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Streamlined Remediation System Evaluation
Intermountain Waste Oil Refinery

Bountiful, Utah

STREAMLINED REMEDIATION SYSTEM EVALUATION

INTERMOUNTAIN WASTE OIL REFINERY
BOUNTIFUL, UTAH

Report of the Streamlined Remediation System Evaluation
Conference Call Conducted for the Intermountain Waste Oil Refinery
June 16, 2011

Final Report
September 28, 2011

EXECUTIVE SUMMARY

Optimization Background

EPA's working definition of optimization as of June 2011 is as follows:

> *"A systematic site review by a team of independent technical experts, at any phase of a cleanup process, to identify opportunities to improve remedy protectiveness, effectiveness, and cost efficiency, and to facilitate progress toward site completion."*

An optimization evaluation considers the goals of the remedy, available site data, site conceptual model, remedy performance, protectiveness, cost-effectiveness, and closure strategy. A strong interest in sustainability has also developed in the private sector and within Federal, State, and Municipal governments. Consistent with this interest, optimization now routinely considers green remediation during optimization evaluations. An optimization evaluation includes reviewing site documents, interviewing site stakeholders, potentially visiting the site for one day, and compiling a report that includes recommendations in the following categories:

- Protectiveness
- Cost-effectiveness
- Technical improvement
- Site closure
- Green remediation

The recommendations are intended to help the site team identify opportunities for improvements. In many cases, further analysis of a recommendation, beyond that provided in this report, may be needed prior to implementation of the recommendation. Note that the recommendations are based on an independent evaluation, and represent the opinions of the evaluation team. These recommendations do not constitute requirements for future action, but rather are provided for consideration by the Region and other site stakeholders.

Site-Specific Background

The Intermountain Waste Oil Refinery (IWOR) is located at 995 South 500 West in the City of Bountiful, Davis County, Utah. The site is approximately 2 acres. It is bordered on the north and east by residences and on the south and west by commercial buildings along US-89 (500 West). The site is mostly flat with a slightly lower elevation to the west. The buildings associated with the IWOR operations have been demolished and the site has been redeveloped. The IWOR facility was a brick manufacturing facility starting prior to 1950. In the 1950s an asphalt business was operated at the site. From 1957 to 1993 a petroleum product hauling business was run at the site and during the 1970s an oil blending operation was operated. Groundwater at the site was impacted with solvents, mainly trichloroethylene (TCE) and petroleum hydrocarbons. TCE was commonly used in asphalt testing laboratories to separate aggregate from bitumen.

Summary of Conceptual Site Model (CSM)

The TCE source appears to have been surface dumping of TCE near the southeast corner of the former laboratory building. Petroleum storage tanks, waste sludge and impacted soil were removed in 1993 and 2001; petroleum compounds are not a concern in groundwater. A narrow plume impacted by TCE and cis 1,2 DCE is interpreted to be present from the former source area to the west edge of the site. The highest TCE concentration detected in April 2011 was 16.1 ug/L; however, the source area well is dry and no longer available for sampling. The size of the TCE plume in excess of Maximum Contaminant Levels (MCLs) is likely up to about 200 feet long and 50 feet wide. The cis-1,2 DCE plume is co-located with the TCE plume but only has periodically had levels detected above the MCL.

PCE potentially from an off-site source was detected at a maximum level of 4.6 ug/L in April 2011. No on-site PCE source was found during previous RI investigations. The occurrence of PCE at the site is most likely the result of PCE in vapors migrating from a source somewhere west of the site. Passive vapor sampling conducted in 2001 found several areas west of the site with elevated PCE and TCE vapor levels but none to the upgradient (i.e., east side) of the site.

Site reports indicate that, based on groundwater sampling, all VOC impacts in groundwater are isolated to the top of the water table to a maximum depth of less than 130 feet bgs. The presence of cis 1,2 DCE above TCE levels indicates naturally occurring reductive dechlorination of the TCE source; however the lack of vinyl chloride indicates that enhancement would likely be needed to achieve complete dechlorination of TCE in the groundwater.

Summary of Findings

Source area TCE concentrations had decreased from 991 ug/L in 1992 to 160 ug/L in 2003, after which the source area well was dry. The operation of a remediation system from 2004 to 2006, including pump and treat (P&T) with vapor extraction, reduced TCE concentrations to below MCLs at locations that were monitored. The capture zone of the formerly operated remedial system likely encompassed the VOC plume. Treatment using granular activated carbon to remove VOCs from water and vapor operated effectively with only one exceedance of a discharge standard. The annual site costs during system operation were about $150,000.

The operation of the remediation system, including P&T at MW-02 and P&T plus vapor extraction at MW-04, reduced concentrations to below MCLs at locations that were monitored. It is very likely that pumping resulted in the contribution of a high percentage of clean water to the pumping wells (from below and/or horizontally from outside the plume). Once the system was shut down natural flow conditions returned and impacts from the source area likely migrated back to the shallow monitoring wells, resulting in the rebound of TCE concentrations. The lack of groundwater monitoring in the source area during and after system operation and the concentrations in the vapor collected just before system shutdown indicate that a rebound of TCE levels in groundwater should not have been unexpected after system shutdown.

Summary of Recommendations

Based on the TCE concentrations during the previous SVE pilot test and DPE system operations, coupled with rebounds in TCE concentrations after those operations were discontinued, it is likely that elevated levels of VOCs remain in the vadose zone in the suspected source area. The RSE-lite team recommends sampling soil gas and shallow groundwater for VOCs at approximately three locations in the source area. Assuming impacts are confirmed, DPE wells suited for soil vapor extraction of the intervals with elevated

VOCs, and extraction of shallow groundwater, should be installed in the three locations. The RSE-lite team recommends operation of a SVE system coupled with groundwater extraction (i.e., dual phase extraction) using the three new wells, and perhaps SVE at existing well MW-7. The primary intent of these wells is to remove remaining TCE source material from the unsaturated zone via SVE. However, since it is assumed that groundwater in this area is more impacted than in other portions of the site, it also makes sense to pump and treat groundwater for the purpose of mass removal. The actual extent of groundwater capture during system operation should not be a significant focus, since concentrations of TCE leaving the site are already so low. Rather, the focus of this system should be to remove remaining TCE mass in the source area (vadose zone and groundwater) to an extent that MCLs for TCE in groundwater near the source area are achieved or approached.

An exit strategy should be developed to indicate when it is possible to terminate active remediation at this site. The RSE-lite team believes that additional active remediation is currently merited since there is likely a remaining TCE source area that is technically feasible to address.

Based on the current and historic distribution of VOCs in groundwater the site, the relatively slow natural groundwater flow velocity, and historic information on soil vapor concentrations (from passive vapor surveys, the SVE tests, and the SVE system operation), it does not appear that upgradient VOC sources are impacting the site. The well most impacted with PCE is the most downgradient well which is closest to the potential off-site sources based on the 2001 passive vapor screening. Thus, previously proposed upgradient monitoring wells are not recommended.

Enhancing reductive dechlorination (by injecting a carbon source such as emulsified oil) was suggested previously, but the RSE-lite team does not believe that technology is a good fit at the site because of the 100 foot depth to groundwater and associated high cost of injection wells, the relatively low VOC concentrations in groundwater, and most importantly, the fact that the vadose zone would not be addressed.

NOTICE

Work described herein was performed by Tetra Tech GEO for the U.S. Environmental Protection Agency (U.S. E.P.A). Work conducted by Tetra Tech GEO, including preparation of this report, was performed under Work Assignment #48 of EPA contract EP-W-07-078 with Tetra Tech EM, Inc., Chicago, Illinois. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

PREFACE

This report was prepared as part of a project conducted by the United States Environmental Protection Agency Office of Superfund Remediation and Technology Innovation (U.S. EPA OSRTI) in support of the "Action Plan for Ground Water Remedy Optimization" (OSWER 9283.1-25, August 25, 2004). The objective of this project is to conduct Remediation System Evaluations (RSEs) at selected pump and treat (P&T) systems that are jointly funded by EPA and the associated State agency. The project contacts are as follows:

Organization	Key Contact	Contact Information
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Tetra Tech EM, Inc. (Contractor to EPA)	Therese Gioia	Tetra Tech EM Inc. 1881 Campus Commons Drive, Suite 200 Reston, VA 20191 phone: 815-923-2368 Therese.Gioia@tetratech.com
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1.0 INTRODUCTION

1.1 PURPOSE

During fiscal years 2000 and 2001 independent reviews called Remediation System Evaluations (RSEs) were conducted at 20 operating Fund-lead pump and treat (P&T) sites (i.e., those sites with P&T systems funded and managed by Superfund and the States). Due to the opportunities for system optimization that arose from those RSEs, EPA OSRTI has incorporated RSEs into a larger post-construction complete strategy for Fund-lead remedies as documented in *OSWER Directive No. 9283.1-25, Action Plan for Ground Water Remedy Optimization*. A strong interest in sustainability has also developed in the private sector and within Federal, State, and Municipal governments. Consistent with this interest, OSRTI has developed a Green Remediation Primer (http://cluin.org/greenremediation/) and now as a pilot effort considers green remediation during independent evaluations.

The RSE process involves a team of expert hydrogeologists and engineers that are independent of the site, conducting a third-party evaluation of the operating remedy. It is a broad evaluation that considers the goals of the remedy, site conceptual model, available site data, performance considerations, protectiveness, cost-effectiveness, closure strategy, and sustainability. The evaluation includes reviewing site documents, potentially visiting the site for one day, and compiling a report that includes recommendations in the following categories:

- Protectiveness
- Cost-effectiveness
- Technical improvement
- Site closure
- Green remediation

The streamlined RSE process or RSE-lite is similar to the RSE process but does not include a site visit.

The recommendations are intended to help the site team identify opportunities for improvements. In many cases, further analysis of a recommendation, beyond that provided in this report, may be needed prior to implementation of the recommendation. Note that the recommendations are based on an independent evaluation, and represent the opinions of the evaluation team. These recommendations do not constitute requirements for future action, but rather are provided for consideration by the Region and other site stakeholders.

The Intermountain Waste Oil Refinery was selected by EPA OSRTI based on a nomination from EPA Region 8 and the State of Utah due to the rebound in contaminant concentrations since the initial active remedial action was concluded in 2006.

1.2 TEAM COMPOSITION

The RSE team consists of the following individuals:

Name	Affiliation	Phone	Email
Peter Rich	Tetra Tech GEO	410-990-4607	peter.rich@tetratech.com
Rob Greenwald	Tetra Tech GEO	732-409-0344	rob.greenwald@tetratech.com

In addition, Jennifer Hovis, Tracy Hopkins and Matt Charsky from EPA Headquarters participated in the RSE-lite conference call. Kimberly White from EPA Region I was an observer on the call.

1.3 DOCUMENTS REVIEWED

The following documents were reviewed. The reader is directed to these documents for additional site information that is not provided in this report.

- EPA Superfund Record of Decision, OU1 – November 2002
- Design Analysis for Treatability Study- March 2004
- Remedial Investigation Report, OU2- June 2004
- Treatability Study Technical Memorandum- July 2004
- EPA Superfund Record of Decision, OU2 – August 2004
- Update Fact Sheet, October 2006
- EPA Five-Year Review Report – September 2008
- Final Remedial Action Status Report, OU2- December 2010
- Annual Update to the Five-Year Review, January 2011
- January 2011 VOC and MNA Sample Results
- April 2011 VOC Sample Results

1.4 PERSONS CONTACTED

The following individuals associated with the site participated in the conference call:

Name	Affiliation	Phone	Email
Lisa Lloyd	U.S. EPA Region 8 (RPM)	303-312-6537	Lloyd.Lisa@epamail.epa.gov
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Nathan Smith	CDM		SmithNT@cdm.com

DEQ= "Department of Environmental Quality"

1.5 BASIC SITE INFORMATION AND SCOPE OF REVIEW

1.5.1 LOCATION

According to the 2008 Five Year Review and other site documents, the Intermountain Waste Oil Refinery (IWOR) ("the site") is located at 995 South 500 West in the City of Bountiful, Davis County, Utah. The site is approximately 2 acres. It is bordered on the north and east by residences and on the south and west by commercial buildings along US-89 (500 West). The site is mostly flat with a slightly lower elevation to the west. A site location map is included in Attachment A. The buildings associated with the IWOR operations have been demolished and the site has been redeveloped.

1.5.2 SITE HISTORY, POTENTIAL SOURCES, AND RSE SCOPE

According to the site documents, the IWOR facility was a brick manufacturing facility starting prior to 1950. In the 1950s an asphalt business was operated at the site. From 1957 to 1993 a petroleum product hauling business was run at the site and during the 1970s an oil blending operation was occurring. Groundwater at the site was impacted with solvents, mainly trichloroethylene (TCE) and petroleum hydrocarbons. TCE was commonly used in asphalt testing laboratories to separate aggregate from bitumen. The TCE source area appears to be near the former laboratory building location.

In 1992, studies by the property owner detected VOCs, specifically TCE (at 991 ug/L) and 1,1 DCA in the original onsite well (later labeled MW-07) which is screened from 80 to 100 ft below ground surface. The Utah DEQ sampled an onsite sump in January 1995 and detected toluene, PCA and TCE above MCLs. In April 1996, Utah DEQ sampled the onsite well and detected TCE and 1,1 DCA above MCLs, and sampled onsite soils and found one or more samples with ethylbenzene, trimethylbenzene, n-butylbenzene, toluene and 1,2 DCA above the Superfund Chemical Data Matrix Cancer Risk Screening Concentrations. Utah DEQ conducted an expanded site investigation in June 1998 and found TCE and cis-1,2 DCE above MCLs in the onsite well. In August 2001 EPA conducted a removal action disposing of the contents of numerous containers, above ground tanks and laboratory chemicals. EPA conducted an RI from December 2001 to June 2004. The site was subdivided into:

- OU1- near surface soil and potential sources including tanks, drums and containers; and,
- OU2- the vadose zone and groundwater contamination.

Nine groundwater monitoring wells were installed as part of the RI.

The active OU-2 remedy operated from May 2004 to February 2006 and included pump and treat (P&T) for groundwater from well MW-02 (at the leading edge of the plume just beyond the west site boundary) and P&T combined with vapor extraction at MW-04 (approximately 50 feet downgradient of the original onsite well MW-07). TCE concentrations in groundwater (measured monthly) dropped below MCLs at MW-02 and MW-04 in December 2004 and June 2004 respectively, and remained below MCLs until system operation was ceased in February 2006. MW-07 was dry for all sampling events after sampling on March 2003 (160 ug/L TCE detected) and was not replaced for sampling during 2005/ 2006 when the decisions to turn off the system and dismantle and remove the system (October 2006) were made. It is noted that MW-08 was installed near MW-07 as part of the RI, but it is much deeper than MW-07 (MW-08 is screened from 130 to 150 ft bgs) and MW-08 is not impacted by VOCs. TCE concentrations increased at MW-04 after the P&T operations were discontinued. TCE was detected at a concentration of 16 ug/L in January 2008 at MW-04 and has typically been above the MCL since that time. MW-02 has also had TCE levels at or just above the MCL during several monitoring events since 2008.

This RSE-lite focuses on:

- performance of the active system during active operation;
- conceptual model(s) for the rebound of TCE (and cis 1,2 DCE) concentrations and the occurrence of PCE detections at the site; and,
- options for future remediation to meet OU2 ROD objectives.

1.5.3 HYDROGEOLOGIC SETTING

Information in this section is primarily from site documents and does not include interpretation by the RSE-lite team.

The site is located between the Wasatch Mountains to the east and the Oquirrh Mountains to the west within the Basin and Range Physiographic Province. It is comprised of basin-fill deposits which were eroded from the mountains and deposited during the Pre-Pleistocene and Pleistocene Epochs. The basin fill is composed of alluvial and lacustrine deposits ranging from coarse to fine grained.

At the site, a one to two foot thick surface fill layer is underlain by a sandy clay layer to a depth of 10 feet to 25 feet bgs. The clay layer is underlain by a mixture of sandy gravel and gravelly sands to 30 feet to 55 feet bgs followed by interbedded gravels, sands, silts and clays extending to 100 feet bgs. Sandy gravels and gravelly sands extend from 100 feet bgs to at least 240 feet bgs. Groundwater is encountered at 100 feet to 110 feet bgs.

Wells at the site are considered completed in the shallow portion of the East Shore Aquifer (60 to 250 ft bgs). The East Shore Aquifer also has intermediate (250 to 500 ft bgs) and deep (>500 ft bgs) portions. The shallow East Shore aquifer is reported to be saline and not used for potable purposes in the area by the site team.

At the site the shallow aquifer flow direction is generally just north of west, with a relatively flat hydraulic gradient of approximately 0.0021 based on April 2011 water levels (MW-09U to MW-02). A slug test at MW-02 indicated a hydraulic conductivity of 7.0X10-4 centimeters/second or about 2 ft/day. Assuming an effective porosity of 0.10 to 0.25 for a gravel, sand and silt mixture the groundwater velocity would range from 6 to 15 feet per year.

1.5.4 POTENTIAL RECEPTORS

Contaminant exposure pathways considered to be most significant at the site at the time of the ROD are summarized as follows:

- Vapor intrusion of VOCs from contaminated soil into indoor air is a risk to structures above. The OU1 ROD included a Land Use Control requiring any building constructed on the site to have measures to eliminate vapor intrusion.
- There is a potential for the site groundwater to be used as drinking water. From the OU2 ROD- "currently no one is using this portion of the aquifer for drinking water. However, the state of Utah considers the groundwater a potential drinking water source. It is not possible to determine

when the upper portion of the aquifer may be used for a drinking water source." There are water supply wells in the area within 1000 feet of the site but they are screened at intervals deeper than 250 feet bgs. Deeper water supply wells in the area have been impacted by TCE and PCE but the RSE team understands that the IWOR site is not suspected as a source of supply well impacts.

1.5.5 DESCRIPTION OF GROUNDWATER PLUME

The first figure in Attachment A illustrates the most recent VOC concentrations in groundwater (April 2011). A narrow plume impacted by TCE and cis 1,2 DCE is interpreted to be present from the former source area well (MW-07) location just south and east of the former laboratory building to the west edge of the site (MW-02). The highest TCE concentration detected in April 2011 was 16.1 ug/L at MW-04 (MW-07 is dry and no longer available for sampling, but historically it had higher concentrations of TCE than are currently observed at MW-04). The size of the TCE plume in excess of MCLs is likely up to about 200 feet long and 50 feet wide. The 1,2 DCE plume is co-located with the TCE plume but only MW-04 has periodically had levels detected above the MCL.

PCE (potentially from an off-site source) was detected at 4.6 ug/L in April 2011 at MW-02, and was also detected at levels below 1 ug/L at three other wells in the northwest portion of the site. No on-site PCE source was found during previous RI investigations. The RSE-lite team believes that the occurrence of PCE in MW-02 and other wells in the downgradient portion of the site is most likely the result of PCE in vapors migrating from a source somewhere west of the site. Passive vapor sampling conducted in 2001 found several areas west of the site with elevated PCE and TCE vapor levels but none to the upgradient (i.e., east side) of the site.

Site reports indicate that, based on groundwater sampling, all VOC impacts in groundwater are isolated to the top of the water table to a maximum depth of less than 130 feet bgs. This is based on sampling results at MW-08 which was installed with a screened depth of 130 ft bgs to 150 ft bgs (near MW-07) and has not had detections of VOCs. The presence of cis 1,2 DCE above TCE levels indicates naturally occurring reductive dechlorination of the TCE source; however the lack of vinyl chloride indicates that enhancement by nutrient and perhaps bacterial introduction might be needed to achieve complete dechlorination of TCE in the groundwater.

The operation of the remediation system, including P&T at MW-02 and P&T plus vapor extraction at MW-04, reduced concentrations to below MCLs at locations that were monitored. However, the lack of groundwater monitoring at MW-07 and the concentrations in the vapor collected just before system shutdown indicate that a rebound of TCE levels in groundwater should not have been unexpected after system shutdown. It is very likely that pumping at MW-02 and MW-04 resulted in the contribution of a high percentage of clean water to the pumping wells (from below and/or horizontally from outside the plume). Once the system was shut down natural flow conditions returned and impacts from the source area likely migrated back to the shallow monitoring wells, resulting in the rebound of TCE concentrations.

2.0 SYSTEM DESCRIPTION

The previously operated remedy included P&T at downgradient well MW-02 and dual-phase (groundwater and vapor) extraction from MW-04 about 50' downgradient of the original source area well (MW-07). The systems began operation with treatability studies from May 2004 to September 2004. The system operation continued until February 2006.

The treatability study included short tests of vapor extraction at MW-07 and MW-02 and air sparging at MW-08 combined with vapor extraction at MW-07 as well as the selected remedy. The tests showed the highest vapor concentrations at MW-07 . MW-07 vapor concentrations were up to approximately 129,000 ug/m^3 versus highs of approximately 14,000 ug/m^3 at MW-02 and 31,000 ug/m^3 at MW-04. It was decided that pumping at MW-02 and MW-04 with SVE at MW-04 would treat the area around MW-07 without SVE at MW-07 or installation of a new groundwater pumping well in the immediate vicinity of MW-07.

2.1 P&T SYSTEM

Groundwater was pumped from MW-04 and MW-02 from May 2004 to February 2006. MW-02 was pumped at an average rate of 0.9 gpm (just above the design flow rate of 0.72 gpm to 0.88 gpm) and MW-04 was pumped at an average rate of 2 gpm (below the design rate of 2.7 gpm to 3.3 gpm). Extraction pumps were Grundfos Redi-Flo2 model with variable speed drive and a maximum 2 HP input.

Groundwater was treated using rented GAC equipment (likely two or three 200-pound drums in series) with pre-filtering for sediment removal. Treated water was discharged to the storm sewer and had to meet Utah Administrative Code R317-2 limits of 30 ug/l for TCE, 70 ug/L for cis 1,2 DCE, and 3.3 ug/L for PCE.

System influent concentrations were quite low, and averaged approximately 10 ug/L for total VOCs during the 1.75 yr system operation yielding a total VOC mass removal during that time of about 0.23 pounds.

$$\frac{3\,\text{gal}}{\text{min}} \times \frac{3.785\,\text{L}}{\text{gal}} \times \frac{10\,\text{ug}}{\text{L}} \times \frac{1\,\text{kg}}{10^9\,\text{ug}} \times \frac{2.2\,\text{lbs}}{\text{kg}} \times \frac{1440\,\text{min}}{\text{day}} \times 640\,\text{days} = 0.23\,\text{lbs}$$

2.2 SVE SYSTEM

The SVE system extracted from MW-04 only. The well is screened from 92.5 feet bgs to 117.5 bgs; this typically provided 10 to 15 feet of exposed screen. The SVE system included a rented 25 HP blower with a capacity of about 200 scfm at about 15 inches mercury (204 inches H_2O). SVE tests showed influence of about 1-inch H_2O at 50 feet from an extraction well (MW-07 or MW-04) during the pilot test at flow rates of 30 scfm and 3.5 inches mercury (47.6 inches H_2O). The system was typically operated at 50 scfm to 80 scfm at 54 to 150 inches H_2O at the well head. Vapor was treated by rented GAC units (likely two 200-pound units in series) prior to discharge to the atmosphere.

Influent vapor concentrations were typically about 2,000 ppbv or 10,000 ug/m^3. At 60 scfm this equates to a total VOC mass removal during the 1.75 year system operation of about 34 pounds.

$$\frac{60\,\mathrm{ft}^3}{\mathrm{min}} \times \frac{0.0283\,\mathrm{m}^3}{\mathrm{ft}^3} \times \frac{10{,}000\,\mathrm{ug}}{\mathrm{m}^3} \times \frac{1\,\mathrm{kg}}{10^9\,\mathrm{ug}} \times \frac{2.2\,\mathrm{lbs}}{\mathrm{kg}} \times \frac{1440\,\mathrm{min}}{\mathrm{day}} \times 640\,\mathrm{days} = 34.4\,\mathrm{lbs}$$

2.3 MONITORING PROGRAM

Process Monitoring

Volatile organic compounds (VOCs) in groundwater and soil vapor were sampled monthly at MW-04 and groundwater was sampled monthly at MW-02 during system operation. Groundwater treatment system effluent was sampled monthly for permit compliance; vapor was sampled to determine GAC change-out frequency (monthly sampling frequency assumed). These were initially sent to a private lab to achieve fast turnaround time, with subsequent transition to the CLP lab as operations stabilized.

Groundwater Monitoring

Groundwater is currently monitored quarterly at 9 locations (13 total samples because 2 locations have 3 depth intervals) with water levels measured and samples analyzed for VOCs. The shallow source area well, MW-07 has not been sampled since March 2003 because it has been dry. A replacement well has not been installed. The current quarterly monitoring schedule is a change that was implemented within approximately the last year to provide as much information as possible for making decisions about what do next. Previously (but after system shutoff) the groundwater monitoring was semi-annual rather than quarterly. The VOC samples are sent to the CLP lab.

In addition, analysis of samples for methane, ethane, ethene, chloride, nitrate/nitrite, sulfate, ferrous iron, alkalinity, dissolve oxygen, ORP and COD monitoring is completed quarterly at all monitoring wells. These types of parameters are generally monitored to evaluate natural attenuation, and these samples for "natural attenuation" parameters are sent to a private lab.

3.0 SYSTEM OBJECTIVES, PERFORMANCE, AND CLOSURE CRITERIA

3.1 CURRENT SYSTEM OBJECTIVES AND CLOSURE CRITERIA

The OU2 ROD for the IWOR Site identifies the following Remedial Action Objectives (RAOs):

- Restore the aquifer to beneficial use (drinking water standards) within a reasonable time frame
- Prevent exposure to contaminated ground water through ingestion of contaminated ground water or inhalation of vapors during use
- Prevent the future contamination of ground water that is currently uncontaminated

The ROD lists the only COC as TCE; however PCE and cis 1,2 DCE have also been detected in samples from site wells. Drinking water standards (MCLs) for these constituents are:

Contaminant of Concern	Cleanup Criteria (µg/L)
PCE	5
TCE	5
cis 1,2-DCE	70

We assume that State standards and Federal MCLs would also apply to other contaminants.

3.2 TREATMENT PLANT OPERATION STANDARDS

Treated groundwater was discharged to the storm sewer and was required to meet Utah Administrative Code R317-2 limits of 30 ug/l for TCE, 70 ug/L for cis 1,2 DCE, and 3.3 ug/L for PCE. The system met these standards during operation except for a PCE exceedance in July 2005 of 5.6 ug/L.

The site documents and site team did not note a vapor discharge limit for the system. A limit, if any, would likely have been many times higher than the actual emissions given the relatively low VOC concentrations (as mentioned earlier, approximately 34 lbs of VOCs were removed over 1.75 years, which equates to approximately 0.05 lbs/day which is lower than would typically be expected for an air permit).

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4.0 FINDINGS

4.1 GENERAL FINDINGS

The observations provided below are not intended to imply a deficiency in the work of the system designers, system operators, or site managers but are offered as constructive suggestions in the best interest of the EPA and the public. These observations have the benefit of being formulated based upon operational data unavailable to the original designers. Furthermore, it is likely that site conditions and general knowledge of ground water remediation have changed over time.

4.2 SUBSURFACE PERFORMANCE AND RESPONSE

4.2.1 GROUNDWATER FLOW AND PLUME CAPTURE

Groundwater flow under non-pumping conditions (see attached Figures for interpreted water levels contours for April 2011 conditions) is just north of west with a relatively flat hydraulic gradient. The RSE-lite team evaluated the site hydrogeology, water levels and potentiometric surface map and generally agrees that when MW-04 and MW-02 were pumped the extent of capture likely encompassed the VOC plume.

Comparing the extraction rate from MW-02 and MW-04 (combined 3 gpm) to the groundwater flow rate yields an estimated capture zone width (963 ft) that is much wider than the estimated TCE plume width (assumed to be less than 100 ft):

$$Q = \textit{Saturated Thickness} \times \textit{Width} \times \textit{Hydraulic Gradient} \times \textit{Hydraulic Conductivity}$$

$$3 \text{ gpm} = 578 \text{ ft}^3/\text{day} = 150 \text{ ft} \times X \text{ ft} \times 0.002 \text{ ft/ft} \times 2 \text{ ft/day}$$

$$X = 963 \text{ ft (many times wider than the plume)}$$

In the above calculations, the saturated thickness is the approximate saturated thickness of the East Shore aquifer shallow portion, the gradient is from the July 2010 contours from just upgradient of the source area to the edge of the site near MW-02, and the hydraulic conductivity of 2 feet per day is from a slug test at MW-02. It is difficult to know what the correct value for saturated thickness is for calculation above, since the capture zone of the wells likely does not extend a full 150 ft below the water table. However, using a smaller value for saturated thickness will result in a wider capture zone, so the saturated thickness utilized above is conservative. Note that calculation above is a simplified analysis that does not address the exact locations of the extraction wells and interference between extraction wells, but the level of simplification is appropriate for this site. The RSE-lite team believes that detailed (e.g., numerical) modeling that incorporates the specific locations of the extraction wells will not alter the general conclusion that the extraction rate will capture water from a width much greater than the plume width, and for this site more detailed modeling is not merited.

Based on the hydraulic conductivity, hydraulic gradient, and an assumed porosity of 0.15 the groundwater velocity in non-pumping conditions would be about 10 feet per year:

V = Hydraulic Conductivity × Hydraulic Gradient / porosity

2 ft/day X 0.002 ft/ft X 365 days/yr / 0.15 = 9.73 ft/yr

4.2.2 GROUND WATER CONTAMINANT CONCENTRATIONS

Initial sampling at MW-07 in May 1992 indicated 991 ug/L TCE. Samples analyzed in 1995 and 1998 had TCE concentrations of 750 ug/L and 870 ug/L respectively. The final sample taken at MW-07 in March 2003 had 160 ug/L TCE (it has been dry since). No PCE was detected in the four samples collected. No other well screened in the interval within 20 feet of the top of the water table has since been installed in this suspected source area.

MW-04, fifty feet downgradient from MW-07, is the closest shallow interval well to this area. The maximum TCE concentration at MW-04 prior to remedial system operation was 12 ug/L with no PCE detections. TCE decreased to levels below 1ug/L during system operation while PCE increased to a maximum of 17 ug/L, suggesting that pumping was drawing PCE in from a different source area. Since system operation was terminated, the maximum TCE and PCE have been 32 ug/L and 1.3 ug/L, respectively. In April 2011, TCE and PCE concentrations were 16.1 ug/L and 0.49 ug/L, respectively.

MW-02 is 190 feet downgradient of MW-07 and appears to be the approximate downgradient limit of the current TCE plume. Prior to remedial system operation, the maximum TCE detected was 19 ug/L and PCE was not detected. During operation, TCE decreased to levels below 1 ug/L while PCE was detected up to 21 ug/L. Since system operation was terminated, the maximum TCE and PCE concentrations have been 7.4 and 25 ug/L, respectively. In April 2011, TCE and PCE concentrations were 3.3 ug/L and 4.6 ug/L, respectively.

Cis-1,2 DCE is typically found with TCE detections; it has been above of the MCL of 70 in MW-04 two times since the system operation was terminated. The cis-1,2 DCE detections indicate some naturally occurring degradation of TCE but there is no indication that the degradation is progressing to vinyl chloride and ethane/ethane.

The shallow sampling interval of MW-10, 40 feet to the northwest of MW-04 is the only other site well that has had a VOC detected above cleanup criteria. The maximum TCE detected at MW-10 was 9.2 ug/L in the April 2011 sampling and the maximum PCE was 0.92 ug/L in April 2010.

4.3 COMPONENT PERFORMANCE

4.3.1 GROUNDWATER EXTRACTION SYSTEM

Both MW-02 and MW-04 were reported to be equipped with Grundfos Redi-Flo2 variable speed electric pumps. These pumps have a maximum 2 HP input but based on the flow rate and depth to water they likely operated at about 1HP and 1.5HP, respectively. The pumps apparently operated effectively. Well yields were low as would be expected based on the hydraulic conductivity. Mass removal was minimal. Extraction reduced groundwater concentrations in extraction wells to below cleanup criteria for TCE during remedial system operation, likely because “clean water” (with respect to TCE) was pulled into the wells from outside the plume. However, it is unknown what impact the pumping had on TCE concentrations in the presumed main source area near MW-07.

Based on the passive vapor survey done in May 2001 and the groundwater concentration trends, there are likely PCE sources downgradient and side gradient from the IWOR site. Remedial groundwater pumping, vapor extraction, and possibly natural vapor migration likely brought PCE impacts into the site wells.

4.3.2 GAC for Water Treatment

A treatment system is no longer present at the site. The GAC system was apparently generally effective for water treatment with only one reported discharge exceedance. Sediment filters were used to prevent fouling of the GAC. No GAC change-outs were reported.

4.3.3 GAC for Vapor Treatment

A treatment system is no longer present at the site. GAC was used to treat vapors prior to discharge. The system was apparently effective for treatment although effluent data were not provided. The Final Remedial Action Status Report (RASR) indicates that the GAC units (1600 lbs total) were changed out once after 6 months of operation.

4.3.4 SVE System

Long-term vapor extraction only took place at MW-04. Vapor mass removal was over 100 times greater than mass removed from groundwater. Vapor concentrations were generally steady from October 2004 through the last sampling data of December 2005.

4.4 Components Or Processes That Account For Majority of Annual Costs

Based on costs for 22 weeks of O&M from October 2005 to February 2006 provided in Table 4-2 of the Remedial Action Status Report (December 2010) and conversations with the site team, the RSE-lite team estimates that annual costs for P&T operation, SVE operation, and groundwater monitoring (not including treatment equipment rental) were approximately $155,700 per year as summarized in the following table.

Item Description	**Approximate Annual Cost When P&T/SVE was Operating***
Project Management	$16,800
Routine system O&M labor	$43,200
Electricity	$13,500
GAC	$4,800
GAC Disposal	$2,000
Bag Filters including disposal	$3,400
Laboratory – process water , process vapor and groundwater	$72,000
Total	**$155,700**

**Items reported over 22 weeks scaled by 52/22; items reported over 5 months scaled by 12/5*

Based on costs provided in Table 4-2 and discussion in Section 4.3 of the Remedial Action Status Report (December 2010) for the period after the system operation was terminated, the total costs without system operation were approximately $71,000 over 4.5 years, or approximately $16,000 per year. Those costs include groundwater monitoring labor and analysis (approximately $11,000 per year), project management (approximately $4,200 per year) and work plans (less than $1,000 per year). Note that the recent annual costs per year for groundwater monitoring are greater than the average cost per year over this 4.5 year period, because monitoring frequency was recently increased from semi-annual to quarterly. The 2010 Remedial Action Status Report (Section 5.3) indicates current events cost between $6,000 and $8,000 per event, which would indicate current groundwater monitoring costs are between $24,000 and $32,000 per year.

The approximate costs summarized above are discussed in more detail below.

4.4.1 UTILITIES

Electricity costs for when the system operated are based on estimated electricity usage by the following motors:

- Submersible pumps: two 2HP Grundfos Redi-Flo2 pumps operating continuously, at 75% load for RW-4 and 50% load for RW-2
- Transfer pumps: assumed 2 HP each for two pumps, 75% load and operating 25% of the time
- SVE blower: 25 HP operating continuously at assumed 75% load

All motors are assumed to have operated at 75% efficiency. Based on these assumptions, the total electricity usage is approximately 193,000 kWh per year, as per the following calculations.

RW2:	2 HP x 0.50 load x 0.75 kW/HP / 0.75 efficiency x 8760 hrs/yr = 8,760 kWh/yr
RW-4:	2 HP x 0.75 load x 0.75 kW/HP / 0.75 efficiency x 8760 hrs/yr = 13,140 kWh/yr
Transfer pumps:	4 HP x .25 x 0.75 load x 0.75 kW/HP / 0.75 efficiency x 8760 hrs/yr = 6,570 kWh/yr
SVE Blower:	25 HP x 0.75 load x 0.75 kW/HP / 0.75 efficiency x 8760 hrs/yr = 164,250 kWh/yr

Assuming an electricity rate of $0.07 per kWh, this translates to a cost of approximately $13,500 per year. As indicated above, the SVE blower represented approximately 85% of the electrical usage during system operation. Currently, there is no electrical usage because the system is not operating.

4.4.2 OPERATOR LABOR

When the system was operating a subcontractor based in Salt Lake City visited the site about twice per month after the first few months. The costs were reported to be approximately $18,000 over 5 months, or approximately $43,200 per year. There are no current operating labor costs because there is no system operating.

4.4.3 PROJECT MANAGEMENT

Based on the information provided, project management costs were reported to be approximately $7,000 over 5 months, or approximately $16,800 per year. Current project management for groundwater monitoring efforts is approximately $4,200 per year. It is not clear if this includes reporting costs.

4.4.4 CHEMICAL ANALYSIS

During system operation, monthly groundwater and process sampling was conducted, as well as vapor sampling via summa canisters. During system operation those costs were reported to be approximately $30,000 over 5 months, or approximately $72,000 per year. Currently there is no process sampling and groundwater sampling is now quarterly at 13 locations for VOC plus bioremediation parameters. The average cost for monitoring (sampling and analysis) since system operation was terminated has been approximately $11,000 per year, but current monitoring costs are likely higher than that average value since monitoring is now quarterly whereas monitoring was semi-annual over much of that period. Thus, current monitoring is more likely on the order of $20,000 per year. It is assumed the analysis for VOCs, which is performed by the CLP lab, is of no cost to the project. The analysis for the MNA parameters at a private lab might be on the order of $5,000 per year (rough estimate) with the balance of the cost ($15,000 per year) for quarterly activities sampling (labor, equipment, etc.).

4.5 APPROXIMATE ENVIRONMENTAL FOOTPRINTS ASSOCIATED WITH REMEDY

The site remedial system has not operated since 2006 so the site currently has a minimal environmental footprint associated with sampling of monitoring wells. During system operation the major contributor to environmental footprints would have been the electricity usage (approximately 193,000 kWh/yr) which was primarily associated with the SVE blower.

It is unclear what the appropriate conversion factors are for converting electricity usage to greenhouse gas emissions and other air pollutant emissions because there is substantial variation and uncertainty in the fuel blend used for electricity and the value of the conversion factors depending on the reference used. According to the city website, the City of Bountiful provides some of its own power generation, some of which is from hydroelectric sources. However the city also purchases power from other providers and the fuel blend and emission factors for the electricity provided by these other sources is not known. The emission factor for greenhouse gases from electricity generation from three different sources is provided below (see Attachment B):

- City of Bountiful from eGRID (www.epa.gov/egrid)* – 252 lbs of CO2 per MWh
- Northwest Power Pool (includes Utah) (www.epa.gov/egrid) – 902 lbs of CO2 per MWh
- Utah (www.eia.gov Utah State Profile) – 1,849 lbs of CO2 per MWh

** Note that this value is for the power generated by the City of Bountiful but would not include the electricity purchased from other providers by the City of Bountiful and used by City of Bountiful customers.*

Given the wide uncertainty associated with the emission factor for electricity and the prevalent role of electricity in the energy used by the remedy, the optimization team has not attempted to calculate the air emission footprints for the previous remedy.

The extracted water (approximately 3 gpm) discharged to the storm sewer would represent a minor use of water associated with the previous remedy. There would have been other minor footprints associated with transportation to and from the site, and for transporting samples. It is assumed that those footprints would be minor versus the electricity footprints. There would have also been minor use of materials such as the bag filters and the GAC.

4.6 RECURRING PROBLEMS OR ISSUES

No recurring problems or issues were reported by the site team.

4.7 REGULATORY COMPLIANCE

No remedial system is currently operating.

4.8 SAFETY RECORD

No health and safety issues were identified during the RSE-lite conference call.

5.0 EFFECTIVENESS OF THE SYSTEM TO PROTECT HUMAN HEALTH AND THE ENVIRONMENT

5.1 GROUND WATER

There are water supply wells within 1000 feet of the site but they are screened deeper than 250 feet bgs and site VOC impacts have not been found below 130 feet bgs. The site team reports that shallow groundwater is not suited for potable use because of high chloride; however, it is considered a potential drinking water source by the state.

5.2 SURFACE WATER

The nearest surface water to the site is Mill Creek approximately 1500 feet to the north. Artesian wells and springs are reported about a half mile to the west of the site. The groundwater plume does not extend to surface water bodies.

5.3 AIR

Vapor levels reported in the SVE extraction well (MW-04) and pilot test wells (MW-07 and MW-02) were high enough to present a concern for vapor intrusion. The site has been redeveloped and the OU1 ROD required measures to prevent vapor intrusion into structures.

5.4 SOIL

Site surface soils have been remediated or the exposure pathway has been eliminated with concrete or asphalt covers (since the OU2 ROD, the site has been redeveloped and the portion of the site in the probable source area is paved). Subsurface soils may continue to be impacting groundwater, and the site surface covers reduce infiltration.

5.5 WETLANDS AND SEDIMENTS

Please refer to Section 5.2.

6.0 RECOMMENDATIONS

Cost estimates provided herein have levels of certainty comparable to those done for CERCLA Feasibility Studies (-30%/+50%), and these cost estimates have been prepared in a manner generally consistent with EPA 540-R-00-002, *A Guide to Developing and Documenting Cost Estimates During the Feasibility Study*, July, 2000. The costs presented do not include potential costs associated with community or public relations activities that may be conducted prior to field activities. The costs and sustainability impacts of these recommendations are summarized in Tables 6-1 and 6-2.

6.1 RECOMMENDATIONS TO IMPROVE EFFECTIVENESS

6.1.1 INVESTIGATE SITE SOURCE AREA AND INSTALL DUAL PHASE EXTRACTION (DPE) POINTS WITH SCREENS AT IMPACTED DEPTHS

Based on the TCE concentrations during the previous SVE pilot test and DPE system operations, coupled with rebounds in TCE concentrations after those operations were discontinued, it is likely that elevated levels of VOCs remain in the vadose zone in the suspected source area near MW-07. MW-07 had the highest TCE concentrations in groundwater at the site until March 2003, but MW-7 could not be sampled after that because of low water levels. The RSE-lite Team recommends using a membrane interface probe (MIP) or another method to actively sample soil gas and shallow groundwater for VOCs at approximately three locations near MW-07 (see the second figure in Attachment A). Assuming impacts are confirmed, DPE wells suited for soil vapor extraction of the intervals with elevated VOCs, and extraction of shallow groundwater, should be installed in the three locations. A small number of DPE wells in this limited area is suggested for the following reasons:

- sampling of existing wells indicates that the potential on-site TCE source area is likely limited to the MW-07 area;
- remedial system operational experience indicates SVE radius of influence of at least 50 feet; and
- groundwater pumping at the proposed wells would be for mass removal purposes (in conjunction with the extraction of vapors that would be the primary method for removing contaminant mass) and not for groundwater capture.

The proposed investigation including well installation should cost about $75,000; including $30,000 for the investigation plan and sampling and $45,000 for the drilling and well installation. An initial round of sampling at these three new wells for VOCs vapor and groundwater might cost on the order of $5,000 for sampling, analysis, and reporting.

6.1.2 OPERATE DPE SYSTEM NEAR MW-7 TO REMOVE TCE MASS NEAR SOURCE AREA

The RSE-lite team recommends operation of a SVE system coupled with groundwater extraction (i.e., dual phase extraction) using three new wells installed near MW-7 discussed in Section 6.1.1 (see second figure in Attachment A for suggested locations of the new wells). MW-7 could also be considered for an extraction well in the SVE system. The primary intent of these wells is to remove remaining TCE source material from the unsaturated zone via SVE. However, since it is assumed that groundwater in this area is more impacted than in other portions of the site, it also makes sense to pump and treat groundwater for the purpose of mass removal. The actual extent of groundwater capture during system operation should not be a significant focus, since concentrations of TCE leaving the site are already so low. Rather, the focus of this system should be to remove remaining TCE mass in the source area (vadose zone and groundwater) to an extent that MCLs for TCE in groundwater near the source area are achieved or approached.

The RSE-lite team does not believe extraction of groundwater or vapor should be conducted at MW-2 or MW-4, for several reasons: 1) those wells are closer to the potential off-site PCE source, and pumping from the suggested new wells are somewhat less likely to draw in PCE impacts from off-site; and 2) it will be logistically more simple to keep air and water extraction in one small portion of the site.

SVE operation should continue until TCE concentrations are reduced to levels of about 200 ppbv (the 2004 SVE pilot test at MW-07 indicated TCE at 2,700 ppbv to 10,000 ppbv). The equilibrium soil vapor concentration for 5 ug/l TCE in groundwater at 15 degrees Celsius is 241 ppbv. Thus, a vapor concentration of 200 ppbv will generally correspond to groundwater concentrations near the MCL or below.

The new wells (drilled as part of recommendation 6.1.1) should be connected by underground piping to a properly sized blower system with appropriate moisture separator and fail safes. It is suggested that the equipment be purchased rather than rented. The blower should have a capacity of about 250 scfm at 60 inches H2O (Ametek Rotron DR858, 10HP or similar). The SVE emissions should be treated through two 400 lb GAC units in series. Well pumps should be installed in the three source area wells. A reasonable pumping rate from the three new wells is likely on the order of 2 gpm total. The water should be pumped through underground piping to a tank where condensate from the SVE system can also be collected then the water would be pumped through sediment filters and two 200 lb GAC units in series prior to discharge to the storm sewer. We assume that an effluent tank will not be required.

In addition to the installation of the new wells discussed in Section 6.1.1, the likely capital costs for this system would be approximately $132,000:

- About 100’ piping: $5,000
- Blower unit with controls: $20,000
- 3 Submersible pumps installed: $18,000
- Conduit and wiring: $6,000
- 4 (2 spare) GAC for vapor: $6,000
- 4 (2 spare) GAC for water: $3,000
- Bag filters; $2,000
- Transfer tank and pump: $2,000
- Installation in an existing building or small shed: $25,000
- Design, Construction Management: $25,000
- Misc: $20,000

Annual operating costs for the proposed system (does not include current groundwater monitoring) are roughly approximated to be $106,000 per year, as follows:

- a weekly system check @$500/wk= $26,000

- monthly water process (3/month) and vapor (3/month) sampling = $15,000
- Approximate 15KW load power (maximum) = $9,000
- GAC including (2) 400 lb vapor and (2) 200 lb water units plus disposal= $6,000
- Project management and reporting = $24,000
- Quarterly sampling of vapor and groundwater for VOCs at three new wells = $6,000
- Misc: $20,000

The quarterly sampling at the three new wells should not significantly add to labor since they will be part of an operating system. It is assumed groundwater monitoring at other existing wells will remain at the same frequency (quarterly) so those costs will not change from current costs.

6.1.3 Institutional Controls

The RSE-lite team recommends that the site team further evaluate if institutional controls would be appropriate to prevent human exposure to contaminated groundwater at the site. The site team has indicated that the shallow groundwater is not used and not suitable for potable use due to inorganics. It appears that there are other VOC sources in the area which could make long-term compliance with MCLs difficult. While active remediation is recommended in Section 6.1.2 to address VOC impacts that likely remain in the source area near MW-07, it is possible that VOC impacts near or at times just above the MCL level may remain at the site.

6.2 Recommendations to Reduce Costs

6.2.1 Stop MNA Analysis

Based on the analytical data, natural reductive dechlorination is not proceeding past DCE at the site and enhanced reductive dechlorination is not a good fit for the site (see Section 6.4.2). Continuing analysis for MNA parameters is not providing information useful for making decisions about remediation and it should be terminated. It was estimated earlier that the analysis cost for these MNA parameters is likely on the order of $5,000 per year. Labor costs would not change.

6.2.2 Reduce Sampling Frequency At Select Wells

The intermediate and deep intervals at MW-09 and MW-10 have not had a VOC detected above 0.5 ug/L in 7 years of sampling. Vertical migration of the VOCs is not a concern at the site and sampling from these wells should be eliminated or at a minimum reduced to an annual frequency. Other wells such as MW-01 and MW-03 offer limited information for site remediation and the site team should consider decreasing sampling frequency at additional select wells as more data is gathered. Assuming MNA parameters are eliminated anyway (see Recommendation 6.2.1) this reduction in monitoring would not reduce analysis costs (since the site does not incur costs for VOC analysis by the CLP lab). Labor will likely be reduced slightly, so there would be some costs savings, but those savings would be minor and are not quantified.

6.2.3 Do Not Install Six of Seven Wells Recommended in 2010 Remedial Action Status Report; Consider Off-site Vapor Survey Instead

The 2010 Remedial Action Status Report suggests the installation of up to seven new monitoring wells (locations are indicated on the first figure in Attachment A). One of the seven proposed monitoring wells, located about 75 feet west (down-gradient) of MW-02, could be useful to indicate potential VOC levels from vapor and the down-gradient extent of the site plume in groundwater beyond MW-02. The RSE–lite team does not suggest that the other six locations be added for the following reasons:

- Based on the current and historic distribution of VOCs in groundwater the site, the relatively slow natural groundwater flow velocity, and historic information on soil vapor concentrations (from passive vapor surveys, the SVE tests, and the SVE system operation), it does not appear that upgradient VOC sources are impacting the site. The well most impacted with PCE is the most downgradient well, MW-02 which is closest to the potential off-site sources based on the 2001 passive vapor screening. Thus, the three upgradient wells suggested in the 2010 report are not likely to yield critical information.

- One of the suggested wells in the 2010 report is near the three new wells suggested in recommendation 6.1.1, so that would be redundant.

- The other two wells suggested in the 2010 report (northeast of MW-10 and southwest of MW-4) are likely not needed, since MW-4 and MW-2 are sufficient to monitor progress of the DPE activities in Recommendation 6.1.2).

The removal of six of the up to seven proposed monitoring well may help avoid up to $90,000 in capital costs, plus the added costs of monitoring those new wells. If an investigation is desired to delineate potential PCE sources off-site, MIP or active soil gas sampling would be suggested, using the locations of the passive vapor screening hits west of the site as a starting point. However, the RSE-lite team does not believe this site should investigate off-site PCE sources (discussed further in Section 6.4.2).

6.3 Recommendations for Technical Improvement

None.

6.4 Considerations for Gaining Site Close Out

6.4.1 Do Not Consider Enhanced Reductive Dechlorination

Enhancing reductive dechlorination (by injecting a carbon source such as emulsified oil) was suggested in the 2010 Remedial Action Status Report, but the RSE-lite team does not believe that technology is a good fit at the site because of the 100 foot depth to groundwater and associated high cost of injection wells, the relatively low VOC concentrations in groundwater, and most importantly, the fact that the vadose zone would not be addressed. The estimates provided in the Section 5.3 of the CDM Final Remedial Action Status Report are likely unrealistically optimistic regarding remedial costs and timeframe. A bioremediation system including 4 injection wells in the source area would likely require approximately $175,000 in capital costs:

- (4) 120 foot deep wells: $60,000
- Inject 200 gallons Emulsified Oil per well diluted to 2%: $15,000
- Injection labor: $20,000
- Injection equipment: $20,000
- Bioaugmentation culture: $3,000
- Initial Performance Monitoring: $15,000
- Work plan/Design: $30,000
- Misc: $12,000

Extra monitoring costs and reporting costs would likely total at least $20,000 per year until closure. Maintenance injections, if required might cost about $60,000 every two years.

This would be a good option at the site if the majority of VOC mass were in groundwater. Based on the mass removal discussions in Section 2.1 and 2.2, the majority (likely >>90%) of the VOC mass at the site is present in the vadose zone. If the vadose zone is not addressed, the groundwater will be re-contaminated. Therefore, SVE should be the main component of the remedy; and if SVE is required the additional cost to install and run a low volume pump and treat system is minimal compared to the cost for enhanced reductive dechlorination. Groundwater pumping also provides a more easily measured and monitored remedy that is more appropriate for this site.

6.4.2 DEVELOP AN EXIT STRATEGY

An exit strategy should be developed to indicate when it is possible to terminate active remediation at this site. The RSE-lite team believes that additional active remediation is currently merited since there is likely a remaining TCE source area near MW-7 that is technically feasible to address. Once an attempt has been made to address that source, several outcomes are possible:

- All VOCs may meet MCLs in groundwater, and the site can be closed after some period of monitoring. The RSE-lite team assumes about three years of sampling would be needed after shutting off the systems to show that a rebound does not occur.

- TCE in groundwater may meet MCLs but the active remedy may pull PCE from off-site sources resulting in low PCE concentrations in groundwater that might exceed MCLs. If that occurs, a reasonable exit strategy might allow for monitoring of continued attenuation of the PCE concentrations in groundwater at the site after the active remedy for TCE is terminated, with no further active remediation.

- TCE may remain on some portions of the site at levels slightly above MCLs, but at lower concentrations than are currently observed and at concentrations that do not result in off-site TCE impacts above MCLs in the future. At that point, a TI waiver for the remaining TCE concentrations exceeding MCLs may be appropriate.

The exit strategy should be developed and documented in a site report as soon as possible, to serve as a basis for the site team to make practical decisions regarding continued active remediation in the future. The RSE-lite team estimates that development of the exit strategy for this site will cost approximately $10,000 total for a draft and final document.

6.5 RECOMMENDATIONS FOR ADDITIONAL GREEN PRACTICES

6.5.1 USE SMALLER SVE BLOWER THAN THE PREVIOUS SYSTEM

As mentioned earlier, approximately 85% of the electric use for the previous system was associated with the 25 HP SVE blower. As described in Section 6.1.2, a 10 HP blower is recommended for SVE in a new DPE system (for up to 3 wells) rather than the 25 HP unit used in the previous system. This will reduce electrical usage on the order of 60% versus the previous system, with associated reductions in emissions (as well as reduction in electricity cost). Since this blower represents a capital cost for another recommendation, cost savings for electricity savings for using a small blower are not estimated.

6.5.2 CONSIDERATIONS FOR RENEWABLE ENERGY AT THE SITE

Due to the projected short-term operation of the proposed system and the redeveloped status of the site, the RSE-lite team does not encourage consideration and investment into a renewable energy system for the site. If the site team chooses to reduce the remedy footprint through the use of renewable energy, it could consider green power purchasing through the local utility (if available) or through the purchase of renewable energy certificates. Green power purchasing would increase costs (perhaps by approximately $0.03 per kWh) but would avoid significant capital costs for renewable energy system design and installation. Assuming a future system might use on the order of 80,000 kWh/yr (lower than the previous system due to lower HP for the blower), so purchasing renewable energy certificates at $0.03 per kWh might cost on the order of $2,400 per year.

Table 6-1. Cost Summary Table

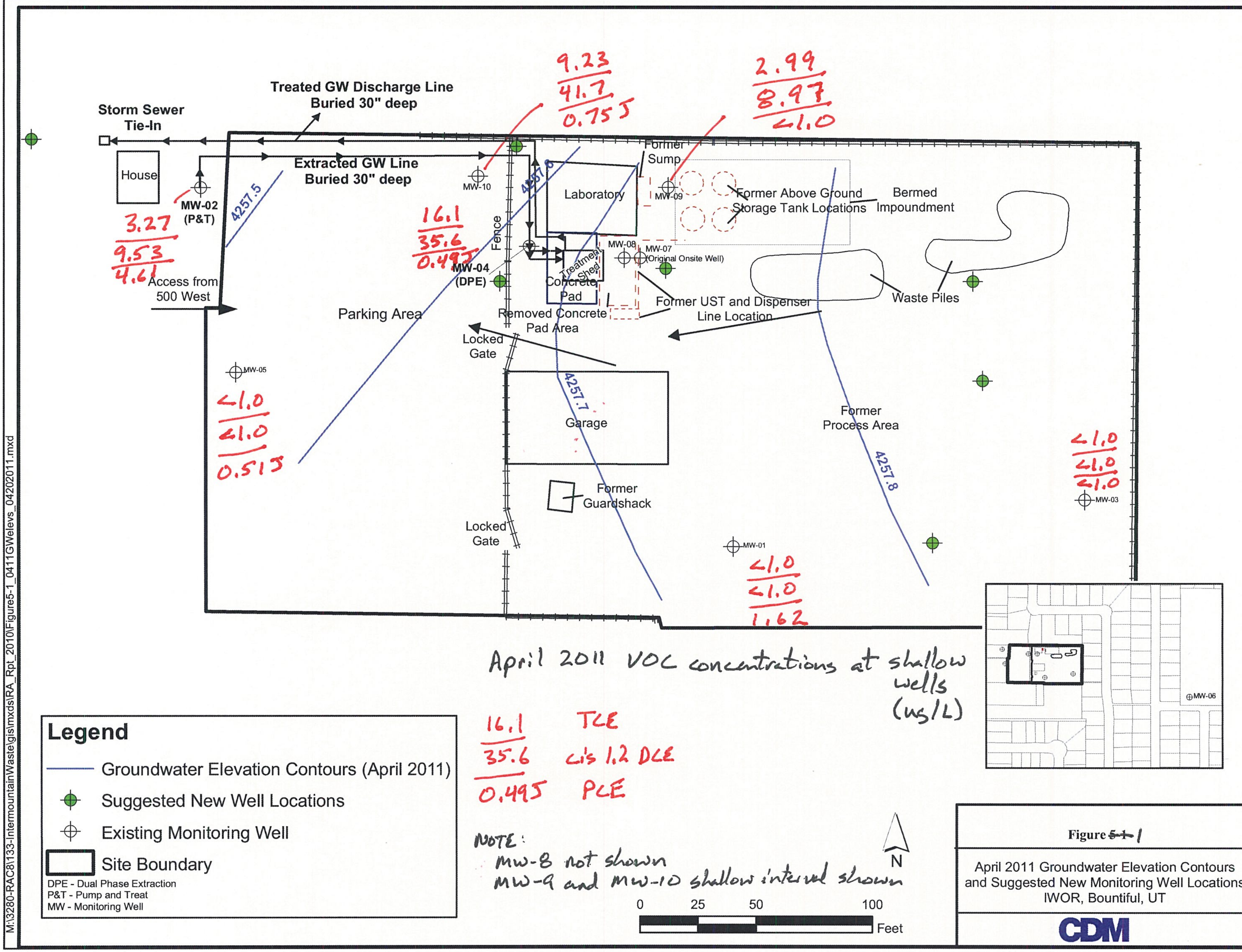
Recommendation	Reason	Additional Capital Costs ($)	Estimated Change in Annual Costs ($/yr)	Estimated Change in Life-Cycle Costs $*	Discounted Estimated Change in Life-Cycle Costs $**
6.1.1 INVESTIGATE SOURCE AREAS AND INSTALL DPE WELLS	Effectiveness	$80,000	$0	$80,000	$80,000
6.1.2 INSTALL AND OPERATE DPE SYSTEM	Effectiveness	$132,000	$106,000	$556,000	$537,874
6.1.3 INSTITUTIONAL CONTROLS	Effectiveness	$0	$0	$0	$0
6.2.1 STOP MNA ANALYSIS	Cost Reduction	$0	($5,000)	($20,000)	($19,145)
6.2.2 REDUCE SAMPLING FREQUENCY AT SELECT WELLS	Cost Reduction	$0	$0	$0	$0
6.2.3 DO NOT INSTALL SIX OF SEVEN PROPOSED WELLS	Cost Reduction	($90,000)	$0	($90,000)	($90,000)
6.4.1 DO NOT CONSIDER ENHANCED REDUCTIVE DECHLORINATION	Site Closeout	$0	Not quantified		
6.4.2 DEVELOP AN EXIT STRATEGY	Site Closeout	$10,000	$0	$10,000	$10.000
6.5.1 USE SMALLER SVE BLOWER	Green Practice	Former system has not operated since 2006, so savings is not quantified			
6.5.2 CONSIDERATIONS FOR RENEWABLE ENERGY AT THE SITE	Green Practice	$0	$2,400	$9,600	$9,190

Costs in parentheses imply cost reductions
* assumes 4 years of operation with a discount rate of 0% (i.e., no discounting)
** assumes 4 years of operation with a discount rate of 3%, no discounting in the first year (P/A= 3.829)

Table 6-2. Green Remediation Summary Table

Recommendation	Reason	Green Remediation Effects
6.1.1 INVESTIGATE SOURCE AREAS AND INSTALL DPE WELLS	Effectiveness	Increase in energy and materials associated with well installation
6.1.2 INSTALL AND OPERATE DPE SYSTEM	Effectiveness	Use of 10 HP blower rather than previous 25 HP Blower may reduce electricity up to ~ 60%.
6.1.3 INSTITUTIONAL CONTROLS	Effectiveness	Negligible increases or decreases in remedy footprint
6.2.1 STOP MNA ANALYSIS	Cost reduction	Reduction in energy and materials usage by laboratory associated with sample analysis as well as shipping
6.2.2 REDUCE SAMPLING FREQUENCY AT SELECT WELLS	Cost Reduction	Reduction in energy and materials usage by laboratory associated with sample analysis
6.2.3 DO NOT INSTALL SIX OF SEVEN PROPOSED WELLS	Cost Reduction	Decrease in energy and materials associated with well installation
6.4.1 DO NOT CONSIDER ENHANCED REDUCTIVE DECHLORINATION	Site Closeout	Decrease in energy and materials associated with well installation and emulsified oil injection.
6.4.2 DEVELOP AN EXIT STRATEGY	Site Closeout	Negligible increases or decreases in remedy footprint
6.5.1 USE SMALLER SVE BLOWER	Green Practice	See 6.1.2.
6.5.2 CONSIDERATIONS FOR RENEWABLE ENERGY AT THE SITE	Green Practice	Consider purchase of Renewable Energy Certificates to offset emission associated with electricity

ATTACHMENT A
FIGURES FROM EXISTING REPORTS



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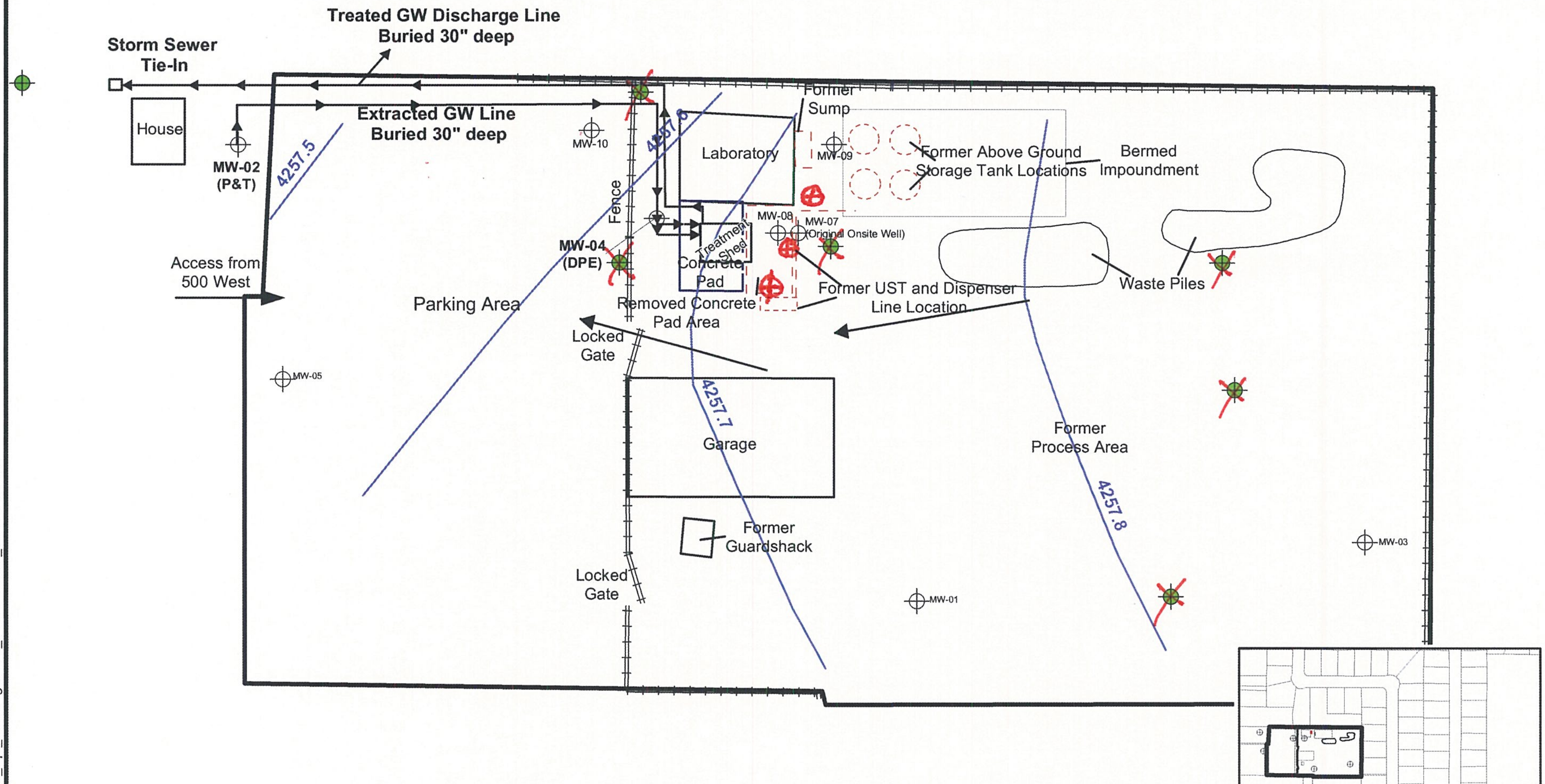


Legend

- Groundwater Elevation Contours (April 2011)
- ~~Suggested New Well Locations~~
- Existing Monitoring Well
- Site Boundary

DPE - Dual Phase Extraction
P&T - Pump and Treat
MW - Monitoring Well

PROPOSED SOURCE AREA WELLS/ SVE OR DPE EXTRACTION POINTS

Figure ~~5-1~~ 2

April 2011 Groundwater Elevation Contours and Suggested New Monitoring Well Locations
IWOR, Bountiful, UT

CDM

M:\3280-RAC8\133-IntermountainWaste\gis\mxds\RA_Rpt_2010\Figure5-1_0411GWelevs_04202011.mxd

ATTACHMENT B
VARIOUS SOURCES OF EMISSIONS DATA ASSOCIATED WITH ELECTRICITY

History

The city of Bountiful, Utah is located ten miles north of Salt Lake City. The citizens of Bountiful first received electric services from a small, local power company called "Bountiful Light and Power Company", which was organized on July 3, 1907. The company was originally capitalized for $10,000. Most of the principal stockholders lived in Bountiful, or the immediate area. The 2005 book value of Bountiful City Light & Power was about $40,000,000.

A distribution system was constructed which served between 200-300 customers. At that time, the officers of the Company conducted a study and determined that it was cheaper to purchase power wholesale than to build a power plant. Accordingly, a contract was signed with the Utah Light and Railway Company, later known as the Utah Light and Traction Company, and presently as Utah Power and Light (UP&L).

The old timers say that the Company failed to keep its distribution system in good repair, and was subject to extensive public criticism, as well as pressure from the Public Service Commission to improve its performance. They also recall that electric service from the Company continued to deteriorate to a level that prompted its customers to petition the city to intervene.

Dr. J.C. Stocks, who was mayor, headed up a citizen's task force to investigate the complaint in about 1934. The investigation eventually lead to the City's decision to own and operate its electric system, and better serve its citizens.

Then, as is the case now, the sources of power and energy were the most challenging aspects of system operation. They realized that cost and reliability are the two most important factors. Meanwhile, the City had negotiated a price for the Company's distribution system, and obtained an option to assure the purchase while the City arranged for financing. Revenue bonds in the amount of $106,000 were issued by the City for construction of the power plant and the purchase of the distribution system. The bonds were paid back through electric revenues.

On May 22, 1935, Bountiful's own power plant produced its first electricity. During that same year, the City Council approved three citizen appointments to serve on the first Bountiful City Light and Power Commission. They were Mayor J.C. Stocks, and Council representatives John S. Ledingham and Alfred G. Brown. One of the first things they did as a Commission was investigate the condition of the power plant. It was then recommended to employ an experienced person as manager. Horton Fackrell served as the first manager for six months. The Commission next appointed Samuel W. Hutchings, who served from 1935 to 1938. Since that time, five men have served as manager: John Ledingham, Robert Nicol, Vaun Bethers, W. Berry Hutchings (twice), and Clifford C. Michaelis.

Berry Hutchings served as manager from 1950 to 1976. Vaun Bethers, the Department Engineer, was appointed manager from 1976 to 1980. During that time Mr. Hutchings served in a new position as Power Resource Manager. His efforts helped Bountiful obtain licenses for the construction of hydro-electric plants on Echo Dam, East Canyon Dam, Moon Lake and Lost Creek Dam. He was also instrumental in Bountiful being awarded the license to take over the Weber River hydro plant in Weber Canyon. However, after nearly ten years of court litigation, Congress decided to re-license that plant to the previous operator.

Mr. Bethers left in 1980 and Mr. Hutchings was reappointed manager. He served in that position until his retirement in 1983. At that time the City promoted from within the department again, selecting Clifford C. Michaelis as manager. The job title was then changed to Director.

The governing board for the Power Department is a Power Commission which is appointed by the mayor and City Council. They work with the staff in making the major decisions for the department and send their recommendations to the City Council. The present members of the Power Commission are: Lowell Leishman (Chairman), David Irvine, Fred Moss (City Council Representative), Richard Foster, Ralph Mabey, John Cushing, and Jed Pitcher.

The Power Department offices were first located in a home at about 180 West 300 South, just east of the present power plant. After the discontinuation of the Bamberger Railroad in 1952, the large warehouse building at 198 South 200 West was owned by Muir-Roberts Produce Company. It was acquired by Bountiful Power in 1964. The building has a historical marker near the front door denoting the railroad connection. In 1978, a major addition was made to the office building, which included ten truck bays and warehouse space on two levels. In 1998, major remodeling of the office spaces was done. In 1988 a six bay garage was constructed to the west of the main building to house more equipment and material.

The City-owned power plant was the first power resource, which at that time consisted of three engines; two six-cylinder Buckeyes (approximately 110 kilowatts), and one three-cylinder Buckeye (approximately 60 kilowatts). As the demand for more power rapidly increased, additional generating units were installed. From 1955 to 1959, four Superior engines were added and only the oldest Buckeye engine was left in place. In 1963 another addition was made to the plant and a Cooper 2,500 kilowatt engine was added. In 1986 Bountiful built a major addition to the plant to allow space for a 7,000 kilowatt Enterprise engine. In 1995, the dispatch center was completely remodeled. In 2001 a gas turbine was installed. At the present time, the power plant houses eight separate turbo-charged generating units, and a gas turbine with an installed capacity of 19,000 kilowatts (if all nine were running at the same time). Today Bountiful City Light and Power serves a population of about 43,000 and has over16,000 metered customer accounts.

In the late 1940's, the cost of diesel fuel to operate the generating units increased to the level where it was as economical to purchase power from UP&L as to generate it; therefore, in 1948, an interconnection with the UP&L system was made. Power was purchased from them for several years to supply the needs of the system.

In 1953 Mountain Fuel Supply Company released an abundant supply of natural gas at a cost substantially below the cost of purchasing power from UP&L. From 1954 to 1957, pressure from several groups tried to force the City out of the power business. The manager, Berry Hutchings, and the Power Commission convinced the City Fathers that natural gas, instead of diesel fuel to operate the power plant generators would save the city millions of dollars. In 1957 another electric revenue bond for $275,000 was issued to convert the existing four generators to dual fuel (natural gas and diesel), upgrade the power plant, and purchase four Superior engines.

The main use of the power plant today is for providing peaking power to meet the needs of the city during high use periods, and for emergency power purposes. It is idle when less expensive power can be purchased to meet the needs of the City. However, in the winter months one engine is put on-line so that the waste heat from it can be sent through pipes to heat the plant buildings and the main office and warehouse building across the street. Bountiful also sells some of its generated power to other utilities. The Power Plant presently supplies less than 10% of the City's power needs.

In 1962 Bountiful was able to successfully contract with the Federal Government to purchase hydroelectric power from the Colorado River Storage Project (CRSP). It was an escalating contract which allowed for more power to be purchased each year to keep up with increased city growth. At that time, that form of power was more expensive than many other sources; but over the years it has become the “low-cost”supply. The City’s present contract is for 43,265 kilowatts per month during the winter season, and 27,148 kilowatts per month during the summer season. The first CRSP power generated at Flaming Gorge Dam was delivered in 1963. Another part of CRSP is power generated by the eight generators at Glen Canyon Dam, which Bountiful started receiving in 1964. Today the Western Area Power Administration (WAPA) is the marketing arm of the Federal Government that was established to allocate those power sales. The City receives about 60 percent of its power from WAPA.

Bountiful City is also a participant in two coal-fired power plants: the Intermountain Power Project (IPP), near Delta, Utah, and the San Juan Project in New Mexico. A portion of the City’s IPP power allocation is presently being sold to six California cities (Anaheim, Burbank, Glendale, Los Angeles, Pasadena and Riverside). Bountiful uses IPP power to cover about 14 percent of its present load. The San Juan plant currently provides about 12 percent of the City’s power requirements.

Over the years, Bountiful has received authorization from the federal government to build and operate hydroelectric facilities at various sites around Utah from the Federal Energy Regulatory Commission (FERC). Bountiful has captured the energy from those renewable resources to provide electricity to its citizens at the most reasonable costs available, while preserving the integrity of the Utah environment. The City was awarded the licenses to operate facilities at Echo Dam and Pineview Dam. The Echo hydro plant was built in 1986. It consists of three vertical turbines, which can generate a total of 4,500 kilowatts. Bountiful built its own 26 mile transmission line to bring that power over the mountains to the city. The Pineview hydro plant was built in 1991. It has one vertical turbine that generates 1,800 kilowatts. Several other projects are currently being studied for their feasibility.

In 1992 Bountiful Power purchased the former Colonial Lumber property on the corner of 200 South and 200 West. The main building is being used for material storage. Part of the land was used to build a new gas turbine in 2001. That unit provides over 4,000 kilowatts.

Bountiful is a member of the Utah Associated Municipal Power System (UAMPS). UAMPS serves 35 cities and 11 other agencies in Utah, Idaho, New Mexico and Arizona. It serves as the power broker and helps make low-cost power available to its members. About 20 percent of Bountiful’s power is purchased through UAMPS.

Over the years the Department has had a variety of experiences with bad weather and the challenges of mother nature. East winds and snow had caused the biggest problems until the floods of 1983. In May 1983 the City endured so called “100 year floods”, which came roaring down the canyons. A wall of water smashed into the City’s Northeast substation on 250 North and caused massive destruction. Rebuilding the substation on higher ground at the same location took a full year. Over the years, the infamous east winds have caused many problems, but Bountiful’s power crews worked through them all. Another notable event took place in the fall of 1990, when the old wooden cooling tower at the Power Plant caught fire (as it was being prepared for demolition) and burned to the ground.

Although the main purpose of the Power Department has been to provide an inexpensive source of power to city residents, much of the margin from the sale of electricity is transferred to the City’s General Fund and Capitol Improvement Fund. Those funds aid in keeping the City’s tax mill levy at a low level. Each year money is transferred to those funds, which helps the City keep its equipment up to date and to help pay for other projects. No tax dollars are used to finance the power system operations.

The most important ingredients for the success of Bountiful City Light and Power are the support of the citizens of Bountiful, the Bountiful City Council, the Power Commission and the great dedication of the Power Department employees. Its employees often work long hours during inclimate weather to restore power and ensure that reliable power is delivered to the customers. Bountiful City Light and Power continues to provide great service to its customers and looks forward to the opportunities that the new century will bring.

Electric Generating Company (EGC) Location (Operator) based Level Data

Company: Bountiful City City of

Parent Company:
Capacity (MW): 25.4
Net Generation (MWh): 26,920.7
Heat Input (MMBtu): 57,511.4

Data Year: 2005
Location (Operator)-based
Owner-based

Generation Resource Mix

Pollutant	Emissions	Units	Output Emission Rates	Units	Input Emission Rates	Units
Annual CO_2	3,397.8	tons	252.43	lb/MWh	118.16	lb/MMBtu
Annual SO_2	0.22	tons	0.0166	lb/MWh	0.0078	lb/MMBtu
Annual NO_x	24.93	tons	1.8522	lb/MWh	0.8670	lb/MMBtu
Ozone Season NO_x	13.17	tons	2.0840	lb/MWh	0.8631	lb/MMBtu
Annual Hg	N/A		N/A		N/A	
Annual CH_4	141.0	lbs	5.24	lb/GWh	N/A	
Annual N_2O	15.2	lbs	0.56	lb/GWh	N/A	

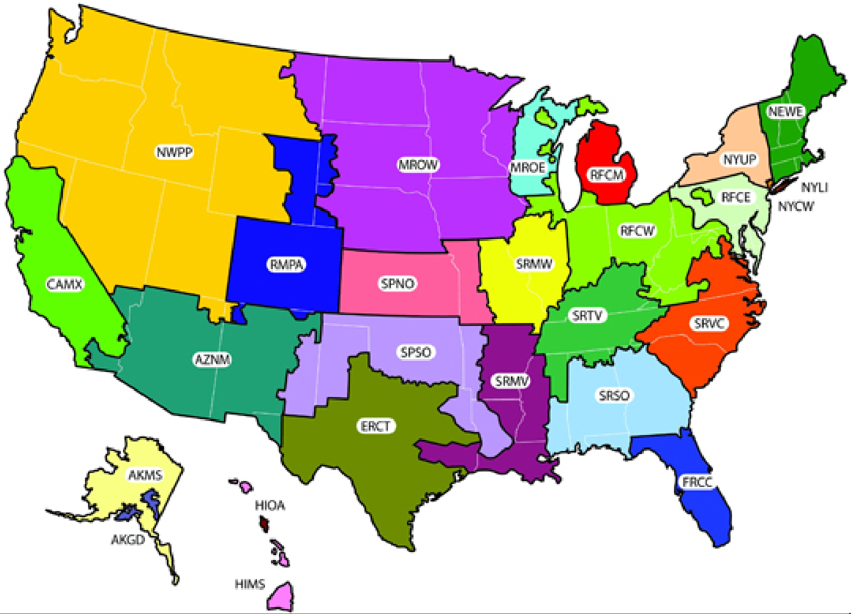
Additional Emissions Rates

eGRIDweb

eGRID2007 Version 1.1 Year 2005 GHG Annual Output Emission Rates

Annual output emission rates for greenhouse gases (GHGs) can be used as default factors for estimating GHG emissions from electricity use when developing a carbon footprint or emission inventory Annual non-baseload output emission rates should not be used for those purposes, but can be used to estimate GHG emissions reductions from reductions in electricity use.

eGRID subregion acronym	eGRID subregion name	Annual output emission rates			Annual non-baseload output emission rates		
		Carbon dioxide (CO2) (lb/MWh)	Methane (CH4) (lb/GWh)	Nitrous oxide (N2O) (lb/GWh)	Carbon dioxide (CO2) (lb/MWh)	Methane (CH4) (lb/GWh)	Nitrous oxide (N2O) (lb/GWh)
AKGD	ASCC Alaska Grid	1,232.36	25.60	6.51	1,473.43	36.41	8.24
AKMS	ASCC Miscellaneous	498.86	20.75	4.08	1,457.11	60.47	11.87
AZNM	WECC Southwest	1,311.05	17.45	17.94	1,201.44	20.80	8.50
CAMX	WECC California	724.12	30.24	8.08	1,083.02	39.24	5.55
ERCT	ERCOT All	1,324.35	18.65	15.11	1,118.86	20.15	5.68
FRCC	FRCC All	1,318.57	45.92	16.94	1,353.72	48.16	12.95
HIMS	HICC Miscellaneous	1,514.92	314.68	46.88	1,674.15	338.44	51.42
HIOA	HICC Oahu	1,811.98	109.47	23.62	1,855.10	120.11	20.79
MROE	MRO East	1,834.72	27.59	30.36	1,828.63	28.82	25.20
MROW	MRO West	1,821.84	28.00	30.71	2,158.79	45.57	35.22
NEWE	NPCC New England	927.68	86.49	17.01	1,314.53	77.47	16.02
NWPP	WECC Northwest	902.24	19.13	14.90	1,333.64	49.28	18.73
NYCW	NPCC NYC/Westchester	815.45	36.02	5.46	1,525.05	56.80	9.08
NYLI	NPCC Long Island	1,536.80	115.41	18.09	1,509.85	60.32	10.78
NYUP	NPCC Upstate NY	720.80	24.82	11.19	1,514.11	45.30	18.41
RFCE	RFC East	1,139.07	30.27	18.71	1,790.50	41.61	24.36
RFCM	RFC Michigan	1,563.28	33.93	27.17	1,663.15	29.40	26.24
RFCW	RFC West	1,537.82	18.23	25.71	1,992.86	24.49	31.72
RMPA	WECC Rockies	1,883.08	22.88	28.75	1,617.71	22.42	20.14
SPNO	SPP North	1,960.94	23.82	32.09	2,169.74	31.18	31.99
SPSO	SPP South	1,658.14	24.98	22.61	1,379.05	24.40	12.04
SRMV	SERC Mississippi Valley	1,019.74	24.31	11.71	1,257.10	29.50	9.82
SRMW	SERC Midwest	1,830.51	21.15	30.50	2,101.16	25.66	32.92
SRSO	SERC South	1,489.54	26.27	25.47	1,697.22	35.20	26.41
SRTV	SERC Tennessee Valley	1,510.44	20.05	25.64	1,998.36	28.25	32.86
SRVC	SERC Virginia/Carolina	1,134.88	23.77	19.79	1,781.28	40.09	27.46



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eGRIDweb

Table 1. 2009 Summary Statistics

Item	Value	U.S. Rank
Utah		
NERC Region(s)		**WECC**
Primary Energy Source		**Coal**
Net Summer Capacity (megawatts)	**7,418**	**39**
Electric Utilities	6,581	32
Independent Power Producers & Combined Heat and Power	838	43
Net Generation (megawatthours)	**43,542,946**	**34**
Electric Utilities	40,991,819	27
Independent Power Producers & Combined Heat and Power	2,551,126	43
Emissions (thousand metric tons)		
Sulfur Dioxide	30	35
Nitrogen Oxide	68	13
Carbon Dioxide	36,518	25
Sulfur Dioxide (lbs/MWh)	1.5	38
Nitrogen Oxide (lbs/MWh)	3.5	5
Carbon Dioxide (lbs/MWh)	1,849	11
Total Retail Sales (megawatthours)	**27,586,700**	**37**
Full Service Provider Sales (megawatthours)	27,586,700	36
Direct Use (megawatthours)	**1,092,589**	**22**
Average Retail Price (cents/kWh)	**6.77**	**45**

MWh = Megawatthours.
kWh = Kilowatthours.
Sources: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor forms.

Table 2. Ten Largest Plants by Generating Capacity, 2009

Plant	Primary Energy Source or Technology	Operating Company	Net Summer Capacity (MW)
Utah			
1. Intermountain Power Project	Coal	Los Angeles City of	1,800
2. Hunter	Coal	PacifiCorp	1,320
3. Huntington	Coal	PacifiCorp	895
4. Lake Side Power Plant	Gas	PacifiCorp	557
5. Currant Creek	Gas	PacifiCorp	540
6. Bonanza	Coal	Deseret Generation & Tran Coop	458
7. Gadsby	Gas	PacifiCorp	348
8. KUCC	Coal	Kennecott Utah Copper Corporation	207
9. Milford Wind Corridor I LLC	Other Renewables	Milford Wind Corridor Phase I LLC	204
10. West Valley Generation Project	Gas	CER Generation LLC	189

MW = Megawatt.
Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 3. Top Five Retailers of Electricity, with End Use Sectors, 2009
(Megawatthours)

Entity	Type of Provider	All Sectors	Residential	Commercial	Industrial	Transportation
Utah						
1. PacifiCorp	Investor-Owned	22,097,825	6,495,687	7,971,632	7,598,164	32,342
2. Provo City Corp	Public	761,759	238,205	390,489	133,065	-
3. City of St George	Public	595,622	265,162	106,452	224,008	-
4. City of Murray	Public	423,943	116,691	258,739	48,513	-
5. City of Logan	Public	397,961	96,476	168,188	133,297	-
Total Sales, Top Five Providers		24,277,110	7,212,221	8,895,500	8,137,047	32,342
Percent of Total State Sales		88	83	87	95	100

- (dash) = Data not available.
Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 4. Electric Power Net Summer Capacity by Primary Energy Source and Industry Sector, 1999 and 2003 Through 2009
(Megawatts)

Energy Source	1999	2003	2004	2005	2006	2007	2008	2009	Percentage Share 1999	Percentage Share 2009
Utah										
Electric Utilities	**5,102**	**5,574**	**5,754**	**6,053**	**6,212**	**6,710**	**6,499**	**6,581**	**97.5**	**88.7**
Coal	4,463	4,461	4,645	4,645	4,645	4,645	4,645	4,645	85.3	62.6
Petroleum	44	46	38	35	35	25	25	25	0.8	0.3
Natural Gas	296	782	796	1,098	1,257	1,755	1,542	1,624	5.7	21.9
Hydroelectric	265	252	252	253	253	253	253	253	5.1	3.4
Other Renewables[1]	35	33	23	23	23	33	34	34	0.7	0.5
Pumped Storage	*	-	-	-	-	-	-	-	*	-
Independent Power Producers and Combined Heat and Power	**131**	**223**	**436**	**475**	**500**	**412**	**633**	**838**	**2.5**	**11.3**
Coal	54	144	181	246	246	226	226	226	1.0	3.0
Petroleum	19	3	-	-	-	-	-	-	0.4	-
Natural Gas	4	72	195	225	215	179	381	378	0.1	5.1
Other Gases[2]	48	-	-	-	-	-	-	-	0.9	-
Hydroelectric	4	2	2	2	2	2	2	2	0.1	*
Other Renewables[1]	1	1	1	1	4	5	23	231	*	3.1
Other[3]	-	-	57	-	32	-	-	-	-	-
Total Electric Industry	**5,233**	**5,797**	**6,190**	**6,528**	**6,712**	**7,122**	**7,132**	**7,418**	**100.0**	**100.0**
Coal	4,517	4,606	4,826	4,891	4,891	4,871	4,871	4,871	86.3	65.7
Petroleum	63	49	38	35	35	25	25	25	1.2	0.3
Natural Gas	300	854	991	1,323	1,473	1,934	1,923	2,002	5.7	27.0
Other Gases[2]	48	-	-	-	-	-	-	-	0.9	-
Hydroelectric	269	254	254	255	255	255	256	256	5.1	3.4
Other Renewables[1]	36	34	24	24	27	38	57	265	0.7	3.6
Pumped Storage	*	-	-	-	-	-	-	-	*	-
Other[3]	-	-	57	-	32	-	-	-	-	-

[1] Other Renewables includes wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[2] Other gases includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[3] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is 1 and values under 0.5 are shown as *).
- (dash) = Data not available.
Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 5. Electric Power Net Generation by Primary Energy Source and Industry Sector, 1999 and 2003 Through 2009
(Megawatthours)

Energy Source	1999	2003	2004	2005	2006	2007	2008	2009	Percentage Share	
									1999	2009
Utah										
Electric Utilities	**36,071,421**	**37,544,892**	**37,165,917**	**36,695,193**	**39,590,509**	**43,319,965**	**44,424,071**	**40,991,819**	**98.1**	**94.1**
Coal	34,125,014	35,579,158	35,634,374	34,824,862	35,667,551	35,910,192	36,761,964	34,284,061	92.8	78.7
Petroleum	29,023	31,386	32,567	40,245	29,619	38,828	43,612	36,057	0.1	0.1
Natural Gas	515,127	1,322,984	864,181	874,505	2,965,072	6,673,998	6,705,185	5,565,584	1.4	12.8
Hydroelectric	1,246,727	412,899	439,919	770,779	737,659	533,021	659,033	826,996	3.4	1.9
Other Renewables[1]	155,530	198,465	194,876	184,802	190,608	163,925	254,277	279,121	0.4	0.6
Independent Power Producers and Combined Heat and Power	**713,207**	**478,774**	**1,046,060**	**1,469,938**	**1,672,815**	**2,052,610**	**2,154,691**	**2,551,126**	**1.9**	**5.9**
Coal	408,767	399,490	983,480	1,145,543	1,187,999	1,260,602	1,258,402	1,242,065	1.1	2.9
Petroleum	1,641	1,480	34	664	32,507	319	-	-	*	-
Natural Gas	94,930	60,123	45,669	302,996	423,478	750,220	661,122	878,458	0.3	2.0
Other Gases[2]	191,285	-	-	-	-	-	35,788	27,933	0.5	0.1
Hydroelectric	8,415	8,440	9,929	13,684	9,124	5,761	9,051	8,261	*	*
Other Renewables[1]	8,169	5,083	3,821	3,948	14,868	31,030	47,585	207,415	*	0.5
Other[3]	-	4,158	3,126	3,102	4,838	4,679	142,743	186,994	-	0.4
Total Electric Industry	**36,784,628**	**38,023,666**	**38,211,977**	**38,165,131**	**41,263,324**	**45,372,575**	**46,578,763**	**43,542,946**	**100.0**	**100.0**
Coal	34,533,781	35,978,648	36,617,854	35,970,405	36,855,550	37,170,794	38,020,367	35,526,126	93.9	81.6
Petroleum	30,664	32,866	32,601	40,909	62,126	39,147	43,612	36,057	0.1	0.1
Natural Gas	610,057	1,383,107	909,850	1,177,501	3,388,550	7,424,218	7,366,307	6,444,042	1.7	14.8
Other Gases[2]	191,285	-	-	-	-	-	35,788	27,933	0.5	0.1
Hydroelectric	1,255,142	421,339	449,848	784,463	746,783	538,782	668,084	835,257	3.4	1.9
Other Renewables[1]	163,699	203,548	198,697	188,750	205,476	194,955	301,862	486,536	0.4	1.1
Other[3]	-	4,158	3,126	3,102	4,838	4,679	142,743	186,994	-	0.4

[1] Other Renewables includes biogenic municipal solid waste, wood, black liquor, other wood waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[2] Other gases includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[3] Other includes non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is 1 and values under 0.5 are shown as *).
- (dash) = Data not available.
Note: Totals may not equal sum of components because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor forms.

Table 6. Electric Power Delivered Fuel Prices and Quality for Coal, Petroleum, and Natural Gas, 1999 and 2003 Through 2009

Fuel, Quality	1999	2003	2004	2005	2006	2007	2008	2009
Utah								
Coal (cents per million Btu)	103	W	W	W	W	W	W	W
Average heat value (Btu per pound)	11,620	11,025	10,718	10,786	10,981	11,156	11,060	10,965
Average sulfur Content (percent)	0.46	0.55	0.52	0.52	0.58	0.58	0.53	0.56
Petroleum (cents per million Btu)[1]	298	722	924	1,291	1,525	1,753	2,217	1,413
Average heat value (Btu per gallon)	104,081	139,493	139,512	139,752	139,660	139,376	138,979	139,467
Average sulfur Content (percent)	3.09	0.23	0.23	0.26	0.25	0.25	0.30	0.31
Natural Gas (cents per million Btu)	254	W	W	W	W	W	W	366
Average heat value (Btu per cubic foot)	1,043	1,062	1,049	1,047	1,052	1,051	1,036	1,043

[1] Petroleum includes petroleum liquids and petroleum coke.
Btu = British thermal unit.
W = Withheld to avoid disclosure of individual company data.
Note: Due to different reporting requirements between the Form EIA-923 and historical FERC Form 423, the receipts data from 2008 and on are not directly comparable to prior years. There may be a notable increase in fuel receipts beginning with 2008. For more information, please see the Technical Notes in the Electric Power Annual.
Sources: U.S. Energy Information Administration, Form EIA-423, " Monthly Cost and Quality of Fuels for Electric Plants Report." Federal Energy Regulatory Commission, FERC Form 423, "Monthly Cost and Quality of Fuels for Electric Plants." U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7. Electric Power Industry Emissions Estimates, 1999 and 2003 Through 2009
(Thousand Metric Tons)

Emission Type	1999	2003	2004	2005	2006	2007	2008	2009
Utah								
Sulfur Dioxide								
Coal	28	32	34	31	34	25	22	30
Petroleum	*	*	*	*	*	*	*	*
Natural Gas	*	*	*	*	*	*	*	*
Other Gases	*	-	-	-	-	-	-	-
Other[1]	*	*	*	*	-	*	*	*
Total	28	32	34	31	34	25	22	30
Nitrogen Oxide								
Coal	67	64	65	62	68	67	62	66
Petroleum	*	*	*	*	*	*	*	*
Natural Gas	3	2	1	1	1	3	2	1
Other Gases	*	-	-	-	-	-	-	*
Other Renewables[2]	-R	-R	-R	-R	*	*	*	*
Other[1]	*	*	*	*	-	*	*	*
Total	70	66	66	64	69	70	65	68
Carbon Dioxide								
Coal	32,081R	33,904R	34,906R	35,528R	35,106R	35,503R	36,106R	33,576
Petroleum	24	26	26	31	56	31	33	27
Natural Gas	462	784	528	701	1,631	3,321	3,182	2,855
Geothermal	4	5	5	5	5	4	7	7
Other[1]	57R	54	57	58	56	46	54	52
Total	32,627R	34,773R	35,522R	36,324R	36,853R	38,906R	39,381R	36,518

[1] Other includes non-biogenic municipal solid waste, tire-derived fuels, and miscellaneous technologies.
[2] Other Renewables includes biogenic municipal solid waste, wood, black liquor, other wood waste, landfill gas, sludge waste, agriculture byproducts, and other biomass.
R = Revised.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is 1 and values under 0.5 are shown as *).
- (dash) = Data not available.
Note: CO2 emissions for the historical years 1998 - 2008 have been revised due to changes in emission factors.
Sources: Calculations made by the Electric Power Systems and Reliability Team; Office of Electricity, Renewables, and Uranium Statistics; U. S. Energy Information Administration.

Table 8. Retail Sales, Revenue, and Average Retail Prices by Sector, 1999 and 2003 Through 2009

Sector	1999	2003	2004	2005	2006	2007	2008	2009	Percentage Share	
									1999	2009
Utah										
Retail Sales (thousand megawatthours)										
Residential	6,236	7,166	7,325	7,567	8,232	8,752	8,786	8,725	28.5	31.6
Commercial	7,282	9,024	9,345	9,417	9,749	10,241	10,286	10,235	33.3	37.1
Industrial	7,568	7,646	7,816	7,989	8,356	8,759	9,086	8,594	34.6	31.2
Other	792	NA	NA	NA	NA	NA	NA	NA	3.6	--
Transportation	NA	25	25	28	29	34	33	32	--	0.1
All Sectors	21,879	23,860	24,512	25,000	26,366	27,785	28,192	27,587	100.0	100.0
Retail Revenue (million dollars)										
Residential	391	494	528	569	625	714	725	740	36.8	39.6
Commercial	385	504	551	571	599	669	686	712	36.2	38.1
Industrial	254	290	314	339	352	396	417	414	23.9	22.1
Other	33	NA	NA	NA	NA	NA	NA	NA	3.1	--
Transportation	NA	1	2	2	2	3	3	3	--	0.1
All Sectors	1,064	1,290	1,395	1,481	1,578	1,782	1,830	1,868	100.0	100.0
Average Retail Prices (cents/kWh)										
Residential	6.27	6.90	7.21	7.52	7.59	8.15	8.26	8.48	--	--
Commercial	5.29	5.59	5.90	6.07	6.15	6.54	6.66	6.96	--	--
Industrial	3.36	3.79	4.01	4.24	4.21	4.52	4.59	4.81	--	--
Other	4.21	NA	NA	NA	NA	NA	NA	NA	--	--
Transportation	NA	6.01	6.57	7.20	7.19	7.44	7.85	8.31	--	--
All Sectors	4.86	5.41	5.69	5.92	5.99	6.41	6.49	6.77	--	--

kWh = Kilowatthours.
NA = Not available.
-- = Not applicable.
Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9. Retail Electricity Sales Statistics, 2009

Item	Full Service Providers					Other Providers		Total
	Investor-Owned	Public	Federal	Cooperative	Facility	Energy	Delivery	
Utah								
Number of Entities	1	40	1	9	NA	NA	NA	51
Number of Retail Customers	787,551	228,120	10	43,729	NA	NA	NA	1,059,410
Retail Sales (thousand megawatthours)	22,098	4,373	61	1,055	NA	NA	NA	27,587
Percentage of Retail Sales	80.10	15.85	0.22	3.82	--	--	--	100.00
Revenue from Retail Sales (million dollars)	1,453	343	2	71	NA	NA	NA	1,868
Percentage of Revenue	77.76	18.37	0.09	3.77	--	--	--	100.00
Average Retail Price (cents/kWh)	6.57	7.85	2.75	6.69	NA	NA	NA	6.77

kWh = Kilowatthours.
NA = Not available.
-- = Not applicable.
Notes: Data are shown for All Sectors. Full Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full Service Providers may purchase electricity from others (such as independent Power Producers or other full service providers) prior to delivery. Other Providers sell either the energy or the delivery services, but not both. Sales volumes and customer counts shown for Other Providers refer to delivered electricity, which is a joint activity of both energy and delivery providers; for clarity, they are reported only in the Energy column in this table. The revenue shown under Other Providers represents the revenue realized from the sale of the energy and the delivery services distinctly. "Public" entities include municipalities, State power agencies, and municipal marketing authorities. Federal entities are either owned or financed by the Federal Government. "Cooperatives" are electric utilities legally established to be owned by and operated for the benefit of those using its services. The cooperative will generate, transmit and/or distribute supplies of electric energy to a specified area not being serviced by another utility. "Non-utility" sales represent direct electricity transactions from independent generators to end use consumers. Totals may not equal sum of components because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10. Supply and Disposition of Electricity, 1999 and 2003 Through 2009
(Million Kilowatthours)

Category	1999	2003	2004	2005	2006	2007	2008	2009
Utah								
Supply								
Generation								
Electric Utilities	36,071	37,545	37,166	36,695	39,591	43,320	44,424	40,992
Independent Power Producers	409	447	406	706	829	1,096	976	1,325
Combined Heat and Power, Electric	8	9	7	7	11	11	-2	10
Electric Power Sector Generation Subtotal	**36,488**	**38,002**	**37,579**	**37,408**	**40,430**	**44,427**	**45,398**	**42,327**
Combined Heat and Power, Commercial	26	22	21	20	28	45	6	3
Combined Heat and Power, Industrial	270	-	612	737	805	901	1,175	1,213
Industrial and Commercial Generation Subtotal	**296**	**22**	**633**	**757**	**833**	**946**	**1,180**	**1,216**
Total Net Generation	**36,785**	**38,024**	**38,212**	**38,165**	**41,263**	**45,373**	**46,579**	**43,543**
Total International Imports	**-**	**6**	**15**	**41**	**15**	**22**	**12**	**8**
Total Supply	**36,785**	**38,029**	**38,227**	**38,206**	**41,279**	**45,394**	**46,591**	**43,551**
Disposition								
Retail Sales								
Full Service Providers	21,879	23,860	24,512	25,000	26,366	27,785	28,192	27,587
Total Electric Industry Retail Sales	**21,879**	**23,860**	**24,512**	**25,000**	**26,366**	**27,785**	**28,192**	**27,587**
Direct Use	**327**	**360**	**361**	**742**	**967**	**73[R]**	**17[R]**	**1,093**
Total International Exports	**-**	**-**	**-**	**1**	**1**	**38**	**55**	**43**
Estimated Losses	**1,586**	**1,522**	**1,861**	**2,135**	**2,323**	**2,680[R]**	**2,627[R]**	**2,322**
Net Interstate Trade[1]	**12,992**	**12,286**	**11,494**	**10,328**	**11,622**	**14,819[R]**	**15,702[R]**	**12,506**
Total Disposition	**36,785[R]**	**38,029[R]**	**38,227[R]**	**38,206[R]**	**41,279[R]**	**45,394[R]**	**46,591[R]**	**43,551**
Net Trade Index (ratio)[2]	**1.55**	**1.48**	**1.43**	**1.37**	**1.39**	**1.48[R]**	**1.51[R]**	**1.40**

[1] Net Interstate Trade = Total Supply - (Total Electric Industry Retail Sales + Direct Use + Total International Exports (if applies) + Estimated Losses).
[2] Net Trade Index is the sum of Total Supply / (Total Disposition - Net Interstate Trade).
R = Revised.
- (dash) = Data not available.
Notes: Totals may not equal sum of components because of independent rounding. Estimated Losses are reported at the utility level, and then allocated to States based on the utility`s retail sales by State. Reported losses may include electricity unaccounted for by the utility. Direct use is commercial or industrial use of electricity that (1) is self-generated (2) is produced by either the same entity that consumes the power or an affiliate, and (3) is used in direct support of a service or industrial process located within the same facility or group of facilities that houses the generating equipment. Direct use is exclusive of station use. Beginning with publication year 2010, Total disposition has been reorganized to include Net Interstate Trade. Therefore, Total Disposition equals Total Supply.
Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor forms. U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." DOE, Office of Electricity Delivery and Energy Reliability, Form OE-781R, "Annual Report of International Electric Export/Import Data," predecessor forms, and National Energy Borad of Canada.