Received by EPA RPM 3/5/99 SJD

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Contingent Approval as Final by EPA RPM ~~[illegible]~~ SJD 12/23/98

1 of 3

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RETEC

Remedial Action Report

UGI Columbia Gas Plant Site
Columbia, Pennsylvania

SDMS DocID 2079865

Prepared by:

Remediation Technologies, Inc.
9 Pond Lane - Suite 3A
Concord, Massachusetts

RETEC Project No.: 1-2507-999

Prepared for:

Pennsylvania Power and Light Company
Two North Ninth Street
Allentown, Pennsylvania 18101

February 26, 1999

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March 3, 1999

Mr. Douglas Ammon
Clean Sites Environmental Services
635 Slaters Lane, Suite 130
Alexandria, VA 22314

Subject: Submittal of Approved UGI Columbia Gas Plant Site Remedial Action Report

Dear Doug:

Enclosed please find the UGI Columbia Gas Plant Site Remedial Action Report. As you know, the Remedial Action Report was approved by both EPA and PADEP.

Based on previous submittals, I am also forwarding copies of this report to Scott Miller, Jim Villaume, Steve Donohue, Elise Juers, Al Leuschner, and Lyle Johnson. If you need additional copies sent, please let me know.

If you have any questions or comments regarding this submittal, please do not hesitate to contact me.

Sincerely,

ThermoRetec Consulting Corporation

Jason A. Gerrish
Environmental Engineer

JAG:sdw

Enclosure

cc: Jim Villaume, PP&L
Scott Miller, Clean Sites
Steve Donohue, EPA
Elise Juers, PADEP
Lyle Johnson, WRI
Al Leuschner, ThermoRetec

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Hazardous Site Cleanup Division
Steven J. Donohue

Direct Dial (215) 814-3215
Mail Code (3HS22)

December 23, 1998

Douglas C. Ammon, P.E.
Project Manager
Clean Sites Environmental Services, Inc.
635 Slaters Lane, Suite 130
Alexandria, VA 22314

Re: UGI Columbia Gas MGP Site
Contingent Approval of the Revised Relief and Gas Holder Remedial Action Report

Dear Doug:

The United States Environmental Protection Agency ("EPA") has received and reviewed the facsimile of a December 22, 1998 letter ("Letter") regarding the finalization of the Relief and Gas Holder Remedial Action Report ("Report") for the UGI Columbia Manufactured Gas Plant Site ("Site"). The revised Report was prepared by Remediation Technologies, Inc. ("RETEC") for the Pennsylvania Power and Light Company ("PP&L") and received by EPA under a cover letter dated October 1, 1998. EPA reviewed the Report and provided RETEC with an electronic mail message ("e mail") with additional comments on November 23, 1998. RETEC's Letter summarizes EPA's comments contained in the e mail and provides responses to the comments. EPA believes the responses are adequate to address the comments contained in the e mail.

EPA contingently approves the Report provided the specific comments, in the Letter, are addressed as specified in the text of the Final Report. Please note that the Executive Summary of the Report may have to be revised based on the RETEC responses. EPA proposes that RETEC provide revised binder and cover pages as well as revised pages for the text of the Report responsive to the comments. EPA will then insert the revised pages in the binder and consider the Report approved. EPA needs a complete copy of all the appendices to the Report sent to the Region III office and the Office of Research and Development in Ada, Oklahoma. If you have any questions please contact me at the phone number listed above.

Sincerely,

Steven J. Donohue

Steven J. Donohue
Project Manager

cc: Elise Juers, PADEP

Remedial Action Report

UGI Columbia Gas Plant Site
Columbia, Pennsylvania

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February 26, 1999

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Remedial Action Report

UGI Columbia Gas Plant Site
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Prepared by:

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9 Pond Lane - Suite 3A
Concord, Massachusetts

RETEC Project No.: 1-2507-999
Prepared for:

Pennsylvania Power and Light Company
Two North Ninth Street
Allentown, Pennsylvania 18101

Prepared by:

Jason A. Gerrish

Jason Gerrish, Environmental Scientist

Technically Reviewed by:

Alfred P. Leuschner

Al Leuschner, Project Manager

February 26, 1999

Executive Summary

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Background

During the 19th century and the first half of the 20th century, MGP facilities were operated to produce gas for illuminating and other purposes. By-products of MGP operations included coal tars which, in some instances, were disposed on-site in unlined lagoons or as fill. Another disposition for coal tar was as abandoned sludge within on-site vessels such as underground holders (tanks) and tar wells. Uncontained liquid coal tar typically causes surrounding groundwater contamination.

Since excavation may not always be feasible for coal tar source removal, alternatives may be necessary. Enhanced recovery may be a feasible alternative if proper hydrologic conditions exist.

Enhanced recovery was used at the UGI Columbia Gas Plant site to remove a coal tar accumulation within the on-site relief holder. Enhanced recovery was used at this site to recover liquid coal tar and evaluate the usefulness of the technology for other MGP facilities with similar physical characteristics.

Investigations and Treatability Testing

Borings into the relief holder determined the presence of free coal tar accumulations. A system was designed to remove the accumulation of tar. Modeling of groundwater flow was performed to determine whether hot-water or steam flushing would provide better performance and what well patterns would provide optimum subsurface flushing. Also, treatability testing of the coal tar was performed to determine the optimum temperature for maximum DNAPL recovery.

Prior to constructing the enhanced recovery system, borings were advanced into the relief holder and continuos split-spoon samples were collected and analyzed for PAHs. From the PAH data, and characteristics of coal tar, a total recoverable volume of tar was calculated. The actual calculation returned a range of recovery of between 5,000 and 14,000 gallons.

Construction

Between July 1996 and February 1997, construction of an enhanced recovery system for the relief holder at the UGI Columbia Gas Plant Site was completed. The system consisted of installing eight (8) equally spaced 4-inch injection wells at the perimeter of the holder and one 10-inch production well in the center of the holder. Aboveground structures included tar separation tanks, a tar storage tank, a boiler for hot water and steam production, water treatment equipment, and instrumentation. In addition, one production well was installed in the gas holder for extraction of contaminated water. No free coal tar was found in the gas holder.

Operations

Between February and November 1997, the enhanced product recovery system was operated in the relief holder. During that period, six pore volumes of water were flushed through the relief holder, and water and coal tar were extracted.

Several operational parameters were manipulated during operations. Specifically, steam injection was switched to hot-water injection after two pore volumes were flushed through the holder due to significant surface leaks caused by the steam injection. Also, because preferential flowpaths seemed to be forming within the holder, alternate flowpaths were desired. To create alternate flowpaths, each injection well was utilized as a production well and the extraction well was utilized as an injection well.

Once enhanced product recovery operations were completed, water was pumped from the relief holder and the gas holder. The contents of both holders were then stabilized by injection of flowable fill (a mixture of cement, fly ash, bentonite, and water). A total of 116,000 gallons of flowable fill were added to the relief holder and 65,500 gallons to the gas holder.

Conclusions

Following completion of enhanced recovery operations, recovered tar within the oil storage tank was measured to determine recovered tar volume. According to physical measurements and analytical results on the tar, approximately 3,350 gallons were contained in the storage tank.

The recovered tar within the oil storage tank was sent in three separate shipments to Systech for thermal destruction in their cement kiln. Each load was sampled and analyzed for water content. The results of this sampling indicated a total tar volume of approximately 2,500 gallons. It is likely that the Systech volume of 2,500 gallons is more accurate than the measurements from the oil storage tank.

Following operation of the enhanced recovery system, additional borings were advanced into the relief holder. Continuous split-spoon samples were again collected and analyzed for PAHs. The results indicated a decrease in holder tar volume of approximately 9,300 gallons.

PAH data indicated that approximately 2,500 gallons of tar were redistributed to the top 0 to 10 feet of the holder. This indicates that the tar in the lower portion of the holder was effectively mobilized during operation of the enhanced recovery system; however, not all of the mobilized tar was recovered in the production well. Rather, a portion of this tar was redistributed into the upper levels of the holder.

According to PAH data (collected before and after the enhanced recovery system was operated) and tar recovery volumes, a residual saturation approaching 7% was achieved in the holder.

The initial cost estimate for the enhanced recovery system was $841,380 while actual costs totaled $1,226,000. Unexpected overruns included an extended operating duration and additional ODCs, services, analytical costs associated with the extended operating duration. Additionally, the grouting process required significantly more time than was initially estimated by the grouting contractor.

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1 Introduction

On behalf of Pennsylvania Power and Light Company (PP&L) and the Electric Power Research Institute (EPRI), Remediation Technologies, Inc. (RETEC) has prepared this Remedial Action (RA) Report to document the completed remediation activities performed at the UGI Columbia Gas Plant Site (Site) in Columbia, Pennsylvania. Following the Site's National Priorities List (NPL) listing, remediation progressed under the Superfund Accelerated Cleanup Model (SACM) process as a non-time critical Removal Action.

The target for remedial action at this Site was defined as the free coal tar in the subsurface within the onsite relief holder and the PAH contaminated water within the onsite gas holder. The relief and gas holders are subsurface tank structures remaining from gas production that occurred at the former Manufactured Gas Plant (MGP). The remedial action performed at this Site did not include contaminated soil, contaminated groundwater, or coal tar that exists in a residual, or immobile, state within, or adjacent to, the relief holder or the nearby gas holder. This report documents that the cleanup performance criteria have been met and certifies that the requirements in applicable enforcement documents have been satisfied.

1.1 Report Organization

This report is organized in 12 sections: Section 1 provides an introduction and a detailed Site description; Section 2 provides a chronology of events; Section 3 presents a remedial technology description; Section 4 discusses the construction of the enhanced recovery system and any deviations from the plans; Section 5 describes the construction quality control; Section 6 discusses the Operations and Maintenance Plan (O&M Plan) and deviations from the plan; Section 7 describes performance standards; Section 8 discusses Site restoration following the remedial action; Section 9 describes required meetings and final reporting; Section 10 describes final inspections; Section 11 presents project costs, and; Section 12 presents references.

This report also contains 12 appendices: Appendix A contains discharge analysis; Appendix B contains construction weekly update forms; Appendix C contains construction change of design forms; Appendix D contains the operator log forms from operations; Appendix E contains operations weekly update forms; Appendix F contains tar transportation manifests; Appendix G contains process sampling analytical results; Appendix H contains decommissioning waste TCLP results; Appendix I contains micro-solvent extraction (MSE) analytical results; Appendix

J contains relief holder tar distillation analysis; Appendix K contains oil storage tank tar analytical results; and Appendix L contains pre- and post-supplemental borings.

1.2 Site Description

The Site is located approximately 400 feet north of the Susquehanna River on 1.6 acres along Front Street in the Borough of Columbia, Lancaster County, Pennsylvania. The Site can be located on the United States Geological Survey (U.S.G.S.) Columbia East, Pennsylvania 7.5 minute series quadrangle at 40° 01' 37" north latitude and 76° 30' 01" west longitude or 0.05 inches east and 4.9 inches north of the southwestern corner of the quadrangle. Figure 1-1 presents the location of the Site.

Currently, two subsurface MGP holders exist at the Site; the former relief holder is 60 feet in diameter and 26 feet deep, and the former gas holder is 40 feet in diameter and 17 feet deep. Both holders were previously capped with a 6-8 inch reinforced concrete pad. Located adjacent to the north boundary of the Site is an active Conrail line that is elevated on an 8 to 15 foot vertical stone embankment. Site access is restricted by a chain-link fence. Figure 1-2 presents a Site map.

Previous investigations revealed that the relief holder contains debris, soil, water, and free-phase coal tar. In contrast, the gas holder contained debris, soil, and water, but no free flowing coal tar. Samples recovered from the gas holder did, however, reveal Polycyclic Aromatic Hydrocarbon (PAH) contamination.

1.3 Site History and Background

1.3.1 Site History

The Former MGP was operated as a gas manufacturing facility from 1851 to the 1950s. Figure 1-3 presents a pre-1937 photo of the Site during MGP operations. Prior reports indicate the Columbia Gas Company (CGC), which was organized in 1851 was the first to operate the Site as a gas manufacturing facility. In 1932, CGC became a subsidiary of Pennsylvania Power & Light Company (PP&L). In 1949, the property was transferred to Lancaster County Gas Company, which later merged into UGI Corporation (UGI). Operations ceased in the 1950s. Thomas Crouse purchased the property in 1976 from UGI Corporation. In

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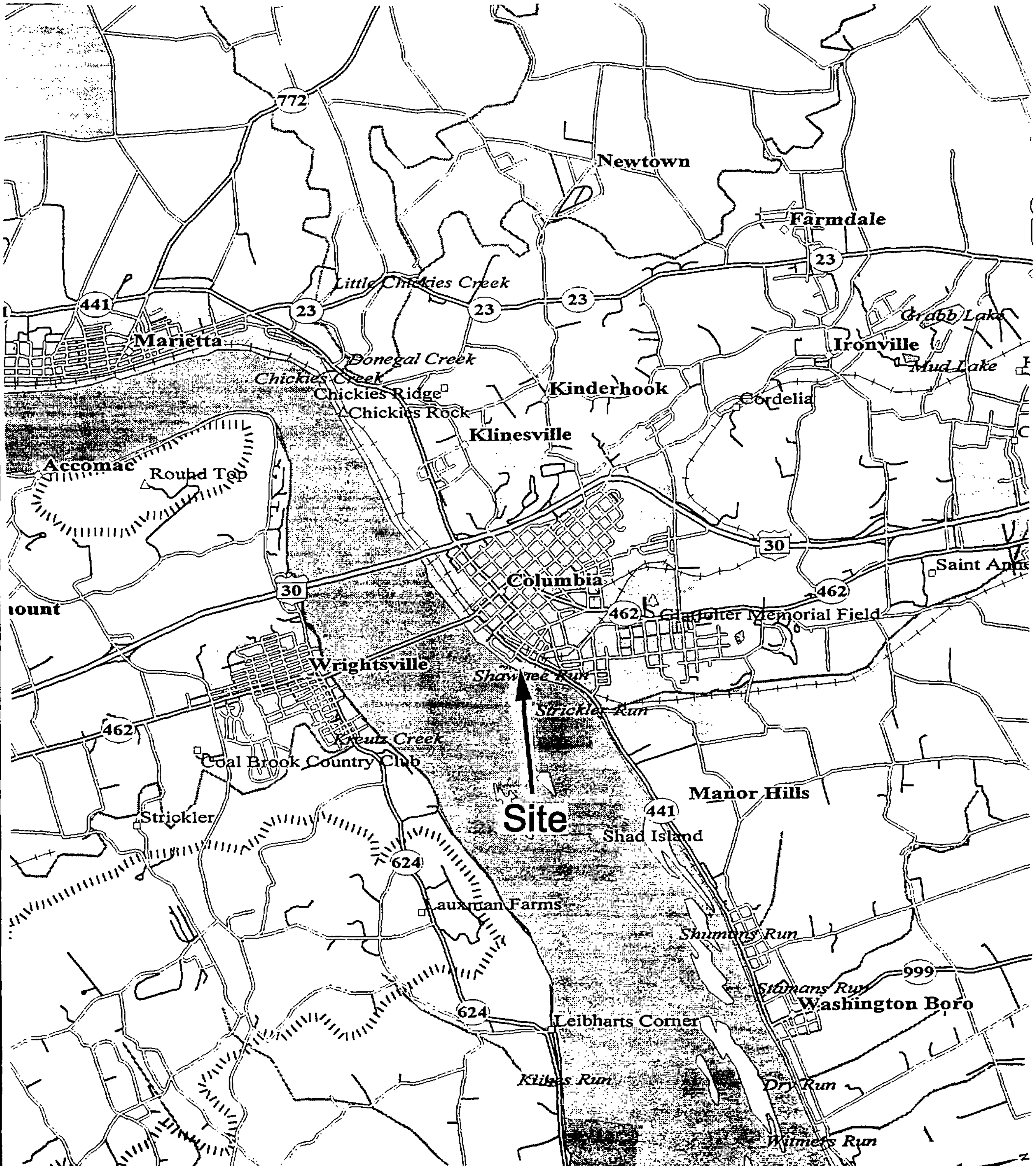
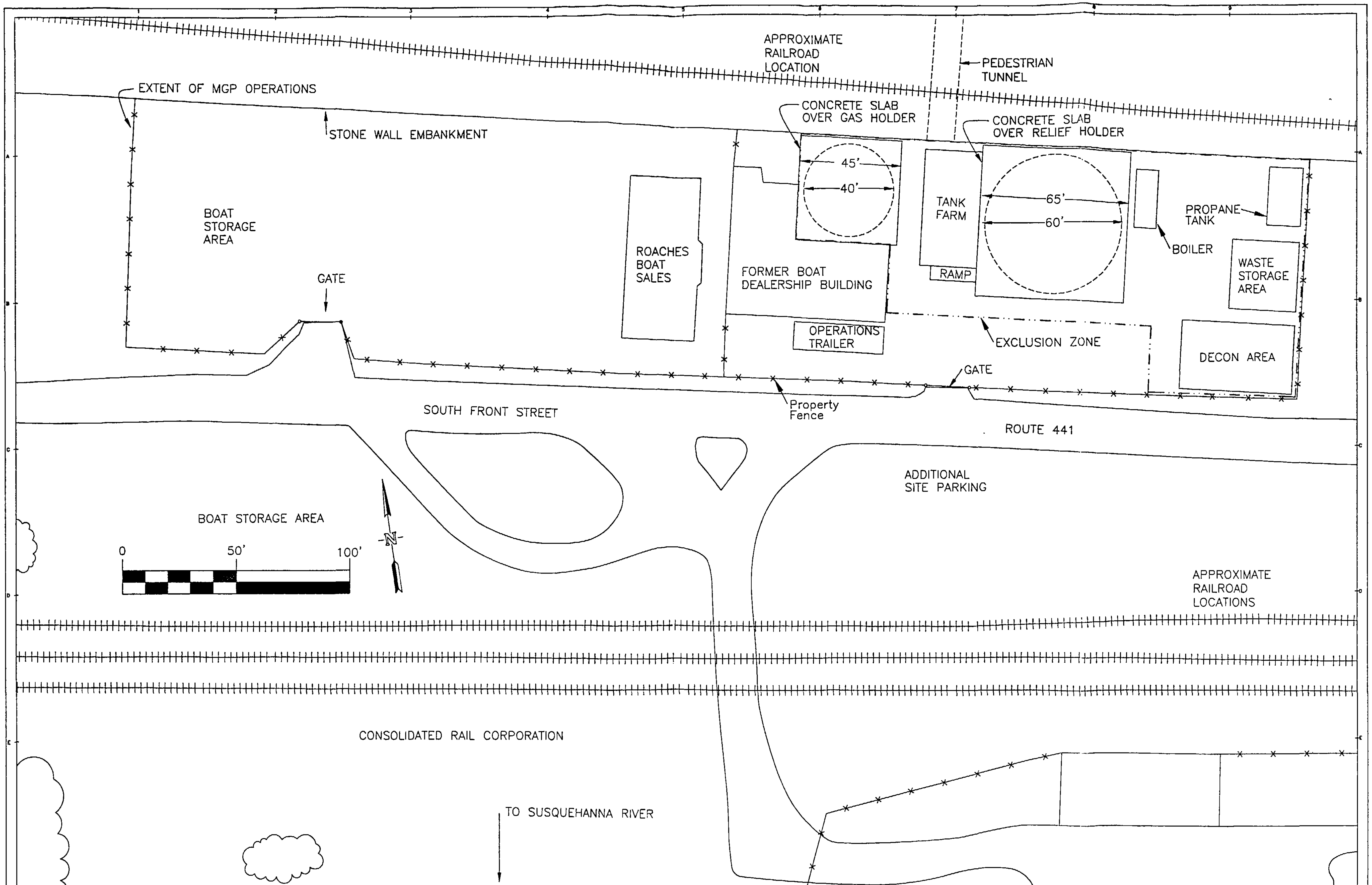


Site Location Map

FIGURE
1-1



NO	DRWN	DATE	REVISION	CHKD	DATE	APPVD	DATE
F	BcV	12/96	MODIFIED SITE DRAWING				
E		9/29/95	NIC				
D		8/18/95	NIC				
C		6/30/95	NIC				
B		6/16/95	NIC				
A		5/10/95	NIC				

REFERENCE DWG | DESCRIPTION

PENNSYLVANIA POWER & LIGHT COMPANY
UGI COLUMBIA SITE
3-1612

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CURRENT DATE: 9/29/95 CAD FILE 1612S002.DWG

SITE LAYOUT

COLUMBIA SITE
COLUMBIA, PENNSYLVANIA

RETEC
REMEDIATION TECHNOLOGIES INC

DRAWING NO. 1-2 REV. F

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RETEC

PRE-1937 SITE PHOTO

FIGURE 1-3

October 1979, George Roach purchase two-thirds of the property from Thomas Crouse and began operating a boat dealership (Halliburton NUS, 1993). The Site was repurchased by PP&L on January 27, 1994 and was placed on the National Priorities List (NPL) in June of 1994.

The process of site remediation was initiated under the Superfund Accelerated Cleanup Model (SACM) as a non-time critical removal action. RETEC prepared an Engineering Evaluation/Cost Analysis (EE/CA) (RETEC, 1994) for the relief and gas holder. The results of the EE/CA showed that the selected relief holder remedy should be enhanced recovery using steam injection. The selected gas holder remedy should be conventional pumping. The final step for both holders is the removal of residual liquids followed by stabilization with flowable flyash. The Pennsylvania Department of Environmental Protection (PADEP) issued a Statement of Decision on July 17,1995, that concurred with the EE/CA's selected remedies. PP&L and EPRI entered into a tailored collaboration to remediate the relief and gas holders at the Site.

1.3.2 Site Background

This section presents a detailed background of the Site leading to the remedial action described in this report.

1.3.2.1 Facility Operations

CGC originated in 1851 with the prospect of supplying the Borough of Columbia, Pennsylvania with manufactured gas. Previous investigations indicate that manufactured gas was originally generated from wood. These investigations also indicate that there is no other information concerning operations at the Site prior to 1910.

The manufactured gas process began with the transport of gas from two gas generating sets through a washbox, condenser, washer cooler, and stored in a relief holder. From the relief holder, the gas proceeded through a tar separator, a purifier, and finally distributed to a holder for distribution to the city.

The handling practices for the manufacturing gas process are of particular interest. These practices include the handling of three major waste streams: tars, boiler ash, and purifier wastes. (The term "tar" in this report refers to dark oily liquids and stained soils which have a distinct odor similar to that of creosote, and does not imply a source.)

The tar separator received liquids produced during the manufacturing process. The liquids originated from the washer-coolers, the drip pumps, and the overflows from the gas holder water seal. Tars were pumped to the relief holder pit and stored to allow for separation of the tar/water emulsion. After separation, the tar was pumped to oil tanks for storage. The water levels in the tar separator did not usually pose a problem in the summer months due to adequate evaporation. However, during the winter months of heavy precipitation, overflows occurred and discharged directly into an open ditch that led to the Susquehanna River. Records indicate that local fishermen complained to the plant that their boats were being covered with tar (Halliburton NUS, 1993).

Boiler ash was stockpiled in the area in front of the relief holder during the 1930s and the 1940s. The ash was hauled away three times per week by a private hauler. A portion of the boiler ash was reported to have been disposed on the eastern side of Front Street (i.e. across the street from the former plant). However, it is not known where the majority of the ash was disposed.

The purifier materials consisted of iron oxide treated wood chips arranged on wooden racks. Once these materials were spent, they were placed in one foot lifts onsite and turned frequently to prevent spontaneous combustion. They were then used as paving and dust control materials via spreading the material over the surface of the Site (Horner, 1985).

1.3.2.2 Physical Description

In 1910, the plant was completely rebuilt, with the exception of two gas holders and one boiler. The reconstruction included new buildings on former building foundations, a tar separator, water gas sets, and a double unit purifier. Old plans reveal the presence of an artesian well. However, post-1910 operations used city water. A Site layout map of the plant, dated 1935 (TRC, 1986), revealed the structures present during operation. They included the following:

- 60-foot diameter relief holder;
- 40-foot diameter gas holder;
- oil tank;
- cooler tank;
- tar separator;
- tar tanks;
- meter house;
- boiler and generating house;
- brick room; and
- purifier house.

The gas holder, also known as the city or distribution holder pit, was located near the center of the property, east of the larger of the two onsite buildings (Figure 1-2). The gas holder was used to store gas prior to distribution. The 40 foot diameter structure was a brick-lined cylindrical pit with a concrete base. A boring drilled in 1985 revealed that the pit contained tar-coated fill material to a depth of approximately 17 feet. The concrete base was found to be fractured. A test pit dug adjacent to the pit indicated that tars were leaking from the wall (TRC, 1986). A more extensive investigation of the gas holder was performed in December 1993 by Remediation Technologies, Inc. to determine the contents of both the gas and relief holders.

The relief holder, shown in Figure 1-2, was constructed of riveted steel plates and was contained within an approximately 26 foot deep pit. Tars were stored inside the relief holder during plant operation to allow separation of tar/water emulsions. In 1947, the relief holder experienced a structural failure. However, the relief pit remained in operation as a separator. High quality tar was sold while low quality tar remained within the relief holder. Once operation of the plant ceased, the pit was filled with general refuse, construction fill, and soil (Halliburton NUS, 1993).

After Mr. Roach purchased the property in October 1979, he observed tar surfacing in parking lot, which subsequently resulted in the regrading of the property (Halliburton NUS, 1993). The relief holder foundation was found to be filled with refuse, construction debris, and fill. During the regrading, tars within the relief holder were displaced and reportedly released to the surface soils in the immediate area. Tars were forced into a former pedestrian tunnel/underpass located on the property and enclosed within the underpass through the construction of a small dike. The total volume of tar contained within the tunnel was estimated at 7,500 gallons during the 1985 Site investigation.

Currently, two buildings exist on the property; both were used by the boat dealership and their locations are shown in Figure 1-2. The buildings occupy the central portion of the Site and were used as repair, showroom, and maintenance facilities. Two concrete pads, one 45 by 45 feet and one 65 by 65 feet, are located southeast of the buildings and cover the former gas and relief holders, respectively. Conrail railroad tracks lay adjacent to the northeastern Site boundary. A former pedestrian tunnel passes under the railroad tracks and has since been blocked off at the eastern end due to the expansion of the railroad track. The remainder of the Site is covered with gravel and was used by the dealership for boat storage.

1.3.2.3 Previous Investigations

UGI filed a Notification of Hazardous Waste Site Form with the EPA for the Site on June 9, 1982. UGI was uncertain of former practices of the gas manufacturing facility or the nature site waste. The company filed with the EPA as a precautionary measure.

On August 14, 1984, PADEP initiated a preliminary assessment of the Site. During the assessment, surface accumulations of coal tar were observed, and coal tar previously moved into the pedestrian tunnel was discovered. PP&L agreed to fund a Site investigation along with UGI on December 7, 1984. The investigation's purpose was to determine the nature and extent of contamination (Halliburton NUS, 1993).

In 1985, PP&L and UGI hired TRC Environmental Consultants, Inc. (TRC) to perform an extensive property investigation. The investigation included installing nine monitoring wells, test pits, and borings to determine the extent of contamination on and around the Site. Also, seismic refraction surveys were performed to delineate fracture zones in the bedrock.

The Site investigation conducted by TRC led to the remedial action in 1987, which included recovering materials in the tunnel area and capping the gas and relief holders. The sludge and soils from the pedestrian tunnel were removed, the tunnel walls steam cleaned, and an eight-inch cement floor was constructed near the entrance of the tunnel. Closure of the relief and gas holders was performed by installing a concrete slab over each holder. One leak discovered during holder closure was plugged. An unknown amount of coal tar remained in the holders.

A second investigation was commissioned by PP&L in 1987 to determine the extent of coal tar contamination in the Susquehanna River. The investigation concluded that approximately 800 cubic yards of Susquehanna River sediment southwest of the Site were contaminated with coal tar.

On August 18, 1988, the NUS Corporation (NUS) performed a non-sampling reconnaissance of the Site. The information obtained during this study is contained in "Non-sampling Site Reconnaissance Summary Report, UGI (PP&L) Columbia Gas Plant Site", dated November 3, 1988. Additionally, NUS completed a Site inspection report in July 1989 using available information for the subject Site.

In December 1993, RETEC implemented an investigation of the gas holder that involved drilling three borings into the holder to determine its contents.

Regulatory action that has taken place at the Site includes numerous inspections by personnel from PADEP. PADEP has overseen and approved the remedial action that has taken place on the Site, monitoring of the Site, and studies and investigations into the contamination of the Site.

1.3.2.4 Previous Removal Actions

Prior to the operation of the enhanced recovery system, there has been only one removal action at the Site. This removal action was performed on the former pedestrian tunnel located on the eastern portion of the Site. Sludge and visually contaminated soil was removed, the tunnel walls steam cleaned, and a cement floor constructed near the entrance of the tunnel. Approximately 100 cubic yards of materials were removed from the pedestrian tunnel. The materials were removed on February 2, 1987 and disposed by Chem-Met Services. Drums that were reportedly stored in the rear of the tunnel, were removed; their contents were determined to be nonhazardous (their nature is unknown) and taken to a landfill.

1.3.2.5 Site Geology/Hydrogeology/Climate

Surface Water Bodies

Three surface water bodies exist in local proximity of the Site: the Susquehanna River, Shawnee Creek, and Strickler Run. The Susquehanna River is used for commercial and recreational purposes. The river flows in a southeasterly direction past Columbia and lies approximately 400 feet southwest of the Site. The average river flow past Columbia is 36,710 cubic feet per second (NUS, 1993). The City of Lancaster Water Authority (CLWA) operates a river intake approximately 800 feet upstream of the Site that serves approximately 110,000 people. The Columbia Boro operates an intake approximately 400 feet upstream of the Site that serves the city of Columbia. The Safe Harbor Authority operates a surface intake 9.8 miles downstream of the Site, serving approximately 90 people. There are no known surface water intakes within three miles downstream of the Site.

Shawnee Creek is a perennial stream that discharges into the Susquehanna River approximately 600 feet west and upstream of the Site. Strickler Run also is a perennial stream, located approximately 3,000 feet southeast of the Site. This stream flows to the west and discharges into the Susquehanna River. It is utilized for recreational purposes (NUS, 1988).

Geology

The Columbia Gas Plant Site is located in the Conestoga Valley Section of the Piedmont Physiographic Province. This section is characterized by a 10,000 foot area of limestones and dolomites of Cambrian and Ordovician age with minor occurrences of quartzite, phyllite, and schist. The majority of the stratigraphic sequence has been folded during the Middle Ordovician age Taconic Orgeny. The regional topography is characterized by rolling terrain with relief controlled by differences in the ability of carbonates and shales to resist erosion. The drainage pattern throughout the area is completely dendritic. The formations at the Site include, in descending stratigraphic order: Conestoga, Ledger, Kinzers, and Vintage Formations.

The Conestoga Formation is characterized by medium gray, fine to coarse grained crystalline limestone with frequently occurring clay laminae and some thin micaceous beds. The formation is approximately 1,000 feet thick and is usually marked by coarsely crystalline, silty, and sandy limestones and beds of conglomerate containing clasts. The structure is characterized by upright or slightly overturned isoclinal folds and steeply dipping axial plane cleavage that strikes east-northeast.

Previous studies indicate that the Conestoga Formation is fractured in discrete zones; north 20 degrees west is the most common orientation. These zones are approximately fifteen to twenty feet wide and seventy to eighty degrees from the horizontal. The dip of the fractures is near vertical, which is uncharacteristic of the region orientations. This is the result of folding within the Columbia syncline (NUS, 1989).

The Cambrian age Kinzers Formation is composed of massive light gray, medium to coarsely crystalline, sparkling dolomite. The formation has been estimated at 1,000 feet thick. The Cambrian age Kinzers Formation is composed of gray and rusty weathered shale, limestone of variable composition, and dolomite. The limestone ranges from white to dark gray, thin bedded to massive, argillaceous, silty, and sandy beds. The dolomite is thick bedded, gray to black, and very finely crystalline. The thickness of this formation ranges from 300 to 600 feet. The Cambrian age Vintage Formation is composed of thick bedded to massive, very finely crystalline dolomite. Its thickness ranges from 350 to 550 feet (Halliburton NUS, 1993).

Soils

There are three major geological divisions that underlie the Site; they are fill material, Quaternary alluvium, and the Conestoga Formation. The fill consists of brown, fine to medium grained sand, brick fragments, wood chips, pulverized coal, and large blocks of stone. The alluvium is a fine grained sand with trace amounts of rounded, coarse grained sand and fine gravel. Also within the alluvium layer, there are some interbedded silt and clay beds. Previous investigations revealed approximately three to twenty-seven feet of fill material overlying zero to twelve feet of alluvium overlying limestone bedrock (NUS, 1989).

Surface and Subsurface Hydrology

The surface water hydrology of the region is dominated by the Susquehanna River. Site surface drainage is to the southwest toward the river and there are no streams or open drainage ditches within the Site boundaries.

Within the region of the Site, groundwater flows toward the Susquehanna River, south-southwest, and continuous across the River. Groundwater movement in the Site's vicinity is strongly influenced by the bedrock characteristics. Secondary permeability is relatively high due to numerous fracture zones. Therefore, groundwater flow is largely controlled by bedrock fractures. The south 85 degrees west fracture trace has a strong influence on groundwater flow (TRC, 1986). Although the major flow gradient is directed southward, there may be a slight westward shift (NUS, 1988). The majority of the Site consists of carbonates, and therefore, water movement and storage are a function of fracturing, solution channels, and to some extent, bedding planes (NUS, 1988). The Conestoga Formation underlying the Site has low primary permeability and low secondary porosity characteristics.

Previous investigations indicate that a shallow water table exists within the Conestonoga Formation in some locations and within the alluvium deposits in other locations. These saturated regions act as a single shallow aquifer (Halliburton NUS, 1993). The water table is much higher in the spring than in the fall. This seasonal fluctuation may be due to precipitation variances and the cumulative effect of higher evapotransportation rates during summer months. The average minimum gradient between Site and river is estimated to vary between 0.020 ft/ft in the fall and 0.026 ft/ft in the spring (TRC, 1986).

Surrounding Land Use and Populations

The regional surrounding communities include Columbia, Wrightsville, and the Borough of Washington. The community of Columbia, Pennsylvania has a population of approximately 11,000, Wrightsville is approximately 3,000, and approximately 450 are within the boundaries of the Borough of Washington. The population within a two mile Site radius is approximately 16,000 (NUS, 1988).

The area consists of light industrial, commercial and residential properties. The Site is bordered by a railroad retaining wall and Conrail railroad tracks to the northeast, a boat repair shop to the northwest, a resident to the southeast, and Front Street to the southwest. Areas to the south and southeast of the Site consist predominantly of agricultural and undeveloped wooded areas. The surrounding area includes a municipal sewage treatment plant, the Susquehanna River, and Conrail Railroad lines. Other residential properties exist to the southeast and north with the closest lying approximately 400 feet from the property. All residences in the Site's vicinity receive the city's water supply (TRC, 1986).

Drinking Water Sources

Residents within a three mile radius of the Site receive their water from the Columbia Water Company (CWC) or from domestic wells.

The CWC utilizes surface water to serve the city of Columbia and about 40 percent of West Hempfield Township, including the villages of Cordelia, Ironville, Farmdale, and part of Chestnut Hill. CWC serves a population of approximately 18,000. Their source of the water is the Susquehanna River. The surface water intake is located approximately 200 feet out into the river, and one-half mile upstream of the Site (Halliburton NUS, 1993). This surface water intake has a capacity of approximately 1.68 million gallons per day (MGD). The treatment system has a capacity of approximately 3.2 MGD and a total storage capacity of 6.3 million gallons. The distribution system is comprised of both cast iron and ductile iron pipes. The CWC has been in operation since 1823 (NUS, 1988).

A second water supply company is the City of Lancaster Water Authority (CLWA), which also has a surface water intake on the Susquehanna River. This intake is located approximately 0.1 mile upstream of the Site. The system serves 110,000 persons in the city of Lancaster and parts of Lancaster County. All of the customers that the CLWA serves reside outside the three mile radius of the Site.

Approximately 3,550 residents within the three mile radius utilize private residential wells as a source of drinking water. A study conducted by PP&L in the summer of 1990 identified three residents that obtain their water from private wells that are close to and downgradient of the Site. These residences are seasonal cottages located approximately one-quarter mile north of the Site. The water from these wells is not used for drinking (Halliburton NUS, 1993).

Critical Environments

According to the United States Department of the Interior, Fish and Wildlife Service, there are no known endangered species located within a three-mile radius of the Site. There are two federally listed endangered birds that are expected to be found as transient species in the vicinity of the Site. These species are the bald eagle and the peregrine falcon. However, there is no known critical habitat for these species in the vicinity of the Site (NUS, 1988).

Meteorology

Since the Site is located in the southern portion of the state, the climate is moderate with an average annual precipitation of approximately 43 inches and an average annual temperature of 53°F. The annual net precipitation at the Site is approximately 10.2 inches, of which the majority is in the form of rain. This figure is based on information obtained for Ephrata, Pennsylvania, which is nineteen miles northeast of the Site. However, annual snow accumulations can be as high as 20 inches or more. The mean monthly temperatures range from a low of 32°F in January to a high of 78°F in July (TRC, 1986).

1.3.3 Source, Nature, and Extent of Contamination

The Site had four major areas of concern consisting of the relief and gas holders, the former pedestrian tunnel, the area of contaminated sediment in the Susquehanna River, and the area located on the western side of Front Street where the boiler ash may have been landfilled. However, the remedial work conducted at the Site in 1987 alleviated the problems associated with the former pedestrian tunnel.

1.3.3.1 Site Investigation, 1986 (TRC, December 1986)

TRC's extensive field investigation included the construction of nine monitoring wells, test pits, and borings to determine the extent of contamination on and around the Site. Samples were collected from the groundwater, the sludge from the tunnel, the Susquehanna River, and the underground tanks before any remedial actions were performed.

One boring was drilled into the gas holder to the base of the holder. The boring had a high rock quality designation (RQD) (i.e. relatively unfractured), and encountered random fill which contained tars. A sample taken from this boring at a depth interval of 15 to 17 feet was collected for analysis. A test pit constructed along the outside of the holder revealed coal tar was leaking through the brick wall of the holder and into the surrounding soil.

A separate boring was drilled directly into the relief holder; it encountered approximately 22 feet of random fill and tars. The outer wall, like the gas holder, was constructed of brick. However, waste was found to be deposited directly onto bedrock, there is no artificial bottom constructed for the relief holder. Comparable to the gas holder, the relief holder has a high RQD. However, tars from the within the holder had reportedly penetrated six inches into the limestone bedrock. Thus, there is evidence of hazardous substance migration from the holder.

The test pit constructed within the relief holder revealed approximately two and one-half feet of cover underlain by random fill, which consisted of metal, wood, pipe, brick, and blocks of rock up to three feet in diameter. Tars were found at a depth interval of 2.5 to 6 feet within the pit.

Demonstration wells were installed in both the relief and gas holders to determine the thickness of the immiscible tar fractions and to evaluate the feasibility of tar removal by pumping. The demonstration well installed in the gas holder contained no tars. The investigation concluded there was no significant floating hydrocarbon fraction within the gas holder. The demonstration well installed in the relief holder contained floating product that appeared to be less than one inch thick and contained a noticeable sinking fraction. Both holders were capped by concrete which is underlain by one to two feet of soil and assorted fill material that includes brick, wood, pipe, garden refuse, refrigerators, and large rocks. The fill material was coated with tar.

Since the groundwater migration pathway is a major route of concern at the Site, nine monitoring wells were installed in six locations during the 1986 Site investigation. These wells were installed to determine the extent of groundwater contamination in the Site's vicinity. Monitoring well pair MW 1S and MW 1D were installed upgradient of the Site and represented background conditions. MW 3S and 3D were installed immediately downgradient of the relief holder, and MW 2 was located on a downgradient fracture zone approximately 280 feet west of the Site. MW 6S and MW 6D were located along a downgradient fracture zone approximately 650 feet west of the Site. MW 4 was positioned on a downgradient fracture zone approximately 60 feet south of the Site. Monitoring well locations are presented in Figure 1-4.

The analytical data from this investigation is contained in "Columbia Gas Plant Site, Columbia, Pennsylvania, Final Report of Investigations" prepared by TRC, dated December 17, 1986. Groundwater samples indicated phenol up to 0.048 mg/l, 2,4-dimethylphenol up to 0.062 mg/l, benzene up to 310 mg/l, toluene up to 190 mg/l, ethylbenzene up to 60 mg/l, naphthalene up to 5.65 mg/l, acenaphthylene up to 0.210 mg/l, acenaphthene up to 0.080 mg/l, fluorene up to 0.050 mg/l, phenanthrene up to 0.040 mg/l, total phenol up to 0.410 mg/l, and total cyanides up to 0.104 mg/l.

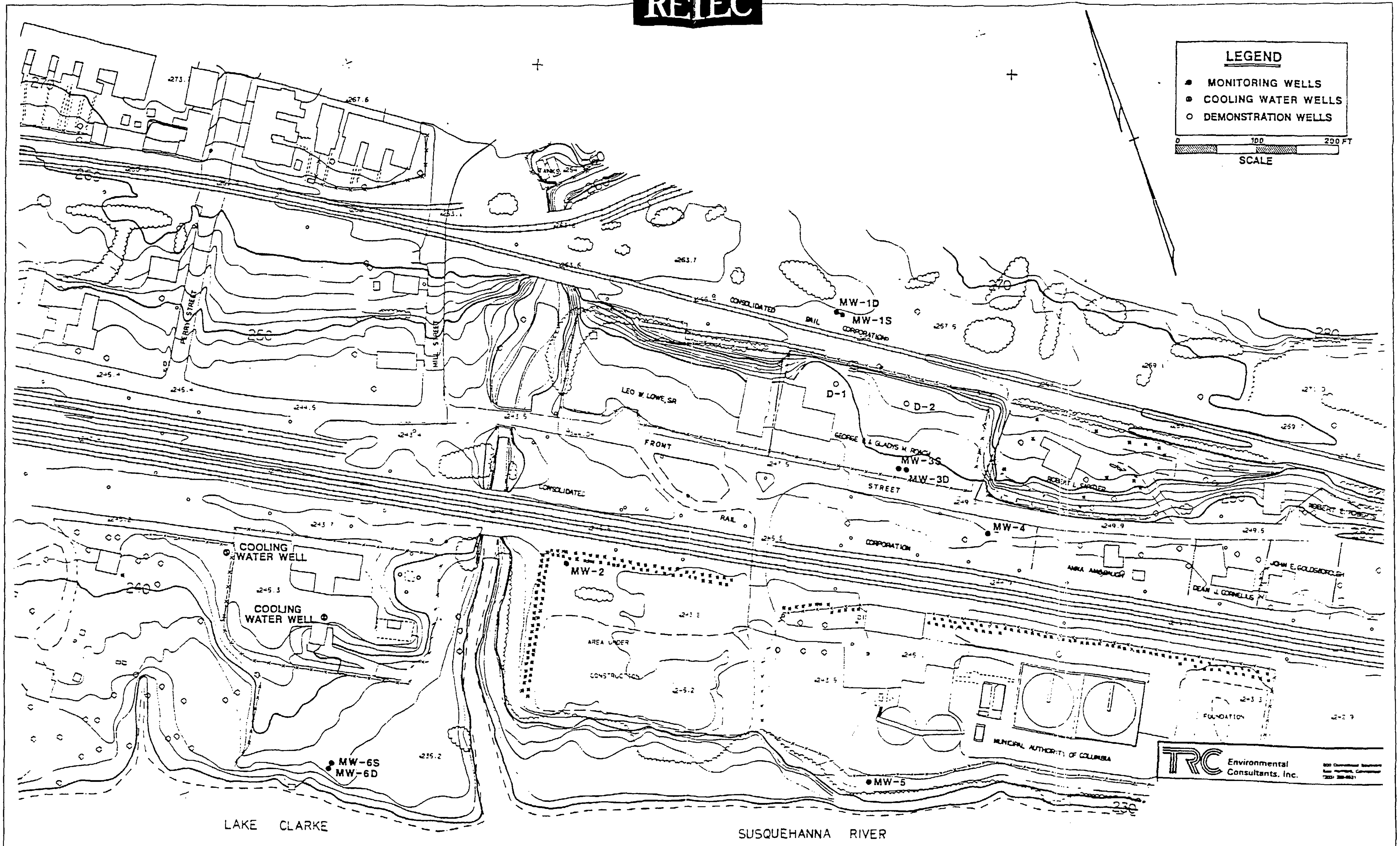
Also, before remedial action on the pedestrian tunnel, sludge samples revealed benzene up to 18 mg/kg, toluene up to 8.8 mg/kg, ethylbenzene up to 0.89 mg/kg, polycyclic aromatic hydrocarbons (PAHs) up to 6.5%, total phenols up to 7.6 mg/kg, and cyanide up to 6.5%.

1.3.3.2 Second Investigation, 1987

Atlantic Environmental Services, Inc. was retained by PP&L to determine the extent of coal tar contamination in the Susquehanna River. Their investigation included a detailed investigation of the alluvial stratigraphy in the Columbia area, the field conditions around the Site, and possible conduits from the Site to the Susquehanna River. The investigation concluded that 800 cubic yards of sediment southwest of the Site contained coal tar constituents. The investigation suggested that tar was actively migrating via groundwater through the flood plain sediments (alluvium) into river sediments and that the source of the tar was probably the open ditch that received overflow from the tar separator. In addition, this study suggested that the contamination found in the river sediments was probably emplaced after 1972, approximately 24 years after the closure of the gas plant (Halliburton NUS, 1993).

1.3.3.3 Expanded Site Inspection, 1991 (NUS, October 1991)

The 1991 expanded Site inspection included the sampling of four potential source areas: onsite surface soil, the two relief holders, the sediments in the Susquehanna River, and the defined area that the boiler ash may have been landfilled.



Monitoring Well Locations
UGI Columbia Gas Plant Site
Columbia, Pennsylvania

FIGURE 1-4

The surface soil samples were taken from four different locations on the Site, three of which contained PAH constituents.

1.3.3.4 Investigation of Holders, 1993

In November 1993, the Western Research Institute (WRI) performed a simulated distillation, viscosity, and density analysis on a sample taken from the relief holder at the Site. Originally there were two samples sent to WRI for analysis, one sample taken from the gas holder and one taken from the relief holder. However, during the organic-water separation process at the laboratory, it was discovered that the sample taken from the gas holder (i.e., B Sample) contained little separable organics. Therefore, this sample was not analyzed. The simulated distillation data for the sample taken from the relief holder is given in Appendix J.

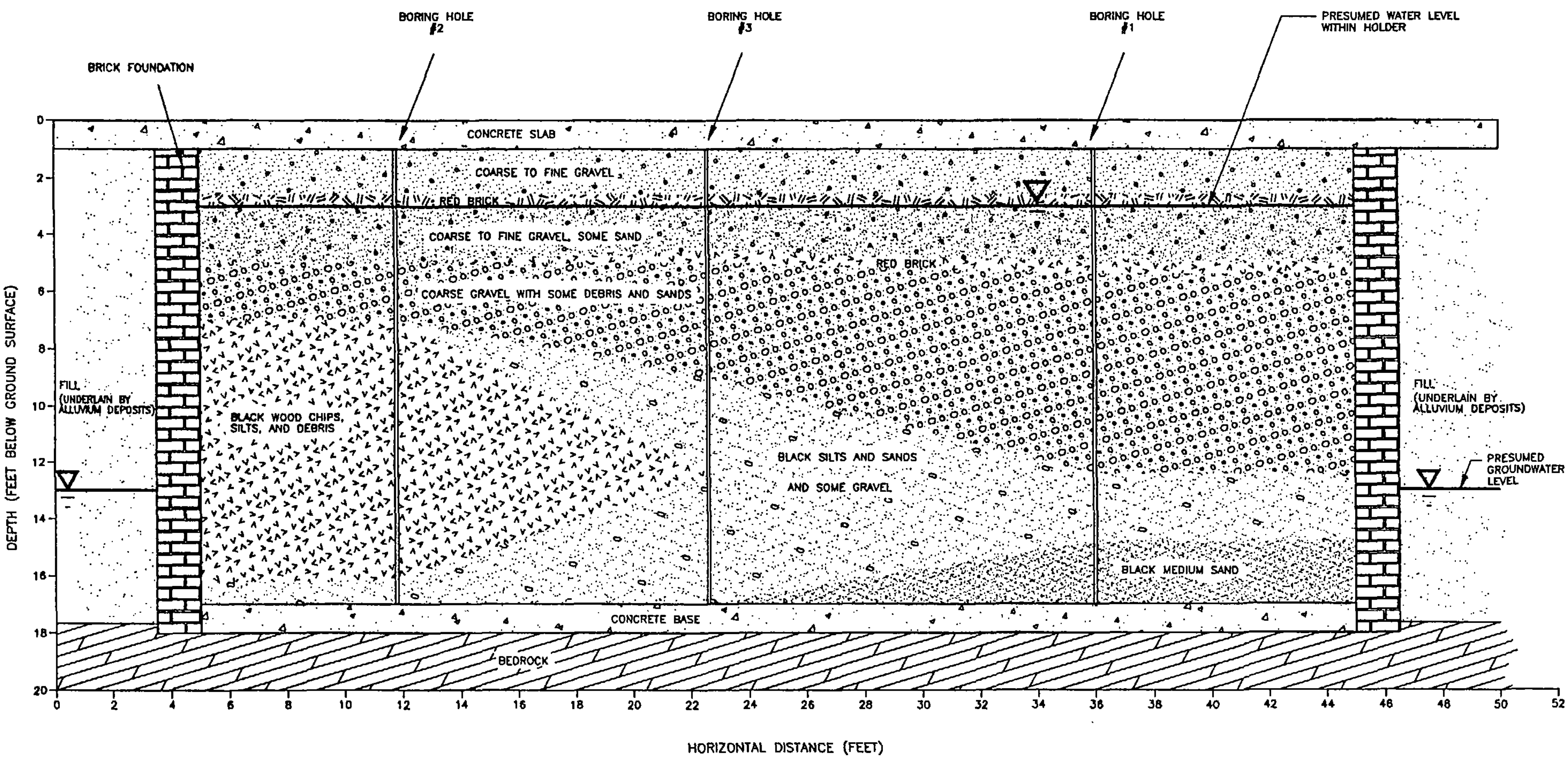
In December 1993, RETEC drilled three borings approximately 17 feet to the bottom of the gas holder. The purpose of the gas holder investigation was to determine the contents of the smaller of the two former holders at the Site. A cross-section of the gas holder was constructed from the information obtained from this investigation and is shown in Figure 1-5.

1.3.3.5 Streamlined Risk Evaluation

As part of the Engineering Evaluation /Cost Analysis (EE/CA) (RETEC, 1994) a streamlined risk assessment was conducted for the Site. The purpose of the streamlined risk evaluation (SRE) was to provide a qualitative assessment of the potential risks to human health and the environment that would be mitigated from the proposed remediation of the former gas and relief holders.

The SRE provided a qualitative assessment of the potential risks to human health and the environment that would be mitigated from the proposed remediation of the former gas and relief holders. The greatest risks that would appear to be mitigated from the remediation effort are those associated with direct contact of the residual materials in the subsurface in and around the former gas and relief holders. Previous investigations reported elevated levels of carcinogenic and noncarcinogenic chemicals in subsurface soils, groundwater, and in both holders. These findings are supported by visual observations of tar-like residuals in each of these media. The reduction in risks to both human and environmental receptors although not quantified, is expected to be potentially significant especially for future excavation workers.

RETEC



Cross Section of Gas Holder, 1993	FIGURE 1-5
	1310X001

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1.3.3.6 Engineering Evaluation/cost Analysis

In August 1994, RETEC submitted an EE/CA (RETEC, 1994) that evaluated remedial technologies for performing a non-time critical removal action for the Site holders. Based on investigations that revealed coal tar migration from the holders, the objective of remedial alternative selection was to eliminate constituent migration.

The four alternatives that were selected for consideration are shown in Table 1-1.

Because the relief holder contained free coal tar and the gas holder contained no evidence of free coal tar, two different removal alternatives were selected. The selected gas holder remedial alternative was pumping followed by stabilization. Because of the significant quantities of coal tar, the selected relief holder remedial alternative was enhanced product recovery followed by stabilization. The no action alternative was rejected because it lacked long term effectiveness and reduction in the mobility, toxicity, or volume of contaminants. Excavation was rejected due to implementability factors relating to the proximity of the active rail line.

As reported in the EE/CA, the UGI Columbia Gas Plant Site is a superfund Site. Therefore, obtaining specific permits was not be required. However, the EE/CA identified several applicable or relevant and appropriate requirements (ARARs). These requirements include state and federal environmental laws and regulations that were appropriate to consider during the remedial action.

Specifically, RETEC/Clean Sites Environmental Services (CSES) had to comply with Article VII, Chapter 92, 25 PA Code 92.1 et. seq., which sets forth provisions for the administration of the National Pollutant Discharge Elimination System (NPDES) Program within Pennsylvania. RETEC/CSES applied for a NPDES permit to discharge treated waters to the Susquehanna River. Although an actual NPDES permit was not be granted, the discharge quality had to comply with the criteria set by permit equivalence as administered by PADEP.

In addition, it was required that the onsite vapor generator/boiler be operated in compliance with Pennsylvania Air Quality Laws including Article VII, Chapter 123, 25 PA Code 123.1 et. seq., which establishes requirements on fugitive emissions, and Article VII, Chapter 131, 25 PA Code 131.1 et. seq., which adopts federal ambient air quality standards.

Table 1-1 Selected EE/CA Alternatives

No Action With Monitoring	Accomplish Site objectives by providing institutional controls and groundwater monitoring, but without removing coal tar and/or coal tar constituents from the holders,
Excavation	Accomplish Site objectives by excavating the contents of the holders and disposing of them at a licensed treatment or disposal facility
Pumping	Accomplish Site objectives by pumping extractable liquids from the holders. Pumping would be followed by stabilization with flowable grout.
Enhanced Product Recovery	Accomplish Site objectives by injecting steam to mobilize free coal tar to a flowable state, pumping the liquid matrix until free coal tar levels diminish, followed by stabilization by grouting with flowable flyash.

Because the removal action included a waste stabilization step and an activated carbon treatment step. The activities had to comply with PA SWMA, Act 97, Chapters 264 or 265 and 297.

Finally, any generated contaminated soils were analyzed for hazardous characteristics. All hazardous wastes were transported and treated or disposed in compliance with Article VII, 25 PA code chapters 260-266, and 270. These regulations apply to the identification and listing, generation, transportation, storage, treatment and disposal of hazardous waste.

2 Chronology of Events

A chronology of events associated with the Site is as follows:

Date	Event
June 1982	UGI Corporation files Notification of Hazardous Waste Site Form with EPA.
August 1984	PADEP initiates preliminary assessment of Site.
December 1984	PP&L and UGI Corporation agrees to fund Site investigation.
1985	PP&L and UGI Corporation hires TRC Environmental Consultants to perform extensive property investigation.
1987	Relief and gas holders capped with cement concrete pad. Impacted materials recovered from pedestrian tunnel.
1987	A second investigation concludes that approximately 800 cubic yards of Susquehanna River sediments are contaminated with coal tar.
1988	NUS Corporation performs a non-sampling Site reconnaissance and completes a report entitled "Non-sampling Site Reconnaissance Summary Report, UGI (PP&L) Columbia Gas Plant Site", dated November 3, 1988.
1991	NUS Corporation performs expanded Site inspection to characterize and evaluate potential risk associated with a hazardous waste control problem.
1993	Halliburton NUS performs hazard ranking system that recommends NPL listing of the Site.
1993	PP&L retains RETEC to perform a holder investigation.
December 1993	RETEC installs three borings into the holders to determine contents.

ORIGINAL (Red)

August 1994	RETEC submits Engineering Evaluation/Cost Analysis targeting enhanced recovery as the selected remedial alternative.
1995	RETEC submits the Design and Implementation Workplan (RETEC, 1995) for the enhanced recovery system. Other Remedial Action Workplan submittals include a Health & Safety Plan, Operations and Maintenance Plan, Contingency Plan, Sampling and Analysis Plan, and Construction Specifications.
April 1996	Atlantic Environmental submits the Draft UGI Gas Plant Site Investigation Report.
July 1996	Construction of the CROW™ enhanced recovery system commences.
February 1997	CROW™ enhanced recovery system startup for relief holder.
July 1997	Conversion from steam to hot water injection.
November 1997	EPA and PADEP approves CROW™ system shutdown.
December 1997	Relief holder pumpdown is performed, relief holder grouting commences.
January 1998	Gas holder pumpdown is performed and gas holder grouting is completed.
February 1998	Demobilize following completion of holder grouting and decommissioning.
June 1998	Draft Remedial Action Report submitted.

3 Technology Description and System Design

ORIGINAL (Red)

3.1 CROW™ Technology Description

In the 1970s, WRI developed CROW™ as a hot water flushing technology to aid oil extraction from oil sands and deep shale deposits. During the 1980s, the hot-water flushing concept was revisited as a potential remedial technology for Sites contaminated with non-aqueous phase liquids (NAPL). WRI licenses CROW™ through RETEC, as a recovery technology for NAPLs, both dense and light.

With the CROW™ process, subsurface accumulations of oily wastes are immobilized by reducing NAPL concentrations to residual saturation. Controlled subsurface heating reverses downward penetration of NAPL. Buoyant oily wastes are displaced to production wells by sweeping hot water through the subsurface. NAPL flotation and vapor emissions are controlled by maintaining temperature and concentration gradients in injection water near the ground surface.

Heating the subsurface reverses the downward penetration of NAPLs and dislodges NAPL accumulations for more effective mobilization during recovery operations. Increasing temperature reduces density differences between NAPLs and water, because water is more polar and resists thermal expansion. Most NAPLs are expected to become buoyant in water at temperatures below the boiling point of water. At these temperatures, the NAPLs still have low vapor pressures and remain thermally stable. The buoyant NAPLs can migrate from fractures or other protected locations that might otherwise reduce the hot-water sweep efficiency.

3.2 UGI Columbia Gas Plant Site Crow™ Description

At the Site, eight injection wells were installed near the edges of the relief holder. One production well was installed centrally within the relief holder. Initially, steam was injected at approximately 1-3 gallons per minute (gpm) water equivalent and production water was recovered at 1-3 gpm. Following the conversion to hot water injection, injection and production rates averaged 5-7 gpm. Water and tar were pumped from the production well and produced a drawdown within the well that induced a gradient from the injection points to the production point. The induced gradient swept the heat within the target zone and created horizontal movement of NAPL toward the production well.

Once the tar/water mixture was pumped to the surface, it was directed into Tank 1 for tar/water separation. The tar that settled in Tank 1 was pumped to the oil storage tank (Tank 2) for subsequent off-site disposal. Ultimately, tar was additionally stored within the gravity settling tank as well as the oil storage tank. A process schematic is presented in Figure 3-1. An as-built process schematic is shown in Figure 3-2.

Throughout hot water injection, approximately 5-7 gpm of the separated water was recycled through a clarifier, then the water heater, and was re-injected into the eight injection wells.

3.3 Design of the Relief and Gas Holder Remediation System

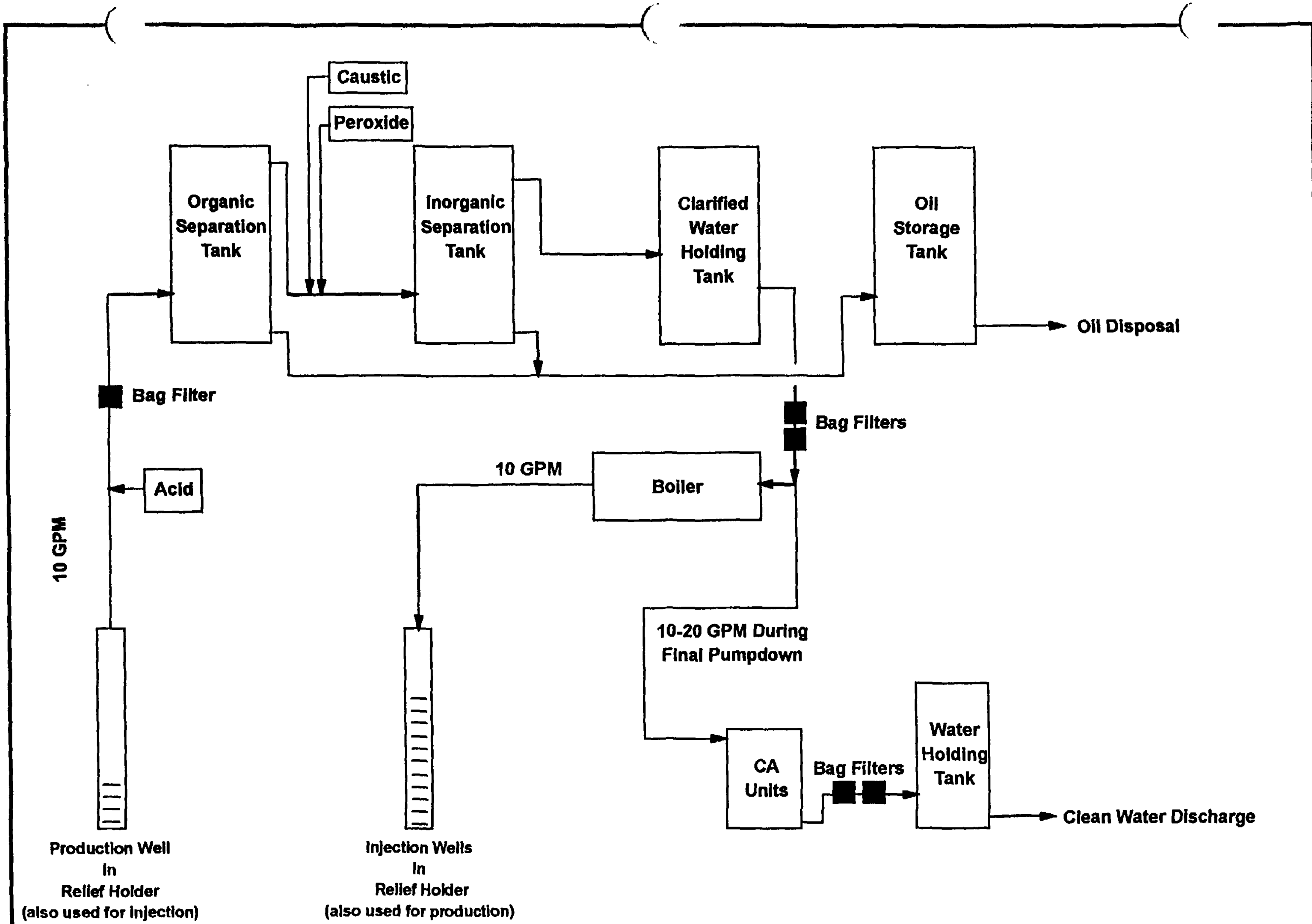
In November 1995, RETEC submitted the Design and Implementation Workplan (Workplan) for the relief and gas holder remediation; the workplan described the design of the enhanced recovery system and the tasks required to perform the remedial action.

The design of the enhanced recovery system for the Site utilized information from various sources. Previous investigations provided a large portion of the data needed for CROW™ system design. However, additional information was required in order to complete the design process including relief holder metals analysis and enhanced recovery modeling.

3.3.1 Design Sampling

Much of the design presented in the Workplan was based on relief holder tar characteristics. In September 1993, RETEC personnel collected a tar sample from the relief holder and submitted it to WRI. An attempt was made to also collect a tar sample from the gas holder, but only aqueous samples could be retrieved. WRI performed a simulated distillation, viscosity, and density analysis on the relief holder tar sample. The results from the tar analysis provided additional insight into the required design elements of the CROW™ enhanced recovery system that were included in the Workplan. The simulated distillation data for the tar sample is provided in Appendix J.

In April 1995, RETEC collected a water sample from the relief holder to obtain additional data to determine if metals pretreatment would be necessary. The sample was analyzed for total and dissolved iron, calcium, aluminum, and



Design Process Flow Diagram (Subsequently Modified)

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FIGURE 3-1

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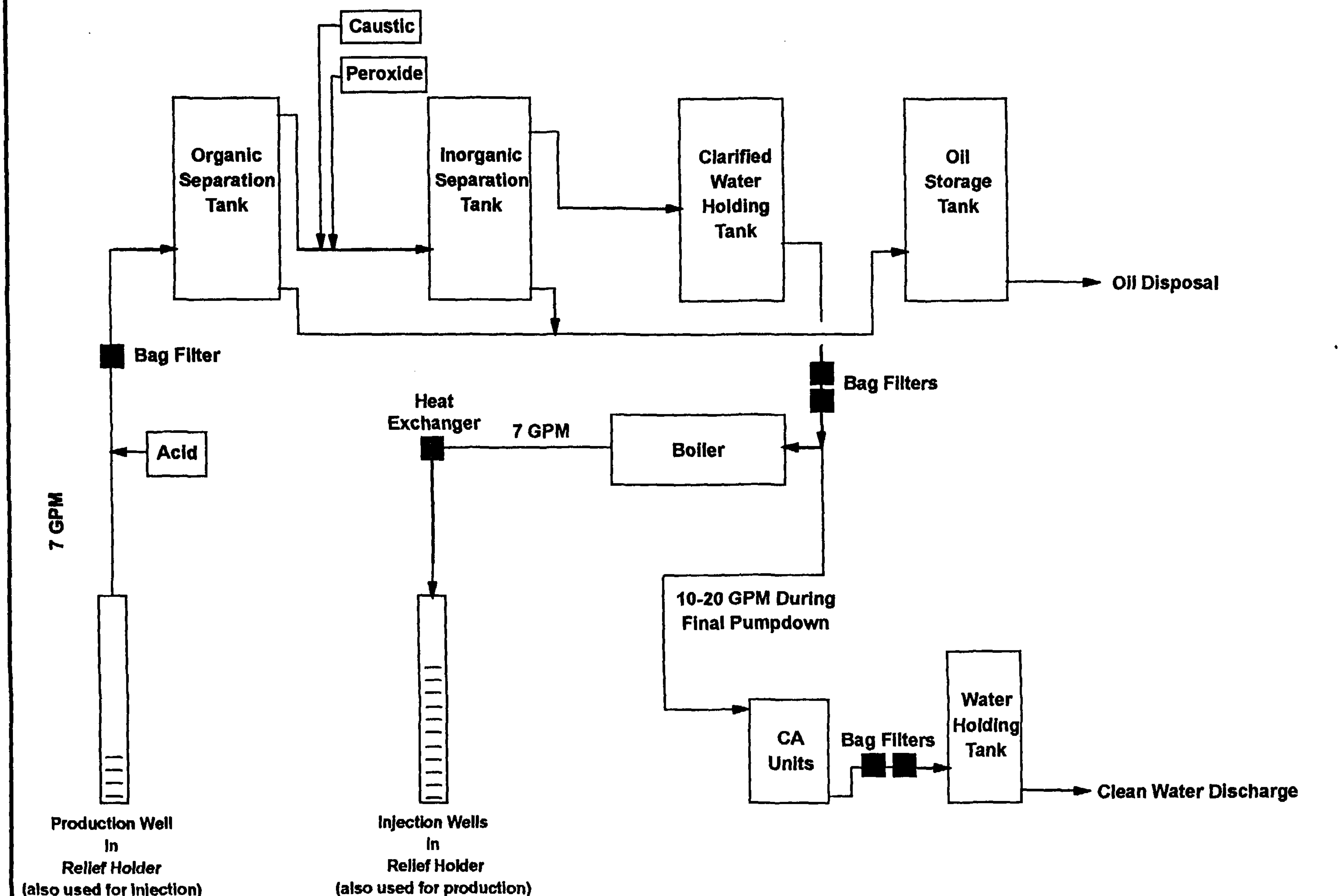

As-built Process Flow Diagram

FIGURE 3-2

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manganese. Based on this information, an iron removal component was added to the design. Other metals were present at very low levels.

3.3.2 Relief Holder Enhanced Recovery Modeling

During the design phase of the UGI Columbia Gas Plant Site CROWTM system, a preliminary modeling effort was undertaken. The modeling was performed primarily as a screening guide to determine the most efficient injection/production well pattern, estimate results based on different injection flowrates, estimate required operating durations, and whether hot-water or steam would provide more efficient operations.

Numerical simulations for the relief holder injection/extraction process were conducted with WRI numerical simulator (TSRS) that describes thermal recovery processes in porous media. TSRS is a highly implicit, four-phase, multi-component, finite difference thermal simulator. The WRI thermal simulator was developed by WRI and verified against CROWTM laboratory data and against a three-dimensional steamflood model that was developed by Keith Coates (Mones 1996).

The model formulation is based on a set of individual-component mass balance, energy balance, and related constraint equations that account for accumulation, vapor-liquid partitioning, chemical reaction, injection and production rates, heat conduction, heat loss, and the transport of mass and energy by Darcy's law. Interblock transport of mass and energy are calculated using a single-point upstream fluid mobility and enthalpy in a five-point, block-centered, finite difference scheme on fixed-size Cartesian grids. The components described by TSRS include noncondensable species (oxygen and inert gas), water (liquid and vapor), oil species (light and heavy), and coke. Source-sink terms are accommodated by specification of molar-rate at a grid block or by specification of a source-sink pressure.

For use as a field-scale simulator, TSRS has the following:

- ability to describe one-, two-, or three-spatial dimensions;
- addition of point-centered spatial grids;
- ability to specify variable grid spacings;
- ability to describe directional permeabilities;

- ability to modify interblock transmissibilities;
- addition of radial well terms (i.e., source/sink) in both horizontal and vertical orientations; and
- improvements to model numerics to reduce memory storage requirements, improve accuracy, and increase computation speed.

Since site-specific data was lacking for the relief holder at the site, simulator conditions were chosen based on CROWTM experience obtained from other sites and from literature surveys.

The conditions used for the numerical simulations are summarized in Table 3-1. No data were available to determine accurately the hydraulic conductivity, porosity or initial organic saturation of the relief holder. Hydraulic conductivity was chosen from the range found at previous CROW™ site applications. A porosity value of 50% was chosen both to minimize simulator instabilities and maximize liquid content of the relief holder.

Residual oil saturations of 21% and 9% for waterflooding and steam/gas flooding systems were chosen for the modeling, respectively. These data were taken from relative permeability end points published in the literature that had been used in history matching laboratory data, sensitivity experiments and in matching a field steam-injection test (Coates 1976). An initial organic saturation of 25% was chosen based on discussions with PP&L personnel. It was further assumed that there was mobile organic phase liquid in the relief holder, consequently, a value higher than the residual oil saturation to water (21%) was chosen.

Relative permeability curves for steam and heavy oil systems are available from published literature. These curves were used since no curves were available that more closely fit this situation.

Numerical simulations of both steam injection and hot-water injection were conducted and the results compared. As indicated earlier, residual oil saturations from steam injection are significantly lower than with hot water. Due to the relatively small, confined area of the relief holder, steam conditions throughout the relief holder should be possible. Therefore, steam stripping in addition to steam displacement to achieve the lower residual organic saturations is possible.

Steam injection rates of 2, 5, and 10 gpm of cold-water equivalent steam were chosen for the final conditions modeled. Hot-water injection at 10 gpm was also simulated for comparison.

TABLE 3-1 Numerical Simulation Conditions and Assumptions

Soil Hydraulic Conductivity, Darcy(ft/day)	25(60)
Porosity, %	50
Initial Relief Holder Temperature, °F	70
Steam Injection Temperature, °F	250
Hot-Water Injection Temperature, °F	190
Initial Organic Saturation, % pore volume	25
Residual Organic Saturation to Steam, %	9
Residual Organic Saturation to Water, %	21
Injection Rates of Steam as Cold-Water, gpm(lb/hr)	2(1000) 5(2500) 10(5000)
Hot-Water Injection Rate, gpm	10
Organic Specific Gravity	1.06
Organic Viscosity at 70 °F, cp	30.8
120 °F, cp	9.8
180 °F, cp	4.0

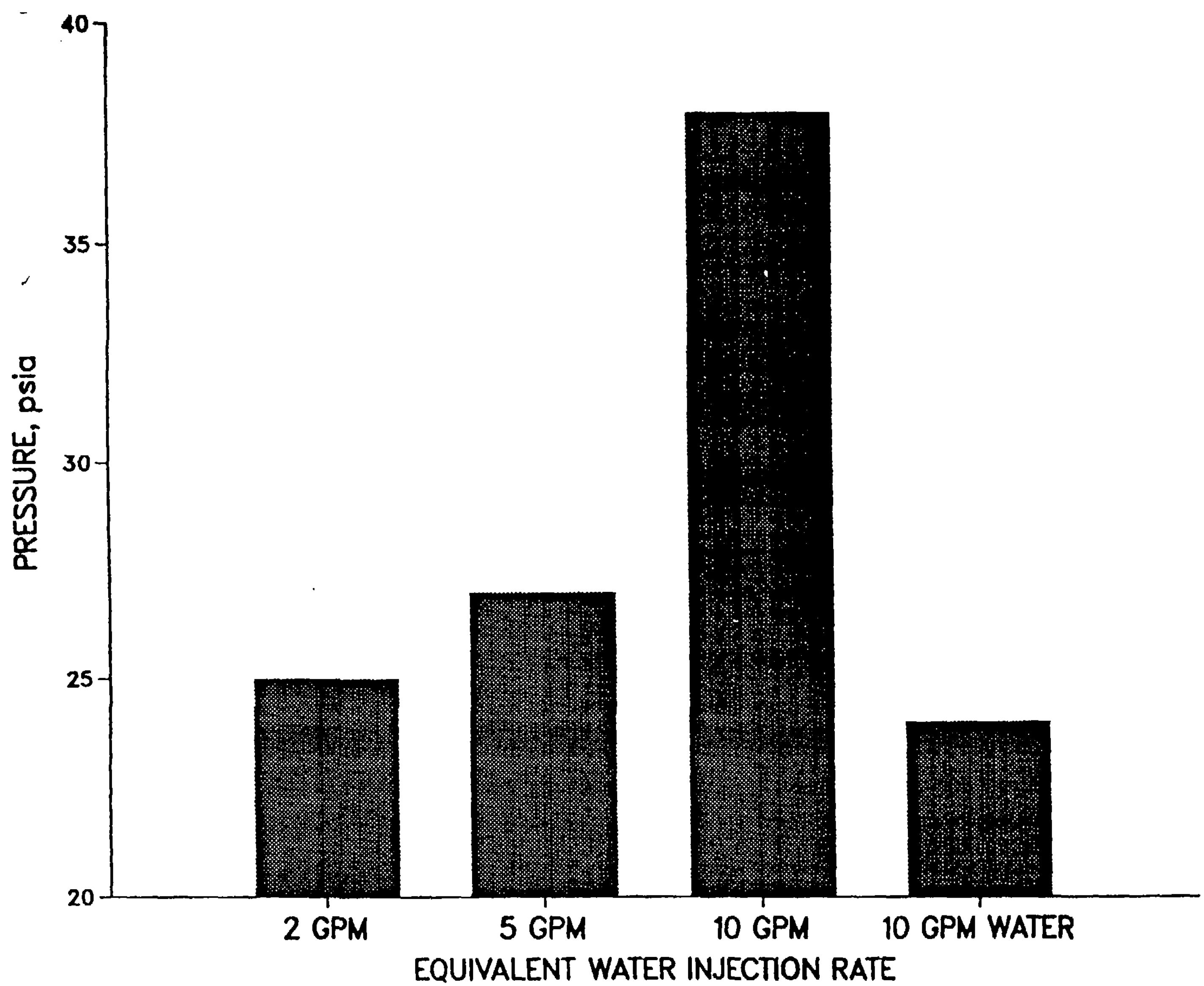
The maximum steam and water injection pressures are presented in Figure 3-3 for the 4 conditions modeled. Due to field conditions, it was desirable to limit steam pressure to about 15 psig or 30 psia. The data in Figure 3-3 indicated that if the model input conditions are close to actual field conditions, it was unlikely that injection rates greater than 10 gpm of cold-water equivalent steam could be used. The 10 gpm hot-water injection case was also run for comparison to the 10 gpm steam case.

Initial work on the project planned for four inner injectors and four outer injectors spaced at 45 degrees to create two off setting five spot patterns with a common inside extraction well. Early modeling runs indicated an immediate steam breakthrough from the inner injection wells. To minimize this affect, the four inner wells were moved to the edge of the relief holder. For the four modeling runs, the injected steam or water was equally divided between the eight injectors. In practice, the steam or water injection could be divided equally between the eight wells or limited to four wells at a time, depending on the actual field conditions.

For the numerical simulations, one quarter of the relief holder was modeled on a 6x6x4 point-centered grid (Figure 3-4). One injector received the fully allotted amount of steam or water while the other two injection wells received one half of the allotted injection rate as it is assumed that the other half of the injected fluid would go to the adjacent patterns.

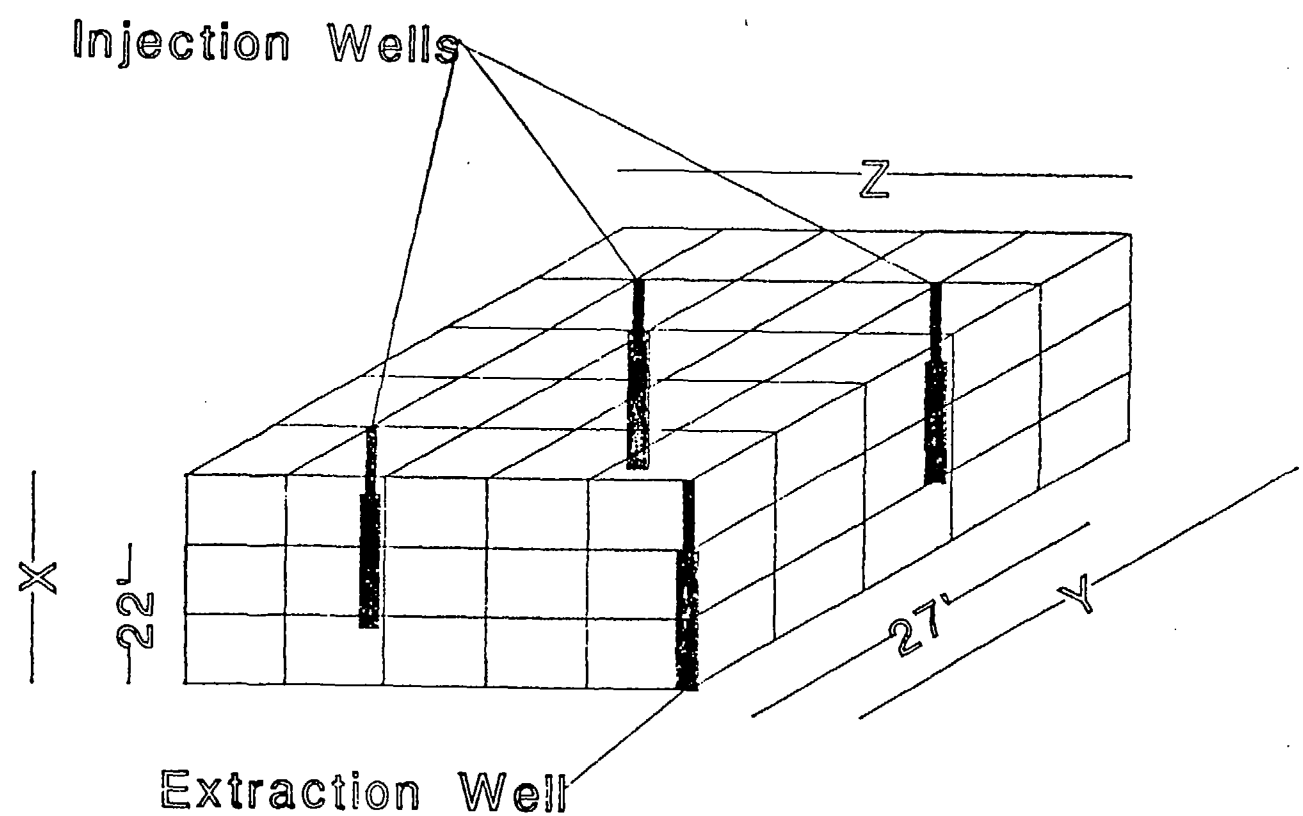
Field results, as well as the modeling results, indicate there is always a tendency for the steam to override. Therefore, injection and extraction was limited to the bottom three grid node rows to simulate well completion in the bottom three-fourths of the injection and extraction wells. Areal and vertical sweeping of the relief holder essentially progressed up from the injection wells, across the top and then downward toward the extraction well, with time, for all steam injection cases. The bottom grid node row always took the longest time to reach residual saturation.

The numerical simulation results are summarized in Figures 3-5 and 3-6. Figure 3-5 gives an indication of how efficient and quickly the different modeled injection rates swept the relief holder to residual saturation. It appears that higher injection rates resulted in a more efficient process. However, actual injection rates were dictated by the injection pressure. As expected, the lowest steam injection rate, 2 gpm, took the longest to sweep the relief holder. However, 80% of the holder was still swept to residual saturation. The hot-water injection case also achieved a high sweep efficiency. However, hot-water flushing (according



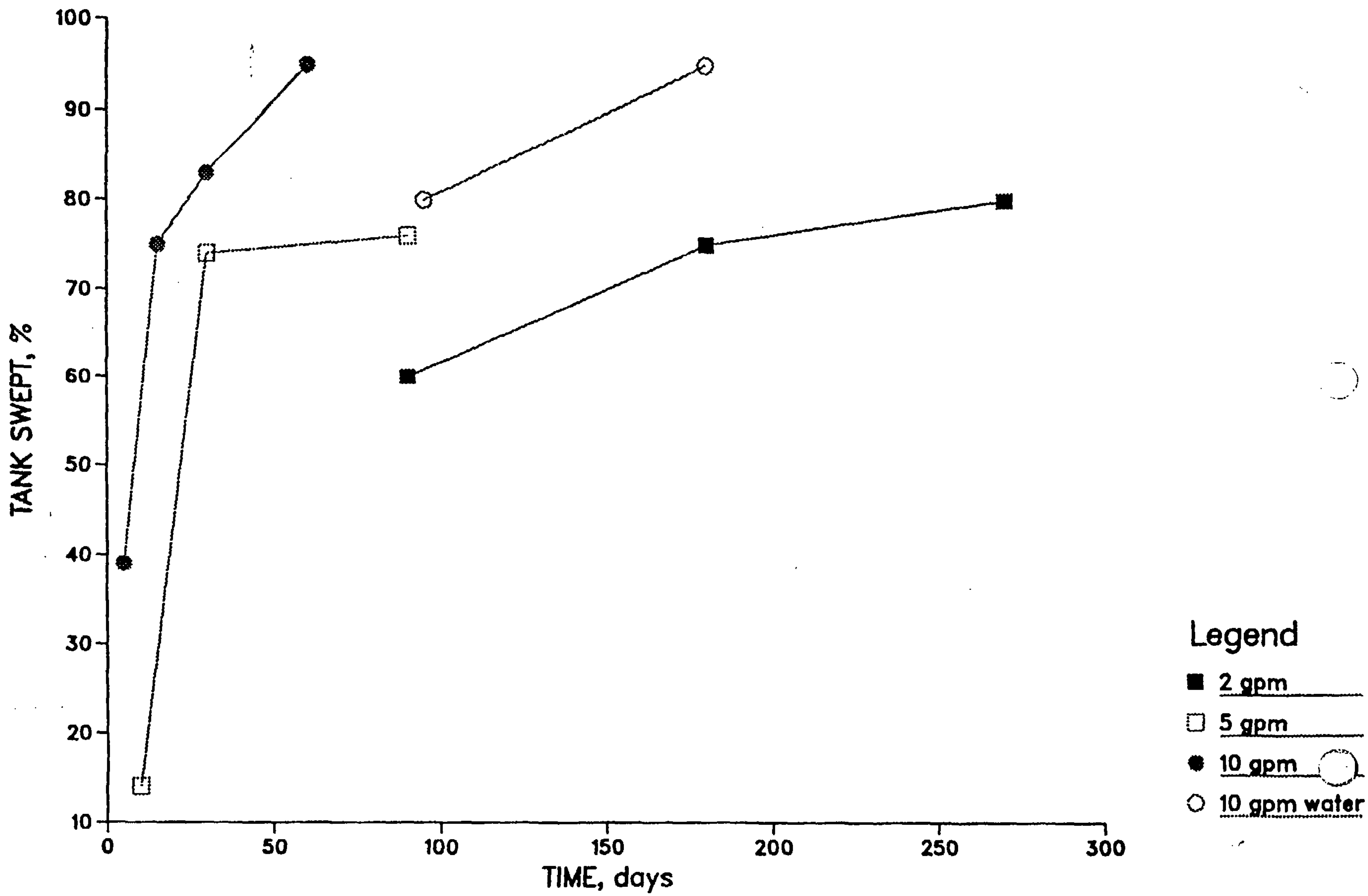
Steam Rate as Cold-water Equivalent

FIGURE
3-3



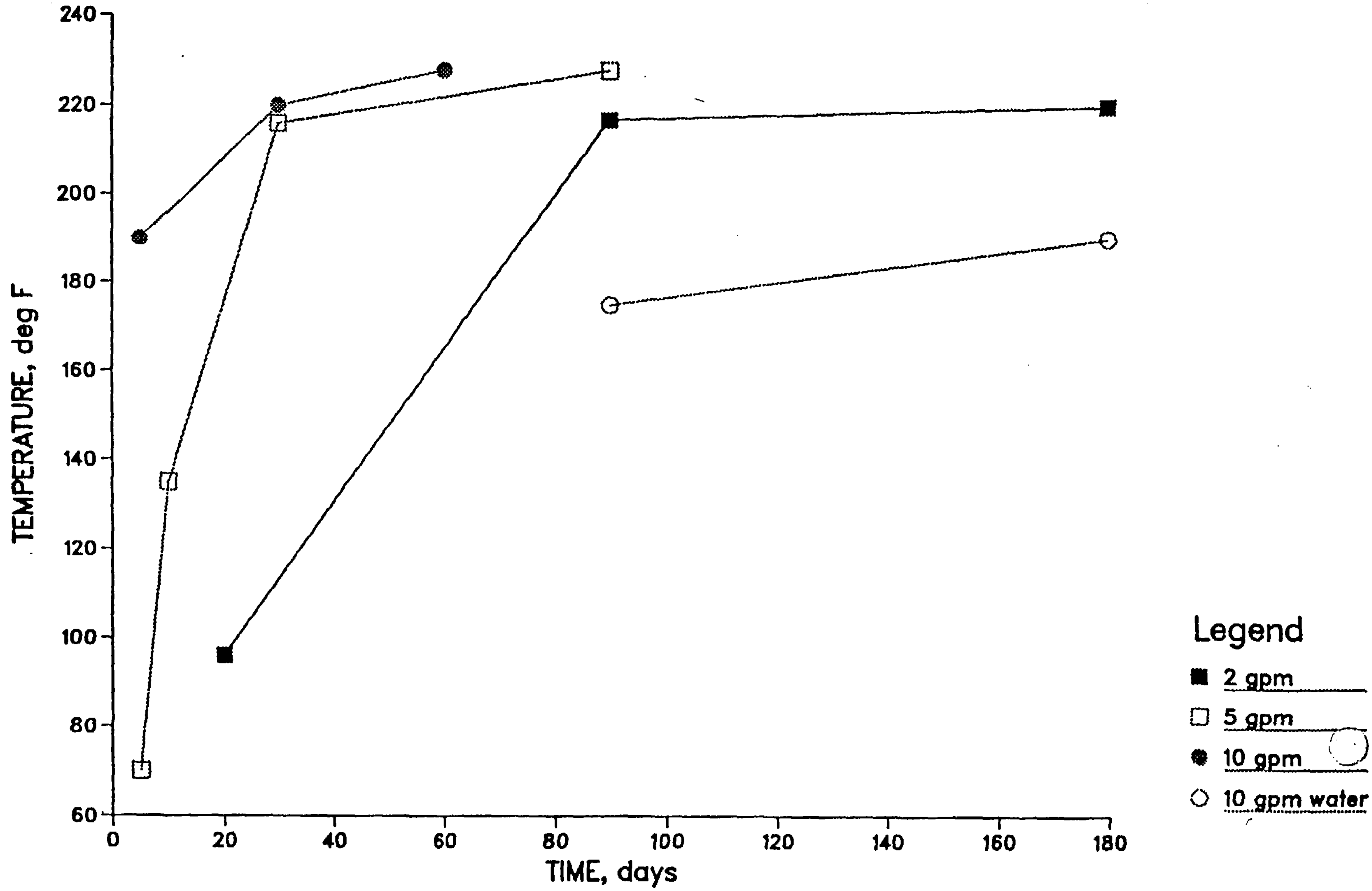
Grid Block Configuration

FIGURE
3-4



Percentage of Holder Swept to Residual Organic Saturation

FIGURE 3-5



Production Well Temperature Curve

FIGURE 36

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to the model inputs) would only result in a residual saturation of 21% while steam flushing would result in a residual saturation of 9%. It would be expected that more organic would be recovered by using steam rather than water.

The predicted temperatures at or near the extraction well are shown in Figure 3-6. According to the simulation, steam breakthrough would occur early and the extraction well and surface production equipment would have to be designed to handle high temperatures and steam production. However, the results discussed in Section 6 indicate that production temperatures never exceeded 180°F.

Following implementation of the CROW system on the relief holder, no effort was made to compare predicted results to actual field results. In many cases, it was determined after the fact that actual conditions were significantly different from the preliminary conditions used in the modeling effort. Also, the holder remediation was conducted differently from the modeling efforts; steam injection then hot-water injection was actually used. In order to adequately compare modeling to actual field results, a relatively large number of additional modeling runs would be required using the actual holder conditions determined from borings installed after the modeling was completed. However, a discussion is presented in Section 7.1.5 that attempts to describe actual system operation and use existing information to compare the modeling results with actual field results.

3.3.3 Well Design/Installation

Based on the WRI modeling, eight injection wells were designed for the outer edge of the relief holder. One extraction well was designed for the center of the relief holder. This configuration formed two five spot patterns at 45 degrees from each other with a commonly shared center extraction well. The design for the eight injection wells included augering an 8-inch diameter hole to the bottom of the relief holder. A 4-inch diameter steel casing string consisting of five-foot of perforated casing on the bottom of the string was set to the desired depth inside the hollow-stem auger. The perforated section of the casing string consisted of 12 one-quarter-inch-diameter perforations per foot. Gravel with a particle diameter between 5/16 and 3/4 inch was placed around the perforated section. Sand then was placed above this section to approximately 5 feet below ground surface (BGS). A five foot bentonite seal was placed to the surface. The casing was then cemented back to the concrete surface with a 4-foot diameter by 1-foot thick cement pad poured and pinned to the existing concrete. A 4-inch flanged wellhead was welded to the 4-inch casing for attachment of the surface casing.

For the extraction well, an 18-inch diameter hole was augured to the bottom of the relief holder. A 10-inch diameter galvanized well screen, 20 feet long, was attached to similar diameter steel line pipe and set to the bottom of the relief holder. Sand, 20/40 mesh, was placed around the well screen and then the hollow-stem auger pulled back to above the well screen. Sand was then placed above the well screen back to approximately 5-foot BGS. A 5 foot bentonite seal was placed to the surface.

The casing was cemented back to the surface with a 3-foot diameter by 1-foot thick cement pad poured and pinned to the existing cement pad. A 10-inch diameter casing head was affixed to the casing.

3.3.4 Injection System

Based on the literature and numerical simulation results discussed above, it was determined that steam injection, at a rate of 10 gpm of water equivalent steam, was the best option for in situ remediation of the relief holder. A natural gas fired boiler from National Vapor Industries was available as a trailer-mounted unit. This boiler was to be able to generate steam up to 1200°F, between 8 and 1000 psi at 10 - 1000 CFM.

3.3.5 Injection System Piping

The injection system piping was detailed in the Piping and Instrumentation Diagram produced with the design. Steam pipe sizes were determined using curves for 1000 to 10,000 pounds of steam per hour (Practical Petroleum Engineers' Handbook, Fifth Edition by Joseph Zaba and W. T. Doherty, page 78).

Due to the very low operating pressure (15 psig), pipe sizes were designed larger than anticipated to keep pressure drops to a minimum, currently designed for 2-3 psi/100 feet. When locating surface equipment, it was imperative that steam line runs be kept as short as possible to further minimize pressure drop and heat loss.

For the main steam line carrying the full 5000 lb/hr (10 gpm water equivalent steam), 4" diameter, schedule 40, welded piping, valves and fittings were required. For the four orifice meter runs which will each meter steam to a pair of injection wells, 3" diameter, schedule 40, welded piping, valves and fittings were required. Finally, for the piping runs to individual injection wells, 2" diameter, schedule 40, welded piping, valves and fittings were required.

3.3.6 Extraction System

For the extraction system design, liquids were pumped from the extraction well at a maximum rate of 10 gpm by a submersible type pump. An oversized pump motor permitted the pump to be rated for the 220°F (the temperature that was expected in the extraction well during operation). If the well was pumped dry, the level switches shut off the pump motor.

Produced liquids were pumped to an air cooled condenser where the fluids were cooled prior to flowing to the vertical separator. Specific gravity information for this organic (Table 3-1) suggested that the heavy organic could be separated by gravity and pumped off the bottom of the vertical separator with a dump valve and pumped to a holding tank. The water was then pumped from the top of the separator to the boiler.

Again, to minimize pressure loss in case large amounts of steam were produced, 2" diameter, schedule 40, piping, valves and fittings were required for the piping run from the extraction wellhead to the heat exchanger. Two inch diameter, schedule 40, piping, valves and fittings were required for the piping run from the heat exchanger to vertical separator. Schedule 40, 2" diameter, piping, valves and fittings were required for the lines into and out of pumps 3 and 6, to the boiler or treatment system, and oil storage, respectively.

3.4 Removal Process Description

The removal of coal tar from the relief holder and the removal and treatment of the impacted water within the relief holder and gas holder were accomplished in three stages. The three stages are as follows:

- implementation of the CROW™ Process in the relief holder;
- removal and treatment of water in the relief holder; and
- removal and treatment of water in the gas holder.

These three stages were implemented in this order to maximize the removal of coal tar and complete removal of impacted water.

Once the system was constructed, the CROW™ portion of the system was initiated. Coal tar and water were to be extracted at 10 gpm from the center of the relief holder. The 10 inch diameter production well was utilized for the extraction well. The well was screened across the bottom three quarters of the holder. The extracted coal tar/water mixture passed through a heat exchanger then a vertical separator. Separated tar was manually transferred via gravity flow and stored at the Site in a 10,000 gallon tank until it was shipped off-site for proper disposal. Eight 4-inch diameter wells were utilized to reinject the recycle water into the relief holder. These wells were spaced equidistant around the inside perimeter of the holder at a distance of 28-feet from the holder center. These wells were utilized initially in two groups of four wells each, but later all eight were operated simultaneously; the two groups had been established by using every other well per group. Before all eight wells were operated simultaneously, the two groups were alternated. The enhanced recovery stage of the holder remediation was operated until shutdown approval was granted from both EPA and PADEP. The enhanced recovery portion of the system had complete recirculation of the extracted water from the holder, so treated holder water discharge was not required.

Once the CROW™ enhanced recovery stage was complete, the production well was utilized to extract all recoverable water held within the relief holder. Water was extracted at a rate of approximately 5 gpm. The water passed through the oil/water separator to separate any free-phase tar from the extracted water. The water was then pumped from the oil/water separator through a series of bag filters. The filters sizes included 20 microns, 1 micron, and 0.5 microns and prevented suspended solids any larger than 0.5 micron in diameter from entering and fouling the carbon units. The water then passed through two 1,800-pound activated carbon units in series to remove any residual tar and/or any dissolved phase organic constituents. The carbon units were removed from the Site for regeneration by the vendor after the project was completed. The water from the carbon treatment was discharged to the Susquehanna River via a 2-inch diameter PVC pipe.

Once the relief holder was empty, the pump in the extraction well in the center of the gas holder was engaged. This pump removed water from the gas holder at a rate of 10 to 20 gpm. The same system used for the relief holder was utilized for treating the water extracted from the gas holder.

Once the gas holder was empty, the pumps were turned off and the system was dismantled. The holders were stabilized as described in Section 8. The stabilization of the holders occurred immediately after all water was pumped from each holder, thereby minimizing the potential for groundwater infiltration. The Site was then restored as described in Chapter 8.

4 System Construction

ORIGINAL (Red)

This section presents the activities involved in constructing the enhanced recovery system at the Site. Included here is a discussion of deviations from the approved design plans.

4.1 Construction Plans and Specifications

Submitted with the original Workplan, was a complete set of construction plans and specifications. The plans were produced on 24-inch by 36-inch sheets. They included a Site location map and a current Site layout map. The plans were divided into three categories; civil, mechanical, and electrical. The civil plans described concrete work, earthwork, drilling, and well installation tasks. The mechanical drawings included a process piping and instrumentation diagram (P&ID), piping layout diagrams, and piping and fitting details. The electrical drawings included the power conduit layout, the data cable conduit layout, the motor control diagrams, logic diagrams, and wiring diagrams including conductivity, liquid levels, pressure, flow, and reset switches.

The construction specifications included the general requirements of the contract, civil construction specifications, mechanical construction specifications, electrical construction specifications, and relevant construction standards. The general requirements defined responsibilities, defined surveying requirements, defined requirements for temporary utilities, discussed health and safety requirements, odor control requirements, and Site security requirements. The construction specifications described each work item to be performed, specified materials to be procured, specified construction methods, and defined the terms of measurement and payment.

4.2 Construction Activities

This section describes the installation of necessary Site utilities and infrastructure facilities; construction of the CROW™ system; and construction of the groundwater extraction and treatment system.

4.2.1 CROW™ Enhanced Recovery System Construction

Construction activities commenced in July, 1996. Eichelbergers Drilling, Inc. was the selected drilling contractor and Remediation, Inc. was the selected general contractor. Each of these contractors was approved by EPA prior to initiating construction activities.

The major construction activities consisted of the following:

4.2.1.1 Civil Construction

- Silt Fence Installation;
- Debris Removal;
- Parking Area/Site Grading;
- Tank Farm Subgrade Construction;
- Tank Farm Slab and Berm Construction;
- Concrete Placement;
- Utility Connection
- Process Control Building Setup;
- Injection Well Installation; and
- Production Well Installation.

4.2.1.2 Mechanical Construction

- Well Header Installation;
- Piping Installation;
- Pump and Mixer Installation;
- Valve Installation;
- Tank Installation;
- Boiler Installation;
- Carbon Adsorber Installation;
- Wiring Installation;
- Junction Box Installation;
- Circuit Box Installation; and
- Lighting Installation.

4.2.1.3 Process Instrumentation

- Temperature Thermocouple Installation;
- Pressure Transducer Installation;

ORIGINAL (Red)

- Water Level Sensor Installation;
- Sample Port Installation;
- Data Acquisition and Control System Installation; and
- Test System Logic Programming.

4.2.1.4 Additional Modifications

- Vapor Generator vs. Boiler;
- Steam Injection to Hot Water Injection;
- Tankfarm Re-Plumbing;
- Chemical Injection Systems; and
- Filter Installations.

For further detail on construction activities refer to the Construction Specifications.

4.2.2 Site Preparation

Site preparation was comprised of two components, the installation of utilities and the construction of infrastructure facilities. The utilities required for the operation of the systems include electricity, gas, and water. The required infrastructure facilities were a decontamination area and a portable toilet.

4.2.3 Utilities

Electric and gas service was reestablished at the Site prior to mobilization. Water service was established to the existing building at the Site.

4.2.4 Infrastructure

The first activity was to install erosion control fencing on the three southern fence lines. The second activity was to grade the Site to provide work areas and construct the soil subgrade for the concrete tank farm. Provisions were made for the characterization and disposal of any excess soil that was graded out during Site preparation. The bermed area was sized to contain 1.5 times the volume of the largest tank. The tank farm contained a sump to collect all water from spillage and rainfall.

Upon completion of the construction of the Site infrastructure, the treatment system was installed.

4.2.5 Construction Sequence

The construction sequence of the treatment system went as follows:

- installation of production and injection wells in the relief holder and gas holder;
- construction of the concrete tank farm;
- installation of pumps, piping, pressure indicators, temperature indicators, flow meters, and low level sensors in the production and injection wells;
- construction of the water treatment system; and
- installation of the boiler.

It was possible to construct some components of the system simultaneously.

4.2.6 Installation of Production and Injection Wells

Nine wells were installed in the relief holder and one well in the gas holder. The nine wells in the relief holder consisted of one 10-inch diameter production well in the center of the holder and eight 4-inch diameter injection wells. The 10-inch well was screened across the bottom three quarters of the holder. The eight 4-inch wells were spaced equidistant from each other and 28 feet from the production well. The eight 4-inch wells were perforated across the bottom five feet of the holder with stinger pipes extending to within 5 feet of the bottom. The well in the gas holder was 7-inches in diameter and located in the center of the holder. It was screened across the bottom three-quarters of the holder.

A concrete saw was used to cut holes through the concrete caps over the holders in the locations of the wells. The 10-inch diameter well required a 16-inch diameter opening and the 4-inch wells required a 10-inch opening. A fully cased drilling method was used to drill the boreholes used for well installation. The appropriate diameter casing was placed in the borehole. The necessary amount of riser pipe was used to construct the well to the ground surface. The annulus of the borehole was filled with silica sand/gravel to five feet below the ground surface. Grout was then placed above the sand to the ground surface. Concrete was then used to secure the casing to the existing concrete cap.

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4.2.7 Installation of Recovery Pumps, Piping and Peripherals

Pumps were installed in the production wells capable of pumping at least 60 feet of head at 20 gpm. The pumps were attached to 2-inch diameter piping. The piping used from the wellheads to the treatment system was 2-inch diameter, carbon steel pipe. The wellhead of each well consisted of a cap through which a 2-inch diameter pipe passed. In the production wellheads low water level sensing equipment, and a thermocouple, also passed through the cap.

All piping downstream of the acid injection port were PVDF (Kynar) piping to avoid potential corrosion of the steel pipe.

4.2.8 Installation of CROW™ Treatment System

The components for the CROW™ treatment system included flow meters/totalizers, ball valves, gate valves, globe valves, an oil/water separation vessel, an oil storage tank, tank level sensor equipment, centrifugal and metering pumps, a 15 micron bag filter, and a boiler. These components were connected to the piping described in Section 4.2.7. Ball valves were utilized to direct the flow of liquids to the appropriate components of the CROW™ and carbon adsorption treatment systems.

4.2.9 Installation of Water Treatment System

The components for the water treatment system also included flow meters/totalizers, centrifugal pumps, and valves. The system utilized the same piping and componentry described in Section 4.2.7. Additionally, this system included a 5 micron bag filter and two 1,800-pound granular activated carbon units. (55-gallon carbon drums were used throughout the operation of the Enhanced Recovery System; the 1800 pound units were only used during holder pumpdown operations.) Ball valves used to direct flow between the carbon and CROW™ systems. Ball valves around the bag filters were used to direct flow through or around the bag filters when they required maintenance. The gate valves were used to redirect flow during equipment replacement or maintenance. This equipment was installed in the sequence it is identified. These components were interconnected with 2-inch diameter, carbon steel piping.

5 Construction Quality Control

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5.1 Introduction

This section describes the observations and tests that were performed throughout construction to ensure that the enhanced recovery system and water treatment system were installed in accordance with the approved plans and specifications.

RETEC was responsible for all construction quality assurance. The individual subcontractors were responsible for quality control. Clean Sites, on behalf of PP&L, was acting as the supervising contractor. RETEC submitted copies of all CQA reports to Clean Sites. Clean Sites distributed the reports to EPA and PADEP as appropriate.

5.2 Preconstruction Inspections

Preconstruction inspections were performed in conjunction with preconstruction meetings with subcontractors prior to the onset of work. These inspections include:

- reviewing work access provisions;
- reviewing methods for documenting and reporting inspection data;
- reviewing methods for distributing and storing documents and reports;
- reviewing work area security and safety protocols; and
- conducting a Site walk to verify that the design criteria, plans, and specifications are understood and to review material and equipment storage locations.

RETEC was responsible for all inspections and QA documentation.

5.3 Construction Inspection and Testing

Inspection of all construction operations was performed during installation of the enhanced recovery system, the gas holder pumping system, and the water treatment system. The inspection and/or testing ensured that system installation was performed according to design criteria and specifications. The inspection and/or testing was also used to verify compliance with environmental requirements such as air quality and emissions monitoring, waste disposal, health and safety procedures, and sample collection. The inspection and testing that was performed during construction was organized according to work task as follows:

5.4 Well Installation

WRI was responsible for supervising the installation of recovery and production wells by the contract driller to ensure that the well installation specifications are adhered to and to record all pertinent data.

5.5 Pipe Installation

CQA of pipe installation included:

- verification that proper materials were being used;
- ensuring that work was performed by qualified pipe fitters;
- confirmation that pipes were located as specified in the design including all valves, meters, sample ports, and other fittings;
- validation that pipes were properly supported as per the design specifications; and
- confirmation that all pipes had been appropriately hydrotested for pressure and leaks.

Piping installation was inspected by RETEC personnel to ensure that all workmanship was performed as per manufacturer's instructions and that all CQA procedures were followed.

Pipes were installed and fitted according to the appropriate standards and codes that were pertinent to the particular piping being installed. For any piping that contained either high pressure or organic materials, ASME/ANSI Standards B-31.1 and/or B-31.3 were followed. All other piping was installed according to local piping and plumbing codes, including the latest BOCA plumbing codes.

Any problems, deficiencies, or leaks noted in piping work were immediately corrected as directed by RETEC personnel.

5.6 Pipe Heat Tracing and Insulation

Pipe heat tracing and insulation were considered for installation in case operations extended into colder months. Steam lines were not heat traced, but were insulated for heat retention. Freezing was not considered problematic for the steam piping because liquids within these pipes would simply drain into the injection wells should a shutdown occur. All other system piping was heat traced and insulated. Heat tracing and insulation was inspected by RETEC personnel to ensure that it was installed as per the manufacturer's specifications. CQA inspection included

- verification that proper materials were utilized;
- examination of heater cable before and after installation to ensure integrity of cable jacket;
- verification of minimum electrical resistance as per manufacturer's specifications;
- proper repair of any deficiencies;
- inspection of circuits prior to and after installation of insulation; and
- verification of proper operation of thermostatic controllers, as per manufacturer's specifications.

Installation of pipe insulation was in accordance with the manufacturer's specifications. CQA procedures included:

- verification of proper type of insulation being used as per design;
- verification of insulation thickness;
- examination of installation techniques to ensure proper overlap or sealing of insulation sections or layers; and
- inspection for proper installation of exterior coating or vapor barrier.

Inspections were conducted by RETEC personnel, and results of inspections were recorded in the field log. Any problems or deficiencies noted in the heat tracing or insulation work were immediately corrected as directed by RETEC personnel. All CQA testing was documented in the field notes.

5.7 Tank Installation

Tank placement and installation was conducted in accordance with manufacturer's instructions and the design specifications. The CQA inspector oversaw installation to ensure that:

- proper equipment was utilized;
- alignment and orientation of tanks was per design drawings;
- installation of tanks was conducted by qualified personnel; and
- workmanship was acceptable.

Any tanks that were to contain organic materials were installed according to ASME/ANSI Standard B-31.3 for Chemical Plant and Petroleum refinery piping. All fittings, pipes, and valves on these tanks was also installed according to the same standard. All plumbing and tank codes, including the latest BOCA plumbing, mechanical, and fire prevention codes were followed.

Tank installation was inspected by RETEC personnel to ensure that all CQA procedures are followed.

5.8 Equipment Installation

Equipment placement was conducted in accordance with the manufacturer's specifications and the design document details. All equipment installations were reviewed to ensure:

- utilization of proper equipment that is in good condition;
- proper orientation and alignment of equipment;
- acceptable workmanship;
- examinations of fittings and attachments to the equipment to ensure that they were not inducing excessive stress in the equipment; and
- acceptable rotation of moving parts.

Any problems or deficiencies noted in equipment installation were immediately corrected as directed by CQA personnel.

5.9 Electrical Installation

Electrical installations were CQA inspected. Inspections were conducted on all installations of conduit, wire, motors, disconnect boxes, breakers, switches, controls and other electrical equipment. CQA activities included:

- verification that all electrical work was performed by qualified electricians;
- verification of lockout/tagout prior to any electrical work;
- inspection of all materials to ensure that they met specifications and were in good condition;
- verification of conduit and wire to ensure they met specifications;
- verification of conduit and equipment locations;
- visual inspection of all connections; and
- witnessing of continuity check and checkout of equipment operation.

Any problems or deficiencies noted in electrical installations were immediately corrected as directed by RETEC personnel.

5.10 Instrumentation

RETEC personnel inspected the installation, calibration, and functional testing of all instrumentation installed by the contractor. The manufacturer's instructions were utilized as a guide for all testing and startup procedures. Any problems or deficiencies noted in instrumentation installation were immediately corrected as directed by RETEC personnel.

5.11 Deviations from Approved Design

This section details design deviations from the approved plans. During construction activities, alterations in the system design were either required or desired for optimal system performance. Changes were made only after prior approval from CSES (PP&L's supervising contractor). None of the changes negatively affected system performance or increased the potential for health & safety violations. All design changes were documented on "Change of Design Forms" that were submitted to CSES. All Change of Design Forms are included in Appendix C.

5.11.1 Injection Wells

WRI was responsible for supervising the installation of injection wells, by the contract driller, to ensure that the well installation specifications were adhered to and to record all pertinent information. Injection wells were designed to have 10 foot screens positioned at the bottom of the holder. RETEC and WRI decided during construction that 5 foot long screens would provide improved heating of the lower-most holder contents by forcing the steam lower into the holder.

5.11.2 Tankfarm

5.11.2.1 Tankfarm Subgrade

The tankfarm was constructed according to specifications with the exception of the level of the subgrade. Due the significant difference in height between the relief holder and gas holder, the tankfarm subgrade was not raised to match the level of the relief holder. Instead, the subgrade was raised just enough to allow proper subgrade completion and ensure that runoff was directed away from the tankfarm. Operation of the system was not affected by the change in the height of the tankfarm.

5.11.2.2 Concrete Pouring Methods

Concrete pouring methods occurred according to all applicable standards. However, the tankfarm design originally specified that the slab and walls be poured as one continuous unit. Instead, the pad and walls were poured as separate units with the slab poured first. Waterstop RX seal was installed between the slab and walls to ensure proper watertight characteristics. The design change was made due to the difficulty of pouring both the slab and the walls as one continuous unit. The structural integrity of the tankfarm was not sacrificed due to this change.

5.11.2.3 Rebar Placement

Rebar placement was not done according to the specifications. Originally, the vertical rebar was to be placed in a single plane within the center of the walls. The rebar was staggered within the wall to provide increased strength.

5.11.2.4 Control Joints

Control joints were placed in the slab to ensure proper integrity of the concrete. Joint materials were industry standard and installed according to applicable standards. The original design called for control joints to be cut and caulked. Instead, a "Keyloc" joint system was used. The Keyloc joint materials are considered to be of higher quality and performance and were chosen over the original specification.

5.11.3 Process Tank Level Switches

Process tank level switches were installed under the supervision of a RETEC field engineer. Height settings were determined by the engineer. Subsequent adjustment of the level switches was necessary in some cases, but system operations were not affected by the changes. All level switches were tested prior to system operation to ensure proper functioning. Original specifications called for level switches LSL-T3 and LSH-T3 to be separate units, but they were installed as one dual switch that functioned equally. Also, LSH-P12 was to be a conductivity-type switch, but it was changed to a float-type level switch for better operator control. Pump P-12 was originally to operate with a manual on/off switch only. A float switch was added for P-12 to prevent the tankfarm from filling with water during periods when the operator was offsite.

5.11.4 Pump Controls

Pump controls were installed under the supervision of a RETEC field engineer. logic settings were inspected by the engineer. Subsequent changes in the logic were necessary in some cases, but system operations were not affected by the changes. All pump controls were tested prior to system operation to ensure proper functioning.

5.11.5 Flow Meters

Flow meters were installed, for the most part, according to the system design. An additional flowmeter was added to the discharge line to monitor total discharge to the river. Details of flowmeter changes are presented in the Change of Design forms located in Appendix C.

5.11.6 Valves

System valves were installed, for the most part, according to the system design; deviations from the design are presented in the Change of Design forms located in Appendix C.

5.11.7 Heat Exchanger

The heat exchanger was installed according to the specifications. For better performance and control, a bypass loop was installed around the heat exchanger. This change is documented in the Change of Design forms located in Appendix C.

5.11.8 Carbon Unit Piping

The carbon units were installed according to specifications. A backwash line was added to the carbon units to allow for occasional flushing of accumulated solids. This addition allowed more efficient use of the carbon canisters.

5.11.9 Vapor Generator Blowdown Line

The vapor generator, that was initially specified for the treatment system, was not included. The delivered vapor generator was not capable of supplying the necessary steam/vapor pressures to overcome back-pressure within the injection piping and wells. Various unsuccessful attempts to correctly modify the original vapor generator resulted in RETEC searching for a new vendor who could supply a useable unit.

The vapor generator design needed by the enhanced recovery system was so unique, other vendors were not capable of supplying a sufficient unit. RETEC began investigating the possibility of using a boiler (hot water) system versus the steam generator system.

A properly functioning boiler system was installed. The new boiler was capable of supplying the pressures needed to overcome system backpressures. The new design utilized hot water/steam instead of pure steam/vapor, but previous modeling by WRI indicated that hot water could also complete the desired treatment process although not as efficiently.

The boiler system included a utility trailer (boiler, water softening system) and a heat exchanger (to keep process water from contacting internal boiler components).

5.11.10 Temperature Indicators

Temperature indicators were installed according to specifications. Additional temperature indicators were added to the system to improve operator control. Deviations from the temperature indicator specifications are presented in the Change of Design forms located in Appendix C.

5.11.11 Sample Ports

Sample Ports were installed according to specifications. Additional sample ports were added to the system to improve operator control and sample collection. Deviations from the original sample port specifications are presented in the Change of Design forms located in Appendix C.

5.11.12 Level Elements and Transmitters

Level elements and transmitters were installed, for the most part, according to specifications. Deviations from the specifications are presented in the Change of Design forms located in Appendix C.

5.11.13 Mixer

The flocculent mixer was removed from tank T-6 and placed into Tank T-9. The change was necessary because the flocculent is actually added to Tank T-9 and not Tank T-6. This deviation from the specifications is presented in the Change of Design forms located in Appendix C.

5.11.14 Cleaver Brooks Boiler System

The originally specified vapor generator was incapable of supplying necessary output pressures to overcome backpressure within the injection wells. Following several unsuccessful attempts to correct the issues with the vapor generator, a Cleaver Brooks boiler systems was mobilized to replace the vapor generator. The Cleaver Brooks system could supply adequate steam/hot-water output pressure and utilized the same fuel (propane) as the vapor generator.

The boiler system used the same piping originally designed for the vapor generator with a few exceptions. Because the boiler (and associated water treatment equipment) was contained within a large trailer, it could not be located on the relief holder concrete pad. Instead, it was positioned adjacent to the northeastern edge of the pad. Due to the change in location of this equipment, additional piping was necessary on the feedwater, injection, and blowdown lines. The additional piping did not change the operation or effectiveness of the enhanced recovery system. The fuel line, from the propane tank located in the northeastern corner of the site, was shortened and connected to the boiler.

5.11.15 Hot-Water vs. Steam

As discussed in Section 3.3.2, steam was chosen over hot water for this enhanced recovery system. However, steam injection appeared to exacerbate leaking through cracks in the relief holder's concrete cap. To prevent surface leaks, steam flowrates were lowered to less than 2 gpm water equivalent. Throughout the operations where steam injection was used, many unsuccessful attempts were made to seal leaks in the pad. Steam was used for a period of approximately four months before the heat exchanger was installed to allow hot-water injection.

Once the heat exchanger was operational, injection flowrates were increased to 5 to 7 gpm without surface leakage. Instead of heating process fluids within the boiler, a continuous steam flow cycled from the boiler to the heat exchanger to heat the process fluids. This new design heated process water to approximately 200 degrees Fahrenheit.

6 Operation and Maintenance

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Operation and maintenance of the CROW™ system included inspecting the system, obtaining process measurements and recording data. All equipment was maintained and serviced according to factory specifications and recommendations. All meters were calibrated according to the manufacturers instructions. Inspections were conducted on a daily basis. A detailed Operations and Maintenance (O&M) plan (RETEC, 1996) was submitted to and approved by PADEP and EPA Region III.

6.1 System Operation

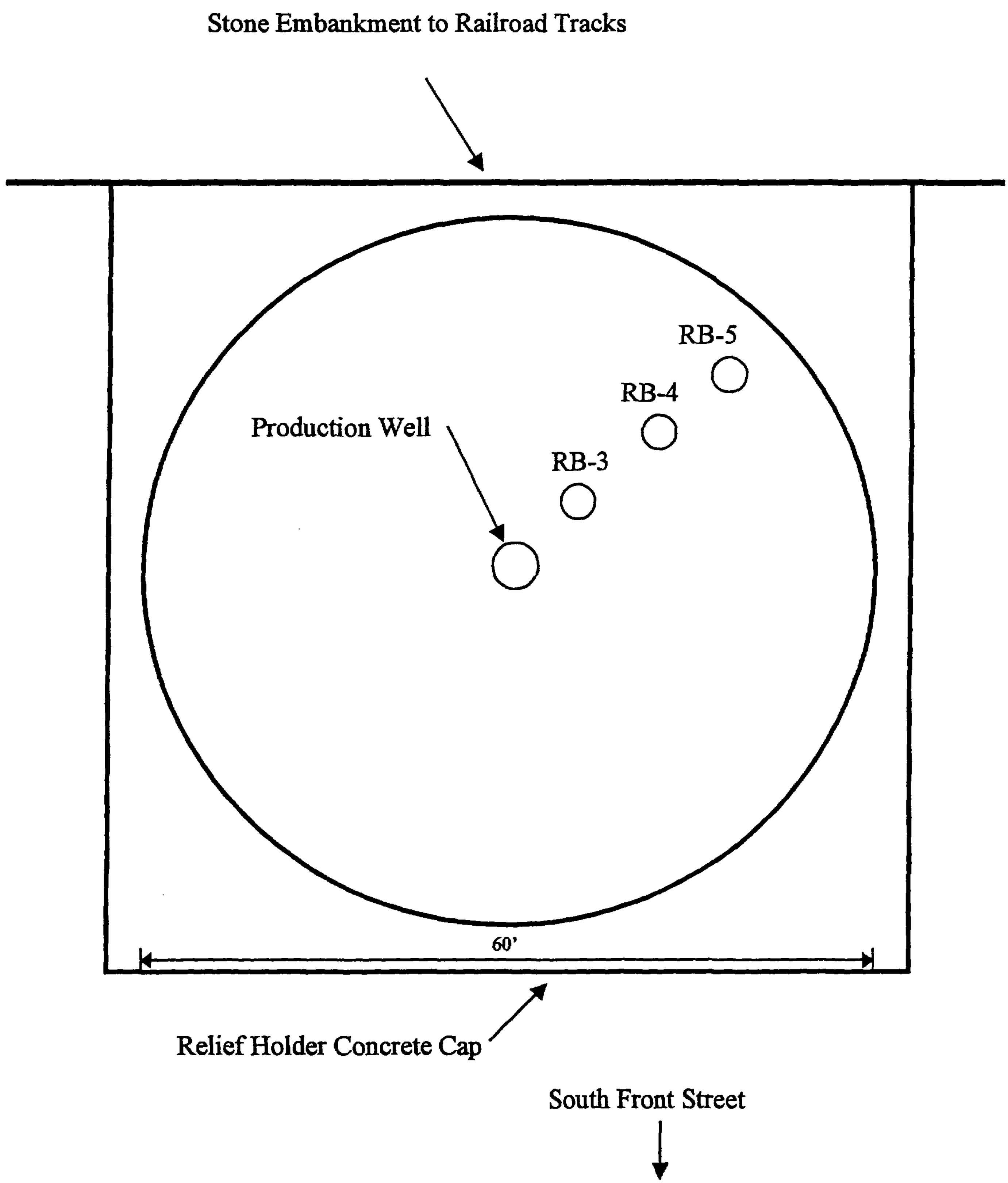
Throughout operation of the enhanced recovery system, operators were required to monitor system operational characteristics. Information obtained from monitoring was used to alert operators of potential problems or indicate necessary equipment adjustments. Operators utilized logforms to record pertinent information about the system. These logforms are presented in Appendix E.

Information regarding production temperature, holder temperature, production flowrates, tar recovery, etc., were recorded and are presented in this section.

6.1.1 Holder Temperature

Over the entire operation of the enhanced recovery system, relief holder temperatures were recorded from three borings installed in the holder. The position of these borings is presented in Figure 6-1. Each boring contained three temperature thermocouples inserted to depths representing the top, middle, and bottom, which corresponds to approximately 8, 15, and 23 feet, respectively. Temperatures were recorded daily on the operator logforms presented in Appendix E.

Two sets of figures were created from the thermocouple temperature readings. Figures 6-2, 6-3, and 6-4 present the top, middle, and bottom temperature progressions per pore volume produced, respectively. Figures 6-5, 6-6, and 6-7 present each boring's temperature progression per pore volume produced. Please note that pore volumes shown on these figures are based on an initial estimated porosity of 30% within the holder.



Relief Holder Temperature Boring Locations

Figure 6-1

Figure 6-2
Holder Temperature Profile (Top)
UGI Columbia Gas Plant Site

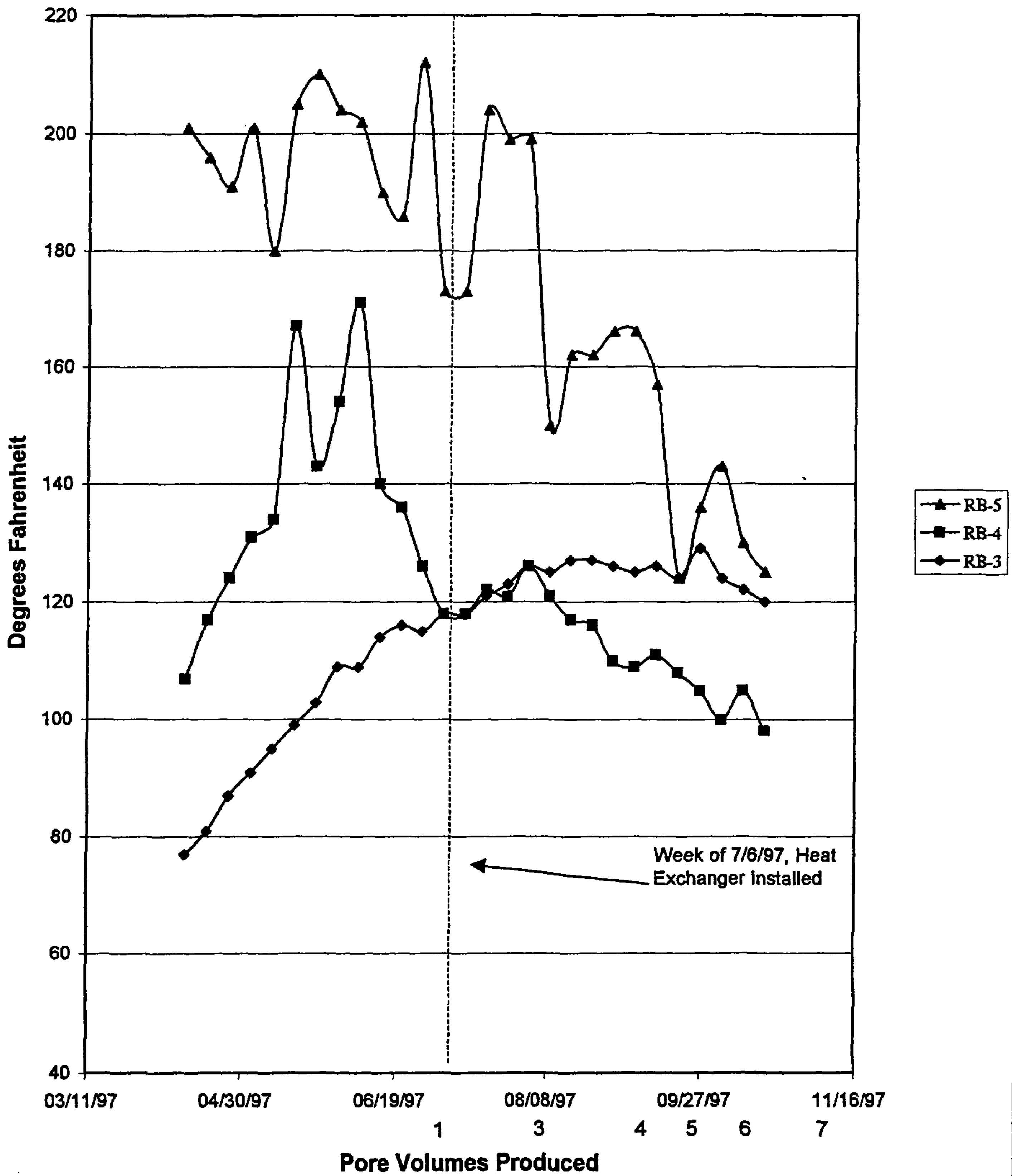


Figure 6-3
Holder Temperature Profile (Middle)
UGI Columbia Gas Plant Site

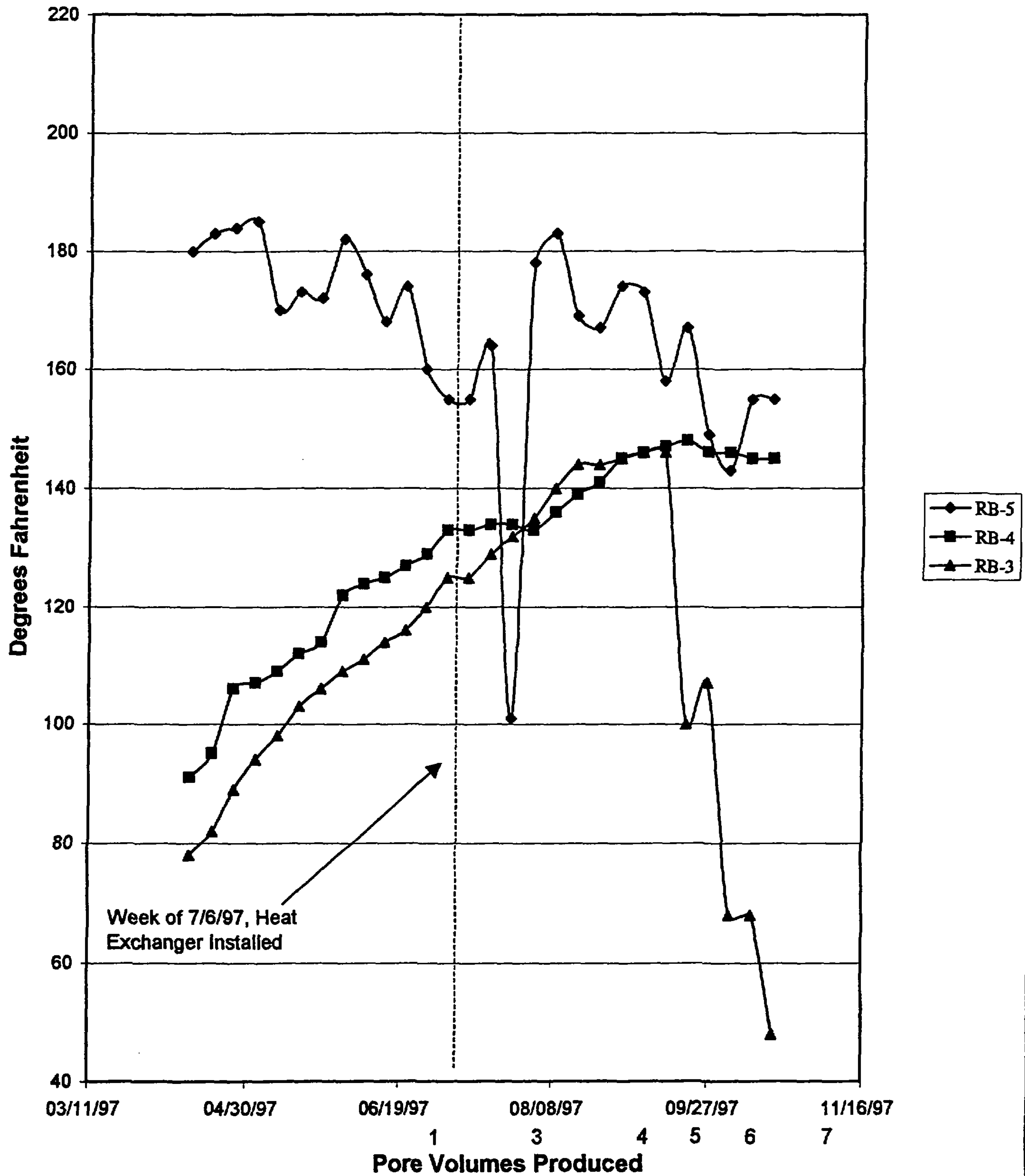
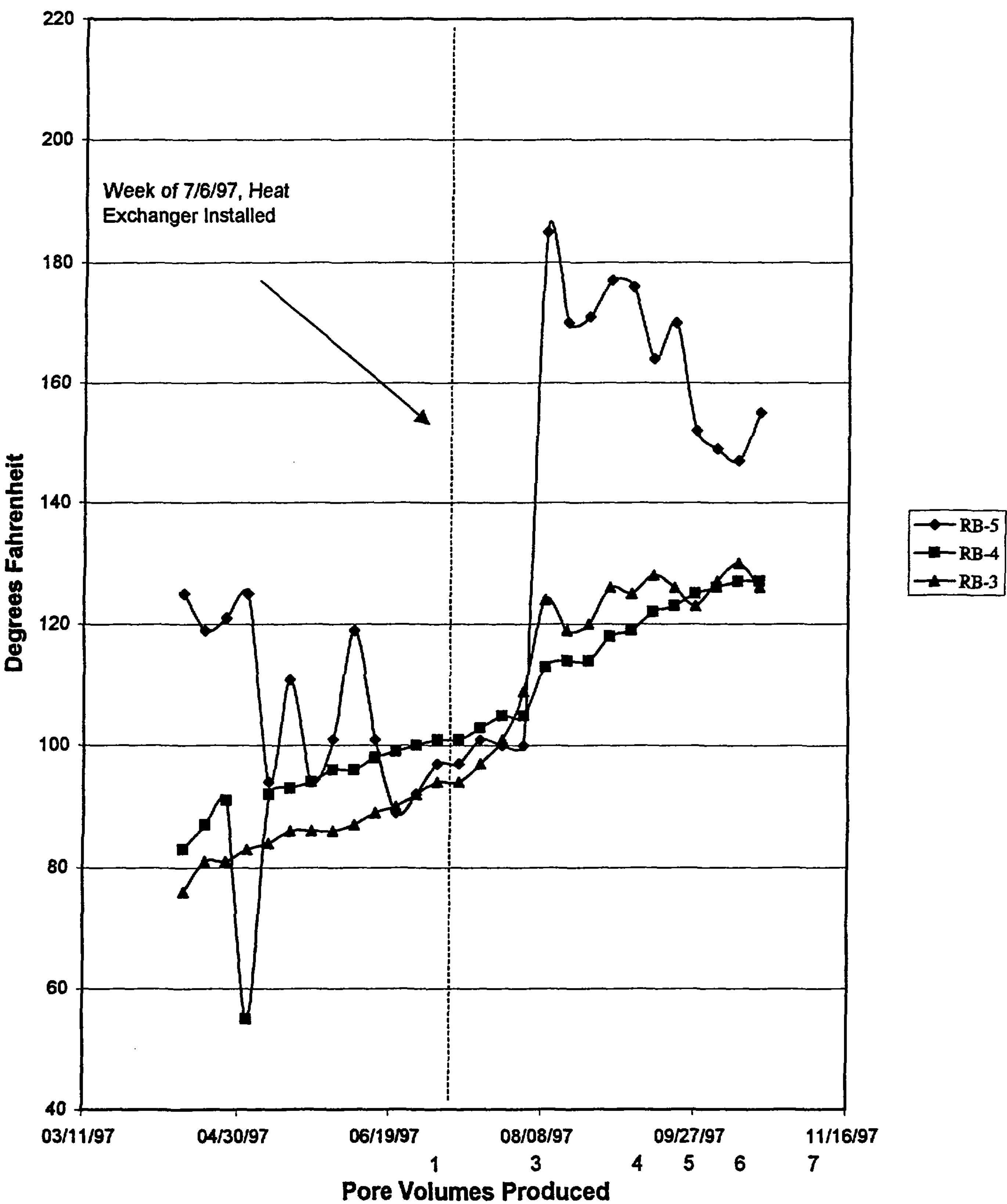


Figure 6-4
Holder Temperature Profile (Bottom)
UGI Columbia Gas Plant Site



AR302802

Figure 6-5
RB-3 Temperature Progression
UGI Columbia Gas Plant Site

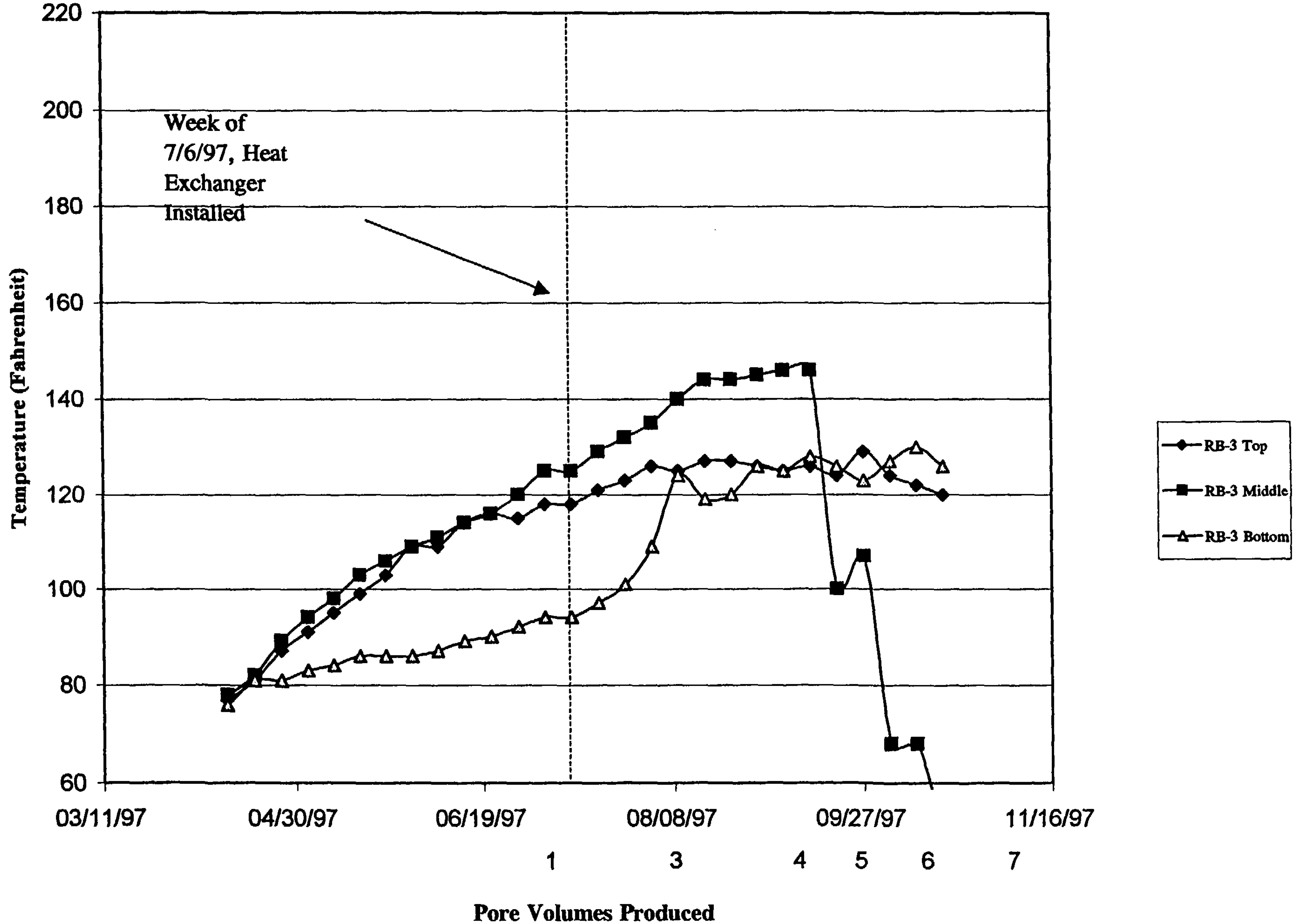
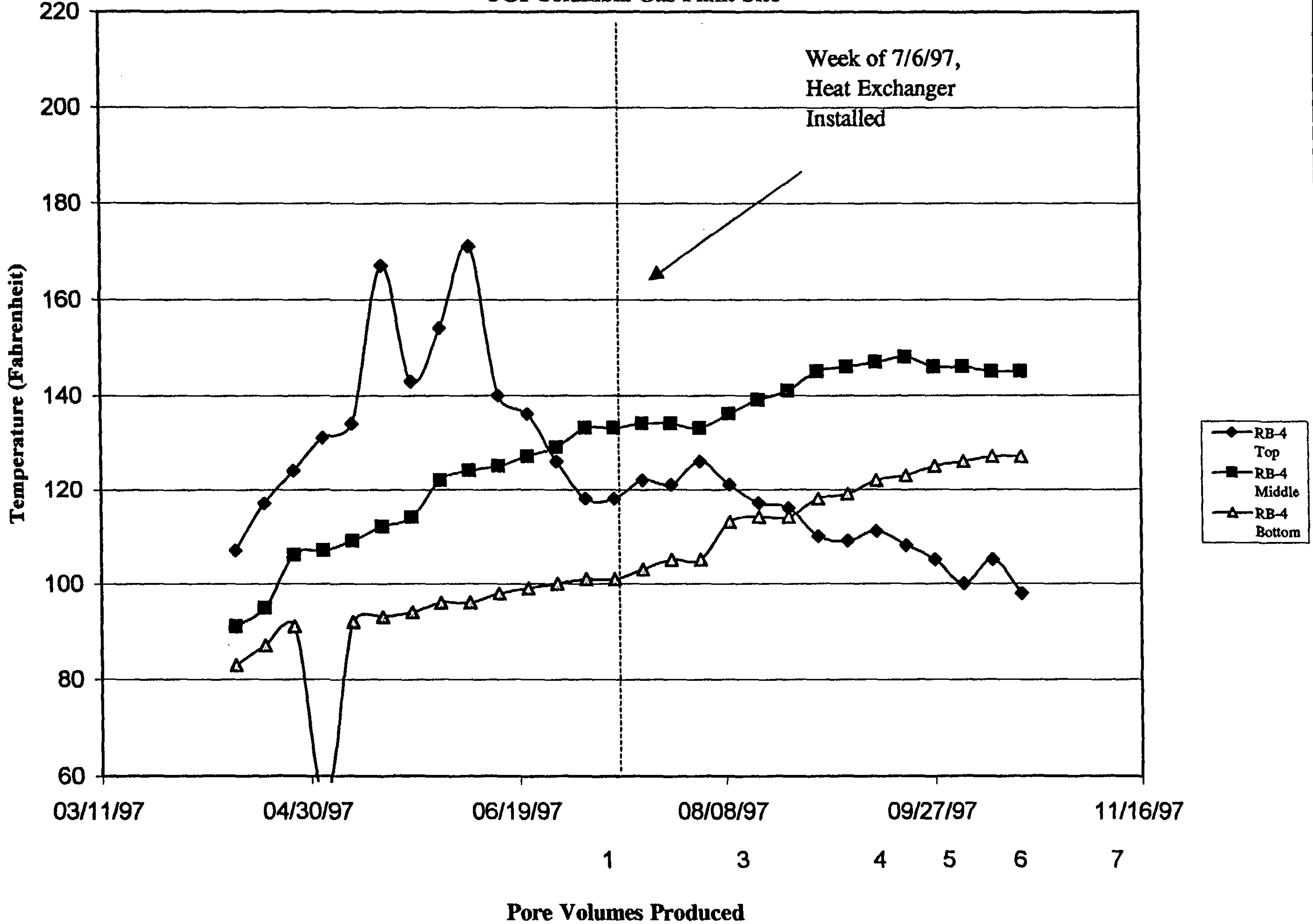


Figure 6-6
RB-4 Temperature Progression
UGI Columbia Gas Plant Site



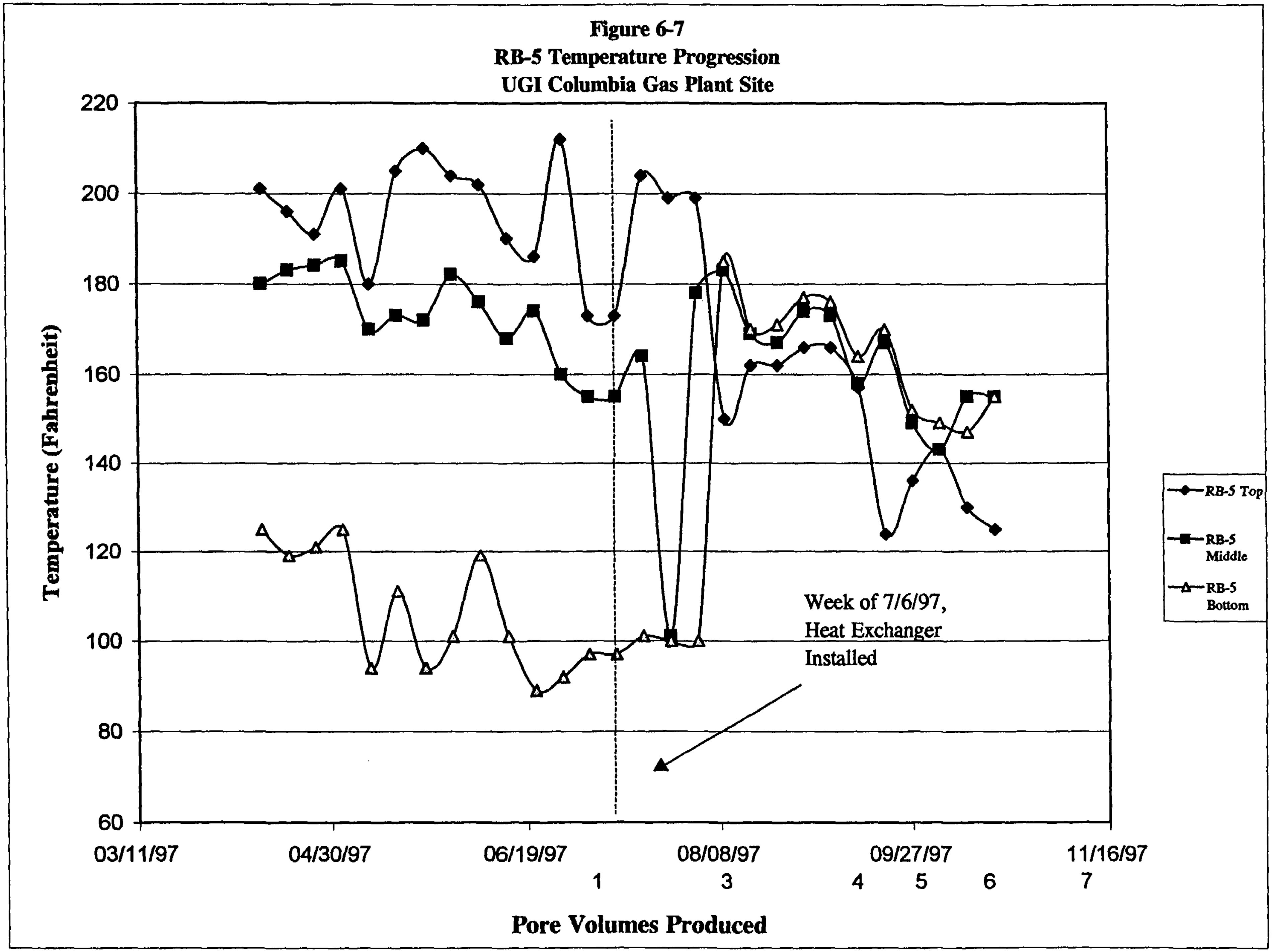


Figure 6-7
RB-5 Temperature Progression
UGI Columbia Gas Plant Site
Temperature (Fahrenheit)
220
200
180
160
140
120
100
80
60
03/11/97
04/30/97
06/19/97
08/08/97
09/27/97
11/16/97
1
3
4
5
6
7
Pore Volumes Produced
Week of 7/6/97,
Heat Exchanger
Installed
RB-5 Top
RB-5 Middle
RB-5 Bottom

The figures show that temperatures within the holder fluctuated during initial operations. These rapid changes were due to system shutdowns related to repairs, crack repair (concrete pad), and operational adjustments. For the most part, RB-5 located on the outer edge of the holder experienced the greatest degree of heating. The reason for this is its proximity to the injection wells; RB-3 and RB-4 were more centrally located within the relief holder.

The holder's top temperatures appear to decrease following installation of the heat exchanger while the bottom of the holder experienced higher temperatures following heat exchanger installation. This occurred because steam has a lower density than water and rose to the surface of the holder. The short-circuiting of steam to the top of the holder also exacerbated surface leaks through the concrete pad.

Additional temperature monitoring was performed on groundwater from a monitoring well (BG-1) located approximately ten feet from the eastern edge of the relief holder. The results of this monitoring are presented in Figure 6-8. The temperature monitoring was intended to assist in determining if holder contents were leaking during operations. Temperatures did increase in BG-1 from an ambient temperature of approximately 55 degrees Fahrenheit (F) to as high as approximately 118 degrees F. Following a close analysis of holder water levels vs. input/output flows, the increase in BG-1's temperature was determined not to be due to leaking, but to heat conductivity from the adjacent holder wall.

RETEC was also requested to collect three samples from BG-1 for PAH analysis for the same purpose of determining if holder contents were leaking. The PAH results are presented in Appendix H. These results do show an increase in PAH levels within BG-1 during operations, but the increase was due not to increased tar within the well, but rather increased dissolved PAH levels caused by the increased groundwater temperatures.

6.1.2 Production Flowrate

Figure 6-9 presents the production flowrate in gallons per minute versus pore volumes produced (again, these pore volumes were based on an estimated 30% holder porosity). The noticeable increase in production flowrate near the first pore volume reflects stabilization of operational conditions that tended to fluctuate during the first pore volume. Production dropped for a period near the fifth pore volume due to a production pump malfunction. Production flowrates were recorded daily on the operator logforms presented in Appendix E.

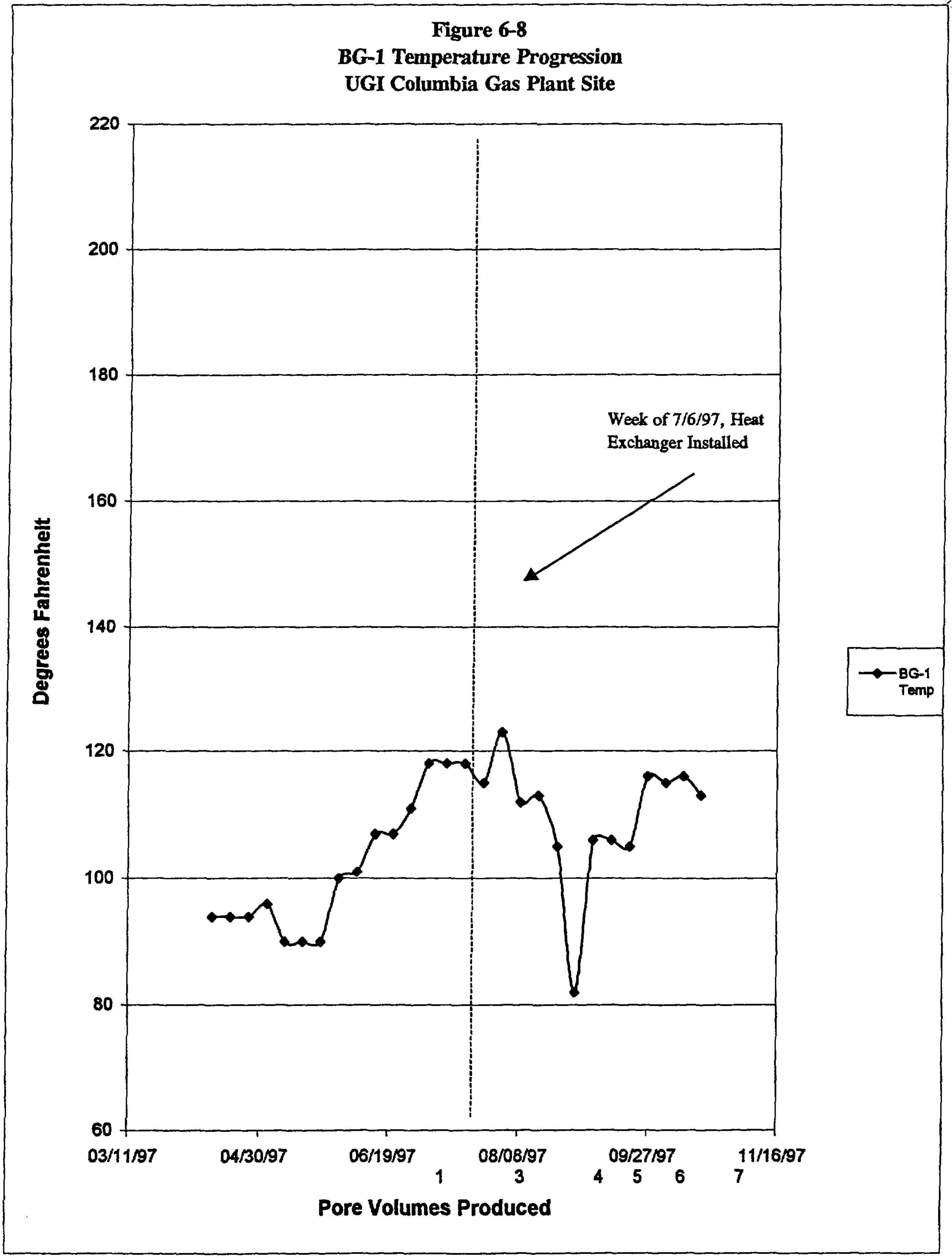
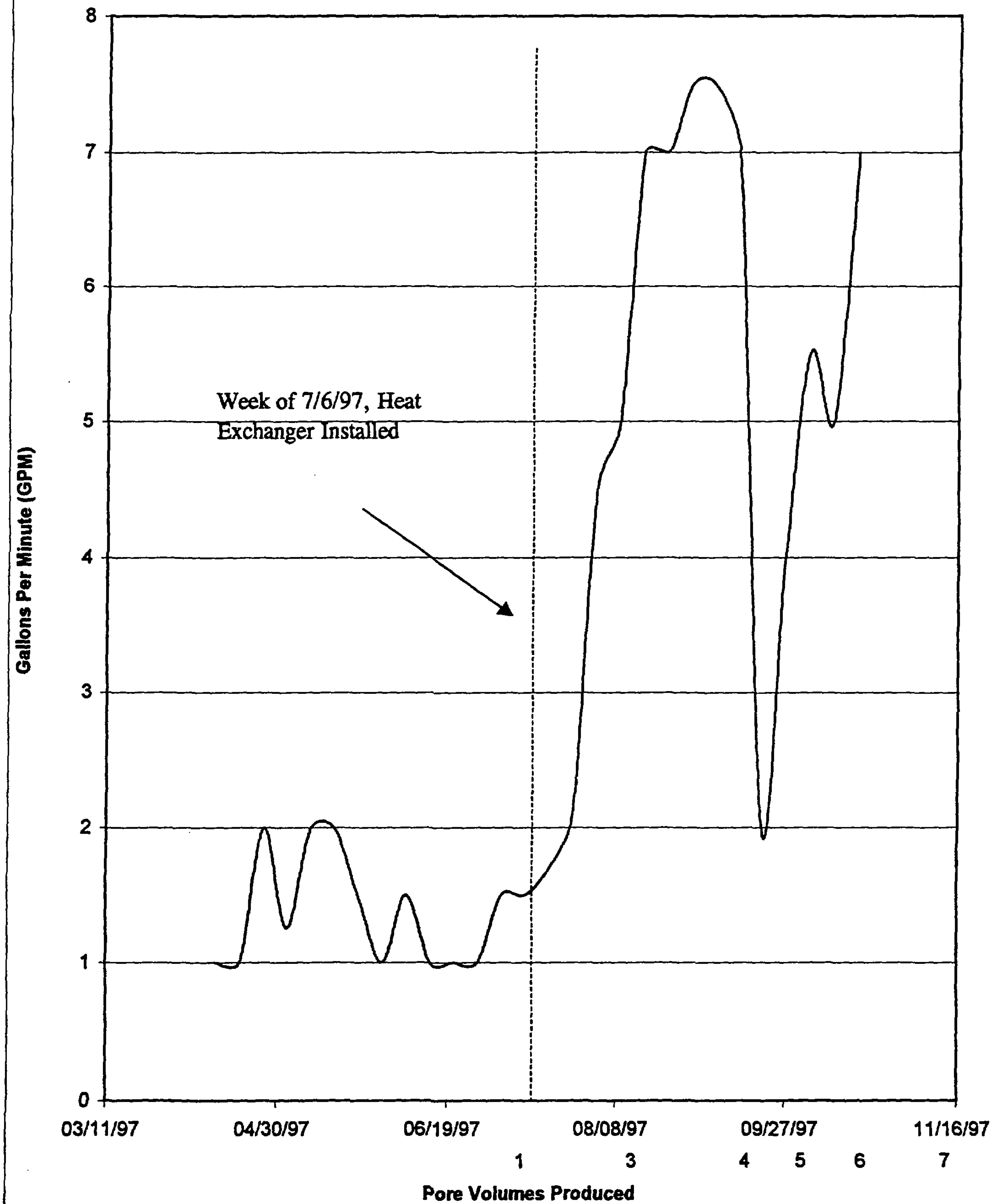


Figure 6-8
BG-1 Temperature Progression
UGI Columbia Gas Plant Site
220
200
180
160
140
120
100
80
60
Degrees Fahrenheit
Week of 7/6/97, Heat Exchanger Installed
BG-1 Temp
03/11/97
04/30/97
06/19/97
08/08/97
09/27/97
11/16/97
1
3
4
5
6
7
Pore Volumes Produced

Figure 6-9
Production Flowrate
UGI Columbia Gas Plant Site



6.1.3 Production Temperature

Figure 6-10 presents production temperatures versus pore volumes produced (again, pore volumes are based on an estimated 30% holder porosity). As with production flowrates, production temperature stabilized following the first pore volume and then remained fairly constant throughout operations. Production temperature was recorded daily on the operator logforms presented in Appendix E.

6.1.4 Production Water Oil & Grease

Throughout operations, production water Oil & Grease (O&G) concentrations were measured weekly (Table 6-1). Results of these analysis were used to indicate the system's effectiveness at coal tar recovery.

A brief discussion follows to help clarify the distinction between the different Oil and Grease (O&G) analyses we have performed to monitor the enhanced recovery system performance.

6.1.4.1 Background

During the first several weeks of the project, production water samples were analyzed for O&G by Method 413.2 (Infrared). These samples were also analyzed for Total Organic Carbon (TOC) by method 9060A. The TOC concentrations were consistently reported at significantly higher concentrations than the O&G concentrations. For example, a single sample had a TOC concentration of 15,700 mg/l and an O&G concentration of 3,820 mg/l. These type of data were clearly not providing accurate/useful information.

6.1.4.2 Analytical Goals

The purpose of the analytical program was to quantify the amount of tar present within the water. Therefore, New England Testing Laboratories was consulted regarding potential analytical methodologies that might yield more reliable results. NET recommended that the samples be analyzed for O&G by a gravimetric method instead of the infrared method. The infrared method is better at providing lower detection limits but not as reliable at quantifying relatively high

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Figure 6-10
Production Temperature
UGI Columbia Gas Plant Site

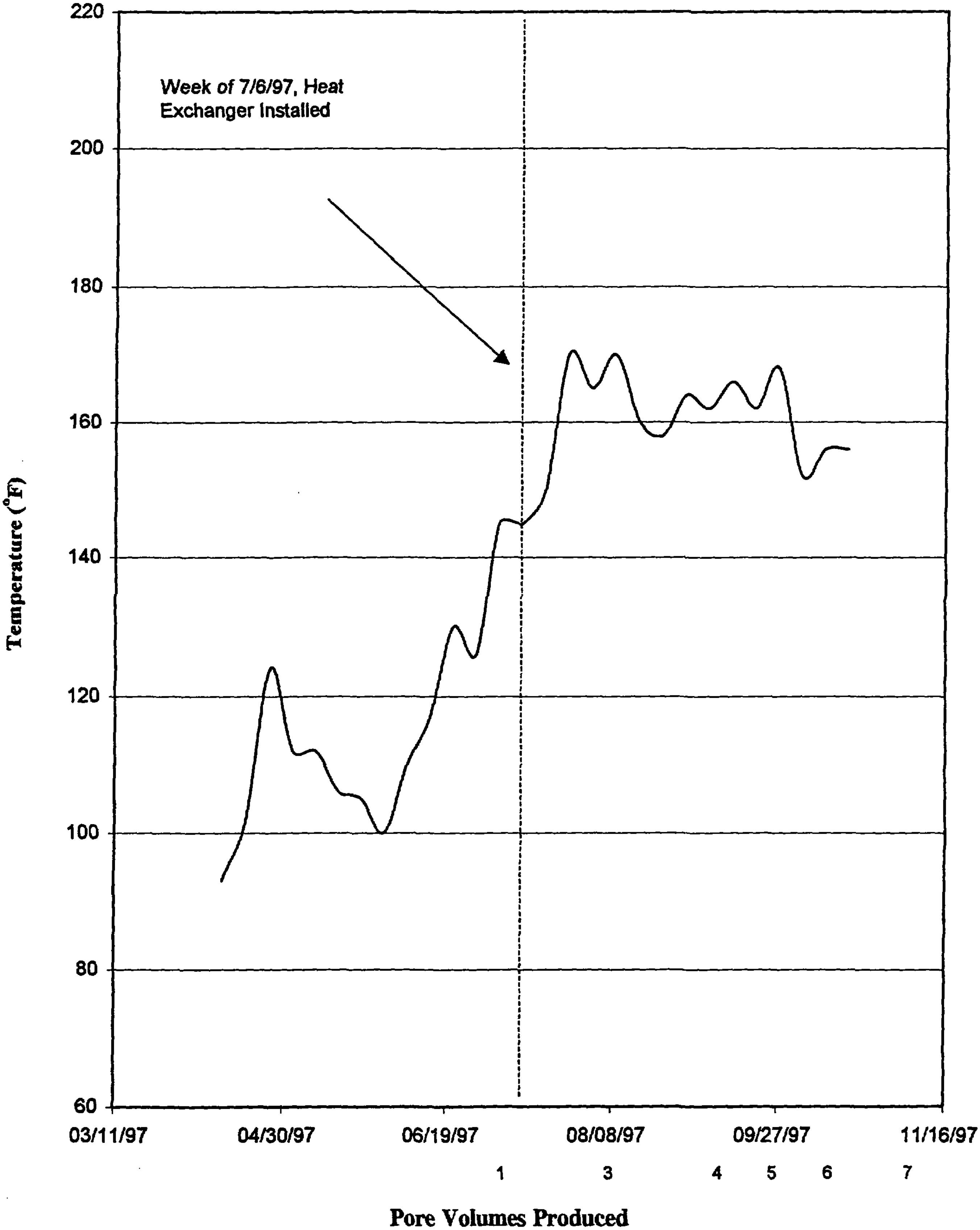

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Table 6-1
UGI Columbia Gas Plant Site
O&G and TOC Results from Production Water Samples

Week Ending	Oil & Grease Gravimetric (mg/L)	Oil & Grease IR (mg/L)	Prod. TOC (mg/L)
03/13/97		3820	15700
03/20/97		2830	9100
03/28/97		N/A	N/A
04/04/97		N/A	N/A
04/12/97		2160	18000
04/19/97		2160	18000
04/26/97		367	8300
05/03/97		768	8200
05/10/97		768	8200
05/17/97		249	82000
05/24/97		249	13250
05/31/97		249	13250
06/07/97		249	13250
06/14/97		57	18500
06/21/97		19	10100
06/28/97	1960	243	10100
07/05/97	1960	243	10100
07/12/97	676	243	8000
07/19/97	676	426	8000
07/26/97	218	426	2500
08/02/97	826	203	8800
08/09/97	10	10	787
08/16/97	10	10	787
08/23/97	15	12	946
08/30/97	4	4.4	848
09/06/97	22		915
09/13/97	22		701
09/20/97	4		932
09/27/97	23		464
10/04/97	422		864
10/11/97	62		732

concentrations. The gravimetric method, on the other hand, quantifies relatively high oil concentrations with better accuracy. Also, unlike the TOC analyses, the O&G analyses are performed on the entire homogenized sample, not a subsample. Therefore, our existing analytical program continued, but gravimetric O&G analyses were added.

6.1.4.3 Results Comparison

Seven samples were collected and analyzed by both the infrared and gravimetric method. The comparison of the results is as follows:

Sample	Infrared (mg/l)	Gravimetric (mg/l)
1	10	10
2	10	13
3	12	15
4	15	18
5	203	826
6	243	1960
7	426	676

These results show that gravimetric O&G analysis detect higher O&G concentrations than infrared analysis; this becomes more apparent at higher relative O&G concentrations. Therefore, as NET suggested, gravimetric analysis for O&G was selected as the preferable method for all future O&G analysis. However, due to lack of a full data set for either the gravimetric or the infrared analysis, and the fact that the analysis results are concentration dependent, these results were not used to calculate the volume. These results were instead used as a relative measure of system performance.

6.1.5 Tar Transfers

Operator responsibilities included tar transfers from Tank 1 to the Oil Storage Tank. The procedures and results of these transfers is discussed in Section 7.

6.2 Responsibilities of Operator

The primary responsibilities of the system operator were to:

1) Maintain Site security and control access;

2) Proactively monitor data points throughout the system including:

   - Flow rates;
   - Temperatures;
   - Pressures;
   - pH; and
   - Iron Levels.

3) Collect samples as required;

4) Clean strainers and bag filters;

5) Inspect pipes and tanks for leaks;

6) Schedule trucks for tar disposal; and

7) Log all data and record all activities.

Detailed sampling and monitoring requirements are described in the Sampling and Analysis Plan (RETEC, 1996). Other requirements are described in the O&M Plan (RETEC, 1996).

6.3 Materials/Tar Disposal

All recovered coal tar was properly manifested and removed from the Site to a properly licensed disposal facility. The contracted disposal company provided the necessary equipment to properly transfer recovered coal tar from the 6,000 gallon holding tank on the Site to the transfer truck. The oil transfer area at the Site was equipped with an inlet connection point. The contracted disposal company ensured that the inlet connection point on the truck was positioned over the oil transfer area. After the Site engineer inspected all connections to ensure their integrity, the coal tar was transferred. The transfer hose was disconnected in a manner that prevented any coal tar from spilling. The transporting company was responsible for decontaminating the transfer vehicle and oil transfer hose.

The transporting company was also responsible for any necessary spill prevention control and countermeasures while in route to the disposal facility. Coal tar did not, at any time, spill or leak during transfer to the truck or transport to the disposal facility.

6.4 Deviations from O&M Plan

This section is presented to discuss deviations from the approved Operations and Maintenance (O&M) Plan (RETEC, 1996) for the remedial action at the Site. Only sections where deviations occurred are presented and the actual O&M procedures used during system operation are discussed. At the end of this section is a discussion about lessons that were learned regarding operation of the enhanced recovery system.

The O&M Plan (RETEC, 1996) was prepared as part of the final Remedial Design for the CROW™ enhanced recovery process. The O&M Plan was approved by EPA and PADEP prior to implementing construction activities at the Site and was prepared for Site operators as an instruction guide for daily operations. Emergency procedures were covered separately in the Health and Safety Plan and Contingency Plan. Sampling and analytical requirements were covered in the Field Sampling Plan. The O&M Plan was limited to providing information on routine operations.

As expected, additional operations and maintenance issues appeared as the system was operated and modified. This section discusses these issues.

6.4.1 Boiler Operation

Since the boiler used for the enhanced recovery system was not initially included in the design, its operational requirements were not included in the Operations and Maintenance Plan. Requirements for proper operation of the boiler included frequent blowdowns, and maintenance of the water softening system.

Boiler blowdown consists of precipitated hard-water chemicals such as calcium and magnesium. The precipitated materials accumulate within the boiler during normal operations and require periodic removal. Blowing down is the standard removal method for this material. The boiler included valves, positioned specifically for blowdown, located at the top and bottom of the main chamber.

Operators were instructed to blow down the boiler when boiler water conductivity measurements exceeded pre-determined values. An exceedance of this pre-set limit indicated the need for blowing down. Blowdown was initially re-injected into the relief holder, but was later kept separate from the system, treated, then discharged along with other treated process water.

The water softening system supplied with the boiler required occasional testing to ensure proper operation. A hardness test kit was used at least once daily to check the hardness of the water-softening system. Hardness levels exceeding pre-determined levels indicated the need to regenerate the softening resin beads.

6.4.2 Operator's Logbook Forms

Initially, the operator log forms were created on separate pages. However, after operations began, operators requested an easier, more efficient method for recording operational parameters. Subsequently, one form was developed that contained all the information from the previous set of log forms. All operator logforms are presented in Appendix E.

6.5 Lessons Learned

Several lessons were learned during construction and operation activities. This section serves to document those lessons for the benefit of design and construction activities of similar systems in the future.

6.5.1 Mechanical Lessons Learned

6.5.1.1 Flowmeters and Totalizers

During enhanced recovery system design, process fluid characteristics were considered for flowmeter and totalizer selection. However, failure of these devices occurred frequently during system operations. The harsh characteristics of process water (high temperature and coal tar constituents) caused damage to the units internal parts. Some of the flowmeters and totalizers functioned properly, but those where high temperatures and coal tar existed failed frequently.

Future enhanced recovery designs should incorporate alternative equipment for measuring flow and total volume. Considering coal tar's effects on most materials, an all-stainless steel design would be preferred. All equipment components should be compatible with high heat and coal tar constituents. Compatibilities were checked for the equipment used at the UGI Columbia Gas Plant Site, but failures still occurred.

6.5.1.2 pH Probes

Due to their proclivity for failure, pH probes are typically designed to be replaceable. Since pH probes were included in this system's design for monitoring pH adjustments (although this part of the system was not actually utilized), replaceable probes were used. However, pH probes were designed as part of the production tank and, therefore, may have needed replacement while the tank contained fluids.

6.5.1.3 Tank Volume Indicators

Both full-scale CROW™ enhanced recovery systems included devices for measuring tank volumes. However, the coal tar and coal tar constituents negatively affected the performance of the devices and, in some instances, caused their failure. The devices used included pressure transducers, conductivity indicators, and flowmeters and totalizers on tank influent pipes; none were completely effective.

A design that may be effective, but was not attempted on this system, is an externally-mounted tank gauge. The gauge would need to be of mechanical design.

6.5.1.4 Tar Level Indicator

Due to coal tar's effects on many materials of construction, equipment designed to measure tar/water interfaces typically do not last very long under continuous exposure scenarios. Tar/water interfaces within tanks are used to determine depth of tar and subsequently the volume of tar. Conductivity indicators located inside a tar storage tank work initially, but ultimately fail after extended exposure times. A few designs are available to overcome this problem.

One design involves providing easy access to the top of the tank being used to store the recovered tar. If access is available, an oil/water interface probe may be used to measure the interface. Oil/water interface probes used frequently with coal tar continue to function properly if they are used for short durations and cleaned following use.

Another option is to install bleed nipples every six inches up the side of the tar storage tank. The nipples can be checked for the presence of tar and do not suffer the damage that most sensitive equipment does. Bleed nipples are an effective alternative if precise depth measurement of the interface is necessary.

An additional option is a cleanable site gauge. This type of gauge allows flushing of the site glass following use of the gauge. Liquids are not left in the gauge between readings which prevents staining of the site glass.

6.5.1.5 Production Pumps

Downhole, submersible, centrifugal pumps are problematic when used with an enhanced recovery system. The high temperatures of the process water caused the pump(s) to overheat and "burn out" prematurely. Surface-mounted "jet pumps" were mores successful when installed, but, ultimately, a stainless steel, hydraulic, submersible pump provided the best recovery well operation.

The lighter-weight design of the hydraulic pump (vs. The submersible centrifugal pump) allowed easier maintenance. In addition, the completely stainless steel design of the downhole portion prevented undesirable chemical incompatibilities with coal tar constituents.

6.5.2 Process Lessons Learned

6.5.2.1 Multi-point Injection/Extraction

During operation of the enhanced recovery system, preferential flowpaths were undoubtedly created. To improve the effective recovery area, flows were temporarily reversed near the end of the system operations. To accomplish this, the central extraction well was utilized for injection, while the eight injection wells were interchangeably utilized for extraction.

During the initial phase of production from most of the injection wells, liquid coal tar was recovered. The tar portion of the extracted water (based on visual inspection) was much greater relative to extraction water (from just the central extraction well when operations were nearing completion).

6.5.2.2 Water vs. Steam

Initially, the UGI Columbia Gas Plant Site's enhanced recovery system design used steam injection. Steam was chosen for various reasons including its higher heat content. During startup activities, however, steam was observed leaking up through the surface of the relief holder's concrete cap. Injection flowrates were initially lowered to prevent continued leakage.

For the initial startup and operation of the system, the steam injection component was adjusted and manipulated in an attempt to increase injection rates without inducing surface leaks. Typically, injection rates exceeding 2 gpm were problematic.

Occasionally, boiler shutdowns resulted in the injection of ambient temperature water versus steam. On these occasions, flowrates could be increased without negative results (i.e., surface leaks). In fact, flowrates as high as 10 gpm were reached without signs of surface leaks.

The decision was made to install a heat exchanger on the boiler to allow continuous hot water injection. Although the increased water flowrate's heat input was less than that of steam, the lack of surface leaks and increased fluids movement (creating increased temperature homogeneity) was considered more beneficial.

Had the relief holder contained materials with higher permeabilities, the steam injection may have been successful. The heterogenous nature of the holder created a false appearance of greater permeability. Future applications utilizing steam or water injection should investigate these geologic characteristics extensively.

The oil industry has used a similar technique for recovering NAPL (oil); however, they utilize a sequence of hot water, then steam. The initial hot water injection first displaces as much oil as possible; this increases the permeability for the subsequent steam injection which allows higher injection rates at lower pressures minimizing the likelihood of surface steam breakthrough. Also, the lower residual saturations that are possible with steam may then be reached.

6.5.2.3 Heat Exchanger

The Clever-Brooks boiler system was initially installed with the process water entering the boiler chamber. This setup was eventually determined to be problematic due to the quality of our process water. Typically, boilers require extremely high water quality due to the following reasons.

The process of boiling fluids causes a buildup of precipitates within the boiler. The precipitates can corrode internal parts and even clog process piping.

Boilers accumulate oil for the same reason that they accumulate precipitates; these materials do not easily volatilize and exit the boiler in the effluent.

Hard water contains relatively higher concentrations of the constituents that tend to precipitate and remain inside the boiler; therefore, a water softening system is typically required as boiler feed pretreatment.

The boiler feed water at the UGI Columbia Gas Plant Site was both hard and also contained oil. For this reason, maintenance of the system was difficult. The water softening system needed almost constant attention to maintain desired hardness levels. Even with proper maintenance of the water softener, blowdowns (of the accumulated precipitates) were sometimes required hourly. Also, the oil content of our process water posed a danger of ruining the entire boiler by coating the boiler tubes and rendering them ineffective.

To lower maintenance requirements, a heat exchanger was installed. The heat exchanger allowed the indirect heating of process water without allowing contact with boiler internals. A small volume of water was recycled between the exchanger and boiler; this drastically reduced the amount of necessary pretreatment water-softening chemicals. Some treatment was still required because recycle water was periodically lost via blowdowns.

7 Certification of Performance Standards

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7.1 The Relief Holder Performance Standard

As specified in the Design and Implementation Workplan (RETEC, 1995), the remediation of the relief holder will be complete when all separable tars within the holder have been removed. The separable tar within the relief holder is defined as tar that can be separated from water within the onsite oil/water separation vessel.

Initially, the performance standard was to be based on recovery of a specified percentage of existing tar, so an attempt was made to quantify the tar volume within the holder. Due to the heterogeneity of the subsurface sampling results, however, the initial tar volume in the holder was difficult to quantify. Therefore, without a reliable starting tar volume, the removal of a certain percentage of existing tar was impossible to document. For this reason, EPA allowed the performance standard to be written as follows:

> *The enhanced recovery process shall be operated until the increase in cumulative recovery of coal tar drops to 0.5% or less per pore volume of water flushed through the formation.*

Therefore, the performance standard became a measure of the system's efficiency. The standard assumes that separation is no longer apparent when the increase in cumulative tar recovery drops to 0.5% or less per pore volume of water injected into the holder. Based on previous laboratory data from the Brodhead Creek Site (Design and Implementation Workplan, RETEC, 1995) and field data from the Bell Lumber and Pole Site (Bell Pole CROW™ Pilot Test Results and Evaluation, October, 1992), it is at this point that 98.5% of the total recoverable coal tar will have been recovered. Therefore, continued operation of the process will yield little benefit.

7.1.1 Cumulative Recovery Measurement

To measure the increase in cumulative recovery of tar during operations, two numbers were needed: the total cumulative recovery, and the recovery in the latest pore volume. However, only indirect methods could be used to calculate volumes. In an attempt to estimate these quantities, the Site operator performed the following procedure:

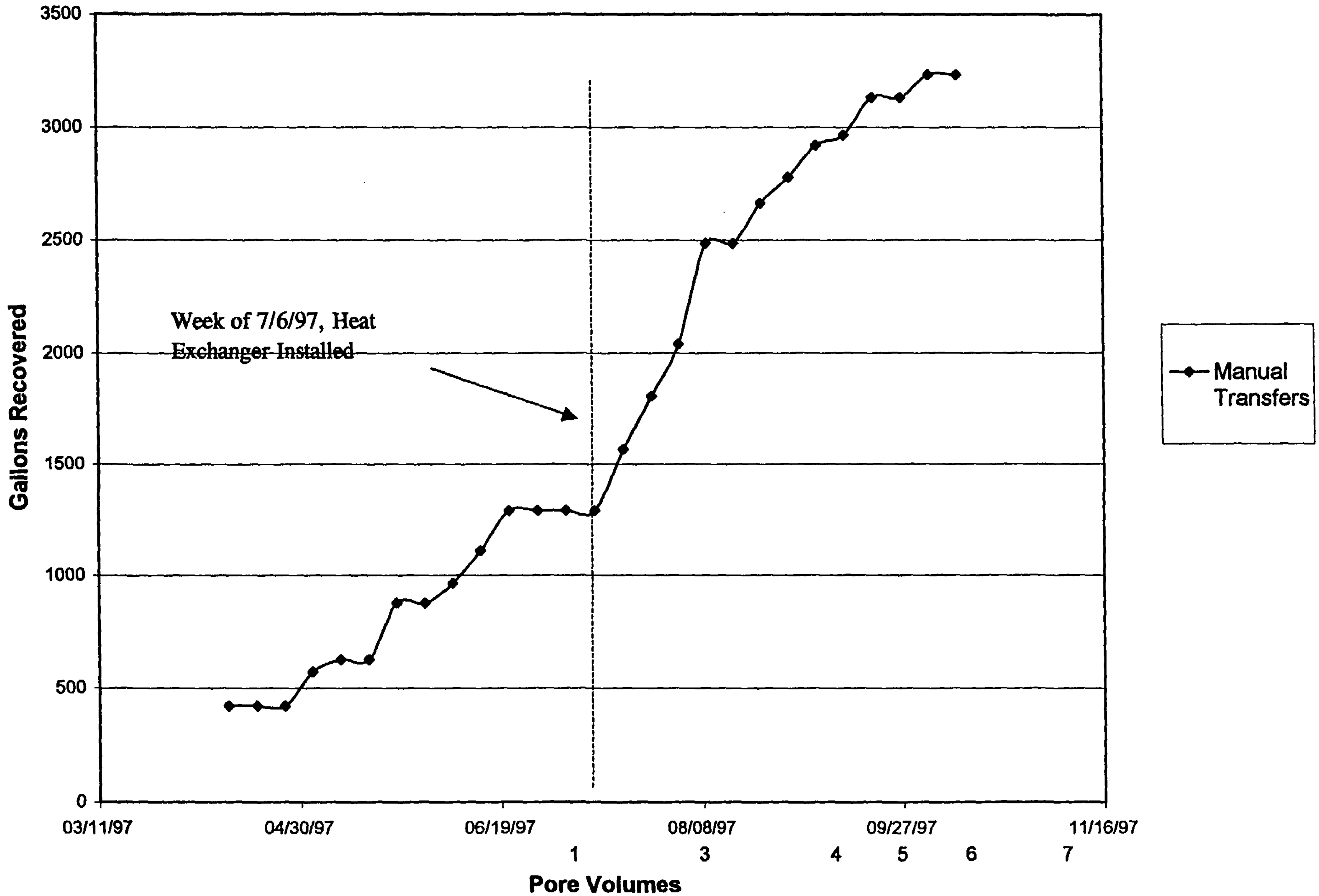
> *Prior to each tar transfer to the tar storage tank, the Site operator inspected the pressure gauge at the base of the tar storage tank and calculated the depth of liquid within the tank; this value was noted. The transfer of tar was then initiated via gravity flow from Production Tank 1. Throughout the transfer process, samples of the transfer liquid were collected and inspected for the presence of water. When water was observed within the sample, the liquid transfer ceased; this prevented large volumes of water from entering the tar storage tank. The operator would then re-inspect the pressure gauge on the tar storage tank and calculate the Δh of the liquid depth. The Δh was then converted to gallons using a constant volume/foot calculated from the tank dimensions.*

As the system was operated, these volumes were recorded. Figure 7-1 presents a graph of manual transfers versus pore volumes (pore volumes were calculated using an estimated 30% holder porosity). By tracking the pore volumes flushed over the same period of time, an estimate was made that allocated specific tar transfers to specific pore volumes. Therefore, estimates of both numbers, the total recovered tar and the recovered tar associated with the latest pore volume flush, could always be accounted for and the system's performance could continuously be compared to the performance standard.

To identify the accuracy of oil transfer methods, a sample of tar from the oil storage tank was analyzed for O&G content (Appendix K contains these results). The results show that the contents of the oil storage tank were primarily tar. Based on these analyses, EPA partially accepted the method of tar transfer measurement as the measure by which we certify achieving the performance standard. EPA also requested that O&G and total organic carbon (TOC) results be used for tar volume calculation.

Cumulative recovery at the Site was to be measured by calculating tar transfer volumes per pore volume of operation. Previous estimates determined that the total pore volume of the relief holder was approximately 170,000 gallons. This figure was based on an estimate of 30% porosity for the holder. This figure was also used to calculate pore volumes shown in Figure 7-1. Following relief holder pumpdown operations, it was determined that 60,000 gallons of water were removed. While this figure (60,000 gallons) does not represent the porosity of the relief holder, it does more accurately reflect the volume of water required for one flush of the holder. Using the 60,000 gallon figure as the effective pore volume, cumulative tar recovery was re-evaluated and is presented in Figure 7-2.

Figure 7-1
Cumulative Tar Recovered (Manual Transfers)
UGI Columbia Gas Plant Site



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7.1.2 Tar Recovery

At the conclusion of operations, an oil/water interface probe was lowered into the tar storage tank and the height of tar in the tank was determined. From this information, a tar volume was calculated based on the tank dimensions. As shown in Table 7-1, this analysis shows that a cumulative tar volume of 3,350 gallons were recovered.

In addition to this analysis, tar volumes and tar water content were determined by Systech when the tar was shipped off site for disposal. These data are presented in Table 7-1 and show that a total of 2,500 gallons of tar were removed from the site.

Lastly, PAH analyses were performed on holder samples prior to operating the CROW™ process and after operations were completed. PAH samples were taken from five borings at two-foot intervals during both sampling rounds. Boring logs are presented in Appendix L. These results are presented in Table 7-2. For each depth interval, the geometric mean of the total PAH data was calculated. This mean was then used to calculate the equivalent gallons of tar. The calculation was based on an analysis of the tar, performed prior to treatment, which showed that 19% of the total oil and grease present was PAH. Appendix K presents these results. This analysis relating PAHs to O&G was performed only on samples before treatment operations began and not after treatment was completed. However, as shown in Figure 7-3, an analysis was performed on pre- and post-remediation samples from the holder assessing the relative distribution on individual PAHs. Those samples designated with a number (i.e., GB-4) are pre-remediation samples while those samples designated with a letter (i.e., RB-D) are post-remediation samples. Figure 7-3 shows no change in the distribution of PAHs from pre- and post-samples. Therefore, using a figure of 19% as the portion of tar that is comprised of PAHs should be representative of both pre- and post-remediation samples. Using this figure, the total holder tar volumes are calculated for pre- and post-remediation and show a removal of approximately 9,300 gallons using this method.

The three methods described above were done independently. While there is a variability in the results by a factor of two to three times, these results are considered to be in fairly good agreement. The most conservative approach is to use the Systech data and conclude 2,500 gallons of tar were removed from the relief holder.

Figure 7-2
Cumulative Tar Recovered (Manual Transfers)
UGI Columbia Gas Plant Site

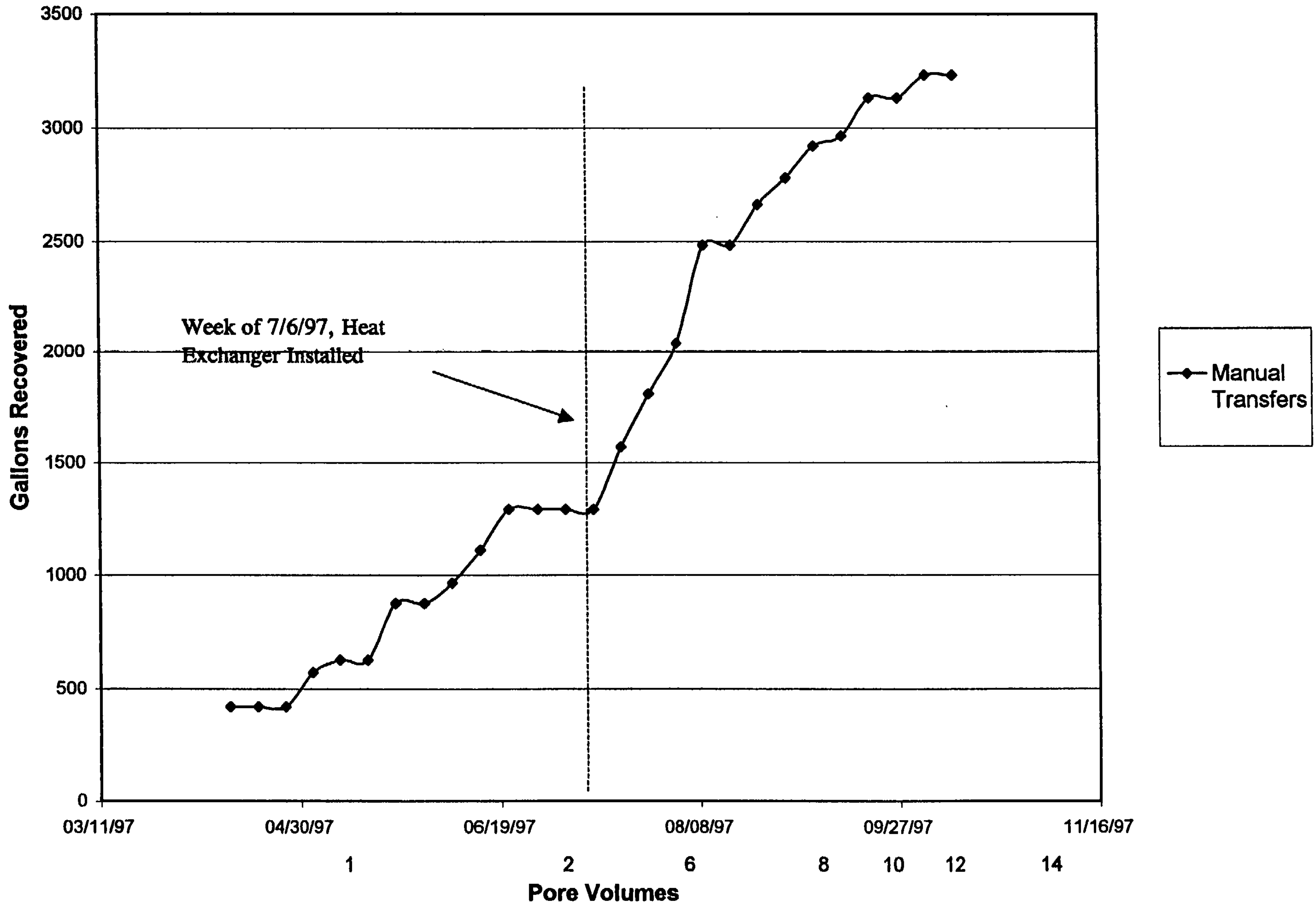

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Table 7-1
UGI Columbia Gas Plant Site
Total Recovered Tar Volume

Based on Systech Shipments (total volume collected by Systech - minus analyzed water content)	Based on Storage Tank Measurements (Calculation uses total tar volume in tank and tar analytics in Appendix K)
Load 1 = 2422 gallons at 47.7% water = 1267 gallons Load 2=4528 gallons at 76.8% water = 1050 gallons Load 3= 1194 at 85.2% water = 177 gallons **Total = 2494 gallons tar**	Tar depth in tank (O/W interface probe) = 9 feet Tank diameter = 8 feet, each 1 foot = 380 gallons 9 feet depth x 380 gallons/foot = 3420 gallons NET analysis from tank contents=98% O&G **3420 gallons x 0.98 = 3351.6 gallons tar**

Notes:

1. Systech samples were collected from each shipment of tar/water sent to Systech for incineration in their cement kiln.
2. Each Systech sample was collected using a Coliwasa sampling tube to effectively grab a core sample of the entire truck-load of material.
3. Water content for each load was analyzed using a Karl-Fisher moisture meter.
4. Systech did not treat any water sent from the UGI Columbia Gas Plant Site. All materials were incinerated although some of the tar/water mixture may have been blended with higher BTU materials before being incinerated.
5. NET analytical results from tar samples are presented in Appendix K.
6. The tar sample collected from the oil storage tank was collected from a sampling point located at the base of the tank approximately 12" from the bottom.
7. The tar sample was collected near the end of operations before any tar was removed from the site.
8. NET utililzed the gravimetric method for analyzing the O&G concentration in the tar sample.

Table 7-2
UGI Columbia Gas Plant Site
Total Tar Volume in Holder based on Geometric Mean
of PAH concentrations from Before and After CROW™

Before CROW Operation

Depth	PAHs in parts per million (ppm) Prior to Startup of CROW System					PAH (ppm) Geometric Mean	Represented Gallons of Tar
	RB-1	RB-2	RB-3	RB-4	RB-5		
0'-2'	1,190	135	715	917	4	211	80
2'-4'	6,290	83	7,550	99	144	562	214
4'-6'	405	6,500	249	44	303	387	147
6'-8'	1,710	14,100	5,590	509	1,610	2,562	974
8'-10'	1,710	4,680	3,660	5,550	1,250	2,895	1,100
10'-12'	7,920	8,340	9,930	9,070	8,990	8,824	3,352
12'-14'	12,200	9,950	7,750	7,060	14,300	9,897	3,760
14'-16'	3,310	N/A	4,490	16,600	11,400	7,282	2,767
16'-18'	N/A	6,790	1,370	16,600	18,100	7,271	2,763
18'-20'	51,300	36,400	5,610	17,500	N/A	20,692	7,862
20'-22'	N/A	28,100	14,200	39,000	N/A	24,966	9,486
22'-24'	N/A	N/A	42,500	2,690	21,000	13,390	5,088
Total						98,940	37,592

Following CROW Operation

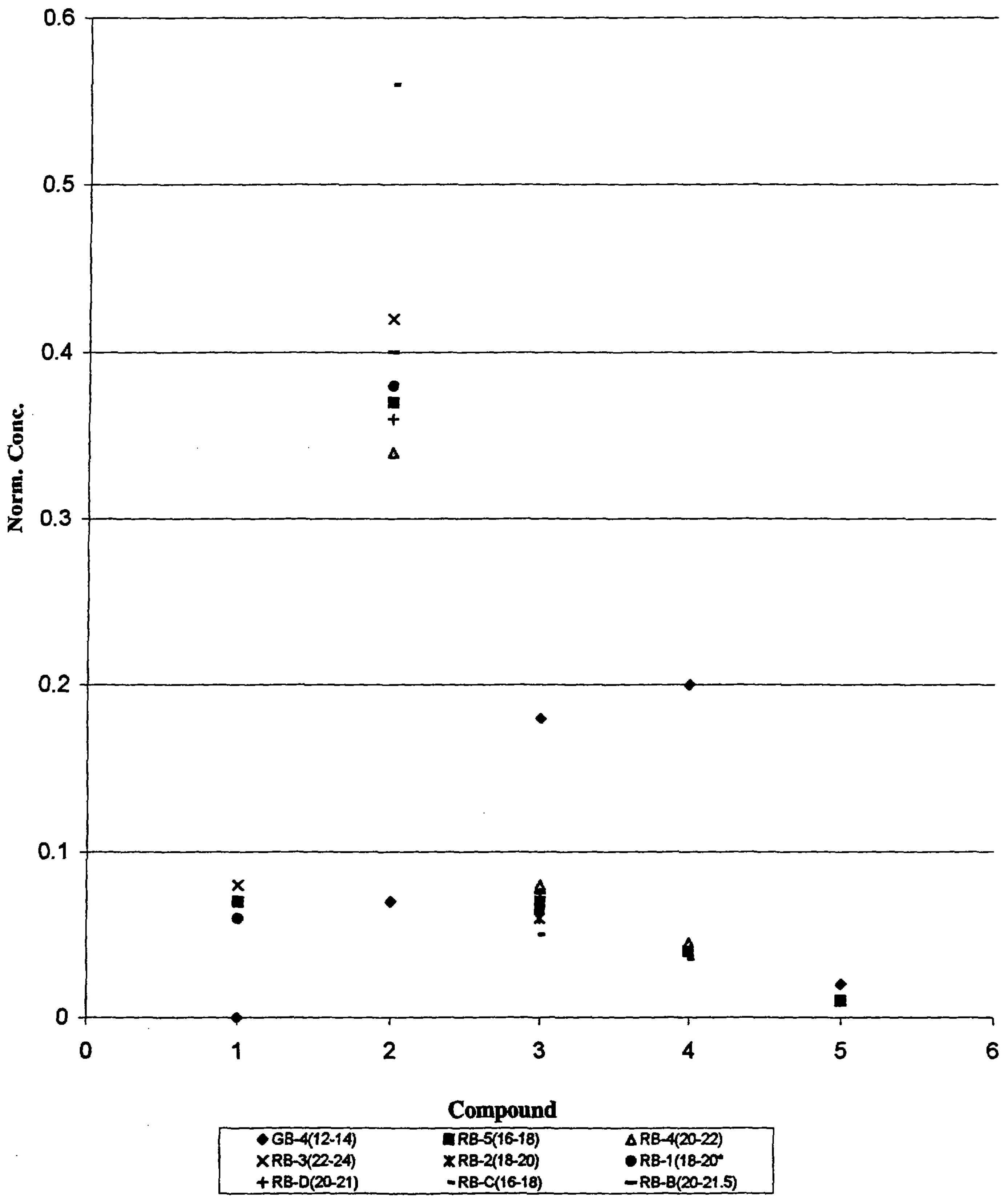
Depth	PAHs in parts per million (ppm) After operation of CROW™ System					Geometric Mean	Represented Gallons of Tar
	RB-1	RB-2	RB-3	RB-4	RB-5		
0'-2'	2,760	839	2,170	113	12,700	1,485	564
2'-4'	7,980	4,010	10,300	2,100	53	2,055	781
4'-6'	8,070	7,500	21,500	646	9	1,499	569
6'-8'	5,940	480	38,000	1,670	2,080	3,274	1,244
8'-10'	20,200	993	14,800	1,320	5,270	4,602	1,749
10'-12'	8,000	6,110	4,180	5,930	13,900	7,003	2,661
12'-14'	12,100	3,750	13,000	19,000	21,100	11,878	4,513
14'-16'	2,560	26,900	13,500	5,150	6,620	7,947	3,019
16'-18'	726	14,400	29,300	10,700	12,200	8,325	3,163
18'-20'	19,300	13,500		3,850	2,770	7,260	2,759
20'-22'	129,000	21,900	7,350	44,900	2,720	19,091	7,253
22'-24'	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total						74,420	28,275

Gallons difference between before and after: **9,316**

Notes:

1. PAH results are on a dry-weight basis.
2. Formula for calculating tar volume from PAH concentration:(Example) =
   (((PAH in ppm/1,000,000) * 5655 * 110/63) * 7.48 / 0.19
3. Explaination = (((PAH in ppm / 1,000,000) * Volume of 2 foot inteval of holder * Density
   of soil / Density of tar [almost that of water]) * 7.48 gallons/ft3 / 0.19 PAHs in Columbia t
   This formula calculates gallons of tar in a 2-foot interval from the ppm concentration in a dri
   recovered from the holder. The calculation takes into consideration the fact that the UGI Co
   contains 19% PAHs and the density of the tar is almost equal to that of water.
4. N/A: samples were not recovered for this interval.
5. The difference in depths of the pre- and post-CROW borings may have been caused by differences in measuring techniques or the length of equipment pieces used for the drilling procedures. Two different types of drill rigs were used for the pre- and post-CROW borings; the mounding of the holder's concrete pad during grouting required a Krupp-track rig for the post-CROW borings. It is believed that both pre-and post-CROW borings were advanced to the bedrock base of the holder for two reasons: 1. All 5 post-CROW borings encountered refusal 2 feet short of the measured pre-CROW borings, and 2. the contents of the holder do not suggest that any standard drill rig should consistently encounter refusal before reaching bedrock. Additionally, pre- and post-CROW borings wer not advanced in the exact same locations because wells were installed in the pre-CROW bore holes and could not be used for the post-CROW borings.

Figure 7-3
Relative Distribution of PAHs
UGI Columbia Gas Plant Site



7.1.3 Tar Redistribution

The data shown in Table 7-2 shows that at each two-foot interval from 0 to 10 feet, the concentration of PAHs after remediation were higher than before remediation. That trend reverses for the lower part of the holder. What these data indicate is that the tar in the lower portion of the holder were effectively mobilized during the operation of the CROW™ process; however, not all of the tar which was mobilized was recovered in the production well. Rather, a portion of this tar was redistributed into the upper levels of the holder. An attempt was made to calculate this quantity of tar that was mobilized and redistributed. Table 7-3 presents these results. The tar volumes were calculated by determining the increase of PAHs in each two-foot interval of the holder (using the geometric mean for each interval) and assuming that PAHs comprise 19% of tar. These data show that an additional 2,419 gallons of tar were mobilized with the CROW™ process, but this tar was not recovered. As will be shown in the next section, this increase in tar in the upper area of the holder was not sufficient to exceed residual saturations in these areas.

7.1.4 Residual Saturation

Modeling of the CROW™ process assumed that the residual saturation of tar in the holder after steam injection would be 9% (see Section 3.3.2). This section attempts to determine the post-CROW™ residual saturation within the holder (the percentage of total holder contents that is tar).

The PAH data collected from pre- and post-CROW™ samples allows for an estimate of the total tar volume difference from before and after CROW™ (Table 7-2). This data can also be used to calculate tar volumes remaining above different residual saturation levels, that may exist in the holder, from both before and after CROW™.

Table 7-4 shows the PAH results from both pre- and post-CROW™ and calculates gallons of tar above varying residual saturation levels based on the geometric mean of PAHs across each 2-foot interval. Table 7-4 also shows the difference in tar volumes, above selected residual saturation levels, for the pre- and post-CROW™ data.

The difference in tar volume shown in Table 7-4 should correlate with the total amount of tar mobilized by the CROW™ process. This is true because the total volume of mobilized tar is the sum of the tar recovered (2,500 gallons) plus the tar that was redistributed into the top ten feet of the holder (2,419 gallons). The

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Table 7-3

UGI Columbia Gas Plant Site

Total Tar Volume (top 10 feet of holder) based on Geometric Mean of PAH concentrations from Before and After CROW™

Depth	Post CROW Geometric Mean PAHs	Pre CROW Geometric Mean PAHs	Difference in PAHs Pre-Post CROW	Total Represented Gallons Tar
0'-2'	1,485	211	1,273	489
2'-4'	2,055	562	1,493	573
4'-6'	1,499	387	1,112	427
6'-8'	3,274	2,562	712	273
8'-10'	4,602	2,895	1,708	656
Total				**2,419**

Notes:

1. PAH results are on a dry-weight basis.
2. Formula for calculating tar volume from PAH concentration:(Example)=
   (((PAH in ppm/1,000,000) * 5655 * 110/63) * 7.48 / 0.19
3. Explaination = (((PAH in ppm / 1,000,000) * Volume of 2 foot inteval of holder * Density

Table 7-4
UGI Columbia Gas Plant Site
Total Tar Volume in Holder based on Geometric Mean
of PAH concentrations from Before and After CROW™

Before CROW Operation

Depth	PAHs in parts per million (ppm) Prior to Startup of CROW System RB-1	RB-2	RB-3	RB-4	RB-5	PAH (ppm) Geometric Mean	In Excess of 7% Residua Saturation	Represented Gallons of Tar	In Excess of 8% Residual Saturation	Represented Gallons of Tar	In Excess of 9% Residual Saturation	Represented Gallons of Tar
0'-2'	1,190	135	715	917	4	211	<RS	0	<RS	0	<RS	0
2'-4'	6,290	83	7,550	99	144	562	<RS	0	<RS	0	<RS	0
4'-6'	405	6,500	249	44	303	387	<RS	0	<RS	0	<RS	0
6'-8'	1,710	14,100	5,590	509	1,610	2,562	<RS	0	<RS	0	<RS	0
8'-10'	1,710	4,680	3,660	5,550	1,250	2,895	<RS	0	<RS	0	<RS	0
10'-12'	7,920	8,340	9,930	9,070	8,990	8,824	<RS	0	<RS	0	<RS	0
12'-14'	12,200	9,950	7,750	7,060	14,300	9,897	<RS	0	<RS	0	<RS	0
14'-16'	3,310	N/A	4,490	16,600	11,400	7,282	<RS	0	<RS	0	<RS	0
16'-18'	N/A	6,790	1,370	16,600	18,100	7,271	<RS	0	<RS	0	<RS	0
18'-20'	51,300	36,400	5,610	17,500	N/A	20,692	7,392	2,839	5,492	2,109	3,592	1,380
20'-22'	N/A	28,100	14,200	39,000	N/A	24,966	11,666	4,480	9,766	3,751	7,866	3,021
22'-24'	N/A	N/A	42,500	2,690	21,000	13,390	90	35	<RS	0	<RS	0
Total							19,149	7,354	15,258	5,860	11,458	4,401

After CROW Operation

Depth	PAHs in parts per million (ppm) After operation of CROW™ System RB-1	RB-2	RB-3	RB-4	RB-5	Geometric Mean	In Excess of 7% Residua Saturation	Represented Gallons of Tar	In Excess of 8% Residual Saturation	Represented Gallons of Tar	In Excess of 9% Residual Saturation	Represented Gallons of Tar
0'-2'	2,760	839	2,170	113	12,700	1,485	<RS	0	<RS	0	<RS	0
2'-4'	7,980	4,010	10,300	2,100	53	2,055	<RS	0	<RS	0	<RS	0
4'-6'	8,070	7,500	21,500	646	9	1,499	<RS	0	<RS	0	<RS	0
6'-8'	5,940	480	38,000	1,670	2,080	3,274	<RS	0	<RS	0	<RS	0
8'-10'	20,200	993	14,800	1,320	5,270	4,602	<RS	0	<RS	0	<RS	0
10'-12'	8,000	6,110	4,180	5,930	13,900	7,003	<RS	0	<RS	0	<RS	0
12'-14'	12,100	3,750	13,000	19,000	21,100	11,878	<RS	0	<RS	0	<RS	0
14'-16'	2,560	26,900	13,500	5,150	6,620	7,947	<RS	0	<RS	0	<RS	0
16'-18'	726	14,400	29,300	10,700	12,200	8,325	<RS	0	<RS	0	<RS	0
18'-20'	19,300	13,500		3,850	2,770	7,260	<RS	0	<RS	0	<RS	0
20'-22'	129,000	21,900	7,350	44,900	2,720	19,091	5,791	2,224	3,891	1,494	1,991	765
22'-24'	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total							5,791	2,224	3,891	1,494	1,991	765

Gallons difference between before and after:	5,130	4,366	3,636

Notes:

1. PAH results are on a dry-weight basis.
2. Formula for calculating tar volume from PAH concentration:(Example)=
   (((PAH in ppm/1,000,000) * 5655 * 110/63) * 7.48 / 0.19
3. Explaination = (((PAH in ppm / 1,000,000) * Volume of 2 foot inteval of holder * Density of soil / Density of tar [almost that of water]) * 7.48 gallons/ft3 / 0.19 PAHs in Columbia tar)
   This formula calculates gallons of tar in a 2-foot interval from the ppm concentration in a dried sample recovered from the holder. The calculation takes into consideration the fact that the UGI Columbia tar contains 19% PAHs and the density of the tar is almost equal to that of water.
4. N/A: samples were not recovered for this interval.
5. The difference in depths of the pre- and post-CROW borings may have been caused by differences in measuring techniques or the length of equipment pieces used for the drilling procedures. Two different types of drill rigs were used for the pre- and post-CROW borings; the mounding

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tar redistributed to the top of the holder is included here because it was mobilized; it did not, however, cause concentrations to exceed residual saturation in the top level of the holder.

Using this total of 4,919 gallons and comparing it to the calculations presented in Table 7-4 shows that a residual saturation of 7% results in 5,130 gallons of mobilized tar due to CROW™.

7.1.5 Comparison to Modeled Predictions

Initially, the CROW™ system was operated with steam injection due to the benefits observed from the modeling effort. During startup activities, however, steam was observed leaking up through the surface of the holder's concrete cap. Injection flowrates were reduced to prevent continued leakage.

During the initial startup and operation of the system, the steam injection component was adjusted and manipulated in an attempt to increase injection rates without inducing surface leaks. Typically, injection rates exceeding 2 gpm were problematic. Occasionally, however, boiler shutdowns resulted in the injection of ambient temperature water versus steam. On these occasions, it was discovered that flowrates could be increased without resulting in surface leaks.

The decision was made to install a heat exchanger on the boiler to allow continuous hot-water injection. Although that increased water flowrate's heat input was less than that of steam, the lack of surface leaks and increased fluids movement (creating increased temperature homogeneity) was considered more beneficial.

Although leaks in the holder's concrete cap reduced steam injection rates and the holder's content provided greater backpressures than expected, the actual field results could still be compared to modeled predictions since steam and hot-water injection rates similar to those actually achieved were created from the model.

To compare model results to actual field results, it is important to understand that steam injection was utilized for approximately the first 130 days while hot-water injection was utilized for approximately the last 110 days. Therefore, when referring to the modeled predictions in Figures 3-5 and 3-6, the reader should keep these time frames in mind.

Steam injection rates were typically in the range of 1-2 gpm (water equivalent). Therefore, the modeled predictions for a steam injection rate of 2 gpm (water equivalent) were most appropriate for comparison of the first 130 days of operation. Also, since hot-water injection rates were typically between 5 and 7 gpm, the modeled predictions for a hot-water injection rate of 10 gpm were most appropriate for that portion of operations.

Modeled predictions indicated that at 2 gpm steam injection, production water temperatures should approach 210 degrees fahrenheit after 90 days of operation and remain at 210 degrees for the duration of operations. Model predictions indicated that hot-water injection would achieve production temperatures of 170 to 185 degrees fahrenheit. Actual field production temperatures, however, only approached 170 degrees fahrenheit after approximately 90 days of steam injection and remained at approximately 165 to 170 degrees through the remaining steam and hot-water injection; production temperatures never exceeded 175 degrees fahrenheit. It appears that the only area of the holder that reached above 200 degrees fahrenheit was the top of the holder closest to the injection wells (near the perimeter of the holder where the injection wells are located).

Modeled predictions also indicated that at 2 gpm steam injection, the percentage of the holder swept to residual saturation by 130 days of operation is approximately 70%. The percentage swept via 10 gpm hot-water injection was predicted to be approximately 95% within 180 days of operation. Since steam injection was used for the initial 130 days, the model suggests that the steam may have swept 65% of the holder to residual saturation and then the following hot-water injection may have swept 95% of the holder to residual saturation. To prove the actual field results, PAH data from post-CROW™ operations was considered.

As Table 7-4 shows, out of 11 2-foot intervals across the relief holder, only one (20-22') contained tar above the 9% residual saturation following CROW™. This calculates to 90.1% of the holder being swept to residual saturation. Unfortunately, since the PAH data was collected following both steam and hot-water injection, it is not possible to identify the percentage of the holder swept by each of the two techniques.

7.2 Materials/Tar Disposal

All recovered coal tar was properly manifested and removed from the Site to a properly licensed disposal facility. The contracted disposal company provided the necessary equipment to properly transfer recovered coal tar from the 10,000 gallon holding tank on the Site to the transfer truck. The oil transfer area at the Site was equipped with an inlet connection point.

The contracted disposal company ensured that the inlet connection point on the truck was positioned over the oil transfer area. After the Site engineer inspected all connections to ensure their integrity, the coal tar was transferred. The transfer hose was disconnected in a manner that prevented any coal tar from spilling. The transporting company was responsible for decontaminating the transfer vehicle and oil transfer hose.

The transporting company was also responsible for any necessary spill prevention control and countermeasures while in route to the disposal facility. Coal tar did not, at any time, spill or leak during transfer to the truck or transport to the disposal facility.

On October 31, 1997, EPA agreed that the performance standard had been met and that injection and production could be stopped until the Close-Out Report could be finalized.

The total volume of recovered sludges totaled 8,144 gallons. RETEC subcontracted Creamer Environmental, Inc. in Hackensack, New Jersey to transport the sludge from the Site to Systech's cement kiln in Paulding, Ohio. EPA had previously approved of this facility for thermal destruction of the recovered tar.

The tar sludge was removed from the Site in three separate loads. The first load of 2,422 gallons was removed on November 17, 1997. The second load of 4,528 gallons was removed on December 11, 1997. The third load of 1,194 gallons was removed on February 10, 1998. Manifests for tar transportation are presented in Appendix G.

7.3 Performance Standard for the Gas Holder

The only action to be taken on the gas holder prior to grouting was the pumping of all liquid from the holder. A performance standard for liquid removal was not developed. The total liquid removed from the holder was metered at 41,280 gallons.

7.4 Discharge Performance Standard

Batches of discharge water from the CROW™ process were treated by passing the water through a bag filters (including 20 μm, 1 μm, 0.5 μm, and oil adsorbing) and granular activated carbon and discharged to the Susquehanna River. The discharge flowrate averaged approximately 10 gpm and operated in batch mode.

During CROW™ system operations, discharge water consisted primarily of boiler blowdown from the Cleaver Brooks boiler system that heated injection water.

EPA and PADEP approved of the discharge after PP&L submitted a NPDES permit application. The NPDES application was not required for this system due to the regulatory status of the Site, but EPA and PADEP requested that the information be submitted in the form of a NPDES permit application. Based on information provided on the NPDES application, EPA and PADEP granted conditional approval for discharge to the Susquehanna River.

The criteria established for discharge from the Site included that the discharge water be initially sampled weekly for the first month of operation and then biweekly thereafter. EPA and PADEP imposed constituent limits of 10 parts per billion (ppb) for benzene and 50 ppb for Naphthalene. Results of all river discharge analysis are included in Appendix A.

During the week of December 21, river discharge analytical results indicated that the discharge criteria had been exceeded; this was the first and only recorded exceedance of the discharge criteria throughout the entire project. The benzene and naphthalene concentrations were 17 parts per billion (ppb) and 326 ppb, respectively.

The origin of the exceedance was water generated from the pumpdown of the relief holder. The elevated organic load from the relief holder water contributed to the one-time breakthrough in the carbon units.

Following the collection of the exceeding water sample, records indicate that only 2,982 gallons of water were discharged; this compared to approximately 200,000 gallons discharged throughout the project. Also, immediately following the discharge exceedance, discharge was halted and new carbon canisters were ordered. To re-examine treatment system effectiveness following installation of the new carbon, a sample was collected of the first batch of treated water; analysis was performed within 48 hours and results fell below the established criteria.

8 Site Restoration

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Following completion of enhanced recovery and holder pumpdown, the system was dismantled, and the holder stabilized. The restoration and final condition of the Site will be evaluated and addressed in the Feasibility Study.

Wastes and contaminated soils that were generated were analyzed for hazardous characteristics. All hazardous wastes were transported and treated or disposed in compliance with Article VII, 25 PA code chapters 260-266, and 270. These regulations apply to the identification and listing, generation, transportation, storage, treatment and disposal of hazardous waste.

All tar and untreated tar contaminated water was shipped to Systech for incineration in their cement kiln. Systech samples were collected from each shipment of tar/water sent to Systech. Each tar/water sample was collected using a Coliwasa sampling tube to effectively grab a core sample of the entire truck load of material (after the tar/water was loaded into the truck). The water content of each load was analyzed using a Karl-Fischer moisture meter. Systech did not treat any water sent from the UGI Columbia Gas Plant Site. All materials were incinerated although some of the tar/water mixture may have been blended with higher BTU materials before being incinerated.

8.1 Holder Stabilization

After removing the liquids from the holders, the holders were stabilized by pressure grouting with flowable fill. Lehigh Concrete Pumping Technologies, Inc. was used to perform grouting activities. Flowable fill is a blend of cement, fly ash, bentonite, and water which requires no compacting or finishing. It is a low strength, high density backfill which is more stable and less permeable than alternate compacted backfill. The flowable fill leaves very few void spaces in the holders. It has a 95% compaction rate which has proven very stable and greatly reduces the risk of surface settling and cracking.

Additional boreholes and the existing wells were used to pump the flowable fill into the holders. Ultimately, 45 holes were used to pump 576 cubic yards (116,337 gallons) of grout into the relief holder. Sixteen holes were used to pump 324 cubic yards (65,440 gallons) of grout into the gas holder. The grout was injected in a 20 foot, then a 10 foot, grid pattern. Injection pressures were regulated to ensure uniform distribution throughout the holders. To ensure complete coverage, injection points were utilized until grout was observed weeping from surrounding injection points. Once injected, approximately two weeks were required for the flowable fill to cure. After the fill had set within the holder, split spoon samples were collected, as described in the Sampling and Analysis Plan, to confirm the stabilization.

The site engineer supervising the drilling crew observed all split-spoon samples to determine the existence and condition of grout within the borings. Boring logs were constructed to present all recorded information; these logs are contained in Appendix L.

Grout was seen in many of the samples during the supplemental boring program. However, some split-spoon samples recovered after holder stabilization did not appear to contain grout. The absence of "visible" grout may indicate that the grout mixed extensively with existing materials and was too heterogenous to be observed. Another possibility is that low permeability zones within the holder inhibited grout flow into those areas. Since the grout was intended to lower the permeability of the holder contents, these low permeability zones may not have required grout anyway.

Approximately 1200 cubic yards were specified for the stabilization of the relief and gas holders. This volume was initially calculated based on a 30% porosity within the holders. This volume was the maximum expected volume necessary for stabilization. Ultimately, 900 cubic yards were used to complete grouting.

The grouting procedure used to stabilize the holders at the site involved pressurized injection of the grout slurry. The high pressures used to maximize grout intrusion tended to raise the concrete cap on the holder. Ultimately the concrete cap was pushed upwards into a dome-like shape with an increase in height of as much as 3 feet. The previously calculated volume of 576 cubic yards (116,337 gallons) of grout injected into the relief holder includes the additional grout under the dome-shaped cap. The approximate increase in volume underneath the dome is 210 cubic yards (42,390 gallons) (assuming 60' diameter holder and a 2' average increase in holder height). If this volume is removed from the total injected volume (for the relief holder), the new total volume of grout injected becomes 366.1 cubic yards (73,947 gallons).

In Section 7.1.1, it was mentioned that during relief holder pumpdown operations, 60,000 gallons of water were removed. While the 60,000 gallon figure does not represent the porosity of the relief holder, it does more accurately reflect the volume of water required for one flush of the holder. Assuming that residual water remained in the holder during grouting procedures, 60,000 gallons of grout should have been required to stabilize the relief holder. According to the calculation above, the actual volume of grout injected totaled 73,947 gallons.

During stabilization, a grout sample was collected for compression testing by PSI, Inc. of Lancaster, PA. Results indicate a 28-day compressive strength of 325 pounds per square inch (psi) or approximately 13,000 pound per square foot. These results, although for pure homogeneous grout, show much higher strength than a very firm clay. Since homogeneity may not exist within the holders, a compressive strength of less than 13,000 pounds per square foot would be expected. It should be noted that strength was not the primary characteristic desired for this application. Low permeability was most necessary and appropriate materials were specified based on that requirement. Strength analysis on the material was only performed to supply information for potential future site development.

The initial estimates of the time required for grouting ranged from 1-2 weeks. The actual time required to grout both holders exceeded 6 weeks. Schedule exceedances were, for the most part, due to slow injection rates. Another main factor was the shutdown of grout production at the facility supplying our grout; an alternate supplier needed to be contracted shortly after operations commenced. Unfortunately, the closest alternate supplier was over one hour from the site, which added to delays. Other factors extending the grouting time included equipment failures and shutdowns due to inclement weather.

Because the removal action included a waste stabilization step, the activities complied with PA SWMA, Act 97, Chapters 264 or 265 and 297.

8.2 Demobilization

Following stabilization, all tanks and piping were decontaminated and removed from the Site. All cleaning waters were treated with the carbon units and discharged to the river. The carbon units were removed after treatment was completed. The concrete tank farm was not demolished as part of decommissioning.

9 Meetings and Final Reporting

ORIGINAL (Red)

Prior to mobilization, a preconstruction meeting was held at the UGI Columbia Site. The meeting was attended by representatives from U. S. EPA and PADEP Clean Sites, PP&L and RETEC. The objectives of the meeting were to review lines of communication, reporting requirements, security and safety protocol and summarize design plans and specifications as they relate to equipment storage and facility footprints.

Upon completion of remedy instruction, the Supervising Contractor and the Engineer conducted a final inspection. The final inspection consisted of a walk-through of the entire Site. The objective was to determine whether the project was complete and consistent with the project plans.

10 Final Inspections

EPA guidance requests a report of the pre-final and final inspections conducted by the contracting party and the contractor after completion of construction of the operable unit. Four inspections were performed during this remedy:

- the EPA final construction inspection for the CROW™ system;
- the PP&L certification inspection for the CROW™ system;
- the EPA final operational data review for the CROW™ system; and
- the EPA final operational inspection for the CROW™ system.

10.1 The EPA Final Construction Inspection for the CROW™ System

Following system construction, EPA personnel inspected the enhanced recovery system. They compared the constructed system against the approved specifications package within the final design. However, several system modifications were made later in the project. The modifications were documented and on "Change of Design" forms, which are included in Appendix C; and discussed in Section 5. EPA approved the final construction of the system.

10.2 The PP&L Certification Inspection for the CROW™ System

Prior to startup of the completed CROW™ system, PP&L personnel inspected the system. PP&L certified that the system had been constructed according to the final design including subsequent documented changes.

10.3 The EPA Final Operational Review for the CROW™ System

Prior to approved shutdown of the enhanced recovery system, EPA met at the Site, with PADEP, Clean Sites Environmental Services (CSES), PP&L, and RETEC to discuss the data required for shutdown approval. EPA requested that several additional items be completed before approval for shutdown would be granted. The EPA requests are as follows:

ORIGINAL (Red)

- Continue to utilize each injection well as a production well for at least on week per well. This caused an addition of at least five weeks to the operating time frame.

- Dispose of the accumulated tar at an approved facility. Perform "percent oil" analysis on a composite sample of the material to determine the organic fraction.

- Analyze the injection and production water for PAHs, both filtered and unfiltered.

- Run the injection water through the existing activated carbon unit on the Site prior to injection into the holder.

- Estimate the initial quantity of tar within the relief holder based on pre-CROW™ analytical data on soil samples.

10.4 The EPA Final Operational Inspection for the CROW™ System

During the month of October 1997, EPA personnel conducted the final operational inspection of the CROW™ enhanced recovery system. EPA confirmed that the items agreed upon at the EPA final operational review were completed to their satisfaction. On October 31, 1997, EPA and PADEP granted approval to cease operations of the CROW™ system.

11 Summary of Project Costs

11.1 CROW™ Enhanced Recovery Project Costs

For the purposes of this RA Report, the project costs presented are those associated with the removal action for the relief and gas holders, and therefore begin with the predesign work associated with the CROW™ enhanced product recovery system.

The removal action work included many functions that were funded by multiple parties. Table 11-1 breaks down the funding for the project by each function.

The Engineering Evaluation/Cost Analysis (EE/CA) (RETEC, August 1994) identified the costs for selected alternatives. The two alternatives chosen for this site (Enhanced Recovery and Pumping) were assigned a total cost of approximately $770,000 in 1994 dollars; this calculates to $841,380 in 1997 dollars at 3% inflation.

Table 11-1 indicates that the total cost of implementation of Enhanced Recovery and Pumping (not including the pre-remedial design work) totaled approximately $1,226,000. The difference between the actual cost and EE/CA cost estimate (approximately $231,620), resulted from the following unexpected costs:

- extended operating time (labor, services, utilities, rentals, ODCs);
- additional ODCs (bag filter, sorbent booms, etc.);
- additional services during operation (cranes, plumbers, electricians);
- additional analytical costs associated with longer operation; and
- increased cost of holder stabilization.

The excavation alternative was estimated to cost $745,000 (or $814,000 in 1997 dollars). Along with the pumping alternative for the gas holder, the total cost would have been approximately $923,332 in 1997 dollars. This total falls below the actual cost incurred from the Enhanced Recovery and Pumping alternative. However, unexpected costs/savings during an excavation alternative could have raised or lowered the actual cost.

Table 11-1

Project Costs

Relief and Gas Holder Remediation
UGI Columbia Gas Plant Site

Cost Component	Total Cost	Estimate for Relief Holder	Estimate for Gas Holder
Project Work Plan	$52,000	$45,000	$7,000
Remedial Design	$101,000	$88,000	$13,000
System Construction	$275,000	$243,200	$31,800
Site Preparation	$2,000	$1,000	$1,000
Permitting and Regulatory Requirements	$7,000	$6,000	$1,000
Capital Equipment	$130,000	$120,000	$10,000
Startup	$28,000	$27,000	$1,000
Effluent Treatment and Disposal	$19,000	$17,000	$2,000
Utilities	$35,000	$31,000	$4,000
Consumable Materials	$20,000	$19,500	$500
Residual Waste Shipping and Handling	$20,000	$20,000	$0
Maintenance	$49,000	$47,000	$2,000
Labor	$205,000	$190,000	$15,000
Holders Stabilization and Demobilization	$188,000	$136,000	$52,000
Analytical	$60,000	$58,000	$2,000
Reporting	$35,000	$32,000	$3,000
Total	**$1,226,000**	**$1,080,700**	**$145,300**

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