group g, segment j (g=3,6 firm demand), ***no seasonal aspect***

NUGS

3. DNntjlg = seasonal NUGS demand for gas in MMcf/day for region n, time t, group g, season l, segment j (g=1,2,3,4 dual-fuel demand)

Process Heat

4. DPnt = annual process heat demand for gas in MMcf/day for region n, time t (we will just hardwire this to a given value for now, later on we may build an appropriate demand curve), ***no seasonal aspect***

Feedstock

5. DFnt = annual feedstock demand for gas in MMcf/day for region n, time t (we will just hardwire this to a given value for now, later on we may build an appropriate demand curve), ***no seasonal aspect***

Note that this notation only covers existing sites without retirements at the present time. We anticipate implementing a retirement factor to decrease the amount of demand over time as well as adding the possibility of new demand as well. Also, we anticipate adding a technology improvement component to be applied over time.

3.3. Models for Industrial Demand

Using SAS, we tried a variety of functional forms eventually settling on the following three:

for gas/distillate

(1) $$q_{ntg} = q^{o}_{nt_0 g}\left(\frac{\text{Energy Intensity}_{nt}}{\text{Energy Intensity}^{o}_{nt_0}}\right)^{\alpha_n}\left(\frac{\text{gas price}_{nt}}{\text{gas price}^{o}_{nt}}\right)^{\beta_n}\left(\frac{\text{distillate price}_{nt}}{\text{distillate price}^{o}_{nt}}\right)^{\gamma_n}$$

for gas/residual fuel oil

(2) $$q_{ntg} = q^{o}_{nt_0 g}\left(\frac{\text{Energy Intensity}_{nt}}{\text{Energy Intensity}^{o}_{nt_0}}\right)^{\alpha_n}\left(\frac{\text{gas price}_{nt}}{\text{gas price}^{o}_{nt}}\right)^{\beta_n}\left(\frac{\text{resid price}_{nt}}{\text{resid price}^{o}_{nt}}\right)^{\gamma_n}$$

for gas only

(3) $$q_{ntg} = q^{o}_{nt_0 g}\left(\frac{\text{Energy Intensity}_{nt}}{\text{Energy Intensity}^{o}_{nt_0}}\right)^{\alpha_n}\left(\frac{\text{gas price}_{nt}}{\text{gas price}^{o}_{nt_0}}\right)^{\beta_n}$$

where

q_{ntg} = quantity demanded for group g, region n, time t

$q^{o}_{nt_0 g}$ = base quantity demanded for group g, region n, time t_0 (i.e., the value in 1995)

Energy Intensity$_{nt}$ = ratio of industrial sector output to GRP for region n, time t

Energy Intensity$^{o}_{nt_0}$ =base year ratio of industrial sector output to GRP for region n, time t

gas price$_{nt}$ = the price of gas ($/Mcf)

gas price$^{o}_{nt_0}$ = the base year price of gas ($/Mcf)

distillate price$_{nt}$ = the price of distillate ($/Mcf)

distillate price$^{o}_{nt_0}$ = the base year price of distillate ($/Mcf)

resid price$_{nt}$ = the price of resid ($/Mcf)

resid price$^{o}_{nt_0}$ = the base year price of resid ($/Mcf)

$\alpha_n, \beta_n, \gamma_n$ = elasticities that were computed using a regression analysis

3.4. Modifications to the Integrating LP

The inclusion of the new industrial demand model in the Integrating LP occurred in three places:

- The material balance constraints MBntl,
- The daily cost accumulations part of the objective function CCDtl, and
- The annual cost accumulations part of the objective function CCAt.

In the material balance constraints, we use the following terms (in place of the current industrial demand terms):

(units are MMcf/day)

(6)	total interruptible boiler demand	$\sum_j \sum_g DB_{ntjlg}$
(7)	total firm boiler demand	$\sum_j \sum_g DB_{ntjg} * idmldf(l,n)$
(8)	total interruptible NUGS demand	$\sum_j \sum_g DN_{ntjlg}$
(9)	total process heat demand	$DP_{nt} * idmldf(l,n)$
(10)	total feedstock demand	$DF_{nt} * idmldf(l,n)$

where idmldf(l,n) is the industrial demand load factor for season l and region n, and the process heat and feedstock values are hardwired to values that are read in from a file.

In the daily cost accumulations sections, the following terms are to be used (in place of the current industrial demand terms):

(units are thousands of dollars/day)

(11)	total interruptible boiler demand	$\sum_j \sum_g DB_{ntjlg} *(-tprc_j)$
(12)	total firm boiler demand	$\sum_j \sum_g DB_{ntjg} * idmldf(l,n)*(-trpc_j)$
(13)	total interruptible NUGS demand	$\sum_j \sum_g DN_{ntjlg} *(-tprc_j)$
(14)	total process heat demand	$DP_{nt} * idmldf(l,n)* tprc_1$
(15)	total feedstock demand	$DF_{nt} * idmldf(l,n)* tprc_1$

where $tprc_j$ is the price of the jth segment. For boiler and NUGS demand, these prices are sampled fro a range that is defined by the user. For process heat and feedstocks, since the demand will be hardwired, we will need to find a reaonable price for $tprc_1$, currently a value of 1.0 is used.

In the annual cost accumulations sections, we will need to add terms relating to capital costs and possibly other factors for the new boilers and NUGS units. For now we will hold off on using this section.

3.5. Generation of Regional Demand Curves Process Heat and Feedstock Subsectors

To model the Process Heat and Feedstock subsectors, we read in exogenous data on demand in these two sectors and force the model to use these forecasts. At a later date, we anticipate generating a step-function approximation (as shown above) but without the micro-level demand models behind it.

4. Organization of Access Modules to Read the Boiler and NUGS Databases

The Access boiler data base was converted to an ASCII file, boilers.spc, using the following Access module.

```
Option Compare Database
Option Explicit

Sub WriteBoilerToAscii()
'This function writes the boiler data to an ascii file

'Declare variable for database,table,ascii file
   Dim db As Database
   Dim tbl As Recordset
   Dim lngFile As Long

' Find number for ascii file and open
   lngFile = FreeFile
   Open "e:\gsam\industrial\boilers.spc" For Output As #lngFile


'Assign database and table to appropriate variables
   Set db = CurrentDb
   Set tbl = db.OpenRecordset("SELECT * FROM [ICI Boilers Final (filtered)] ORDER BY [ORIS
Code]", dbOpenSnapshot)

'Write the data to the file
   While Not tbl.EOF
      Print #lngFile, _
         Format$(Format$(Nz(tbl![ORIS Code], -1), "#########0"), "@@@@@@@@@@");
Format$(Format$(Nz(tbl![Coal Demand Region], -1), "####0"), "@@@@@"); _
         Format$(UCase$(Nz(tbl![Region Name], " ")), "@@@@@@@@@@"); Format$(Format$(Nz(tbl![Region
Code], -1), "####0"), "@@@@@"); _
         Format$(UCase$(Nz(tbl![State Abbv], " ")), "@@"); Format$(UCase$(Nz(tbl![State Name], "
")), "@@@@@@@@@@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl![State Code], " ")), "@@@@@"); Format$(Format$(Nz(tbl![State Code
No], -1), "####0"), "@@@@@"); _
         Format$(UCase$(Nz(tbl!CountyName, " ")), "@@@@@@@@@@@@@@@@@@@@@");
Format$(UCase$(Nz(tbl![County Code], " ")), "@@@@@"); _
         Format$(Format$(Nz(tbl![County Code No], -1), "####0"), "@@@@@");
Format$(UCase$(Nz(tbl!CityName, " ")), "@@@@@@@@@@@@@@@@@@@@@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl![City Code], " ")), "@@@@@@@@@@@@@@@");
Format$(UCase$(Nz(tbl!PLANTID, " ")), "@@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl!POINTID, " ")), "@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!Efficiency, -1), "######0.00"), "@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl![SCC 2x], " ")), "@@@@@@@@@@"); Format$(UCase$(Nz(tbl!SicV1, "
")), "@@@@@"); _
         Format$(UCase$(Nz(tbl!SicNameV1, " ")), "@@@@@@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl![NOx Base Rate], -1), "####0.0000"), "@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl![SO2 Rate], -1), "##########0.00000000"),
"@@@@@@@@@@@@@@@@@@@@"); Format$(Format$(Nz(tbl![CO2 Rate], -1), "##########0.00000000"),
"@@@@@@@@@@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl!IPMFuel, " ")), "@@@@@@@@@@"); Format$(UCase$(Nz(tbl!IPMFuel2, "
")), "@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!FuelCap, -1), "###########0.00"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!SteamCap, -1), "########0.00000"), "@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!CapFac, -1), "###############0.00000000"),
"@@@@@@@@@@@@@@@@@@@@@@@@@"); Format$(Format$(Nz(tbl![New Steam Demand TBtu], -1),
"###############0.00000000"), "@@@@@@@@@@@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!NOxTons, -1), "##############0.0000"), "@@@@@@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!CO2Tons, -1), "##############0.0000"), "@@@@@@@@@@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl!FuelSwitch, " ")), "@@@@@@@@@@@@@@@")
```

```
            tbl.MoveNext
Wend
'Close and reset variables
   Close #lngFile
   tbl.Close
   Set tbl = Nothing
   db.Close
   Set db = Nothing

End Sub
```

The NUGS data base was converted to and ASCII file using the following Access module.

```
Option Compare Database
Option Explicit

Sub WriteNugsToAscii()
'This function writes the nugs data to an ascii file

'Declare variable for database,table,ascii file
   Dim db As Database
   Dim tbl As Recordset
   Dim lngFile As Long

' Find number for ascii file and open
   lngFile = FreeFile
   Open "e:\gsam\industrial\nugs.spc" For Output As #lngFile


'Assign database and table to appropriate variables
   Set db = CurrentDb
   Set tbl = db.OpenRecordset("SELECT * FROM [Nugs_Final_Gabriel (filtered)] ORDER BY RIDCODE",
dbOpenSnapshot)

'Write the data to the file
   While Not tbl.EOF
      Print #lngFile, _
         Format$(Format$(Nz(tbl!RIDCODE, -1), "##########0"), "@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl![ElectricModel V2], " ")), "@"); _
         Format$(UCase$(Nz(tbl!GEN_TYPE, " ")), "@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl!TvsNT, " ")), "@@@@@@@@@@"); Format$(UCase$(Nz(tbl!Nonattain, "
")), "@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl!ST_abbv, " ")), "@@"); _
         Format$(UCase$(Nz(tbl!EEI_SIC, " ")), "@@@@@@@@@@"); Format$(UCase$(Nz(tbl!IPM_PF, "
")), "@@@@@@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl!IPM_FUEL, " ")), "@@@@@@@@@@"); Format$(UCase$(Nz(tbl![Fuel
Description], " ")), "@@@@@@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl![Input Firing Rate], -1), "###########0.00"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!ipm_cap, -1), "###########0.00"), "@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!OnL_YEAR, -1), "#########0"), "@@@@@@@@@@");
Format$(Format$(Nz(tbl!OffL_Year, -1), "#########0"), "@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!Final_Nox_Rate, -1), "########0.00000"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!sox_est, -1), "########0.00000"), "@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!cap_fac, -1), "########0.00000"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!gen_MWh, -1), "###########0.00"), "@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!MMBtu_E, -1), "###########0.00"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl![Pwr/Ht], -1), "########0.00000"), "@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!MMBtuT, -1), "###########0.00"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!MMBtu_Fuel, -1), "###########0.00"), "@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!HeatRate, -1), "#######0.0"), "@@@@@@@@@@");
Format$(Format$(Nz(tbl!NetHeatRate, -1), "#######0.0"), "@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!Sox_TonsR, -1), "########0.00000"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!Nox_TonsR, -1), "########0.00000"), "@@@@@@@@@@@@@@@"); _
         Format$(Format$(Nz(tbl!CO2_EmisRate, -1), "########0.00000"), "@@@@@@@@@@@@@@@");
Format$(Format$(Nz(tbl!CO2_MMtons, -1), "########0.00000"), "@@@@@@@@@@@@@@@"); _
         Format$(UCase$(Nz(tbl!SecondaryFuel, " ")), "@@@@@@@@@@@@@@@");
Format$(UCase$(Nz(tbl!EWG, " ")), "@@"); _
         Format$(UCase$(Nz(tbl!FuelSwitch, " ")), "@@@@@@@@@@@@@@@")

         tbl.MoveNext
   Wend

'Close and reset variables
Close #lngFile
```

```
    tbl.Close
    Set tbl = Nothing
    db.Close
    Set db = Nothing

End Sub
```

5. FORTRAN Programs

The industrial model consisted of a set of FORTRAN programs that were added to the existing code for the downstream model. These new programs fell into two main categories: read in the data and create the industrial demand information for the linear programming MPS files. The organization of these programs is shown below.

Figure II-17: FORTRAN Programs to Read in the data

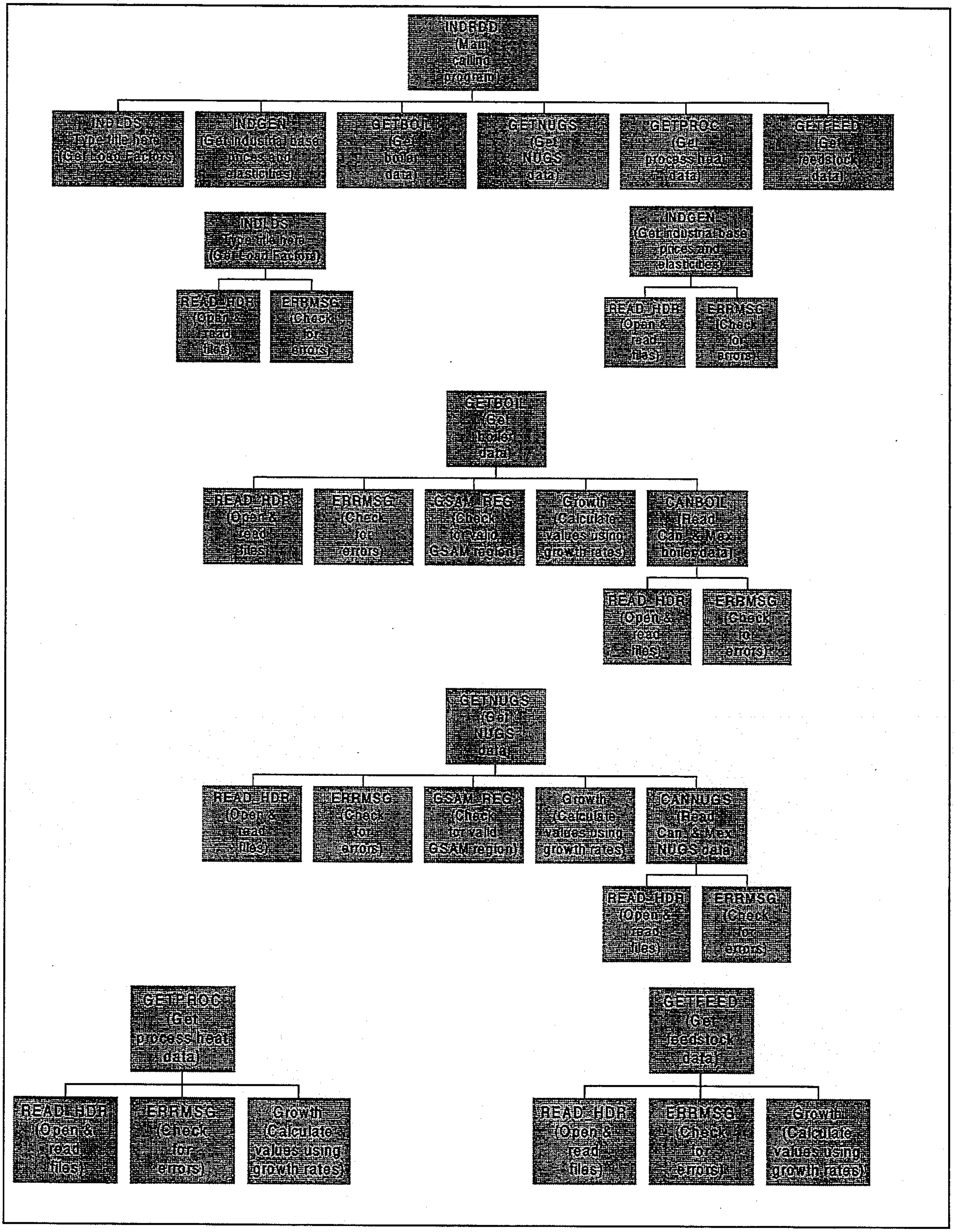
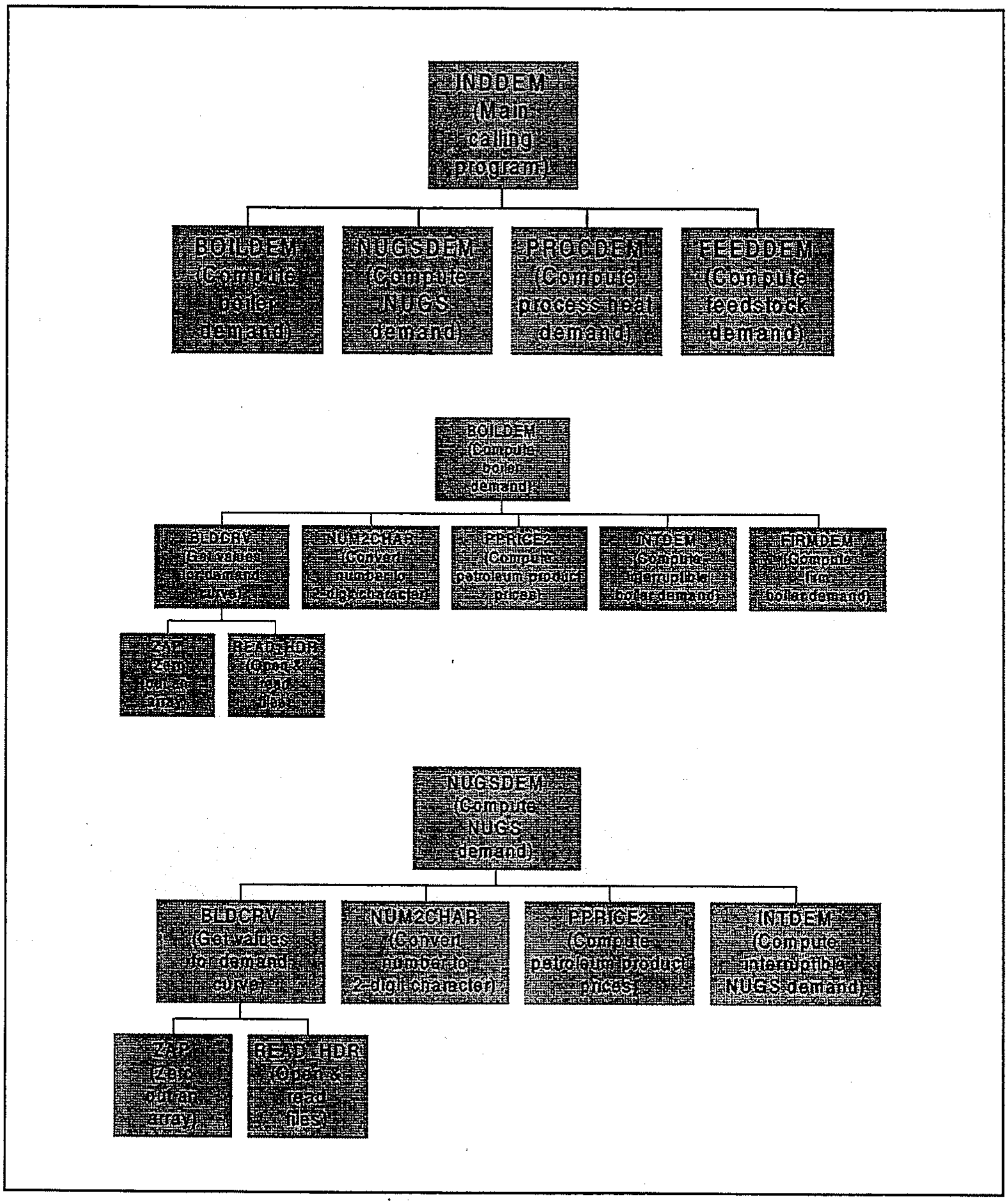


Figure II-18: FORTRAN Programs to Generate Demand by Subsector and Write to the MPS Files



K. UPDATES ON GSAM ANNUAL MODEL

1. Background

This section describes some additional changes to the Demand and Integrating modules that we have made during the previous fiscal year.

2. New Supply Load Factors

We modified the GSAM FORTRAN code to allow for greater seasonal variation in the production levels for supply regions. In particular, we now have a file (sup_ld.spc) which indicates by region the supply seasonal load factor. A value of 1.0 indicating an average day for the year, a value of 1.5 indicating a 50% increase for days in the particular season in question. This extra detail on converting annual production levels from the Exploration & Production Module to seasonal values was important in the calibration efforts in converting GSAM to an annual model.

3. Allowing Wholesale-to-Retail Markups to Vary Over Time

We modified the downstream model to allow for sectoral markups to vary over time (the sectors being: residential, commercial, industrial, and electrical power generation). Now, for instance, the residential sector markup that translates citygate or wholesale prices to burnertip (i.e., retail) prices is allowed to change over time. The flexibility of this new feature allows one to simulate the effects of deregulation/restructuring wherein the level of competition and consequently the markup factor could change.

4. Producing Seasonal Reports

We added the feature of producing seasonal reports to GSAM; the file that contains the relevant data is "gsamsln.sea". These reports provide both quantity and price data for each region and season each year thus allowing the user to gain a fairly complete picture of how things are changing.

5. Allowing for Weather Influence

To allow for yearly impacts of weather on demand (either forecasts or historical values), we added the file "weather.spc". This new file contains data on heating useful for modifying winter demand in the residential, commercial, and industrial sectors. This file also include cooling data useful for the electrical power sector in the summer (i.e., air conditioning demands for natural gas).

6. Allowing Heat Rates to Vary by Vintage

We modified GSAM to allow the heat rates (btus/kwh) to vary not only by plant type but also by plant vintage. Previously, they had only varied by plant type.

L. MODIFICATION TO COST FILES IN PRODUCTION AND ACCOUNTING MODULE

1. Consistency of Cost Files between RP and P&A Modules

The method in which data has been recorded in the costing files has always been identical, regardless of whether the file was for the Reservoir Performance (RP) module or the Production and Accounting (P&A) module. However, a problem with the consistency of the costing files arose because of the manner in which the RP and the P&A modules were coded to identify the costing files. The RP module uses multiple costing files to represent all of the regions, which the model deals with. Conversely, the P&A module can only read one costing file. Hence, the RP module can be "run" at multiple cost files (by copying appropriate costing file in generic cost.dat file corresponding to the .GSM file), P&A can only take one cost file and can misrepresent costs.

The outcome would be that costing calculation in the P&A model would be accurate only for the cost file, which was applicable to the particular region but would be incorrect for other regions. To remedy this problem, a new costing file was created. The new costing file held all the costing information for all the regions that the model deals with at one place. Figure II-19 shows a section of the new cost file that contains regional cost information. The P&A module was then modified to accept this costing file. The RP module was also modified accordingly.

Figure II-19: Example of New Costing File with Selected Regions Displayed

```
C*** Number of Regions (Excluding Default - 99)
12
Region#   Number of Steps
01          1                (Appalachia)
Max. Depth     $/Well     $/(Well-ft)
C---------  C---------  C----------
 15000.0      1003.1      0.40
Region#   Number of Steps
14          1                (Gulf of Mexico-East)
Max. Depth     $/Well     $/(Well-ft)
C---------  C---------  C----------
 15000.0    298786.0      0.00
Region#   Number of Steps
99          1                (Default)
Max. Depth     $/Well     $/(Well-ft)
C---------  C---------  C----------
 15000.0      8869.0      1.44
```

The inherent costs for the reservoir performance module and the production and accounting module must also take into account the impact of technology on different aspects of drilling, production, etc. As part of the need for technology, the two modules take technology files into their computation of costs. These technology files have been set up in the same manner as the earlier costing files, i.e. the reservoir performance module reads in a variety of files for different regions while the production and accounting module can only take in one file. Currently, efforts are underway to redesign the necessary technology files and to modify the code to accept the new files. The current expectation is that these changes will be in place by the end of the next fiscal year.

2. Chapter Summary

The manner in which the R&P module and the P&A module has accepted costing files has created some problems in ensuring compatibility and ease of use. To change this problem, we modified the necessary costing files so that they would contain all the necessary cost information for all regions that the modules cover in one file. We then modified the code of the RP module and the P&A module to ensure that it could facilitate the new changes. Currently we are undergoing the same process of change with the technology files that the two modules utilize. We expect these changes to be incorporated into the modules by the end of the next fiscal year.

M. INSTALLATION OF GSAM VERSION 1999 AT FETC

1. Delivered Models

Three employees of ICF Consulting, David Ribar, Steve Gabriel, and Shree Vikas, met with Mr. Ray Boswell of FETC and delivered five modules of GSAM. These modules encompassed all aspects of GSAM and were all at their most accurate phase of development when they were delivered. The modules delivered were the Reservoir Performance (RP) module, the Exploration and Production (E&P) module, the Production and Accounting (P&A) module, the Demand and Integrating (D&I) module, and the Storage Reservoir Performance module (SRPM). The delivery and installation of the SRPM was done for the first time at FETC. Prior to its delivery, the SRPM was updated and calibrated based upon the 1997 Energy Information Administration and American Gas Association information.

2. Ran Cases for Client

During their meeting with Mr. Boswell, the employees of ICF Consulting preformed a full, overnight, demonstration of various modules. The employees discussed in depth the uses of the different modules and the specific requirements of each module. The employees installed the modules on Mr. Boswell's computer and insured that all hardware and software needs regarding its usage were met. After demonstrating the use of all the modules, the employees answered questions that Mr. Boswell posed to them. Since this time they have continued to provide support to Mr. Boswell in running and understanding various sections of GSAM.

3. Chapter Summary

ICF Consulting has ensured that all requirements regarding the installation of GSAM Version 1999 at FETC have been met. We ensured that the most recent aspects of all the modules of GSAM have been included and that FETC has been fully exposed to their uses and needs. Furthermore, ICF Consulting has insured continued support on all aspects of GSAM use by FETC.

III. CONCLUSION

During the period of July 1, 1998 to September 30, 1999, several enhancements have been implemented to GSAM's database and computer model. Furthermore, new specification files have been created and new modeling approaches have been implemented. These modifications and new developments in GSAM improve its overall performance and increase its ability and flexibility to control various modeling parameters. The key improvements in GSAM are summarized below:

- GSAM is able to control proportion of exploration and development activities in Federal lands
- New tight reservoir model eliminates doubling effect in horizontal well production and provides consistent performance between hydraulically fractured and horizontal wells
- Drilling cost model differentiates the onshore and offshore wells
- Storage Reservoir Performance Module provides data that is consistent with injection/extraction programs in Demand and Integrating Module
- New exploration drilling algorithm increases number of exploration wells
- The new breakeven drilling cost formulation is able to control utilization and transportation of drilling rig capacity
- The breakeven drilling cost factor is used together with the MASP to rank the development and exploration projects