Department of Energy

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MAY 10 2016

PPPO-02-3440759-16

Mr. Brian Begley
Federal Facility Agreement Manager
Division of Waste Management
Kentucky Department for Environmental Protection
200 Fair Oaks Lane, 2nd Floor
Frankfort, Kentucky 40601

Ms. Julie Corkran
Federal Facility Agreement Manager
U.S. Environmental Protection Agency, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

Dear Mr. Begley and Ms. Corkran:

TRANSMITTAL OF THE TREATABILITY STUDY REPORT FOR THE C-400 INTERIM REMEDIAL ACTION PHASE IIB STEAM INJECTION TREATABILITY STUDY AT PADUCAH GASEOUS DIFFUSION PLANT, PADUCAH, KENTUCKY, DOE/LX/07-2202&D2

References:

1. Letter from J. Corkran to T. Duncan, "U.S. EPA Region 4 Comments on: Treatability Study Report for the C-400 Interim Remedial Action Phase IIb Steam Injection Treatability Study at the U.S. Department of Energy Paducah Gaseous Diffusion Plant (DOE/LX/07-2202&D1), Issued December 21, 2015, EPA ID KY8890008982, McCracken County, KY," dated March 6, 2016
2. Letter from A. Webb to T. Duncan, "Submittal of Comments to the Treatability Study Report for the C-400 Interim Remedial Action Phase IIB Steam Injection Treatability Study (DOE/LX/07-2202&D1), Paducah Site, Paducah, McCracken County, Kentucky, KY8-890-008-982," dated March 3, 2016
3. Letter from T. Duncan to B. Begley and J. Corkran, "Transmittal of the Treatability Study Report for the C-400 Interim Remedial Action Phase IIB Steam Injection Treatability Study, DOE/LX/07-2202&D1," (PPPO-02-3162756-16C), dated December 21, 2015

Please find enclosed the *Treatability Study Report for the C-400 Interim Remedial Action Phase IIb Steam Injection Treatability Study at Paducah Gaseous Diffusion Plant, Paducah, Kentucky,* DOE/LX/07-2202&D2, for your approval.

The enclosed document incorporates responses to comments on the *Treatability Study Report for the C-400 Interim Remedial Action Phase IIb Steam Injection Treatability Study at Paducah Gaseous Diffusion Plant, Paducah, Kentucky,* DOE/LX/07-2202&D1, received from the U.S. Environmental Protection Agency and Kentucky Division of Waste Management on March 6, 2016, and March 3, 2016, respectively. In addition, agreements reached during the April 5, 2015, and April 15, 2015, comment resolution meetings have been incorporated into the document.

To assist with your review, a redline version of the C-400 Treatability Study Report and comment response summaries with responses to each agency's comments are enclosed. The U.S. Department of Energy requests approval of this document on or before June 9, 2016.

If you have any questions or require additional information, please contact David Dollins at (270) 441-6819.

Sincerely,

Tracey Duncan
Federal Facility Agreement Manager
Portsmouth/Paducah Project Office

Enclosures:

1. Treatability Study Report for the C-400 Interim Remedial Action Phase IIb, DOE/LX/07-2202&D2 (Clean)
2. Treatability Study Report for the C-400 Interim Remedial Action Phase IIb, DOE/LX/07-2202&D2 (Redline)
3. Treatability Study Report Comment Response Summary—EPA
4. Treatability Study Report Comment Response Summary—KDWM

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DOE/LX/07-2202&D2
Secondary Document

Treatability Study Report for the C-400 Interim Remedial Action Phase IIb Steam Injection Treatability Study at Paducah Gaseous Diffusion Plant, Paducah, Kentucky

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DOE/LX/07-2202&D2
Secondary Document

Treatability Study Report for the C-400 Interim Remedial Action Phase IIb Steam Injection Treatability Study at Paducah Gaseous Diffusion Plant, Paducah, Kentucky

Date Issued—May 2016

U.S. DEPARTMENT OF ENERGY
Office of Environmental Management

Prepared by
FLUOR FEDERAL SERVICES, INC.,
Paducah Deactivation Project
managing the
Deactivation Project at the
Paducah Gaseous Diffusion Plant
under Task Order DE-DT0007774

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CONTENTS

FIGURES

TABLES

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ACRONYMS

2D	two-dimensional
3D	three-dimensional
API	American Petroleum Institute
atm	atmosphere
bgs	below ground surface
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CT	cooling tower
CVOC	chlorinated volatile organic compound
DELV	deliverability conditions
DNAPL	dense nonaqueous-phase liquid
DOE	U.S. Department of Energy
DPE	dual-phase extraction
DQO	data quality objective
EPA	U.S. Environmental Protection Agency
ERH	electrical resistance heating
ESRB	extreme steam rapid buoyancy
FFA	Federal Facility Agreement
FCR	field change request
FTE	full-time equivalent
GAC	granular activated carbon
HEX	heat exchanger
IDW	investigation derived waste
IRA	interim remedial action
LATA Kentucky	LATA Environmental Services of Kentucky, LLC
LSRS	LATA-Sharp Remediation Services, LLC
NRMSE	normalized root mean square error
PGDP	Paducah Gaseous Diffusion Plant
RAO	Remedial Action Objective
RGA	Regional Gravel Aquifer
ROI	radius of influence
rz	radially symmetric cylindrical geometry that depends on two coordinate directions, radius (r) and elevation (z)
SEE	Steam-Enhanced Extraction
SPH	six-phase heating
SVE	soil vapor extraction
TDAM	temperature data acquisition module
TMP	temperature monitoring point
TS	treatability study
UCRS	Upper Continental Recharge System
USEC	United States Enrichment Corporation
vac	volts alternating current
VOC	volatile organic compound

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1. INTRODUCTION

The objective of this report is to present the results/interpretation of data collected during the C-400 Interim Remedial Action (IRA) Phase IIb Steam Injection Treatability Study (TS). The TS was designed to obtain data specific to understanding the behavior of steam injected into the Regional Gravel Aquifer (RGA) under variable injection scenarios. Table 2 in the *Treatability Study Work Plan for Steam Injection* presented the data quality objectives (DQOs) resulting from the collaborative effort among DOE Portsmouth/Paducah Project Office, the U.S. Environmental Protection Agency (EPA), and Kentucky Department for Environmental Protection (DOE 2014a). Two principal study questions were developed for the study. First is, "under what conditions can steam be injected into the RGA to develop a technically effective steam front as a basis for preliminary technology design and cost estimation?" Second is, "how does steam injection using two injection intervals (middle and lower RGA) differ from injection using a single, deep injection interval?" The TS results provide information to the regulatory decision process for determining the technical implementability and cost-effectiveness of steam injection as a potential technology for the heating of the RGA in the Phase IIb treatment area of the C-400 Cleaning Building. The TS at the C-400 Building was conducted under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and was consistent with the guidance set forth in EPA's *Guidance for Conducting Treatability Studies under CERCLA* (EPA 1992). The TS was conducted to address uncertainty regarding hydrogeological conditions in the middle and lower RGA; to assess the use of steam injection as a heating technology; and to facilitate an evaluation of the requirements for a full-scale implementation of steam injection throughout the RGA in the Phase IIb treatment area (DOE 2012).

1.1 SITE DESCRIPTION

Paducah Gaseous Diffusion Plant (PGDP) is located in western Kentucky on a large U.S. Department of Energy (DOE)-owned property west of Paducah, Kentucky, and is comprised of numerous large industrial buildings, modular office compounds, equipment storage areas, on-site landfill facilities, railroad lines, and a network of paved roads.

1.1.1 Site Name and Location

PGDP is located approximately 10 miles west of Paducah, Kentucky, and 3.5 miles south of the Ohio River in the western part of McCracken County. The plant is located on a DOE-owned site; approximately 650 acres are within a fenced security area, approximately 800 acres are located outside the security fence, and the remaining 1,986 acres are licensed to the Commonwealth of Kentucky (the West Kentucky Wildlife Management Area).

1.1.1.1 Site Geology/Lithology

In the immediate vicinity of PGDP, Coastal Plain deposits unconformably overlie Mississippian carbonate bedrock. The full Coastal Plain stratigraphic sequence to the immediate south of PGDP consists of the following three units (from bottom to top): sands and clays of the Clayton/McNairy Formations; the Porters Creek Clay; and Eocene sand and clay deposits (undivided Jackson, Claiborne, and Wilcox Formations). Continental Deposits unconformably overlie the Coastal Plain deposits, which are, in turn, covered by loess and/or alluvium. Both the loess and alluvium typically are composed of clayey silt.

In the central and northern part of the PGDP site, including the area of the C-400 Cleaning Building, the Coastal Plain sediments are composed exclusively of unconsolidated, interbedded, fine-grained sand, silt, and clay of the Upper Cretaceous-aged McNairy Formation. The thickness of the McNairy Formation at C-400 is approximately 250 ft.

A principal geologic feature in the PGDP area is the buried fore slope of the Porters Creek Clay Terrace, a subsurface boundary that trends approximately east to west across the southern portion of the plant. The fore slope of the Porters Creek Clay Terrace represents the southern limit of erosion or scouring of the ancestral Tennessee River. In the area north of the subsurface terrace fore slope, including the C-400 area, Continental Deposits directly overlie the McNairy Formation. Thicker sequences of Continental Deposits, as found underlying most of PGDP, represent valley fill deposits and can be divided informally into a lower unit (gravel facies) and an upper unit (silt facies). The Lower Continental Deposits is a Pliocene to Pleistocene-aged gravel facies consisting of fine-to-coarse chert gravel in a matrix of very fine-to-medium sand and silt. These gravels rest on an erosional surface representing the beginning of the valley fill sequence beneath PGDP. In total, the gravel units commonly average approximately 30-ft thick.

1.1.1.2 Site Hydrogeology

The main hydrogeologic units in the C-400 area consist of the Upper Continental Recharge System (UCRS), the RGA, and the McNairy Formation. In the study area, the RGA and the first major sand of the upper McNairy Formation are separated by an approximately 9-ft thick lens of McNairy silts, sands, and clays, which act as an aquitard. Approximately 56 ft of silt and clay (UCRS), with horizons of sand and gravel lenses, overlies the RGA.

In the area of C-400, the UCRS is mostly unsaturated. The RGA, the uppermost aquifer in the C-400 area, consists of the lowermost sand interval of the Upper Continental Deposits and the underlying sand and gravels to the top of the McNairy Formation. The RGA potentiometric surface is encountered at a depth of approximately 56 ft below ground surface (bgs). Groundwater flow in the RGA generally is to the north, eventually discharging into the Ohio River, although some flow diverges to the east and to the west. The sand and gravel of the RGA is highly permeable and pore velocity is thought to be on the order of 0.1 to 0.3 ft per day. The vertical anisotropy of the RGA was thought to be low.

Below the RGA is the McNairy Formation. The uppermost portion of the McNairy Formation typically contains a significant proportion of clay or silty clay. The hydraulic potential (water level) of the uppermost McNairy Formation is slightly less than that of the RGA and dips northward, similar to the RGA. The clayey uppermost McNairy functions as an aquitard restricting groundwater flow between the RGA and lower McNairy Flow System.

1.1.2 History of Operations

DOE and its predecessor, the Atomic Energy Commission, performed uranium enrichment at PGDP from 1952 through 1992, at which point uranium enrichment operational responsibility was transferred to the United States Enrichment Corporation (USEC). USEC leased real property, facilities, and infrastructure from DOE to continue enrichment operations. Enrichment operations were conducted by USEC from 1993 until May 2013. Following the end of USEC operations (October 2014), the site environmental activities continued and are currently under a new Deactivation Contractor (Fluor Federal Services, Inc., Paducah Deactivation Project).

Activities related to enrichment operations resulted in the release of trichloroethene (TCE), a chlorinated volatile organic compound (CVOC), and technetium-99 (Tc-99) to the environment at PGDP. Figure 1, Site Location Map, shows the C-400 Building and some of the sources of TCE contamination in the C-400 area (TCE storage tank, transfer pipeline, and transfer pump).

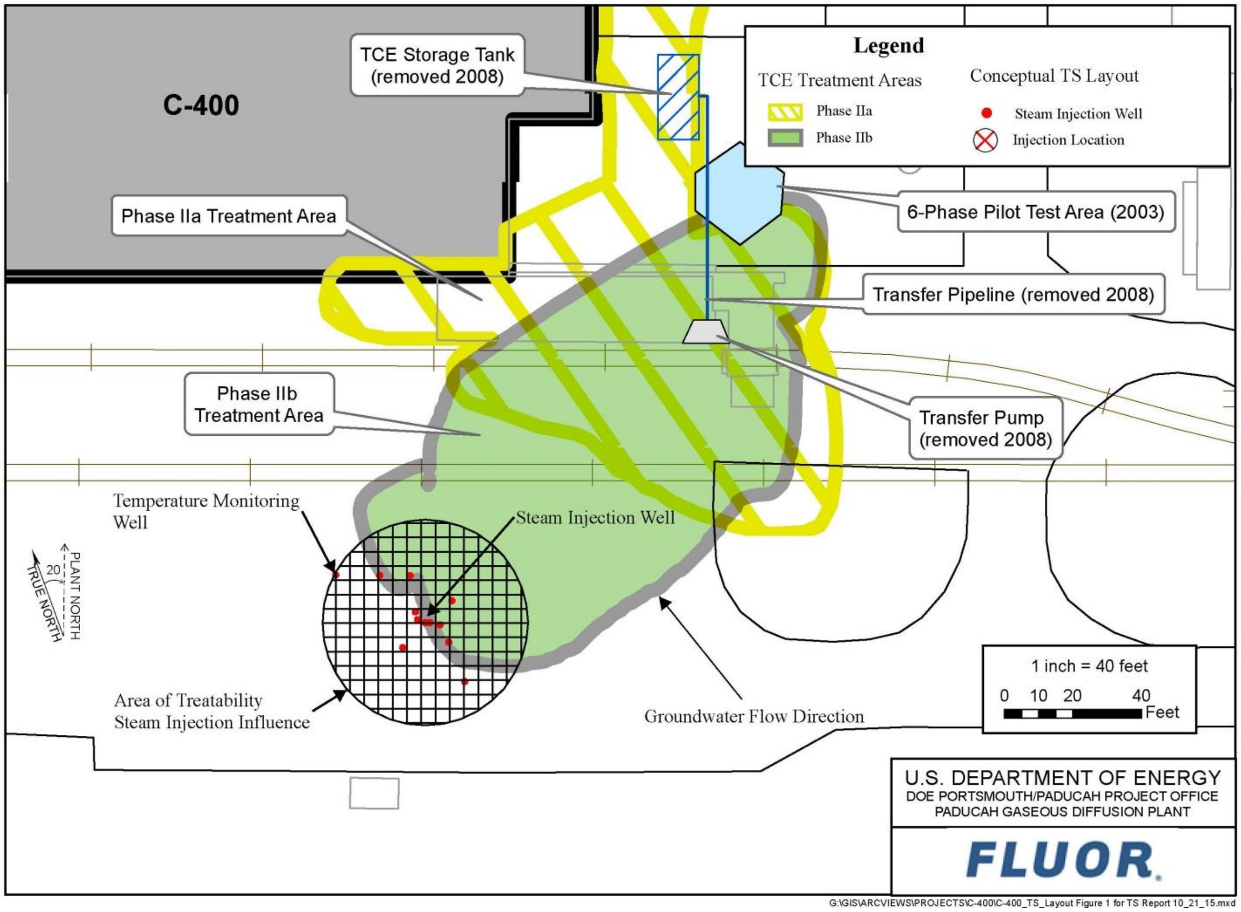

Figure 1. Site Location Map

1.1.3 Prior Removal and Remediation Activities

TCE use was discontinued at C-400 Cleaning Building in 1993. Implementation of an IRA for the C-400 Cleaning Building, as part of the *Record of Decision for Interim Remedial Action for the Groundwater Operable Unit for the Volatile Organic Compound Contamination at the C-400 Cleaning Building at the Paducah Gaseous Diffusion Plant, Paducah, Kentucky* (DOE 2005), was initiated in December 2008. DOE completed 3-phase electrical resistance heating (ERH) Phase I of the IRA for the C-400 Cleaning Building in 2010 by implementing ERH to address volatile organic compound (VOC) source mass in the UCRS and the upper RGA in the east and southwest treatment areas.

ERH was implemented in two phases, Phase I and Phase II. The Phase I ERH system consisted of a network of in ground electrodes and vapor extraction wells distributed throughout the east and southwest zones of contamination in a three-phase heating pattern. The east and southwest areas were selected for Phase I because they were the smallest of the source areas near C-400 and had contaminants primarily in the UCRS. Phase II was to follow Phase I to treat the southeast area, which was expected to contain a larger amount of source contamination in both the UCRS and the RGA.

Phase I ERH consisted of heating soil in the saturated and unsaturated zones by passing current among electrodes buried in the soil, with simultaneous injecting water through the electrodes to maintain conductivity and to transfer heat by convection. The coupling of ERH with heat transfer via convection enhances the efficiency and uniformity of heating by ERH technology. Volatilization of contaminants was achieved by heating subsurface soils to or above the TCE boiling point. A phase change for a

TCE/water mixture is achieved at the azeotropic boiling point of the solvent/water mixture (a lower temperature than that of either TCE or water). Within the vadose zone (at or above the water table), temperatures must be above the boiling point of TCE [i.e., > 87.2°C (189°F)]. For zones below the water table, the co-boiling temperature of TCE DNAPL and water is applicable. The co-boil temperature of TCE DNAPL and water is approximately 73°C (163.4°F) at the groundwater potentiometric surface and is approximately 98°C (208.4°F) at 45 ft below the top of the water table (Kingston et al. 2014).

Simultaneous vapor extraction removed the contaminants from the subsurface. The vapor produced from Phase I ERH operations was a mixture of air, water vapor, and varying levels of VOCs (primarily TCE). The organic vapors extracted during the Phase I ERH operations were condensed, and liquid VOCs were collected. The water vapor was discharged to the atmosphere. Phase I operations were completed in December 2010. Approximately 535 gal of VOCs (primarily TCE) was removed from the subsurface during Phase I. ERH reduced soil TCE concentrations by 95% in the east treatment area and by 99% in the southwest treatment area.

An important objective of Phase I was to evaluate the heating performance of the base ERH design through the RGA down to the McNairy Formation interface in the southwest treatment area. During Phase I, temperature goals were not attained in the lower RGA in the southwest treatment area, particularly in the lower RGA, below 70 ft bgs (refer to *Phase I Technical Performance Report* DOE/LX/07-1260&D1).

DOE evaluated attainment of remedial action objectives (RAOs) in the Technical Performance Evaluation for the C-400 IRA (DOE 2011) for ERH Phase I operations in the east and southwest treatment areas. The RAOs, as established in the C-400 Record of Decision (DOE 2005), were as follows:

- Prevent exposure to contaminated groundwater by on-site industrial workers through institutional controls (e.g., excavation/penetration permit program);

- Reduce VOC contamination (primarily TCE and its breakdown products) in UCRS soil at the C-400 Cleaning Building area to minimize the migration of these contaminants to RGA groundwater and to off-site points of exposure; and

- Reduce the extent and mass of the VOC source (primarily TCE and its breakdown products) in the RGA in the C-400 Cleaning Building area to reduce the migration of the VOC contaminants to off-site points of exposure.

DOE's evaluation determined that the RAOs were met for the UCRS and upper RGA in the east and southwest treatment areas.

Because of the inability of ERH to reach target temperatures in the lower RGA, the Federal Facility Agreement (FFA) parties agreed to divide Phase II into Phase IIa (using ERH to address the UCRS and upper RGA to a depth of 60 ft bgs) and Phase IIb (using a technology to be decided to address the lower RGA). Phase IIa operations were completed in fall of 2014 and consisted of the implementation of ERH in the UCRS and upper RGA in the southeast treatment area. Phase IIa operations removed approximately 1,137 gal of VOCs (primarily TCE). The median of soil TCE concentration reductions in collocated preoperational versus post operational samples of Phase IIa was 99.8%.

In October of 2014, after conclusion of Phase IIa remedial actions in the southeast treatment area, the FFA parties agreed that Phase IIa remedial goals were met to allow for vapor extraction to cease after 30 days from turning off the electrodes (DOE 2014b; EPA 2014; KDWM 2014).

C-400 IRA ERH Phase I and Phase IIa well plugging activities were performed concurrently with the TS construction activities. In order to install TS components, previously installed ERH wells were plugged and abandoned following criteria defined in the *Remedial Action Work Plan of Phase IIa of the Interim Remedial Action for the Volatile Organic Compound Contamination at the C-400 Cleaning Building at the Paducah Gaseous Diffusion Plant, Paducah, Kentucky* (DOE 2013). Due to complications plugging injection lines associated with electrode wells, DOE requested and was granted a variance by the EPA Region 4 Administrator to plug 12 electrode wells located within the footprint of the TS area (for further information, refer to the EPA letter dated March 19, 2015, in Appendix A). The ERH Phase I and Phase IIa well plugging activities included an additional 82 electrodes located outside of the footprint of the TS area and with similar complications plugging the injection lines. DOE demonstrated that the potential for residual shallow subsurface volatile contamination to migrate into the electrode borings was minimal and requested a similar variance for the remaining 82 electrodes. EPA agreed to an interim path forward to abandon the remaining electrodes per DOE's original variance request. Abandonment activities were completed on June 17, 2015.

1.2 WASTE STREAM DESCRIPTION

During drilling activities to install steam injection wells and temperature monitoring points (TMPs), investigation derived waste (IDW), soil cuttings, drilling fluids, personal protective equipment, and material packaging were generated and managed in accordance with the approved work plan (DOE 2013).

Soil cuttings generated during drilling were screened continuously by industrial hygiene specialists for the presence of VOCs, utilizing a Sirius MSA photoionization detector unit. In addition to VOCs, health physicist technicians continuously screened the soil cuttings for radiological contamination (alpha, beta, and gamma). All IDW generated during implementation of this TS met the waste acceptance criteria and was placed into a covered intermodal container for transport and disposal to on-site landfill facility. Solids generated during drilling activities and solids generated during water/solid separation operations were characterized by LATA Environmental Services of Kentucky, LLC, (LATA Kentucky) and were dispositioned at C-746-U Landfill.

Potentially impacted waters generated and collected during the implementation of this TS included water produced during drilling activities, groundwater displaced within the borehole, and water generated while decontaminating the drill rig and tooling. These waters were collected either within a settling basin sealed in place around the borehole, or at a designated concrete decontamination pad (C-752-C) equipped with containment berms and sumps. The waters generated during drilling operations were collected daily and transferred to mobile poly-tanks then transported to the C-752-C facility for water/solid separation, were characterized by LATA Kentucky, and then were transported to the C-612 water treatment facility for treatment and discharge.

1.3 TREATMENT TECHNOLOGY DESCRIPTION

1.3.1 Treatment Process and Scale

Steam-enhanced extraction (SEE) technology is the engineered combination of steam injection and multiphase extraction for subsurface remediation. This technology significantly enhances the removal rate of volatile and semivolatile source contaminants from the subsurface, both above and below the water table when compared to natural attenuation. One of the key factors that leads to the successful implementation of the SEE approach is the ability to use steam to heat the target source area uniformly. The source area heating process works as steam injected into the subsurface uniformly sweeps the target volume. As steam moves through the subsurface, it condenses and releases energy, heating the surrounding soil and groundwater. This heating volatilizes and mobilizes the contaminant present in all phases—separate phase DNAPL, sorbed, and dissolved. Once mobilized, the contaminant can be collected through the use of dual-phase extraction (DPE) wells and consolidated at the ground surface for treatment or disposal.

1.3.2 Operating Features

Steam injection can be implemented using established engineering methods. Subsurface temperatures required for treatment of VOC compounds, such as TCE and its breakdown products, are attainable over broad treatment areas with standard equipment. Steam generated in boilers can be delivered through insulated, pressure-controlled steam piping or hoses and delivered to individual wellheads. The steam injection system installed during this TS incorporated the use of two nested steam injection wells to inject steam at the lower (88 to 93 ft bgs) and upper (68 to 73 ft bgs) depth intervals. Steam flow rates are controlled by a system of valves and gauges located at the steam boiler, as well as valves, gauges, and by-pass loops located upstream of the injection wellheads. The presence of valves between the main steam piping split and the individual wellheads allows for the operation of both wells individually or simultaneously. The steam injection system installed was capable of producing a maximum steam injection rate up to 6,000 pounds per hour (pph).

1.4 PREVIOUS TREATABILITY STUDIES AT THE SITE

Four treatability studies have been conducted to investigate methods for reducing or remediating the VOC contamination in the C-400 area. The first was conducted in 1994 at the southeast corner of the C-400 area using an existing RGA monitoring well. Results are reported in *The In-Situ Decontamination of Sand and Gravel Aquifers by Chemically Enhanced Solubilization of Multiple-Component DNAPLs with Surfactant Solutions* (INTERA, Inc. 1995). In the first study, researchers screened 99 surfactants in a laboratory and identified four surfactants that were good solubilizers of three common DNAPL components—TCE, tetrachloroethene, and carbon tetrachloride—and selected one surfactant, a sorbitan monooleate, for testing at PGDP. The field test consisted of a push-pull (injection-extraction) test in MW156 to assess the efficacy of the surfactant to solubilize DNAPL. Extraction during the test was able to recover only one third of the injected surfactant. (It is believed that the surfactant became sorbed to the aquifer matrix, precipitated, or formed a liquid crystal.) There was no enhancement of the concentration of TCE recovered from the well. The field test demonstrated that sorbitan monooleate is unsuitable for use as a solubilizer in the RGA.

The next two studies were bench scale tests of RGA remediation conducted as part of the 1995 remedial investigation of Waste Area Grouping 6 (the C-400 area). The second study looked at other surfactants and co-solvents. Results were documented in *Surfactant Enhanced Subsurface Remediation Treatability Study Report for Waste Area Grouping 6 at the Paducah Gaseous Diffusion Plant, Paducah, Kentucky*, DOE/OR/07-1787&D1 (DOE 1999a). Through laboratory screening, the study identified two surfactant systems (a 5% Dowfax 8390 mixture and an 8% AMA-80 mixture) that would be effective in the RGA. The Dowfax 8390 system had greater surfactant recovery efficiency; the AMA-80 system was a more effective solubilizer. The study determined that surfactant-enhanced remediation had the potential to remove a high percentage of TCE mass from the RGA.

The third study evaluated chemical oxidation and reported the results in *Bench Scale In-Situ Chemical Oxidation Studies of Trichloroethene in Waste Area Grouping 6 at the Paducah Gaseous Diffusion Plant, Paducah, Kentucky*, DOE/OR/07-1788&D1 (DOE 1999b). Thermal acceleration tests, batch tests, and column tests using RGA soil demonstrated that chemical oxidation of TCE-impacted Waste Area Grouping 6 soils and groundwater was achievable and should be investigated further for full-scale field implementation.

The fourth treatability study (conducted in 2003) was a test of full-scale deployment of ERH technology in the area adjacent to the southeast corner of the C-400 Building. This study included the installation and operation of one six-phase heating (SPH) treatment array and a vapor recovery system. The SPH treatability study began on February 14, 2003, and was discontinued on September 6, 2003. A key operational criterion of the test was to raise the temperature of soil and groundwater within the treatment volume sufficient to drive groundwater and targeted contaminants into their vapor phases. During the test, a design/construction flaw prevented the two deepest electrodes from reaching target temperatures. The primary objective, as outlined in the *Treatability Study Work Plan for Six-Phase Heating, Groundwater Operable Unit, at the Paducah Gaseous Diffusion Plant, Paducah, Kentucky*, DOE/OR/07-1889&D2/R1 (DOE 2001), was to demonstrate the implementability of the ERH technology in the unsaturated and saturated soils of the UCRS and in the groundwater of the underlying RGA. Comparison of pretreatment and post treatment sample results was used to measure treatment efficacy. The SPH treatability study achieved a 98% reduction of TCE concentrations in UCRS soils and a 99.1% reduction in TCE concentration in RGA groundwater, which met the removal efficiency criteria outlined in *Six-Phase Heating Technology Assessment* (GEO Consultants 2003).

The success of the SPH project, lead to a 2005 Record of Decision to implement ERH to remove additional volatile organics from the UCRS and RGA. In 2013, a series of multiphase flow numerical simulations were performed to evaluate likely behavior of steam injection in the RGA at the C-400 Area of PGDP site in Kentucky (Falta 2013). The numerical simulations bound the range of hydrogeologic and operational conditions that reasonably could be expected during steam injection in the RGA at PGDP. A total of 41 two-dimensional (2D) and three-dimensional (3D) simulations were performed using steam injection rates of 1,000 to 5,000 pph per well, with either one or two injection screen intervals per well location. The simulations were performed using the DOE TOUGH2-TMVOC model, developed at the Lawrence Berkeley National Laboratory specifically for simulating fluid flow and heat transfer in porous and fractured media. The numerical simulations indicated that injecting steam with rates of 1,000 pph per well may be effective in evenly heating the base of the RGA provided that the horizontal hydraulic conductivity is moderate (less than a few hundred feet/day) and the anisotropy ratio is high (10:1 or more).

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2. CONCLUSIONS AND RECOMMENDATIONS

2.1 CONCLUSIONS

2.1.1 Lithology and Hydrogeology

- During the installation of TS subsurface infrastructure, the thickness of the RGA was observed to be slightly thinner than the expected 39.6 ft, based on previous borehole logs. In the vicinity of the C-400 Steam TS area the top of the RGA begins at 59.1 ft bgs on average. The average depth to the base of the RGA occurred at 93.1 ft bgs, for an average RGA thickness of 34 ft (see Appendix B, Boring Logs).

- Within the RGA, chert gravel up to 3.5 inches in diameter comprised 20–60% of the grain size distribution. The remaining material in the RGA was coarse chert sand and fine to very fine quartz sand. A few gravelly lenses (20–40% gravel) occurred within the UCRS between 23 and 40 ft bgs and ranged in thickness from 6 inches to 3 ft. The base of the RGA was marked by a sharp transition to fine sands, silts, and clays of the McNairy Formation.

- The RGA potentiometric surface in the vicinity of the steam injection wells was encountered at approximately 55 ft bgs. Groundwater flow in the RGA is generally northwest with some flow diverging to the east and west.

- Groundwater pore velocity in the study area likely is on the order of 0.1 ft to 0.3 ft per day, dependent upon the spatial distribution of hydraulic conductivity and temporal variation of hydraulic gradient.

- Sonic drilling was demonstrated to be an effective method for achieving target depths within the UCRS, RGA, and McNairy Formation while generating reasonably low volumes of soil cuttings and drilling fluids and other wastes.

- The numerical model calibration to the field data indicated that the system has a moderate to high permeability and high anisotropy (as discussed in Section 4.1.2.4 and in Appendix E). The basic structure of the RGA consists of an upper zone with a horizontal hydraulic conductivity of about 100 ft/day and a lower zone with a horizontal hydraulic conductivity of about 300 ft/day. Both zones have horizontal to vertical conductivity ratios of 20:1 to 30:1. The calibration effort also showed that there are isolated zones and lenses of lower conductivity material within the RGA, and that the RGA is laterally heterogeneous.

2.1.2 Extreme Steam Rapid Buoyancy

For purposes of this treatability study, extreme steam rapid buoyancy (ESRB) is defined by rapid vertical movement of steam to the upper portions of the RGA and by the lack of observed steam temperatures at the lowest 3 temperature sensors in the RGA (TMP-04-00, TMP-04-03, and TMP-04-06) located at a distance of 5 ft (TMP-04) from the injection well (refer to Figure 2).

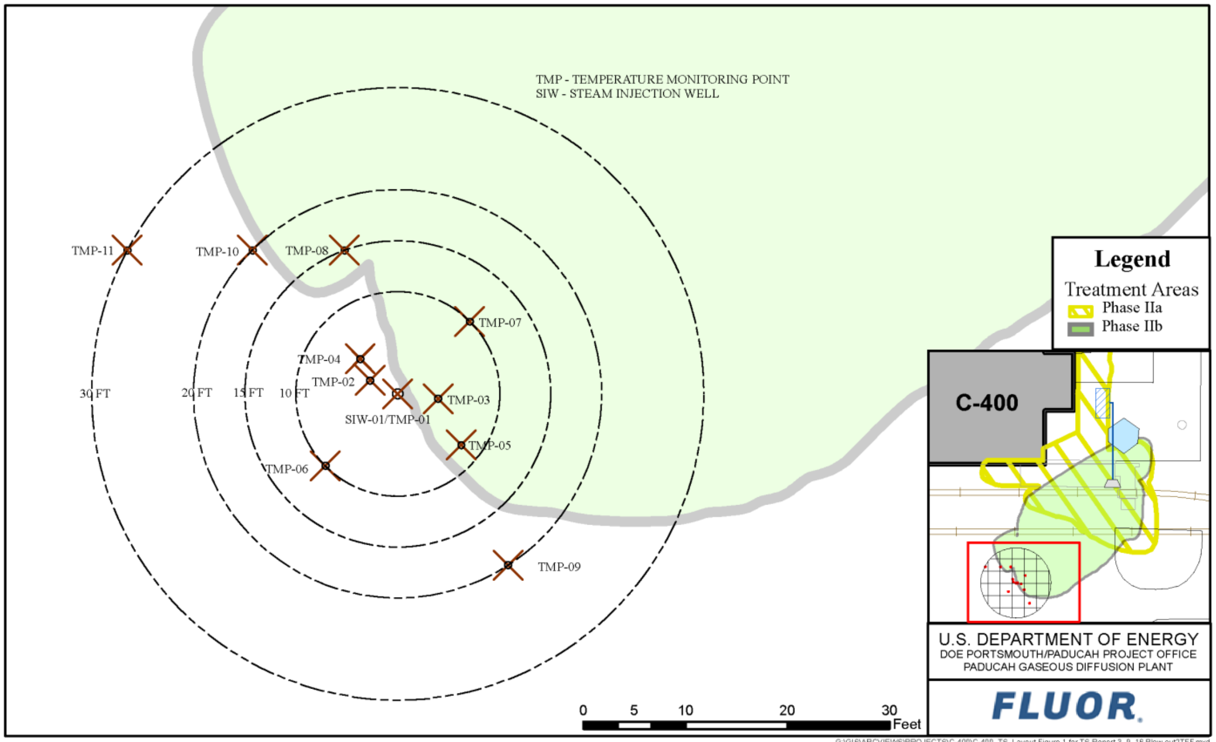

Figure 2 Steam Treatability As Built Layout

Figure 2. Steam Treatability As Built Layout

- Evidence that supports the conclusion that ESRB was not observed during TS Phase 1, Initial Steam Injection includes the following:

  — After April 12, 2015, (Day 4) of Phase 1 steam injection, steam temperatures were observed in two of the three lowest temperature sensors in the RGA in the near field (0 to 5 ft from SIW-01) at TMP-04.

  — Steam exited both the upper and lower screens and was observed at TMP-04 in the near field to have travelled horizontally in two well defined steam fronts, separated by an intervening "cooler" zone.

  — Horizontal migration of these two well defined steam fronts was observed beyond the critical near[1] field 5-ft radius of influence (ROI) at TMP-04. 3D vertical profiles of temperature for the TMPs, as discussed in Section 4.1.1.5 (see Figure 9, TMP-08, and Figure 12, steam front on Day 20 of Phase III), are the principal evidence of horizontal migration of two steam fronts.

  — Data from the mid[2] field at TMP-08 at a ROI of 15 ft indicated that horizontal steam front migration continued beyond this distance in the Lower RGA.

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[1] Near field equates to 0 to 5 ft from the steam injection well(s).
[2] Mid field equates to 5 to 15 ft from steam injection well(s).

- Data from the far[3] field locations at TMP-09 and TMP-10 at a ROI of 20 ft indicated that horizontal steam front migration continued beyond this distance in the Upper RGA.

- A steam zone in the near and mid fields at the top of the RGA at TMP-04, which would be indicative of ESRB was not observed.

- The high temperature grout seals performed as designed and prevented upward migration of steam in the borehole annular space.

2.1.3 Steam Front Migration

- TS Phase 1—Initial Steam Injection

  - Steam injection was initiated into the upper and lower screened intervals at an injection rate of 500 pph and an approximate pressure of 18 psi (pounds per square inch).

  - Horizontal migration of the steam front proceeded from both the upper and lower screens at slightly different rates of outward migration.

  - The rate of horizontal migration of the steam front over time is highly variable due to the exponential, volumetric nature of radial flow from a single point source.

  - The steam front migration during Phase 1 initially was horizontal. As the Phase 1 injection progressed, some vertical movement (override) of the steam was apparent as the steam front migrated beyond TMP-07, 10 ft from the injection well. These features were captured accurately in the 3D numerical model calibration.

  - Outward migration of the steam front proceeded slightly faster in the Upper RGA than in the lower RGA.

  - The steam front migrated beyond 20 ft in the Upper RGA.

  - Steam front extent reached beyond 15 ft, but did not reach 20 ft, in the Lower RGA.

  - Temperatures of the near field McNairy Formation/RGA interface were raised from the baseline of approximately 65°F to a maximum of approximately 155°F at TMP-04.

- TS Phase 2—Initial Cool Down

  - The steam front collapsed throughout both the Upper and Lower RGA within three days of the termination of steam injection (see Figure 10).

  - The cooling rate in the Lower RGA varied between 8°F to 16°F per day.

  - The cooling rates were greater in the Lower RGA then in the Upper RGA.

  - Lower RGA cooling predominantly was due to the influx of cold groundwater as the result of the collapse of the steam zone.

[3] Far field equates to 15 to 30 ft from steam injection well(s).

— Cooling in the Upper RGA was slower due to a combination of upward buoyancy flow from the underlying Lower RGA, and to the lower conductivity of the Upper RGA.

- TS Phase 3—Steam Injection

— Steam injection was limited to the lower screened interval at an injection rate of 1,000 pph and an approximate pressure of 18 psi.

— The steam front was reestablished in three days after the restart of steam injection.

— The temperature of the near field McNairy/RGA interface increased from approximately 97°F to approximately 222°F or an additional 35°F over the change observed in TS Phase 1 at TMP-04.

— Upward buoyancy appears to have resulted in heating of the zone between the two screens.

— A smaller amount of heating in the Upper RGA where no steam was injected also can be attributed to upward buoyancy.

— The steam front migration during Phase 3 was dominated by horizontal steam flow for a longer period compared to Phase 1. The behavior shows the benefit of high steam injection rates at the bottom of the RGA.

- TS Phase 4—Final Cool Down

— The steam front collapsed in three days as in TS Phase 2.
— Cooling proceeded at similar rates (between 8 to 16°F per day) as TS Phase 2.
— At the end of TS Phase 4, temperatures in many TMPs were below 100°F.

2.1.4 Thermal Modeling

- Model Calibration to TS Data

— A 2D radially symmetric model was developed during the first few days of the Phase 1 injection. This model was capable of capturing the dominant behavior of the steam front advancement and collapse during the entire test.

— The 2D model was unable to match the temperature response at some TMP locations due to the presence of local zones and layers of lower permeability.

— A 3D heterogeneous model was calibrated to all of the 186 TMP data locations at the end of Phase 1. The normalized root mean square error (NRMSE) of the model predictions was about 11.6%.

— A 3D model, including the maximum observed hydraulic gradient, showed that regional groundwater flow plays only a small role in the movement of the steam front. The force of gravity, effects of heterogeneity, and pressure gradients due to injection are much larger factors in the steam front migration.

- Simulations of Full-Scale Design

  — Small 3D simulations of a repeated injector-extractor pattern (quarter five-spot) showed the benefit of injecting steam at a high rate (1,000 pph) into the lower screen.

  — The quarter five-spot simulations indicate that the conceptual design is capable of achieving steam conditions throughout almost all of the RGA (boiling point temperature of water range, from potentiometric surface to base of RGA, is 100°C to approximately 123°C, respectively). Zones that do not reach steam temperatures will be well above the TCE DNAPL/water co-boiling temperature (TCE DNAPL and water co-boiling temperature range, from potentiometric surface to base of RGA, is approximately 73°C to 94°C, respectively). The TCE DNAPL/water co-boiling temperature is lower than the boiling temperature of either liquid due to the additivity of the liquid vapor pressures. When the sum of the DNAPL and water vapor pressures exceed the total (hydrostatic) pressure, the mixture boils.

  — A large 3D simulation of the entire system of injection and extraction wells was performed, and it showed very good steam coverage of the RGA. The entire treatment zone was heated above the TCE DNAPL/water co-boiling temperature in this simulation.

2.1.5 Lessons Learned

A number of lessons learned during the TS should be considered in the full-scale design and the cost estimate, if this technology is chosen as the final remedy for C-400 Phase IIb.

1. The TS demonstrated that the encountered site conditions are within the expected range and that steam is technically implementable to heat the target zone to facilitate VOC remediation.

2. The 3D simulations determined that lowering the upper screen by 6.5 ft resulted in a more even heat distribution in the RGA and could be implemented during full-scale deployment.

3. Local heterogeneities result in radially asymmetric steam flow. A 3D model is required to simulate steam injection for the Phase IIb remedial action.

4. The temperature sensor failure rate of less than 2% does not justify the use of redundant temperature sensors in the critical zone above the McNairy/RGA interface.

5. Closely spaced temperature sensors (1 ft vertical separation) could be used to more closely monitor the 5 ft vertical zone of the lower 3 ft of the RGA and the top 2 ft of the McNairy.

6. The injection pressure of 18 psi is very close to the hydrostatic pressure at the lower screen indicating that the screen slot size didn't restrict steam flow and increase the injection back pressure.

7. With respect to phased injection, project optimization should incorporate adjustments to steam injection rates to prevent the 3-day collapse of the steam zone and adjustments to vapor extraction rates to promote even heating. At the end of the heat-up phase, the steam injection rate should be reduced to a level necessary to maintain temperatures and overcome heat loss to the surrounding soils.

8. The well completion design of the TS prevented vertical short circuiting and will be used for the full-scale design.

2.1.6 Engineering Design Criteria

- The engineering design criteria used as the basis for the full-scale conceptual design are shown in Table 1.

Table 1. Full-Scale Deployment Design Criteria[1]

Design Parameter	Value
Thermal ROI for wells screened in the RGA	20 ft
Steam injection rate per well—Upper Screen	500 pph
Steam injection rate per well—Lower Screen	1,000 pph
Steam injection pressure	5 to 40 psi
Injection interval—Upper Screen	73.5 to 78.5 ft bgs[2]
Injection interval—Lower Screen	88 to 93 ft bgs[2]
Steam temperature—Upper Screen	227 to 238°F[3]
Steam temperature—Lower Screen	240 to 255°F[3]
Co-boiling target temperature (Kingston et al. 2014)	203°F[4]

[1] Design parameters are based upon 3D modeling results.
[2] Exact depth will be determined during installation based on actual depths of the top of the RGA and top of the McNairy Formations.
[3] Steam temperature exceeds the water and TCE co-boiling target temperature.
[4] The co-boiling temperature of 203°F corresponds to approximately 38 ft below the water table.

2.1.7 Full-Scale Conceptual Design

- The full-scale conceptual design is comprised of the following and shown on the drawings in Appendix C2.
  - — The wellfield (Drawing M5E-FA1530-A02) will consist of the following:
    - – 23 (one existing and 22 new) dual nested steam injection wells;
    - – 17 dual nested DPE wells; and
    - – 38 TMPs (11 existing, 12 new, collocated in DPE wells and 15 new in individual boreholes).
- The treatment compound, as shown on the Process Flow Diagram (Drawing M5E-FA1530-A03), will be comprised of existing ERH Phase IIa major equipment, new major equipment, and associated subsystem components (compressed air, pumps, motorized valves, sampling systems, etc.).
  - — Vapor Treatment System
    - – Heat exchanger HEX-200 (new)
    - – Cooling Tower CT-500, 501 (new)
    - – Knockout Tank KO-200 (new)
    - – Blowers and filters B-200–201 (existing)
    - – Vapor Treatment System to be determined in remedial design report (new)
    - – Carbon and zeolite adsorption systems (existing)
  - — Groundwater Treatment System
    - – Storage tank T-310 (existing)
    - – DNAPL separator and storage tank (new)
    - – Air stripper AS-400 (existing)

- Liquid granular activated carbon (GAC) vessels GAC-400, 401 (existing)
- Ion exchange vessels IX-400, 401 (repair/replace existing)

— Steam Generation System

- Steam boilers (two boilers at 20,000 pph each) SB-100 (new)
- Blowdown tank T-100 (new)

- A numerical model of the full-scale conceptual design shows that the system will be capable of achieving steam coverage and target temperatures throughout the treatment zone.

2.1.8 Total Project Cost Estimate for Full-Scale Implementation

An engineer's cost estimate for the conceptual design for full-scale deployment described in Section 4.3.2 was prepared. The engineering cost estimate incorporates the results of the thermal modeling and the conceptual design with subcontractor experience at other sites and includes all elements expected to be required for full-scale deployment of steam injection with multiphase extraction at C-400. The estimated total project cost for full-scale implementation ranges from \$23.4−\$50.0 M[4] (adjusted for escalation through project completion).

2.2 RECOMMENDATIONS

Based on the results of the TS, the steam injection technology proved to be technically implementable in the hydrogeologic conditions tested; as such, the data were used to develop a conceptual design for full-scale implementation should this technology be chosen as the final remedy for C-400 Phase IIb.

[4] The wide range in the cost estimate is due to several uncertainties. These uncertainties include, but are not limited to, (1) the FFA parties have not discussed the scope of a remedial action using steam (e.g., extent of mass removal expected using steam); (2) the wellfield and treatment system designs needed to meet the selected scope have not been determined (e.g., wellfield component spacing, steam injection rates, vapor/liquid extraction rates, vapor/liquid treatment system components); (3) the duration of steam treatment required to meet the selected completion target has not been established (e.g., criteria for ceasing operations, operational strategy); (4) methods to estimate power costs are uncertain; (5) design of critical system components is not complete (e.g., during power losses and/or inclement weather); and (6) waste disposition determinations, both on-site and off-site, are unavailable.

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3. TREATABILITY STUDY APPROACH

3.1 TEST OBJECTIVES AND RATIONALE

The use of heat to remove VOCs (TCE and related degradation products) from the subsurface has been demonstrated successfully at numerous sites worldwide, including the UCRS at C-400 during a previous six-phase heating TS and during the C-400 IRA ERH Phase I and Phase IIa remedial actions. The effectiveness of steam injection with multiphase extraction in an appropriate geologic setting has been demonstrated at numerous sites, including the DOE Savannah River Site (SRS) and DOE Lawrence Livermore labs, where the closure criteria were met and mass reduction in excess of 95% was achieved. Given the site-specific lithological and hydrogeological conditions of the RGA, the goal of this TS is to determine the mobility of steam in the RGA and whether steam injection is an applicable approach for heating the RGA. Data collected during ERH Phase I, as well as data collected from numerical simulations performed prior to the implementation of this TS (Falta 2013), suggested that the buoyancy of injected steam at this site might impact the distribution of steam and the ability to achieve target temperatures in the lower portions of the RGA (i.e., the RGA/McNairy interface).

This study focused on refining the understanding and the behavior of steam in the complex hydrogeologic conditions typical of the RGA (a thick sand and gravel aquifer, with high permeability, low to moderate anisotropy, and moderate to high groundwater velocity) and obtaining relative data to support the Phase IIb decision process. To do so, this study addressed whether/how injected steam could heat the full thickness of the RGA, maintain target temperatures at the RGA/McNairy interface, and move the steam front effective distances from the injection wells. Two principal study questions were developed for the study. First is, "under what conditions can steam be injected into the RGA to develop a technically effective steam front as a basis for preliminary technology design and cost estimation?" Second is, "how does steam injection using two injection intervals (middle and lower RGA) differ from injection using a single, deep injection interval?" Subsurface temperatures in the RGA were measured at various depths and distances from steam injection points throughout the duration of the TS to monitor the change in temperatures and the arrival of the steam front horizontally and vertically in the subsurface. The injection strategy (500 pph in both screens in Phase 1 and 1,000 pph in the lower screen only in Phase 3) was varied to assess the effects on steam front mobility, configuration, and heating effectiveness under varying steam injection conditions.

3.2 EXPERIMENTAL DESIGN AND PROCEDURES

The TS was designed to understand the behavior of steam when injected into the complex hydrogeology within the RGA below the C-400 Building. Temperature monitoring locations were constructed 2 ft into the overlying UCRS and 2 ft into the underlying McNairy Formation to ensure coverage of the full thickness of the RGA.

The TS injection and monitoring array were constructed near the southeast corner of the C-400 Building, as shown on Drawing C7DC40000A027, in Appendix C1. Due to safety concerns, three TMP locations (TMP-8, TMP-10, and TMP-11) were requested to be moved away from utilities. The FFA parties agreed that moving these TMPs would not impact results of the study (further documentation is provided in the letter from DOE in Appendix A).

Eleven borings were installed during the implementation of this study. One central boring was drilled to install two nested steam injection wells and one TMP (TMP-01). The remaining 10 borings contained TMPs and were installed surrounding the steam injection wells with increasing radial distance from the point of injection (see Figure 2). Temperature data were collected from TMP-01 to TMP-11 at radial distances of 0 ft, 2 ft, 3 ft, 5 ft, 8 ft, two at 10 ft, 15 ft, two at 20 ft, and 30 ft, respectively, from the point of injection (see Appendix D, Data).

The two nested steam injection wells were constructed to allow for steam injection at upper and lower screened intervals simultaneously, while maintaining the ability to isolate the upper and lower wells to focus steam injection to a single depth interval.

Boreholes for the injection well and TMP installations were drilled using a ProSonic 600T truck-mounted sonic drill rig. Field geologists performed lithologic evaluations and boring logs of continuous core soil sampling over the entire boring depth of the first three boreholes (TMP-1, TMP-9, and TMP-10). The observations were used to determine the thickness of the RGA within the study area. RGA thickness at the remaining eight boreholes was determined by collecting continuous core samples from a depth of 50 ft bgs to the total depth of each boring (Appendix B).

To install the 12.75-inch diameter borehole required for the nested steam injection well/TMP-01 construction, a 6-inch diameter initial borehole was advanced using a 4-inch diameter core barrel for soil sample collection followed by a 6-inch diameter drill casing. Once the 6-inch diameter borehole was advanced to the final depth as determined by the RGA thickness at the location, the final borehole diameter was achieved by advancing 10-inch diameter drill casing followed by 12.75-inch diameter drill casing.

The ten TMPs were installed using a 6-inch diameter borehole, which was constructed by advancing a 4-inch diameter core barrel for soil sample collection followed by a 6-inch diameter drill casing. Once the 6-inch diameter borehole was advanced to the final depth as determined by the RGA thickness at the location, the TMPs were installed as described below.

3.3 EQUIPMENT AND MATERIALS

3.3.1 Injection Well

The location of the upper and lower nested steam injection wells, SIW-01S and SIW-01D, respectively, is shown on Figure 2 and Drawing C7DC40000A027, Appendix C1. The steam injection well construction consisted of 3-inch diameter carbon steel casings with 0.010-inch slotted stainless steel screens. The total depths of SIW-01S and SIW-01D were 72 ft bgs and 93 ft bgs, respectively. SIW-01S and SIW-01D were screened from 67 ft to 72 ft bgs and 88 ft to 93 ft bgs, respectively. Within the borehole, the two steam injection wells were isolated from one another, as well as from the ground surface, by layers of course sand filter pack around the well screens, fine sand, and a high temperature, high viscosity Class H cement [American Petroleum Institute (API) equivalent to Class G cement] and silica flour grout. Well details are shown on Drawing C7DC40000A028, Appendix C1 and additional details on Class H cement can be found Section 3.6.5.

3.3.2 Temperature Monitoring Points

The locations of the 11 TMPs installed as part of the TS are shown on Drawing C7DC40000A027, Appendix C1. The drawing reflects the as-built location of TMP-08, TMP-10, and TMP-11 that were moved due to safety concerns related to existing subsurface utilities. TMP-01 was installed in the steam injection well boring against the borehole wall to determine if short circuiting within the gravel pack was occurring. The remaining 10 TMPs were installed in individual boreholes at distances ranging from 2 ft to 30 ft away surrounding the steam injection point. TMPs were comprised of bundles of thermocouple wires and were grouted in place using the same high temperature, high viscosity Class H cement (API equivalent to Class G cement, see Section 3.6.5) and silica flour grout mixture used for the steam injection wells.

Each TMP, except for TMP-08, was comprised of 17 temperature sensors (type K thermocouples) that were connected to temperature data acquisition modules (TDAMs) with a user-definable, data gathering capability of every 1 to 100 seconds. Due to spatial variability in the thickness of the RGA, TMP-08 was comprised of 18 temperature sensors. Thirteen of the temperature sensors (14 at TMP-08) installed in each TMP were spaced vertically 3 ft apart within the RGA. In some cases the top two temperature sensors within the RGA were spaced closer than 3 ft due to spatial variability in the thickness of the RGA. Additionally, two temperature sensors at the bottom of the UCRS and two in the top of the McNairy Formation were spaced vertically 1ft apart to better define heat transfer characteristics into these formations that bound the RGA. The numbering of individual temperature sensors at each TMP followed the nomenclature TMP-xx-(yy), where TMP-xx is the individual TMP number and yy is the vertical designation within the TMP. The nomenclature in each individual TMP begins with the temperature sensor that is positioned at the boundary between the top of the McNairy and the base of the RGA, which is designated TMP-xx-(00). Distance above the McNairy/RGA boundary is used for temperature sensors in the RGA and UCRS. The two temperature sensors in the McNairy are designated by the distance below the McNairy/RGA boundary [TMP-xx-(-01) and TMP-xx-(-02)].

3.3.3 Steam Generation System

A portable, electric steam boiler was installed to provide up to 6,000 pph of saturated steam at 140 pounds per square inch gauge (psig) to the two steam injection wells. The boiler, supplied by P.M. Lattner Manufacturing Company, Model # 2080HS-480-32, used existing on-site utilities. Electrical power [480 volts alternating current (vac), 3 phase] supplied two heater panels (16 heaters each) in the electric steam boiler. The feed water system consisted of a skid-mounted tank and dual pump assembly using makeup water from existing fire hydrant FH-01. A separate tank received daily blowdown water. Although rated for 140 psig, the boiler was generally operated to provide approximately 100 psig steam. Steam-rated and insulated piping and valves connected the boiler to the steam injection wells. Steam then was conveyed to the wells in a 4-inch diameter header that split into two branch lines. Steam traps and a moisture separator ensured that any free moisture in the header was removed prior to the branch lines to ensure delivery of dry saturated steam. The branch lines contained pressure regulators, gauges, and energy meters to control the steam pressure to approximately 30 psig and monitor steam parameters. Downstream throttle valves were used to regulate flow into the wells and maintain an injection pressure (generally less than 25 psig) that was expected for the formation. Thermal expansion was accommodated through directional changes in the piping and flexible hoses. Refer to Drawing P7DC40000A060, Appendix C1.

3.3.4 Temperature Monitoring System

The temperature monitoring system consisted of TDAMs that received the type K thermocouple signals. Each TMP used three 8-channel TDAMs that were daisy chained with the other TMPs to provide output signals to the main computer. The TDAMs were supplied by ICP DAS USA, Inc. (Model # M-7018) and were installed in weather-proof enclosures (aboveground for all except TMP-05, TMP-06, and TMP-09, which were installed in vaults in Tennessee Avenue). The data were displayed in real-time on the main computer and logged into the computer's hard drive.

3.4 DATA COLLECTION AND ANALYSIS

Table 2 in the *Treatability Study Work Plan for Steam Injection* (DOE 2014a) presented the DQOs resulting from the collaborative effort between DOE Portsmouth/Paducah Project Office, EPA, and

Kentucky Department for Environmental Protection. The problem statement, "How will steam flow in the RGA in the southeast treatment zone?" and the TS objectives of understanding the response of the RGA to steam injection and determining the effect of groundwater flow on heating of the RGA (discussed in Section 4.1.2.5) formed the premise for DQO development. The primary data required were engineering parameters associated with steam injection (flow rate, temperature, and pressure) and resulting temperature distribution in the subsurface. The quality objectives for these data are shown in Table 3, Metric Monitoring Program, of the TS Design Report (DOE 2014c). As mentioned, data were sent to the main computer for real-time display and historical archiving. Hard copies of field forms were stored in locked fire safes per LATA Kentucky procedure PAD-ENM-2700, "Logbooks and Data Forms."

Instrumentation and monitoring equipment were included to monitor and control the TS progress. The instrumentation included type K thermocouples to monitor subsurface temperatures, pressure gauges to monitor and control injection pressure, energy meters to monitor and control steam parameters, a flow meter to measure water consumption and power meters to monitor electrical consumption by the steam boiler.

All of the logged data were stored in the main computer in one minute increments. The data then were downloaded to hard disks for backup and distribution to other team members. Additionally, the data were reported, in one-hour increments, daily at approximately 0700. This information was used to monitor steam system performance and subsurface response.

For reporting, a 24-hour time range, usually 0700 to 0700, was selected, and individual reports were generated for each instrument (TMP-01 through TMP-11, ET-100S and ET-100D, and ET-01A and ET-01B). The individual reports included real-time and historical trends of temperature, flow, energy, and power (see Appendix D). Water usage was documented on the daily operational logs (Appendix D).

The results of the TS were used to calibrate modeling simulations to support the subsequent assessment of technical implementability and cost-effectiveness of steam injection at the C-400 site.

3.4.1 Temperatures

As previously described, subsurface temperatures were monitored in real-time using type K thermocouples installed in 11 different boreholes. The radial spacing provided a means to monitor the horizontal and vertical propagation of the steam front during all phases of the TS. The temperature data were continuously uploaded to the main computer for real-time display and historical archiving (see Appendix D).

3.4.2 Steam Parameters

Energy meters (ET-100S and ET-100D) were installed in both steam branch lines to monitor the steam conditions prior to injection. Of particular importance was steam flow rate and enthalpy to ascertain the energy being injected into the formation. From the meters (Spirax Sarco Model VLM10), the readings were sent to the main computer for real-time display and historical archiving. Flow rate adjustments were made based on the decision rules provided in the *Treatability Study Design, Design Drawings and Technical Specifications Package for the C-400 Interim Remedial Action Phase IIb Steam Injection Treatability Study at Paducah Gaseous Diffusion Plant, Paducah, Kentucky*, DOE/LX/07-1295&D2/R1 (DOE 2014c). Additionally, pressure gauges provided local indication to ensure the piping system and formation was not overpressurized (see Appendix D).

3.4.3 Boiler Electrical Requirements

The electrical consumption from the steam boiler was monitored using wattnode modbus meters (ET-01A and ET-01B) installed on the power leads to electrical panels PDP-ES1-01A and PDP-ES-01B. The data (power, voltage, amperage) were sent to the main computer for real-time display and historical archiving. Although not used for system control, the data were collected to monitor the status of the boiler electrical heaters (see Appendix D, Table D-3).

3.5 DATA MANAGEMENT

Data management for this treatability study was governed by the Data Management Implementation Plan Section 10 of the C-400 Phase IIa *Remedial Action Work Plan* (DOE 2013).

3.6 DEVIATIONS FROM THE WORK PLAN

The deviations from the work plan consisted of changes to the construction plans to respond to field conditions (relocation of TMPs and relocation of the steam boiler and electrical transformers), to utilize existing DOE equipment and facilities (pipe supports, electrical equipment and materials, pipe bridge), to manage cost, and improve overall system functionality.

The FFA parties agreed that relocation of the TMPs would not impact results of the study (further documentation is provided in the letter from DOE in Appendix A). The field change request (FCR) procedure PAD-ENG-0027 was used for the major deviations to the design. An FCR was approved prior to implementation of each change. All changes were documented on the as-built plans (see Appendix C1).

3.6.1 Redlines On As-Built Drawings

The approved design drawings were used to complete the construction. Per PAD-ENG-1027, *Project Drawings*, and PAD-ENG-0027, *FCR and Field Change Notice*, all changes were documented as redlines on the as-built drawings (see Appendix C1).

3.6.2 Field Change Requests

The need for changes to the approved drawings and specifications was identified from field observations. An FCR then was developed per LATA-Sharp Remediation Services, LLC, (LSRS) procedure PAD-ENG-0027 R1, *FCR and a Field Change Notice*, and was submitted for approval. Once approved, the FCR was noted on the drawings and/or specifications as a redline and was incorporated into the As-Built Drawings (see Appendix C1). Table 2 summarizes the project FCRs.

Table 2. Summary of Project Field Change Requests

FCR Number	FCR Title	TS Impact
FCR-PHC400-P019	New Power Panel	Two new panels were added to the existing panel to accommodate the electric steam boiler.
FCR-PHC400-020	Electric Tie In Point	Power tie point moved from Pole P23B-6 to P23B-2 to use existing equipment.
FCR-PHC400-021	Move Steam Boiler ESB-1	Move steam boiler to use existing equipment and reduce cable size and cost of electrical equipment.

Table 2. Summary of Project Field Change Requests (Continued)

FCR Number	FCR Title	TS Impact
FCR-PHC400-022	Relocation of three TMP borings	Relocate 3 TMP locations impacted by subsurface high voltage cable to eliminate safety concerns.
FCR-PHC400-023	Reuse Existing Pipe Supports	To reduce cost, existing DOE-owned pipe supports will be used.

The FCRs did not impact the TS results.

3.6.3 Temperature Monitoring Points

Based on the following considerations, a decision was made to use the temperature data from the 221 TMPs (188 from the original design, 33 redundant thermocouples in the critical zone at the base of the RGA, and one in TMP-08 due to increased thickness of the RGA) instead of steam front arrival times as required by the TS Design for calibration of the models' simulations.

- In total, 221 different temperature monitoring points were installed in the 11 TMP arrays. Temperature variations were observed in all 11 TMPs in nearly all of the thermocouples. Conversely, during the Phase 1 steam injection, steam temperatures were observed only in about 70 of the TMPs or about 1/3 of the total. As a result, a deviation from the work plan was made so that all temperature data were utilized instead of steam arrival times, which eliminated loss of data from nearly 2/3 of the measuring points.

- The model error determined by summing the square of differences in the observed and simulated steam arrival times was relatively insensitive to poor model performance. This is due to the fact that only locations where both the model and the field data show steam arrival are used in this calculation. If the model fails to predict steam arrival at a location where it is observed or if steam is not observed at a location where the model predicts it, that data point is removed from the calculation, and there is no penalty for the inaccuracy of the model.

- In some locations, it can be difficult and ambiguous to determine exactly when the steam front reaches a given location from temperature measurements alone. This is due to the fact that the water boiling point is a function of depth, distance from the injection well, and time as the subsurface pressure changes. At several locations, the field-measured temperature climbed slowly past 100°C (212°F) and gradually approached 124°C (255°F). It is not clear from these data when to define the steam arrival time.

- The steam arrival time is irrelevant during the Phase 2 and Phase 4 cool downs, so there is no way to compare model performance during these periods using steam arrival times.

- It is very time consuming to extract the steam arrival time (if any) from each of the 186 TMP locations in the model. For each simulation, it requires generating a time series plot of temperature and gas saturation for each temperature monitoring point to find the model steam arrival time.

3.6.4 Relocation of Temperature Monitoring Points

Due to safety concerns related to existing subsurface utilities, three TMP locations (TMP-8, TMP-10, and TMP-11) were requested to be moved away from the utilities. The FFA parties agreed that moving these TMPs would not impact results of the study (further documentation is provided in the letter from DOE in Appendix A).

3.6.5 Substitution of Class H Cement for Class G Cement

Class G and Class H are equivalent per API specifications. API definition is as follows:

The oil industry purchases cements manufactured predominantly in accordance with API classifications as published in API Specification 10A, *Specification for Cements and Materials for Well Cementing*, 23rd edition, Washington, DC, 2002. The G and H classes of API cements for use at downhole temperatures and pressures are defined below.

Class G—Portland Cement: A basic cement for use from surface to 8,000 ft (2,440 m) depth as manufactured. Primary difference: finely ground cement—primarily used by international entities.

Class H—Portland Cement: A basic cement for use from surface to 8,000 ft (2,440 m) depth as manufactured. Primary difference: courser ground cement—primarily used by U.S. entities.

API identifies both classes of cement intended for use as a basic well cement. Both are available in moderate sulfate-resistant and high sulfate-resistant grades, and no additives other than calcium sulfate or water or both are permitted to be interground or blended with the clinker during manufacture of the cements.

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4. RESULTS AND DISCUSSION

4.1 DATA ANALYSIS AND INTERPRETATION

The results of the TS for steam injection are based upon analysis and interpretation of measurements of subsurface properties and engineering data from the operation of the steam injection system and the results of thermal modeling of the field data (See Appendix D). Data were collected from each of the Phases:

- Phase 1, Initial Steam Injection—April 9 to April 29, 2015;
- Phase 2, Initial Cool Down—April 29 to May 12, 2015;
- Phase 3, Steam Injection—May 12 to May 31, 2015; and
- Phase 4, Final Cool Down—May 31 to June 30, 2015.

In overview, the data were summarized and used to assess the following:

- Field and operational data:
    - Lithology conditions in the TS area;
    - Hydrogeology;
    - Steam operating parameters (injection rates, pressures);
    - Boiler electric requirements; and
    - Subsurface temperatures.
- Thermal modeling data:
    - Zone of influence of an individual injection well;
    - Anisotropy to steam in the RGA;
    - Horizontal permeability to steam;
    - Effects of two-well screen injection scenario on heating patterns in the RGA;
    - Effects of single-well injection scenario on heating patterns in the RGA;
    - How long steam migration across the full thickness of RGA will take to reach 10 ft, 20 ft, and 30 ft distance from an injection well; and
    - Groundwater velocity and calculation of the amount of heat groundwater flow will remove from the target treatment zone.

These objectives were met as follows:

- Field and operational data:
    - Logs of continuous soil borings and grain size analyses provided the lithology conditions in the TS area;
    - Site hydraulic conductivity, as measured by the behavior of the steam front, was the key remaining parameter of the site hydrogeology;
    - Steam injection rates and pressures of the TS determined the expected steam operating parameters of a full-scale operation;
    - Electrical consumption measurements of the TS helped bound boiler electric requirements; and

— Subsurface temperatures provided assessment of short circuiting through the injection well, ESRB, steam front configuration, and radius of the steam front propagation.

- Thermal modeling data:

  — Results of modeling confirmed a 20 ft radius of influence of steam injection wells;

  — Steam front advancement determined the anisotropy of horizontal to vertical hydraulic conductivity to be 10:1 in the upper RGA and 30:1 in the lower RGA;

  — In matching observed conditions, modeling defined a 3D distribution of permeability applicable to the RGA;

  — Effects of single-well and two-well injection scenarios on heating patterns in the RGA were identified (Section 4.1.2.6);

  — Estimates of steam front migration rates were established (Section 4.1.2.6);

  — Modeling determined groundwater flow has very little effect on development of the steam zone in the Phase IIb area.

4.1.1 Summary of Field and Operational Data

4.1.1.1 TS Area Geology

As discussed in Section 1.1, the geologic setting in the immediate vicinity of the C-400 TS area is comprised of valley fill Continental Deposits that overlie Coastal Plain deposits. The Continental Deposits consist of a lower gravel facies—the RGA—and an upper silt facies—the UCRS. The Coastal Plain deposits are composed exclusively of unconsolidated, interbedded, fine-grained sand, and silt and clay of the Upper Cretaceous-aged McNairy Formation. Based on previous borings in the study area, the UCRS was anticipated to be present to a depth of 56.0 ft bgs, and the RGA/McNairy contact was anticipated to occur at a depth of 95.6 ft bgs. The upper RGA is approximately 5 ft to 12 ft thick and typically consists of fine to medium grained sands. The middle and lower RGA (undifferentiated) is approximately 20 ft to 33 ft thick and typically consists of sandy gravels or gravelly sands.

Eleven boreholes were installed to a depth of 97 ft bgs during the TS. The UCRS/RGA interface occurred at depths ranging from 58.4 ft bgs to 59.9 ft bgs, with an average depth of 59.1 ft bgs. The RGA/McNairy interface occurred at depths ranging from 92.6 ft bgs to 94.6 ft bgs, with an average depth of 93.1 ft bgs (see Boring Logs, Appendix B). Both the top and base of the RGA are undulating surfaces. Within the Phase IIb treatability study area, the RGA averages 34.1 ft thick. Over the larger Phase IIb treatment area, the RGA averages 40.6 ft thick: the average top is at 54.7 ft bgs and the average base is at 95.6 ft bgs. The maximum thickness of the RGA is found in soil boring SB59 at 45.6-ft thick, and the deepest RGA is found in soil boring SB56 at 96.6 ft bgs.

The UCRS in the vicinity of the study area was characterized by silt, silty sand, and sand deposits. The sand predominantly was fine to very fine grained quartz sand. Soil color ranged from light gray (10YR7/2) to very pale brown (10YR7/3) to reddish yellow (7.5YR7/8), with mottles ranging in color from light gray (7.5YR7/1) to very pale brown (10YR7/3) to reddish yellow (7.5YR6/8) to brownish yellow (10YR6/6). Occasional interbedded layers of subangular and subrounded chert gravel occurred within the UCRS ranging in thickness from approximately 1 to 2 ft.

During the TS, three borings (SIW-01/TMP-01, TMP-09, and TMP-10) were logged continuously to further define the lithologic characteristics of the RGA. The RGA in the vicinity of the study area was characterized by gap graded sand and gravel. Subrounded to subangular chert gravel ranging in diameter from 0.2 inches to 3.5 inches accounted for 40–80% of the RGA composition. Coarse- to very coarse-grained chert sand accounted for 15–40% of the RGA, with the remaining material made up of very fine to medium grained quartz sand and little clay/silt. Soil color within the RGA ranged from white (7.5YR8/1) to pink (7.5YR8/4) to reddish yellow (7.5YR6/8) to very pale brown (10YR7/4), with mottles ranging in color from black (10YR2/1) to light grey (10YR7/2) to reddish yellow (7.5YR6/8) to white and pink (7.5YR8/1, 8/4). The grain size analyses of the three continuously logged borings are presented on Figure 3.

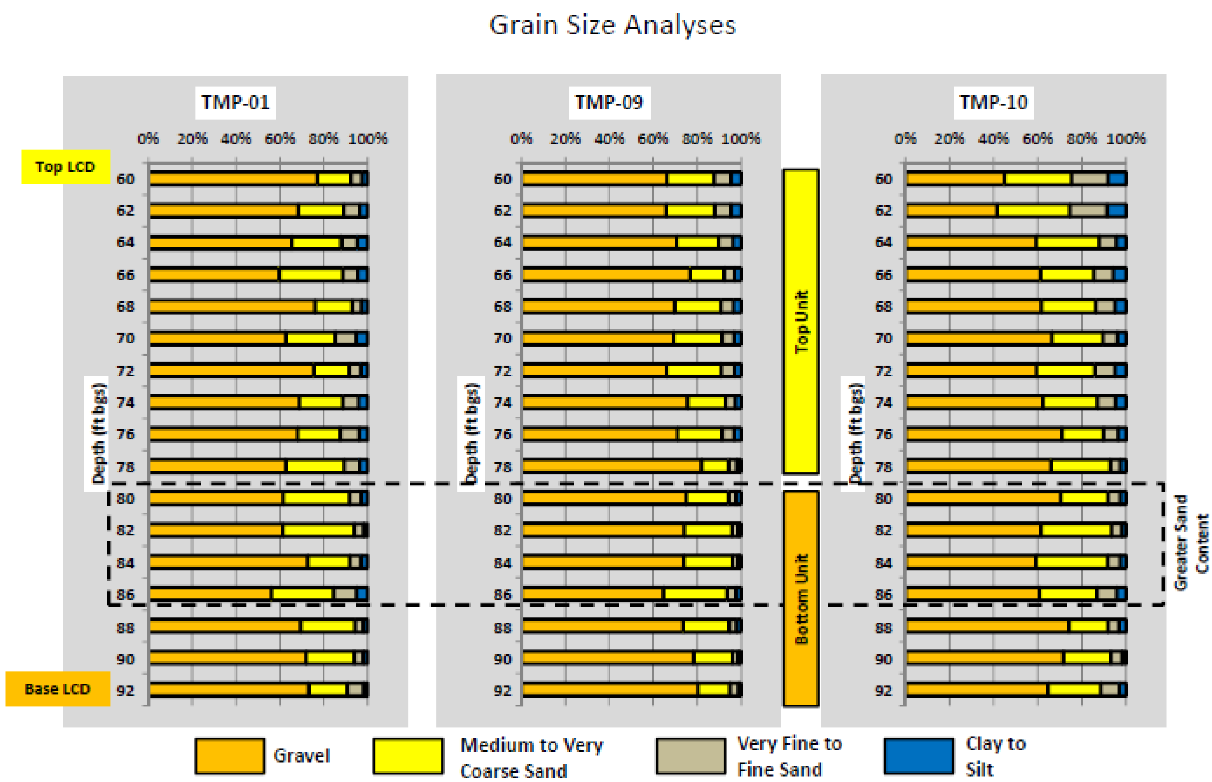

Figure 3. Grain Size Analyses of Continuously Logged Borings

The interface between the RGA and the McNairy Formation was characterized by a sharp transition to interbedded clays, silts, and fine sands. Sediments in the McNairy Formation ranged in color from reddish yellow (7.5YR6/6) to light gray (10YR7/2) to yellow (10YR7/6) to very pale brown (10YR8/2), with mottles ranging from light gray (10YR7/2) to reddish yellow (5YR7/6).

4.1.1.2 Hydrogeology

In the vicinity of the C-400 work area, the UCRS mostly is unsaturated. The RGA potentiometric surface typically is encountered at a depth of approximately 56 ft bgs. During the TS, the RGA potentiometric surface was encountered at SIW-01S and SIW-01D at depths of 54.9 ft bgs and 54.5 ft bgs, respectively. Groundwater flow in the RGA in the C-400 area is generally to the northwest in the Northwest Plume. The groundwater flow diverges to the east and to the west in the Northeast and Southwest Plumes, respectively.

There is significant spatial variability within the RGA regarding hydraulic conductivity. Historically, aquifer testing at PGDP has indicated that hydraulic conductivity in the RGA ranges from approximately 50 to 5,700 ft/day. Groundwater modeling using a calibrated hydraulic conductivity value of 100 ft/day, a maximum observed hydraulic gradient of 6.1×10^{-4}, and a typical porosity of 35%, the groundwater pore velocity in the RGA in the vicinity of C-400 is likely around 0.1 to 0.3 ft/day.

4.1.1.3 Steam Parameters

Energy meters (ET-100S and ET-100D) were used to monitor the steam system conditions prior to injection into the wells. A totalizing flow meter was used to measure the volume of water used to generate the steam. TS Phase 1—Initial Steam Injection was started on April 9, 2015, after completion of startup and commissioning activities. During startup, steam injection rates of less than 200 pph were used to verify system functionality. Subsequently, steam was injected into the upper and lower injection wells at a mass flow rate of 500 pph. The key steam parameters—amperage, power, pressure, temperature, and enthalpy measured upstream of the pressure reducing valve—are shown in Appendix D, Tables D-1, D-2, and D-3. The injection pressure in each well stabilized quickly and remained at about 18 psig, which is roughly the pressure required to overcome the hydrostatic head throughout TS Phase 1. The steam injection well pressures are presented in Appendix D, Table D-17.

After the TS Phase 2—Initial Cool Down, TS Phase 3—Steam Injection—was initiated on May 12, 2015. Steam was injected into the lower well only, at 1,000 pph. The pressure remained at 18 psig, though the injection flow rate into the lower portion of the RGA was doubled. This is indicative of a highly permeable formation that provides little resistance beyond the hydrostatic head to steam flow. The key steam parameters for TS Phase 3 are shown in Appendix D, Tables D-1, D-2, and D-3. The complete set of raw data are presented in Table D-15, Appendix D.

4.1.1.4 Boiler Electrical Requirements and Water Consumption

The electrical consumption from the steam boiler was monitored using meters ET-01A and ET-01B. The data (power, voltage, amperage) were transmitted to the main computer for real-time display and historical archiving. Although not used for system control, the data were collected to monitor the status of the boiler electrical heaters as one of the defined metrics for the TS (see Appendix D, Table D-3). The water consumption data was collected daily on the operational logs (see Appendix D, Table D-16).

4.1.1.5 Subsurface Temperatures

Subsurface temperatures were monitored in real-time using type K thermocouples installed in 11 different boreholes. The data were downloaded on a daily basis and tabulated for each individual TMP location. The temperature data for each TMP location are presented on Tables D-4 to D-14, Appendix D. Of the 11 TMP locations, five (TMP -01, -04, -08, -09, and -10) were monitored closely to evaluate key objectives of the TS—short circuiting through the injection wells, ESRB, steam front configuration, and radius of steam front propagation. The temperature indicative of a steam front (steam temperature), which is higher than the co-boiling temperature of TCE and water (target temperature), is pressure and depth dependent and varies from 227°F to 255°F throughout the RGA. The data from the key TMPs is discussed below.

4.1.1.5.1 TS Phase 1—Initial Steam Injection

TS Phase 1—Initial Steam Injection—began into SIW-01S on April 8, 2015, and into SIW-01D on April 9, 2015, as part of the system start up and commissioning procedures. Commissioning of the TS steam injection system was conducted in accordance with PAD-400-0048, *Treatability Study Steam Injection Shakedown and Startup Procedure Subcontractor*, submittal (Appendix F). Steam was injected at low rates of less than 200 pph in SIW-01S in order to verify functionality of the system. Once the functionality of the system was verified, the injection rate was increased to the design rate of 500 pph. The following electric steam boiler shakedown activities were followed to verify functionality before the transition to operations:

- Fill feed water and blow down tanks and test level controls;
- Test the pump operations and recirculation through lines;
- Perform instrumentation and control functions checks;
- Test interlocks; and
- Make adjustments, as required.

Steam injection at flow rates and pressures less than the design values was started on April 8, 2015, to verify system functionality. Steam injection at the design rate of 500 pph and the system pressure of 30 psi was started in both wells on April 9, 2015, at 1700 (24-hour time format). By April 10, 2015, the thermocouples opposite the upper (TMP-01-27, TMP-01-24, and TMP-01-21) and lower well screens (TMP-01-03,[5] TMP-01-06, and TMP-01-09) located at the borehole wall (approximately 4 inches from the well screen) registered steam temperatures. Temperatures in the thermocouples opposite the two well screens remained at steam temperature throughout the remainder of the TS Phase 1 injection period.

The thermocouples located opposite the zone between the well screens (TMP-01-18 and TMP-01-15) located at 75 to 78 ft bgs were heated at a slower rate than those immediately opposite the screens. This likely is the result of conductive heating of the grout seal materials from the steam exiting the screens on either side of the seal and not due to direct contact with steam moving up the borehole. The observed temperatures in the zone between the well screens indicate that the grout seals performed as designed and that short circuiting up the steam injection well bore did not occur. The temperatures observed during TS Phase 1 at TMP-01 are shown in Figure 4.

During the initial steam injection period of TS Phase 1, the thermocouples located in TMP-01 and TMP-04 (Figures 4 and 5) at the depth of the upper screen (67 to 72 ft bgs) and the lower screen (84 to 90 ft bgs) measured temperatures that increased rapidly to steam temperature and remained there throughout TS Phase 1. The temperatures measured in the key near field TMPs (TMP-01 and -04) in the depth interval between 75 and 81 ft bgs increased at a much slower rate than the surrounding depth intervals. It is clear from the near field thermocouple results (TMP-01 and TMP-04), that steam exited the screens and migrated mostly horizontally. Rapid heating by direct contact with steam was not observed from the lower screen up to the bottom of the UCRS, as would be expected if ESRB occurred. The steam front did not show rapid vertical migration, as demonstrated by the results from TMP-04-12, -15, and -18, which did not increase rapidly and did not approach steam temperatures until after April 16, 2015. Temperatures in TMP-04-18 never exceeded 216°F.

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[5] During initial heating period, data evaluations identified inconsistencies in the recorded temperatures for TMP-01-00/ TMP-01-00(-01) and TMP-01-03/TMP-01-03(-01). The temperature data points for TMP-01-00/TMP-01-00(-01) were displayed as TMP-01-03/TMP-01-03(-01) and vice versa. The sensor connections were adjusted on 4/14/15 at 1400 hours to correct the issue. Temperature data points impacted by this issue occurred between 4/8/15 0600 hours and 4/14/15 1300 hours.

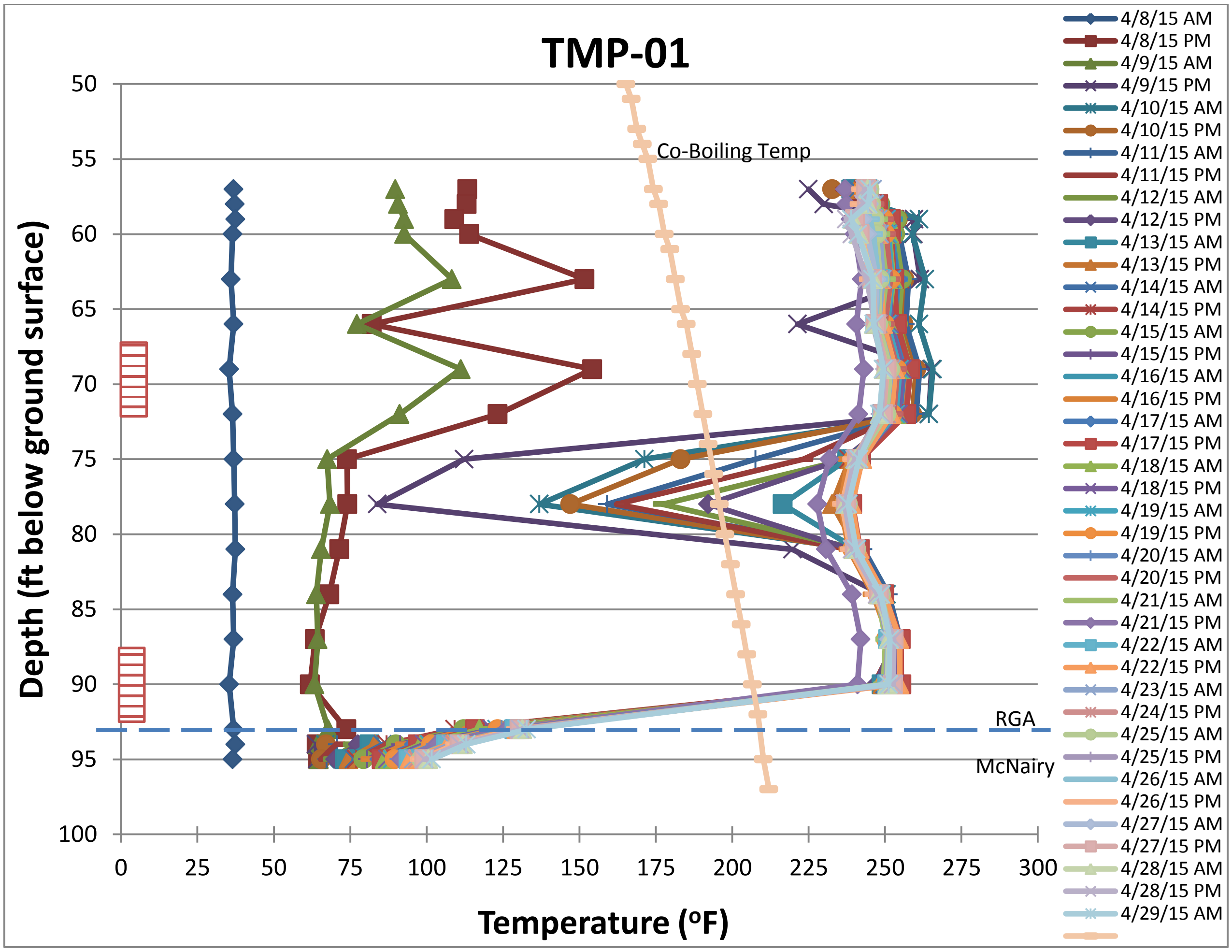

Figure 4. Subsurface Temperatures Measured in TMP-01 during TS Phase 1—Initial Steam Injection

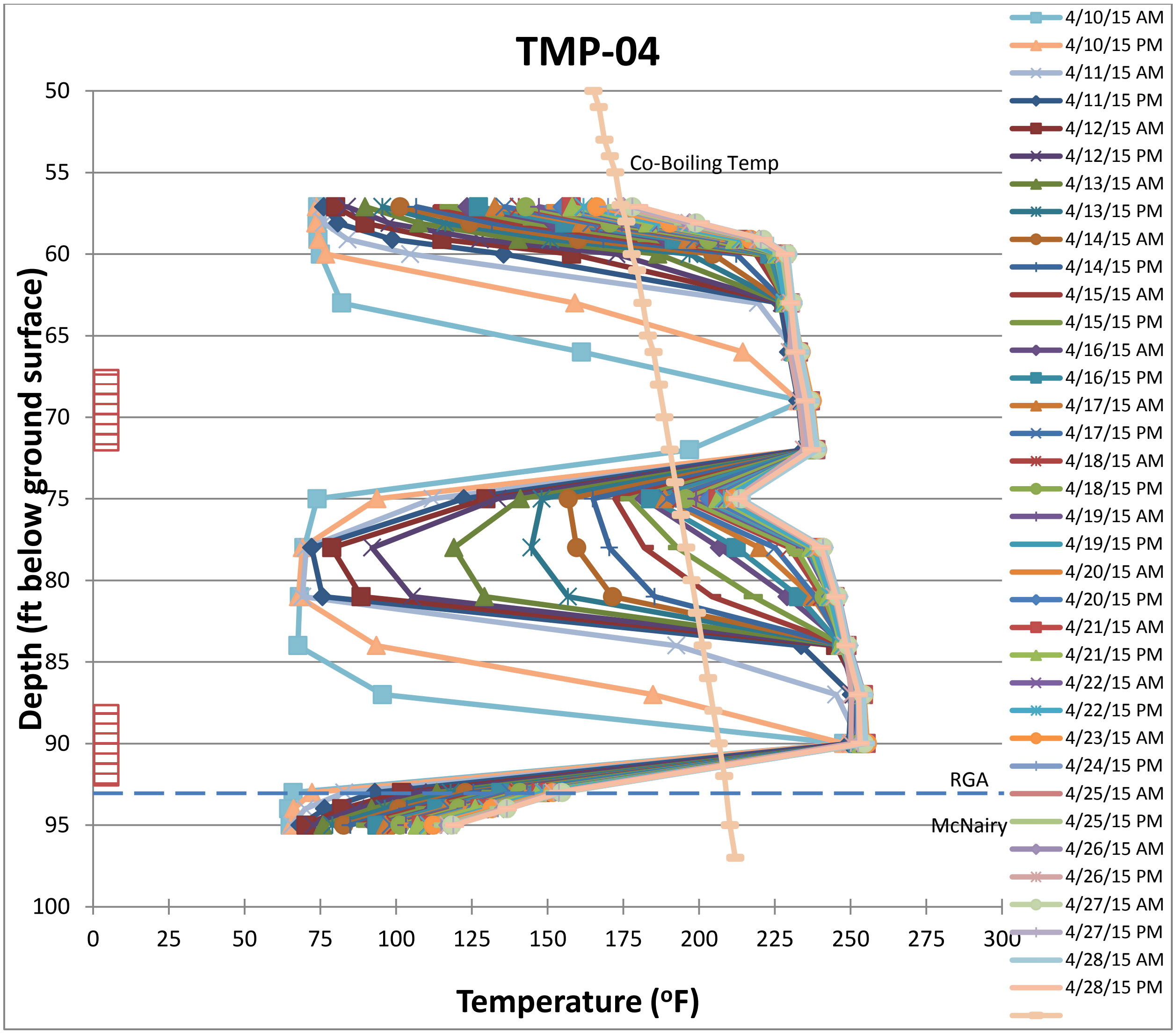

Figure 5. Subsurface Temperatures Measured in TMP-04 (5 ft from SIW-01) during TS Phase 1—Initial Steam Injection

The data of TMP-04, the defined monitoring point for ESRB (DOE 2014c), demonstrate that the conditions for ESRB were not observed. The steam front propagation was dominantly horizontal from both the upper and the lower screens during the first 10 days of Phase 1, and no temperature sensor evidence of rapid heating from the lower screen to the base of the UCRS was observed. While steam temperatures were not observed at TMP-04-00 (indicative of some steam over-ride at the base of the RGA), steam temperatures in the other two lowest temperature sensors (TMP-04-03 and -06) were observed on April 10, 2015, and April 11, 2015, respectively. There was no evidence that ESRB occurred.

During TS Phase 1, the steam front migrated horizontally from the two screens. Evidence of a steam front in the mid field zone was observed beyond TMP-04 (Figure 5, 5 ft from injection wells) and at TMP-08 (Figure 6, 15 ft from injection wells). Steam temperatures were observed at TMP-08-12 and in TMP-08-24 through TMP-08-36. In the far field (> 15 ft from the SIW well) steam temperatures were observed at TMP-09-27 (Figure 7, 20 ft from injection wells) and at TMP-10-24 to TMP-10-30 (Figure 8 20 ft from injection wells). A zone of slower heating rates between approximately 75 to 85 ft bgs that was observed in the near and mid fields still is observed in TMP-08, TMP-09, and TMP-10.

The steam front appears to be more extensive in the Upper RGA than in the lower RGA in the mid field. At TMP-08, steam temperatures were observed in thermocouples TMP-08-24 to TMP-08-36 (71 to 59 ft bgs), while steam temperature was observed only at TMP-08-12 (83 ft bgs) in the lower RGA. In the far field, steam temperatures were observed only in the upper RGA in TMP-10-24 to TMP-10-30 (70 to 64 ft bgs) at TMP-10. Steam temperatures were observed only at TMP-09-27 at 66 ft bgs in TMP-09. Steam temperatures were not observed in the lower RGA in either TMP-09 or TMP-10. The horizontal migration and the extent of the steam front at Day 20 in both the upper and lower RGA can be seen in the 3D plot of the data, Figure 9.

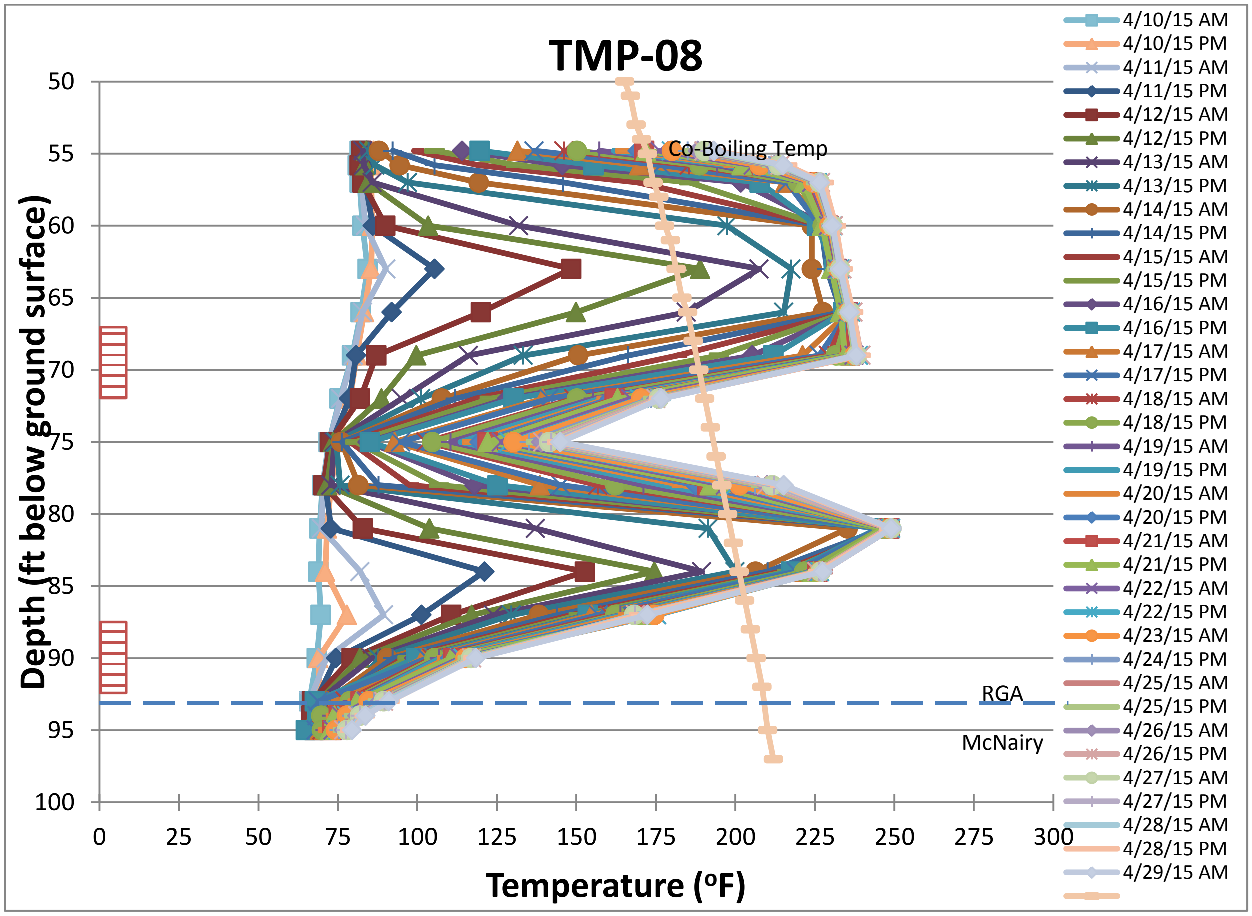

Figure 6. Subsurface Temperatures Measured in TMP-08 (15 ft from SIW-01) during TS Phase 1—Initial Steam Injection

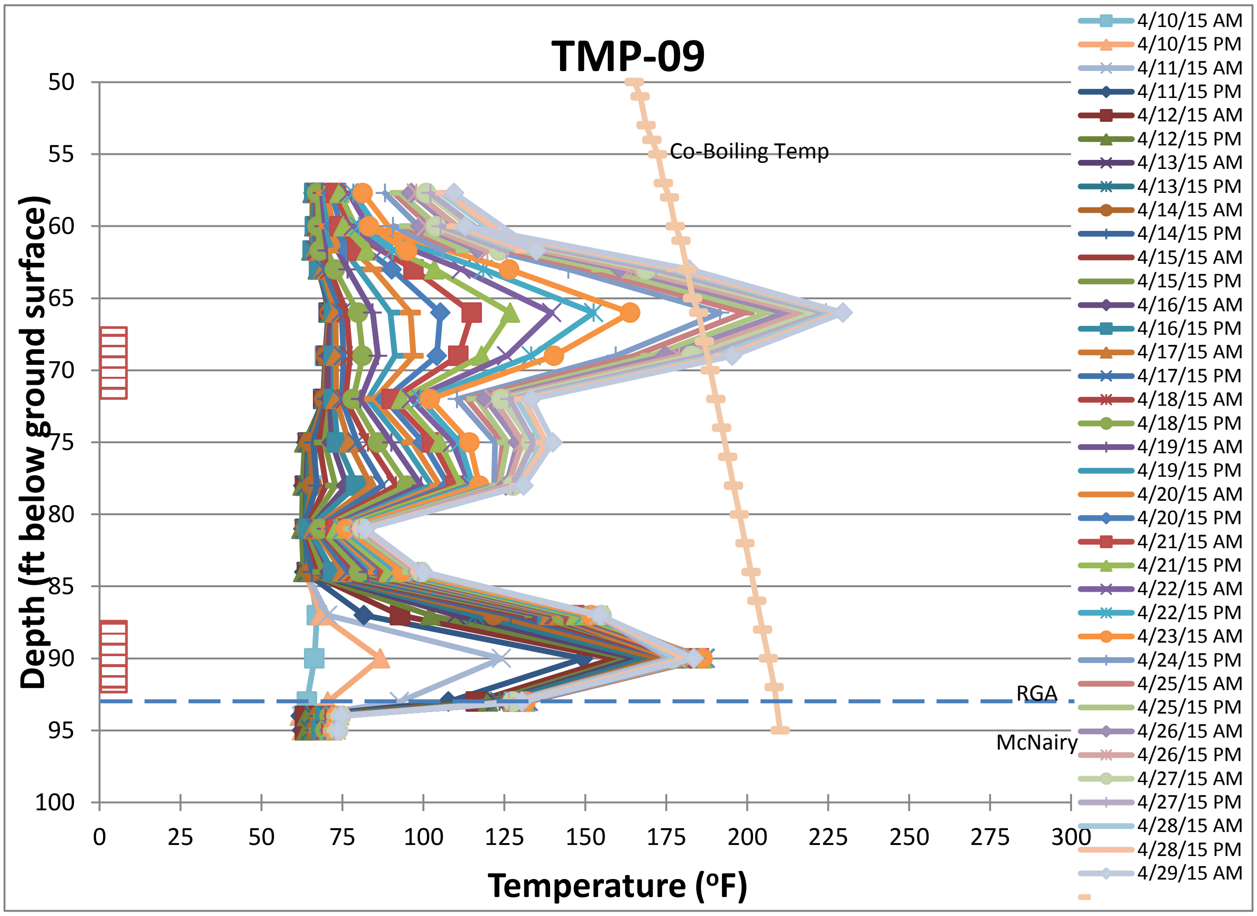

Figure 7. Subsurface Temperatures Measured in TMP-09 (20 ft from SIW-01) during TS Phase 1—Initial Steam Injection

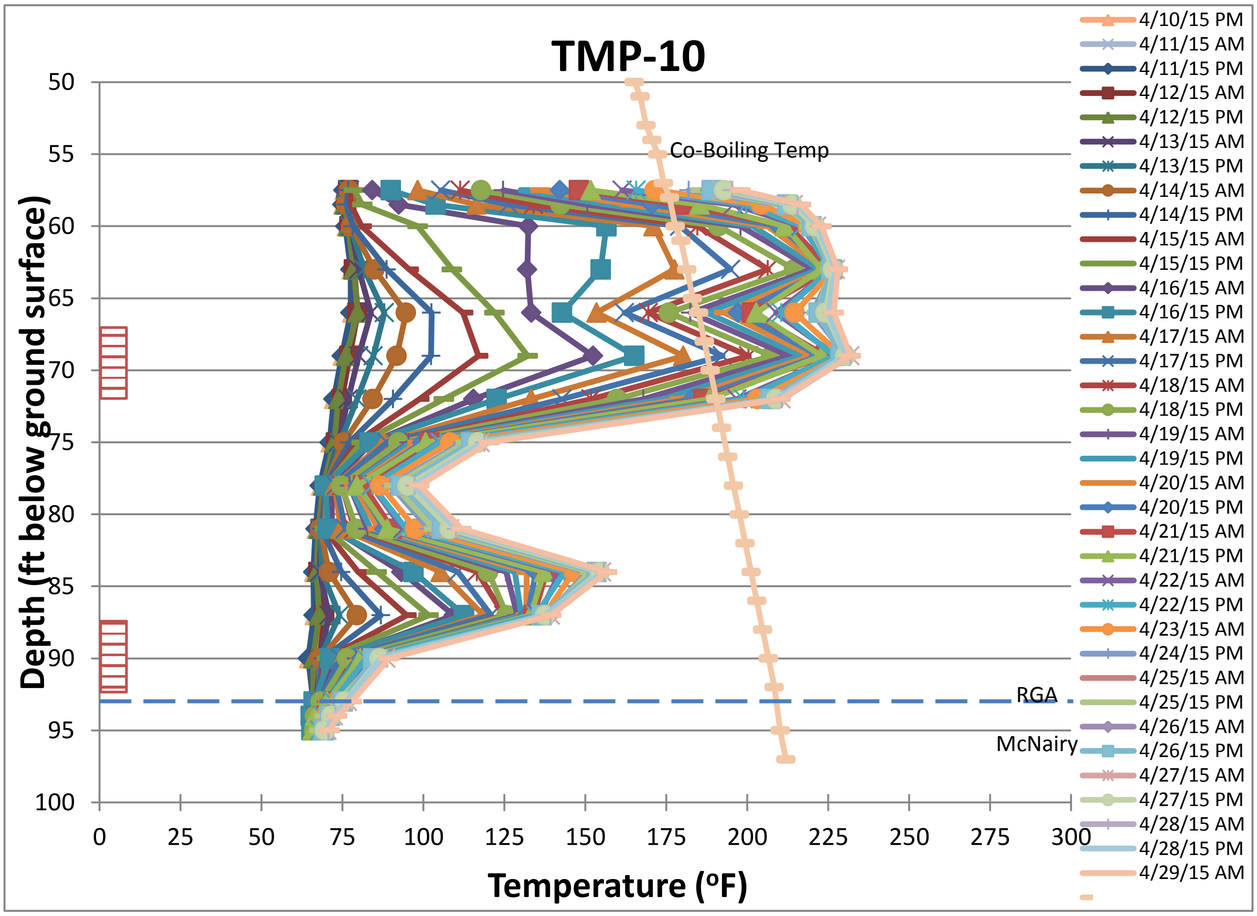

Figure 8. Subsurface Temperatures Measured in TMP-10 (20 ft from SIW-01) during TS Phase 1—Initial Steam Injection

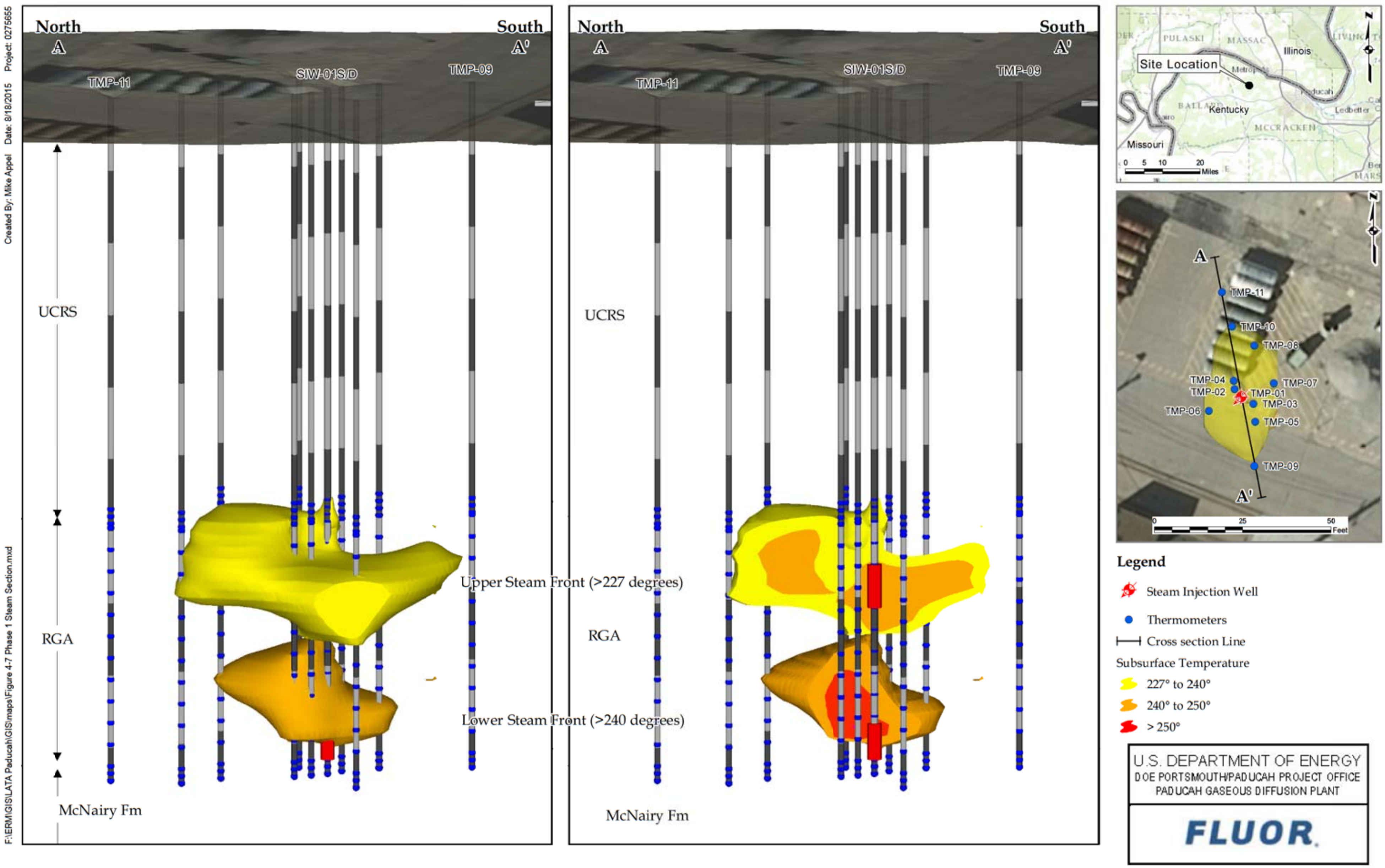

Figure 9. Day 20, Phase 1, Steam Front Extent—April 28, 2015

4.1.1.5.2 TS Phase 2—Initial Cool Down

TS Phase 2—Initial Cool Down—started on April 29, 2015, when steam injection was stopped in both of the injection well screens. The steam zones established during the TS Phase 1—Initial Steam Injection—collapsed rapidly within three days. The initial cool down rates in the lower portion of the RGA near the steam injection wells varied from about 8°F to 16°F per day as shown in TMP-04 (Figure 10). Significantly greater cooling was observed in the lower RGA than in the upper RGA. While some of this difference may be attributable to lithologic factors, the cooling rates in the lower RGA were predominantly affected by the influx of cold groundwater as the steam zone collapsed. Cooling in the upper RGA likely was impacted by the heat transfer by buoyancy from the lower RGA to the upper RGA, resulting in significantly slower cooling rates than in the lower RGA.

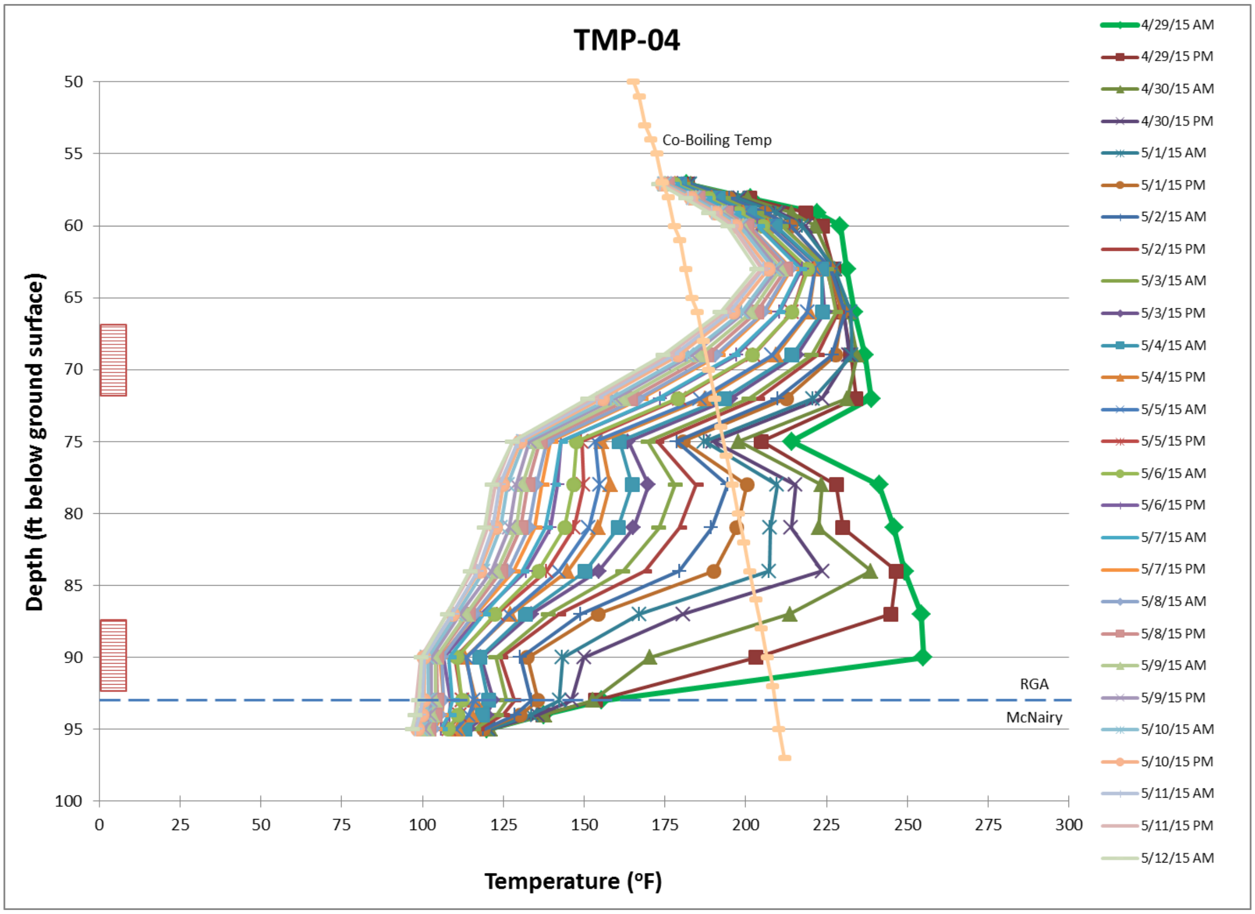

Figure 10. Subsurface Temperatures Measured in TMP-04 (5 ft from SIW-01) during TS Phase 2—Initial Cool Down

4.1.1.5.3 TS Phase 3—Steam Injection

During TS Phase 3, steam injection was continued in the lower screen at a rate of 1,000 pph. The injection pressure remained at 18 psi as observed during Phase 1. The injection rate was increased to evaluate the impact on steam front migration along the top of the McNairy Formation. The temperature results from TMP-04 at the end of TS Phase 3 (Figure 11) and other TMPs at larger distances illustrated some of the key steam front propagation conditions that can be attributed to injection of steam into the lower RGA only at an increased injection rate as follows:

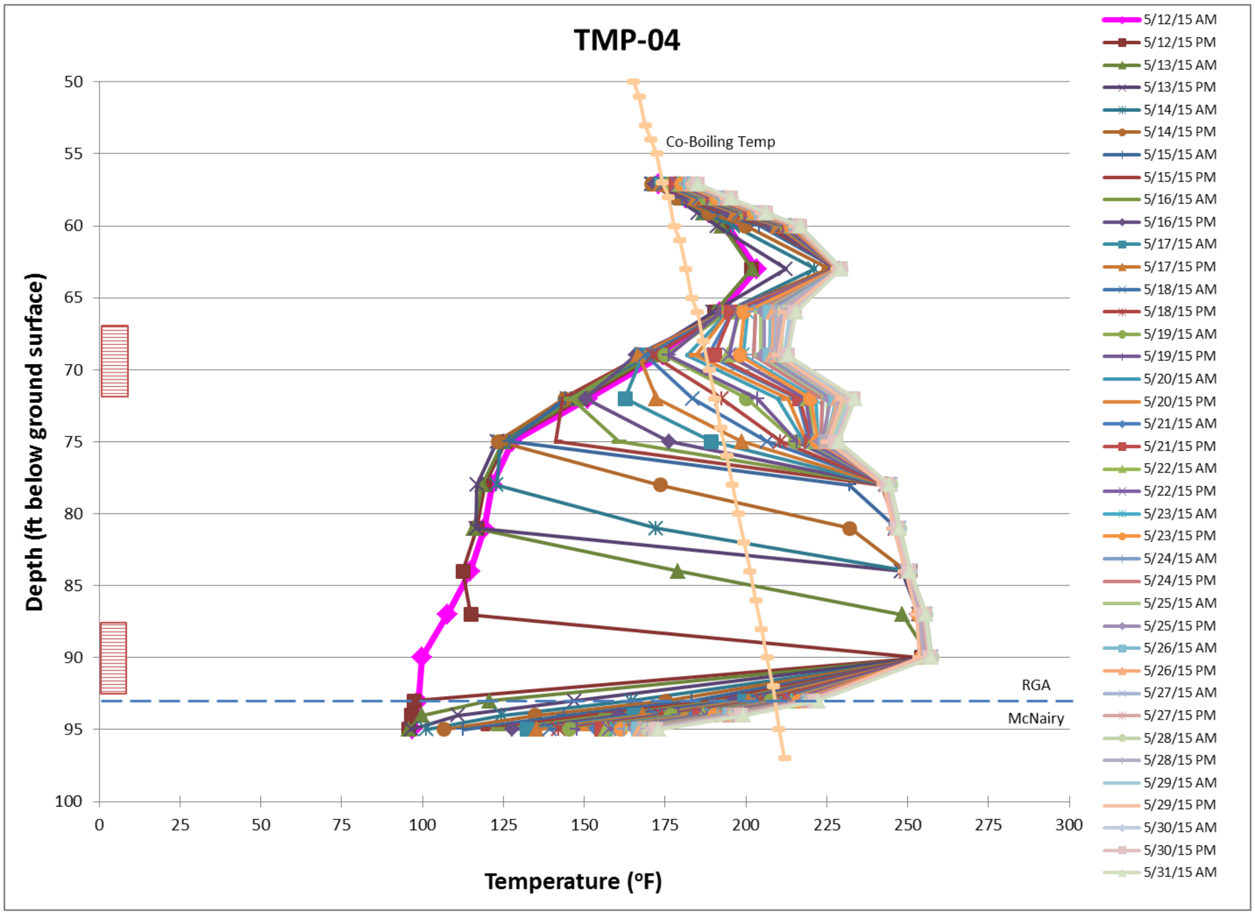

Figure 11. Subsurface temperatures measured in TMP-04 (5 ft from SIW-01) during TS Phase 3 Steam Injection

- The steam front was reestablished in the lower RGA quickly (within three days) as in Phase 1 starting from the base of the RGA and moving upward;

- A much more extensive steam front was established during the TS Phase 3 heating. Steam temperatures were observed in both TMP-09 and TMP-10 (20 ft from the injection well) in the lower RGA during Phase 3 steam injection, while steam temperatures were not observed in the lower RGA beyond TMP-08 (15 ft from the injection well) during Phase 1 heating;

- While some override was evident, heating to the top of the McNairy Formation appears to have occurred to an ROI beyond 8 ft from the single well injection as compared to 5 ft in Phase 1; and

- Upward steam buoyancy was the likely cause of the increasing temperatures in the zone between the upper and lower screens at depths from 70 to 80 ft bgs and the small increases in the upper RGA where no steam was injected.

During the TS Phase 1—Initial Steam Injection—the temperatures at the McNairy Formation/RGA interface were raised from the baseline of approximately 65°F to a maximum of approximately 155°F at TMP-04. During TS Phase 3, the temperature of the McNairy/RGA interface increased from approximately 97°F to approximately 222°F or an additional 35°F over the change observed in TS Phase 1 at TMP-04. The temperature of 222°F achieved in the McNairy Formation/RGA interface is greater than the TCE DNAPL/water co-boiling target temperature (the co-boil temperature is approximately 203°F at a depth of 38 ft below the water table, Kingston et al. 2014). The horizontal migration and the extent of the steam front at Day 20 in both the upper and lower RGA can be seen in the 3D plot of the data, Figure 12.

4.1.1.5.4 TS Phase 4—Final Cool Down

During TS Phase 4, as in TS Phase 2—Initial Cool Down—the steam zone collapsed within three days after shutdown of the steam injection system. Cooling continued in a similar manner to the cooling in TS Phase 2, with greater cooling in the lower RGA compared to the upper RGA.

4.1.2 TS Thermal Modeling

4.1.2.1 Introduction

Multiphase flow heat transfer numerical simulations were performed in order to better analyze the results of the TS, and to extrapolate those results to the predicted full-scale steam remediation field performance. The analysis of the TS was conducted by calibrating 2D radially symmetric models and 3D heterogeneous models to the observed TMP temperature data. The variables adjusted during the model calibration consisted mainly of the distribution of horizontal and vertical permeability.

The 2D model provided good matches with some of the TMP temperature data, but was unable to accurately reproduce the temperature response at other TMP locations (TMP-05, TMP-06) due to local scale heterogeneity in the RGA. The heterogeneous 3D model yielded much better simulations of the entire collection of TMP data, and it illustrated the impact of isolated lower permeability zones in the RGA on the steam front propagation. Additional details of the numerical model and the model calibration process are given in Appendix E.

Following the model calibration effort, 3D simulations of a proposed full-scale steam remediation design concept were performed. These simulations included small models of an internal part of a full-scale system, as well as a full field-scale simulation that included all of the proposed injection and extraction wells.

4.1.2.2 Key Assumptions

The modeling approach uses a transient multiphase flow formulation that is based on conservation of mass and energy at each numerical grid block at each time-step. As in almost all studies of multiphase flow in porous media, the flow terms assume that the multiphase version of Darcy's Law is valid, and use macroscopic descriptions of phase relative permeability and capillary pressure. The thermal formulation assumes that at the scale of a grid block, the fluid phases and solid aquifer materials are in thermal equilibrium. The thermal equilibrium assumption is valid in porous media where the rate of heat conduction in the solid grains is fast relative to the rate of convective heat flow in the fluids. This assumption is used in virtually all geothermal and petroleum reservoir simulations that involve porous media.

The 2D radially symmetric models assume that system properties are axisymmetric, and only depend on radial distance and elevation. The 3D models can account for full system heterogeneity at all locations in the model domain.

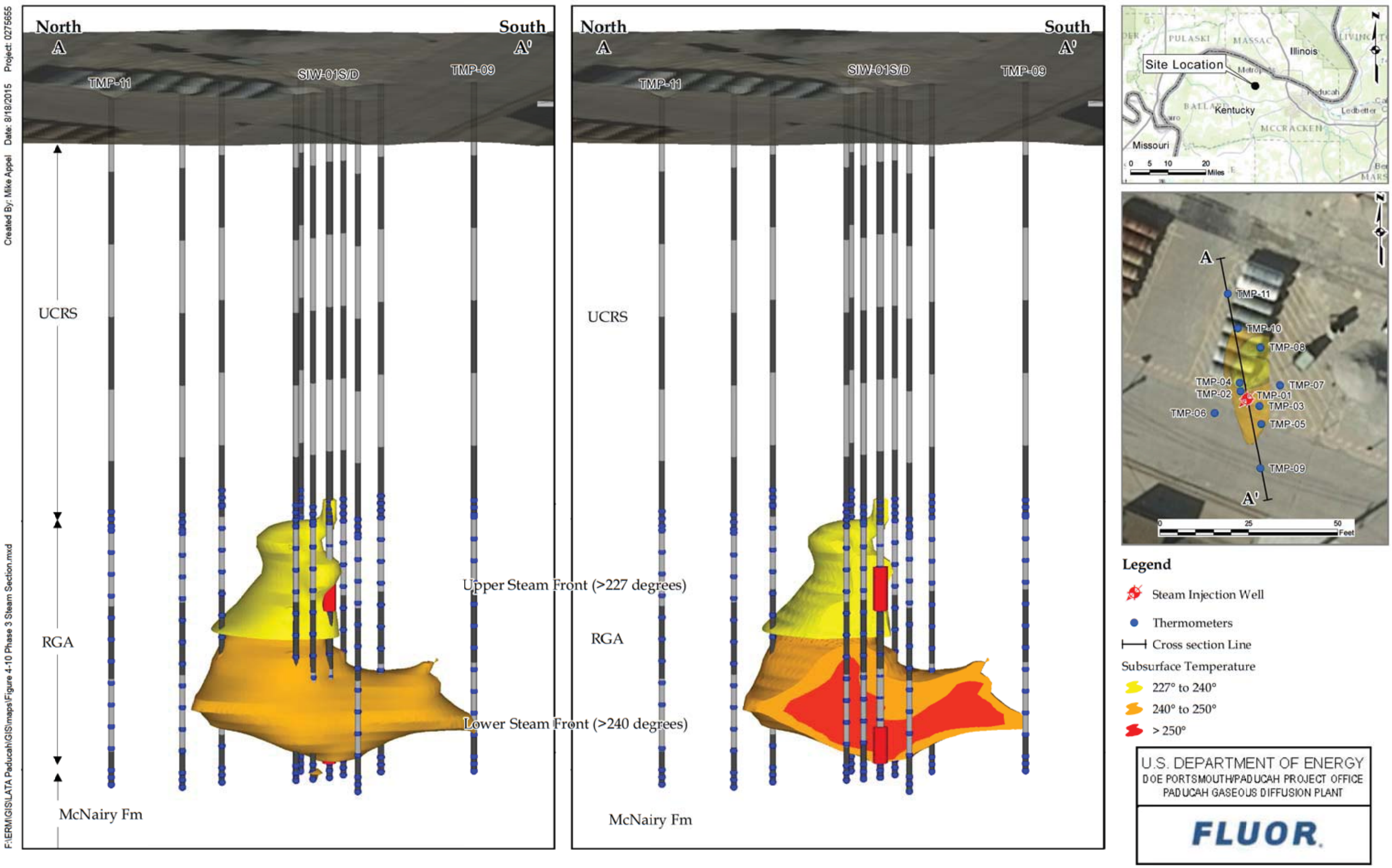

Figure 12. Day 20, Phase 3, Steam Front Extent—May 31, 2015

4.1.2.3 TOUGH2 Numerical Simulator

The simulations were performed using the TMVOC (Pruess and Battistelli 2002) version of TOUGH2 (Pruess et al. 1999). TOUGH2 is a 3D multiphase flow heat and mass transport code that was developed and refined at the DOE Lawrence Berkeley National Laboratory over the past 30 years. The code originated in the 1980s as a geothermal reservoir simulator and later was adapted for use in a variety of fields, including high-level nuclear waste isolation, enhanced oil recovery, environmental remediation of VOCs, and carbon dioxide sequestration. The models are written in FORTRAN, and the source code is publicly available from DOE. TOUGH2 currently is in use at more than 350 research laboratories, private companies, and universities in 40 countries. The results of scientific and engineering studies using the TOUGH2 codes have appeared in more than 500 refereed journal papers (http://esd1.lbl.gov/research/projects/tough/documentation/publications.html). A graphical user interface called PetraSim (http://www.thunderheadeng.com/petrasim/) was used to develop the input files for TMVOC and to process the output files.

The TMVOC module of TOUGH2 has a capability for simulating 1D, 2D, or 3D geometries using cylindrical, Cartesian, or unstructured grids, with the integral finite difference method. The model domain may be fractured or porous, heterogeneous and anisotropic, with various types of boundary conditions. The model simulates full multiphase (gas, aqueous, non-aqueous phase liquid) flow with relative permeability and capillary pressure effects. Each phase moves in response to pressure and gravitational forces, including buoyancy driven flows. Heat transfer occurs by multiphase convection of sensible and latent heat with thermal conduction. Multiphase thermodynamics include evaporation and condensation of water and multiple VOCs that may form a nonaqueous phase liquid. Multiphase contaminant transport occurs by advection and diffusion with retardation and first order decay in the aqueous phase.

The TMVOC code and its predecessors, M2NOTS (Adenekan et al. 1993) and T2VOC (Falta et al. 1995; Falta et al. 1992a), were used to simulate a variety of steam injection operations, ranging from the lab-scale (Falta 1990; Falta et al. 1992b; Falta 2001; Gudbjerg et al. 2004a; Gudbjerg et al. 2004b; Hodges et al. 2004; and Chen et al. 2012) to the field scale (Adenekan and Patzek 1994; Ochs et al. 2003; and Gudbjerg et al. 2005).

During a previous study, Falta (2013) found that the numerical performance (speed) was relatively poor compared to past experience on other problems. It later was determined that this was due to a numerical phenomenon identified and described by Gudbjerg et al. (2004b). During steam injection into cold water with high permeability, numerical pressure fluctuations can sometimes occur at the steam/water interface While these fluctuations do not affect the overall accuracy of the simulations, they dramatically can reduce the rate of numerical convergence, leading to very small time-steps, and poor numerical performance (Gudbjerg et al. 2004b; Gudbjerg et al. 2005). To alleviate this problem, the TOUGH2 code modification proposed by Gudbjerg et al. (2004b) was made to the TMVOC source code. This eliminates the pressure fluctuations, and it improved the speed of the simulations by a factor of 20 or more for some cases. The FORTRAN code modification is shown in Appendix E.

The TMVOC model users guide (Pruess and Battistelli 2002) contains a set of benchmark test problems. The slightly modified version of TMVOC used in this study was verified by rerunning these benchmark problems on the current computing platform used for this work.

4.1.2.4 Two Dimensional Modeling of the TS

2D RZ Simulations—Model Design. The 2D rz calibration simulations use a cylindrical model that is centered around a steam injection well with two screens. In the vertical direction, the model extends from the ground surface to a depth of 115 ft and it includes the UCRS, the RGA, and the upper part of the

McNairy unit. The ground surface is maintained at atmospheric temperature (20°C) (68°F) and pressure [1 atmosphere (atm)]. In the radial direction, the model starts at the center of the steam injection well borehole. The first grid block has a radius of 6 inches (corresponding to the borehole) and the grid extends to an outer radius of 328 ft. The outer lateral boundary and the model initial condition have a constant temperature of 20°C (68°F) and a water table at a depth of 57 ft, with the fluid pressures and saturations determined from gravity-capillary equilibrium. During the calibration process, the water table was raised several feet in order to match the observed hydrostatic pressure in the steam zone as reflected in the steam temperatures. The bottom boundary is a no-flow boundary. Figure 13 shows a scale cross-section of the rz grid. The 2D model has a total of 2,451 grid blocks, and simulations of the TS Phase 1 steam injection run in about 15 minutes. Simulations of all four phases require close to one hour of computer time.

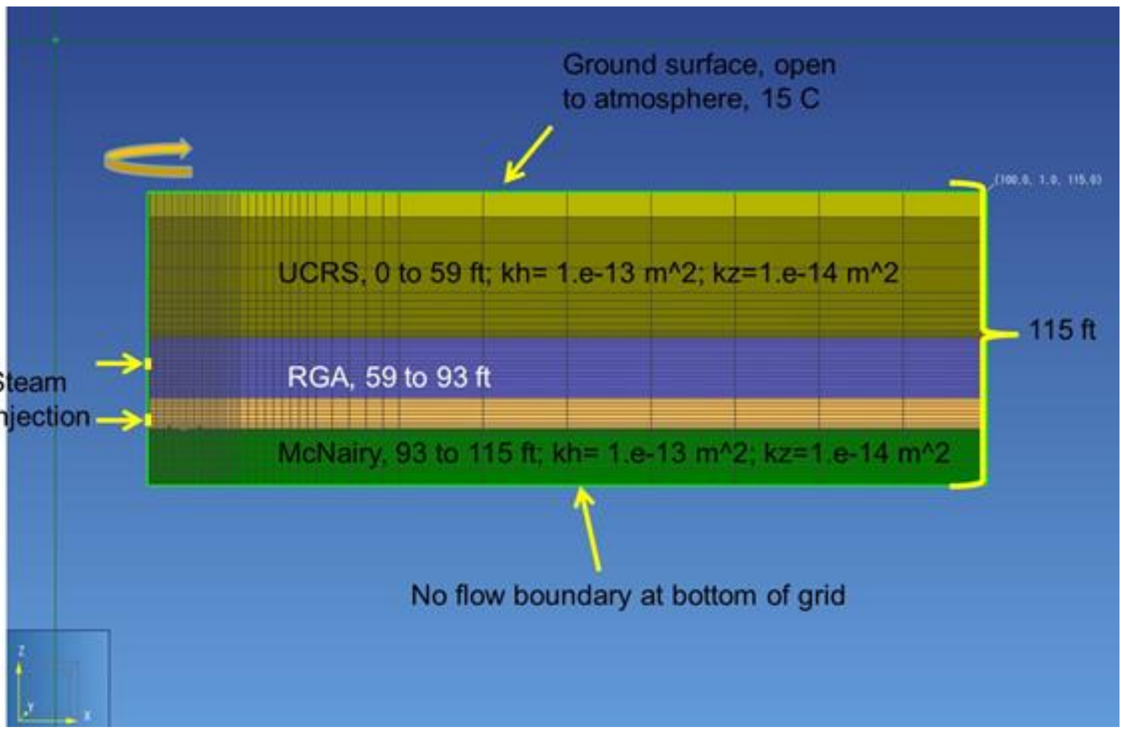

Figure 13. Cross-section of rz Grid Used in the TMVOC Simulations
(The grid is rotated around the left hand side to form a cylinder, and steam is injected into one or two locations at the radial center of the model.)

In the model, the UCRS extends from the ground surface to a depth of about 57 ft. The base of the UCRS/top of the RGA is slightly variable across the different TMP locations. The RGA extends from about 57 ft to about 93 ft bgs. The base elevation of the RGA also is slightly variable across the TMP locations. Figure 14 shows the TMP locations in the grid. Due to the assumption of radial symmetry, all of the TMP locations appear in one rz plane in this model. In Figures 13 and 14, the RGA has been divided into two layers: an upper zone, and a lower zone. Further details of the 2D model design are provided in Appendix E.

Initial simulations of the TS Phase 1 steam injection were performed as the steam injection was taking place in April 2015. It quickly became apparent that at least a two-layer configuration was needed to approximately match the field measured temperatures at the TMP locations.

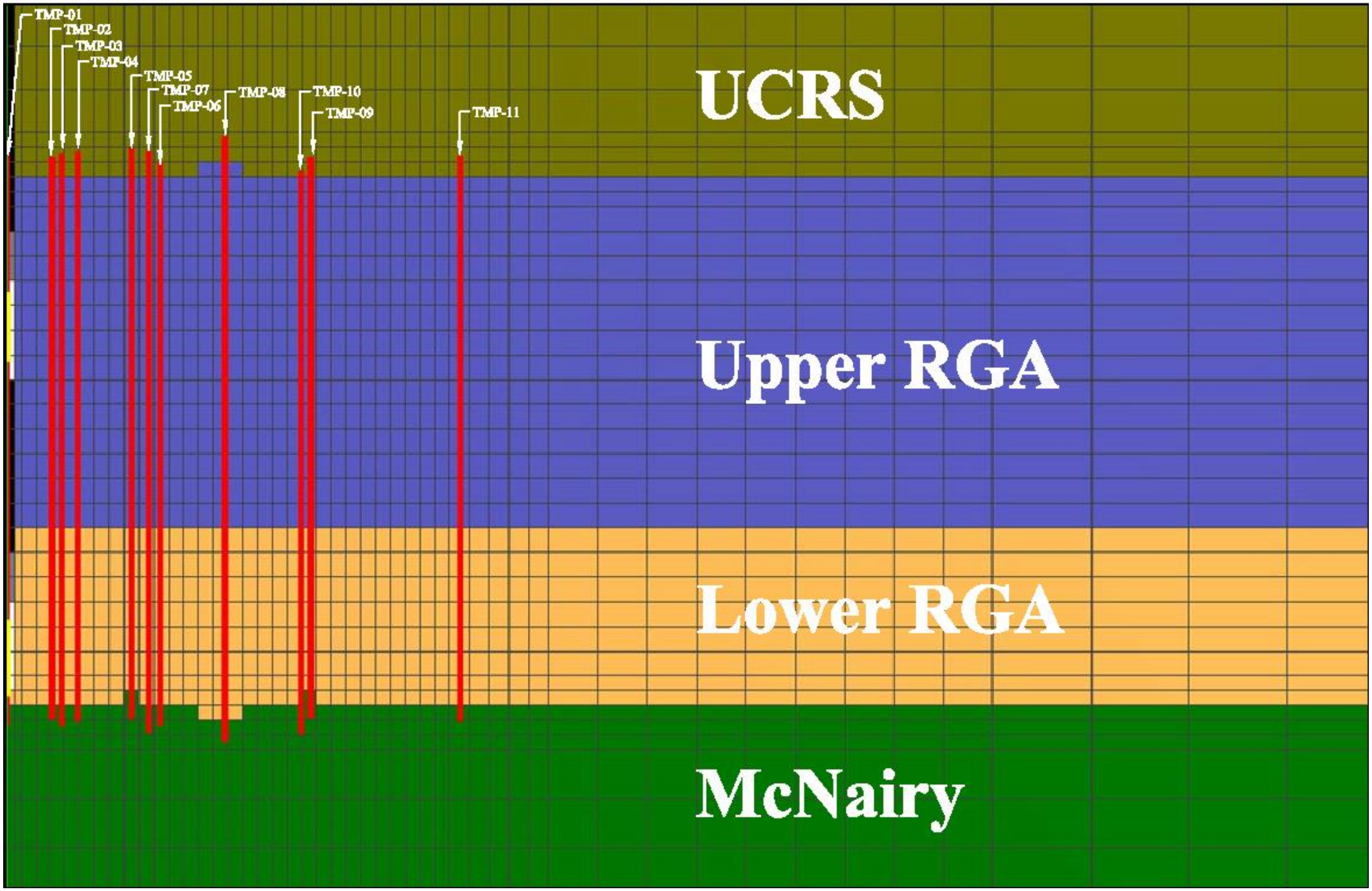

Figure 14. Cross-section of rz Grid Used in the TMVOC Simulations Showing the TMP Locations

2D RZ Simulations—TS Phase 1 Model Calibration. The 2D TS Phase 1 model calibration was performed during, and immediately following the TS Phase 1 steam injection (Appendix E). The model that was calibrated to the Day 4 steam injection temperatures provided a match to the 20 Day TS Phase 1 steam injection temperatures and was consistent with others produced during the later 2D calibration runs.

After performing more than 20 simulations, it was found that the best matches with the 2D rz model had a NRMSE of around 20%, which is somewhat larger than the NRMSE goal of 10% stated in the TS Design document (DOE 2014c). 3D simulations were conducted as discussed below that achieved an NRMSE of 11.6%. Figure 15 shows a comparison of the simulated and observed temperatures at the end of TS Phase 1 for a 2D simulation with a NRMSE of 21%. This model was the one that originally was calibrated during the fourth day of steam injection. Subsequent 2D rz modeling efforts for TS Phase 1 did not improve on this model substantially.

This model uses a two layer structure for the RGA, as shown in Figures 13 and 14. The upper part of the RGA in this model has a horizontal hydraulic conductivity of 100 ft/day and an anisotropy ratio of 20:1. The lower part of the RGA has a horizontal hydraulic conductivity of 300 ft/day and an anisotropy ratio of 30:1.

The 2D model closely matches several of the TMP locations such as TMP 3, 4, and 7, and generally matches TMP locations 1, 2, and 8. This model, however, generally does not match with locations 5, 6, 9, 10, and 11 due to the effects of lateral heterogeneities that cannot be accounted for in the radially symmetric 2D model.

These field data indicate that the steam flow is not radially symmetric. For example, both TMP 6 and TMP 7 are located 10 ft from the steam injection well, but they show very different temperature responses. Similarly, both TMP 9 and TMP 10 are located 20 ft from the injection well, but they also show different temperature responses. Due to the asymmetry of steam flow, a 3D model was used for the final model calibration and model validation. This second calibration effort is summarized in Section 4.1.2.5 and is described fully in Appendix C.

2D RZ Simulations—TS Phase 1, 2, and 3 Model Calibration. The 2D model described above (which was developed on Day 4 of TS Phase 1) was used during the TS to predict the future performance of the TS Phase 1 steam injection, the TS Phase 2 cool down, and the TS Phase 3 steam injection. This model generally predicted all of TS Phase 1, the TS Phase 2 cool down, and the early part of the TS Phase 3 lower steam injection. However, as the TS Phase 3 injection continued, it became apparent that the original base rz model was starting to overpredict the amount of vertical steam migration from the lower zones.

Based on these observations, the model was rebuilt in an effort to match the temperature profiles during all three phases. A total of 15 parameter combinations were tested. The key feature that was required in order to match the TS Phase 3 temperature data were the inclusion of a thin layer of cemented, lower permeability material at the top of the lower RGA high permeability zone. In the model, this layer is 1.6-ft thick, and it has a horizontal hydraulic conductivity of 1.5 ft/day, with an anisotropy ratio of 10:1. This revised 2D model matches the TS Phase 1 data with accuracy similar to the original model, but it does a much better job of simulating the TS Phase 3 behavior (Appendix E). However, as in the earlier 2D model, the effects of lateral heterogeneity prevent a better match of the field data with the 2D radially symmetric model.

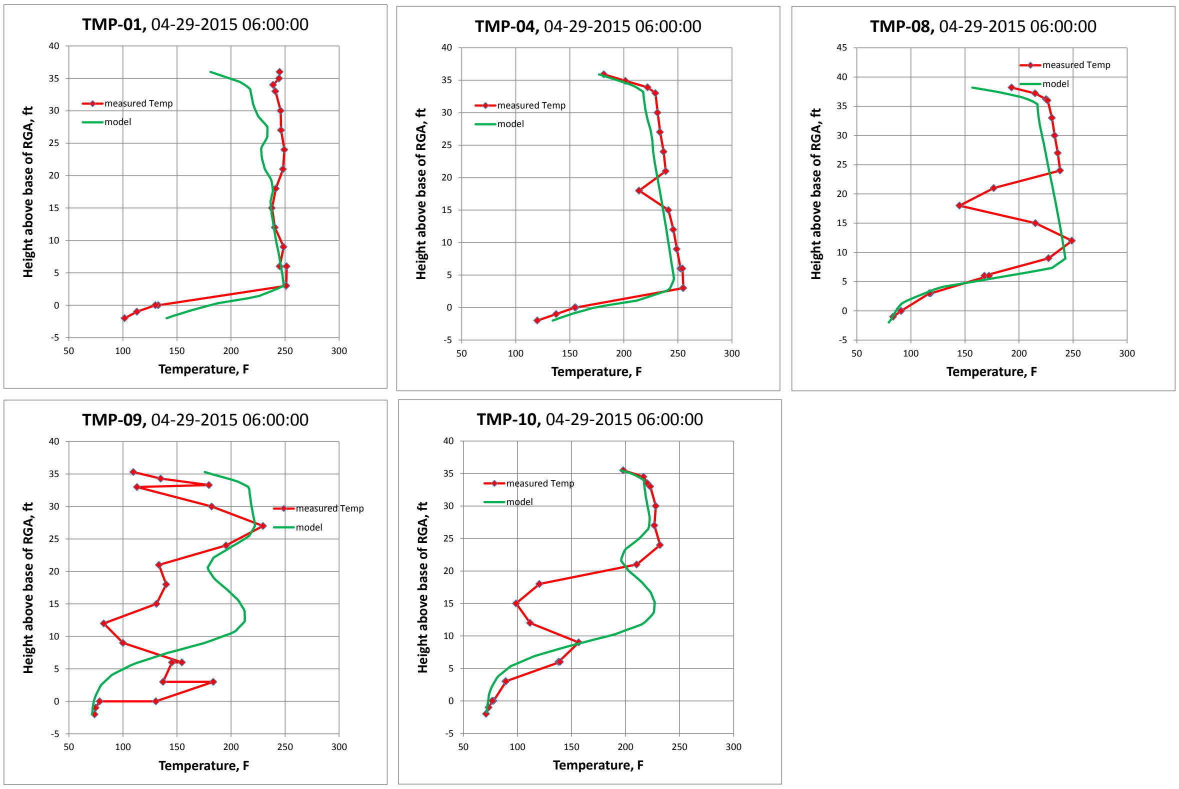

Figure 15. Comparison of Simulated and Observed Temperatures at the End of TS Phase 1 Using the Radially Symmetric 2D Model
(The other 6 TMP matches are shown in Appendix C.)

4.1.2.5 Three Dimensional Modeling of the TS[6]

3D Model Process. A total of 11 full-scale 3D simulations was performed. The first eight model simulations used a small well pattern (but with the same well spacing) consisting of 15 shallow and 15 deep steam injection wells, and 11 DPE wells. Various numerical treatments of the extraction wells were tested during the first five simulations to develop the most realistic modeling approach.

The initial simulation had 22,600 elements and used the TOUGH2 DELV model feature for simulating the DPE wells. The DELV approach is used widely to simulate flow to wells under a pressure constraint. With the DELV model, a downhole well pressure at the top of the screen is specified, along with a flow resistance term called the productivity index. Fluids then flow from the gridblock into the modeled well according to the multiphase Darcy's law using the difference in the gridblock and well pressure. When a well is screened over a series of gridblocks (as in this case), the DELV well model needs to perform a flowing gravity calculation to determine the vertical pressure distribution in the wells, based on the fluids that are flowing into the well.

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[6] The 3D figures presented in these sections are screenshots from the modeling software simulations. These screenshots are provided as visual aids to assist the reader with interpretation of the theoretical model(s).

The DELV well model normally works well for simulating soil vapor extraction (SVE) or water wells, but in this first simulation, the DPE wells were removing far too much water (hundreds of gpm). This occurred as steam vapor reached the DELV wells, the average density of fluids in the wellbore decreased, leading to a lower wellbore pressure along the well. This calculated pressure was much lower than hydrostatic, allowing the large water flow to occur.

In the second simulation, several strategies were tested for correcting the DELV model well treatment of the DPE wells, but none of these attempts produced a realistic water extraction rate. It also was observed that the simulation run times were long, in the range of 7 hours per simulation.

A smaller numerical grid with 14,000 elements was developed in the third simulation, and an alternate modeling approach was tested for DPE wells. This new approach uses high hydraulic conductivity columns to represent DPE wells. In locations above the well screen, the high conductivity column is surrounded by very low conductivity material to seal the wellbore. Then the DELV condition for SVE is applied at the very top of the simulated well. This approach was found to reliably simulate the SVE and removal of steam vapor from locations below the water table without the unrealistic water flow.

The fourth simulation added a small amount of water pumping from the bottom of DPE wells using a single element DELV approach. This was found to be stable and realistic. At this point, the model had a simple layer, heterogeneity structure and a flat water table, with steam injection rates of 500 pph in both the upper and lower screens. Simulation run times still were long, about 5 hours.

The fifth simulation included 3D heterogeneity in the model. This model ran well and produced good results, but the long run time (5 hours) was hindering the ability to test different steam configurations.

The sixth simulation used a new numerical grid with 8,700 elements. This model continued to simulate the small well pattern (15 steam locations and 11 DPE locations) with 500 pph of steam in the upper and lower screens for 40 days. This model also included 3D heterogeneity that was patterned after the calibrated 3D TS model. This simulation showed relatively good heating of the upper RGA, but some zones along the base of the RGA were not heated to steam temperatures. The overall heated zone with this simulation is substantially smaller than the final simulation shown in the report due to the smaller well pattern.

The seventh simulation continued with the same grid and heterogeneity, but altered the steam injection rates to 300 pph in the upper screens and 700 pph in the lower screens in an effort to improve the sweep of the lower RGA. While this helped a little, parts of the base of the RGA still failed to reach steam temperature in this simulation.

The eighth simulation increased the steam injection rates to 500 and 1,000 pph in the upper and lower screens using the same numerical grid and well pattern. This produced a much more effective steam sweep along the base of the RGA. These steam rates were consistent with the rates used in the TS, and appear to be the minimum injection rates that produce complete heating of the base of the RGA with the selected well spacing (approximate radius of influence of 20 ft).

At this point, it was decided by the project team that a larger treatment zone pattern should be evaluated. The size of the pattern and number of wells more than doubled to consist of 31 upper and lower steam injection wells, and 26 DPE locations. This required generating a new grid to achieve high resolution around the new wells. The new grid had 10,200 elements, and 3D heterogeneity was added, as had been done previously. This ninth simulation ran the steam injection wells at 500 and 1,000 pph in the upper and lower injection wells for 20 days, and then reduced this rate to 250 and 500 pph for an additional 70 days. This simulation showed effective heating of the lower RGA for the larger treatment zone.

For the simulation 10, the project team decided to reduce the size of the treatment zone slightly, with 27 upper and lower steam injection locations, and 23 DPE locations. This model used the same numerical grid as before, but with fewer wells. The steam injection rates were the same as in the ninth simulation. The results were similar to the previous simulation, except the heated zone was smaller due to the smaller pattern size.

The final simulation (#11) was presented in the report. This simulation uses 23 steam injection locations and 17 DPE locations that were selected by the project team. This model uses the same numerical grid and steam injection rates as simulations #9 and #10, and produces similar results. The only significant difference in the last 3 models was the well pattern, which was adjusted among simulations in response to project team decisions.

3D Calibration—Model Design. A 3D model of the TS was built in order to account for the effects of lateral heterogeneity and regional groundwater flow on the steam flow and cool down patterns. The initial model was based on the layered structure of the 2D model described above. The model grid, shown in Figure 16, extends from the ground surface to a depth of 115 ft, and it has horizontal dimensions of 120 ft on a side. The rectangular model volume is oriented so that it is parallel to the regional groundwater flow direction (DOE 2014c).

The 3D model was developed by building geologic layers that correspond to the UCRS, the RGA, and the upper part of the McNairy. The ground surface was assumed to be flat, but the top and bottom surfaces of the RGA were interpolated and extrapolated using the well logs from each of the 11 TMP locations. Both surfaces undulate slightly, with elevation changes of about 1.5 ft across the TMP array. The model is centered around the steam injection wells (Figure 17), and it extends well beyond the steam zone in the test.

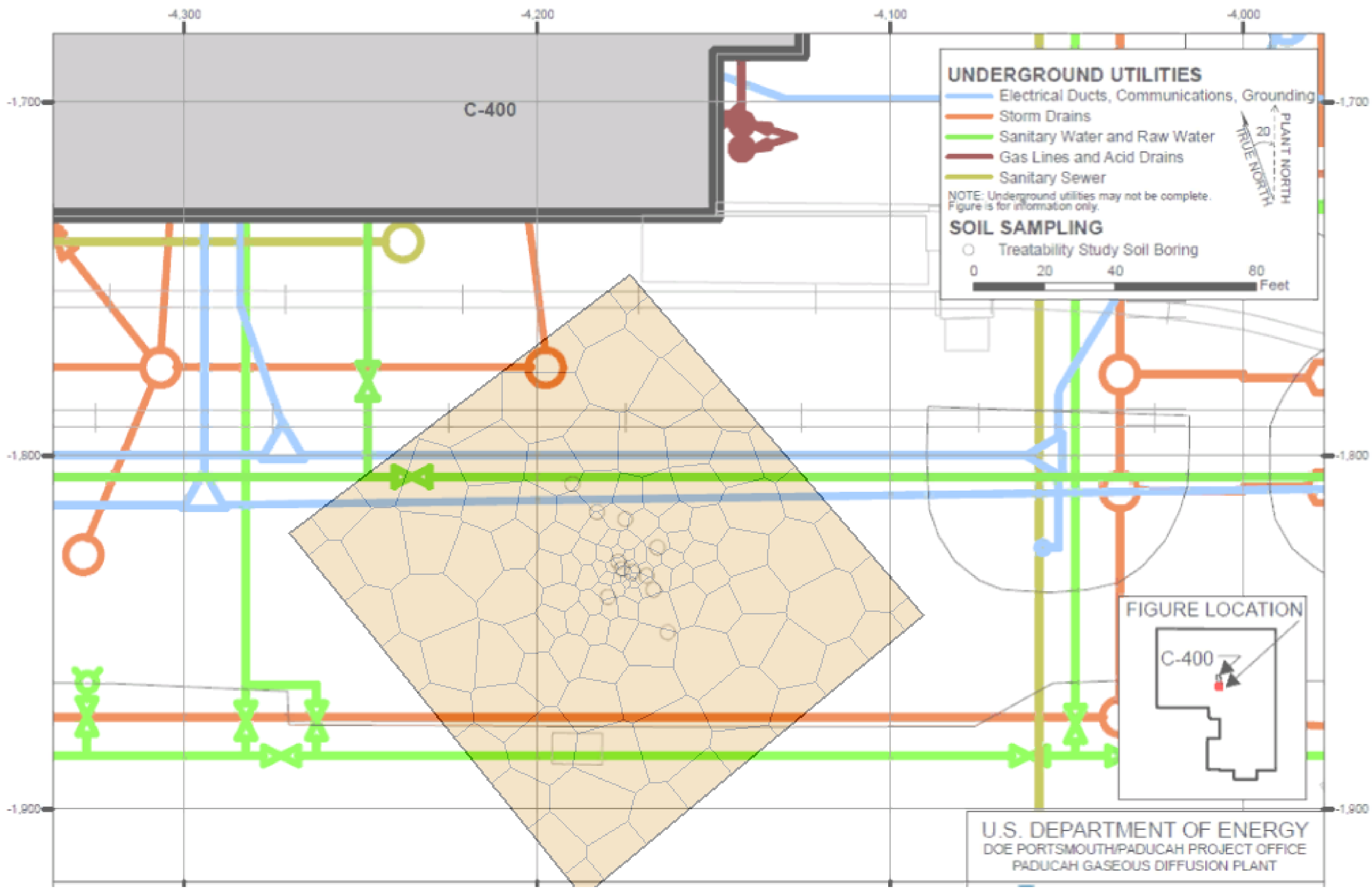

Figure 16. Top View of the 3D Model Used to Simulate the Treatability Study

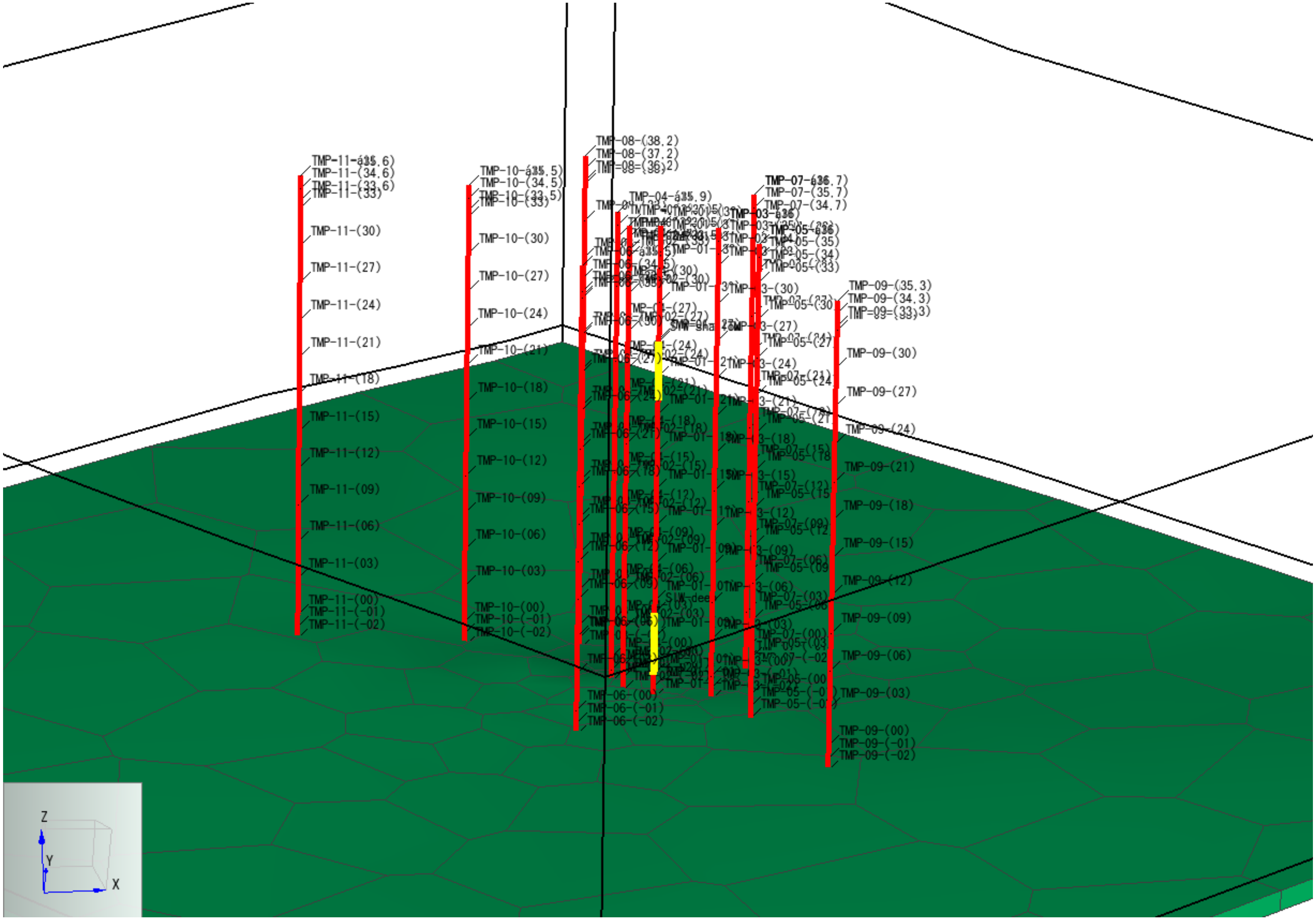

Figure 17. Perspective Cutaway View of the 3D Model from Plant South Showing the 188 Temperature Monitoring Point Locations
(The steam injection well screens are shown in yellow.)

The model contains 26 layers, with a vertical spacing that is slightly coarser than the 2D rz model. In the horizontal dimensions, the model is discretized using Voronoi polygons (Thunderhead Engineering 2015). The Voronoi polygons allow for a fine model discretization near the steam injection wells, with coarser discretization as the model boundaries are approached. The overall model contains 3,432 grid blocks, and typical simulations of the entire TS require about 30 minutes of computer time.

The initial and boundary conditions for this model are similar to the 2D rz model, except that this model includes a regional hydraulic gradient from the southeast to the northwest. The top of the model is maintained at atmospheric temperature and pressure [20°C (68°F) 1 atm], while the bottom is a no-flow boundary. The regional hydraulic gradient in this area has been observed to range from a minimum of 1.79×10^{-5} to a maximum of 6.10×10^{-4} (DOE 2014a). The gradient is largely controlled by the stage of the nearby Ohio River. During the early part of the TS, the river was in near flood stage, so gradients would have been minimal at C-400. During the latter part of the TS, the river stage was low, and hydraulic gradients would have been near the higher part of the range (USGS 2015).

The hydraulic gradient was implemented in the model by fixing the water table at the appropriate elevations at either end of the model (assuming gravity-capillary equilibrium for the water pressure and saturation above the water table). A steady-state groundwater flow simulation then was performed with no-flow boundaries on the sides of the model parallel to flow. The results of this steady-state groundwater flow model were then used for the model initial conditions. The outer lateral boundary conditions are fixed in time, and consist of the fluid pressures and saturations determined from the steady state flow simulation, with gravity-capillary equilibrium.

3D Calibration—Model Calibration. The model calibration was performed by trial and error, adjusting the 3D distribution of permeability to minimize the root mean square of difference between the simulated and measured TMP temperatures at the end of the TS Phase 1 steam injection. As would be expected, it was necessary to include substantial volumes of lower permeability material around the TMP locations that showed reduced heating (e.g., TMP 6 and some locations around TMP 5, 9, 10, and 11). The TS Phase 1 simulations were performed using the minimum observed hydraulic gradient due to the fact that the Ohio River was near flood stage during this time.

Sixteen 3D calibration simulations were performed to minimize the error between simulated and observed temperatures. The best simulation had a NRMSE of 11.6%. For comparison, the 2D rz model of TS Phase 1 had a NRMSE of 21%. The simulated and observed temperature profiles at the end of TS Phase 1 are shown in Figure 18, and additional details of the model calibration process are given in Appendix E.

Calibrating the 3D model required adding substantial zones of lower hydraulic conductivity material in some areas of the model. The basic hydrogeologic structure from the 2D rz model was modified mainly through the addition of these localized, discontinuous zones of lower conductivity. Figures 19 and 20 show southeast-northwest and southwest-northeast cross sections through the calibrated model. The grey material in these figures represents a lower conductivity sand or silty sand, with a horizontal conductivity of 1.5 ft/day. The tan material and the light blue material represent the main lower and upper RGA gravels, with horizontal hydraulic conductivities of 300 ft/day and 100 ft/day, respectively. The anisotropy ratio for the fine sand is 10:1, while the anisotropy ratios for the lower and upper RGA gravels are 30:1 and 20:1 as before.

The calibrated model described above was used to simulate the entire TS. The model matches the TS Phase 3 temperature profiles (NRMSE = 13.6%), but the match with the temperature profiles at the end of the two cool down periods (Phases 2, and 4) is not as good with NRMSE values of 17.9% and 21.2%,

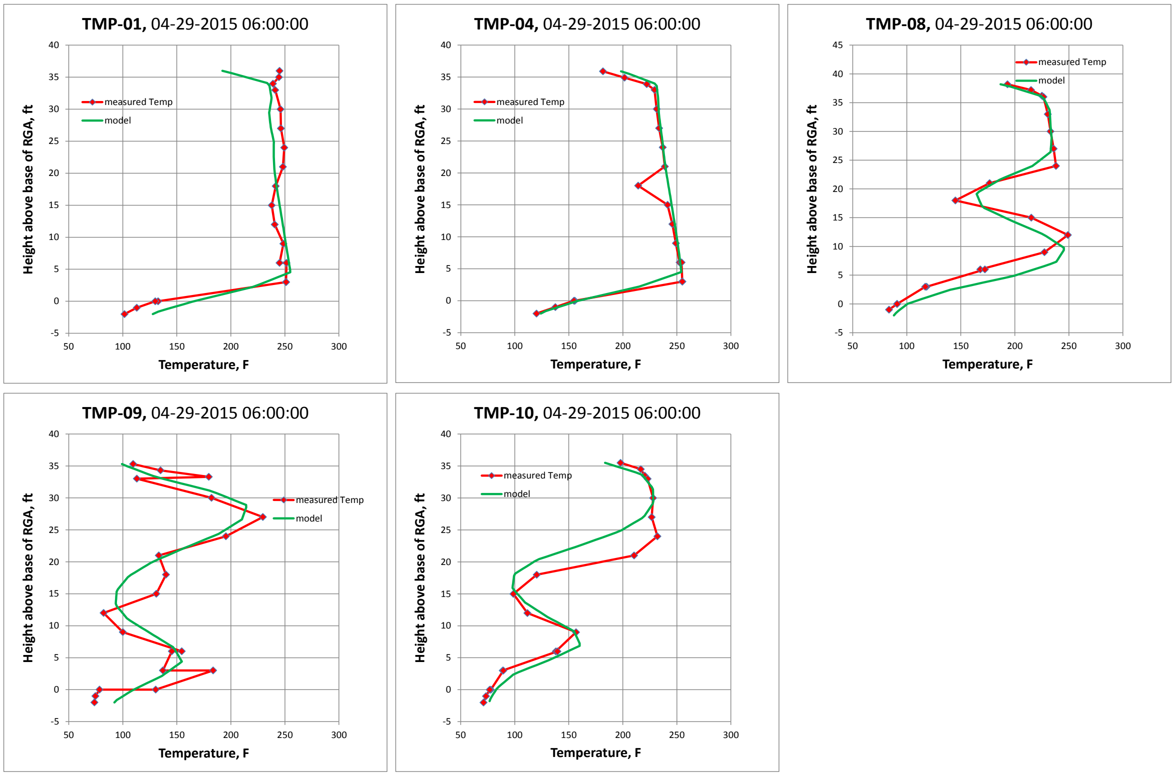

Figure 18. Comparison of Simulated and Observed Temperatures at the End of TS Phase 1 Using the 3D Model

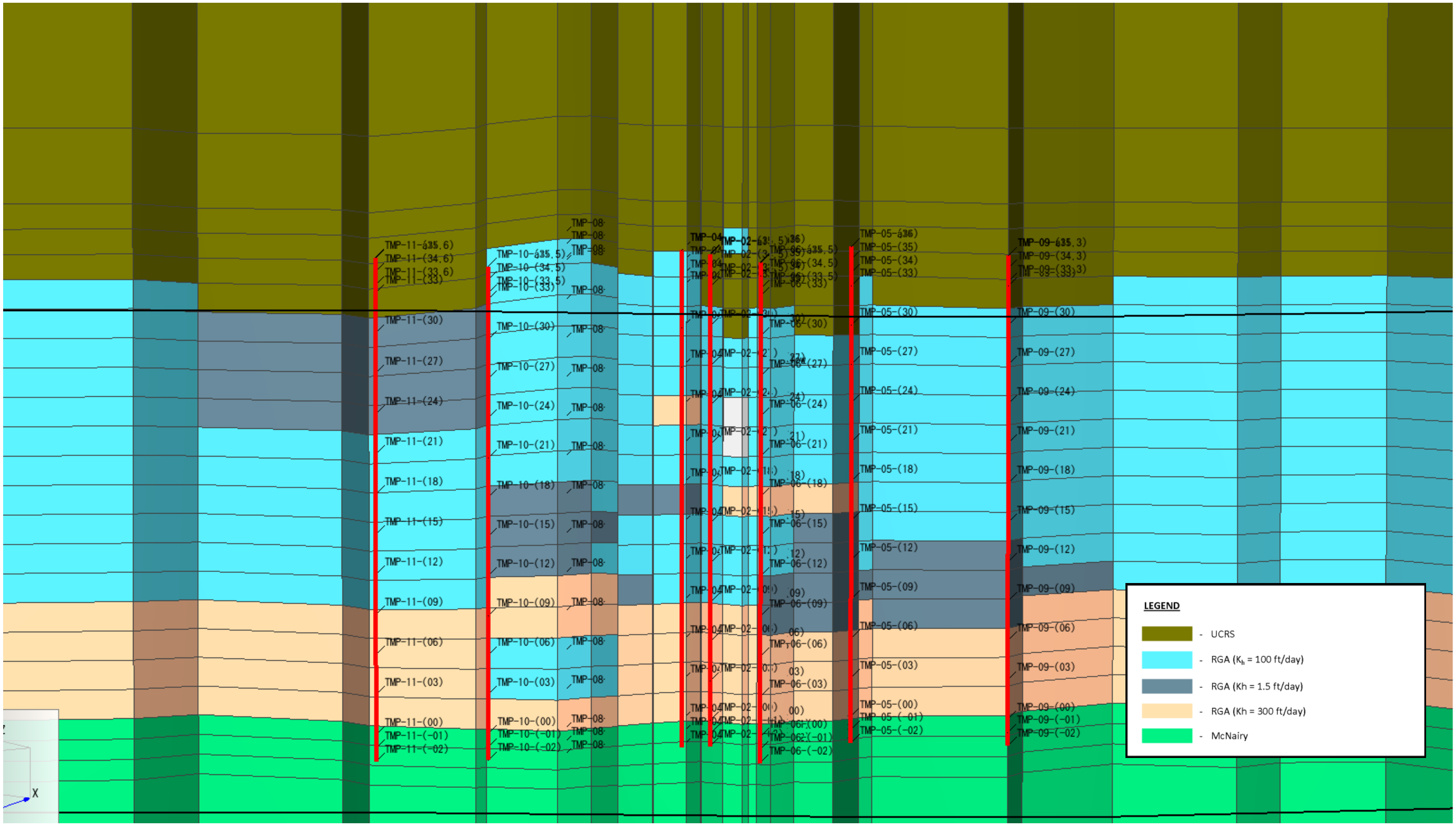

Figure 19. Southeast-Northwest Cross Section through Model
(The grey material represents a fine sand or silty sand with a horizontal hydraulic conductivity of 1.5 ft/day.)

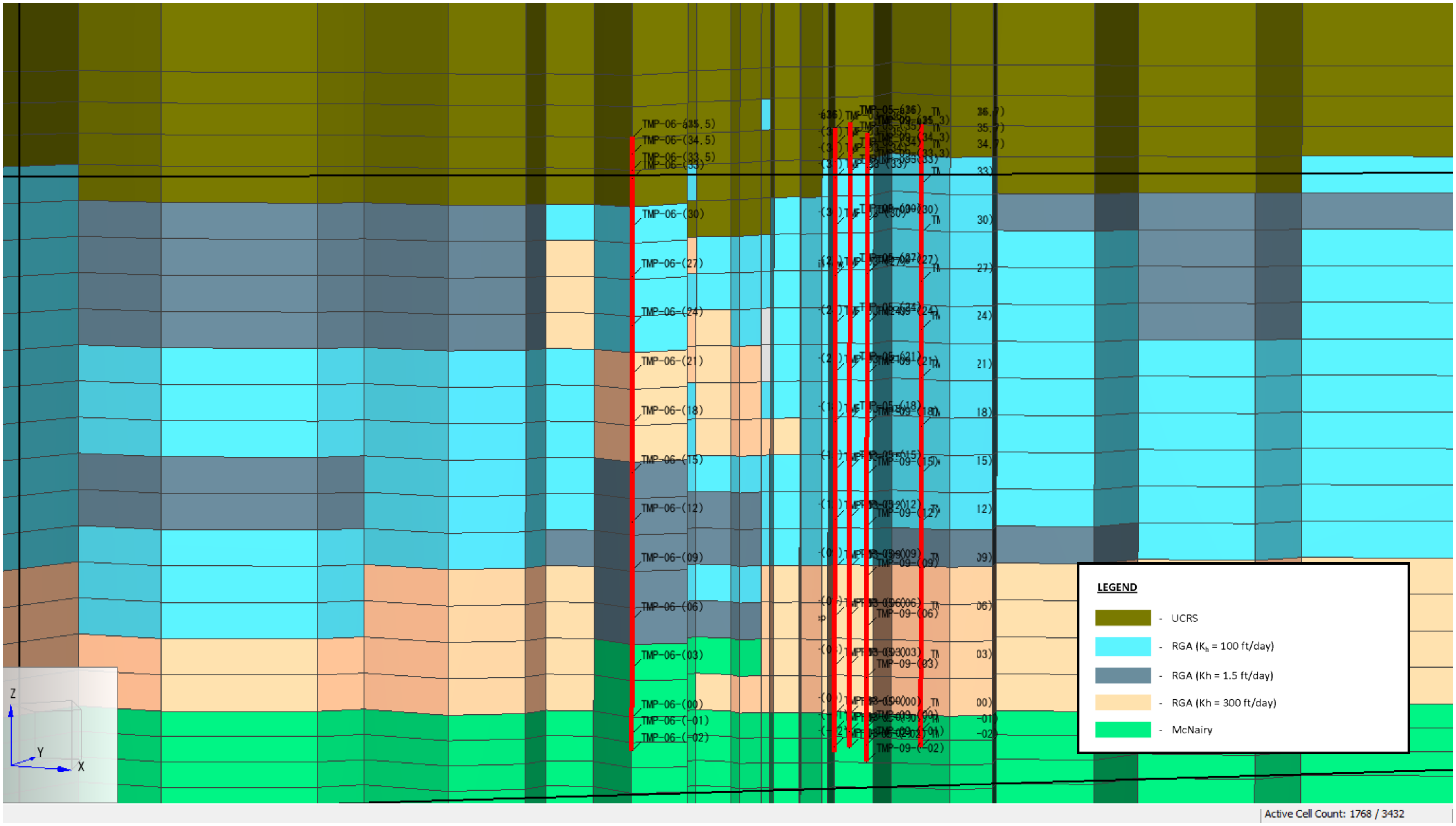

Figure 20. Southwest-Northeast Cross Section through Model
(The grey material represents a fine sand or silty sand with a horizontal hydraulic conductivity of 1.5 ft/day.)

respectively. Because this simulation used the minimum observed hydraulic gradient of 1.79×10^{-5}, a second simulation was performed with the same model, but using the maximum observed hydraulic gradient of 6.10×10^{-4}. This second 3D model matches the TS Phase 1 and TS Phase 3, temperatures with an accuracy similar to the low gradient model (NRMSE = 12.2% and 13.5%, respectively), but it does a somewhat better job of matching the TS Phase 2 and TS Phase 4 cool down periods with NRMSE values of 16.5% and 18.1%, respectively. Model comparisons with the measured temperature profiles near the end of TS Phase 3 are shown in Figure 21.

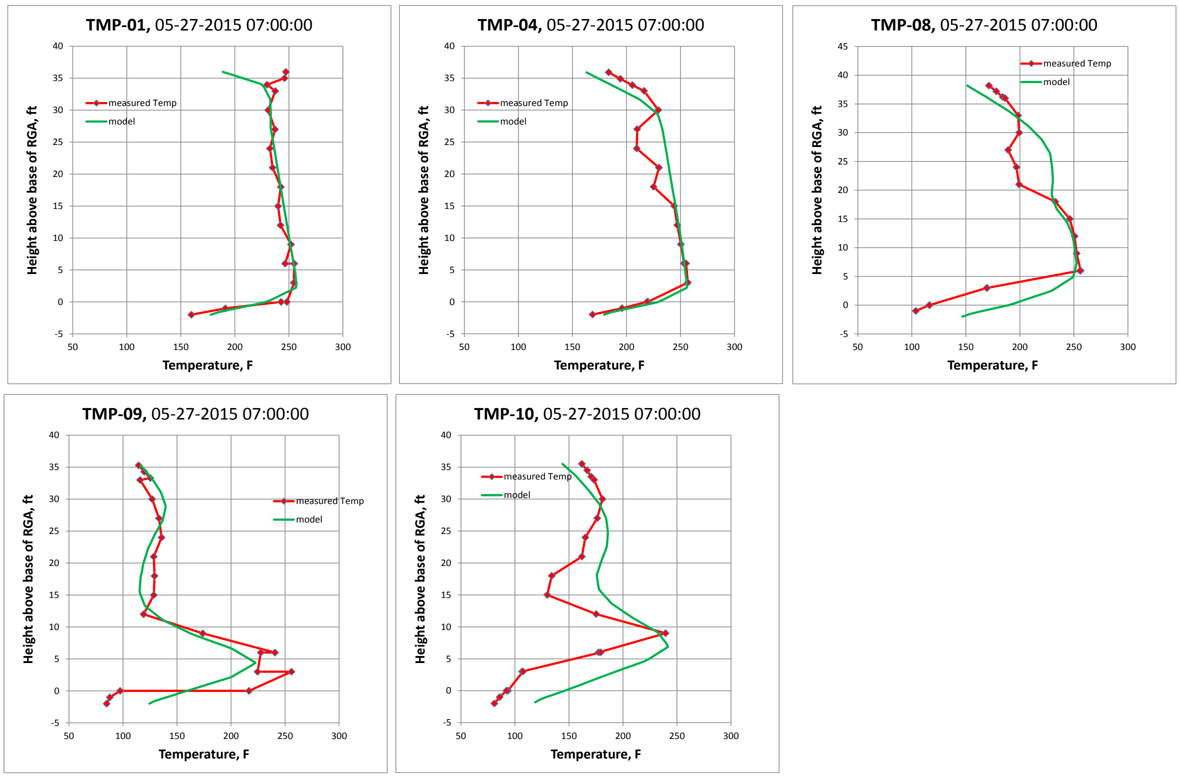

Figure 21. Comparison of Simulated and Observed Temperatures near the End of TS Phase 3 Steam Injection Using the 3D Model
(The other 6 TMP matches are shown in Appendix C along with results for other times.)

The relatively poorer match during the cooldown phases suggests that the assumptions related to water flow past the site may be underestimated, and that somewhat more heat might be lost during the cooldown period than predicted. It also is noted that a laterally displaced plume of hot water was not observed in the TMP data.

The simulation run with the maximum hydraulic gradient shows that the regional groundwater flow has very little effect on the development of the steam zone during steam injection. When steam injection stops, the steam zone quickly (over a matter of a couple days) collapses back into liquid water, causing a rapid radial inflow of cold groundwater. The steam zone collapse tends to occur from the bottom of the steam zone towards the top. Once the steam zone has collapsed, the entire system is once again in a single phase liquid water condition. At this point, there are still very significant temperature variations within the system (nearly 80°C or 176°F). These temperature variations result in water density differences of up to 40 kilograms per cubic meter.

It can be shown that the form of Darcy's law that applies to buoyancy flow is driven by the density contrast divided by the magnitude of the density (Falta et al. 1989). During the steam collapse period, the density contrast between the steam and liquid water is equivalent to a hydraulic gradient of one, which is thousands of times larger than the regional hydraulic gradient. Following collapse, the density difference between the hot and cold groundwater is equivalent to hydraulic gradient of 0.04, which is about 100 times larger than the regional hydraulic gradient. The regional flow does appear to affect the heat plume slightly during the cool down phases, moving the hot water downgradient by a few feet during the cool down period.

3D views of the steam zone at the end of TS Phase 1 and 3 are shown in Figures 22 and 23. These results were calculated using the 3D model that includes the maximum regional gradient. The iso-surface in these figures corresponds to a gas phase saturation of 20%; much higher gas saturations (up to 70%) occur inside the steam zone.

4.1.2.6 Three Dimensional Modeling of Full-Scale Steam Injection Design Concept

Full-Scale Design Simulations—Introduction. 3D numerical simulations were performed to help evaluate the likely behavior of SEE in the RGA at the C-400 area at PGDP site. These simulations build on the data and calibrated numerical model of the Phase IIb Steam Injection TS. The RGA formation properties determined during the TS model calibration effort were used to develop two types of 3D models of SEE for treatment of the RGA.

The first type of 3D SEE model assumes that the symmetry of an idealized repeating pattern of injection and extraction wells can be approximated with a much smaller model of an internal part of the pattern. This approach, which is widely used in petroleum reservoir engineering, is known as a "quarter five-spot" model. The quarter five-spot model approximately accounts for multi-well effects through the symmetry no-flow boundary conditions on all lateral sides of the model. This type of model is much easier to set up and run than a true full-scale model, but it cannot simulate some important effects, such as the inflow of cold groundwater on the edges of the steam injection pattern.

The second type of 3D SEE model is a comprehensive model of the entire remediation site, including all steam injection and DPE wells. This model extends well beyond the treatment area, and groundwater may flow freely into or out of the steam zone, depending on the flow dynamics. The major disadvantage of the full 3D SEE model is that it is very time-consuming to set up and run. Typical simulation run times for the models that are presented here were around 5 hours, compared to about 10 minutes for the quarter five-spot simulations.

It is useful to consider the mechanisms by which TCE will be removed during steam injection. While it is well known that TCE is effectively removed from the steam vapor zone, it also may be possible to achieve effective TCE DNAPL removal from zones that are hot, but are not directly contacted by the steam. This removal can occur due to the phenomenon of co-boiling at a target temperature of 95°C (203°F).

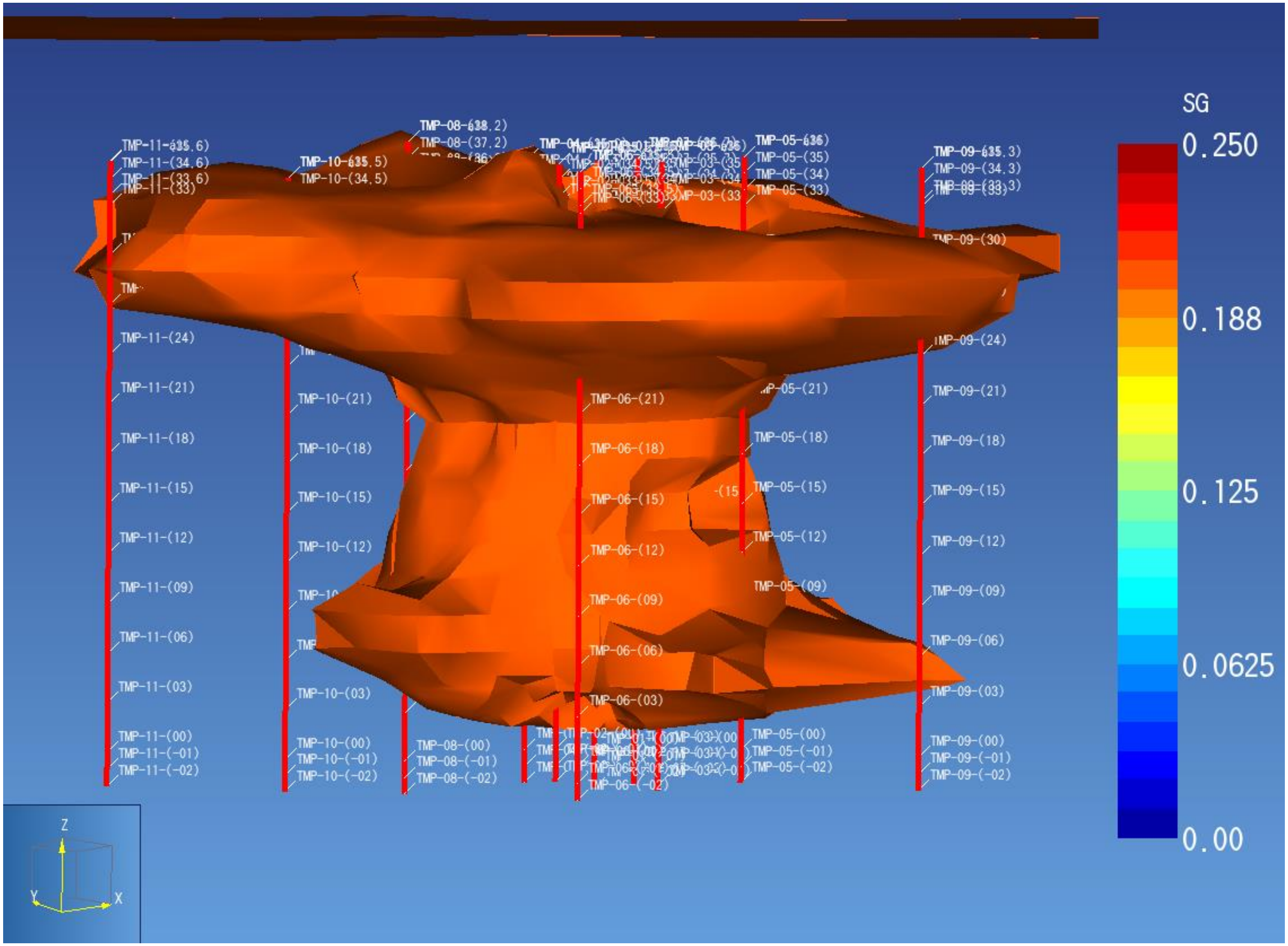

Figure 22. Simulated Steam Zone at the End of TS Phase 1 Steam Injection

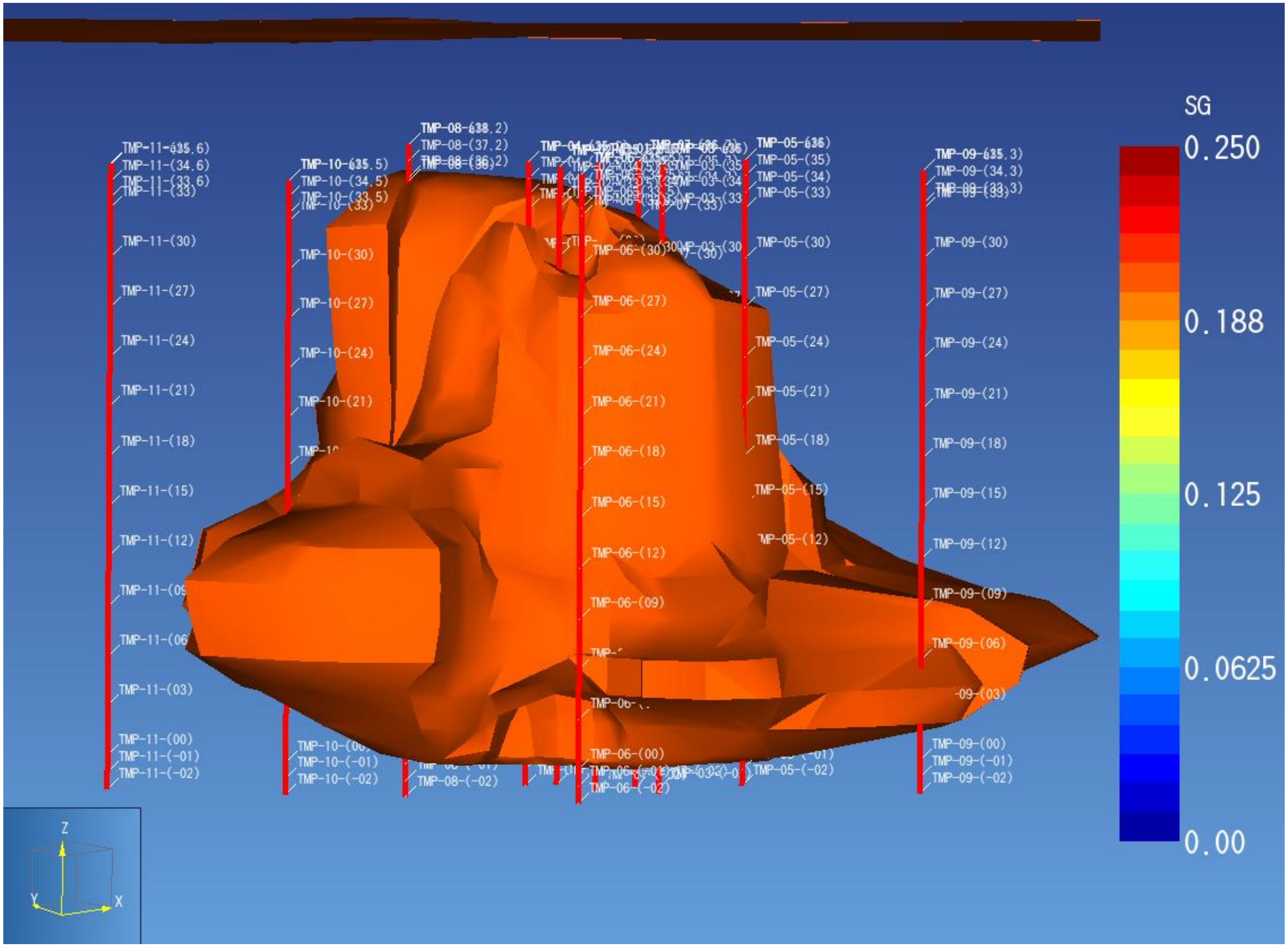

Figure 23. Simulated Steam Zone at the End of Phase 3 Steam Injection into the Lower Screen

When two separate phase liquids are present (DNAPL and water), the vapor pressures of the two liquids are additive. When the sum of the vapor pressures exceeds the total pressure, boiling occurs. Because both liquids contribute to the overall gas pressure, the co-boiling temperature for a given total pressure is less than the boiling point for either liquid (DeVoe and Udell 1998; Burghardt and Kueper 2008; Martin and Kueper 2011; Kingston et al. 2014). Considering TCE DNAPL and water, at a pressure of 1 atm, co-boiling occurs at about 73°C (163°F). At higher hydrostatic pressures, the co-boiling temperature increases, but it is still around 25°C (77°F) lower that the boiling point of water. The base of the RGA is located about 35–40 ft below the water table. At this hydrostatic pressure the normal water boiling point is about 122°C (252°F), but the TCE DNAPL/water co-boiling point is only about 95°C (203°F) (Kingston et al. 2014). Therefore, even if steam does not directly contact the DNAPL, as long as the temperature exceeds the target temperature of 95°C (203°F), the DNAPL will vaporize.

Gudbjerg et al. (2004a) demonstrated removal of TCE DNAPL by this mechanism in the laboratory, and concluded that it was an effective mechanism for TCE DNAPL recovery from the boundaries of the steam zone. While co-boiling will vaporize DNAPL, removal of dissolved TCE likely requires direct contact with steam (Chen et al. 2010). As discussed below, a full-scale implementation strategy would use variations of injection and extraction rates in response to real time temperature data to maximize the heating effectiveness and consequently the mass removal.

Full-Scale Design Simulations—Quarter five-spot simulations. Most applications of SEE involve multiple steam injection and extraction wells. With multiple injection and extraction sites, there can be positive interactions between the wells that help limit steam override. Simulation of these flows generally requires a 3D approach, and one approach is to model the entire pattern of steam injection and extraction wells. The full simulation approach is the most comprehensive and realistic, but these types of models are relatively time-consuming to set up and run.

A simpler modeling approach that can capture some of the key physical processes involves using symmetry elements to reduce the size of the model. This modeling approach, which is used widely in petroleum and geothermal reservoir simulation, assumes that the fluid injection and extraction wells are placed in a regular repeating pattern, and that all of the injection wells and extraction wells are operated in the same manner. Figure 23 shows a typical well pattern called a “five-spot,” where the injection wells and the extraction wells are located on a square grid with constant spacing. Each extraction well is surrounded by four injection wells. This repeated pattern gives rise to a symmetry that allows interior portions of the treatment area to be modeled using a smaller symmetry element. The most commonly used symmetry element in thermal and oil recovery models is a quarter of a single five-spot pattern (Figure 24).

With the quarter five-spot model, all of the lateral boundaries are no-flow, due to the symmetry of flow. The injection well is simulated by injecting one-fourth of the full well rate, while flows that leave the extraction well are multiplied by 4 to get the full well rate. In the vertical direction, the model retains the same structure as the calibrated 3D model of the TS. The heterogeneity required to calibrate that model was recreated in a generic way for this quarter five-spot model. At each elevation, fine-grained zones of similar dimensions and spacing to those observed in the calibrated TS model were included.

A scale model of the simulation domain is shown in Figure 24. The vertical layering, discretization, initial conditions, and top and bottom boundary conditions are identical to the calibrated 3D TS model described earlier. In the horizontal plane, the model has dimensions of 19 ft by 19 ft, so that the distance from corner to corner (injection well to extraction well) is 26.9 ft. This is equivalent to a repeated pattern where each steam well is located 38 ft from its neighbors, and each extraction well is located 38 ft from its neighbors. The 19 ft by 19 ft horizontal plane is divided into 7 elements in each direction, for a total of 49 elements per grid layer. The overall 3D model has 1,274 elements.

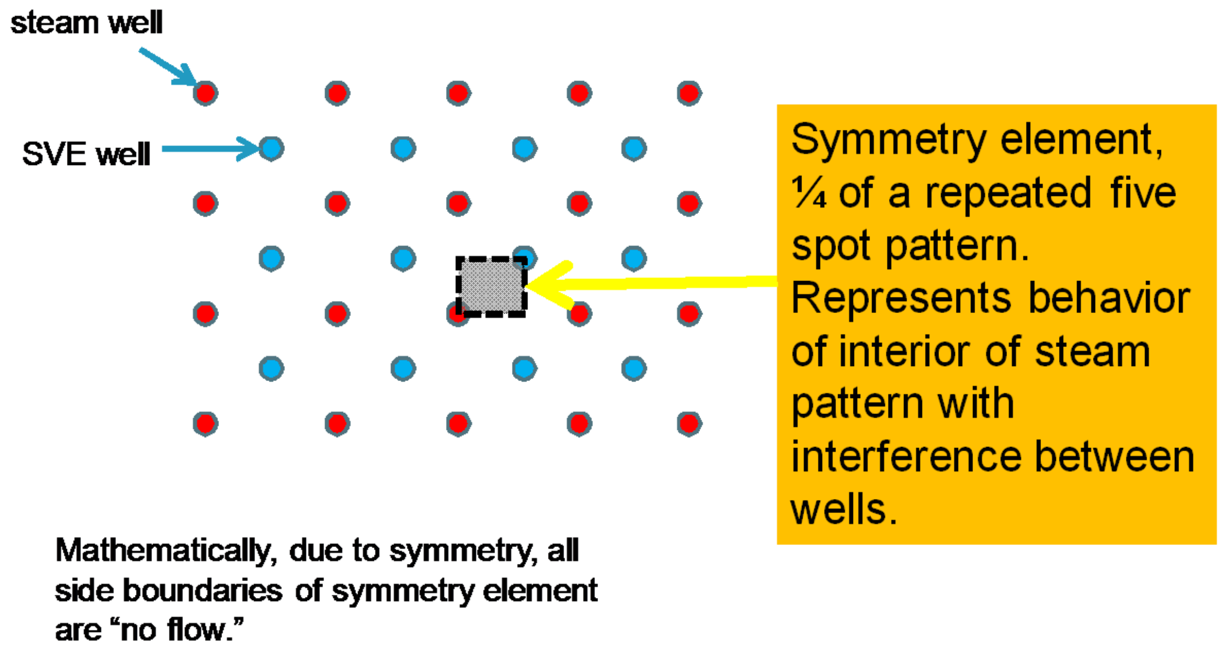

Figure 24. Repeated Five-Spot Pattern Showing Quarter Five-Spot Symmetry Element

In a previous study, Falta (2013) performed similar 3D quarter five-spot simulations using a slightly larger well spacing of 42 ft. That study showed the benefit of high injection rates in the lower screen for sweeping the base of the RGA. A subsequent study used a smaller well spacing of 28 ft. Those results showed the closer spacing could effectively treat the base of the RGA under more challenging conditions (higher conductivity and lower anisotropy), but many more wells would be required. The current well spacing of 38 ft used in the models here is based on our observations of the heating pattern from the TS as well as the results of the earlier numerical modeling work.

In the simulations, steam is injected at the appropriate elevations in the left hand corner elements in the RGA, using one-fourth of the full well rate. On the right-hand corner of the model, a fully screened extraction well extends from the top of the RGA to the bottom of the RGA (Figure 25, right-hand side).

This extraction well is modeled as a DPE well. Numerically, the DPE well is simulated using a column of grid blocks that have a very high vertical permeability, to simulate the open well casing. These grid blocks are open to the RGA, but are surrounded by a low permeability material (grout) in the UCRS, to simulate the unslotted casing. The vapor and liquid extractions parts of the well are simulated using well deliverability conditions (DELV) (Pruess et al. 1999; Pruess and Battistelli 2002) at the top and bottom of the DPE well, respectively.

At each location (top and bottom of the well) the well deliverability model extracts fluids against a specified pressure in the well bore. The deliverability model allows multiphase flows (vapor or liquid water in this case) into the well screen according to the multiphase version of Darcy's Law.

With this model, if fluid phase pressures in a grid block containing the DELV condition exceed the wellbore pressure at that elevation, then flow out of the well occurs. If a fluid phase pressure in the grid block does not exceed the flowing wellbore pressure at that elevation, then the flow of that phase in that interval of the well screen is zero.

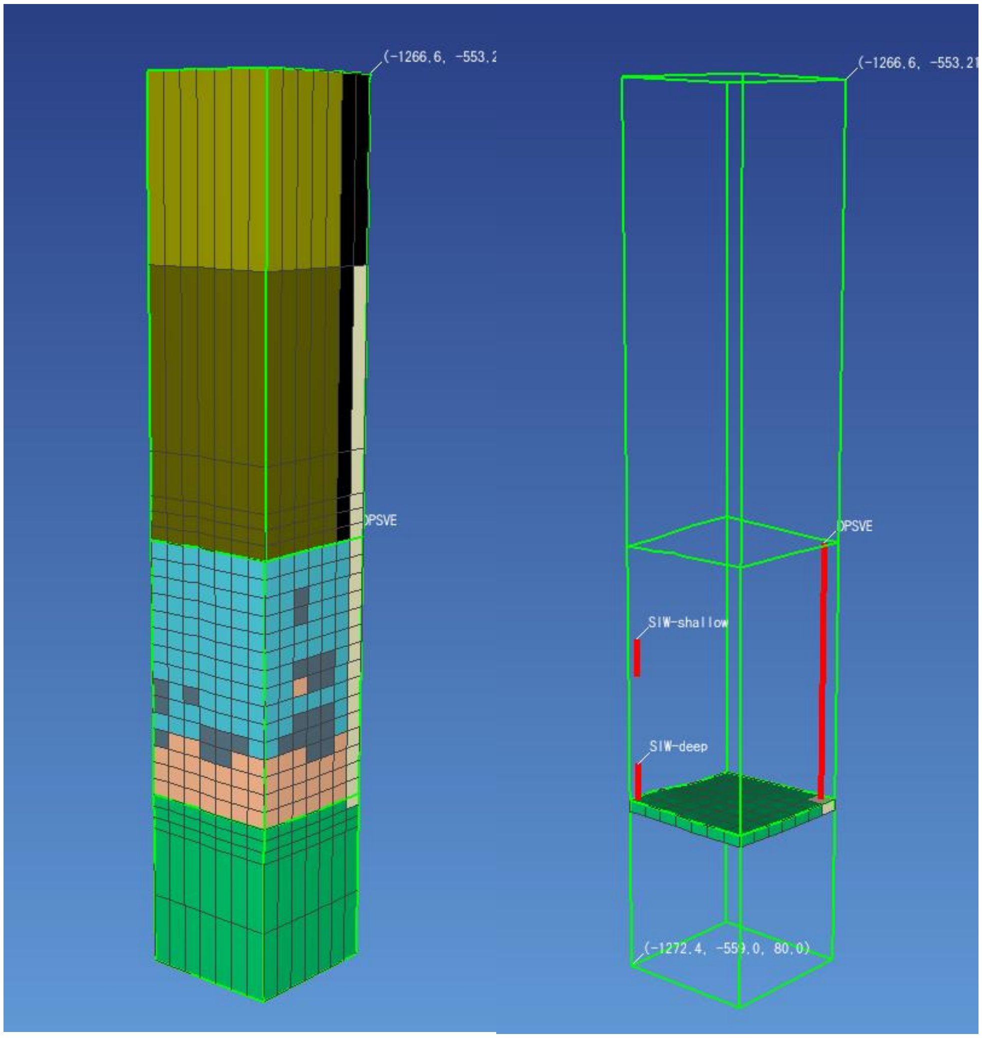

Figure 25. 3D Quarter Five-Spot Model Used in Numerical Simulations of Steam Injection

The vapor extraction part of the DPE well used a specified absolute pressure of 85,000 pascals (Pa), or about .85 atm. This DELV condition was imposed in the high permeability well bore at a depth of about 36 ft bgs to avoid excess production of liquid water. The liquid water extraction part of the DPE well was located at the base of the RGA, and it used a specified pressure slightly less than the background hydrostatic pressure (235,000 Pa absolute). The DELV Productivity Index in the liquid extraction part of the well was set to a relatively low value in order to restrict liquid water flows to realistic values. The DELV Productivity Index in the vapor extraction part of the well was set to a high value so that vapor can flow freely out of the well without restriction.

The upper and lower steam injection wells (Figure 24) are screened over 5 ft. The steam is distributed into the formation from the wells using a permeability-thickness product weighting. With this method, if there are layers of high and low permeability in the screened zone, the steam is preferentially injected into the high permeability layers. The specific enthalpy used in these simulations was 2,700 kilojoules per kilogram, which corresponds to a saturated vapor steam at a temperature of 120°C (248°F), with a steam quality of one.

Simulations with Injection Rates of 500 pph into Both Screens. The initial design tested during the TS Phase 1 injected steam at equal rates into the upper and lower screens. The first quarter five-spot simulation duplicates this configuration, using the same screen elevations as in the TS. Figures 26 and 27 show the temperature and gas saturation distributions after 10, 20, and 40 days of steam injection. These figures show an oblique cutaway view of the temperature and gas saturation. The layer at the bottom of the figures is the lowest model layer in the RGA.

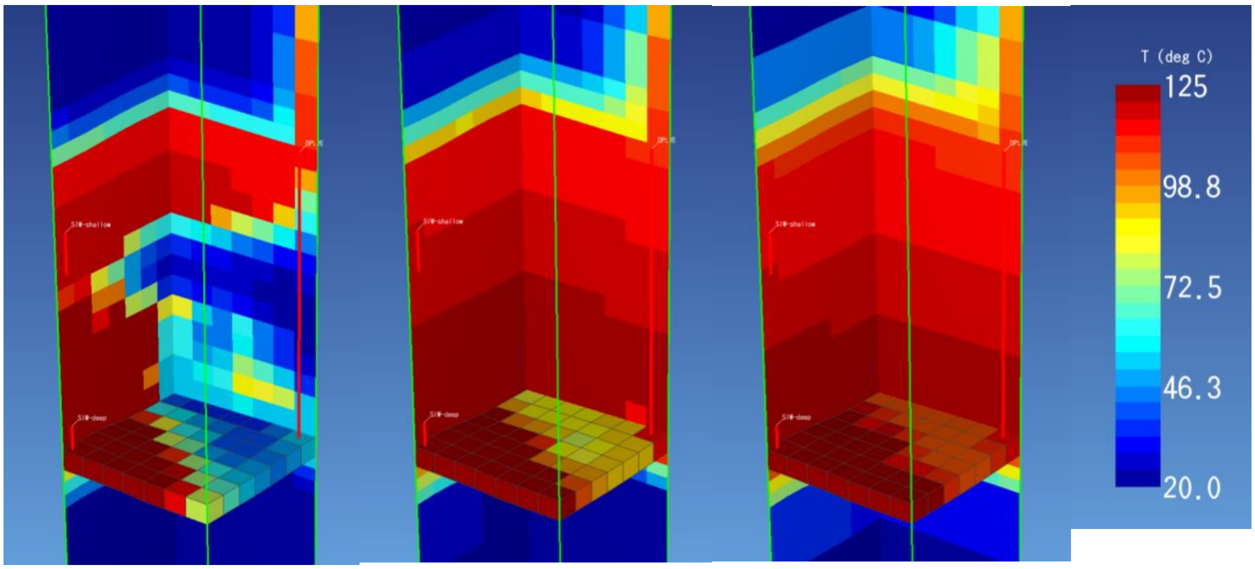

Figure 26. Temperature Distributions after 10, 20, and 40 Days of Steam Injection at Rate of 500 pph into the Upper and Lower Screens
(The screen elevations are the same as those used in the TS.)

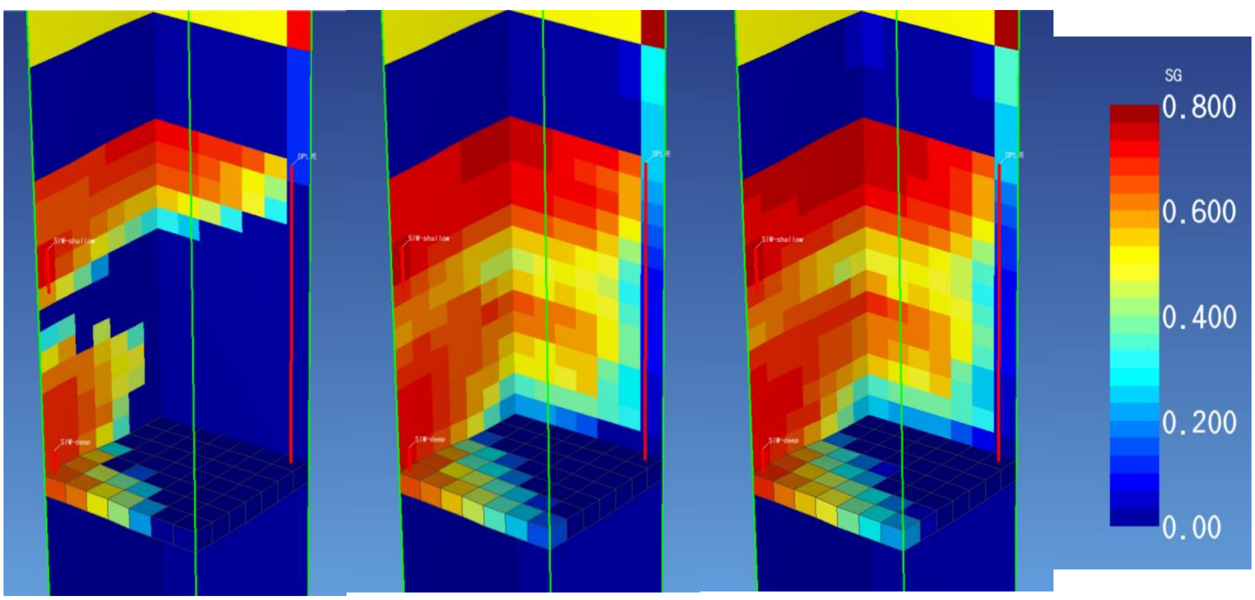

Figure 27. Gas Saturation Distributions after 10, 20, and 40 Days of Steam Injection at Rate of 500 pph into the Upper and Lower Screens
(The screen elevations are the same as those used in the TS.)

Initial steam breakthrough at the extraction well occurs after about 10 days of steam injection. The initial breakthrough is at the top of the RGA, and, over time, the steam zone extends downward towards the base of the RGA. By the end of the simulation, most of the RGA has been swept by steam, and the temperature distribution reflects the steam temperature corresponding to the hydrostatic pressure at a given depth.

There is, however, a small zone at the base of the RGA that does not quite reach steam conditions. This is due in part to some steam override near the extraction well, and it is due in part to the presence of low permeability zones in the bottom layer of the RGA in the model. These zones of low permeability are shown in Figure 28, and are similar to ones used to calibrate the 3D model of the TS.

Although steam temperatures are not achieved in part of the base of the RGA in this model, the minimum temperature in this layer is 104°C (219°F), which is well above the TCE DNAPL co-boiling target temperature of 95°C (203°F) (Kingston et al. 2014), at this pressure.

An examination of the TS TMP data showed that the middle parts of the RGA failed to reach steam temperatures at most locations during the TS Phase 1 steam injection. Likewise, the temperature and gas saturation profiles at 10 days in Figures 26 and 27 also show that most of the steam by-passes the middle part of the RGA at early times. Based on these observations, a second quarter five-spot simulation was performed with the same parameters as the first simulation, but with the upper steam injection screen lowered by 6.5 ft. It is believed that lowering the upper screen will result in a more uniform steam front.

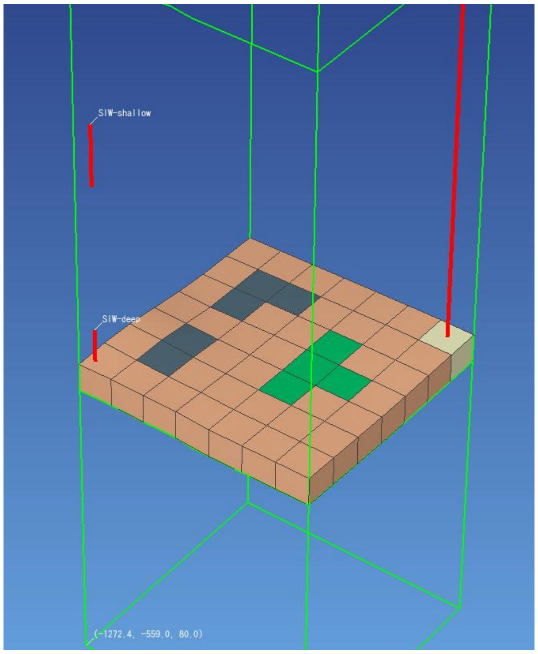

Figure 28. Heterogeneity in the Model Layer that Represents the Bottom Part of the RGA
(The green material has the properties of the McNairy silt, and the grey material has the properties of a silty sand.)

The simulated temperature and gas saturation distributions for the case where the upper steam injection screen is lowered by 6.5 ft are shown in Figures 29 and 30. Although the numerical differences between the two configurations are small, the lowered screen configuration shows a more uniform steam sweep at early times. This vertical screen configuration is used in the remaining 3D simulations here.

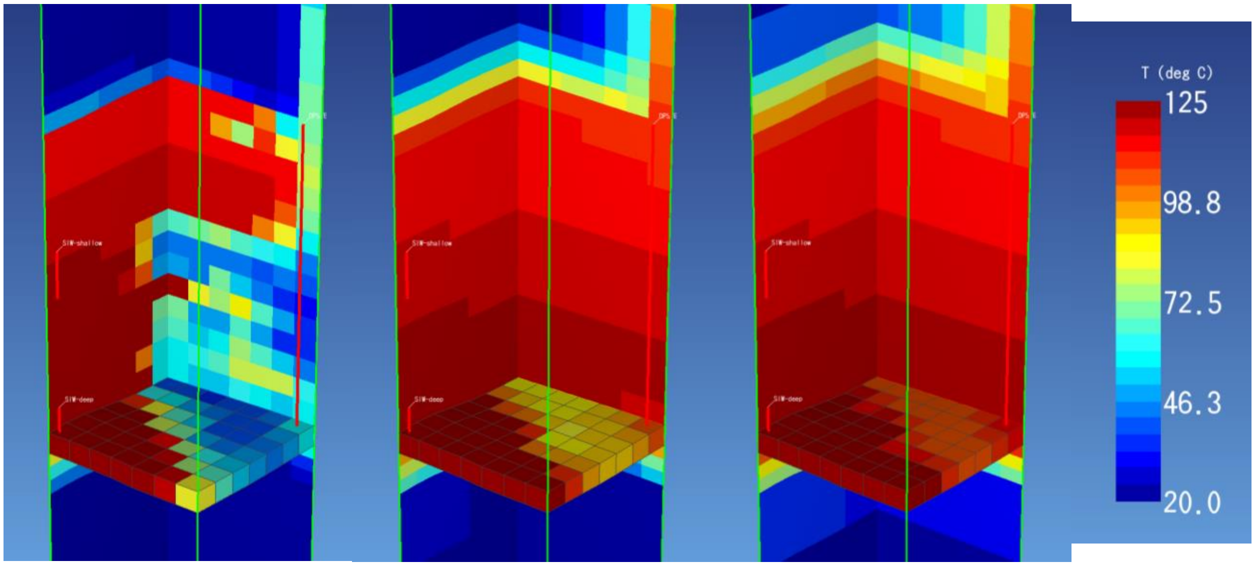

Figure 29. Temperature Distributions after 10, 20, and 40 Days of Steam Injection at Rate of 500 pph into the Upper and Lower Screens
(The upper screen has been lowered by 6.5 ft compared to the simulation shown in Figures 23 and 24.)

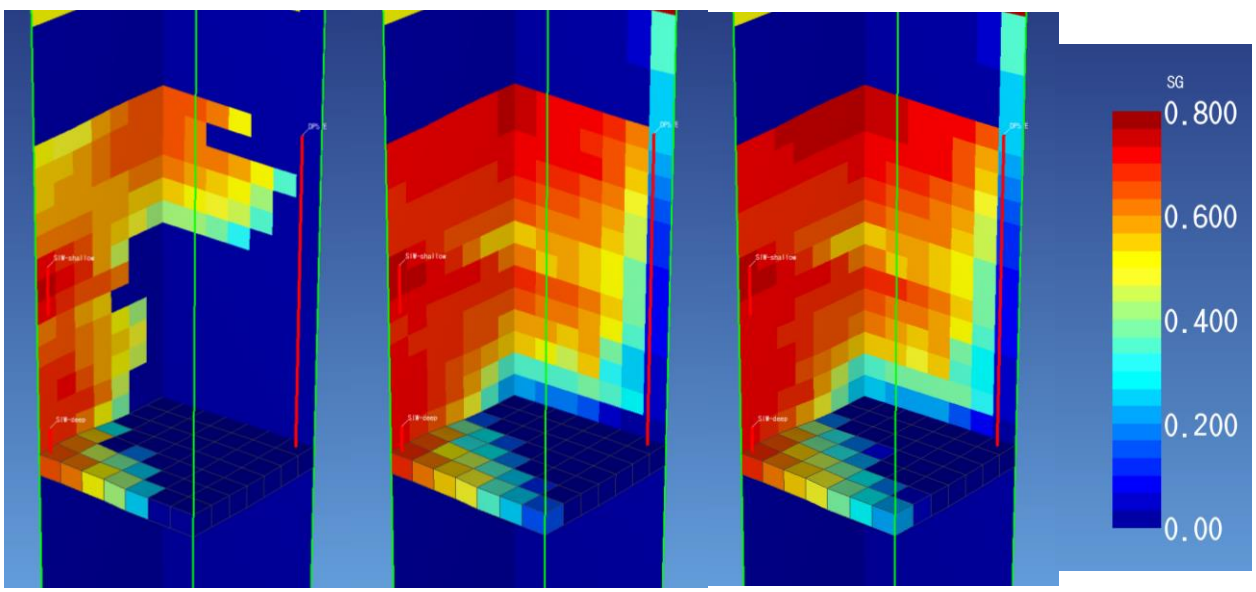

Figure 30. Gas Saturation Distributions after 10, 20, and 40 Days of Steam Injection at Rate of 500 pph into the Upper and Lower Screens
(The upper screen has been lowered by 6.5 ft compared to the simulation shown in Figures 23 and 24.)

The two simulations with steam injection at 500 pph in the upper and lower screens show that the steam front has stabilized by 20 days of steam injection. There is, however, a substantial increase in temperature near the base of the RGA from 20 days to 40 days of steam injection. This increase occurs in the zone that still is liquid saturated due to conductive and convective heating. After 20 days, parts of this lower zone remain below the TCE DNAPL/water co-boiling point of 95°C (203°F), but after 40 days, the entire zone is well above that temperature.

Simulation with Steam Injection Rates of 500 pph into the Upper Screen and 1,000 pph into the Lower Screen. The TS Phase 3 steam injection during the TS injected steam at 1,000 pph into the bottom screen. The temperature data from this phase showed substantially better heating of the lower RGA compared to the 500 pph injection rate in both screens. A 3D quarter five-spot simulation was performed to evaluate this higher rate of steam injection in a repeated well pattern. The TS Phase 3 field data showed that lower steam injection alone may not sweep the upper parts of the RGA due to the strong layering present. Therefore, this simulation also includes steam injection at 500 pph into the upper screen. The temperature and saturation distributions shown in Figures 31 and 32 illustrate an improved steam sweep of the RGA compared to the previous cases.

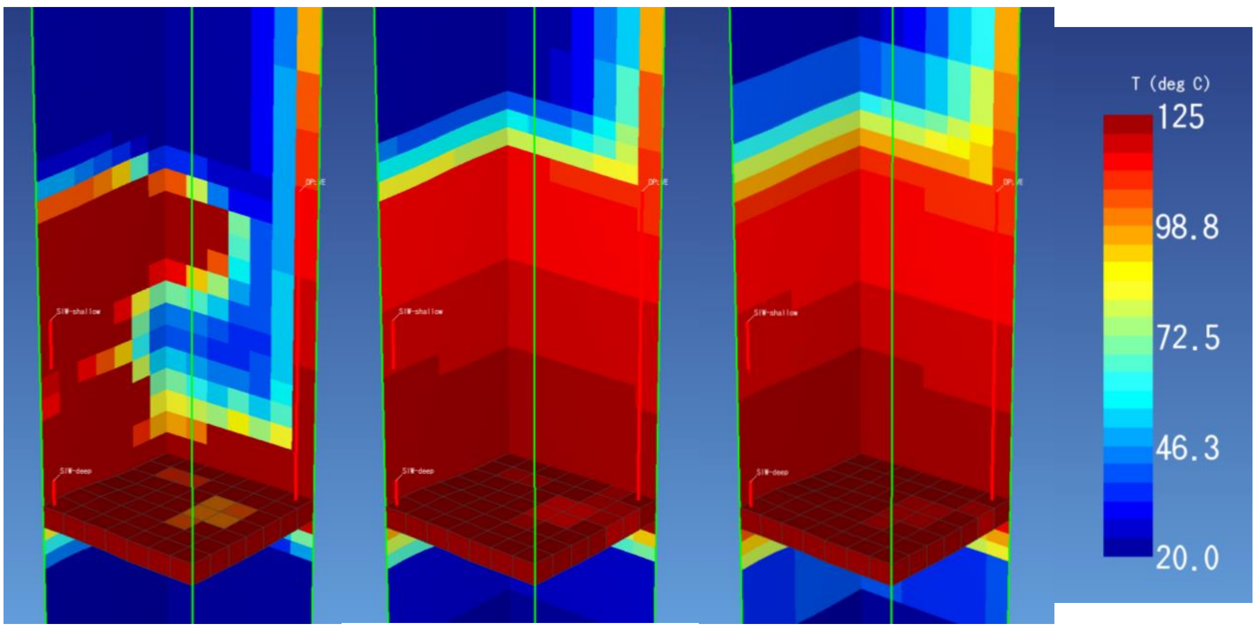

Figure 31. Temperature Distributions after 10, 20, and 40 Days of Steam Injection at Rate of 500 pph into the Upper Screen and 1,000 pph into the Lower Screen

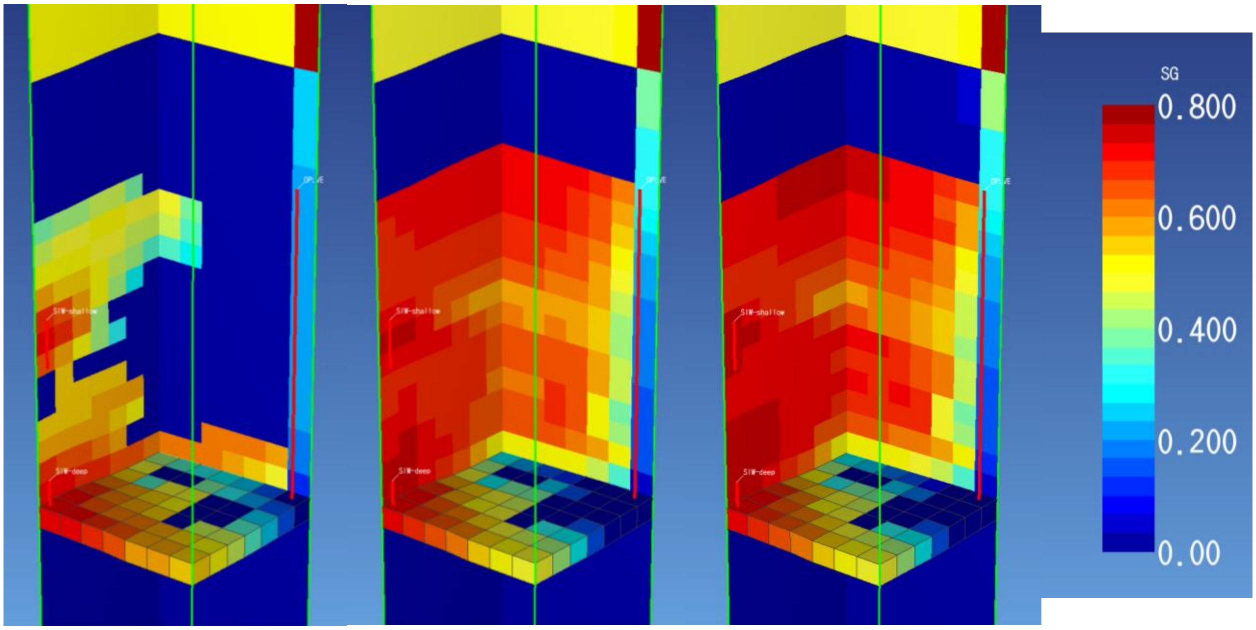

Figure 32. Gas Saturation Distributions after 10, 20, and 40 Days of Steam Injection at Rate of 500 pph into the Upper Screen and 1,000 pph into the Lower Screen

Initial steam breakthrough in the extraction well occurs near the base of the RGA in less than 10 days. During this early period, the steam sweeps the entire bottom of the RGA layer in the model except for two low permeability zones that remain water saturated. With increasing time, the steam zone expands, reducing the horizontal pressure gradients in the lower part of the RGA. The lower steam pressure gradients result in some liquid water accumulation in zones that were previously occupied by steam vapor, but the majority of the base of the RGA reaches steam conditions. After 20 days of steam injection, the minimum temperature in the bottom RGA model layer is 113°C (235°F), and this increases to 117°C (243°F) by 40 days.

Full-Scale Design Simulations—3D Full Field Scale. Based on data from the TS and from the quarter five-spot simulations, a conceptual design for full-scale steam treatment was simulated. This design uses 23 upper and 23 lower steam injection wells along with 17 DPE wells arranged in a pattern around the Phase IIb treatment area. The average well spacing is slightly less than 40 ft, and steam injection wells extend about 30–40 ft beyond the edge of the Phase IIb treatment area on the south half of the pattern (Figure 33) to expand the treatment area (shown as an orange line on Figure 33) to maximize contaminant removal.[7] DPE wells are located between steam injection wells. With this scenario, steam is injected into the bottom screens at a rate of 1,000 pph, and it is injected into the upper screens at a rate of 500 pph. These injection rates are maintained for 20 days (assumed duration to achieve steam temperature and exceed target temperature throughout), and then they are reduced to approximately half of the initial rate for another 70 days (90 days total). The DPE wells operate in the same way as in the quarter five-spot

[7] The conceptual design locations were placed outside the target treatment area so that, in conjunction with the DPE wells, an outside-in migration pattern is maintained for hydraulic control (based on TS field data and modeling results). The expanded conceptual design was intended to mitigate uncertainties and provides flexibility to allow adjustments to wellfield component spacing during finalization of the design; field adjustments for existing subsurface and overhead obstructions; and increased steam injection points to address potential cool zones and mitigate areas where the inflow of cooler groundwater at the perimeter of the target heating area may impact subsurface temperatures.

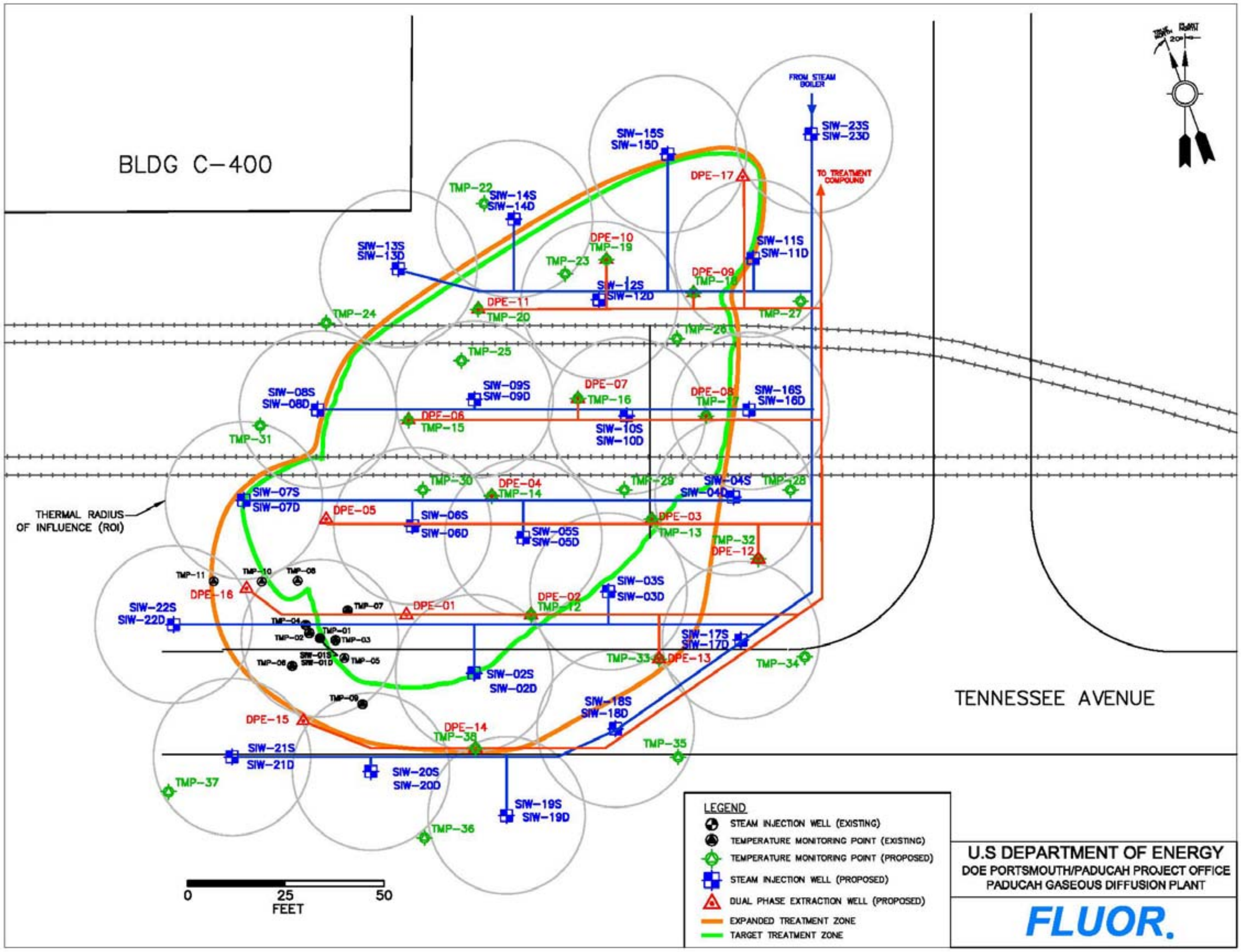

Figure 33. Steam Injection and Dual-Phase Extraction Well Layout for Conceptual Design

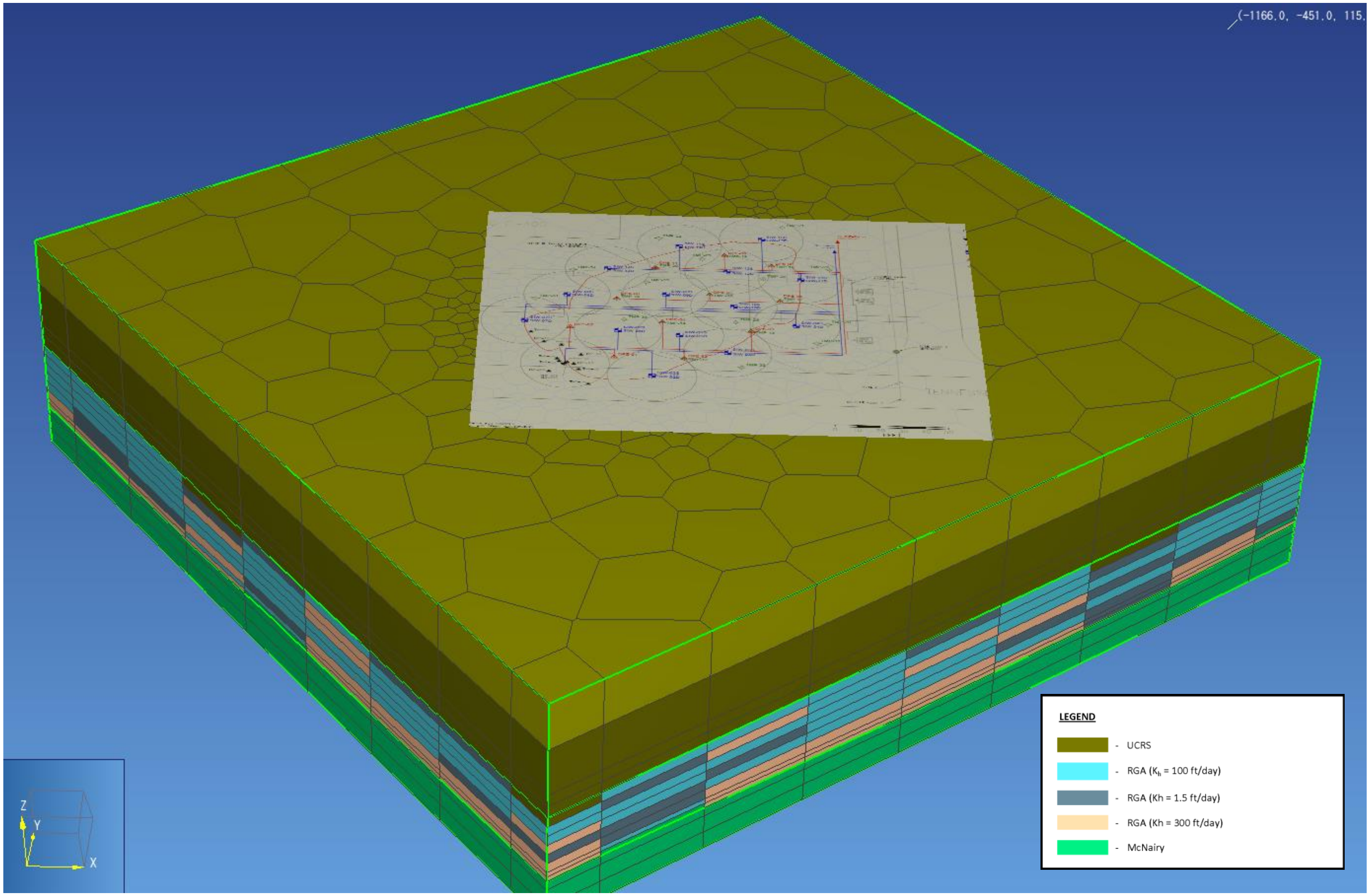

Figure 34. Numerical Grid Used for Full-Scale Simulations the Conceptual Design

simulations, with a vacuum at the top of 100 inches of H_2O and a simulated water pump at the bottom that maintains a pressure just below the original hydrostatic pressure

The numerical model domain is enlarged compared to the previous models so that it can encompass the entire treatment pattern (Figure 34). The model gridding used here is somewhat coarser than in the earlier models in order to keep simulation run times to reasonable levels (about five hours per simulation). This model uses a total of 10,170 cells with a variable Voronoi grid spacing in the horizontal dimension. The grid is refined around each of the injection and extraction wells, but becomes coarser toward the boundaries.

The top of the model, which is open to the atmosphere, is assumed to be flat. The top of the RGA also is modeled as a flat surface in this model, at a depth of 59 ft. The base of the RGA (top of the McNairy) undulates throughout the model domain. This surface was created from a map provided in the *Treatability Study Work Plan for Steam Injection* (DOE 2014a). The total relief of the RGA/McNairy interface through the entire model domain is about 10 ft.

The RGA is modeled as a heterogeneous system, using a pattern of heterogeneity that is similar to that used in the calibrated 3D model of the TS. It should be emphasized that this particular distribution of materials is essentially random, but with characteristics that were observed during the model calibration. The actual distribution of low permeability materials in the RGA beyond the TS area is not known.

In this model, the RGA is dominated by strongly anisotropic zones of high permeability with isolated zones and lenses of finer grained materials. Figure 35 shows an east-west cross section through the model.

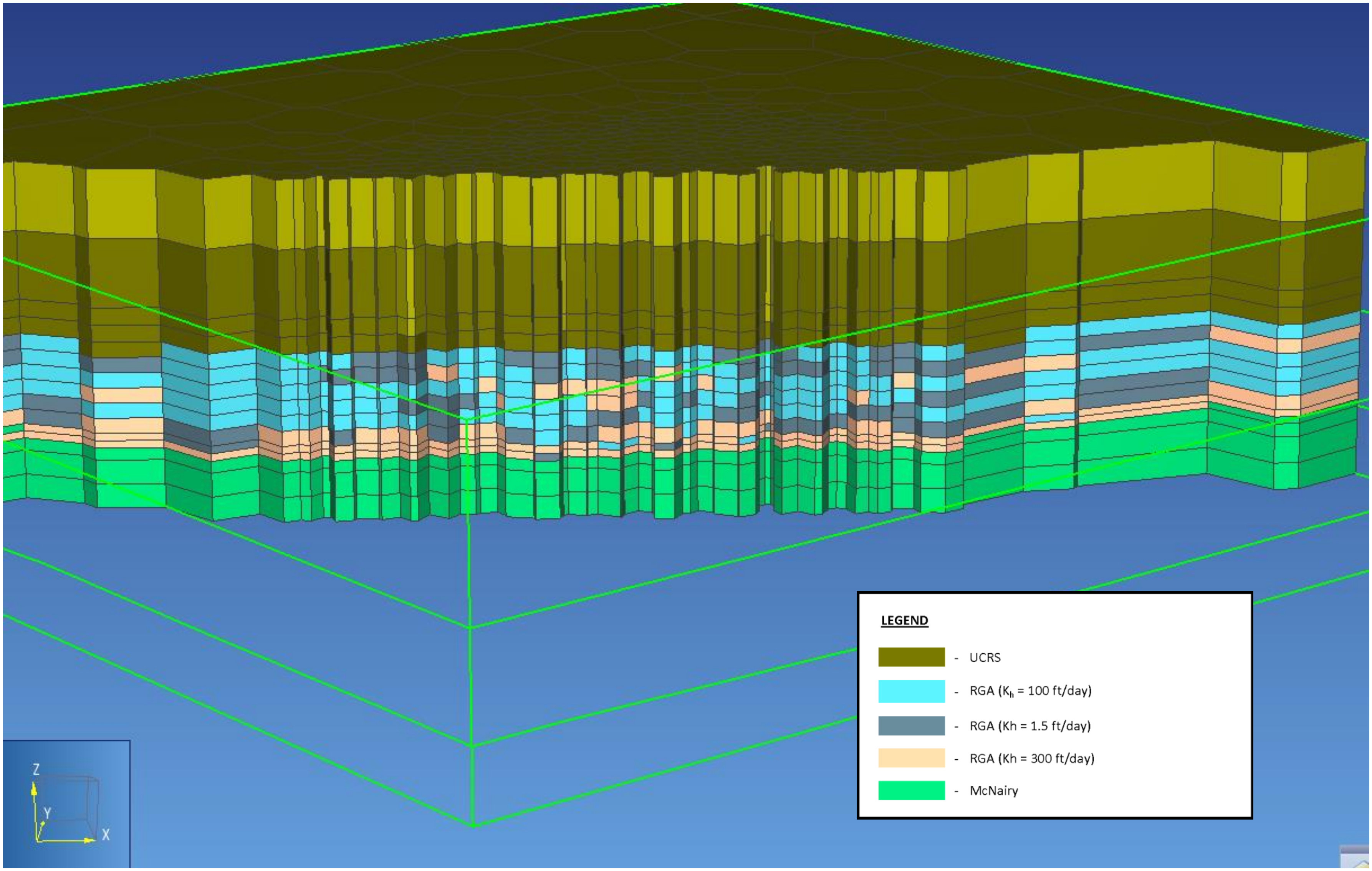

Figure 35. East-West Cross-Section through the Model

The color scheme used in Figure 35 is the same as before; with the grey zones representing a fine grained sand within the RGA. The light green material at the base of the model represents the McNairy, and some of this low permeability material also is placed in the lower parts of the RGA, based on observations from the 3D model calibration of the TS.

The initial condition for this model is one of hydrostatic gravity capillary equilibrium, with a flat water table located about 53 ft bgs. The conditions on the sides of the entire model are held constant so that water can flow freely into or out of the model from the outer boundaries.

The injection and extraction wells have the same configuration as in the 3D quarter five-spot simulations. The lower injection wells are screened from the base of the RGA (which is at a variable elevation) 5 ft up; the upper injection wells are screened at a uniform depth of 71 to 76 ft bgs, and the DPE wells are screened over the entire thickness of the RGA. The vapor extraction part of the DPE wells is simulated using the specified pressure DELV condition with a pressure of 75,000 Pa (.75 atm) in the well casing about 15 ft above the water table. The liquid extraction part of the DPE wells is simulated using the DELV condition at the bottom of the well with a pressure just below the initial hydrostatic pressure, and a productivity index that restricts the flows to a few gal per minute. Figure 36 shows the complete array of wells for the conceptual design. The bottom surface shown is the top of the McNairy formation (the base of the RGA). The DPE wells are shown extending above the top of the RGA in this figure, but these wells are screened only in the RGA and are surrounded by low permeability grout in the UCRS.

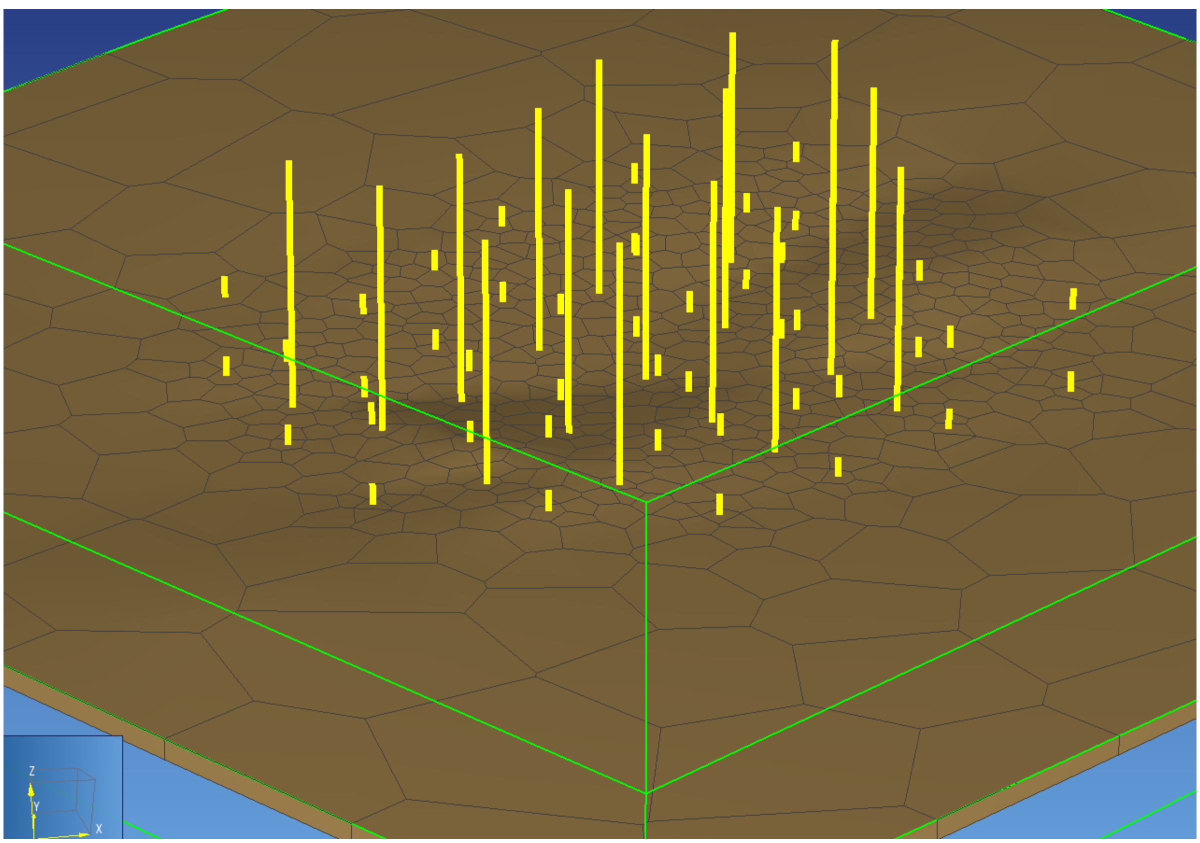

Figure 36. Well Locations for the Conceptual Design Showing the RGA/McNairy Interface

The simulation was initialized with a zone containing a dilute dissolved TCE tracer. This tracer was placed uniformly throughout the RGA within the boundary of the Phase IIb treatment area, including the fine grained low permeability zones. The TCE tracer was omitted from the top model layer in the RGA, because that zone has been treated by the Phase IIa remediation effort. The inclusion of this TCE tracer is not intended to represent the actual TCE concentration distribution in the RGA, which is likely highly variable, uncertain, and that may include DNAPL. Instead, this tracer is used in the model to illustrate the steam sweep of the RGA and to demonstrate capture of vapors and contaminated water from the treatment zone. As was discussed earlier, TCE DNAPL co-boils with water at a maximum temperature of 95°C (203°F) in the RGA, so DNAPL will not be present in zones that are heated above this level.

The predicted temperature distributions after 10, 20, and 90 days of steam injection are shown in Figures 37, 38, and 39, respectively. These figures show an oblique view from plant south, with an east-west vertical cross-section at plant Northing -1,772 ft, and with a horizontal slice at a depth of 90 ft from the ground surface. With the aggressive steam injection scheme, the system is rapidly heated, so that by 20 days, most of the RGA in the treatment zone will have reached steam temperatures and exceed the co-boiling target temperature. At that point, the assumed steam injection rates are cut in half, and injection continues until 90 days.

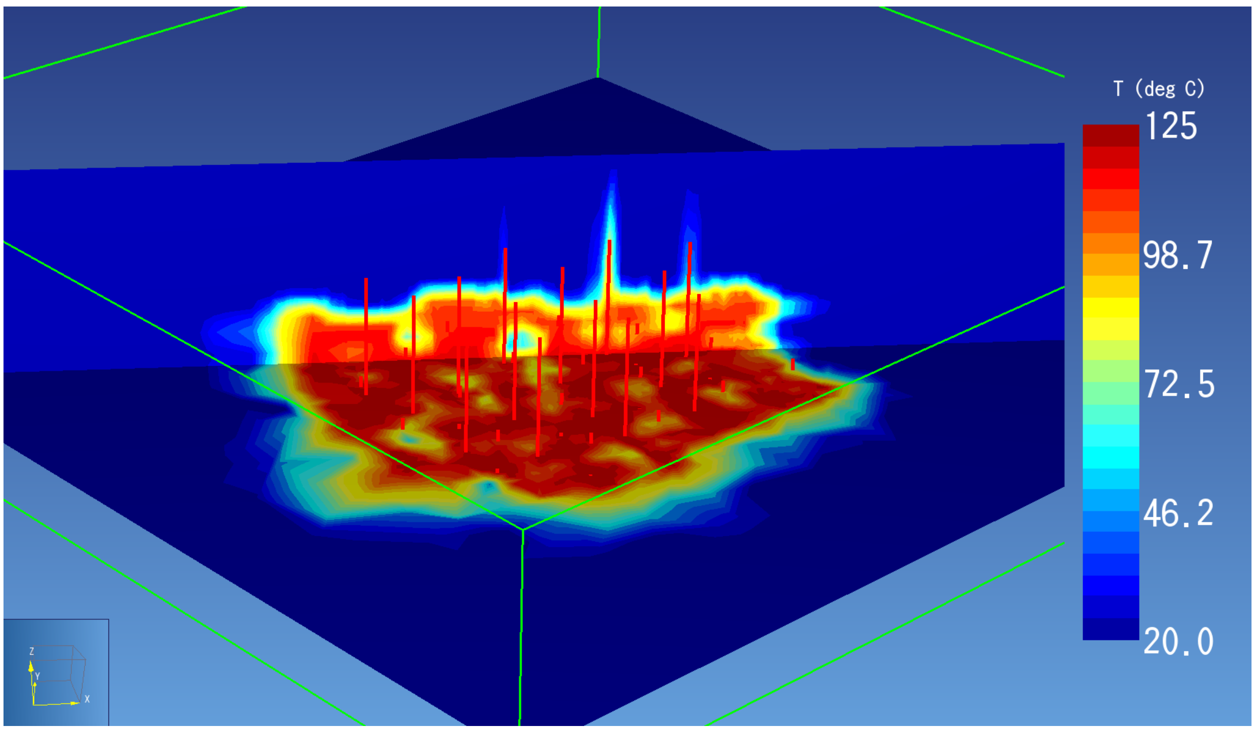

Figure 37. Temperature Distribution after 10 Days of Steam Injection for the Conceptual Design

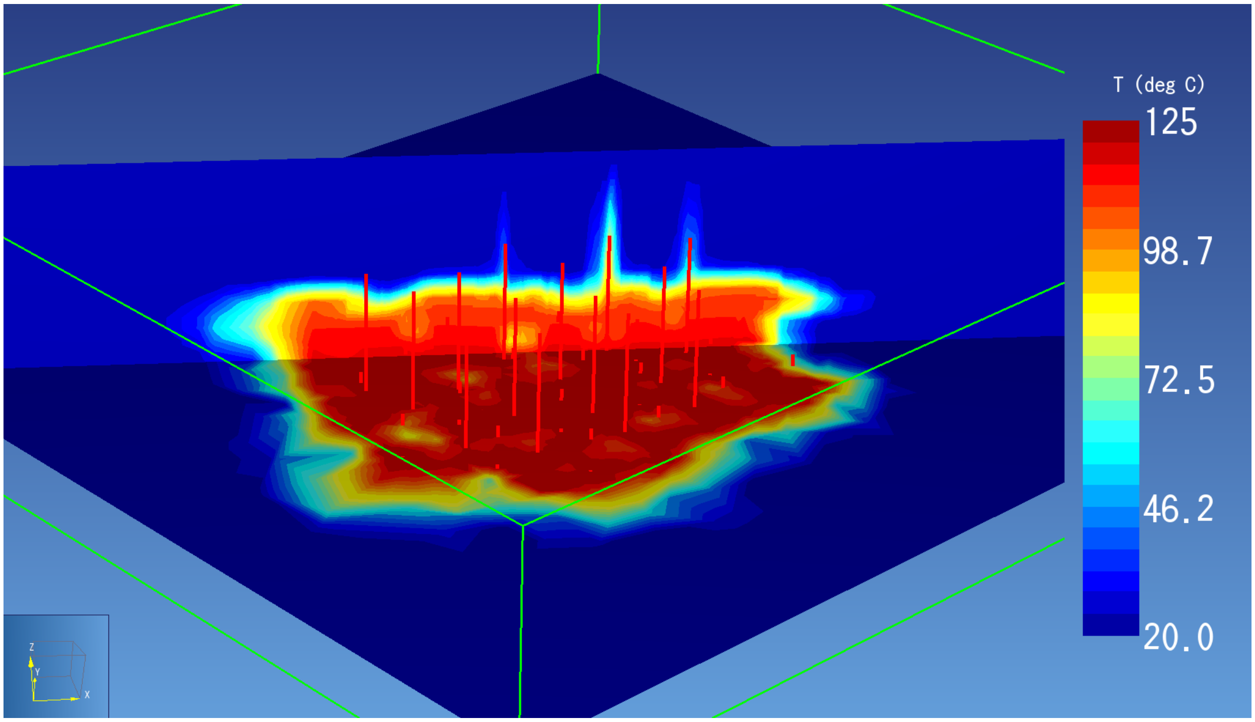

Figure 38. Temperature Distribution after 20 Days of Steam Injection for the Conceptual Design

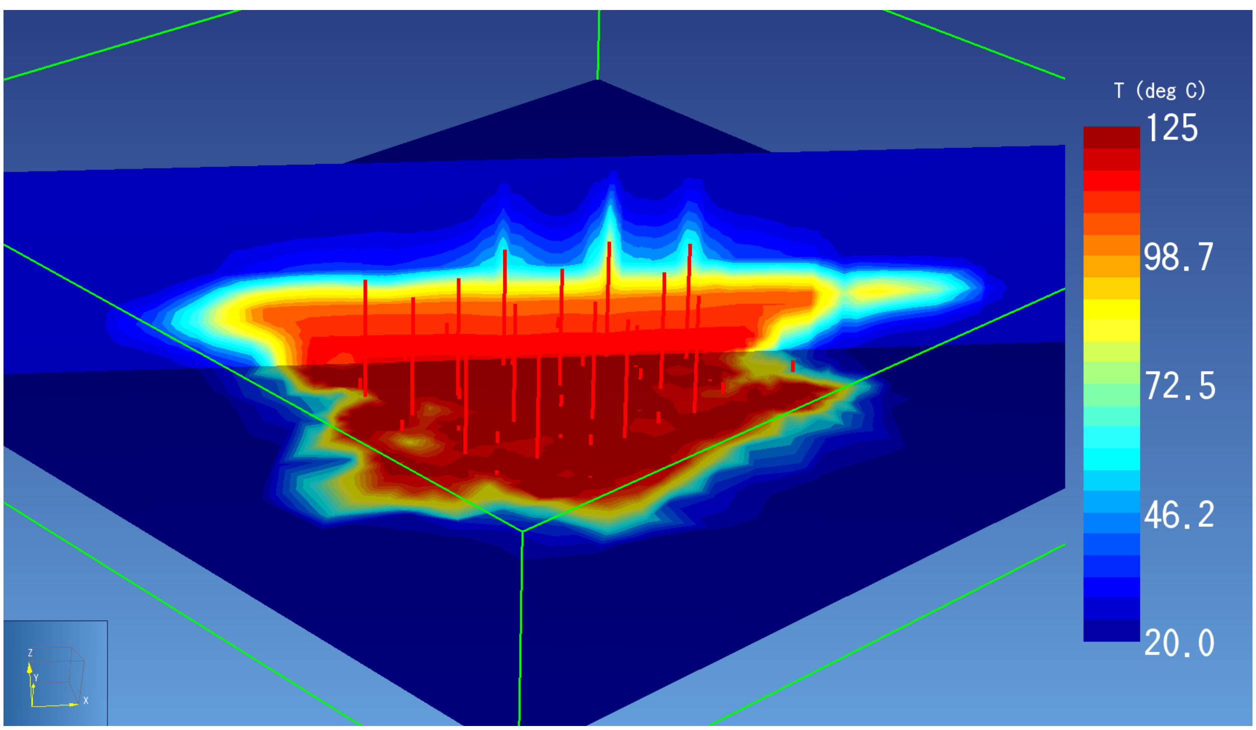

Figure 39. Temperature Distribution after 90 Days of Steam Injection for the Conceptual Design

The simulated temperatures at the base of the RGA can be seen by looking at the temperatures in the lowest RGA model layer (which has a variable elevation). This is shown in Figures 40 and 41, which show the temperatures in each model grid block after 20 and 90 days of steam injection. At 20 days, the model predicts that most of the lowest part of the RGA has reached steam temperatures. There are a few areas where temperatures are lower than the water boiling point. These locations correspond either to hydraulic stagnation zones between the wells, or to locations where low permeability materials are present near the base of the RGA. During a full-scale implementation, these hydraulic stagnation zones would be identified by the subsurface thermocouple data in real time and would be heated by altering the steam injection and/or multi-phase extraction rates in nearby wells to change the heat flow patterns.

At 90 days (Figure 41), the temperature pattern at the base of the RGA is similar, but the isolated cooler spots are now for the most part heated to above the TCE DNAPL/water co-boiling target temperature. There is some shrinkage of the outer perimeter of the steam zone volume at this time due to the reduced steam injection rates. The lower pressure resulting from the lower rate allows some groundwater to flow back into the edges of the steam zone; however, these zones already have been heated to the steam temperature and above the co-boiling target temperature.

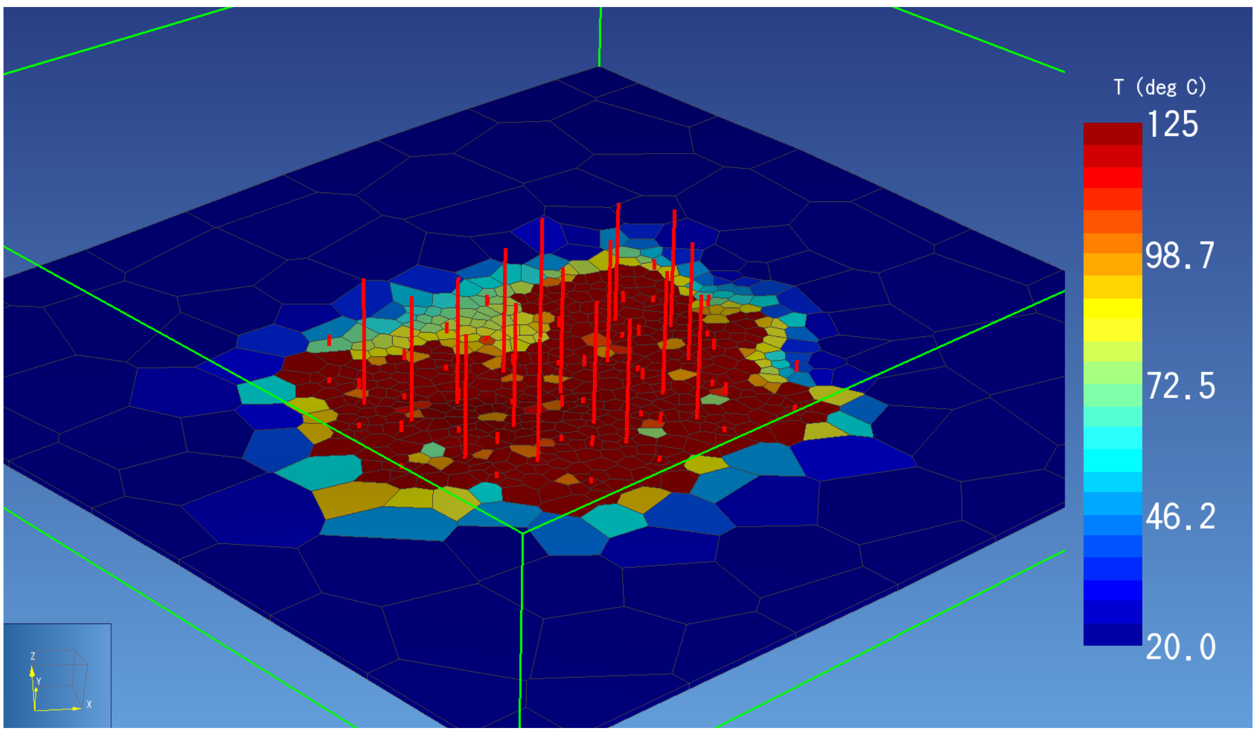

Figure 40. Temperature Distribution along the Base of the RGA after 20 Days of Steam Injection for the Conceptual Design

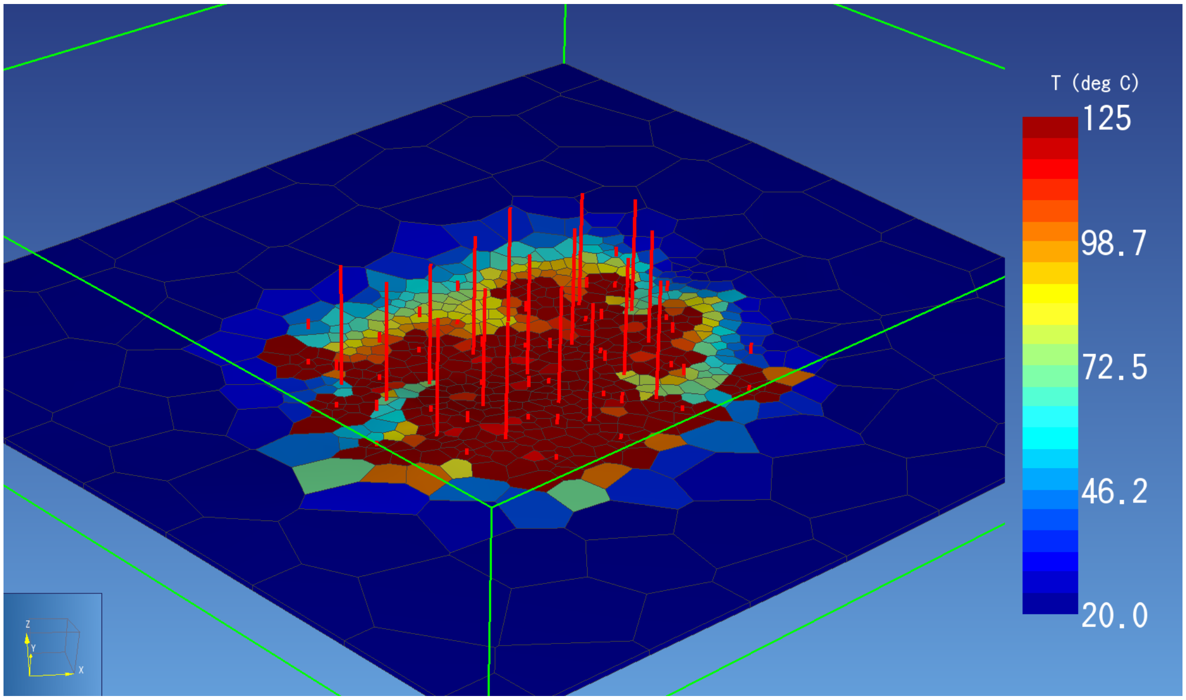

Figure 41. Temperature Distribution along the Base of the RGA after 90 Days of Steam Injection for the Conceptual Design

The steam vapor and liquid water recovery from the DPE wells varies substantially during the steam injection simulation (Figure 42). At early times before steam breakthrough, only liquid water is produced, reaching a maximum flow rate of about 50 gpm at 5 days (an average of about 3 gpm per well). The major steam breakthrough in most of the wells occurs between 5 and 10 days, and the steam vapor recovery reaches a maximum value of about 10,500 cubic ft per minute (cfm) at day 20 (an average of about 600 cfm per well). As the steam vapor recovery increases, the liquid recovery decreases to a value of around 30 gpm. The steam vapor removal rate drops rapidly when the injection rates are reduced at day 20, and then stabilizes at a value of around 6,000 cfm. Similarly, the liquid extraction rate stabilizes at a rate of around 20 gpm.

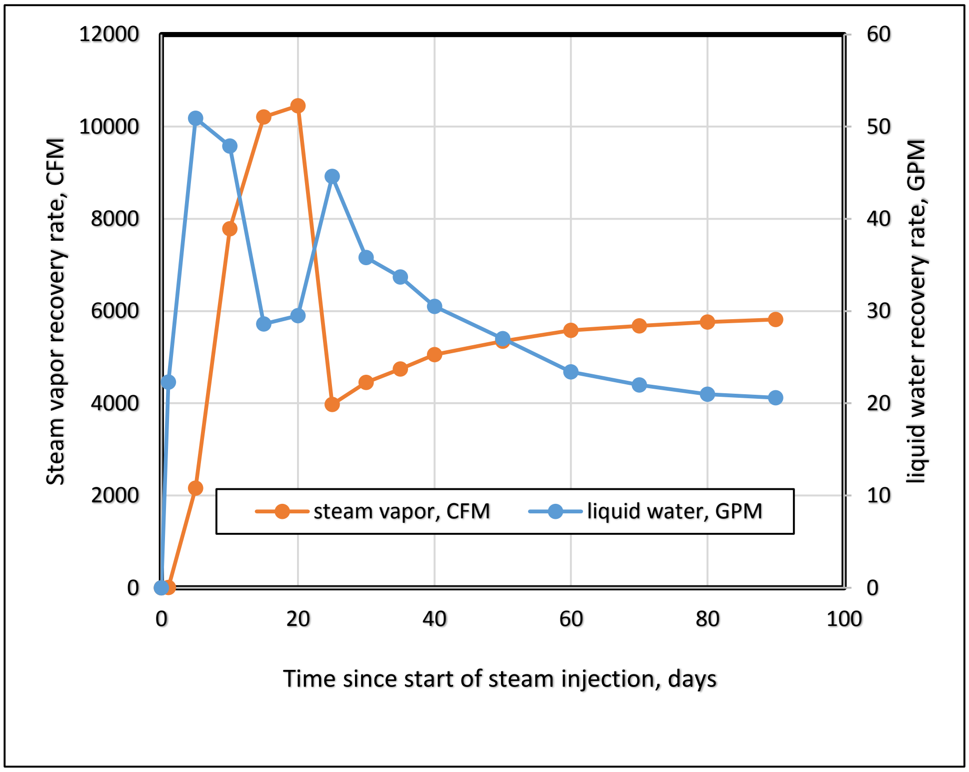

Figure 42. Simulated Steam Vapor and Liquid Water Recovery Rates from the DPE Wells

For the conceptual design, a period of 30 to 45 days is assumed to achieve the target temperatures through optimization, such as adjusting steam injection pressures and flow rates based on field data and modeling results. At the end of the heat-up phase, the steam injection flow rate is reduced to a level necessary to maintain temperatures and overcome heat loss to the surrounding soils. At other sites, this rate has varied between 25% and 40%, depending on the soil and groundwater thermal characteristics. A reduction of 50% is used in the model, with a 90-day time frame chosen for modeling purposes only.

The total rate of thermal energy injection (the thermal power) is about 650,000 BTU/minute during the first 20 days, and about 325,000 BTU/minute during the remaining 70 days of the simulation. After a few days, as steam begins to be produced from the DPE wells, much of this energy is extracted (Figure 43). The rate of thermal energy extraction climbs in parallel to the rate of steam vapor recovery (Figure 42), and reaches a peak of about 495,000 BTU/minute at 20 days. The energy removal rate drops as the steam injection rate is dropped, and by the end of the steam injection period, the energy extraction rate is about 273,000 BTU/minute. Most of the recovered energy is in the steam vapor, but about 10% of the extracted energy is in the hot liquid water that is produced from the DPE wells.

The assumed operational time frame used for the full-scale conceptual design and budgetary cost estimates is approximately 14 months and includes start-up, testing, commissioning, operation, and cool down. This duration far exceeds the predicted amount of time to reach target temperatures, as simulated in the model, and allows an increased number of days of steam injection to address and mitigate uncertainties.

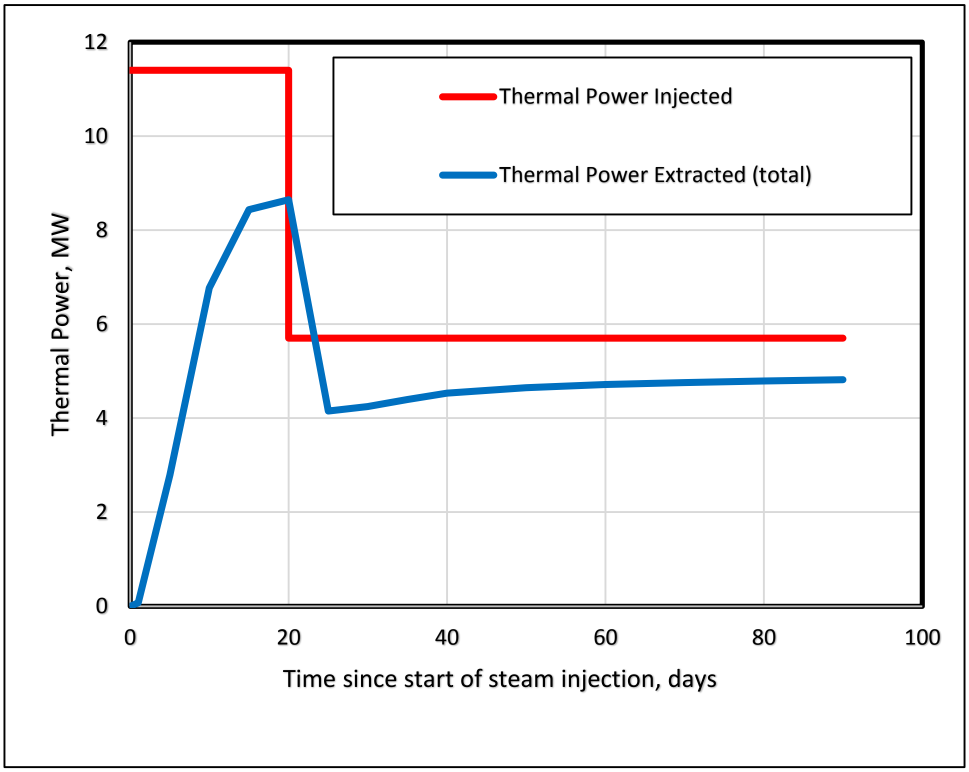

Figure 43. Rate of Energy Injection and Extraction (Thermal Power) during the Field Scale Simulation

4.2 QUALITY ASSURANCE/QUALITY CONTROL

Quality assurance/quality control procedures were followed as described in the Treatability Study Design for Steam Injection (DOE 2014c) and the Treatability Study Work Plan for Steam Injection (DOE 2014a). Additionally, as required in the contract documents, the subcontractor provided numerous submittals to the prime contractor (LATA Kentucky) in support of the overall project quality assurance/quality control program. Those submittals included Task Work Instruction documentation for major project tasks and required documentation for general contract categories such as General Conditions, Special Conditions, Scope of Work, Technical Specifications for Engineering Services, and Environment, Safety, and Health. All submittals were reviewed and approved by LATA Kentucky.

The work was conducted in accordance with LATA Kentucky procedures. The standard operating procedures documented in the LATA Kentucky *Health and Safety Plan*, and the *Treatability Study Steam Injection Shakedown and Startup Procedure* (LATA Kentucky PAD-400-0048) were used along with applicable LATA Kentucky procedures to implement the work (Appendix F, Standard Operating Procedures).

The numerical simulations were performed using DOE TMVOC (Pruess and Battistelli 2002) version of TOUGH2 (Pruess et al. 1999). TOUGH2 is publicly available and currently is in use at more than 350 research laboratories, private companies, and universities in 40 countries. The results of scientific and engineering studies using the TOUGH2 codes have appeared in more than 500 refereed journal papers (http://esd1.lbl.gov/research/projects/tough/documentation/publications.html).

The TMVOC code, and its predecessors, M2NOTS (Adenekan et al. 1993) and T2VOC (Falta et al. 1995; Falta et al. 1992a) have been used to simulate a variety of steam injection operations, ranging from the lab scale (Falta 1990; Falta et al. 1992b; Falta 2001; Gudbjerg et al. 2004a; Gudbjerg et al. 2004b; Hodges et al. 2004; Chen et al. 2012) to the field scale (Adenekan and Patzek 1994; Ochs et al. 2003; Gudbjerg et al. 2005).

The TMVOC model users guide (Pruess and Battistelli 2002) contains a set of benchmark test problems. The slightly modified version of TMVOC used in this study was verified by rerunning these benchmark problems on the current computing platform used for this work.

4.3 COSTS/SCHEDULE FOR PERFORMING THE FULL-SCALE IMPLEMENTATION

The results of the steam injection TS operations and the 3D simulations of the steam injection data provided the basis for a conceptual full-scale design for deployment of the steam injection technology to remediate the RGA. Based on modeling results, the final well layout, incorporating optimal injection-extraction well spacing, was designed. The design criteria are shown previously in Table 1.

Proper well spacing is critical because it will ensure that steam reaches the bottom of the RGA across the entire target zone within a reasonable operational period, and without excessive heat requirements. The well layouts are shown on Drawing No. M5E-FA1530-A02. The process flow diagram is shown on drawing M5E-FA1530-A03. Detailed engineering specifications for the treatment equipment were derived from the 3D simulation and engineering experience on other steam injection projects and are also shown on Drawing M5E-FA1530-A03. The conceptual design drawings are included in Appendix C2.

4.3.1 Conceptual Design

The conceptual design was developed based on a treatment area that was extended beyond the boundaries of the treatment area determined during preparation of the Remedial Design Work Plan. Based on lessons learned from previous investigations, sampling events and well decommissioning activities, a roughly 20-ft wide additional treatment zone around the perimeter of the southern portion of the area used during the TS Design was added to maximize contaminant removal. Based on review of the continuously cored boring logs of the injection well cluster (SIW-10S, SIW-01D, and TMP-01) and TMP-09, the southernmost extent of the suspected treatment area is confirmed to be located near Tennessee Avenue (Drawing M5E-FA1530-A02). This drawing shows that the proposed conceptual well field layout will consist of 23 dual nested steam injection wells, 17 DPE wells, and 38 TMPs (15 TMPs in individual boreholes, 12 collocated with DPE wells and 11 TMPs from the TS).

The conceptual design locations were chosen, with steam injection wells placed outside of the target treatment area, so that, in conjunction with the DPE wells, a strong outside-in migration pattern for hydraulic control was developed. The expanded conceptual design was intended to mitigate uncertainties and to provide flexibility to allow adjustments to wellfield component spacing during finalization of the design, field adjustments for existing subsurface and overhead obstructions, and increased steam injection points to address potential cool zones and mitigate areas where the inflow of cooler groundwater at the perimeter of the target heating area may impact subsurface temperatures. The expanded conceptual design is an industry standard (Kingston et al. 2014).

A treatment compound to treat the extracted vapors and groundwater was designed using a combination of new equipment and existing LATA Kentucky equipment. The LATA Kentucky equipment compound was inspected during a site walk conducted on July 9, 2015, at which time the condition of the equipment was evaluated and a decision was made regarding the use of the equipment during the full-scale implementation. The details of the conceptual design are discussed below.

4.3.1.1 Well design

The wellfield will consist of steam injection wells and DPE wells that are designed to effectively distribute steam completely throughout the treatment volume, from the RGA/McNairy boundary upward to the RGA/UCRS boundary. TMPs will be used to monitor the subsurface temperatures within the treatment volume.

Steam Injection Wells

The 3D simulations confirmed that steam injection would best be accomplished by 23 dual-nested steam injection wells that are located using a 20 ft ROI. The location of the upper and lower nested steam injection wells, including the existing TS wells, SIW-01S and SIW-01D, are shown on Drawing M5E-FA1530-A02, Appendix C2. The steam injection well construction will consist of 3-inch diameter carbon steel casings with 0.010-inch stainless steel screens. The new injection wells will have total depth of the lower screen similar to SIW-01D (93 ft bgs). In response to the simulation results, the total depth of the upper screen will be lowered approximately 6.5 ft to 78.5 ft bgs. A 5-ft screen section will be installed for each of the nested wells. Within each borehole, the two steam injection wells will be isolated from one another, as well as from the ground surface, by layers of course sand filter pack around the well screens, fine sand, and a high temperature, high viscosity Class H cement and silica flour grout. Well details are shown on Drawing M5E-FA1530-A04, Appendix C2.

Dual-Phase Extraction Wells

Liquids and vapors mobilized during the initial heat-up phase of the operation will be extracted using 17 DPE wells, as shown on Drawing M5E-FA1530-A02, Appendix C2. The dual-phase wells will consist of 6-inch diameter, carbon steel casings with stainless steel screens. As with the steam injection wells, the DPE well screen will be isolated from the ground surface, by layers of course sand filter pack around the well screens, fine sand, and a high temperature, high viscosity Class H cement and silica flour grout. Well details are shown on Drawing M5E-FA1530-A04, Appendix C2.

Temperature capable down-hole pumps will be used to pump groundwater and establish an inward hydraulic gradient. The extracted fluids will be pumped to the groundwater treatment system. Mobilized and volatilized contaminants of concern vapors will be extracted and sent to the vapor treatment system. Once the target temperatures have been reached, extraction will be comprised of condensable (predominantly water) and noncondensable vapors.

Temperature Monitoring Points

The locations of 38 TMPs are shown on Drawing M5E-FA1530-A02, Appendix C2. In addition to the existing 11 TMPs from this TS, 15 TMPs will be installed in individual boreholes. Twelve collocated TMPs will be installed within select DPE wells. The new TMPs in individual boreholes will be comprised of bundles of thermocouple wires, grouted in place using the same high temperature, high viscosity Class H cement and silica flour grout mixture used for the steam injection and DPE wells. Bundles of thermocouple wires will be installed in select DPE wells by attaching the bundle to the DPE well screen and casing with temperature resistant connectors, such as nylon zip ties. Each thermocouple will be isolated from the DPE well with a nonconductive pad. Each TMP, will be comprised of approximately 19 temperature sensors (type K thermocouples) depending on the depth and thickness of the RGA. As in the TS, the top two temperature sensors within the UCRS will be spaced vertically 1 ft apart. In lieu of the redundant thermocouple construction (less than 2% of the thermocouples failed), the bottom 5 thermocouples in the top of the McNairy Formation and the bottom of the RGA will be spaced 1 ft apart to better define heat transfer characteristics into these formations that bound the RGA.

4.3.1.2 Steam generation system

The steam generation system will be comprised of two portable steam boiler packages, each capable of providing up to 20,000 pph (40,000 pph total) of saturated steam at 140 psig to the steam injection wells. The boilers will be powered by petroleum fuel (assumed to be natural gas). The feed water systems will consist of a skid-mounted tank and dual pump assembly using makeup water from existing fire hydrants. Blowdown water from the daily blowdown operation will be stored in an on-site tank prior to disposal to the PGDP water treatment system. Although rated for 140 psig, each boiler generally will be operated to provide approximately 100 psig steam to the main headers. Steam rated and insulated piping and valves will connect the boilers to the steam injection wells. Steam will be conveyed to the injection wells in a 6-inch diameter header that splits into five branch lines. Steam traps and moisture separators will ensure that any moisture in the headers is removed prior to the branch lines to ensure delivery of dry saturated steam. The branch lines contain pressure regulators, gauges, and energy meters to control the steam pressure to approximately 30 psig and monitor steam parameters. Downstream throttle valves are used to regulate flow into the wells and maintain a safe injection pressure (generally less than 25 psig). Thermal expansion is accommodated through directional changes in the piping and flexible hoses. Refer to Drawing M5E-FA1530-A02, Appendix C2 for the proposed piping layout.

Both boilers will be used during the start-up and initial heating phases of the full-scale implementation. While the 3D simulations indicated that heating goals would be achieved in 20 days, an initial heat up period of 30 to 45 days was assumed for cost estimating. Approximately 30 to 45 days after the start of steam injection, when the target steam temperatures are achieved throughout the treatment area, steam generation from one of the boilers may be terminated. The boiler will remain on-site as a contingency. The boiler rental rate was maintained in the estimate, but the natural gas cost was eliminated. Steam injection will continue at injection rates necessary to balance the heat loss to the surrounding areas and maintain target temperatures.

4.3.1.3 Groundwater extraction and treatment

Pneumatic operated groundwater pumps will be installed in each of 17 DPE wells to pump contaminated groundwater from the formation. The purpose is to ensure an inward and upward gradient to account for the additional water that will result from steam condensation and prevent contaminant migration outside the existing plume. The pumps will have a design rate of 3 gpm, but will be able to pump up to 14 gpm. An air compressor (AC-600) will supply the motive air to operate the pumps. The extracted groundwater will be pumped to an existing storage tank (T-310), where it combines with other contaminated water sources (vapor condensate from KO-200 and any spillage water within the containment pad from existing pump P-800). The contaminated water from Tank 310 is then pumped through existing bag filters (BF-310, BF-311, BF-312, and BF-313) to the existing air stripper. There are four bag filter vessels to allow continuous operations during required bag filter change outs. The water flows from Tank 310 through the filters into the air stripper, and contaminants are stripped off by counter flowing clean air from existing blower B-400. The contaminated air stream is then sent to the vapor treatment system, (to be determined in future design). Treated water from the air stripper is pumped by existing pump P-400 through existing ion exchange vessels (IX-400 and IX-401) for removal of Tc-99. The water then flows to existing polishing GAC vessels (GAC-400 and GAC-401. Treated water is discharged to the existing Kentucky Pollutant Discharge Elimination System 001 Outfall. Details of the groundwater treatment system are shown on Drawing M5E-FA1530-A03, Appendix C2.

4.3.1.3.1 Vapor extraction and treatment

Contaminated vapors are pulled under vacuum from the 17 DPE wells. The design flowrate is based on providing 1.5 times the steam injection volumetric flow rate to ensure complete capture of all volatilized contaminants. The hot vapors must first be cooled and moisture removed as a preconditioning measure for the vapor extraction blowers. This is accomplished in a new shell and tube heat exchanger HEX-200 (vapors in shell side, cooling water in tube side). Design conditions are 210°F hot side and 100°F cold side. As a result of the cooling, most of the condensable portion of the extracted vapors will condense and gravity drain to knockout tank KO-200. The knockout tank is designed to remove entrained moisture through centrifugal force on the sidewalls and coalescence on a demister pad. All liquid collects at the bottom of KO-200 and is pumped to storage tank T-310. The relatively dry vapor exits out the top of KO-200 and enters the existing vacuum blowers (B-200 and B-201). There are two vacuum blowers to allow controlled increase of extracted flow rate as vapor screens become exposed due to groundwater extraction and steam bubble creation. Additionally, the blowers will have variable frequency drive motors to maintain subsurface vacuum at a value sufficient to ensure the ROI completely captures all volatilized contaminants within the heat-affected volume.

The extracted vapors from the blower discharge are combined with the contaminated air from the air stripper (AS-400). These vapors are routed to a vapor treatment system (to be determined in future design). Treated vapors exit the vapor treatment system and are routed to polishing vapor carbon and zeolite, prior to discharging to the atmosphere.

The vapor extraction and treatment system uses auxiliary equipment to condition the vapor stream for optimal performance. New cooling towers (CT-500 and CT-501) provide cooling water to remove latent and sensible heat and condense liquids from the extracted vapors in HEX-200. Details of the vapor treatment systems are shown on Drawing M5E-FA1530-A03, Appendix C2.

4.3.1.3.2 Temperature monitoring system

The temperature monitoring system consists of TDAMs that received the type K thermocouple signals from the 38 TMPs. Each TMP uses three 8-channel TDAMs that are daisy chained with the other TMPs to provide output signals to the main computer. The TDAMs will be ICP DAS USA, Inc. (Model # M-7018) or equivalent and are installed in weather-proof enclosures. The data are displayed in real-time on the main computer and logged into the computer hard drive.

4.3.2 Engineer's Cost Estimates

An engineer's cost estimate for the conceptual design for full-scale deployment was prepared. The engineer's cost estimate incorporates expected operational time frame, preliminary equipment lists, and large item specifications. This cost estimate includes all elements expected to be required for a successful full-scale deployment of steam injection with multiphase extraction at C-400. The assumed operational time frame used for the full-scale conceptual design and budgetary cost estimates is approximately 14 months and includes start-up, testing, commissioning, operation, and cool down. This duration far exceeds the predicted amount of time to reach target temperatures, as simulated in the model, and allows an increased number of days of steam injection to address and mitigate uncertainties.

4.3.2.1 Full-scale implementation incorporating existing components with new equipment

The following assumptions were used in developing the cost estimate.

<u>GENERAL ASSUMPTIONS</u>:

- Cost estimate is based on conceptual design as required by the Treatability Study Work Plan (DOE 2014a) and Treatability Study Design Report (DOE 2014c).

- Budgetary estimate (-30%/+50% pre-design) is developed in accordance with AACE 18R-17 guidelines.

- Estimate includes total project costs through completion of the project.
- Escalation incorporates total project cost and projected schedule.
- Cost estimate is based on fiscal year 2015 dollars.
- SEE is selected remedy for Phase IIb.
- Feasibility study is not required.
- C-400 Phase IIb is determined not to be a capital project.
- No additional characterization sampling is required to define Phase IIb treatment area.
- No additional effort is required to abandon C-400 Phase I and Phase IIa well borings.
- No monitoring wells are abandoned or installed for either Phase IIb or associated long-term monitoring efforts.
- C-400 Building stabilization does not impact C-400 IRA construction and/or operations.
- Resources are available for concurrent work across the project(s).
- Cost estimate includes fully burdened rates for all support resources including, but not limited to, project management, labor, RADCON, Industrial Hygiene/Health and Safety support, waste, etc.
- The full-scale implementation has been scheduled for uninterrupted work.
- The work area will be unencumbered by equipment from other projects. (Plant utility grids were reviewed during the design of the conceptual wellfield.)
- Demolition of nearby facilities and associated work will not impact the project.
- Costs associated with developing the CERCLA documents (Record of Decision, Proposed Plan, Remedial Design Work Plan, Remedial Action Work Plan, Remedial Design Report, and Operation and Maintenance Plan) are estimated based on previous site experience.

<u>PHASE IIB CONSTRUCTION</u>:

- Well field Components

  — 23 steam injection wells
  — 17 multiphase extraction wells
  — 38 temperature monitoring wells

- Subsurface drilling installation costs assumed based on previous site experience.
- Assumes two drill rigs will be operated simultaneously for subsurface installation.
- Level B personal protective equipment cost included for subsurface drilling activities.

- As previously described in Section 2.1.7, some of the existing C-400 treatment equipment was incorporated into the design of the full-scale treatment system. Equipment not used in the full-scale system will be dispositioned, to the extent practical, to make room for the new treatment equipment. Costs for the disposition effort have been included. New vapor/liquid treatment system equipment cost is assumed, based on past site experience.

- Assumes aboveground construction of well field and treatment compound will happen simultaneously.

- Includes winterization costs (heat trace, insulation, heaters, emergency generators, etc.).

<u>Operations</u>:

- Includes 14 months of operations, including start-up/testing, operations, and cool down periods.

- Staffed operation 24/7, from system start-up until mass removal rate as the vapor extraction stream reaches an observed peak and begins to decline.

- Includes 8 hours per day/5 days a week staffed operations after mass removal rate begins to decline through the end of operations.

- After mass removal rate begins to decline, SEE subcontractor to monitor system off-site with limited on-site support via remote monitoring.

- Includes costs to rent steam boiler and water conditioning equipment during operations.

- Includes costs to maintain operability of critical treatment system components (i.e., emergency generators).

- Natural gas assumed to be available from on-site utilities. Assumes existing photoacoustic analyzers are available and functioning properly for operational sampling. Cost estimate does not include purchase of new analyzers.

- Cost estimate includes only 1-year of long-term monitoring and assumes quarterly sampling of 17 existing MWs located in the immediate vicinity of and downgradient of the C-400 Phase IIb area. Additional long-term monitoring costs after 1 year are not included.

<u>Waste Disposition/Site Restoration:</u>

- Assumes 4,500 gal of VOCs recovered.

- Recovered VOCs assumed to be RAD-contaminated and will require additional disposal costs.

- Costs for decommissioning and waste disposal of both existing Phase IIa treatment system equipment and Phase IIb treatment systems have been included.

- Used ratio for on-site/off-site waste disposal based on previous site experience.

- Includes costs for Phase IIb subsurface well abandonment activities with the following assumptions:

- — Liquid extraction, vapor extraction, and steam injection wells are overdrilled, the casing extracted, and the boring grouted to the surface, as required for monitoring wells.
- — Temperature monitoring arrays are abandoned in place with associated placement tubing grouted to the surface (if applicable).

- Subsurface well abandonment costs assumed based on previous site experience.
- Subsurface well abandonment assumes two drill rigs will be operated simultaneously.
- Level B personal protective equipment costs included for subsurface well abandonment activities.
- Includes costs for site restoration following Phase IIb.

4.3.2.2 Cost metrics

Based on the full-scale cost prepared above, the following metrics were determined:

- Estimated total project cost for full-scale implementation ranges from \$23.4−\$50.0 M[8] (adjusted for escalation through project completion) (see Table 3).
- Estimated volume of treatment area is 18,500 yd^3.
- Estimated cost per unit volume treated (\$/yd^3) ranges from \$1,265/yd^3−\$2,703/yd^3.
- DNAPL volume estimate is 576–4,500 gal (DOE 2013).
- Estimated cost per unit volume of mass removed (\$/gal) ranges from \$5,200/gal−\$86,806/gal.
- Theoretical minimum energy required per unit volume = 110,000 BTU/yd^3.

[8] The wide range in the cost estimate is due to several uncertainties. These uncertainties include, but are not limited to, (1) the FFA parties have not discussed the scope of a remedial action using steam (e.g., extent of mass removal expected using steam); (2) the wellfield and treatment system designs needed to meet the selected scope have not been determined (e.g., wellfield component spacing, steam injection rates, vapor/liquid extraction rates, vapor/liquid treatment system components); (3) the duration of steam treatment required to meet the selected completion target has not been established (e.g., criteria for ceasing operations, operational strategy); (4) methods to estimate power costs are uncertain; (5) design of critical system components is not complete (e.g., during power losses and/or inclement weather); and (6) waste disposition determinations, both on-site and off-site, are unavailable.

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Table 3. C-400 Total Project Cost Estimate Breakdown

C-400 Total Project Cost Estimate (Based on the Conceptual Design)	Values Reported in Thousands ($K)
Project Plans	$1,365
Engineering Design	$787
Procurement of Long Lead Items	$6,904
Construction	$7,913
Operations	$6,086
Decommissioning and Waste Disposition	$10,287
Total	$33,342
-30%	$23,339
50%	$50,012

The total project cost estimate was developed using engineering judgment, past site experience, discussions with vendors, and historical costs. The total project cost was adjusted for escalation through project completion. This total project cost does not include additional costs for 29 of 30 years of long-term monitoring estimated at $114,000/year. It was assumed that costs associated with these monitoring wells would be transferred to the site Sample Management Organization 1-year after completion of the Phase IIb action. These assumed long-term monitoring costs were escalated, based on quarterly sampling of 17 existing monitoring wells for 29 of 30 years. In addition, Section 6.8, "Determination of Full-Scale Steam Injection Cost and Energy Requirements," of C-400 Phase IIb Treatability Study Design (DOE 2014c) states the following, "Uncertainty associated with the cost drivers listed above, such as the estimated mass in the target zone, the operating duration, and power costs, will necessitate the development of ranges for these metrics."

4.4 KEY CONTACTS

The key members of the TS team and their contact information are listed in Table 4.

Table 4. Treatability Study Key Contacts

Contact	Role	Telephone	E-mail
Todd Powers	LSRS Project Manager	270-816-1354	todd.powers@ffspaducah.com
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Rob Flynn	LSRS Senior Scientist	270-816-2698	robert.flynn@ffspaducah.com
Ken Davis	LSRS Senior Geologist	270 816-4112	ken.davis@ffspaducah.com

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CD DATA

Appendix A: Variance Letters

Appendix B: Boring Logs

Appendix C: Drawings

Appendix D: Data

Appendix E: Model Development and Calibration Documentation

Appendix F: Standard Operating Procedures

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