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Fracture Diagnostics Research at the GRI/DOE Multi-Site Project: Overview of the Concept and Results

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Abstract

The Multi-Site Hydraulic Fracture Diagnostic Project was initiated to develop independent diagnostic technologies and methodologies that will result in increased accuracy in measuring hydraulic fracture dimensions. Through a series of field experiments, the project has provided key insights into the time-dependent growth and total dimensions of hydraulic fractures. Wireline-retrievable and cemented-in triaxial accelerometer arrays provide the basis for plan and profile maps of microseismic events associated with the hydraulic fracture. A vertical inclinometer array provides data on the earth's mechanical response to fracture opening and closure.

A directionally drilled wellbore remotely intersected the hydraulic fracture interval, verified the accuracy of microseismically imaged hydraulic fracture azimuth, and provided ground-truth observations on the far-field character of hydraulic fractures. Although eleven far-field hydraulic fractures were observed, it cannot be definitively determined if they are the result of multiple injections. Collectively, data resulting from M-Site research indicate that hydraulic fracture wings are not always symmetrical, rapidly attain their full length extent with only limited fracture height growth, and that hydraulic fractures propagated only with fluid retain their width for a long time period. Although these results apply to the zones being tested at the M-Site, they should also transfer to other zones with comparable thickness and stress contrast.

Introduction

Project Objective and Initiation Logic. The jointly funded Gas Research Institute (GRI) and U.S. Department of Energy (DOE) Multi-Site (M-Site) Project is focused on performing field-scale experiments and gathering high-quality, independent diagnostic data that will result in increased accuracy in measuring hydraulic fracture dimensions. The ultimate goal of the project is to develop the hardware and methodology necessary to establish a microseismic-based system that can be used as the foundation for a commercial hydraulic fracture mapping capability.

Several inter-related technology- and economics-based reasons prompted GRI and DOE to initiate a project of this magnitude. Each organization has a long history of supporting research directed toward determining the size and shape of hydraulic fractures. These research efforts include the development of real-time models for history matching of fracture treatment pressures, the collection and analysis of rock and reservoir properties that control fracture growth (e.g., in-situ stresses and rock properties), the estimation of fracture length and conductivity based on production, and the development of various fracture diagnostics for azimuth and height measurement. However, throughout all of these efforts, no reliable tool or technique was developed for determining the total fracture extent, primarily because of the difficulty in estimating fracture length.

Fracture modeling is currently the most common method for estimating hydraulic fracture extent. However, without a definitive method for imaging or mapping the hydraulic fracture extent there is no field-scale ground-truth measurement with which to compare fracture model results. Lacking an accurate measurement of fracture dimensions, modelers and stimulation treatment designers are likely to continue to have diverse opinions regarding the importance of various fracturing mechanisms (e.g., tip effects, complex fracturing and height growth) and controlling parameters (e.g., closure stress measurements and in-situ modulus). Thus, a reliable fracture mapping technique could begin to provide data that results in resolution of the disagreements, thereby

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enabling a more systematic and uniform analysis of hydraulic fracture data.

The potential economic impact of providing a reliable fracture mapping technique to the industry provides the real driving force for having initiated the project. Resolving the issues associated with model mechanisms and fracturing technology will have significant effects on treatment design and therefore fracturing economics. These issues are becoming even more vital as the domestic industry attempts to access the more marginally economic gas reserves. For example, real-time mapping of a hydraulic fracture (particularly when coupled with a real-time model) would allow the field engineer to make adjustments to the treatment to optimize results and raise the level of confidence as to the actual length and orientation of the fractures. Hydraulic fracture maps and novel stimulation approaches could also be used to optimize treatments on wells in the same field and to plan field development (e.g., spacing and well pattern).

Evolving from an R&D Project to Commercially Available Technology. The M-Site Project, as will become evident in the remainder of this technical paper, includes comprehensive instrumentation arrays and facilities which represent a technology system whose scale is beyond that which is envisioned for the commercial fracture mapping capability. However, this complex system is essential while in the research mode to develop and synthesize the various data sets and analytical methods into a cohesive framework. The comprehensive arrays provide an accurate baseline against which the reduced-scale commercial system can be compared. The end result of the M-Site research phase will be simplified and calibrated fracture diagnostics tools and techniques which provide complementary, yet independent, information regarding hydraulic fracture growth and final dimensions.

With confidence in the accuracy of the results and reliability of the technology, the next logical steps are technology demonstration coop wells and, ultimately, commercialization of the fracture mapping technique. A commercialization partner has been working with of the M-Site contractor team in the research phase of the project. This partner has invested in unique equipment and instrumentation, similar in scale to a wireline logging truck, which has been fielded in tandem with the permanent instrumentation arrays at the site. The experience gained by the commercialization partner, having participated in the research program, will then be carried forth into the demonstration project and ultimately to a fully independent, commercial service.

Site Characteristics. The site of the former DOE Multi-Well Experiment (MWX) near Rifle, Colorado (Figure 1) was chosen for the fracture diagnostics and fracture technology experiments included in the M-Site Project. The site was found to be attractive for several reasons: 1) multiple thick, laterally continuous sandstone units were known to be present in the upper Mesaverde Group at reasonable operating depths; 2) extensive background data from the MWX project (e.g., cores and core analyses, logs, stress magnitude and direction data, well tests, geophysical data, hydraulic fracture data) were archived and available; 3) the closely spaced MWX wellbores (see Figure 1) were available for continued research; and 4) surface infrastructure which would facilitate the implementation of the project was already in place.

Figure 2 illustrates a cross-section which includes the informally designated A, B and C Sands which were targeted for M-Site fracture diagnostics research. This cross-section illustrates several key points: 1) the stacked character of the sandstone units allows for a staged research program to be implemented (i.e., research work proceeds from the deepest to the shallowest interval, "using up" each sand interval before testing begins in the next un-fractured sand interval with a new set of experiment goals); 2) sandstone units are separated by shale, mudstone, and siltstone of sufficient thickness to reduce the risk of propagating fractures from one target sand zone to another; 3) the continuity and thickness of the target sand units remains relatively constant across the site and therefore provides a suitable subsurface laboratory for conducting fracture diagnostics experiments; 4) the relatively shallow depths (i.e., 4000 - 5000 ft) decrease operational costs associated with conducting experiments and promote higher-quality data acquisition from surface-deployed instrument arrays.

The reservoir characteristics of the M-Site targeted sand units are reasonably well known through data collected and analyzed in the MWX and M-Site research programs. Reservoir permeabilities of the A, B, and C Sands range from 0.01 to 0.1 md as determined by core analysis and analysis of extended shut-ins following stress tests. The reservoirs are normally pressured, and core and borehole image log data (including data from deviated boreholes) indicate few natural fractures. The lithologies separating the A-, B-, and C-Sand units are mixed siltstone, mudstone, and shale which result in a variable range of laminated stresses ranging from 700 to 1500 psi. Log analyses indicate that the A-, B- and C-Sand units are highly water saturated and are not considered to be capable of sustained gas production. However, the rock does have sufficient gas saturation to be a compressible system and to allow fluid leakoff during injections. Overall, the M-Site targeted sand units do not have a significant distinction from many tight gas reservoirs which are hydraulically stimulated for production on a routine basis. The implication is that the technology developed from M-Site research could be successfully extrapolated to many other areas and formations.

Technology Basics. Two fracture diagnostics technologies are the focus of M-Site R&D. The primary M-Site technology development effort is the application of subsurface triaxial accelerometers for detection and location of microseismic signals associated with hydraulic fracturing. A triaxial receiver system must be able to faithfully detect the particle motion of impinging seismic waves to accurately determine the compressional (p) and shear (s) arrival times and the directionality of the p-wave particle motion. Accelerometers are installed at M-Site because of their superior frequency response and lower noise floor (at high frequencies) than geophones. Such characteristics are critical for accurate detection of low amplitude microseismic events.

A single triaxial accelerometer may be used to approximate microseismic event locations, but a vertical array provides the most accuracy in locating seismic events. Plan and profile microseismic event maps can then be developed to image the hydraulic fracture at any point in its growth history. Multi-level accelerometer instruments are envisioned as the most practical and economical way to obtain fast, accurate seismic data for fracture diagnostics.

The supporting fracture diagnostics technology being developed involves the application of a vertical array of subsurface inclinometers to detect the mechanical response of the earth to hydraulic fracturing. These data can be used directly to assess earth tilt associated with fracture inflation and deflation, or entered into a homogenous or finite element model to interpret fracture dimensions. Inclinometers are the subsurface equivalent to tiltmeters which are normally employed at ground level to measure deflections in the earth's surface in response to hydraulic fracturing. This instrumentation is extremely sensitive and provides nanoradian-accuracy data.

A variety of standard approaches to assessing hydraulic fractures are also included in the M-Site project. These approaches include acquisition of bottomhole treating pressures to be entered into 3-D models and use of radioactive tracers for assessing near-wellbore fracture height with wireline logging tools.

Results

M-Site field work and data analyses began in October 1992 and are scheduled for completion by the end of 1996. Within this overall time framework, the M-Site research program can be subdivided into following elements: A-Sand Experiments, Facilities and Capabilities Expansion, B-Sand Fracture Diagnostics Experiments, and B-Sand Fracture Intersection Well, and Future Work. The objectives and results of each of these project elements are discussed in the following sections.

A-Sand Experiments. Two sets of experiments were performed in the A Sand, one in October 1992 and another in November 1993. Both sets of experiments were conducted using MWX-3 as the injection well and MWX-2 as a seismic observation well (Figure 3). Previous research in the MWX project had provided reasonable confidence that hydraulic fracture azimuth at the site ranged from N72°W to N80°W. Thus, as shown in Figure 3, the hydraulic fracture azimuth and MWX wellbore layouts were ideal for imaging fracture extent.

The initial A-Sand efforts consisted of limited-scope experiments and data acquisition to verify the suitability of the wellbores and assess the capability of remotely detecting seismic signals generated during a minifrac using a single triaxial accelerometer.[2] These assessments provided the following conclusions:

- Wellbore and cement conditions of the MWX-2 and MWX-3 wells were suitable for acquiring high-quality seismic signals with low ambient noise levels.
- Log-derived stress data calibrated with in-situ stress test data confirms that a stress contrast ranging from 500 to 1,000 psi exists between the target sandstone units and the bounding lithologies. This stress contrast was considered suitable for limiting excessive fracture height growth.
- There were no unusual pressure response occurrences (e.g., near-wellbore effects) that could have increased the fracture modeling complexity.
- Remote-well monitoring during the minifracs clearly identified over 1,000 microseisms associated with the hydraulic fracture injections. Limited analysis of these data indicated that the seismic signals can be spatially located and used for mapping the hydraulic fracture.

The positive results associated with the initial verification tests provided the basis to proceed to the next level of experiment complexity (i.e., microseismic data acquisition/mapping using a four-level triaxial accelerometer array).

Similar to the initial A-Sand injections, the second set of A-Sand experiments also used MWX-3 as the injection well and MWX-2 as a seismic observation well. Three fluid-only injections (each 400 to 450 bbl of 40 lb/Mgal linear gel) and a fluid/proppant injection (617 bbl of cross-linked gel and 16,900 lb of proppant) were performed primarily to support the goal of microseismically mapping hydraulic fracture extent.[3,4] Fracture dimensions were also measured or predicted by several other methods: fracture modeling, post-frac radioactive tracer logging, H/Z microseismic survey (i.e., post-frac treatment well monitoring with a single accelerometer).

Figure 4 shows a combined plot of the Injection 1-A fracture geometry calculated from the fracture model and the locus of microseismic points as detected by the 4-level array. Tracer height from Injection 4-A and H/Z fracture height from Injection 3-A are also shown for comparison. There are elements of agreement and disagreement between these techniques. The most obvious disagreement is the asymmetric wing length measured from microseisms compared to the geometry calculated by the model. On one wing, the microseisms extend somewhat farther than the model predicts, and on the other wing, the measured fracture length is considerably less. Although there is limited supporting evidence, it is possible that the asymmetry is a function of lenticular sand body geometry in the fluvial-transition depositional environment in which the A Sand was deposited. Fracture growth upward is one feature that found agreement between the techniques: radioactive-proppant height was almost identical to the microseismic height, and both agreed with the model at the top of the fracture. Fracture growth downward found more of a difference between the microseismic and the model calculations.

Figure 4 illustrated the fracture dimensions at the end of the Injection 1-A. Microseismic imaging, however, permits fracture growth to be continuously observed. For example, the Injection 1-A fracture growth with time can be described as follows:

- After only 12 minutes of pumping, the fracture reached its total half-length extent (approximately 250 ft) with height growth essentially confined to the A Sand.
- Seven minutes later some upward and downward height growth are noted which correlates to a decrease in the treating pressure.
- At the shut-in time of 30 minutes, there is some additional height growth and an increasing width of signals in the horizontal plane.
- Upward and downward growth continue for about nine minutes after shut-in and result in the fracture extent illustrated in Figure 4.

Also note in Figure 4 the significant discrepancy in the surface areas of the hydraulic fracture as determined by 3-D modeling and microseismic analysis. This phenomena was also observed in B-Sand data analysis and will be discussed in that section.

M-Site Facilities and Capabilities Expansion. The cumulative A-Sand results and the realization that the research had the potential for advancing hydraulic fracturing technology provided the incentive for continued expansion of the M-Site facilities and scope of work.

The most significant expansion effort was the drilling and instrumentation of Monitor Well No. 1 in 1994.[5] As previously summarized, A-Sand experimentation used only four seismic receivers on a fiber-optic wireline for detecting microseismic events. However, comprehensive instrumentation arrays (e.g., permanently emplaced accelerometers and inclinometers) would be required to more accurately map and understand fracture propagation, and to develop reliable fracture diagnostics interpretation methodologies.

A-Sand experiment results provided guidance in designing the Monitor Well seismic array where it was determined that a 30-accelerometer array with 30-ft spacing between the instruments would be optimal for imaging microseismic events in the B- and C-Sand intervals. Similarly, an array of six inclinometers located at depths corresponding to above, within, and below the B and C Sands was appropriate. After drilling and casing the Monitor Well to 5,000 ft, these instrumentation arrays and associated cabling systems were systematically secured to the outside of a tubing string, placed at known subsurface depths, and cemented in place.

The Monitor Well was sited to take advantage of the hydraulic fracture azimuth and the locations of the existing MWX wellbores (i.e., both wings of a propagating hydraulic fracture could be more effectively evaluated by propagating a hydraulic fracture between two observation wells). Thus, MWX-2 was converted to the treatment well for B- and C-Sand injections; the Monitor Well (and included instrumentation arrays) was used for data acquisition on the south side of the hydraulic fracture; and MWX-3 was used as a remote observation well for deploying the wireline-retrievable accelerometer array on the north side of the fracture. Figures 5 and 6 illustrate plan and profile views of these wellbore layouts and instrumentation arrays to be used for B- and C-Sand injections.

In addition to the new wellbore and comprehensive instrumentation arrays, data acquisition systems were necessary to monitor and store the large volume data streams generated by this instrumentation. Three data acquisition systems (DAS) were designed and fabricated to acquire low-to-moderate-speed data (e.g., pressure, injection rates, inclinometer signals) during project experiments. Each DAS was configured to acquire data gathered at satellite locations (e.g., Monitor Well, DOE wireline unit, GRI wireline unit) and automatically transfer pertinent information back to the central client/server in a specific format for systematic review, analysis and archiving. In addition, two high-speed DASs that serve the microseismic receivers arrays in the Monitor Well and the MWX-3 observation well were designed and fabricated, both of which were specially configured to accommodate the time-synchronized data streams from the two downhole seismic receiver arrays. The layout of this network is illustrated in Figure 7.

The data acquisition systems are networked to a central on-site facility (see Figure 7) where microseismic and inclinometer data can be evaluated and modeled in near real-time at computer workstations. One of the key elements to improving the microseismic data-analysis time efficiency was the development of automatic event detection to complement the collection of all of the raw data. Microseismc event amplitudes which are beyond a resettable threshold level are immediately transmitted over fiberoptics line to the analyst's workstation. These high-graded data are then used to image fracture growth while the hydraulic fracture injection is in progress.

B-Sand Fracture Diagnostics Experiments. M-Site research activities in 1995 focused on performing a series of field operations which were designed to extend fracture mapping capabilities and hydraulic fracturing technology in the B-Sand interval. The B-Sand experiments made full use of the site infrastructure and fracture mapping capabilities made possible by the Monitor Well No. 1 comprehensive instrumentation arrays and wireline-retrievable arrays in MWX-3.

The initial experimentation conducted in the B Sand focused on fracture diagnostics and fracture mapping by performing a series of seven hydraulic fracture injections in MWX-2 between April and August 1995, as summarized in Table 1.[6] Although extensive, interesting and useful data were acquired in all of the injections, only select data and results are presented to illustrate key points.

Injections 6-B and 7-B provide excellent contrasting examples of fracture growth and dimensions as determined by microseismic mapping.[6,7] Microseismic data were acquired from the 30-level (Monitor Well) and 5-level (MWX-3) accelerometer arrays in association with Injection 6-B. This injection consisted of 400 bbl of 40-lb/Mgal linear gel circulated to the perfs and pumped at an average rate of 22 bpm. Injection 7-B microseismic data were acquired using these same seismic arrays, but the treatment consisted of a total clean fluid volume of 601 bbl (132 bbl of KCl water, 30 bbl of 40-lb/Mgal linear gel, and 439 bbl of 40-lb/Mgal cross-linked gel) carrying 77,600 lb of 20/40-mesh sand staged in concentrations ranging from 1 to 8 ppg.

Figures 8 a, b and c illustrate the profile-view growth history of the Injection 6-B hydraulic fracture at several points in time as determined by the microseismic event mapping. There are several key observations noted from this series of figures:

- Microseismic events indicate that the hydraulic fracture attained its full half-length extent (300-400 ft) in the initial 11 minutes of the 18-minute injection.
- The microseismic events indicate limited fracture height growth (approximately 65 ft) during the minifrac.
- The plan view (Figure 8d) of microseismic events associated with the hydraulic fracture indicates an azimuth of N78°W (based on a linear regression of data points derived from the 5-level and 30-level accelerometer arrays), but a "process zone" having some width lends a degree of uncertainty to this determination.

It is important to note that the other liquid-only minifracs performed in the B Sand (Injections 1-B through 5-B) all had fracture growth characteristics similar to Injection 6-B (i.e., rapid length extension and limited height growth).

Figures 9 a, b, c and d illustrate a similar set of profile and plan views from Injection 7-B. Key observations noted from this series of figures are as follows:

- Microseismic events associated with the fracture propagated by the larger volume of cross-linked gel attained about the same length extent as that achieved with the linear gel.
- Height growth was initially well contained, but as the treatment proceeded the fracture grew upward out of the B Sand to attain a maximum fracture height of 150 ft near the wellbore.

The inclinometer array also provided an independent data set from which B-Sand fracture height, vertical asymmetry, and residual fracture width were assessed.[6,8] Inclinometer-based fracture height for Injection 6-B was estimated to be 60-65 ft using a finite element model incorporating multiple stresses and rock moduli. Vertical-array inclinometer data acquired in conjunction with Injection 7-B clearly indicated that the center of the hydraulic fracture had shifted upward later in the treatment signifying upward, out-of-zone fracture growth. A fracture height of 135 ft based on finite element modeling data independently confirms a similar height-growth observation based on microseismic event mapping.

The B-Sand injections also provided interesting data which suggest that the unpropped hydraulic fractures (i.e., fluid-only propagation), when permitted to close, may yet retain a residual width. As an example of this character, inclinometer data acquired for the initial four B-Sand injections (Figure 10) yield a pre-frac baseline, maximum inclinometer inflection for each injection, and post-frac baseline. The post-frac baseline has clearly shifted when compared to the pre-frac baseline. This residual width represents approximately 20 percent of the maximum width of the hydraulic fracture.

A detailed model analysis of the A- and B-Sand injections is beyond the scope of this paper, but will be subject of a future paper to be submitted to the SPE once the C-Sand injections are completed. However a general overview of the modeling performed to date follows.

All injections were modeled using the FRACPRO simulator. The stress profile was used for all injections and was based on a stress-test calibrated stress log. Other reservoir properties were obtained from previous work at the site. Bottomhole pressure was measured for all treatments and was used as input to the fracture model. As well, measured bottomhole pressure indicated entry friction losses (some combination of perforation and near-wellbore friction) varying from 150 - 400 psi among the injections. All prefrac and postfrac modeling results presented to date are for a single fracture.

Pressure matches for Injections 2-B through 6-B were considered good, however the pressure match for Injection 7-B (i.e., propped fracture treatment) was not very good. Initial indications for the low-quality match point to some difficulty in pumping sand into the fracture system, which is quite conceivable considering the fact that multiple fractures were found at a distant point from the wellbore (as will be discussed in a subsequent section) and would be expected to exist throughout most of the fracture system. Measured bottomhole pressure immediately rose upon sand entering the perforations, increasing dramatically even at low (e.g., 2-4 ppg) concentrations.

Fracture dimensions for Injections 6-B and 7-B are shown in Figures 8 and 9 superimposed over the seismic event maps. The most notable features between the two representations of the fractures are the difference in surface areas and the greater height growth predicted by the model.

Given the fact that multiple fractures were recovered in the Intersection Well 1-B core (again, as discussed in a subsequent section), it is reasonable to assume that such fractures could explain the area difference. However, if multiple fractures are assumed to be present during more than just Injection 7-B (although there is no definitive proof one way or the other), this fact would question the relatively the relatively good pressure match. The simplest way to inhibit downward growth in the model is to increase stress in the zones below the B Sand, however the calibrated stress log indicates a relatively thin (e.g., 30 ft) high-stress interval and a lower-stress sandstone lithology.

B-Sand Hydraulic Fracture Intersection Well. Following the B-Sand injections and fracture diagnostics experimentation, a well was drilled in October 1995 to intercept the B-Sand hydraulic fracture(s) and define their "far-field" character.[6,9] It was also anticipated that the genesis of multiple fractures (if any) could be resolved through unique radioactive tracers associated with several B-Sand injections, and that fracture width and proppant distribution could be determined through recovery of colored proppant included in Injection 7-B. From a surface location adjacent to the Monitor Well No. 1 (see Figure 1), Intersection Well No. 1-B was directionally drilled to intersect the southeast fracture wing at a point approximately 126 ft from the MWX-2 treatment well and at a wellbore angle of 54° from vertical.

A total of eleven hydraulically induced fractures, most of which are seen in Figure 11, were observed in core and on borehole image log data over a horizontal distance of 2.6 ft. The fractures were vertical and subparallel, and all fracture surfaces were disassociated (i.e., no fracture faces were "glued" by gel or by proppant). A correlative data set confirms that hydraulic fractures were intersected:

- A pressure transient was immediately observed in MWX-2 (instrumented with a bottomhole shut-in, surface readout pressure tool) when the Intersection Well No. 1-B corebit penetrated the first conductive hydraulic fracture.
- Colored proppant pumped in Injection 7-B was circulated to the surface after having cut through the fractured interval. None of the colored proppant, however, was observed as a proppant pack in the hydraulic fractures
- A gamma ray anomaly, shown in Figure 12, is present in the fractured interval which when spectrally analyzed corresponds to the Iridium isotope included as solid beads with the proppant. The gamma anomaly corresponds to Fracture Nos. F_1 , F_2 , and/or F_3 (see Figure 11). No liquid tracers were identified through spectral gamma ray analysis of core fractures or in spectral gamma ray wireline logging data.

Hydraulic fracture azimuth was definitively determined to be N72°W as a result of the fracture intersection and known wellbore-location geometry. This compares to the N75°W and N78°W values estimated by linear regression lines drawn through the seismic events located by the 5-level and 30-level accelerometer arrays (see Figures 8 and 9).

Future Work. Hydraulic fracture conductivity testing, using the unique combination of two remote wells connected by a 126-ft-long propped hydraulic fracture, remains to be performed. The primary test objectives will be to determine the hydraulic fracture conductivity using fluid flow rate and pressure measurements between MWX-2 and Intersection Well 1-B; quantify individual fracture fluid flow rates using wireline production logging tools; and assess leakoff transients and formation characteristics during injection and shut-in cycles. This testing will complete the B-Sand fracture diagnostics and fracture technology experiments.

Further verification and development of fracture diagnostic technologies will be performed in 1996 in the C-Sand interval, an 80-ft-thick blanket sand above the B Sand. A deviated borehole, drilled as a kickoff to the existing Intersection Well No. 1, will be emplaced in the C Sand approximately 300 ft from the MWX-2 treatment well (Figure 13). A series of hydraulic fracture injections will again be designed to approach and ultimately cross the new C-Sand lateral. The primary C-Sand program objectives are described as follows:

- Fracture dimensions determined by microseismic event mapping will be compared to the pressurized crack dimension at the time that the hydraulic fracture breaks into the C-Sand intersection well. This "ground-truth" comparison is expected to lead to an improved understanding and a more accurate microseismic event map.
- Fracture-tip pressure at the time of breakthrough into the C-Sand lateral will be measured. Different fracture models use high or low tip pressure which results in significant differences in modeled fracture dimensions. This measurement will provide a key data point for fracture modelers to assess.
- Fracture dimension evaluations based on multi-level microseismic monitoring in the treatment well will be performed. Microseismic monitoring within a treatment well represents the most basic operational scenario for hydraulic fracture mapping on a commercial basis. The advantage is that no offset wells will have to be shut in or prepared for instrument deployment and the distance from the offset well to the hydraulic fracture will no longer be a factor.
- The genesis of multiple hydraulic fractures will be assessed through multiple borehole image logging surveys in the intersection well after each injection.
- Hydraulic fracture conductivity and residual fracture width will be more comprehensively assessed after

fluid-only injections.

Conclusions

Significant advancements have been made in fracture diagnostics as a result of accelerometer and inclinometer technologies being developed at the M-Site:

1. Hydraulic fracture dimensions, including fracture height and length, have been successfully imaged using subsurface accelerometer arrays in remote observation wells. The fracture height dimension has been independently confirmed through inclinometer data modeling.
2. Hydraulic fractures, based on microseismic mapping of multiple hydraulic fracture injections in the A and B Sands, appear to rapidly propagate to their full length extent with only limited out-of-zone height growth. Continued injection, however, especially with cross-linked, proppant-laden fluids, leads to increased fracture height growth. This height growth is confirmed by inclinometer responses.
3. Inclinometer data indicate that hydraulic fractures propagated by fluid-only injections may retain a significant degree of permanent residual width.
4. Acting collectively or individually, hydraulic fracture growth history and residual width character have potential for significantly modifying hydraulic fracture treatment designs and treatment economics.
5. Multiple (11) far-field hydraulic fractures were observed in core and borehole image log data. Data collected to date cannot resolve which fracture or fractures are associated with which of the seven B-Sand injections.
6. The results of the two completed sets of M-Site experiments suggest that there are still some elements of hydraulic fracturing that are not completely reproduced by computer models, either because of incorrect input data or uncertain model mechanisms. The lack of agreement in total surface area of the A-Sand fracture and the minimal downward growth of the B-Sand fracture cannot be accounted for except by invoking special mechanics (e.g., multiple fractures and interface slip, respectively) for which there is no supporting information other than the lack of agreement with the model.

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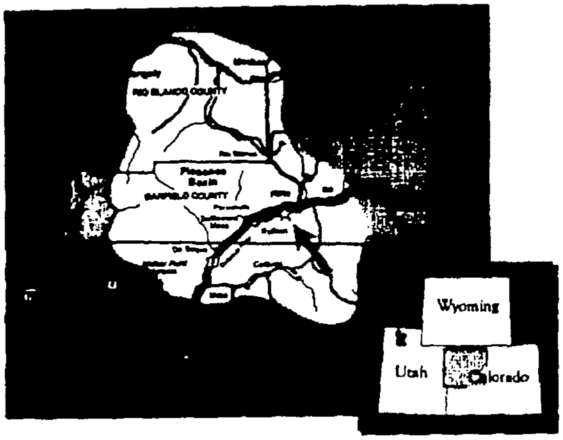


Figure 1: M-Site Location Map and Wellbore Layout

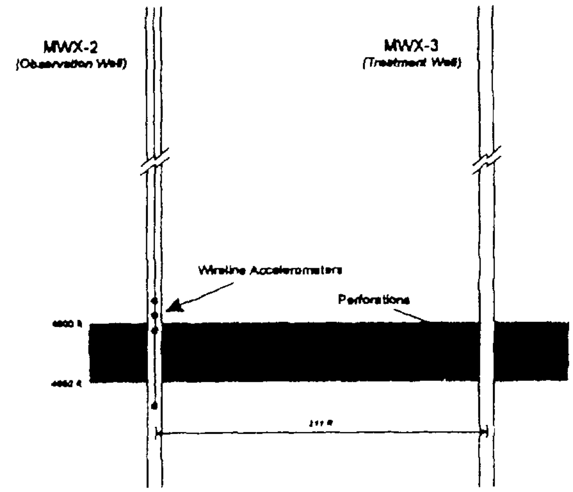


Figure 3: Profile of Wellbore Layout for A Sand Injections

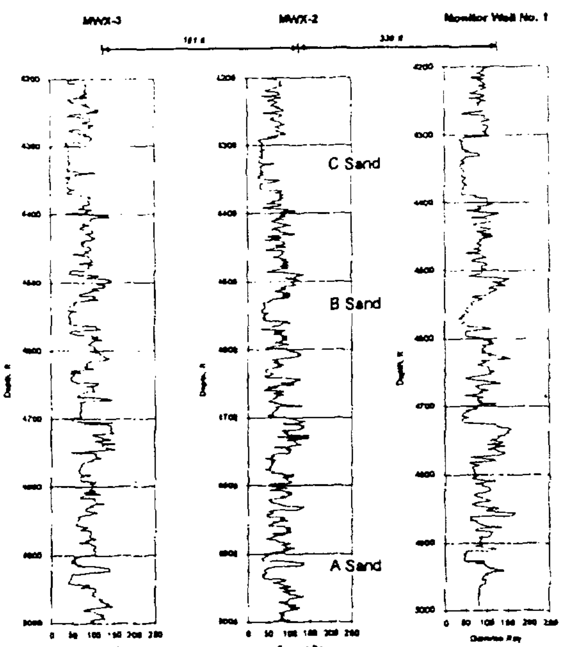


Figure 2: Cross-Section of M-Site Target Sand Intervals

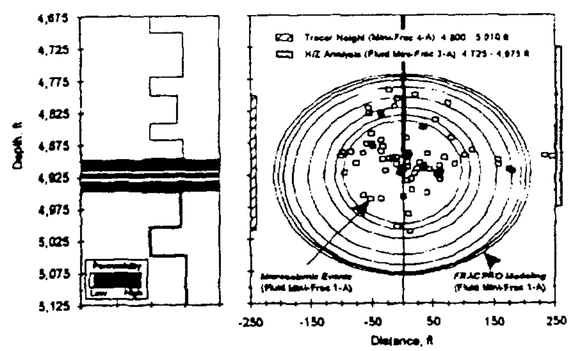


Figure 4: Composite Plot of A-Sand Fracture Diagnostic Results

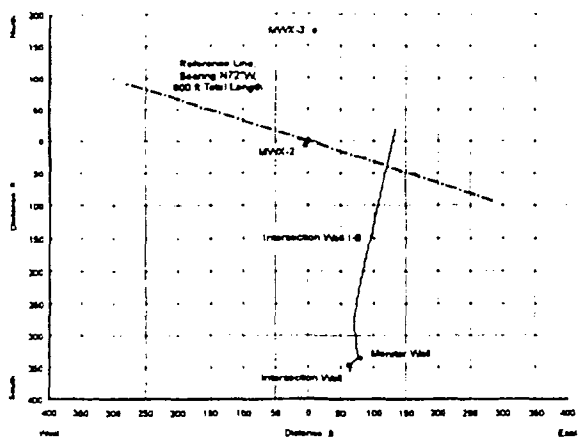


Figure 5: Plan View of Wellbore Layout for B and C Sand Injections

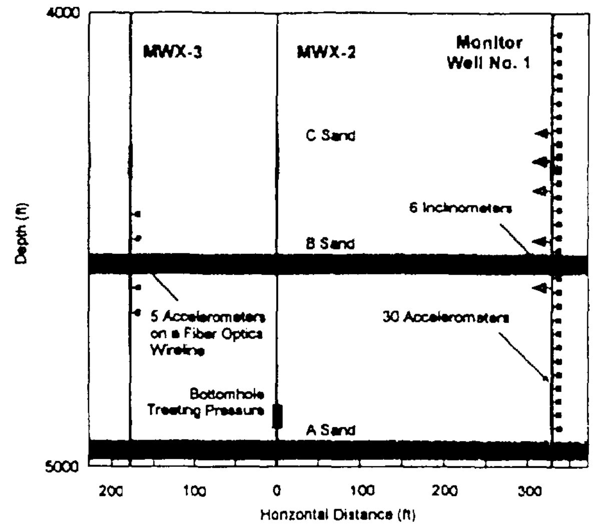


Figure 6: Profile of Instrumentation Arrays Relative to B and C Sands

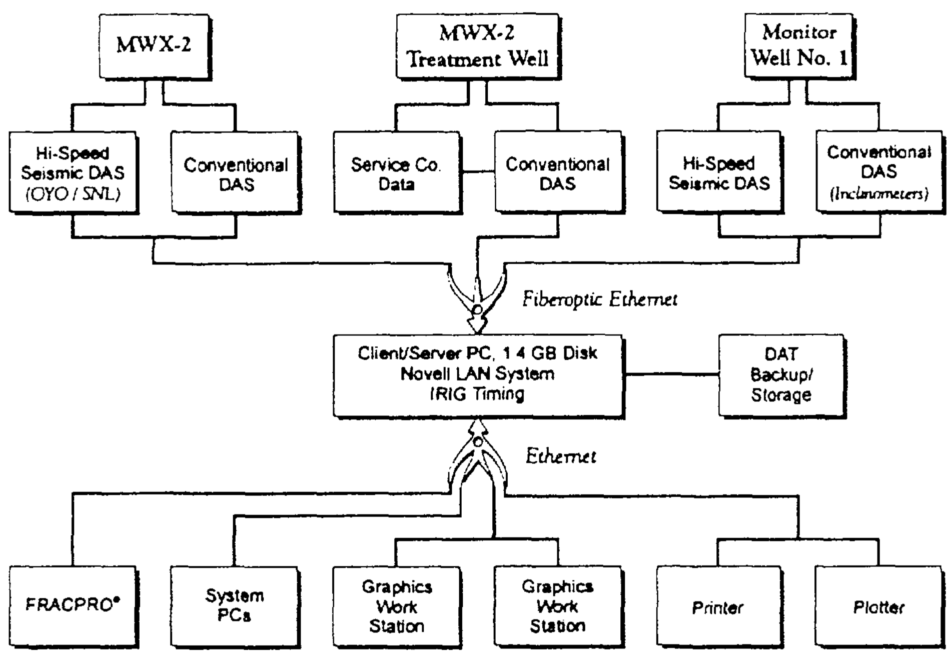


Figure 7: Layout of Networked Data Acquisition Systems

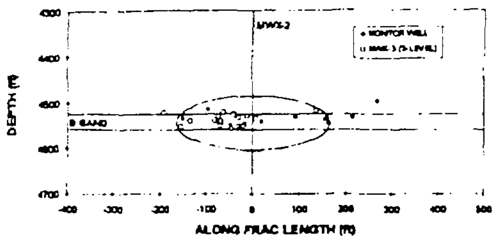


Figure 8a: Profile Map 6 Minutes After Initiating Injection

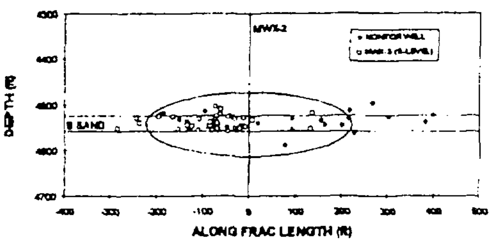


Figure 8b: Profile Map 11 Minutes After Initiating Injection

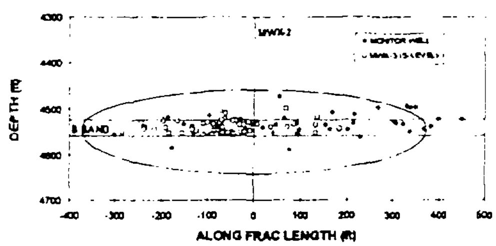


Figure 8c: Profile Map 45 Minutes After Initiating Injection (18-Minute Injection Plus 27-Minute Shut-In)

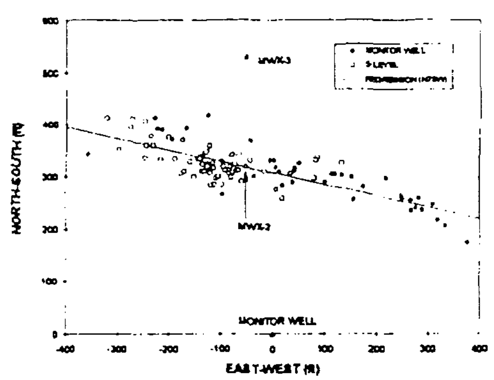


Figure 8d: Plan View of All Microseismic Events

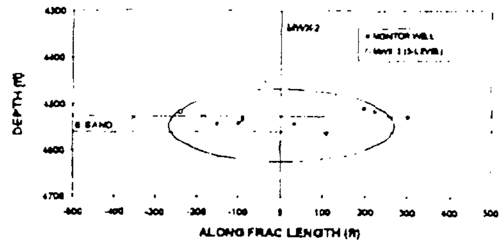


Figure 9a: Profile Map 20 Minutes After Initiating Injection

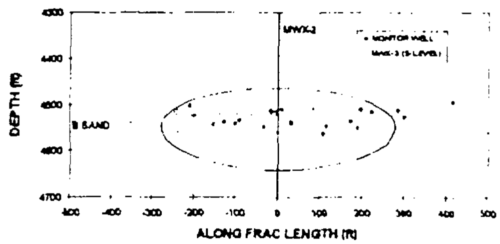


Figure 9b: Profile Map 27 Minutes After Initiating Injection

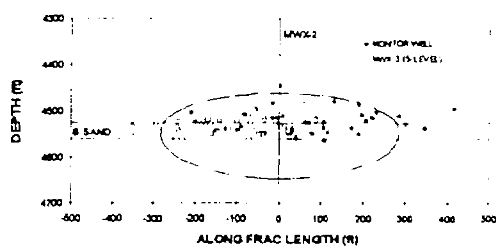


Figure 9c: Profile Map 49 Minutes After Initiating Injection (33-Minute Injection Plus 16-Minute Shut-In)

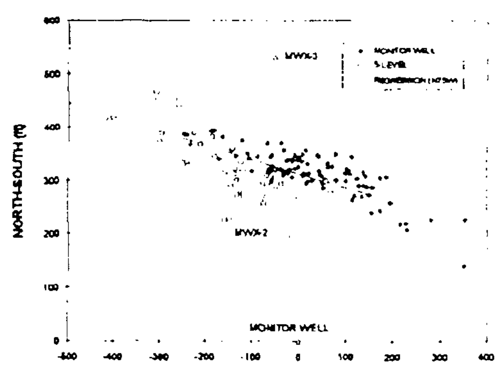


Figure 9d: Plan View of All Microseismic Events

Figure 8: Microseismic Event Maps and Modeled Fracture Geometry Resulting from Injection 6-B

Figure 9: Microseismic Event Maps and Modeled Fracture Geometry Resulting from Injection 7-B

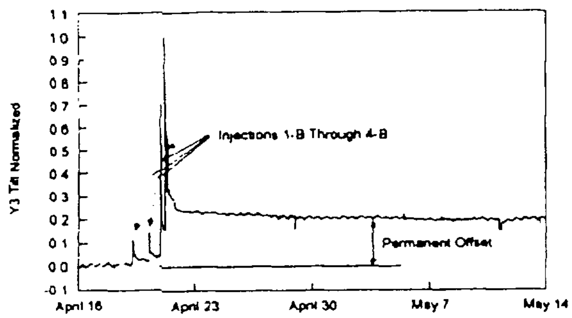


Figure 10: Residual Frac Width Estimated from Inclinometer Data

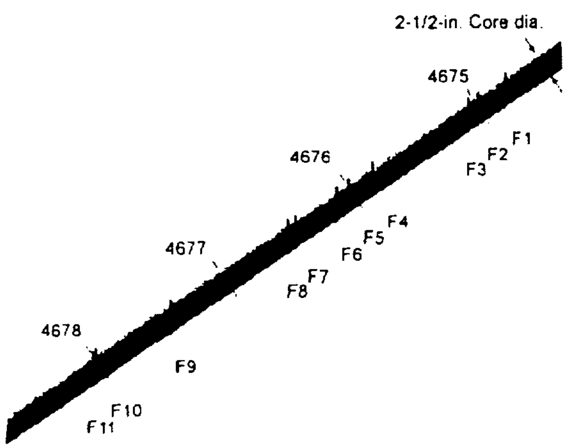


Figure 11: Hydraulic Fractures Observed in Core

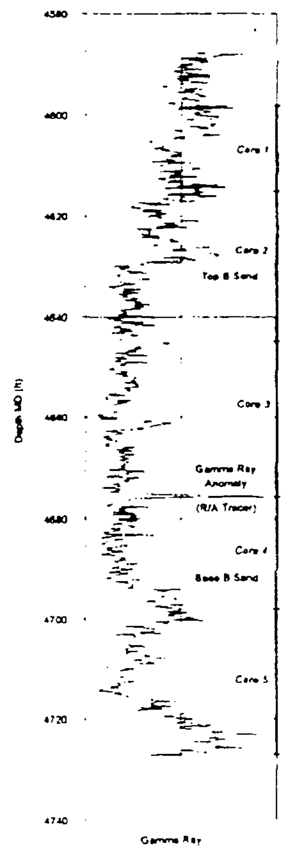


Figure 12: Gamma Ray Anomaly in the Intersection Well 1-B Resulting from Intercepting the R/A Tagged Hydraulic Fracture

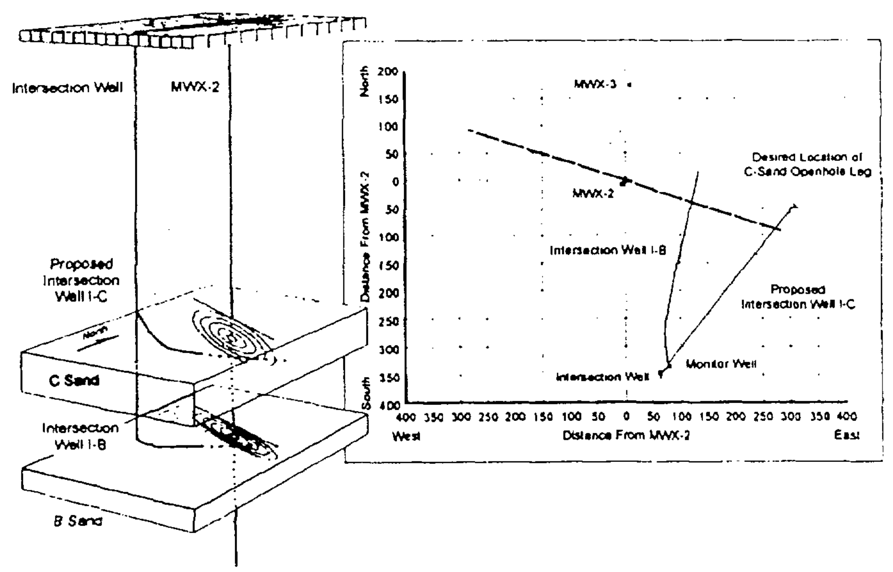
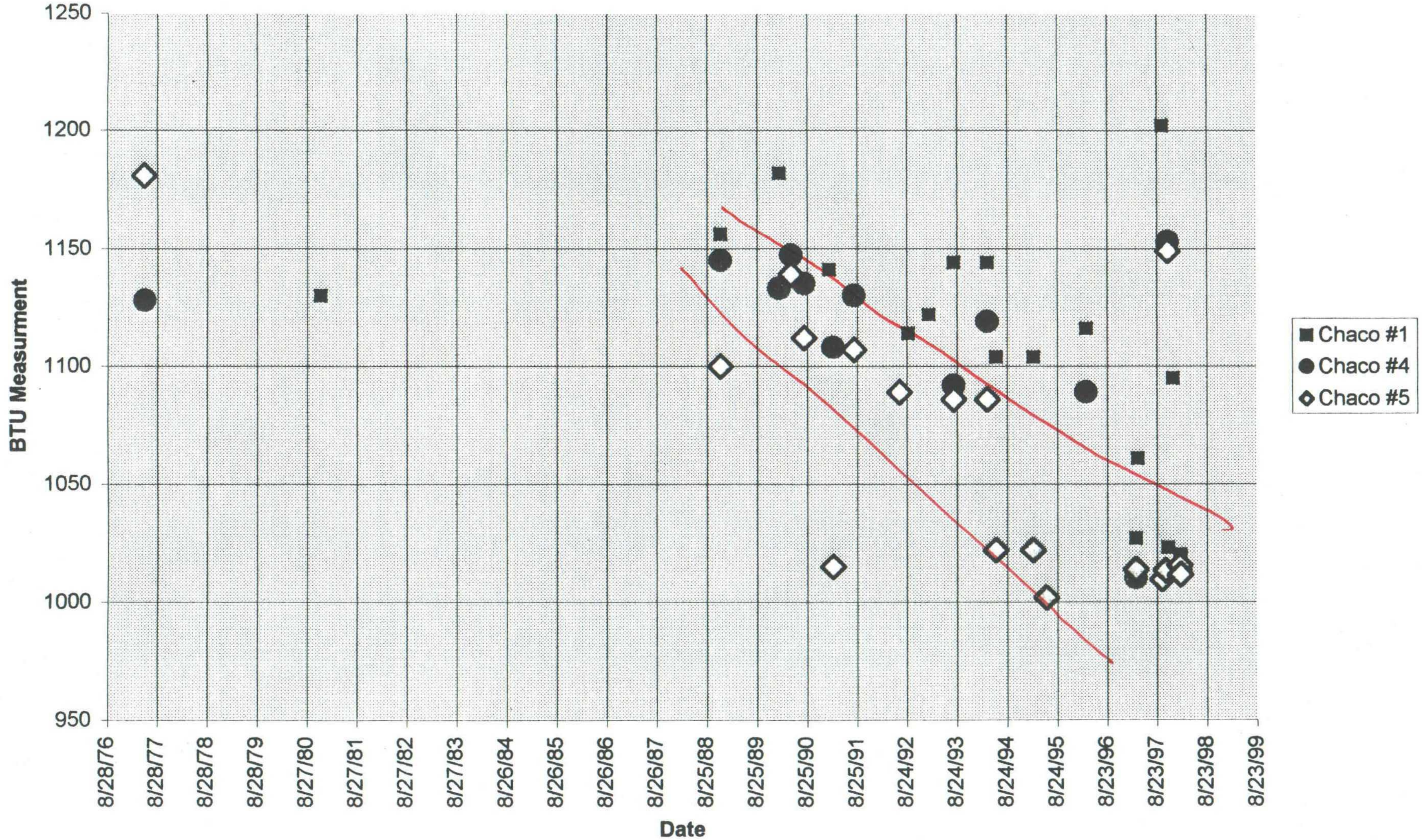


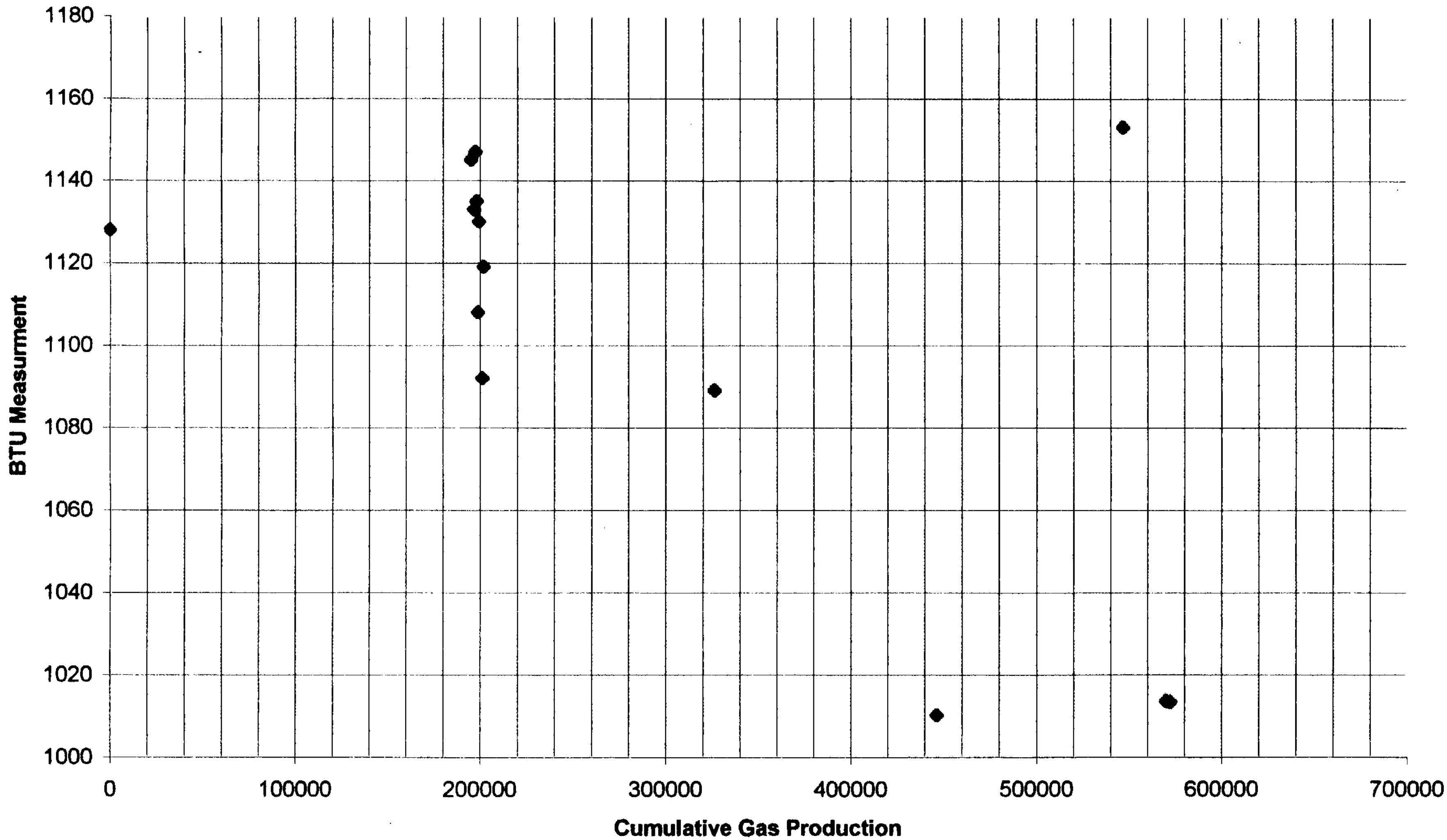
Figure 13: Concept of C Sand Program Objectives

BTU vs. Time

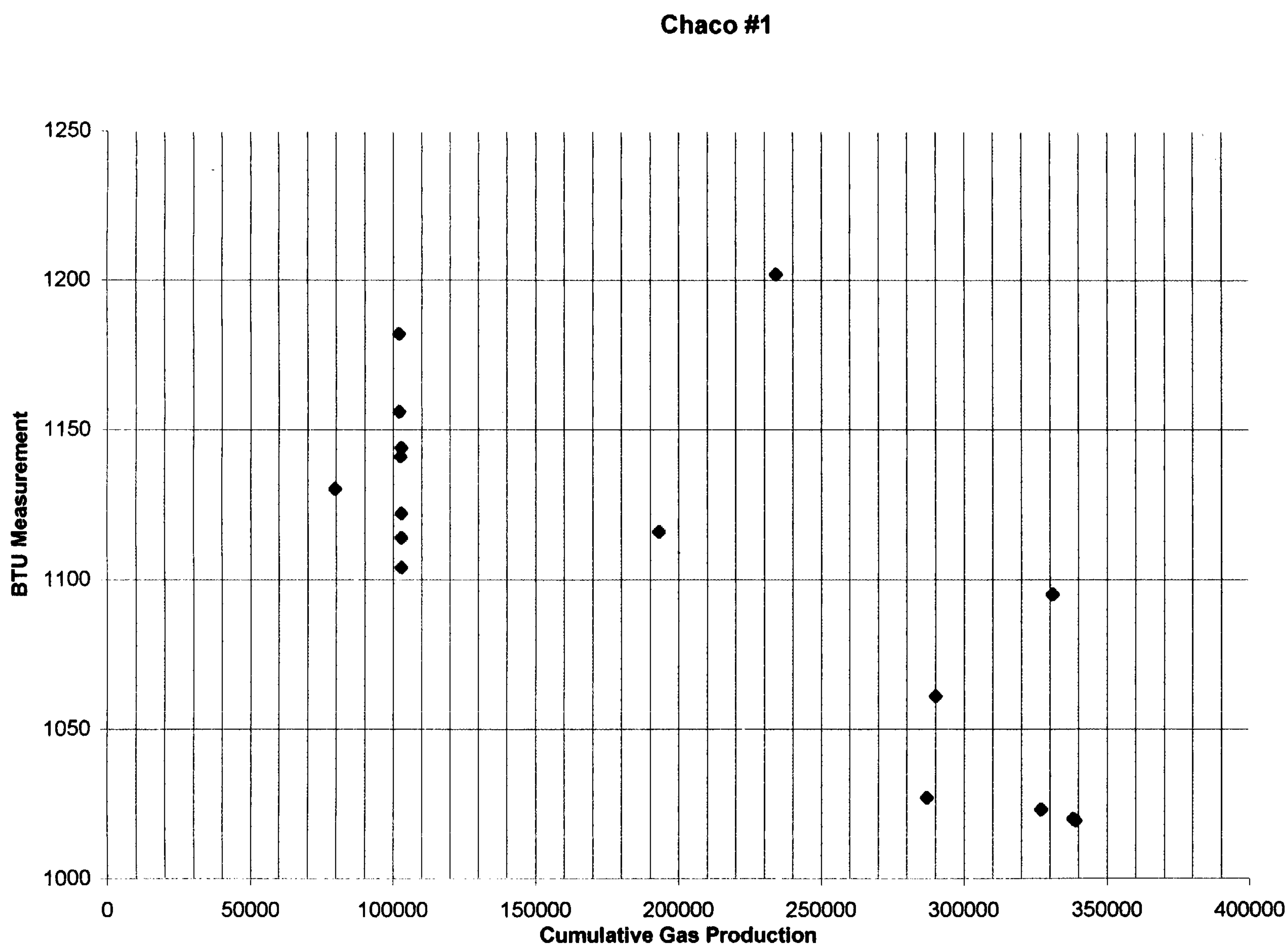


B.14

Chaco #4



1180
1160
1140
1120
1100
1080
1060
1040
1020
1000
BTU Measurment
0
100000
200000
300000
400000
500000
600000
700000
Cumulative Gas Production


Chaco #1
BTU Measurement
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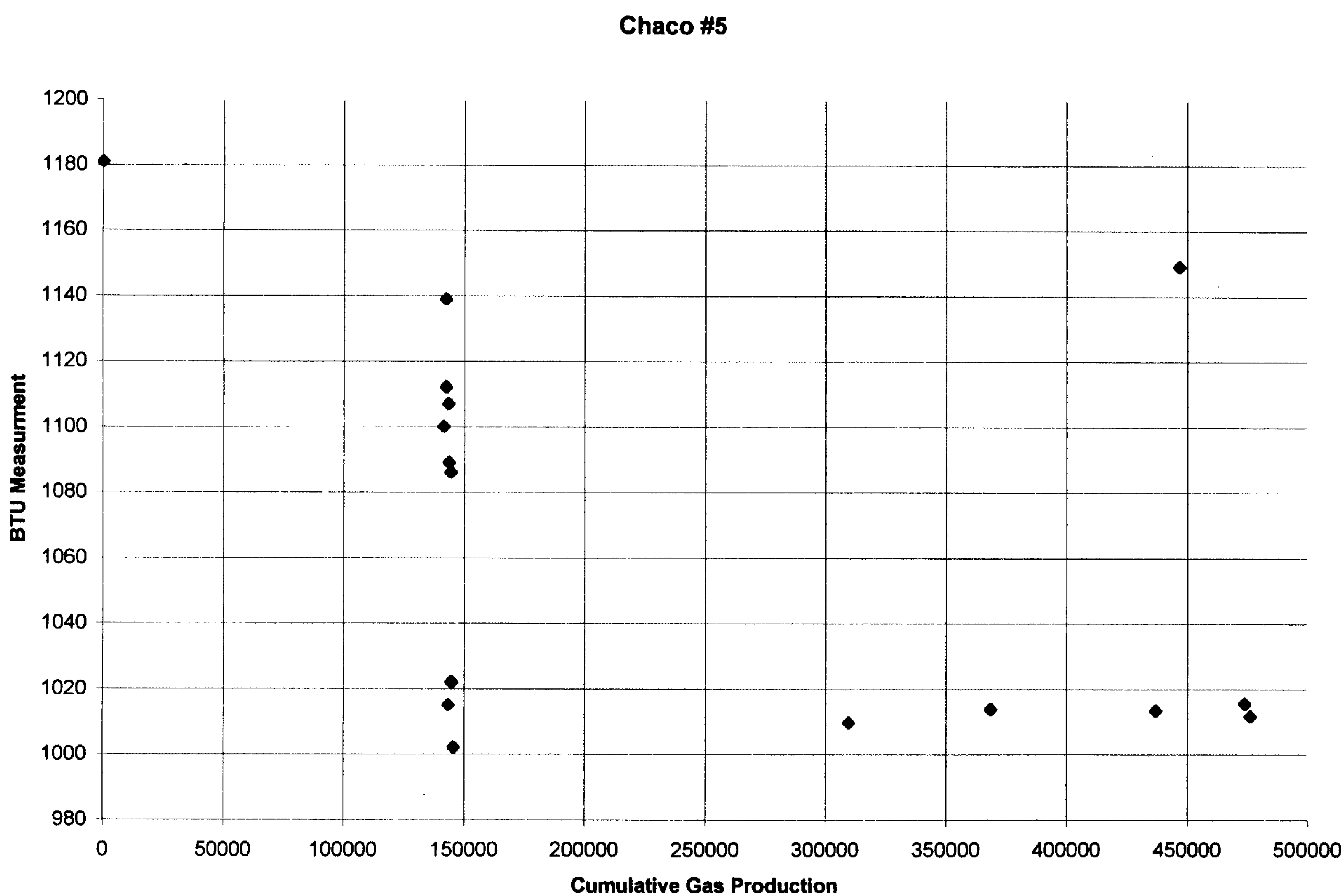
1150
1100
1050
1000
0
50000
100000
150000
200000
250000
300000
350000
400000
Cumulative Gas Production


Chaco #5
BTU Measurment
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1160
1140
1120
1100
1080
1060
1040
1020
1000
980
0
50000
100000
150000
200000
250000
300000
350000
400000
450000
500000
Cumulative Gas Production