UNDERGROUND INJECTION CONTROL (UIC) WELL PERMIT RENEWAL APPLICATION

Seneca Well #38268
Location Coordinates: 41.618992, -78.821267
Highland Township
Elk County, Pennsylvania 15870

Prepared for:

Seneca Resources Company, LLC
2000 Westinghouse Drive, Suite 400
Cranberry Township, Pennsylvania 16066

October 20, 2023

ARM Project 23011021

ARM Group LLC
Engineers and Scientists

2548 Park Center Boulevard, State College, PA 16801
Voice: (814) 272-0455

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

Underground Injection Control
Permit Application for a Class II Well

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, and 40 CFR Part 144)

For Official Use Only

Date Received:

Permit Number:

Read Attached Instructions Before Starting

I. Owner Name, Address, Phone Number and/or Email	II. Operator Name, Address, Phone Number and/or Email
Seneca Resources Company, LLC 2000 Westinghouse Drive, Suite 400 Cranberry Township, PA 16066 (412) 548-2500 NemitzJ@srcx.com	Seneca Resources Company, LLC 2000 Westinghouse Drive, Suite 400 Cranberry Township, PA 16066 (412) 548-2500

III. Commercial Facility	IV. Ownership	V. Permit Action Requested	VI. SIC Code(s)	VII. Indian Country
☐ Yes ☒ No	☒ Private ☐ Federal ☐ State/Tribal/ Municipal	☐ New Permit ☒ Permit Renewal ☐ Modification ☐ Add Well to Area Permit ☐ Other	1389 - Oil & Gas Field services, not elsewhere classified.	☐ Yes ☒ No

VIII. Type of Permit (For multiple wells, use additional page(s) to provide the information requested for each additional well)

	Number of Wells	Well Field and/or Project Names
☒ A. Individual ☐ B. Area	1	Seneca Well #38268

IX. Class and Type of Well (see reverse)

A. Class	B. Type (enter code(s))	C. If type code is "X," explain.
II	D	

X. Well Status

☒ A. Operating	☐ B. Conversion	☐ C. Proposed
Date Injection Started: 01/21/2018	Date Well Constructed: 03/22/2007	

XI. Well Information

API Number	37-047-23835
Permit (or EPA ID) Number	PAS2D025BELK
Full Well Name	FEE SRC Warrant 3771 38268

XII. Location of Well or, for Multiple Wells, Approximate Center of Field or Project

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Latitude: 41.618975

Longitude: -78.821267

XIII. Attachments

In addition to this form, complete Attachments A-U (as appropriate for the specific well class) on separate sheets. Submit complete information, as required in the instructions and list all attachments, maps or other figures, by the applicable letter.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please Type or Print)*	Signature	Date Signed
Douglas A. Kepler		10/05/23

EPA Form 7520-6 (Rev. 4-19)

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Prepared for:

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2000 Westinghouse Drive, Suite 400
Cranberry Township, Pennsylvania 16066

Prepared by:

ARM Group LLC
2548 Park Center Boulevard
State College, Pennsylvania 16801

ARM Group LLC Project 23011021

October 20, 2023

Respectfully Submitted,
ARM Group LLC

Charles A. Burger, P.G.
Senior Project Manager

Vice President, Sr. Project Manager

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Figure 2	AOR ¼ Mile Radius Map	Following Text
Figure 3	½ Mile Radius Map	Following Text
Figure 4	1¼ Mile Radius Map	Following Text

TABLES

Table 1	Wells & Features Within ¼-Mile (AOR)	Following Text
Table 2	Wells & Features Within ½-Mile	Following Text

APPENDICES

Appendix A	AOR Well Bore Diagrams and Public Records	Following Text
Appendix B	Well #38268 & #38281 Information	Following Text
Appendix C	Tetra Tech June 2012 Injectivity Test Report	Following Text
Appendix D	Well Construction Diagram & Well Completion Report	Following Text
Appendix E	Tetra Tech June 2012 Permit Application	Following Text
Appendix F	Well Flow Diagram and Layout	Following Text
Appendix G	P&A Plan & Plugging Estimates	Following Text
Appendix H	SRC Financial Statement	Following Text
Appendix I	SRC PPC Plan	Following Text
Appendix J	Existing Permits	Following Text

1.0 MAPS AND AREA OF REVIEW

Part I. Well Location(s) – This permit renewal application has been completed to request the continued operation of brine disposal activities at Seneca Resources Company, LLC (SRC) Injection Well #38268, America Petroleum Institute (API) #37-047-23835, as well as the associated monitoring well activities associated with SRC monitoring well #38281. A permit application was submitted by Tetra Tech on behalf of SRC in June 2012 to convert existing natural gas well #38268 to an underground injection control well along with subsequent notice of deficiency response letters completed by SRC. Well #38268 was formally permitted by the United States Environmental Protection Agency (US EPA) in June 2014 and subsequently by the Pennsylvania Department of Environmental Protection (PADEP) through its March 2017 Record of Decision. The US EPA Permit is set to expire in January 2024. A minor permit modification was approved by the US EPA in April 2019, thereby increasing the approved injection volume limit from 45,000 barrels per month to 75,000 barrels per month. No further requests for alterations to this permit have been made by SRC as of the date of this permit renewal application. The coordinates for the aforementioned injection well and associated monitoring well are as follows:

- SRC Well #38268 (Injection Well) – 41.618992 N. Latitude, -78.821267 W. Longitude
- SRC Well #38281 (Monitoring Well) – 41.617255 N. Latitude, -78.824872 W. Longitude

Refer to **Figure 1** for the location of SRC Well #38268. SRC Well #38268 is located in a rural setting with the nearest town (James City) located approximately one mile west of the well. A small cluster of homes also exists approximately 0.75 miles east/southeast of the well with one residential home located closer at approximately 0.40 miles to the east/southeast. The well is located within the High Plateau section of the Appalachian Plateaus Physiographic province. The High Plateau Section consists of broad, rounded to flat uplands cut by deep angular valleys. The uplands are underlain by flat-lying sandstones and conglomerates. Local relief between valley bottoms and adjacent uplands can be as much as 1,000 feet but is generally in the area of half that amount. Elevations in the area range from 980 to 2,360 feet. Drainage of the area has a dendritic pattern. The western boundary of the area is located proximal to the Late Wisconsin glacial boundary. The area between this border and the Allegheny River a few miles east was glaciated by pre-Wisconsin glaciers.

Part II. Area of Review Size Determination (40 CFR § 146.6) – As outlined within the original Underground Injection Control (UIC) Class II D Brine Disposal Well Permit Application (Tetra Tech, 2012) the US EPA default area of review (Area of Review [AOR] – ¼ mile fixed radius) was proven to be applicable for the permit application. As such, the AOR for this permit renewal application will continue to be the fixed radius ¼-mile as further outlined in the US EPA Region 3 UIC Class II-D Instructions for Permit Renewal Application Document.

Part III. Map(s)(40 CFR 144.31 & 146.24) – Refer to **Figure 2** for a map depicting the AOR (default ¼-mile radius), **Figure 3** for a map depicting the ½-mile radius beyond the well, and

Figure 4 for a map depicting the 1¼-mile radius beyond the well. Features depicted on these maps include the following where present:

AOR – The following features, if present, are depicted:

- Name and location of all production wells, injection wells, abandoned wells, dry holes, and water wells including type (i.e. public water system, domestic drinking water, stock, etc.)
- Springs and surface water bodies
- Mines (surface and subsurface) and quarries, and;
- Other pertinent site features, including residences, schools, hospitals, and roads.

It should be noted that one structure is depicted on the associated topographic maps at the end of an unimproved road south of Lamont Road, just southeast of Well #38268. Based on aerial photographic review and field observations completed by SRC staff, no structures are present at this location nor are any other structures (other than the infrastructure associated with Well #38268) located within the ¼-mile AOR.

½-mile beyond the Well (1/4-Mile beyond AOR) – The following features, if present, are depicted:

- Name and location of all production wells, injection wells, abandoned wells, dry holes, and all water wells including type (i.e., public water system, domestic drinking water, stock, etc.)
- Springs and surface water bodies
- Mines (surface and subsurface) and quarries, and;
- Other pertinent surface features including residences, schools, hospitals, and roads.

1-mile beyond the well (1 ¼-Mile beyond the AOR) – The following features if present are depicted:

- Project injection well(s), well pad(s) and/or project area
- Applicable AOR
- All outcrops of injection and confining formations,
- All surface water intake and discharge structures, and;
- All hazardous waste treatment, storage, or disposal facilities.

Refer to **Table 1** and **Table 2** for additional information regarding the features present within each applicable radius.

Part IV. Area of Review Wells and Corrective Action Plans (40 CFR 144.55 & 146.24) – Three wells were identified with the AOR which penetrate the confining zone: Well #38268 (injection well), Well #38281 (monitoring well), and Well #1328 (plugged well). Refer to **Figure 2** for the locations of these wells and to **Appendix A** for additional data and wellbore diagrams reasonably available from public records or otherwise known to the applicant. The information, where available, includes:

- Well name, location, and depth
- Well type,
- Date well was drilled,
- Well construction that includes casing and cement materials, including demonstrated or calculated top of cement,
- Cement bond logs (if available), and;
- Record of well completion and plugging (if applicable).

Note: Past information has been included to document unchanged findings, new information has been tabulated as warranted. Based on the information contained in this section, no wells which were noted to be improperly sealed, completed, or abandoned were identified. Refer to **Table 1** and **Table 2** for additional information regarding the features present within each applicable radius.

Part V. Landowners Information (40 CFR 144.31 and part 147) – The following are listed as owners of record for land within the AOR (1/4-Mile).

- Seneca Resources Company, LLC - Land & Timber Division, 51 Zents Boulevard, Brookville, PA 15825.
- Collins Kane Hardwood, 95 Hardwood Drive, Kane, PA 16735.

2.0 GEOLOGICAL AND GEOPHYSICAL INFORMATION

Part I. Geological Data (40 CFR 146.24) – The following information is being provided concerning geological and geophysical information:

Well log information for Well #38268 (**Appendix A**) indicates that the uppermost bedrock unit at the site is comprised of the Allegheny Formation rocks of Pennsylvanian age. The Allegheny Group consists of limestone, sandstone, shale, and coal deposits. At a depth of 30 to 35 feet below ground surface (bgs) the Pennsylvanian Age Pottsville Formation also consists of limestone, sandstone, shale, and coal deposits. At approximately 200 feet bgs the Mississippian-Devonian Age Shenango through Oswayo Formation Undivided is encountered and is comprised of sandstone, siltstone, and shale. The Upper Devonian siltstones, shale, and sands are present beneath the site beginning from approximately 500 feet bgs to the total depth of the borehole at 2,530 feet bgs.

Fluid injection is designed to inject into the Upper Devonian Elk 3 Sand and associated notched and frac'd intervals at depths of 2,354 to 2,403 feet bgs. Refer to **Appendix B** for a generalized stratigraphic column with the Elk Sand highlighted in yellow. As depicted on the stratigraphic column, most of the geologic groups and formations overlying the Elk 3 Sand can be considered confining units totaling approximately 2,000 feet with the exception of the overlying Upper Devonian Speechley Sand, which also contains reservoir rock.

Suspected faults and fracture systems were not identified in any of the permitting or regulatory review activities performed during the permitting process for this well. It is also noted within a technical review completed by PADEP geologist (Harry C. Wise, P.G. – Seneca Resources Elk County Well #38268, Geological Review; EPA UIC Application Documents; February 8, 2017) that there are no mapped faults or structural fronts in the quarter-mile radius area of review submitted with the original permit application documents. The nearest fault was identified as an "Unnamed Structural Fault", approximately 13-miles to the southeast of the site. The technical review is presented in **Appendix B**.

Seismic activity is not known to exist within the area of Well #38268, this is further verified through the document referenced above (PADEP, February 2017) and SRC Seismic Monitoring Reports for 2018, 2019, 2020, 2021, and 2022. The PADEP indicated through its review that "there are no historical seismic events within the quarter and one-mile radius of review and that there have been no recorded earthquakes of 2M or greater within Elk or McKean Counties". Furthermore, induced seismic events from underground injection have been noted to primarily occur in crystalline basement rocks. Analysis of depths to crystalline basement rocks completed by PADEP (February, 2017) show that crystalline basement rocks within the site area are located at depths between 12,000 and 13,000 feet bgs. The separation of the injection zone for Well #38268 and mapped crystalline basement rocks is offset by approximately 9,600 to 10,600 feet of overlying strata. The March 2017 SRC Class II Disposal Well Seismic Monitoring and Mitigation Plan and the SRC Seismic Monitoring System Activity Reports are presented in **Appendix B**.

Also included as additional information within **Appendix B** are the following:

- Laboratory Analytical Data
- Maximum Injection Pressure (MIP) Calculations
- Porosity and permeability of injection formation as outlined on page 2 of the June 2012 Tetra Tech Brine Disposal Well Permit Application (Seneca Well #38268). It should be noted that the majority of the parameters used in the analysis were taken from the injection test performed by Tetra Tech on well #38368 in March 2012.

<u>Part II. Proposed Formation Testing Program (40 CFR 146.22)</u> – An Injectivity Test Report dated June 2012 was submitted on behalf of Seneca Resources by Tetra Tech.. Testing was performed in March 2012 on the Elk 3 Sand interval located at 2,354 to 2,403 feet bgs. Other notched and frac'd intervals noted in Well #38268 include the Speechley 5, 6, and 7 and Tiona 1. A packer was installed beneath each interval for the test. Well #38268 has a total of 553.2 feet of 7-inch cemented surface casing (well below the deepest drinking water zones in the area). Physical and chemical characteristics of the injection zone and injected fluid are further outlined within the June 2012 Tetra Tech Report and are highlighted as follows:

- <u>Elk 3 Sand Maximum Porosity</u> – 18% (entire frac'd interval average = 13.5%).
- <u>Specific Gravity of Injected Fluid</u> – 1.14 to 1.16
- <u>Maximum recorded surface wellhead pressure</u> – 31.3 pounds per square inch (psi), well below the 1,433 psi approved by EPA for the test.
- <u>Maximum recorded bottom-hole pressure</u> – 1,163 psi.
- <u>Estimated Permeability</u> – 190 millidarcies (md), based on formation thickness of 49-feet, a porosity of 13.5%, and S_w = 100%.

In summary, the test included a total of 5,000 barrels (bbls) of injected fluid at an average rate of 2.67 barrels per minute (bpm) over a course of approximately 33 hours. Conclusions from the test surmise that Well #38268 could sustain an injection rate of greater than 2 bpm (approximately 3,000 barrels per day [bpd]) with pressures remaining under the UIC Class II D permit limits for maximum injection pressures. The June 2012 Tetra Tech Injectivity Test Report is included as **Appendix C**. The current EPA injection permit allows for a maximum surface injection pressure of 1,416 psi (assuming a specific gravity of injection fluid not exceeding 1.16) and total allowable fluid injection of 75,000 bbl per month (April 9, 2019 EPA Permit Minor Modification; 45,000 bbl/month to 75,000 bbl/month).

3.0 WELL CONSTRUCTION/CONVERSION INFORMATION

Part I. Well Schematic Diagram (40 CFR 146.24) – Refer to **Appendix D** for a copy of the well construction diagram, and the PADEP well record and completion report. The diagram also depicts the associated casing and cementing details. As noted in previous documentation, the surface casing for Well #38268 extends to 553 feet bgs, which is more than 200 feet deeper than the deepest groundwater drinking source in the site area (SRC October 2, 2012 Addendum to Permit Application / PADEP, March 20, 2017 Record of Decision). Well #38268 is cased and grouted to 553.2 feet bgs.

Part II. Well Construction or Conversion Procedures (40 CFR 144.52, 146.22, & 146.24) – Refer to **Appendix E** for additional information from the June 2012 Tetra Tech Permit Application concerning well construction and conversion procedures as well as additional information provided within the June 2012 Tetra Tech Injectivity Test Report for Well #38268, which is provided in **Appendix C**. SRC has implemented numerous preventative measures through the submittal of a Control and Disposal Plan/Preparedness, Prevention, and Contingency Plan (PPC), the measures include:

- Staff training
- Sound detection
- Remote access
- Battery back-up
- Material compatibility
- Automatic shut-in
- Clay absorption material
- Floor sloping sumps
- Emergency shut-off
- Fire extinguishers
- Facility fencing
- Secondary containment
- Totes for chemicals
- Injection rate, cumulative volume, and injection pressure continuous monitoring
- Emergency contacts
- Cameras
- Motion lights
- Access codes for entry and regular inspection
- Treatment to protect the injection well geologic formation (i.e. oil/water separation, biocide, corrosion and scale inhibitors).

Per SRC staff, a Coriolis meter is installed prior to injection on Well #38268 and is used to track instantaneous flow rate, totalized daily flow, density, and temperature. A pressure transducer and manual pressure gauge are installed on both the casing and inner tubing to tack annulus and injection pressures. The data is then collected through an onsite SCADA system which will alarm and shut down the site at specific set points. Representative fluid samples are collected annually for recordation.

4.0 INJECTION OPERATION AND MONITORING PROGRAM

Refer to **Appendix F** for a flow diagram of fluid flow through the facility as well as a drawing of surface construction. As noted in the original permit application, pressure will be measured in the annulus between the 4 ½-inch casing and tubing and continuously monitored, should a pressure increase occur in the monitored space, injection will cease and the USEPA will be notified within 24 hours and notified in writing within 7 days. The cause of the pressure increase will be investigated by SRC, and remedial measures implemented following discussions with the US EPA on the proposed remedial approach. Additional explanation regarding the monitoring program is provided above (Section 3.0 - Part II).

Additional information included within this section of the permit renewal are the SRC Annual Class II Disposal/Injection Well Monitoring Reports for the years 2018, 2019, 2020, 2021, and 2022 **(Appendix F).** These Reports document monthly injection pressures, monthly injection volumes and monthly annulus pressures as required by US EPA. Existing well #38281 continues to be a monitoring location for this injection well and has been noted to be properly constructed for this purpose through prior documentation.

Historical analysis of the chemical and physical characteristics of the injection fluids have also been provided. The nature of the injection fluid has not changed since the issuance of the original permit and has been limited to fluids produced solely in association with SRC oil and gas production activities. Per the existing permit for this injection well, the injection pressure shall not and has not exceeded 1,416 PSI (surface pressure) and the injection volume shall not and has not exceeded 75,000 barrels per month. SRC is not proposing to change these pressures and volumes.

5.0 PLUGGING AND ABANDONMENT PLAN

A plugging and abandonment (P&A) plan was submitted along with the original permit application, refer to **Appendix G** for a copy of the original P&A plan (Form 7520-14), along with the June 22, 2012 plugging cost estimate from ALCO Well Services, Inc. Also included in **Appendix G** is an updated plugging estimate for Well #38268 from Coastal Well Service, LLC. It should be noted that the required plugging information has not changed since the June 2012 plan which includes the following:

- Type, and number of plugs to be used,
- Placement of each plug including the elevation of top and bottom,
- Type, grade, and quantity of cement to be used, and;
- Method of placement of plugs.

At the point where the well will no longer be used, SRC will properly plug and abandon the well under all applicable PADEP and US EPA guidelines and requirements. The PADEP will be notified through a "Notice of Intent to Plug a Well" no less than 3 days and no more than 30 days prior to abandoning the well, to allow the PADEP inspector to be present during the plugging activities. After receiving the approval from PADEP to proceed, the well will be abandoned, and a certificate of plugging will be completed and submitted. The US EPA will be notified of the abandonment activities at least 45 days prior to the commencement of activities which will include an updated and final form 7520-19.

As noted, the P&A plan has not changed since what was originally presented within the original 2012 permit documents. However, form 7520-19 may be modified prior to the actual plugging activities in order to meet current requirements set forth at the time of abandonment. The June 2012 ALCO Well Services Inc. estimate was $24,650 (includes $10,000 for contingencies), the September 2023 quote from Coastal Well Service LLC is $100,750 and includes a $16,000 reclamation fee.

6.0 FINANCIAL ASSURANCE

Refer to **Appendix H** for an updated financial statement from SRC. As previously noted, SRC acquired an updated cost estimate to plug Well #38268, the quote is dated September 12, 2023 and was provided by Coastal Well Service LLC in the amount of $100,750.00. The updated quote from Coastal Well Service LLC is provided in **Appendix G** along with prior quote information from ALCO Well Services Inc as well as the original PADEP P&A Plan dated June 2012. Note, the P&A plan has not changed since 2012. Should a decision to plug and abandoned SRC Well #38268 materialize in the future, SRC will complete, sign, and submit the updated US EPA P&A plan (EPA Form 7520-19), any alterations will be documented on the updated US EPA P&A Plan. Updated Form 7520-19 has been included in **Appendix G** for purposes of this renewal application, the form attached has not been formalized or signed by SRC.

7.0 SITE SECURITY AND MANIFEST REQUIREMENTS

Refer to **Appendix I** for SRC's Class II Injection Well Preparedness, Prevention, and Contingency (PPC) Plan. Page 12 of this plan describes several security strategies to maintain control of the site and prevent unauthorized or accidental entry that could result in injury to persons or wildlife or could result in a violation of local, state, and federal regulations. An overview of these security strategies is listed as follows:

- There is a chain link fence around the perimeter of the site. Gate access to the site is controlled by a padlock.
- There are closed-circuit cameras monitoring activities on location 24-hours a day. These cameras provide video feed to Seneca offices in Pittsburgh and Brookville, PA. They also record video footage. This video footage is stored for a period of time deemed applicable by SRC.
- Lights that run from dusk to dawn are installed onsite to illuminate the unloading pads, the tank farm, and the pump/filtration room.
- The entry road to the site from Lamont Road accommodates two-way traffic but converts to a one-way loop into and out of the truck unloading facility. Before vehicles can leave the location, they must come to a complete stop at a stop sign to prevent traffic incidents.

The PPC Plan provides additional information on security, emergency response, and alarm measures that have been implemented at the site. Also included in SRC's PPC plan is a facility layout diagram (Figure 3), which depicts security fencing among other site features.

Well #38268 is not considered a commercial injection well as the produced water being injected into the well comes from SRC's conventional and unconventional gas or combination of oil and gas wells located in several counties throughout northwestern and northcentral Pennsylvania.

8.0 AQUIFER EXEMPTIONS

An aquifer exemption is not being requested as part of this application renewal nor has been requested for this well in the past.

9.0 EXISTING EPA PERMITS

A listing of all permits or construction approvals received or applied for under the following programs in connection with Well #38268 are included as **Appendix J** as warranted. Per this section of the renewal process, the following programs permits are required to be listed if applicable:

- Hazardous Waste Management Program under the Resource Conservation and Recovery Act (RCRA),
- UIC program under the Safe Drinking Water Act (SDWA),
- National Pollutant Discharge and Elimination System (NPDES) program under the Clean Water Act (CWA),
- Prevention of Significant Deterioration (PSD) program under the Clean Air Act,
- Nonattainment program under the Clean Air Act,
- National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act,
- Ocean dumping permits under the Marine Protection Research and Sanctuaries Act,
- Dredge and fill permits under section 404 of CWA, and,
- Other relevant environmental permits, including state permits.

10.0 DESCRIPTION OF BUSINESS

Seneca Resources Company, LLC (SRC) is the exploration and production entity of National Fuel Gas Company which is headquartered in Houston Texas. SRC produces natural gas in the Appalachian Region of the United States and includes development of the Marcellus, Upper Devonian, and Utica Shales stretching from the Southern Tier of New York state through Pennsylvania, Ohio, and West Virginia. SRC controls more than one million net prospective acres in the Shale Fairway of Pennsylvania with 65 percent of their holdings being fee acreage, with the mineral rights owned outright by SRC with no royalty obligation or lease expiration. In total, SRC has been producing natural gas in Pennsylvania for over 100 years. In 2015 Highland Field Services, LLC (HFS), a subsidiary of SRC, was established to address the water management needs for SRC and other oil and gas companies in the Appalachian Basin and currently operates nine treatment facilities in northwest Pennsylvania near the heart of SRC's Western Development area.

Well #38268 is utilized by SRC and HFS as an effective, responsible, and environmentally friendly alternative to dispose of natural gas well production fluids that can no longer be utilized for the stimulation of natural gas across SRC's northern PA natural gas assets. The use of injection wells greatly limits the amount of on-road trucking for the disposal of well production fluids creating a viable alternative to traditional means.

11.0 OPTIONAL ADDITIONAL PROJECT INFORMATION

Based on prior submissions, the following Federal Laws either do not apply to this project or have been addressed through the original permitting process (note this additional information is optional and is to be supplied to the USEPA for assistance in its analysis):

- The Wild and Scenic Rivers Act 16 U.S.C. 1273 et seq. – There are no wild and scenic rivers within the project area.
- The National Historic Preservation Act of 1996, 16 U.S.C. 470 et seq. – Based on existing information there are no historic places or archeological sites within the project area (i.e., districts, sites, buildings, structures, or objects significant on a national, state or local level in American history, architecture, archeology, engineering and culture). Preliminary information from the Pennsylvania Natural Heritage Program web page (Pennsylvania Natural Heritage Program (state.pa.us) did not indicate concerns in regard to the National Historic Preservation Act for the site area.
- The Endangered Species Act, 16 U.S.C. 1531 et seq. – Based on exiting information there are no threats to endangered species proximal to Well #38268. The well and existing infrastructure has been built out and there are currently no plans for additional construction at the site.
- The Coastal Zone Management Act, 16 U.S.C. 1451 et seq. - Based on the location of Well #38268, this Act is not applicable.

12.0 REFERENCES

Pennsylvania Department of Environmental Protection, eMapPA, web mapping application, eMapPA

Pennsylvania Department of Conservation and Natural Resources Online Geologic Data Exploration Application (PaGEODE) PaGEODE (state.pa.us)

Pennsylvania Department of Environmental Protection, March 20, 2017, Record of Decision Letter and Attachments (A-D), Seneca Resources Corporation Well Permit No. 047-23835.

Pennsylvania Natural Heritage Program Conservation Explorer, Home | PA Conservation Explorer

Seneca Resources Company, LLC, Annual Class II Disposal/Injection Well Monitoring Reports, 2018, 2019, 2021, and 2022.

Seneca Resources Company, LLC, Annual Seismic Monitoring System Activities Reports, 2018, 2019, 2020, 2021, and 2022 .

Seneca Resources Company, LLC, Class II Disposal Well Seismic Monitoring and Mitigation Plan, March 2017.

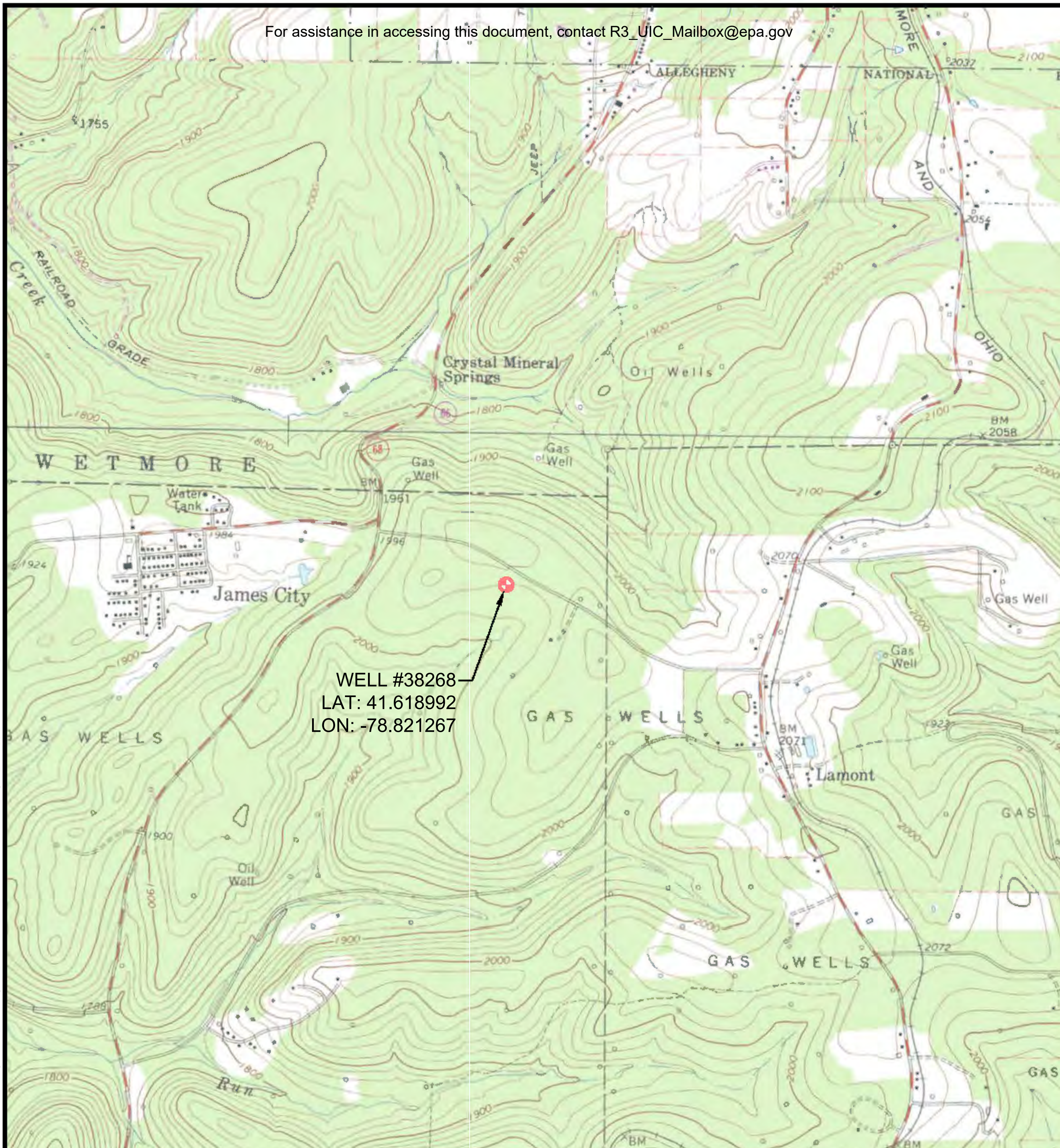
Seneca Resources Company, LLC, Class II Injection Well Preparedness, Prevention, and Contingency (PPC) Plan, July 2017.

Tetra Tech, Underground Injection Control (UIC) Class IID Brine Disposal Well Permit Application, June 2012.

Tetra Tech, Injectivity Test Report, Seneca Resources Well #38268, June 2012.

United States Department Environmental Protection Agency, Region III, Minor Permit Modification, Permit PAS2D025BELK, April 9, 2019.

FIGURES



Base map from PASDA Aerials, 53001660PAN_PEMA_2018, 53001670PAN_PEMA_2018, 53001680PAN_PEMA_2018, 54001660PAN_PEMA_2018, 54001670PAN_PEMA_2018, and 54001680PAN_PEMA_2018.

0 2000 4000 6000

SCALE IN FEET

N

SITE LOCATION MAP-TOPO

SENECA RESOURCES COMPANY, LLC
WELL #38268
HIGHLAND TWP, ELK CO, PENNSYLVANIA

SEPTEMBER 2023	SCALE: 1" = 2000'	23011021

ARM Group LLC
Engineers and Scientists
www.armgroup.net

Figure
1

P:\Seneca Resources\23011021 James City UIC Well Permit Renewal\Drwg\Production\Figures\23011021-FI-C-101-UPDATED.dwg Plotted: October 17, 2023

Base map from PASDA Aerials, 53001660PAN_PEMA_2018, 53001670PAN_PEMA_2018, 53001680PAN_PEMA_2018, 54001660PAN_PEMA_2018, 54001670PAN_PEMA_2018, and 54001680PAN_PEMA_2018.

0 1000 2000 3000

SCALE IN FEET

N

AOR - $\frac{1}{4}$ MILE RADIUS MAP

SENECA RESOURCES COMPANY, LLC
WELL #38268
HIGHLAND TWP, ELK CO, PENNSYLVANIA

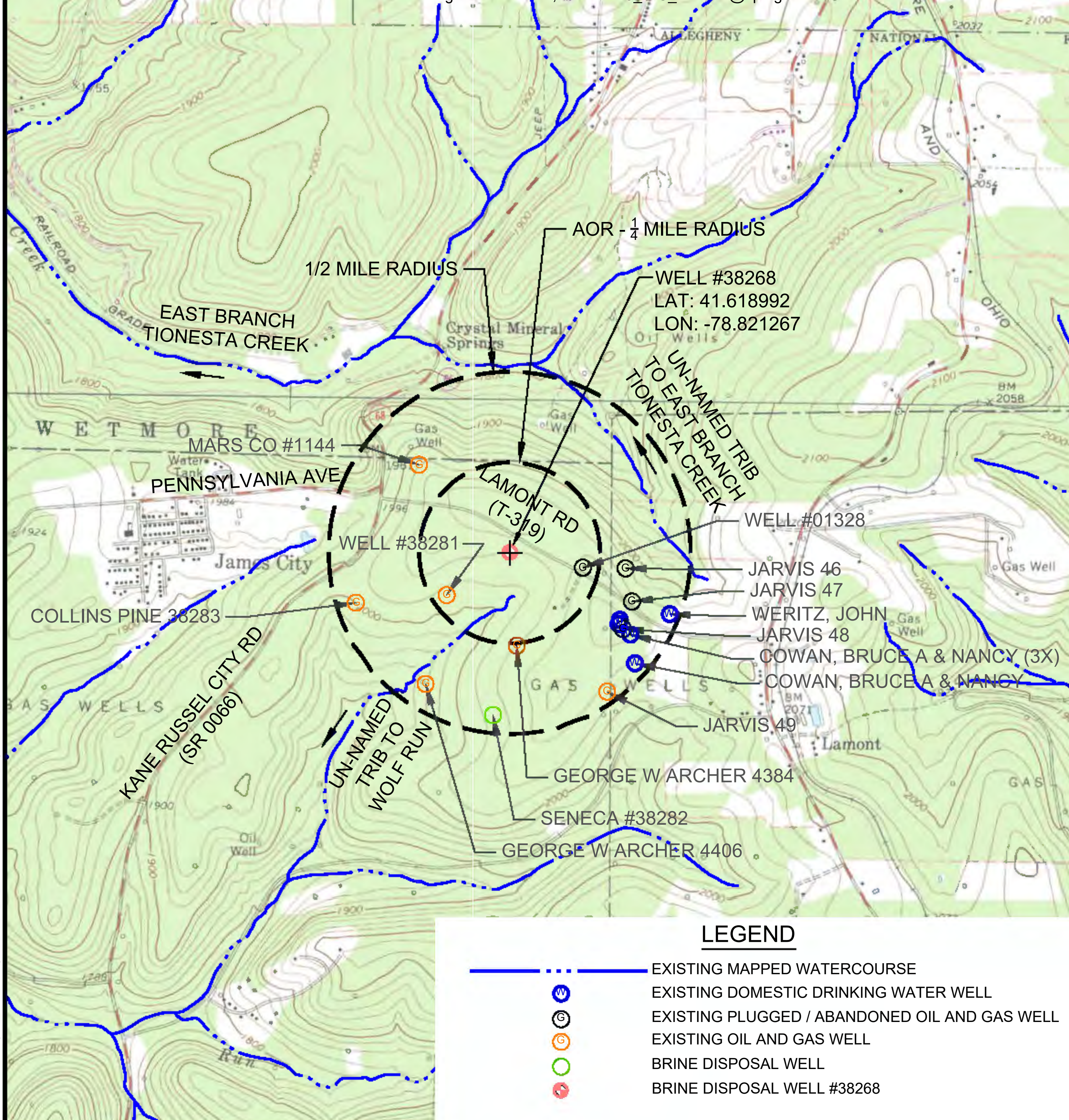
SEPTEMBER 2023	SCALE: 1" = 1000'	23011021

ARM Group LLC
Engineers and Scientists
www.armgroup.net

Figure
2

P:\Seneca Resources\23011021 James City UIC Well Permit Renewal\Drwg\Production\Figures\23011021-FI-C-101-UPDATED.dwg Plotted: October 17, 2023

For assistance in accessing this document, contact R3_UIC_Mailbox@epa.gov



Base map from USGS 7½ minute quadrangles, James City 1966, and Kane 1966, Photo Revised 1973, Photo Inspected 1977.

0 2000 4000 6000

SCALE IN FEET

N

$\frac{1}{2}$ MILE RADIUS MAP

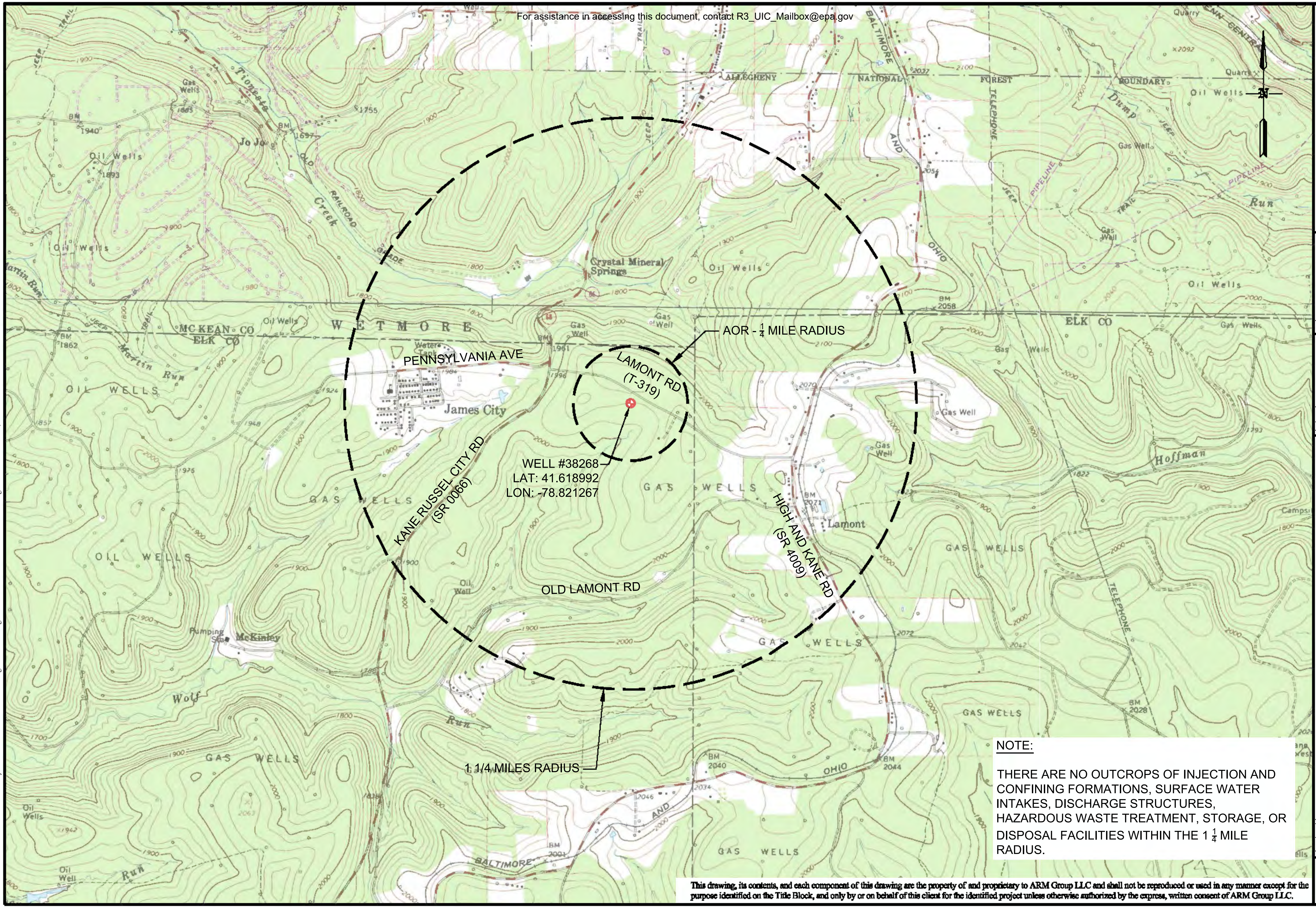
SENECA RESOURCES COMPANY, LLC
WELL #38268
HIGHLAND TWP, ELK CO, PENNSYLVANIA

SEPTEMBER 2023	SCALE: 1" = 2000'	23011021

ARM Group LLC
Engineers and Scientists
www.armgroup.net

Figure
3

P:\Seneca Resources\23011021 James City UIC Well Permit Renewal\Drwg\Production\Figures\23011021-FI-C-101-UPDATED.dwg Plotted: October 17, 2023



NOTE:

THERE ARE NO OUTCROPS OF INJECTION AND CONFINING FORMATIONS, SURFACE WATER INTAKES, DISCHARGE STRUCTURES, HAZARDOUS WASTE TREATMENT, STORAGE, OR DISPOSAL FACILITIES WITHIN THE 1 $\frac{1}{4}$ MILE RADIUS.

ARM Group LLC
Engineers and Scientists
www.armgroup.net

scale	1" = 2000'
date	09/27/2023
project no.	2301102120
designed	CAB
checked	CAB
drawn	JAW

0 2000 4000
SCALE IN FEET

project title: SENECA RESOURCES COMPANY, LLC WELL #38268
HIGHLAND TOWNSHIP, ELK COUNTY, PENNSYLVANIA

drawing title: 1 $\frac{1}{4}$ MILE RADIUS MAP

Figure 4

P:\Seneca Resources\23011021 James City UIC Well Permit Renewal\Drwg\Production\Figures\23011021-FI-C-101-UPDATED.dwg Plotted: October 17, 2023

TABLES

TABLE 1 - WELLS & FEATURES WITHIN 1/4 MILE (AOR)
Seneca Resources Company, LLC Well #38268
Highland Township, Elk County, Pennsylvania
ARM Project #23011021

Seneca Resources Co.	7/3/2007	37-047-23835	38268 / Injection	2,530'	553.2'	Notched & Frac'd 2,354-2,403'	Approved Class IID Injection Well
Seneca Resources Co.	3/11/2008	37-047-23884	38281 / Monitoring	2,544'	602'	Notched & Frac'd 2,338-2,390'	Monitoring Well for #38268
Seneca Resources Co.	5/16/1933 (spud date)	047-00449	01328 / Plugged Gas	2,433'	460'	Shot (2,370-2,400')	Plugged 2/12/1991

Notes:
One surface water body is located 630' south of Well #38268 (Unnamed Tributary to Wolf Run).
No other features of interest were located with the 1/4-mile AOR (EPA Region 3 Clarification of Maps required for Class II Permit Application)

TABLE 2 - WELLS & FEATURES WITHIN 1/2-MILE
Seneca Resources Company, LLC Well #38268
Highland Township, Elk County, Pennsylvania
ARM Project #23011021

Owner/Operator	Completion Date	API No./Permit Number	Well ID & Type	Total Depth	Casing Depth	Comments
Diversified Prod. LLC	3/21/2008	047-23893	Collins Pine 38283/Vertical O&G Well	UNK	UNK	Active Well
National Fuel Gas Corp.	5/16/1933 (spud date)	047-00449	Seneca Well 01328/Vertical O&G Well	2,433'	460'	Plugged Well
Cowan, Bruce A & Nancy	1976	NA	W1/Private Water Well	330'	UNK	Sampled by SRC in 2021 (41.616185. -78.815423).
Cowan, Bruce A & Nancy	2014	NA	W2/Private Water Well	320'	UNK	Sampled by SRC in 2021 (41.615759, -78.814781).
Cowan, Bruce A & Nancy	2012	NA	W3/ Private Water Well	100'	UNK	Sampled by SRC in 2021 (41.616346, -78.815343).
Cowan, Bruce A & Nancy	2012	NA	W4/Private Water Well	64'	UNK	Sampled by SRC in 2021 (41.614622, -78.814520).
Seneca Resources Co.	UNK	047-00516	George W. Archer 4406/Monitoring	3,732'	404'	Monitoring Well for Seneca Well #38282
PADEP Oil & Gas MGMT	UNK	047-01143	Jarvis 46/Vertical O&G Well	UNK	UNK	PADEP Orphan Well List (Abandoned)
East Resources Inc.	UNK	047-01144	Jarvis 47/Vertical O&G Well	UNK	UNK	Plugged Well
East Resources Inc.	UNK	047-01145	Jarvis 48/Vertical O&G Well	UNK	UNK	Plugged Well
PADEP Oil & Gas MGMT	UNK	047-01146	Jarvis 49/Vertical O&G Well	UNK	UNK	PADEP Orphan Well List (Abandoned)
Seneca Resources Co.	UNK	047-21054	Mars Co. 1144/Monitoring	UNK	UNK	Monitoring Well for Seneca Well #38268
Seneca Resources Co.	UNK	047-00515	George W. Archer 4384/Monitoring	2,527'	411'	Monitoring Well for Seneca Well #38282
Seneca Resources Co.	1/25/2008	37-047-328855/PAS2D026BELK	Seneca Well #38282/Disposal	2,571'	553'	Existing brine disposal well
Seneca Resources Co.	1/22/2008	37-047-32884	Seneca Well #38281/Monitoring	2,540'	602'	Monitoring Well for Seneca Well #38268
Weritz, John	1985	NA	W1 / Private Water Well	140'	UNK	Sampled by SRC in 2021 (41.616603, -78.812698)

Notes:
Unnamed Tributary to Wolf Run is located approximately 630' south of Well #38268.
Unnamed Tributary to East Branch Tionesta Creek is located approximately 0.4 miles northeast of Well #38268.
UNK = Unknown
NA = Not Applicable

APPENDIX A

AOR Well Bore Diagrams and Public Records

Well #38268 Information

Figure 2
Well Construction Diagram
Injection Test Well
Seneca Well #38268
Highland Township
Elk County, PA
37-047-23835

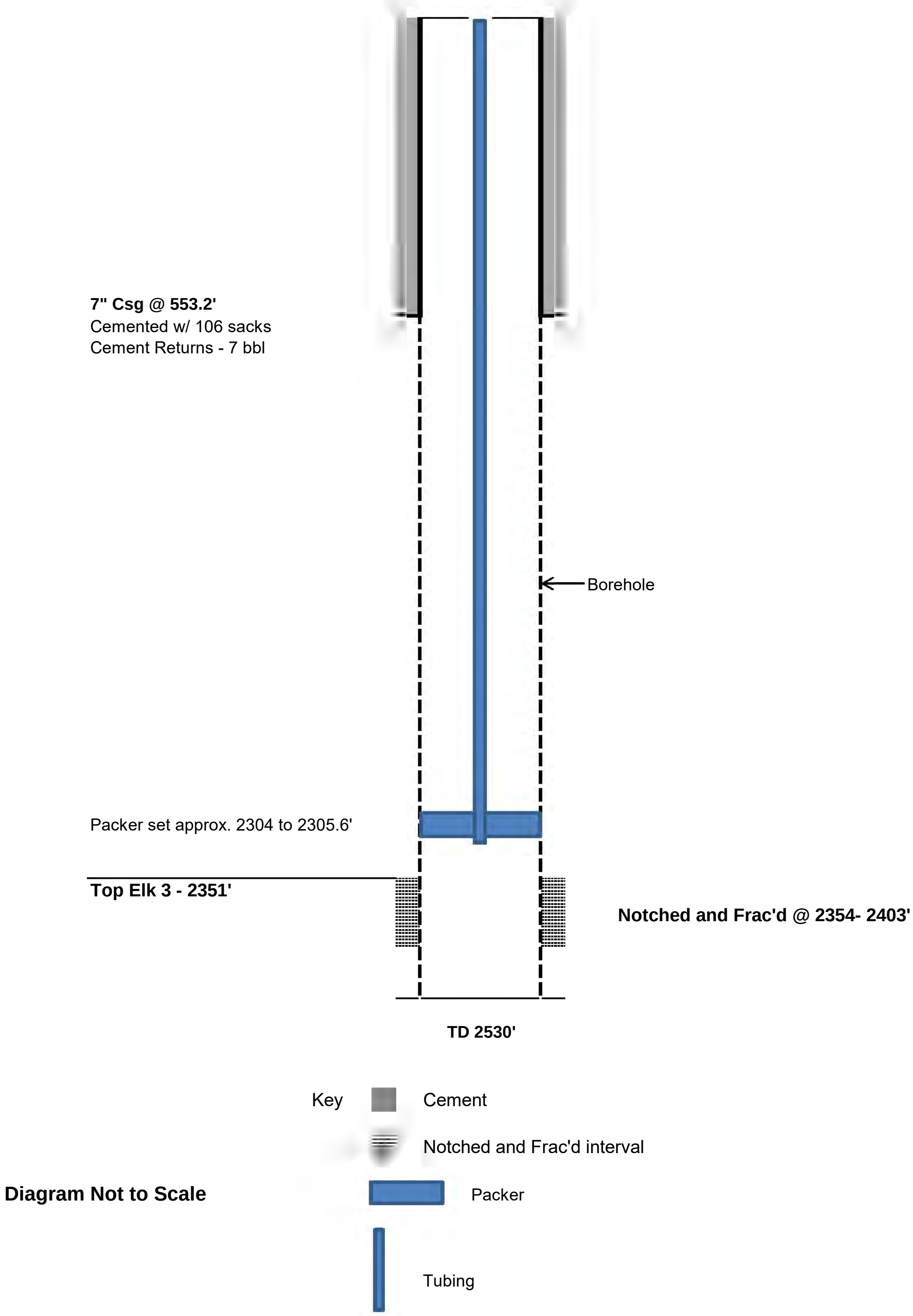
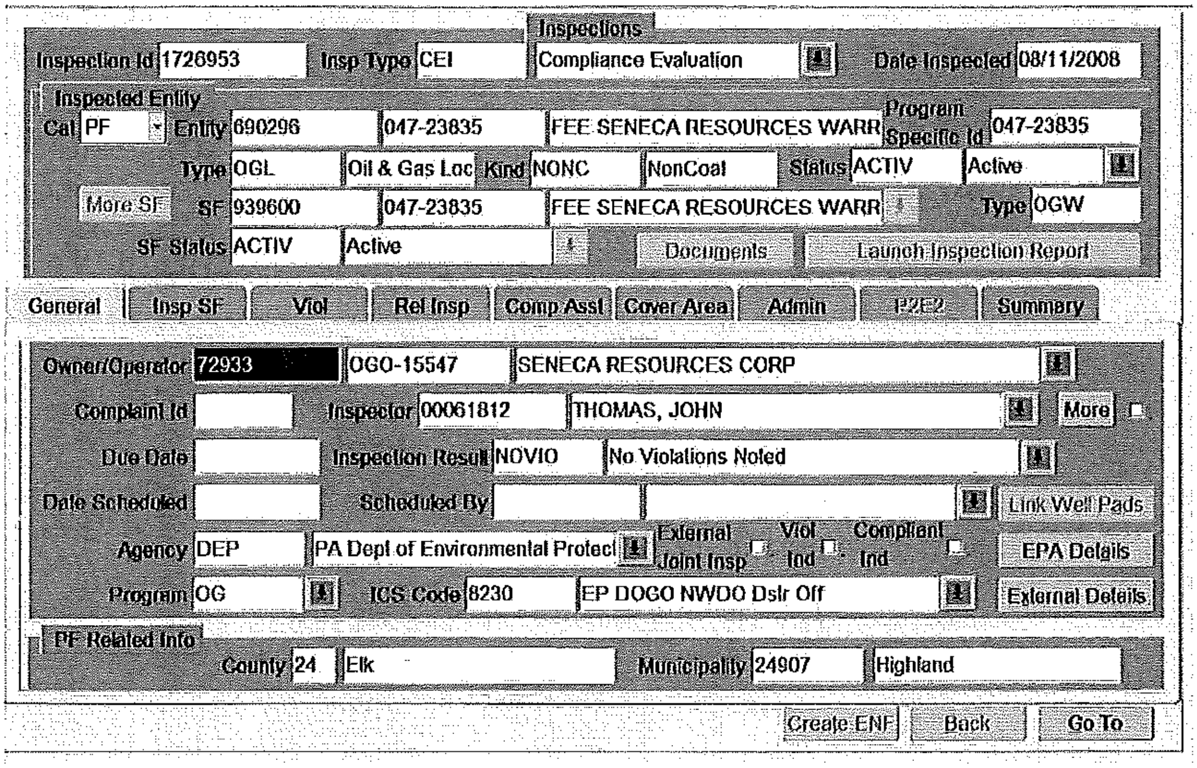


Table #2 – DEP eFACTS Inspection Report Dated 8/11/08



Inspections

Inspection Id 1726953 | Insp Type CEI | Compliance Evaluation | Date Inspected 08/11/2008

Inspected Entity

Cat PF | Entity 690296 | 047-23835 | FEE SENECA RESOURCES WARR | Program Specific Id 047-23835

Type OGL | Oil & Gas Loc | Kind NONC | NonCoal | Status ACTIV | Active

More SF | SF 939600 | 047-23835 | FEE SENECA RESOURCES WARR | Type OGW

SF Status ACTIV | Active | Documents | Launch Inspection Report

General | Insp SF | Viol | Rel Insp | Comp Asst | Cover Area | Admin | P2E2 | Summary

Owner/Operator 72933 | OGO-15547 | SENECA RESOURCES CORP

Complaint Id | Inspector 00061812 | THOMAS, JOHN | More

Due Date | Inspection Result NOVIO | No Violations Noted

Date Scheduled | Scheduled By | Link Well Pads

Agency DEP | PA Dept of Environmental Protect | External Joint Insp | Viol Ind | Compliant Ind | EPA Details

Program OG | ICS Code 8230 | EP DOGO NWDO Dstr Off | External Details

PF Related Info

County 24 | Elk | Municipality 24907 | Highland

Create ENF | Back | Go To

Table #1 – Seneca #38268 Mechanical Integrity Report – 2014 and 2015

OPERATOR	OGO	PERMIT_API	INSPECTION_YEAR	INSPECTION_DATE	RECEIVED_DATE	FORM_ID	DOCUMENT_CATEGORY	PRIMARY_____ _PRODUCTION_ PRESSURE_PSIG	PRODUCTION_OPEN_VENT_FLOW	PRODUCTION_OPEN_VENT_FLOW_UNIT_CFPD	ANNULAR_PRODUCTION_PRESSURE_PSIG
SENECA RESOURCES CORP	#	047-23835	2015	12/1/15	2/12/2016	C	DEP Integrity Short Form C	14		NA	
SENECA RESOURCES CORP	#	047-23835	2014	10/1/14	2/11/2015	C	DEP Integrity Short Form C	12		NA	

MAX_____ ALLOWABLE_ PRESSURE__ _EXCEEDED	WATER_ LEVEL_ OR___ OTHER	WATER__ LEVEL_OR _OTHER_ UNIT___ VARIOUS	PRODUCTION _ANNULUS_ OPEN_FLOW OR SHUT_IN___ PRESSURE	PRODUCTION_AN NULUS__OPEN___ FLOW_OR_SHUT_ _IN_PRESSURE___ _UNIT_CFPD__OR _PSIG	FLUIDS_ NOTED	OPEN_FLOW_ OUTSIDE___ FRESHWATER _CASING	OPEN_FLOW_ OUTSIDE____ FRESHWATER_ CASING_UNIT_ CFPD	OPEN_FLOW_ OUTSIDE_INTE RMEDIATE___ CASING	OPEN_FLOW__O UTSIDE______ INTERMEDIATE_ CASING_UNIT__ __CFPD	SURFACE___ WELLHEAD_ EQUIPMENT _EMISSION_ RATE	SURFACE______ WELLHEAD_____ EQUIPMENT____ EMISSION_RATE_ UNIT_CFPD
NA			0	cfpd	N		NA		NA		NA
N			0	cfpd	N		NA		NA		NA

SURFACE___ WELLHEAD_ EQUIPMENT _EMISSION_ RATE	SURFACE______ WELLHEAD_____ EQUIPMENT____ EMISSION_RATE_ UNIT_CFPD	LIQUIDS_TO__ SURFACE_OR_ OUTSIDE_____ FRESHWATER_ CASING	CORROSION _PROBLEMS	COMMENTS	STANDARD___ COMMENTS__ _FOR_NO____ __INSPECTION	FILE____ NAME	REGION	COUNTY	MUNICIPALITY	UN-CONVENTIONAL	WELL_TYPE
	NA	N	N			PA_DEP_In	EP DOGO NWDO Dstr Off	Elk	Highland	No	MULTIPLE WELL BORE TYPE
	NA	NA	N			PA_DEP_In	EP DOGO NWDO Dstr Off	Elk	Highland	No	MULTIPLE WELL BORE TYPE

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program
WELL LOCATION PLAT 7¢C

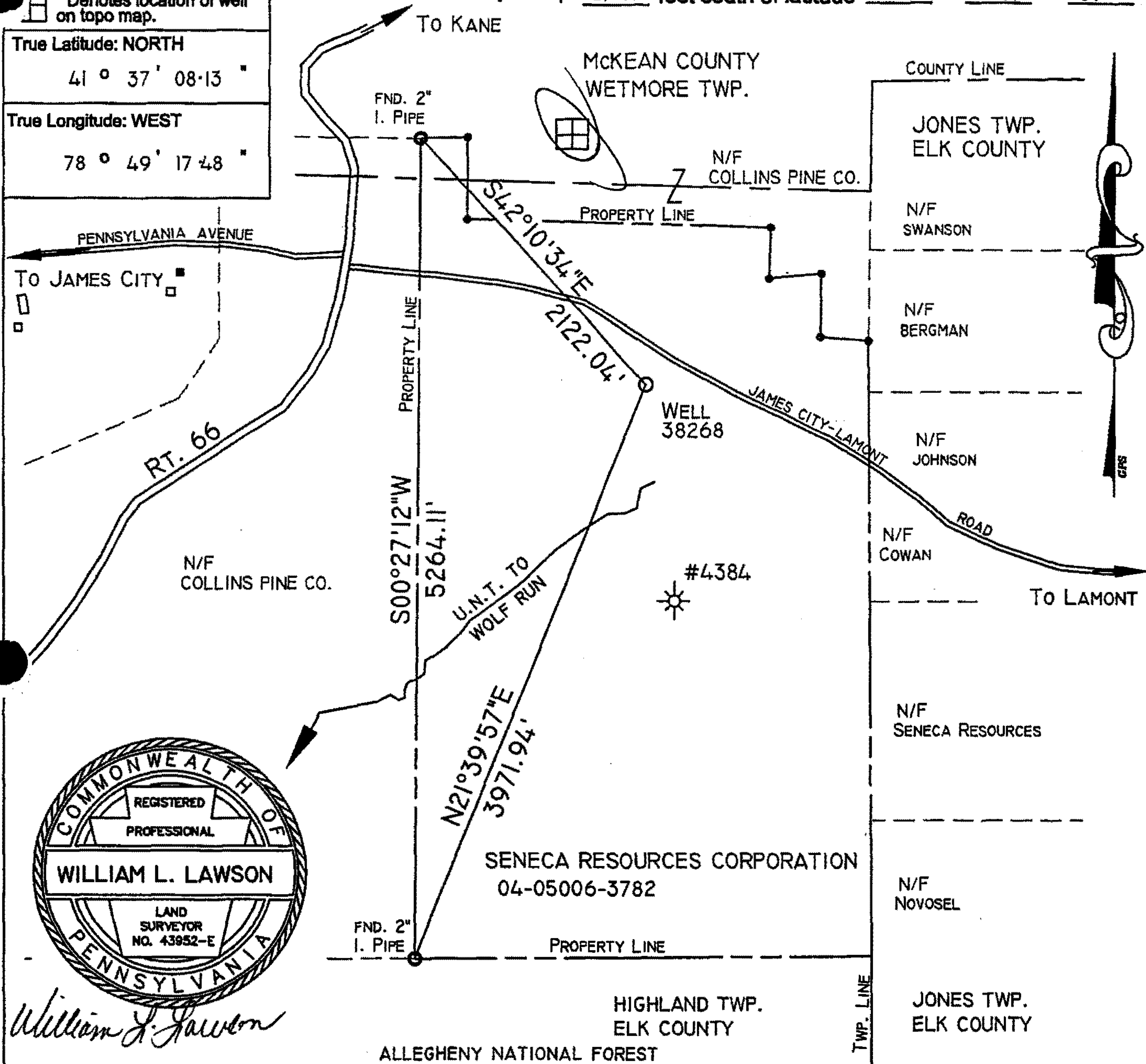
DEP USE ONLY	
DEP Application Tracking #	
Permit #	047-23835
Project #	
GC: 2/20/07	
C:	

Well is located on topo map 2,207 feet south of latitude 41 ° 37 ' 30 "

Denotes location of well on topo map.

True Latitude: NORTH
41 ° 37 ' 08.13 "

True Longitude: WEST
78 ° 49 ' 17.48 "



Well is located on topo map 8,163 feet west of longitude 78 ° 47 ' 30 "

Surveyor or Engineer: WILLIAM L. LAWSON	Phone # (814) 752-2291	Dwg. # P:/WELLFILES/38268.DWG	Date 02/09/07
Scale 1" = 1000'	Tract Acreage 299.6		

Lat. & Long Metadata Method GPSDF Accuracy +/- 3 ft. Datum NAD - 27	Elevation Metadata Method TOPO Accuracy +/- 10 ft. Datum NGVD-29 Survey Date 01/30/07
Applicant / Well Operator Name: SENECA RESOURCES CORPORATION	Well (Farm) Name: FEE- SRC WT. 3771 — Well # 38268 — Serial #
Address: 286 OLD 36 ROAD SIGEL, PA 15860	County - Code: ELK - 24 — Municipality: HIGHLAND TOWNSHIP
Surface Landowner: SENECA RESOURCES CORPORATION	USGS 7 1/2 Quadrangle Map Name: JAMES CITY, PA 0615 — Map Section "2"
Surface Lessor: NONE	Angle & Course of Deviation (Drilling): VERTICAL — Surface Elevation 2040 ft. — Anticipated Total Depth 2530 ft.

Surface Owner or Water Purveyor with a Water Supply within 1,000 feet	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
NONE			

HQ WATERSHED
Martin Run

RECEIVED
FEB 14 2007
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil & Gas Management Program

LYNN AUG 15

WELL RECORD AND COMPLETION REPORT

DEP USE ONLY

Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

Well Operator	DEP ID#	Well API # (Permit / Reg)	Project Number	Acres
SENECA RESOURCES CORPORATION	72993	37-047-23835-00		

Address	Well Farm Name	Well #	Serial #
286 OLD 36 ROAD	FEE SENECA RESOURCES WARRANT 3771	38268	

City	State	Zip Code	County	Municipality
SIGEL	PA	15860	Elk	Highland

Phone	Fax	USGS 7.5 min quadrangle map
814-725-2291	814-752-6204	James City 2

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type ☒ Gas ☐ Oil ☐ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
3/20/07	3/22/07	2040'	2530'	2532'

Casing and Tubing

Cement returned on surface casing? ☒ Yes ~~No~~ See Drillers Log
Cement returned on coal protective casing? ☐ Yes No X N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	Material Behind Pipe Type and Amount	Packer / Hardware / Centralizers Type	Size	Depth	Date Run
11 ¼	9 5/8	26	T	63					
8 ¾	7	17	T	553	106 sks. Common Class A, 3% CaCl, ½#unicele			523, 349, 175	3/21/07
6 1/4	2 3/8		T	2498					7/03/07
	5/8		T	2475					7/03/07

COMPLETION REPORT

Perforation Record / Stimulation Record

Perforation Date	Interval Perforated From	To	Stimulation Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			7/03/07	1667 0	Gel Water	8770 gal	20/40 sand	120 sks	19 8
				1671 5	Gel Water	11,040 gal	20/40 sand	160 sks	20
				1676 0	Gel Water	10,910 gal	20/40 sand	160 sks	20
				1721 0	Gel Water	8910 gal	20/40 sand	120 sks	20
				1739 5	Gel Water	9250 gal	20/40 sand	120 sks	20 3

Natural Open Flow mcfd	Natural Rock Pressure	Hours	Days

After Treatment Open Flow Mcfd	After Treatment Rock Pressure	Hours	Days
350	125		2

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name	Name	Name
Dallas-Morris Drilling Co	Universal Well Services	Schlumberger
Address: Morris Lane	Address: P O Box 180	Address: 95 Rutherford Run
City - State – Zip: Bradford PA 16701	City - State – Zip: Bradford, PA 16701	City - State – Zip: Bradford, PA 16701
Phone: (814) 362-6493	Phone: (814) 368-6175	Phone: (814) 362-7441

RECEIVED
AUG 20 2007
ENVIRONMENTAL PROTECTION
WARREN DISTRICT OFFICE

RECEIVED
AUG 06 2007
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

LOG OF FORMATIONS

Well API#: 37-053-23835-00

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

RECEIVED
AUG 2 0 2007
ENVIRONMENTAL PROTECTION
WARREN DISTRICT OFFICE

Well Operator's Signature: Guy A. Shuey

Title: Superintendent / Prod. & Eng. Date: 7/26/07

DEP USE ONLY

Reviewed by: T Cuny

Date: 6-4-08

Comments.

RECEIVED
AUG 0 6 2007
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	
Bits Used:	12 ¼", 8 ¾", 6 ¼"				
Fuel Use:	Spud: 8057	T. D.: 8916		Rig Hours:	5051 - 5093

TOP	BOTTOM	FORMATIONS	TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock	1910	1925	Gas
5	15	Sand	1925	1980	Cooper 4.0 & Sand
15	40	Sand	1980	2135	Cooper 6.0
40	55	Sand	2135	2275	Gas
55	70	Shale	2275	2295	Elk 1.0 (gas)
70	95	Sand	2295	2355	Sand (gas)
95	120	Sand & Shale	2355	2390	Gas
120	225	Sand	2390	2420	Elk 4.0
225	415	Sand & Shale	2420	2510	Sand (gas)
415	558	Sand	2510	2530	Sand
558	635	Red Rock	2530		Total Depth
635	650	Shale			
650	820	Red Rock			
820	865	Shale			
865	915	Red Rock			
915	1270	Sand & Shale			
1270	1345	Sand			
1345	1360	Red Rock			
1360	1385	Sand & Shale			
1385	1555	Base Warren 1.0			
1555	1565	Red Rock			
1565	1575	Sand			
1575	1598	T-12 Marker			
1598	1675	Speechley 2.0			
1675	1725	Gas			
1725	1750	Speechley 6.0 (gas)			
1750	1765	Gas			
1765	1875	Tiona 1.0			
1875	1890	Red Rock (gas)			
1890	1910	Sand			

RECEIVED
AUG 2 0 2007
ENVIRONMENTAL PROTECTION
WARREN DISTRICT OFFICE

RECEIVED
AUG 0 6 2007
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	
Bits Used:	12 ¼", 8 ¾", 6 ¼"				
Fuel Use:	Spud: 8057	T. D.: 8916	Rig Hours:	5051 - 5093	

TOP	BOTTOM	FORMATIONS	TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock	1910	1925	Gas
5	15	Sand	1925	1980	Cooper 4.0 & Sand
15	40	Sand	1980	2135	Cooper 6.0
40	55	Sand	2135	2275	Gas
55	70	Shale	2275	2295	Elk 1.0 (gas)
70	95	Sand	2295	2355	Sand (gas)
95	120	Sand & Shale	2355	2390	Gas
120	225	Sand	2390	2420	Elk 4.0
225	415	Sand & Shale	2420	2510	Sand (gas)
415	558	Sand	2510	2530	Sand
558	635	Red Rock	2530		Total Depth
635	650	Shale			
650	820	Red Rock			
820	865	Shale			
865	915	Red Rock			
915	1270	Sand & Shale			
1270	1345	Sand			
1345	1360	Red Rock			
1360	1385	Sand & Shale			
1385	1555	Base Warren 1.0			
1555	1565	Red Rock			
1565	1575	Sand			
1575	1598	T-12 Marker			
1598	1675	Speechley 2.0			
1675	1725	Gas			
1725	1750	Speechley 6.0 (gas)			
1750	1765	Gas			
1765	1875	Tiona 1.0			
1875	1890	Red Rock (gas)			
1890	1910	Sand			

INVOICE NO. 536463

STAGE NO.

UNIVERSAL WELL SERVICES INC

JOB LOG

CUSTOMER Seneca Res

LEASE NAME 38268

DATE 3-21-07

	NO. OF SACKS	COMPOSITION OF CEMENT	YIELD	GAL. WTR/SK	DENSITY	BBL. OF MIX WTR.	CU. FT. OF SLURRY	BBL. OF SLURRY
1.	106	class A, 3% cacl2, ½#sk unicele	1.18	5.2	15.6	13.1	125	22.2
2.								
3.								
					TOTAL	13.1	125	22.2

CIRCULATE CEMENT TO SURFACE

☒ Yes ☐ No ☐ Not Applicable

7 bbls return

JOB TYPE

☒ Surface ☐ Longstring ☐ Acid

☐ Other 7" surface

	NEW USED	SIZE	FROM	TO	WEIGHT	MAXIMUM PSI ALLOWANCE
CASING	N	7"	0	553.2	17#	
TUBING						
OPEN HOLE		8¾	553.2	568		
~~PERFORATIONS~~ LJ			4'			

DISPLACEMENT CAPACITY 23.1 BBL.

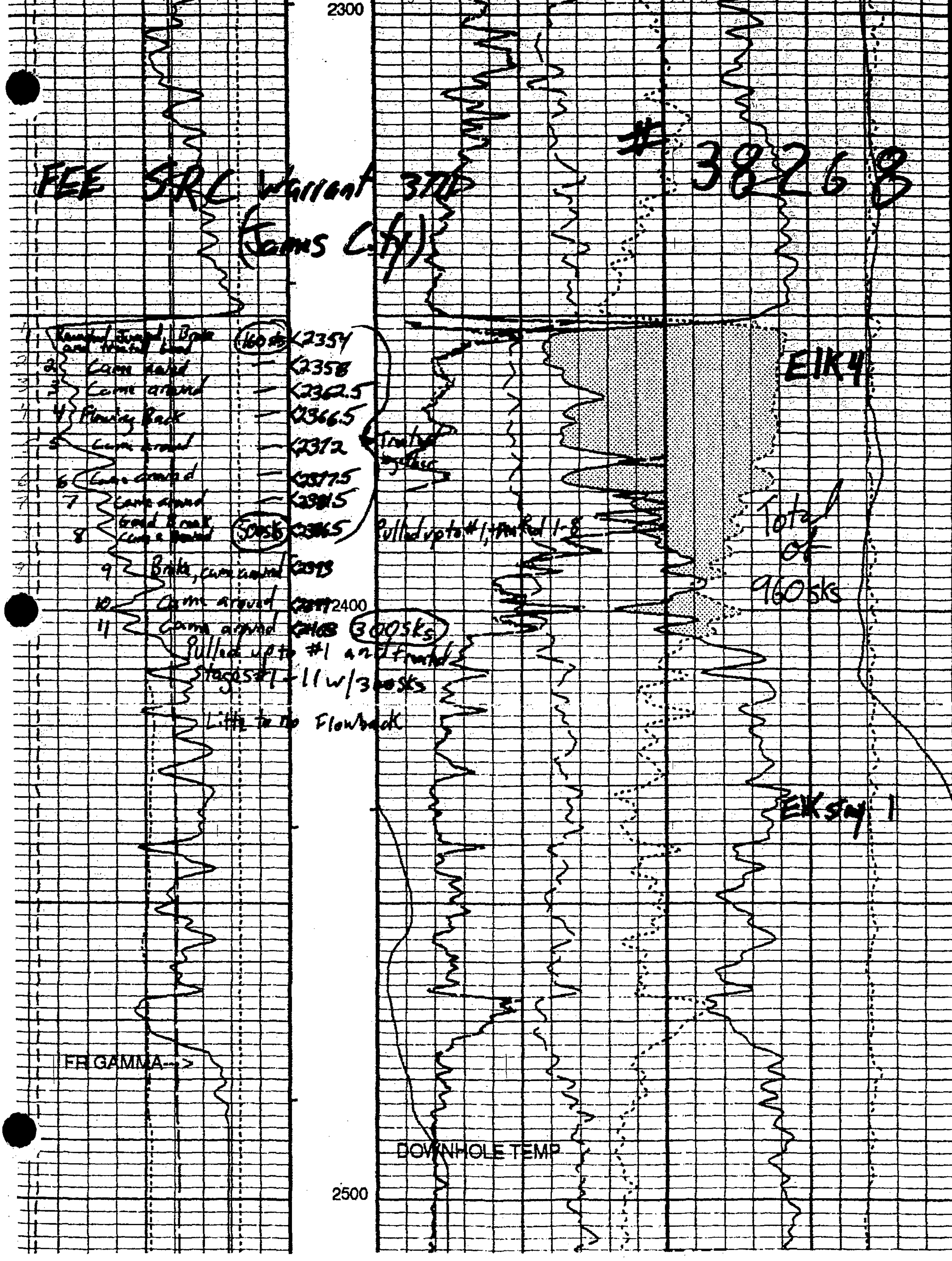
DISPLACEMENT DEPTH 557.2 FT.

TIME	RATE (BPM)	VOLUME (BBL)	PRESSURE (PSI) TUBING	PRESSURE (PSI) CASING	DESCRIPTION OF STAGE OR EVENT
1830					SPOT Truck, rig up
1855					Safety meeting
1900	2-3	10		0-50	Start H^2O
1903	3	10		50-100	Start Gel unicele
1906	3	5		100	Start spacer
1909	3-4	22.2		100-200	Start class A, 3% cacl2, ½#sk unicele
1916					SDTP
1918	4-2	23.1		0-550	Start H^2O displacement
1925					Plug Landed, closed manifold
1928				550-0	release pressure, wash up
1945					rig down
					Job complete

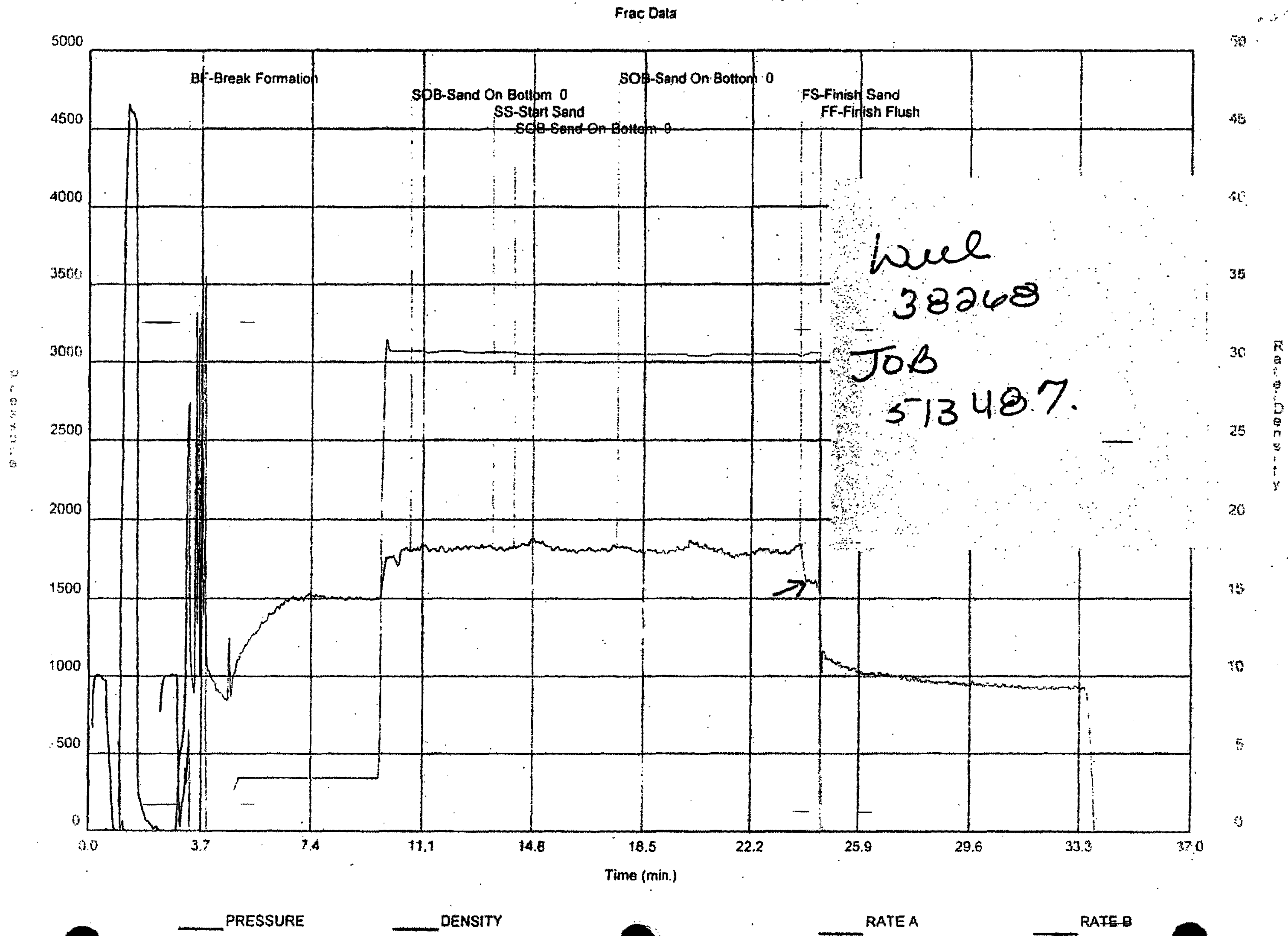
REMARKS Ph 7 H^2O 38 W&D sample

SERVICE ENGINEER Everly

CUSTOMER REPRESENTATIVE [signature]


2300
FEE SRC Warrant 37D
(Jams City)
38268
1 Rounded, Jumped, Broke and treated band 160 sks <2354
2 Came around <2358
3 Came around <2362.5
4 Flowing Back <2366.5
5 Came around <2372
6 Came around <2377.5
7 Came around <2381.5
8 Good Break, came around 500 sks <2386.5
Treated by stage
Pulled up to #1, treated 1-8
9 Broke, came around <2393
10 Came around <2397 2400
11 Came around <2403 300 sks
Pulled up to #1 and treated stages #1-11 w/ 300 sks
Little to no Flowback
Elk 4
Total of 960 sks
Elk stray 1
FR GAMMA-->
DOWNHOLE TEMP
2500

#1 100 sks 4/5/07
Elk 4



Well
38268
JOB
513487.

Well #38281 Information

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT

T $\oint$ 0

DEP USE ONLY	DEP Application Tracking #	G: 35
	Permit # 047-23884	5/10/07
	Project #	C:

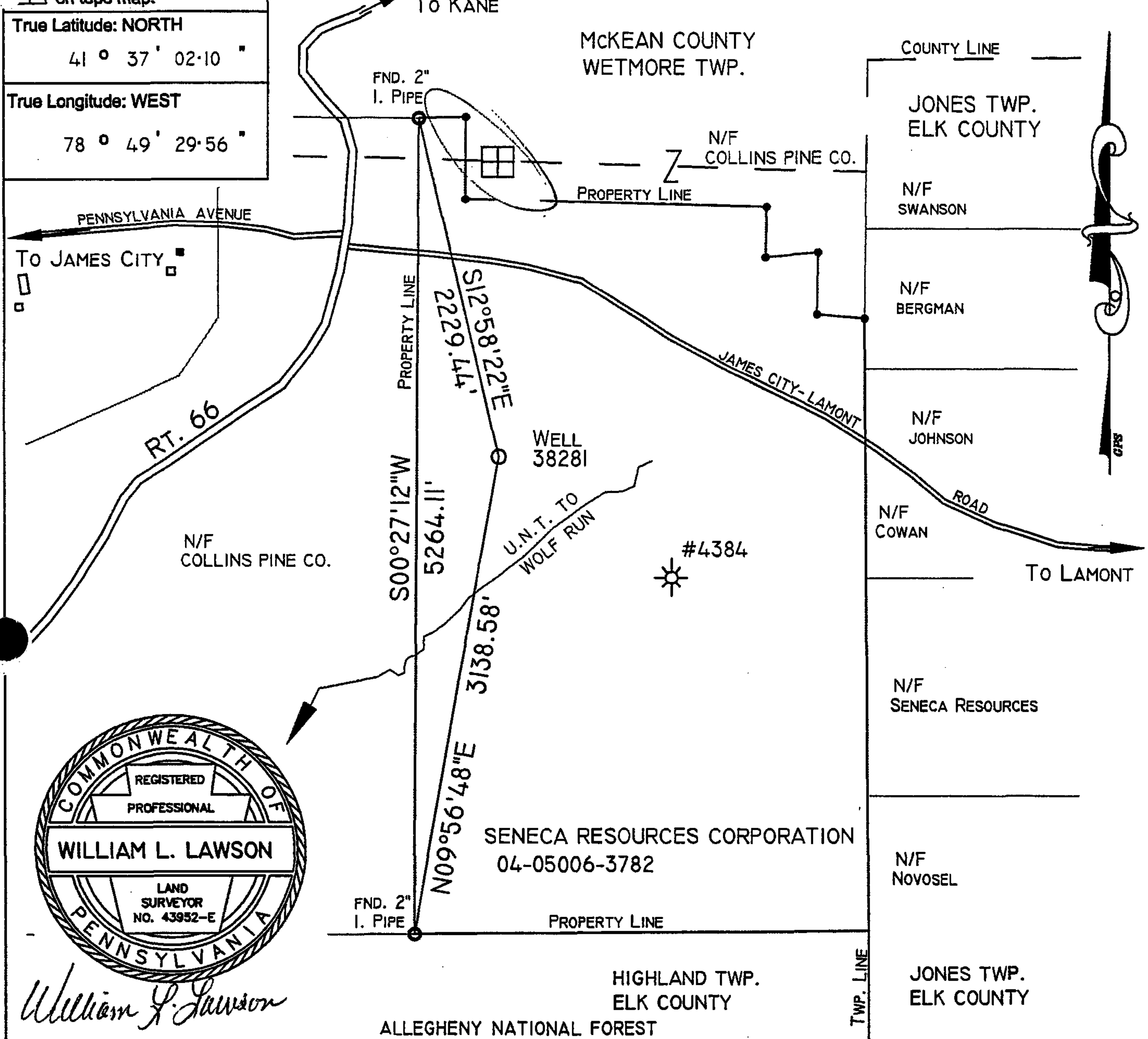
Well is located on topo map 2,815 feet south of latitude 41 ° 37 ' 30 "

Well is located on topo map 9,081 feet west of longitude 78 ° 47' 30 "

Denotes location of well on topo map.

True Latitude: NORTH 41 ° 37 ' 02.10 "

True Longitude: WEST 78 ° 49 ' 29.56 "



William L. Lawson

Surveyor or Engineer WILLIAM L. LAWSON Phone # (814) 752-2291 Dwg. # P:/WELLFILES/38281.DWG Date 04/09/07 Scale 1" = 1000' Tract Acreage 299.6

Lat. & Long Metadata Method GPSDF Accuracy +/- 3 ft. Datum NAD - 27	Elevation Metadata Method TOPO Accuracy +/- 10 ft. Datum NGVD-29	Survey Date 02/30/07	
Applicant / Well Operator Name SENECA RESOURCES CORPORATION	Well(Farm) Name FEE- SRC WT. 3771	Well # 38281	Serial #
Address 286 OLD 36 ROAD SIGEL, PA 15860	County - Code ELK - 24	Municipality HIGHLAND TOWNSHIP	
Surface Landowner SENECA RESOURCES CORPORATION	USGS 7 1/2 Quadrangle Map Name JAMES CITY, PA 0615		Map Section "2"
Surface Lessor NONE	Angle & Course of Deviation (Drilling) VERTICAL	Surface Elevation 2020 ft.	Anticipated Total Depth 2570 ft.
Surface Owner or Water Purveyor with a Water Supply within 1,000 ft. NONE	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated

HQ

WATERSHED Martin Run

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil & Gas Management Program

WELL RECORD AND COMPLETION REPORT

DEP USE ONLY	
Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

Well Operator: SENECA RESOURCES CORPORATION	DEP ID#: 72993		Well API # (Permit / Reg): 37-047-~~3288+~~ 23884	Project Number	Acres
Address: 51 Zents Blvd			Well Farm Name: FEE-SRC Wt 3771	Well #: 38281	Serial #
City: Brookville	State: PA	Zip Code: 15825	County: McKean	Municipality: Highland	
Phone: 814-849-4555	Fax: 814-849-4795		USGS 7 5 min quadrangle map		

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type ☐ Gas ☐ Oil ☒ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
01/22/08	01/24/08	2020	2544	2540

Casing and Tubing

Cement returned on surface casing? ☒ Yes ☐ No
Cement returned on coal protective casing? ☐ Yes ☐ No ☒ N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	Material Behind Pipe Type and Amount	Packer / Hardware / Centralizers Type	Size	Depth	Date Run
12 ¼	9 5/8	26	T	47					01/22/08
8 ¾	7	17	T	602	124 sks Class A Cement, 3% CaCl, ½# unicele/sk	3 centralizers			01/23/08
¼	2 3/8	4.9	T	2482					03/11/08
	5/8		T	2475					03/11/08

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COMPLETION REPORT

Perforation Record Date	Interval Perforated From	To	Stimulation Record Date	Interval Treated	Fluid Type	Amount	Propping Agent Type	Amount	Average Injection Rate
			03/11/08	1650	Gel Water	8460	20/40 sks	120	20
				1655	Gel Water	9620	20/40 sks	140	20
				1658	Gel Water	10728	20/40 sks	160	20
				1662	Gel Water	8672	20/40 sks	140	20
				1704	Gel Water	7401	20/40 sks	100	20
				1719	Gel Water	9111	20/40 sks	120	20

Natural Open Flow Mcfd 1	Natural Rock Pressure	Hours	Days
After Treatment Open Flow Mcfd 500	After Treatment Rock Pressure	Hours	Days

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name: Natural Oil and Gas	Name: Keane and Sons Drilling	Name: Schlumberger
Address: 1410 W Warren Road	Address: 12 Keane Lane	Address: 95 Rutherford Run
City - State - Zip: Bradford, PA 16701	City - State - Zip: Bradford, PA 16701	City - State - Zip: Bradford, PA 16701
Phone: 814-362-2543	Phone: 814-362-2659	Phone: 814-362-7441

COMPLETION REPORT API#37-047-32884

Perforation Record			Stimulation Record						
Date	Interval Perforated		Date	Interval Treated	Fluid		Propping Agent		Average Injection Rate
	From	To			Type	Amount	Type	Amount	
			03/11/08	1728	Gel Water	8779	20/40 Sand	120	20
				1734	Gel Water	8779	20/40 Sand	120	20
				1893	Gel Water	7567	20/40 Sand	100	20
				2123	Gel Water	8770	20/40 Sand	120	17
				2133	Gel Water	9949	20/40 Sand	140	20
				2151	Gel Water	9903	20/40 Sand	140	19
				2156	Gel Water	10256	20/40 Sand	140	18
				2339-2390	Gel Water	23228	20/40 Sand	500	23
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		

LOG OF FORMATIONS

Well API#: 37-047-32884

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

RECEI...
APR

Well Operator's Signatures

Guy A Shuey

Title: Superintendent / Prod. & Eng. Date: 4/14/08

DEP USE ONLY

Reviewed by: T Curry

Date: 6-4-08

Comments:

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVAN
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL #	38281	PERMIT #	37-047-23884
SPUD DATE	1/22/2008	COUNTY	Elk
SPUD TIME	4:30 p.m.	TOWNSHIP	Highland
CONDUCTOR	47 ft.	LEASE	James City
CASING	603 ft.	TD DATE	1/24/2008
TOTAL DEPTH	2544 ft.	TD TIME	11:57 a.m.

PIPE TALLY

1	23.2 ft.	7	23.2 ft.	13	23.2 ft.	19	23.2 ft.	25	23.2 ft.
2	23.2 ft.	8	23.2 ft.	14	23.2 ft.	20	23.2 ft.	26	23.2 ft.
3	23.2 ft.	9	23.2 ft.	15	23.2 ft.	21	23.2 ft.	27	
4	23.2 ft.	10	23.2 ft.	16	23.2 ft.	22	23.2 ft.	28	
5	23.2 ft.	11	23.2 ft.	17	23.2 ft.	23	23.2 ft.	29	
6	23.2 ft.	12	23.2 ft.	18	23.2 ft.	24	23.2 ft.	30	

#JOINTS	26	CEMENT CO.	Universal
SACKS	124	RETURNS	6 Barrels
PLUG DOWN	9:45 a.m.	CEMENT DATE	1/23/2008

OPERATOR: Seneca WELL NAME: Fee-SRC WT 377

WELL # : 38281 PERMIT #: 37-047-23884-(

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD. BRADFORD. PENNSYLVANIA 167
Telephone: (814) 362-6890 Fax (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
45	4:30		Gravel, Shale	645	10:40	10	Shale
75	4:56		Shale	675	8:02	12	Shale
105	6:00		Shale	705	8:11	9	Shale
135	6:11	11	SandStone	735	8:21	10	Shale
165	6:21	10	SS/Shale	765	8:31	10	RedRock
195	6:34	13	Shale	795	8:43	12	RR/Shale
225	6:45	11	Shale	825	8:53	10	Shale
[illegible]	6:58	13	Sand	855	9:04	11	Shale
285	7:10	12	Shale	885	9:16	12	Shale
315	7:25	15	Sand	915	9:27	11	Shale
345	7:37	12	Shale	945	9:40	13	Shale
375	8:49	12	RedRock	975	9:55	15	RedRock
405	9:00	11	RedRock	1005	10:05	10	Shale
435	9:12	12	RR/Shale	1035	10:15	10	Shale
465	9:26	14	Sand/Shale	1065	10:26	11	RedRock
495	9:40	12	Shale	1095	10:37	11	RedRock
525	9:52	12	Shale	1125	10:50	13	RedRock
555	10:04	12	Shale	1155	11:02	12	Shale
585	10:17	13	Sand/Shale	1185	11:13	11	RR/Shale
[illegible]	10:30	13	Shale	1215	11:23	10	Shale

COMMENTS:

OPERATOR: Seneca WELL NAME: Fee-SRC WT 37

WELL # : 38281 PERMIT #: 37-047-23884-(

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVANIA 167
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
1245	11:33	10	RedRock	1845	7:25	11	Shale
1275	11:43	10	Shale	1875	7:39		Sand (Cooper 4-0)
1305	11:56	13	Shale	1905	7:52	13	Sand/Shale
1335	12:30		Shale	1935	8:03	11	Sand/Shale
1365	3:00		RR/Shale	1965	8:16		Sand (Cooper 6-0)
1395	4:20		Shale	1995	8:28	12	Sand/Shale
1425	4:30	10	Shale	2025	8:38	10	Shale
[illegible]55	4:43	13	Shale	2055	8:49	11	Shale
1485	4:55	12	Shale	2085	9:00	11	Shale
1515	5:05	10	Shale	2115	9:12	12	Shale
1545	5:20	15	Shale	2145	9:22	10	Shale
1575	5:34		Sand (Speechley 2-0)	2175	9:33	11	Shale
1605	5:45	11	Sand/Shale	2205	9:43	10	Shale
1635	5:58	13	Shale	2235	9:56	13	Sand (Elk 1-0)
1665	6:12		Sand (Speechley 6-0)	2265	10:09	13	Sand/Shale
1695	6:25	13	Sand/Shale	2295	10:20	11	Shale
1725	6:40	15	Sand (Tiona 1-0)	2325	10:31	11	Shale
1755	6:53	13	Sand/Shale	2355	10:45	14	Sand (Elk 3-0)
1785	7:04	11	RR/Shale	2385	10:48	13	Sand/Shale
[illegible]15	7:14	10	RR/Shale	2415	11:00	12	Sand/Shale

COMMENTS:

OPERATOR: Seneca WELL NAME: Fee-SRC WT 377

WELL # : 38281 PERMIT #: 37-047-23884-0

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVANIA 167
Telephone (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
2445	11:14	14	Shale				
2475	11:26	12	Shale				
2505	11:36	10	Shale				
2535	11:46	10	Shale				
2544	11:57	11	TD Shale				

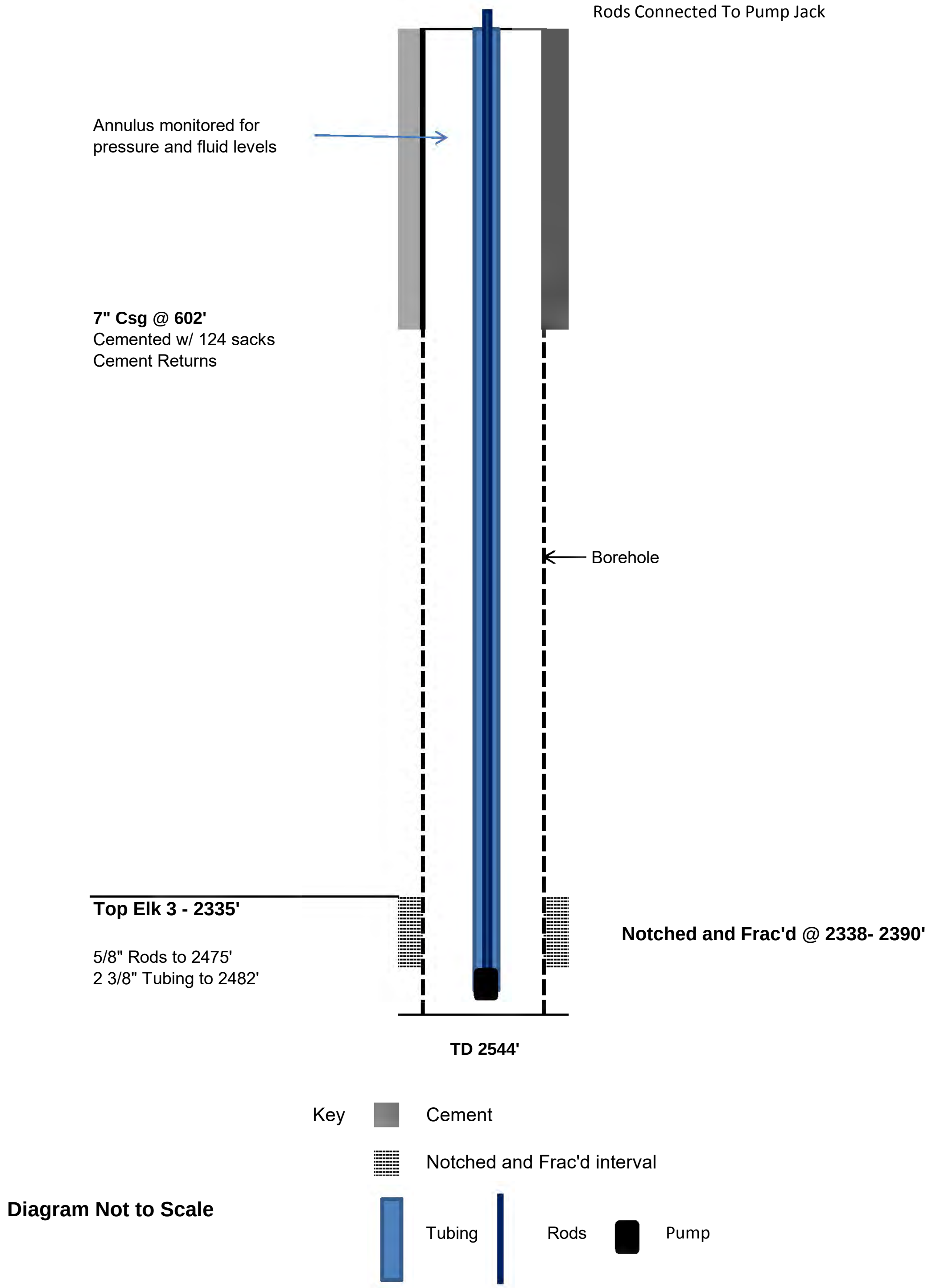
COMMENTS:

Figure 3

Well Construction Diagram

Observation Well

Seneca Well #38281
Highland Township
Elk County, PA
37-047-23884



Well #1328 Information

RE
2400' S 41°37'30"
7100' W 78°47'30"
(B3)

BUREAU OF OIL AND GAS REGULATION

Date Approved 3-26-9

CERTIFICATE OF PLUGGING WELL

JAMES City
047-7
00449-7

Type of Well Natural Gas

Name of Well Operator National Fuel Gas Supply

1400 Gilbert Dr. P.O. Box 626 Titusville, PA 16354
Address

February 26 19 9
Date

Highland
Political Subdivision, Borough, City or Township

Elk Coun

Farm James Bros.

Well (Farm) No 1328 Serial No. ______

☐ Coal Operator ☐ Owner ☐ Lessee

Address

☐ Coal Operator ☐ Owner ☐ Lessee

Address

☐ Coal Operator ☐ Owner ☐ Lessee

Address

COMPLETE ABOVE SECTION IF APPLICABLE

KANE FIELD, NANSEN POOL

We, the undersigned representatives of the Well Operator certify that we participated in the plugging of the abo well, and that the work was started Feb. 7 19 91, and that the well was plugged as follo

FILLING MATERIAL AND PLUGS		FROM	TO	Casing and Tubing SIZE	PULLED	LEFT
Solid Cavings		2433'	2431'	6¼"	336'	124
Cement	90 sacks	2431'	2100'	4"	497'	25
Cement	70 sacks	1850'	1500'			
Cement	20 sacks	600'	500'			
Cement	20 sacks	500'	346'			
SP/Mud		346	30'			
Cement	10 sacks	30'	surface	Depth of Coal Seam, If Any		
				NONE		
				Description of Monument		
~~NOTE: Gelled water between cement plugs.~~				Installed marker to extend 4' above ground.		

RECEIVED MAR 28 1991 Bureau of Oil and Gas Management Environmental Resources

RECEIVED MAR - 6 1991 WARREN DISTRICT OFFICE ENVIRONMENTAL RESOURCES

I certify that the work of plugging and filling said well was completed on the 12th day of Feb. 19 91 and that the above information is true and accurate.

RECEIVED APR 9 1991

National Fuel Gas Supply Corporation
(Well Operator)

Karl Alberg
(Qualified Participant)

PERMIT/REGISTRATION NO. 37-047-00449

S.J. Stauffer
(Qualified Participant)

PROJECT NO. ______

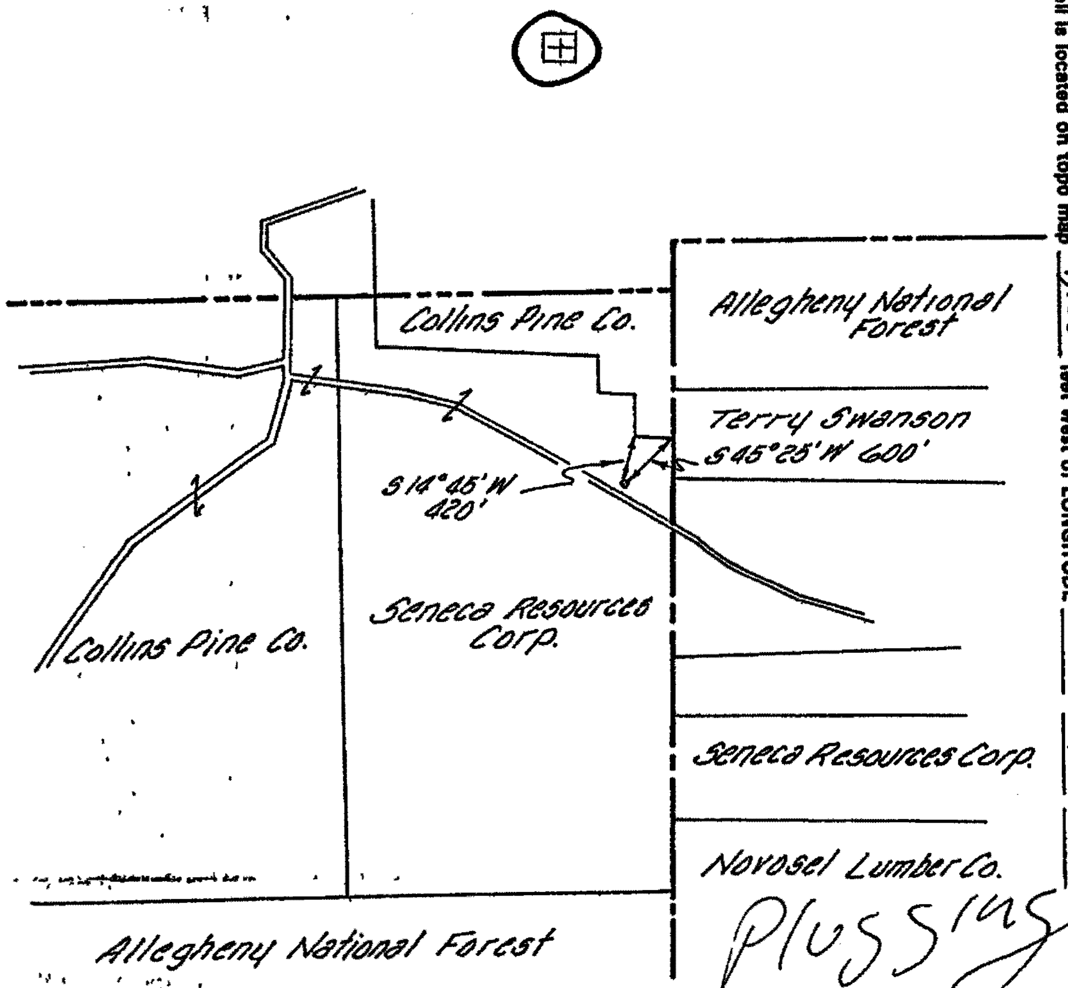
Bruce E Johnson
(Qualified Participant)

ER-OG-7. Rev. 3/85 **WELL LOCATION PLAT**

047-00449

Well is located on topo map 2400 feet south of LATITUDE 41 ° 37 ' 30 "

Well is located on topo map 7100 feet west of LONGITUDE 78 ° 47 ' 30 "



Plugging

Include description of the property and courses and distances of the well(s) location to two or more permanent identifiable points or land marks, all buildings and water supplies within 200', all springs, bodies of water and streams within 100' identified on the most current 7½" topographic map and wetlands within 100'.
Reference to buildings, springs, bodies of water and wetlands is not required for well plugging.

⊞ Denotes location of well on 7½" topo map   Permit # 37-047-00449   Project # ______

National Fuel Gas Supply Corp Well Operator	Revision ☐	J Porterfield Surveyor/Engineer
308 Seneca St. Address	Re-Issue ☐	RS 15283-E Registration Number
Oil City, Penna. 16301	Alteration ☐	Aug. 6, 1986 Date
Seneca Resources Corp. Surface Owner	Storage Recondition ☐	1" = 1320' Scale
— Surface Lessor (If any)	New Location ☐	
Seneca Resources Corp. Farm Name	Drill Deeper ☐	
1328 Well No / 1328 Serial No	Abandonment ■	
310 Acres / 2049 Ground Elevation	Registration ☐	
James City OG15 Topo Quadrangle / #2 Section	Plugging ☐	
Elk County / Highland Twp. Political Subdivision	Surface landowner and water purveyor with water supply within 1,000' None	Approximate course and distance to water supply
None Angle of Deviation / Anticipated TD	Owner/Operator	Workable Coal Seam(s)
	RK 2/4/91	No Coal

RECEIVED JAN 31 1991 Bureau of Oil & Gas Management

FEB 12 1991 PA GEOLOGICAL SURVEY (Oil & Gas Geology Division)

Commonwealth of Pennsylvania
Department of Environmental Resources
Bureau of Oil and Gas Management

eMapPA Wells

pennsylvania DEPARTMENT OF ENVIRONMENTAL PROTECTION

For assistance in accessing this document, contact R3_UIC_Mailbox@epa.gov

Josh Shapiro, Governor | Richard Negrin, Secretary | DEP Home | Help

eMapPA

Layers | Legend | Tasks | Themes | Links

Legend

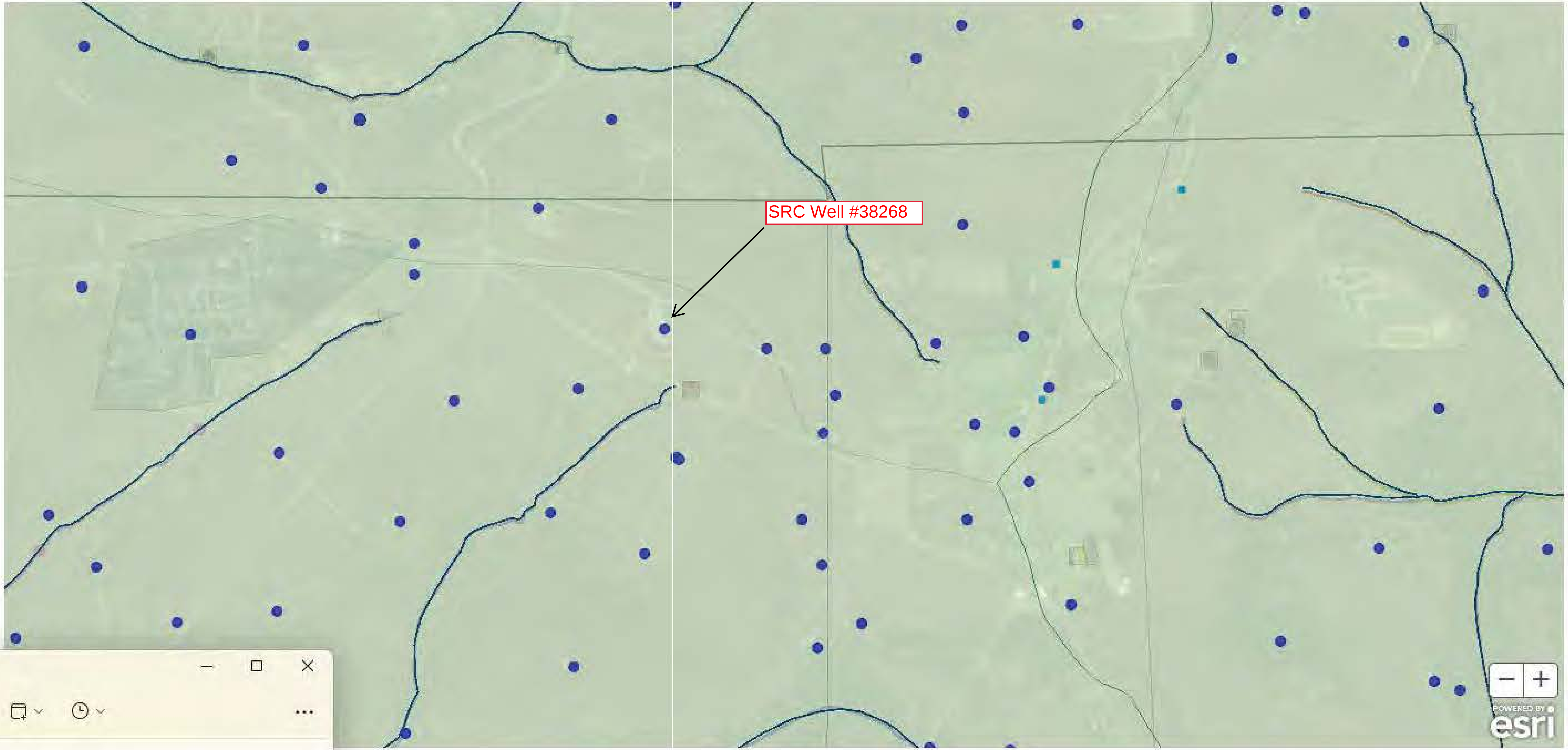
Regulated Facilities and Related Information

- Oil and Gas
  - Unconventional Wells
  - Conventional Wells
  - Well Pads
  - Well Access Roads
  - Oil and Gas Locations
    - Land Application - OGL
    - Oil and Gas Well
    - Pit - OGL
  - Conservation Wells
  - Plugged Conservation Wells
  - Abandoned and Orphaned Wells
    - Injection Well
    - Dry Hole
    - Gas Well
    - Oil Well

Map | eFacts Query | Advanced Query

ESRI Streets & Imagery | Topographic | National Geographic

Streets | Imagery



Snipping Tool

New

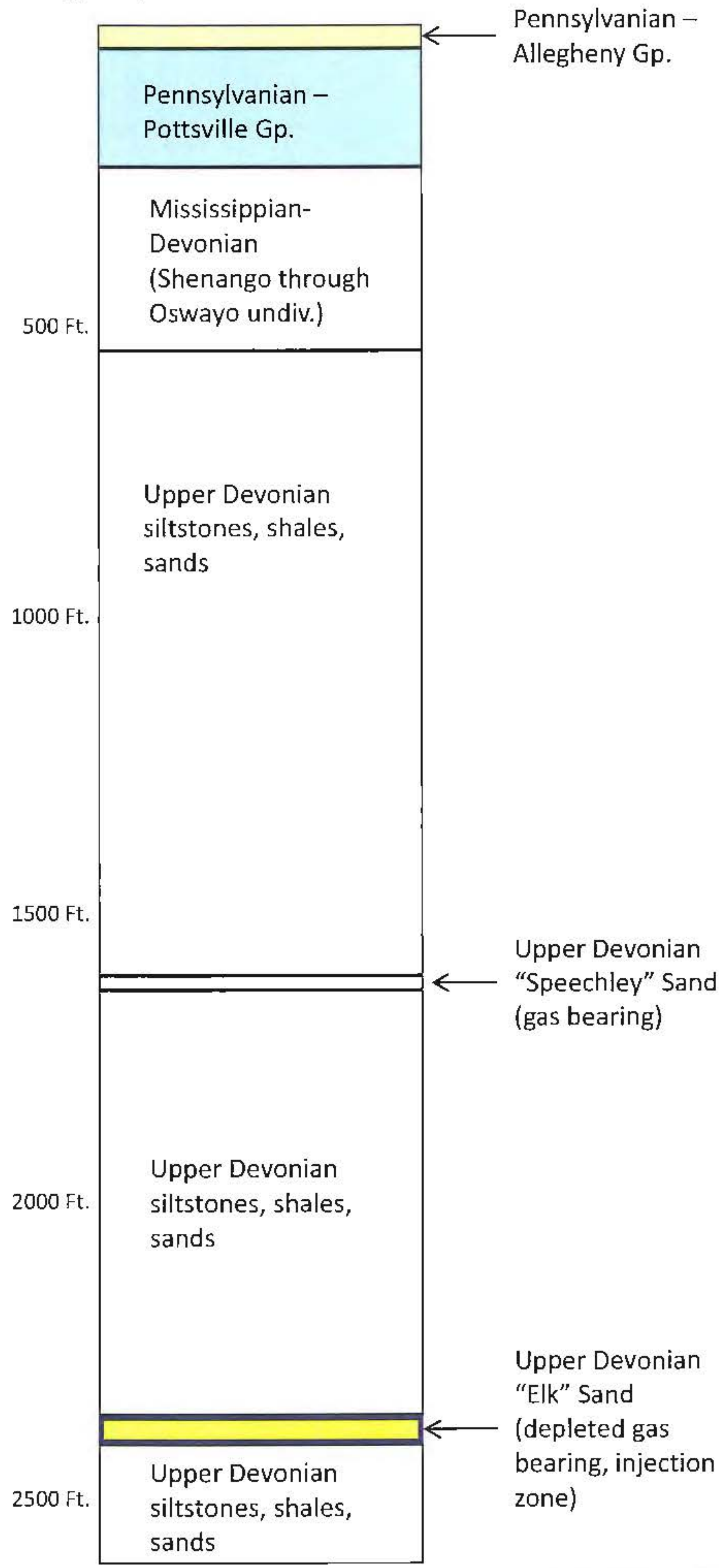
Community; ESRI Streets: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, (c) OpenStreetMap contributors, and the GIS User Community

APPENDIX B

Well #38268 & #38281 Information

Well #38268 Stratigraphic Column

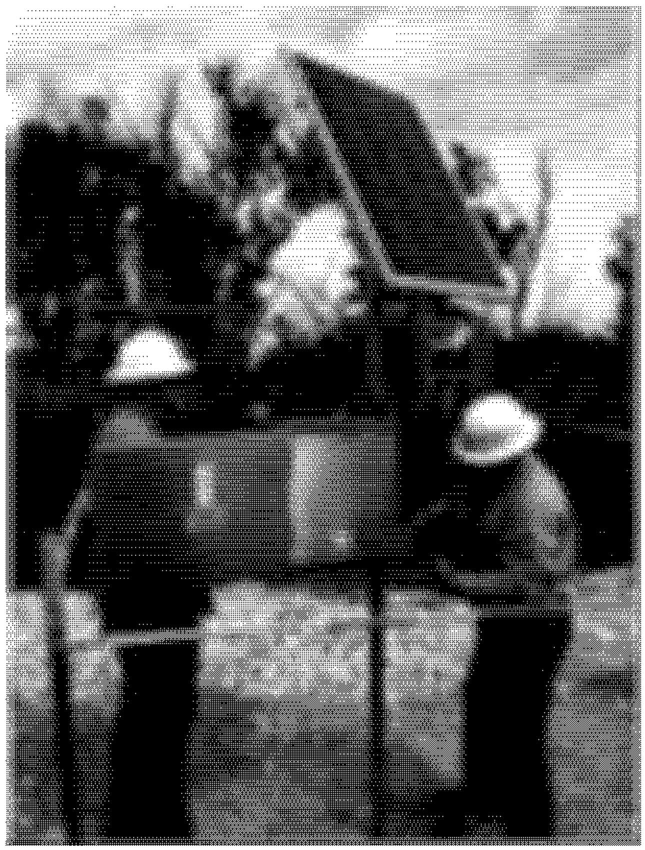
Stratigraphic Column



Seismic Monitoring Information

SENECA RESOURCES CORPORATION

CLASS II DISPOSAL WELL SEISMIC MONITORING AND MITIGATION PLAN



March 2017

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Appendices

Appendix A - Manufacture's Specifications, IESE Seismometer, Model S31f-2.0

Appendix B – Datasheet – Trimble REF TEK 130S-01 Broadband Seismic Recorder

Appendix C – Datasheet – Trimble REF TEK 147A Accelerometer

1 Introduction

This plan was developed to provide guidance on appropriate seismic monitoring and mitigation actions to be taken by Seneca Resources Corporation (Seneca) personnel operating the Class II disposal well (API No. 37-047-23835) in the Commonwealth of Pennsylvania. These actions include installation and layout of seismic monitoring equipment, initial and ongoing monitoring activities, mitigation actions to address incidents of varying type or degree that could potentially occur within the Area of Interest (AOI), which consists of the land within a three (3)-mile radius, of Seneca's disposal well operations as well as required incident and periodic reporting.

This plan does not replace or specifically cover tactical asset or facility site-specific emergency response actions but is used in conjunction with them.

The information provided in this plan is based on:

- Commonwealth of Pennsylvania, Department of Environment Protection (PADEP), Oil and Gas Management Program, Well Permit (Permit Number: 37-047-23835-00-01) for UIC Well #38268. Specifically the Special Permit Conditions that require the preparation and implementation of a Seismic Monitoring and Mitigation Plan (SMMP);
- Meetings with Seneca and PADEP;
- ALL Consulting's (ALL) experience and expertise in seismic monitoring, installation, induced seismicity, and working relationships with seismologists who do the interpretations; and
- Review, evaluation, and assessment of Class II injection operations.

For the purposes of this report, and as stated in PADEP's Permit Conditions, the following definitions will apply:

- Seismic Event: seismic activity above seismometer detection thresholds.
- Injection-Induced Seismic Events (IISE): detected seismic events that are determined to not be attributable to surface activities or system noise, nor events with hypocenters deeper than the top of the Salina Salts, after processing the data as described above.

1.1 Purpose

The purpose of this plan is to describe monitoring and mitigation elements to be implemented 30-days prior to the anticipated start of injection activities at Seneca's proposed Class II disposal well API No. 37-047-23835. This disposal well will inject into the Elk 3 Sandstone at a depth of approximately 2,354 to 2403 feet and is located in Elk County, Pennsylvania. This plan includes regulatory seismic monitoring requirements proposed in the PADEP Special Permit Conditions.

1.2 Objective

The overarching objective with respect to this Seismic Monitoring and Mitigation Plan is to establish a local seismic monitoring network and institute a traffic light system that would alert Seneca and the PADEP if seismic activity were detected within the AOI that deviated from historical baselines. The traffic light system would prescribe predetermined mitigation actions based on measured seismic events associated with injection operations to protect the safety and health of its employees and the general

2 Plan Maintenance and Review

2.1 Plan Administration

The SMMP is under the direction and control of Seneca, and will have an assigned "Plan Administrator." The Plan Administrator is responsible for document version control and will maintain the official version. Any recommended changes to the SMMP will require approval of the Plan Administrator prior to being incorporated into the SMMP document.

2.2 Plan Review

Seneca will perform regular evaluations to ensure that the SMMP is kept current and effective. To facilitate maintenance of the SMMP and to identify and rectify any plan deficiencies, the Plan Administrator will review the SMMP:

- On an annual basis at a minimum;
- Whenever there is a significant change to facility activities/operations; and
- Following any implementation of this SMMP in response to an event.

The following items will be considered during reviews:

- Telephone numbers and contact lists;
- Changes in facility operations and equipment;
- Changes in facility organization or key personnel;
- Federal, State, and local regulatory changes;
- Lessons learned during events; and
- Changes in mitigation measures.

Areas requiring revision will be identified through the review process and in consultation with Seneca, as deemed appropriate. Recommended changes to the plan will be documented by, or submitted to, the Plan Administrator and will include:

- Name and Title of person submitting the change(s);
- Description of the recommended change(s); and
- Rationale for making the change(s).

The Plan Administrator will be responsible for distributing information on the proposed change(s) to appropriate members of Seneca's management for review and comment. Once approval has been obtained, the Plan Administrator, or their designee, will prepare revisions to the plan as required. Minor revisions that are considered to be editorial in nature can be made by the Plan Administrator without further review.

The Plan Administrator will also be responsible for submitting an updated plan to PADEP in cases where the risk profile associated with injection activities changes, or as otherwise requested. Such updating of the plan will follow the same general procedures outlined above.

3 Monitoring

3.1 Seismic Monitoring Hardware

The local seismic monitoring network will consist of a minimum of four (4) velocity seismometer units, with associated data loggers, and a single strong surface vibration monitor (accelerometer) and an associated data logger (recorder). The seismometers will be three (3)-component, (X, Y, and Z axes) 120 second broadband velocity sensor stations that have a minimum 250Hz sampling rate for real-time data collection. The seismometer units record data on the x, y, and z axes, with one (1) sensor detecting up and down motion, while the other two (2) sensors detect horizontal motion in the north-south and east-west directions. These units measure the body waves (P and S waves) and surface waves, thus providing data to calculate the depth and magnitude of any seismic event. A copy of a manufacturer's specification sheet representative of seismometers which might be used can be found in **Appendix A** while the specifications for a representative data recorder can be found in **Appendix B.** These or equivalent equipment will be used. Details of the equipment specifications and installation of these or similar velocity seismic units are as follows:

- Institute of Earth Science and Engineering (IESE), Shallow Posthole Seismometer Sensor: Model S31f-2.0 (see **Figure 3-1**);
- REF TEK RT 130S-01 Broadband Seismic Recorder (see **Figure 3-2**) are equipped with 3 or 6 channels, 24-bit ADC, Global Positioning System (GPS) timing, and sample rates of 1 to 1,000 samples per second.
- Model S31F-2.0 have a frequency range of 0.1 to 1,000 hertz with a natural frequency of 2 hertz;
- Uses a solar powered radio transmitter to send time-stamped data to a central receiving point where it is processed and archived.

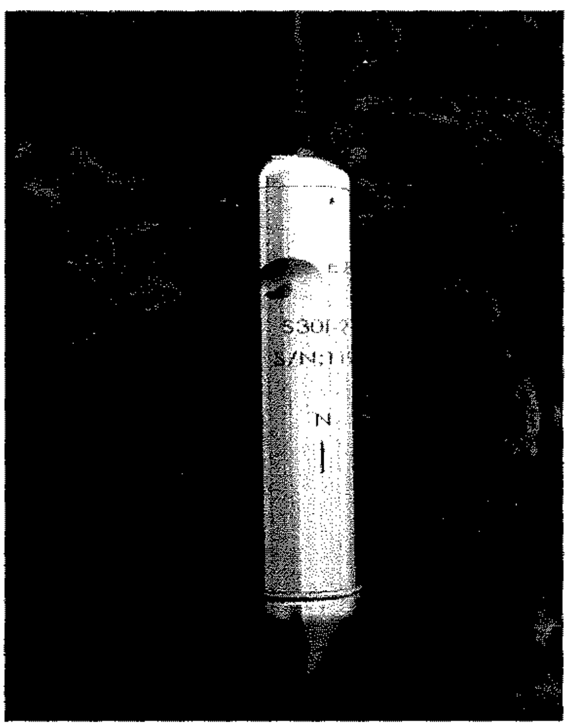


Figure 3-2: IESE Seismometer Sensor Model S31f-2.0 (Source: IESE)

Figure 3-1: Trimble REF TEK 130S-01 Broadband Seismic Recorder (Source: IESE)

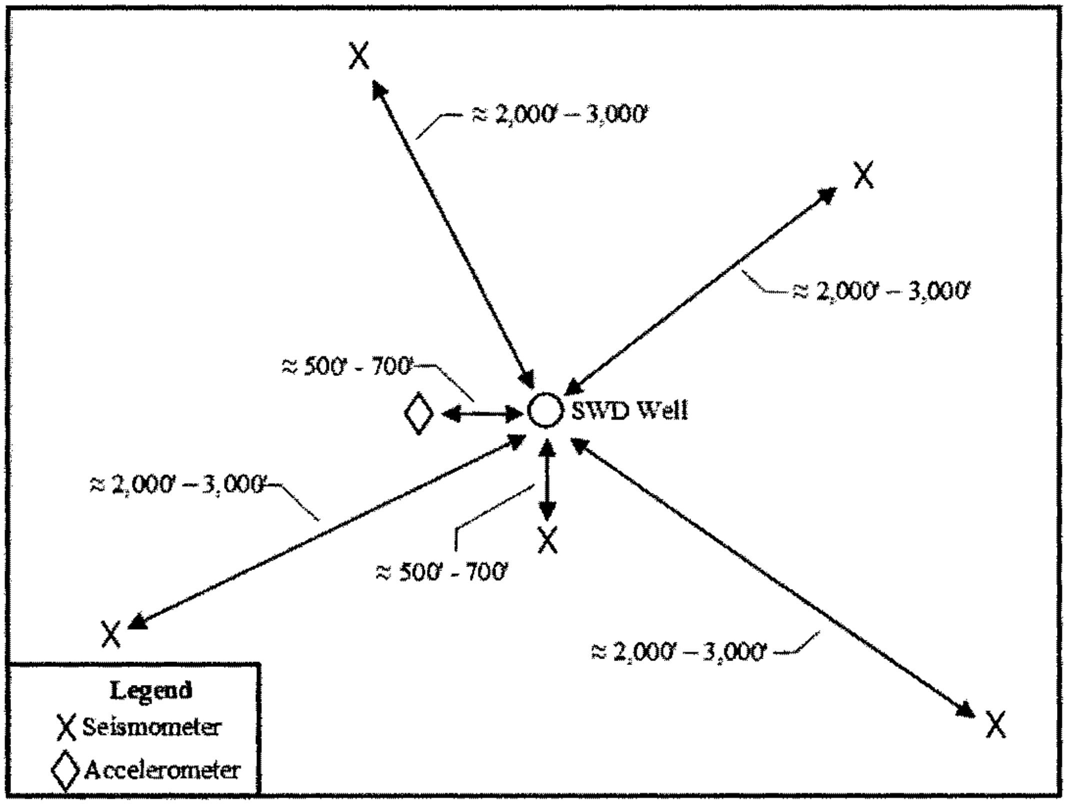


Figure 3-4: Typical seismic monitoring unit layout

The local seismic network will have a detection sensitivity of approximately magnitude (**M**) 0.5, depending upon unit placement and surface noise, with an estimated horizontal (epicenter) and depth (hypocenter) location accuracy of ±750 feet for events greater than **M** 1.0. Calculation of horizontal and depth location errors will be based on the distance of any detected seismic events from the seismometers. The magnitude of the event will be determined based on the measured movements and the recording of peak ground acceleration at or near the site. The velocity seismometer units will continuously record data, meaning they record all the time (whether there is ground motion or not), whereas the accelerometer will only record when triggered by movement.

3.4 Seismic Monitoring Equipment Calibration

The protocol for operating and calibrating the seismometer and seismic recorder installed at the disposal well site will conform to the standards employed by the Pennsylvania State Seismic Network (PASEIS) and the manufacturer's instructions. Calibration records for both the seismometers and recorder will be maintained for a minimum of five (5) years.

Figure 3-6: Control Box Post and Sensor Installation Options

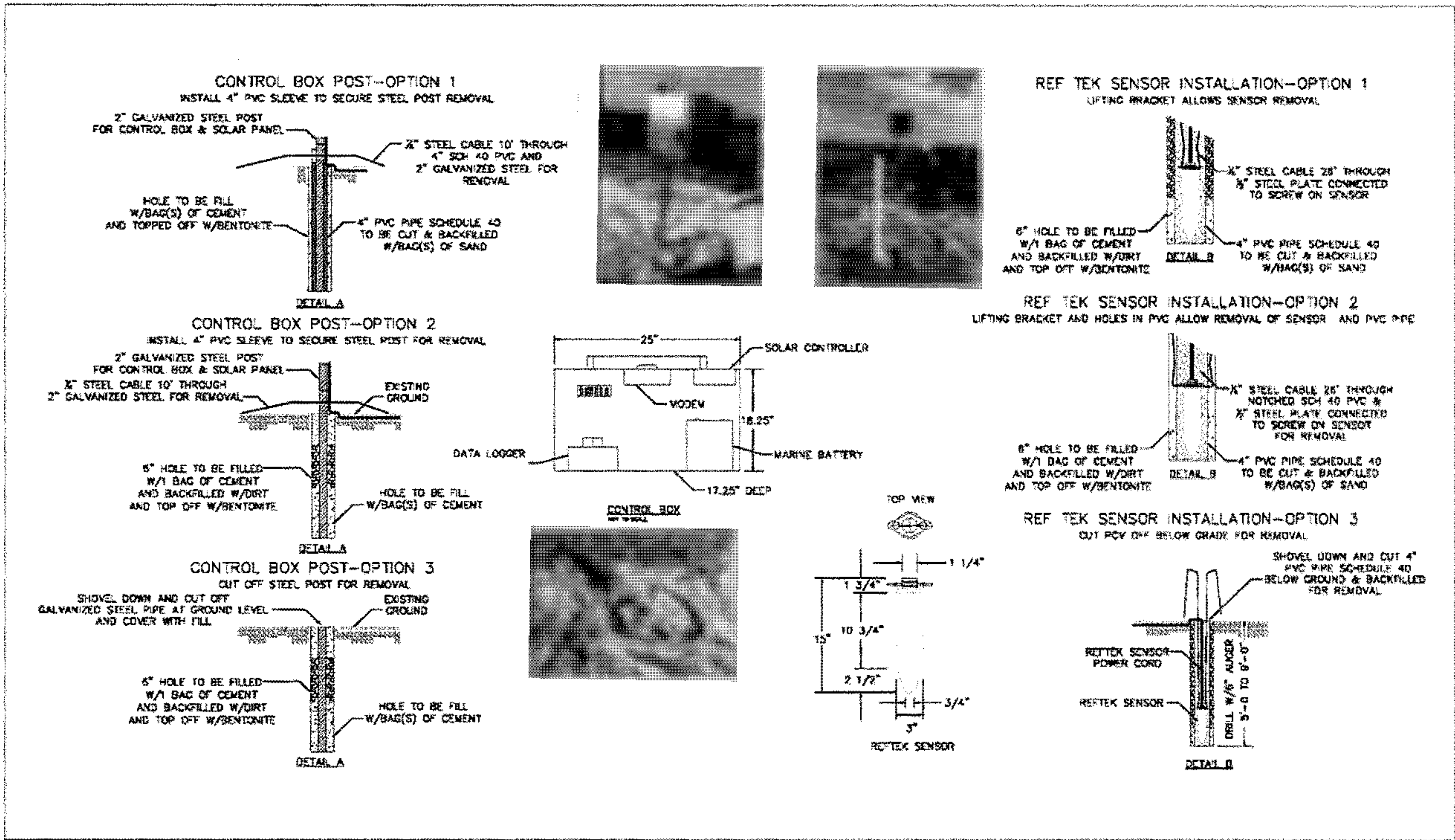
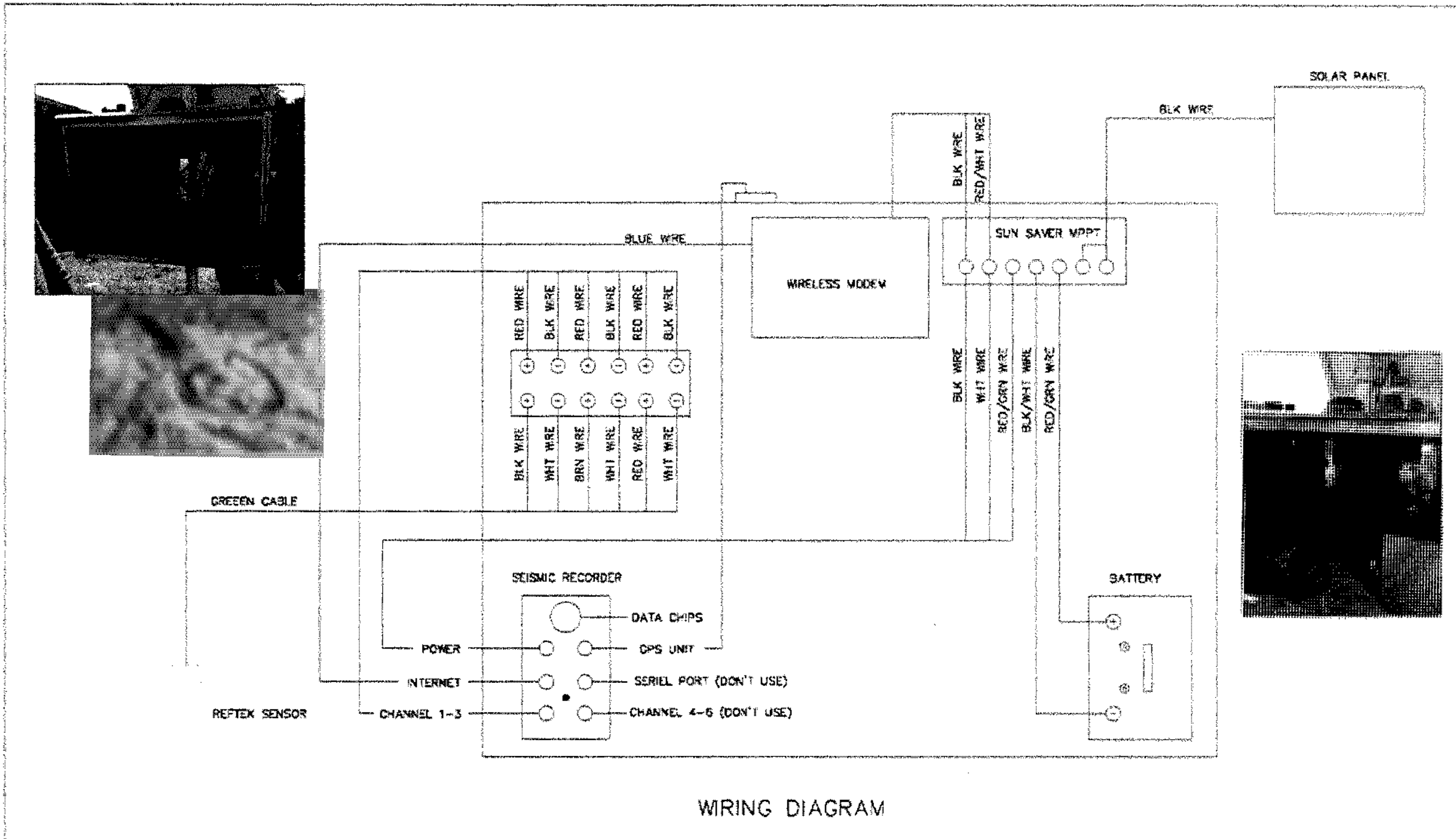


Figure 3-8: Seismic Station Wiring Diagram



transmission is interrupted, ALL will notify the PADEP verbally within 24-hours and in writing within seven (7) days.

3.7 Injection Well Monitoring

Many types of tests are available to assess injection well operational conditions including down-hole geophysical tests and traditional testing methods. A common example of a traditional testing method is annual pressure fall-off/shut-in testing, which involves monitoring pressure buildup in the well. This test can also be used to evaluate reservoir pressure characteristics and stabilization. Pressure fall-off tests will be performed annually to assess injection zone performance. Other testing that might be considered to detect faulting or fractures can include:

- Down-hole caliper logging to detect fractures;
- Down-hole resistivity logging to detect fractures and lithologic changes;
- Down-hole spontaneous potential logs;
- Down-hole gamma ray logging to detect formation changes;
- Down-hole porosity determinations;
- Fracture-finder logs to detect fractures;
- Compression tests on formation samples to determine rock strength; and
- Geotechnical tests on formation samples (porosity and permeability measurements).

Various injection well characteristics will be monitored and recorded to facilitate demonstration of mechanical integrity, evaluate formation pore pressures, and support potential seismicity assessments. **Table 3-1** summarizes the anticipated monitoring parameters, monitoring frequency, and reporting frequency to be implemented. Records of this injection information will be maintained in accordance with the permit conditions and be available to the PADEP upon request.

Table 3-1: Anticipated Monitoring Requirements for Seneca's Injection Facility

Parameter	Monitoring Frequency	Reporting
Injection Surface Pressure	Continuous	Monthly
Bottomhole Pressure	Calculated every four (4) hours	Monthly
Casing-Tubing Annulus Pressure	Continuous	Monthly
Temperature	Continuous	Monthly
Injection Flowrate	Continuous	Monthly
Fluid Density	Weekly	Monthly
Specific Gravity	Weekly	Monthly
pH	Weekly	Monthly
Composition of Injectate	Quarterly	Quarterly
Cumulative Volume	Daily	Monthly

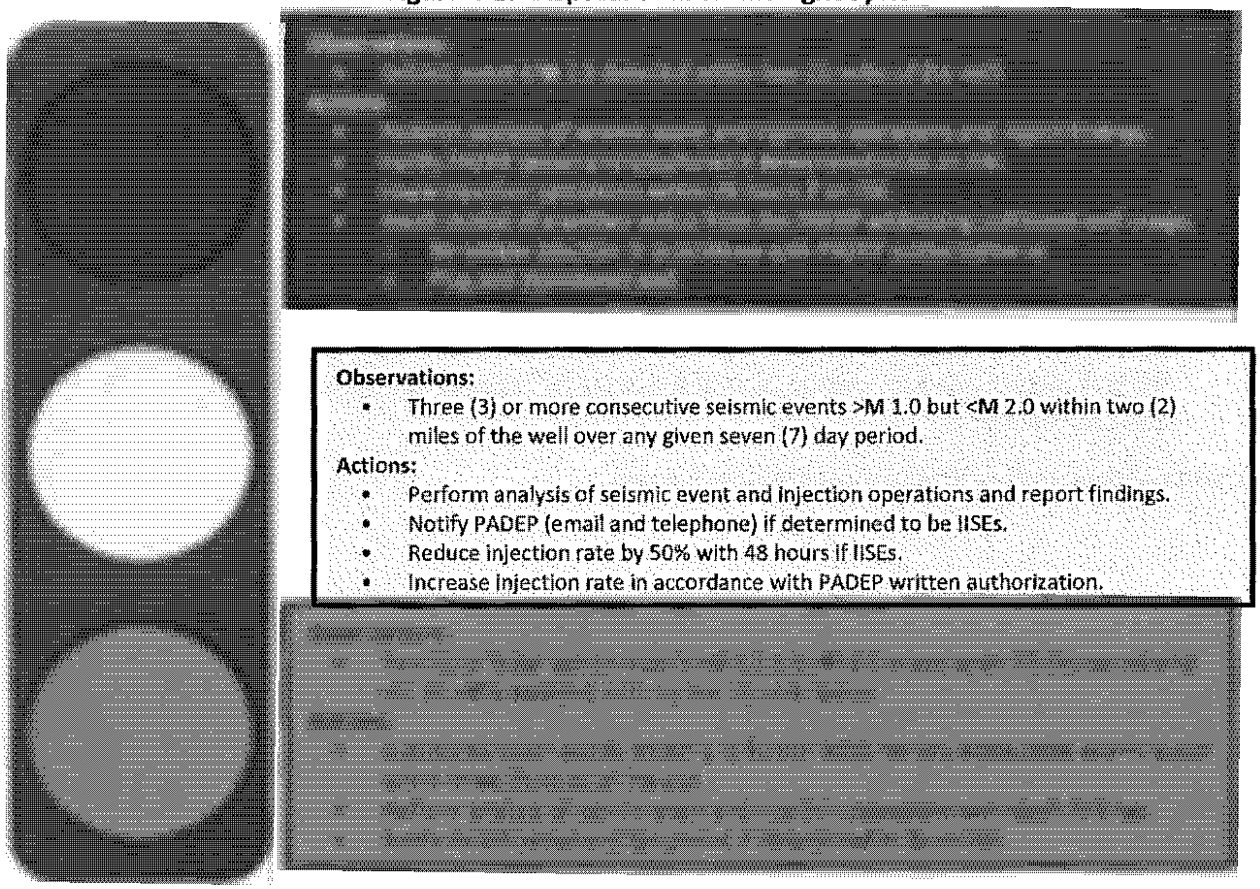
If the injection well data indicates that mechanical integrity of the subject injection wells may have been compromised, PADEP will be notified verbally within 24 hours and in writing within seven (7) days and injection operations will cease immediately.

3.8 Monitoring Modification

Pursuant to condition 17 of Seneca's UIC Well Permit, following five (5) years of injection activities, Seneca may submit a Summary Report and Plan (SRP) to modify or discontinue the SMMP. The SRP may propose to modify or discontinue SMMP in no less than 90 days absent an objection in writing

The traffic light system presented in **Figure 4-1** is based on site-specific, real-time risk management system observations that will become increasingly effective when updated as new data becomes available. The level of risk at a site will determine the proper mitigation measures and any necessary operational adjustments.

Figure 4-1: Disposal Well Traffic Light System



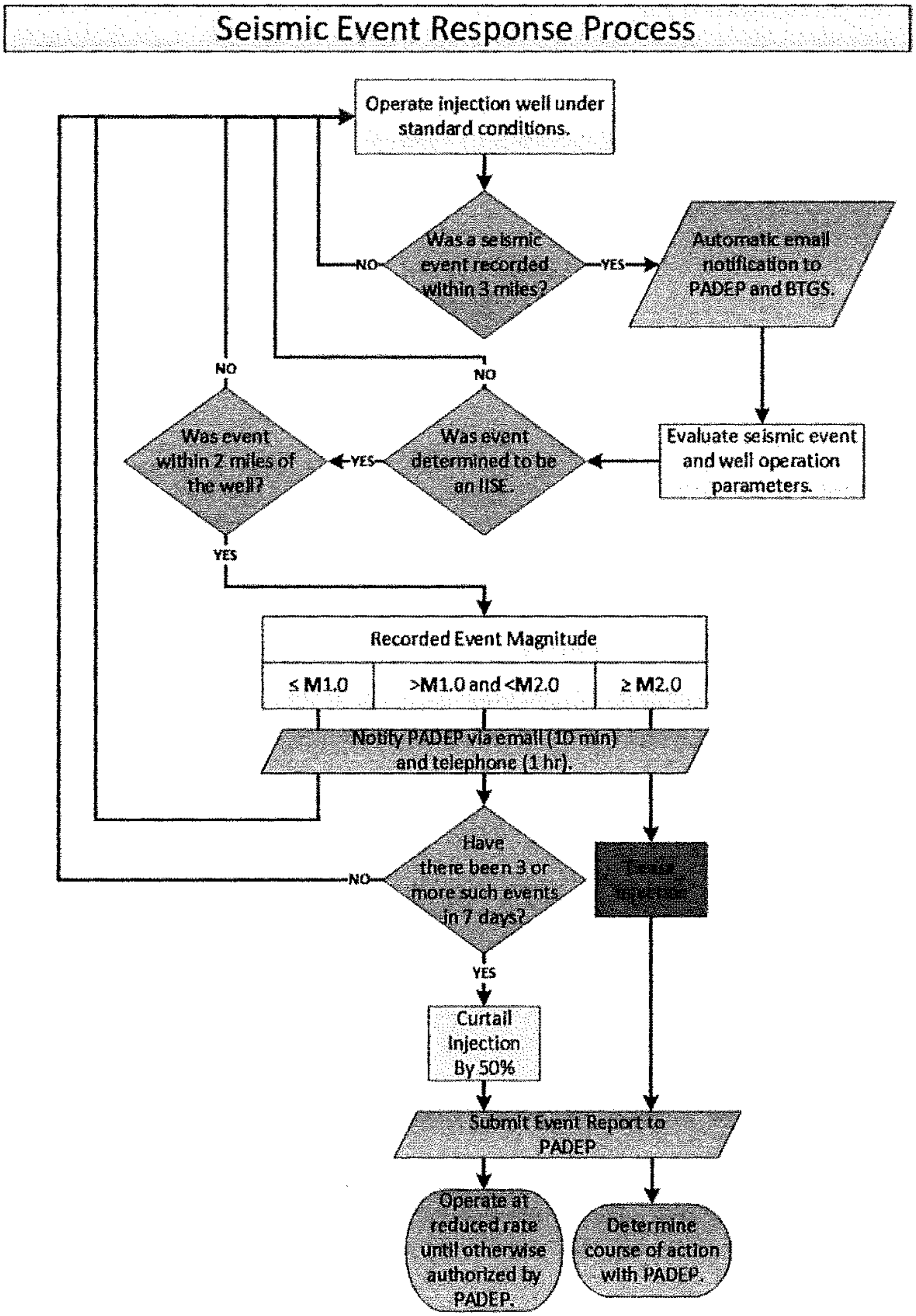
4.2 Mitigation Measures

All injection operations will begin in the green zone of the traffic light system, where operations and monitoring would be carried out as planned. If injection operations moves into the yellow zone of the Traffic Light System due to the occurrence of an IISE that meets prescribed thresholds, then caution will be exercised at all times in the form of heightened awareness, enhanced monitoring and the reduction of injection rate by the prescribed percentage. It should be noted that the yellow of the traffic light may not necessarily be interpreted as a disadvantageous phase nor should it be thought that the well would inevitably move to the red zone.

Listed below are the mitigation measures to be implemented based on observed seismic events, as depicted in the Traffic Light Figure (**Figure 4-1**):

- For seismic events determined to not be IISEs, no changes to operations (injection rates or volumes) is required.

Figure 4-2: Seismic Event Response Process



Appendix A

Manufacture's Specifications - IESE Seismometer, Model S31f-2.0

IESE
Institute of
Earth Science
and Engineering
Aotearoa

OSOP
Distributor of IESE Products

Shallow Posthole Seismometer: Model S31f-2.0

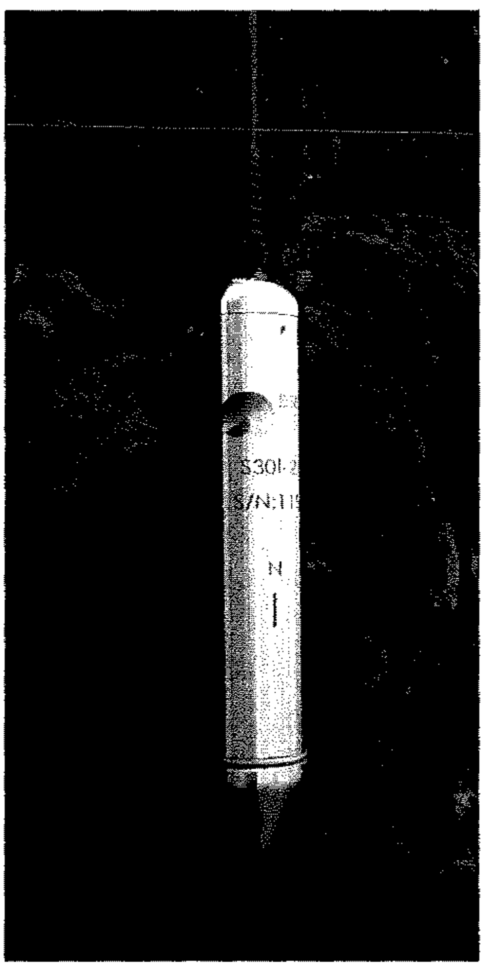
Easily installed seismometer for micro-earthquake monitoring

The S31f-2 is IESE's readily deployed shallow posthole sonde for use in micro-earthquake detection and analysis. The S31f-2 is designed for installation in up to 100m vertical holes.

The S31f-2 features the highest current performance level in sensitivity, reliability, and longevity for micro-earthquake detection.

Features

- Fixed
- Withstands up to 50°C
- Passive sensors
- For permanent or temporary installations



Parameter	Specification
Geophone orientation	Triaxial, Orthogonal
Natural frequency	2 Hz
Operational temperature	45° to +50°C
DC resistance	3810 Ω
Sensitivity	2.0 V/in/sec
Open circuit damping	0.61
Moving mass	23 g
Max coil excursion p-p	0.30 in (0.76 cm)
Normalised transduction constant	0.0317 $\sqrt{R_c}$ V/in/sec

Dimensions	
Outer diameter	2.8 in (7.2 cm)
Wall thickness	0.213 in (0.541 cm)
Height	3.5 ft (106.68 cm)
Weight	11 kg
Casing Material	304 stainless steel

For more information, please email us at sales@osop.com.pa
WEB - www.osop.com.pa

Appendix B

Datasheet – Trimble REF TEK 130S-01 Broadband Seismic Recorder

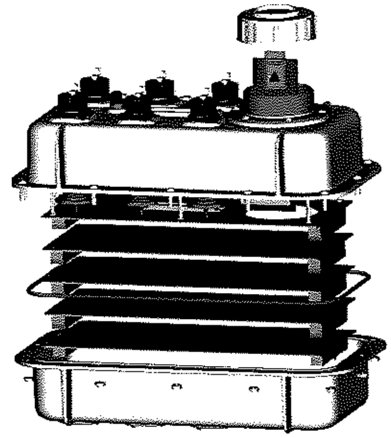
HARDWARE MODULARITY

The 130S is constructed with up to five internal boards stacked together – an arrangement that is more reliable and less costly than a traditional backplane arrangement. The 130S comes with a Lid Interconnect Board, a Microcomputer Board, one or two ADC Boards and a Sensor Control Board.

One or two removable disks reside in a sealed compartment that is accessed by opening a lid located on the top of the 130S case. The main electronics section is sealed with the lid open or closed.

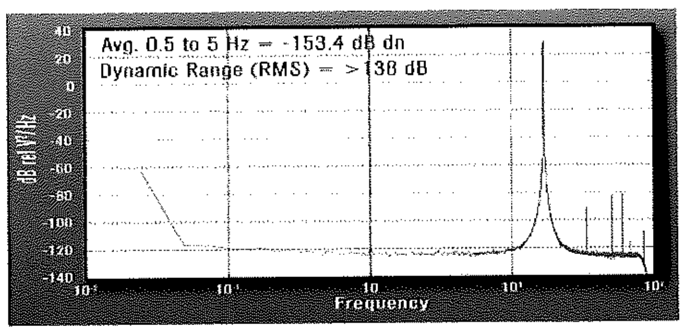
The GPS Receiver is separate from the main unit in order to allow the GPS antenna to be located some distance away.

Module	Description	Contents
1	Lid Interconnect Board (RT520) (▲)	Power Supply Lightning Protection Physical Interface DC-DC Converter
2	Microcomputer Board (RT506) (▲)	CPU Battery Backed SRAM (up to 16 MBytes) Serial Ports Real-time Clock Ethernet Controller, full stack Enhanced Integrated Drive Electronics (EIDE)
3	ADC (RT649) (▲)	24-Bit ADC Channels (3 each) Input Pre-Amplifier Digital Anti-Alias Filters 1M SRAM Direct Memory Access (DMA) Controller DC-DC Converter
4	Sensor Control Board (RT527) (▲)	Monitoring of Mass Position Re-Centering Command; Mass Lock/Unlock Calibration Commands Calibration Signals DC-DC Converter
5	Removable Mass Storage (External)	Compact Flash (two slots available) 2 to 32 Gbytes total capacity RT526 Interface Board
6	GPS Receiver (External)	Garmin GPS Receiver



NOISE PERFORMANCE

The 130S series recorder incorporates the 3rd generation 24-bit delta sigma type analog-to-digital converter with state-of-the-art design. The combination produces the highest performance low power 24-bit seismic recorder. Below is the power spectral density of the ADC with the full scale sine wave input.



DATA RETRIEVAL

The 130S series recorder may be equipped with one or two Compact Flash Type I or Type II storage media (disks). CF flash storage is available in 8GB or 16 GB capacity. For example, 8 GB is enough storage to hold more than 200 days of three channel, 100 sps data recorded with Steim 2 compression.

Files are written in FAT32 format allowing high capacity disks to be used. To swap a disk during acquisition, simply open the cap that seals the disk compartment. A red LED indicates the disk is busy.

When inactive a green LED signals to remove the disk and insert another one in its place. Replace the cap resealing the compartment.

Data from the disk may be read on any PC / Workstation using a CF-II reader. Data can also be remotely downloaded from the 130S disk using FTP over LAN/WAN.

DATASHEET

130S-01 BROADBAND SEISMIC RECORDER

Model	130S-01/3 (P/N 97100-00) 130S-01/6 (P/N 97100-01)
Mechanical	
Size	6.3" high x 6.9" wide x 13.1" long (16 cm x 17.5 cm x 33.3 cm)
Weight	4.5 lbs (2 Kg)
Watertight Integrity	IP68
Shock	Survives a 1 meter drop on any axis
Operating Temperature	−20° to +70°C
Power	
Input Voltage	9 to 24 VDC (ethernet) 11 to 24 VDC (writing to disk)
Average Power (no communications)	1 W (3 ch., GPS, writing to disk) ~1.45 W (6 ch., GPS, writing to disk)
Average Power (with communications)	1.25 W (3 ch., GPS, writing to disk) ~1.7 W (6 ch., GPS, writing to disk)
Communications	
NET Connector:	
Ethernet	10-BaseT, TCP/IP, UDP/IP, FTP, RTP
Serial	Asynchronous, RS-232, PPP, TCP/IP, UDP/IP, FTP, RTP
Serial Connector:	
Terminal	Asynchronous, RS-232, 130 Command
A/D Converter	
Type	Δ-∑ Modulation, 24-bit Output Resolution
Dynamic Range	>138 dB @ 100 sps
Channels	3 or 6
Input Impedance	2 Mohms, 0.002 uFd, differential @ x32; 25 Kohms, 0.002 uFd, differential @ 1
Common Mode Rejection	>70 dB within ±2.5 VDC
Gain Selection	x1 and x32
Input Full Scale	40 VPP @ x1 and 1.24 VPP @ x32
Bit Weight	2.724 μvolts @ x1 and 85 nV @ x32
Noise Level	~1 count RMS @ 50 sps @x1
Sample Rates	1000, 500, 250, 200, 125, 100, 50, 40, 20, 10, 5, 1 sps
FIR Filter	130 dB down passband to Nyquist
Compliance	
Compliance	CE

Auxiliary Channels	
Inputs	3 Channels available on each Sensor Connector: Supply Voltage, Backup Battery Voltage, Temperature
Time Base	
Type	GPS Receiver/Clock plus Disciplined Oscillator
Accuracy with GPS	±10 μsec after validated 3-D Fix and Locked
Free-Running Accuracy	0.1 ppm over the temp. range of 0° to 70°C and 0.2 ppm from −20° to 0°C
Recording Capacity	
Battery Backed SRAM	8 to 16 MB user specified
Hard Disk	8 GB or 16 GB CFII Card, settable in "Ring-Buffer" Configuration
Recording Modes	
Continuous	Record length
Time Trigger	Specific record length at periodic interval
Time List Trigger	A list of record times and lengths
Event Trigger	STA/LTA with advanced features including bandpass filter LTA hold, etc.
Level Trigger	Absolute value, user selectable: g, or % of full scale, or counts including bandpass filter
Vote Trigger	Level trigger with weighting
External Trigger	External pulse on trigger input line
Cross Trigger	One stream triggers recording of another
Recording Format	
Format	PASSCAL Recording Format

RELATED SUB-SYSTEMS:

Strong Motion Accelerographs, 130-SMHR & Accelerometers, 147A-01
Broadband Seismometers, 151B-120, 151B-60, 151B-30

Specifications subject to change without notice.

Contact your local dealer today

NORTH AMERICA
Trimble Navigation Limited
10368 Westmoor Drive
Wesminster, CO
USA
MonSol_Sales@Trimble.com

DATASHEET

147A

HIGH RESOLUTION ACCELEROMETERS

The 147A High Resolution Accelerometers are a force-balance accelerometer that converts acceleration signals into voltage signals to measure various low frequency and ultra-low frequency motion. The 147A accelerometer is available in both triaxial and uniaxial packages.

The 147A accelerometer uses a stateof-the-art force balance feedback technique to make up for the mechanical characteristic limitations of conventional accelerometers. This overcomes the shortcomings of nonlinear distortion and threshold of sensitivity of elastic measuring parts.

The advanced features of the 147A accelerometer include high sensitivity, large linear range, high resolution, and high dynamic range.

The 147A accelerometer has DC response. The 147A Low Noise model is +/- 4g full scale and provides excellent dynamic range, which is useful when used with 24-bit digitizers like the 130-MC Multi-Channel Recorder and 130S Series Data loggers. High sensitivity, large linear range, high resolution, and high dynamic range make the 147A model best suited for free field applications such as micro zonation, site response, earthquake monitoring, and more.

The 147A housing is sealed to meet IP67 standards for watertight integrity. For the triaxial package, mounting is accomplished with a single bolt, and 3 point leveling.

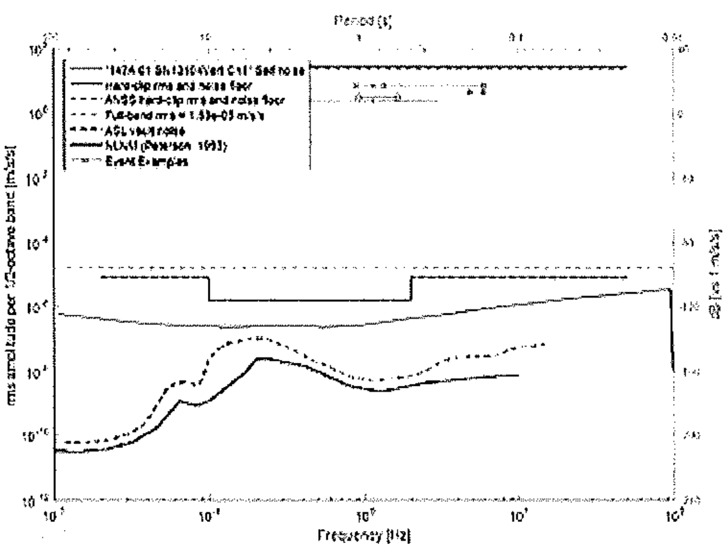
The chart below is a graphic presentation of the sensor amplitude operating range via the ANSS method.

Key Features

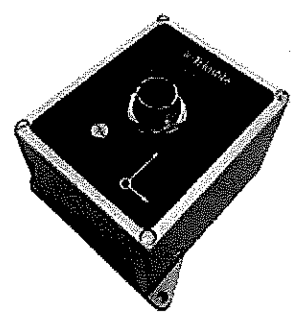
- Low Noise
- State-of-the-Art Accelerometer
- Sensitivity & Offset Stable

Applications:

- Free Field Reference
- Building Arrays
- Structural Monitoring
- Site Response
- Aftershock Studies



Amplitude Operating-Range Diagram in Acceleration Units; Strong-Motion Acceleration Sensor "Class A"; Test of "147A-01 Ch. 1"



Trimble 147A Triaxial Accelerometer

Trimble 147A Uniaxial Accelerometer

SENECA RESOURCES COMPANY, LLC

2018 ANNUAL SEISMIC MONITORING SYSTEM ACTIVITIES REPORT FOR THE FEE SENECA RESOURCES WARRANT 3771 #38268 (API NO. 37-047-23835-00-01) CLASS II DISPOSAL WELL

February 2019

Introduction

ALL Consulting (ALL) has been requested by Seneca Resources Company, LLC (Seneca Resources) to prepare an annual summary of all 2018 activities associated with the Seismic Monitoring and Mitigation Plan (SMMP) that was submitted to the Pennsylvania Department of Environmental Protection (PA DEP) in March of 2017. The SMMP, which was developed for Seneca Resources by ALL, was a permit condition requirement of the Class IID saltwater disposal permit issued for the Fee Seneca Resources Warrant 3771 #38268 injection well (API No. 37-047-23835-00-01). This injection well is located in Highland Township of Elk County, Pennsylvania, near James City. The annual summary of all activities associated with the SMMP includes any maintenance, system upgrades, downtime periods, and triggered event detections and are detailed in the following sections.

Maintenance and System Upgrades

Since installation of the seismic monitoring network (five seismic stations and one accelerometer) in late August of 2017, ALL has maintained the seismic network on a routine basis and has conducted inspections of the seismic stations as needed to ensure the system was active and sending the data to the Incorporated Research Institutions for Seismology (IRIS). Below is a summary of the maintenance and system upgrade activities performed by ALL on the seismic monitoring network since initial installation:

- 09/13/2017 – Seismic station ALL02 was not sending data. The modem was replaced and a new antennae was added to the station.
- 09/15/2017 – Station ALL02 was still down and was not transmitting data. The data logger was swapped out and ALL02 started sending out data.
- 11/17/2017 – Some issues were detected with the accelerometer. Ground cover insulation and infiltration barrier were added over the accelerometer.
- 01/13/2018 – Snow was cleaned from solar panels and insulation was added around the batteries.
- 02/12/2018 – Battery was replaced at ALL02.
- 02/12 to 02/15/2018 – Additional solar panels were added to three stations and accelerometer. ALL04 was inaccessible due to lease road conditions.
- 06/01/2018 – Second solar panel was added to ALL04 and insulation was removed from all station batteries.
- 06/19/2018 – Modem was replaced at ALL05 and firmware was upgraded on ALL00 and ALL03. ALL04 was working after resolution of network provider issues.
- 11/28/2018 – Solar panels were covered with snow. Battery at Station ALL00 was replaced and batteries at other stations were charged. ALL04 station was inaccessible due to lease road conditions.
- 12/03/2018 – Batteries were replaced at seismic stations ALL01, ALL02, ALL03, and ALL05.

Seismic Station Downtime

The seismic monitoring network is monitored in real time and did experience some station downtime in 2018, which normally was caused by weather-related conditions, but was also due to random equipment failure. Cold weather and heavy snow had the biggest impact on seismic station downtime due to snow cover on the solar panels or low-voltage readings on the batteries due to cold weather and lack of sunlight. Whether it was weather conditions or random equipment failure, ALL would mobilize staff as quickly as possible to go out to the station sites and restore operating conditions at the seismic stations.

- 01/10/2018 – Cold weather and snow conditions caused stations ALL01, ALL02, and ALL03 to go down and stop sending data. These stations came back online the next day with sunny weather. On 01/13/2018, ALL was onsite to clean off solar panels and wrap insulation around the batteries.
- 02/09/2018 – All stations were down due to cold weather and snow. On 02/12/2018, ALL was onsite to charge batteries, replace as needed, and add more solar panels to stations.
- 05/31/2018 – Accelerometer went down and was not sending data. Accelerometer came back on later in the day.
- 06/07/2018 – ALL04 was down due to issues with Verizon network. ALL got station back up and working on 06/19/2018.
- 11/23/2018 – Stations ALL02 and ALL03 were down due to cold weather and snow.
- 11/28/2018 – ALL00 was down due to cold weather and snow. ALL was onsite that day and replaced one battery and charged the other batteries.
- 12/03/2018 – ALL01, ALL02, ALL03, and ALL05 were down due to the weather. Batteries were replaced by ALL at four of the seismic stations.

Event Triggers and Detection

Since initiation of seismic monitoring at Seneca Resources Class IID disposal well in late 2017, there has been no detection of any seismic events due to the injection operations. Since commencement of monitoring operations at this seismic network, only two false triggers have been detected and recorded by the network and these have been caused by thunderstorm activity in 2018. Below are the dates of the triggered activity.

- 06/18/2018 – The seismic network was initially triggered with false detection due to a thunderstorm. **Figure 1** is seismic waveforms of the event detected on ALL02 seismic station and the accelerometer.
- 09/03/2018 – Thunderstorm triggered event and false detection. **Figure 2** is a weather map shown a thunderstorm that triggered a false detection on the seismic network.

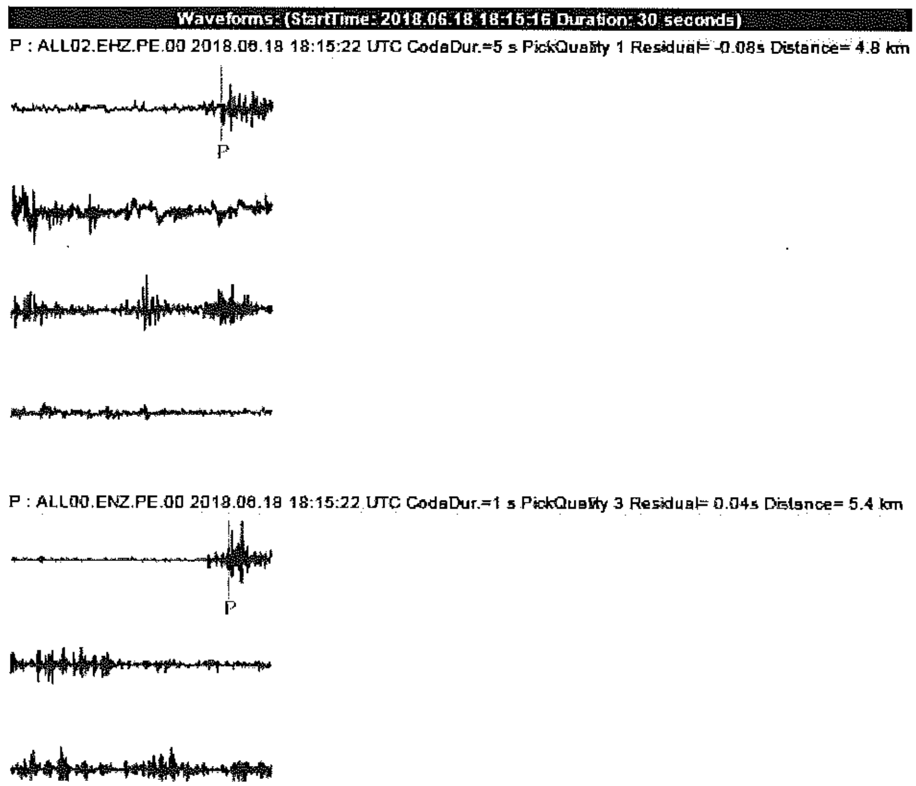


Figure 1. Thunderstorm-induced Trigger Event Detected on the ALL Seismic Monitoring Network in Pennsylvania

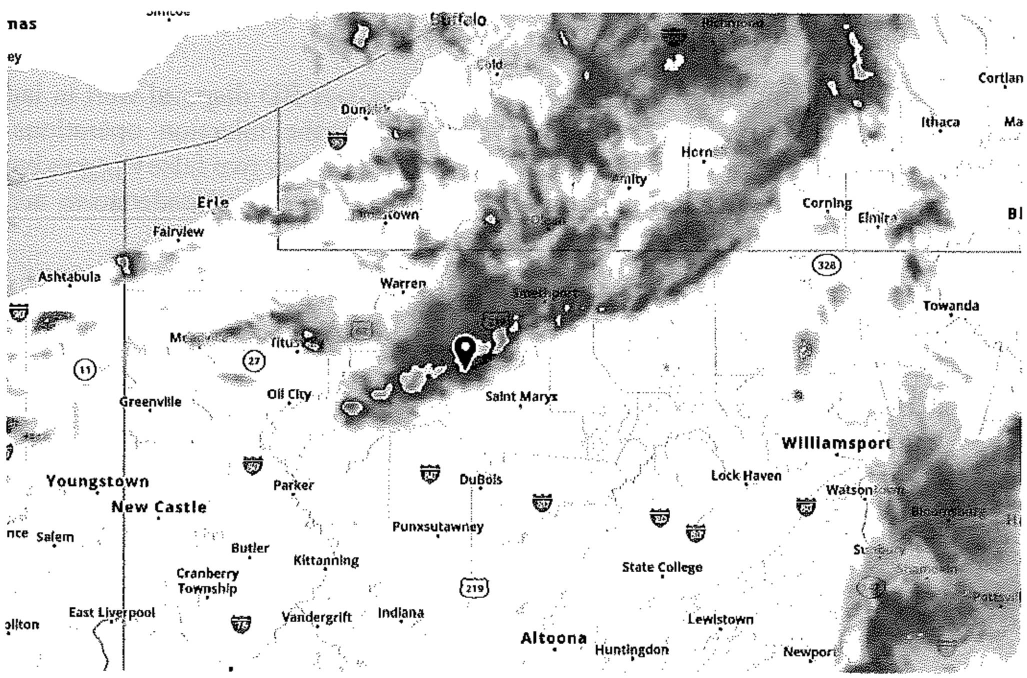


Figure 2. Weather Map Showing Location of Seneca Resources Disposal Well and Thunderstorm that Triggered a False Detection on the ALL Monitoring Network

Conclusions

As discussed in the previous sections, the annual 2018 evaluation and assessment of Seneca Resources seismic monitoring network clearly demonstrates that there was no injection-induced seismic activity due to the operations at the Class IID disposal well. The two false detections that triggered the ALL seismic monitoring network were caused by weather-related thunderstorm events.

Routine maintenance and replacement of equipment due to random failure occurred during the entire 2018 year. Most of the issues were caused by cold weather and snow, which were addressed by ALL by adding insulation to the batteries, replacing some batteries, and adding additional solar panels to improve sunlight capture to maintain battery life.

ALL will continue performing routine maintenance and inspection per equipment manufacturers' recommendations in 2019. Additionally, ALL will be upgrading the modems due to forthcoming changes to the Verizon cellular network.

SENECA RESOURCES COMPANY, LLC

2019 ANNUAL SEISMIC MONITORING SYSTEM ACTIVITIES REPORT FOR THE FEE SENECA RESOURCES WARRANT 3771 #38268 (API NO. 37-047-23835-00-01) CLASS II DISPOSAL WELL

January 2020

Introduction

ALL Consulting (ALL) has been requested by Seneca Resources Company, LLC (Seneca Resources) to prepare a 2019 annual summary of all activities associated with the Seismic Monitoring and Mitigation Plan (SMMP) submitted to the Pennsylvania Department of Environmental Protection (PA DEP) in March of 2017.The SMMP, which was developed for Seneca's Resources by ALL, was a permit condition requirement of the Class IID saltwater disposal permit issued for the Fee Seneca Resources Warrant 3771 #38268 injection well (API No. 37-047-23835-00-01). This injection well is in Highland Township of Elk County, Pennsylvania near James City. The annual summary of all activities associated with the SMMP includes any maintenance, system upgrades, downtime periods, and triggered event detections and are detailed in the following sections.

Maintenance and System Upgrades

Since installation of the seismic monitoring network (five seismic stations and one accelerometer) in late August of 2017, ALL has maintain the seismic network on a routine basis and has conducted inspections of the seismic stations as needed to ensure the system was active and sending the data to the Incorporated Research Institutions for Seismology (IRIS). Below is a summary of the maintenance and system upgrade activities performed by ALL on the seismic monitoring in 2019.

- 01/28/2019 – Replaced batteries at ALL00 and ALL02. Added dielectric grease to battery terminals at ALL01, ALL03, and ALL05. Removed snow from solar panels. ALL04 inaccessible due to weather conditions.
- 04/24/2019 – Upgraded modems at ALL00, ALL01, ALL03, ALL04, and ALL05 (ALL02 already had 5G modem) to Cradlepoint IBR650-LP4. 1-3 Hours of downtime per station during upgrade process. Replaced battery at ALL04. Sprayed round-up on weeds growing at station pads.
- 10/30/19 – Installed high gain antennae at ALL01 to increase signal strength.

Seismic Station Downtime

The seismic monitoring network is monitored in real-time and did experience some station downtime in 2018, which normally was caused by weather-related conditions, but was also due to random equipment failure. Cold weather and heavy snow had the biggest impact on seismic station downtime due to snow cover on the solar panels or low voltage readings on the batteries due to cold weather and lack of sunlight. Whether it was weather conditions or random equipment failure, ALL would mobilize staff as quickly as possible to go out to the station sites and restore operating conditions at the seismic stations.

- 01/01 to 01/06/19 – Intermittent downtime on ALL01 and ALL03 due to cold weather and snow.
- 01/20/2019 – ALL01 down due to cold weather and snow.
- 01/23/2019 – ALL00, ALL01, ALL03, and ALL04 down due to cold weather and snow.

- 01/28/2019 – ALL00, ALL01, ALL02, ALL03, and ALL04 down due to cold weather and snow. ALL on-site 1/28/2019 to replace batteries, add dielectric grease to battery terminals, and remove snow from solar panels.
- 10/17/19 – ALL01 down due to poor signal strength. ALL on-site 10/31/2019 to install high gain antennae.
- 12/10/19 – ALL00 down due to cold weather and snow.
- 12/18/19 to 12/19/19 – ALL02 down due to cold weather and snow.

Event Triggers and Detection

Since initiation of seismic monitoring at Seneca Resources Class IID disposal well in late 2017, there has been no detection of any seismic events due to the injection operations. During monitoring operations at this seismic network in 2019, a single false trigger was detected and recorded by the network was determined to be caused by thunderstorm activity. Below are the details of the triggered activity.

- 01/08/2019 – Trigger of the seismic network with false detection due to a thunderstorm. **Figure 1** is seismic waveforms of the event detected on seismic station ALL04 and the accelerometer ALL00. **Figure 2** is a weather map from the date of the false trigger.

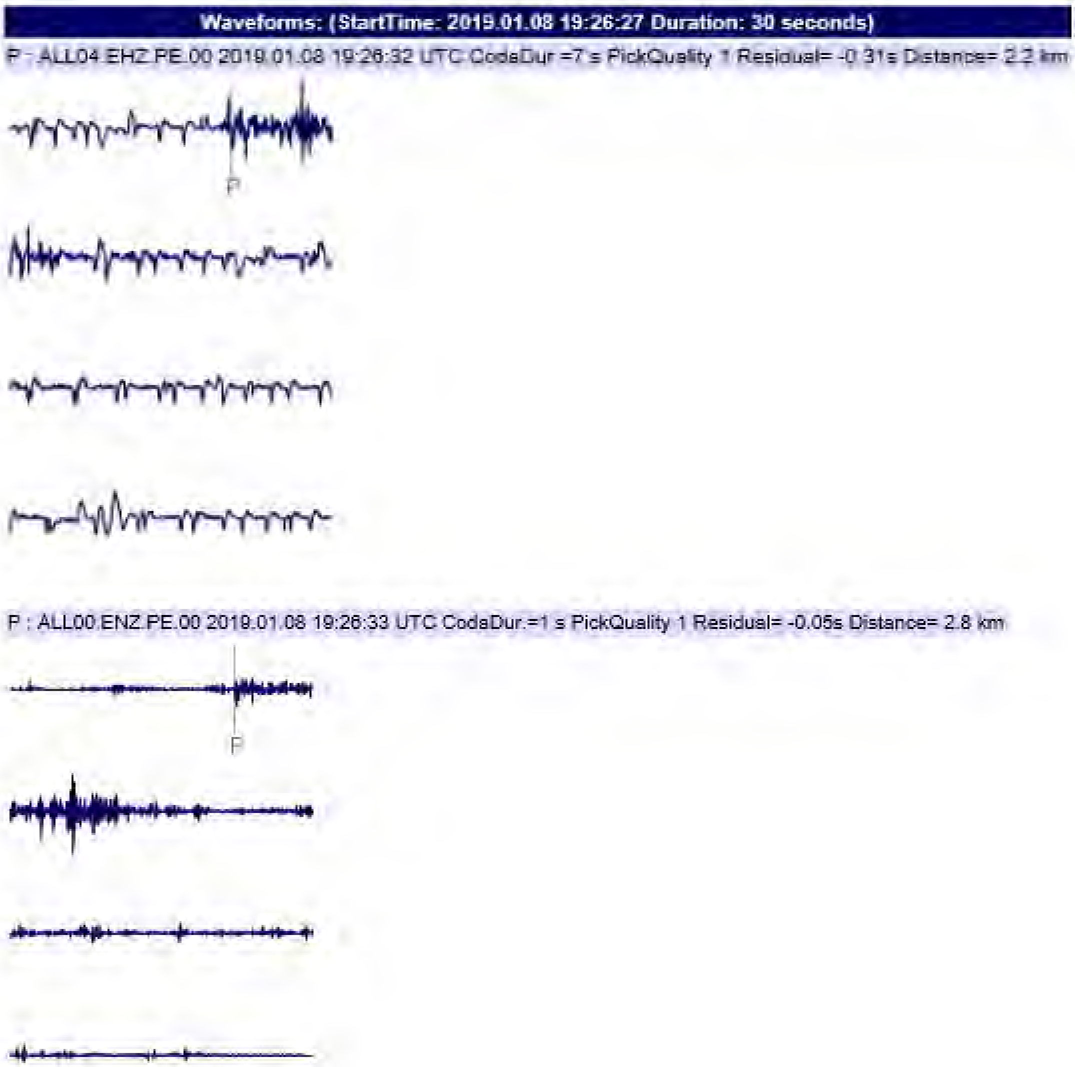


Figure 1. Thunderstorm induced trigger event detected on the ALL seismic monitoring network in Pennsylvania.

Figure 2. Weather map showing location of Seneca Resources disposal well and thunderstorm that triggered a false detection on the ALL monitoring network.

Conclusions

As discussed in the previous sections, the annual 2019 evaluation and assessment of Seneca Resources seismic monitoring network clearly demonstrates that there was no injection-induced seismic activity due to the operations at the Class IID disposal well. The two false detections that triggered the ALL seismic monitoring network were caused by weather-related thunderstorm events.

Routine maintenance and replacement of equipment due to random failure occurred during the entire 2019 year. Most of the issues were caused by cold weather and snow, which were addressed by ALL by adding dielectric grease to the batteries, replacing some batteries, upgrading modems, and adding additional antennae to increase signal strength.

ALL will continue performing routine maintenance and inspection per equipment manufacturer’s recommendations in 2020. Additionally, ALL will be upgrading the firmware at the dataloggers to the newest version.

SENECA RESOURCES COMPANY, LLC

2020 ANNUAL SEISMIC MONITORING SYSTEM ACTIVITIES REPORT FOR THE SENECA RESOURCES #38268 (37-047-23835 - PAS2D025BELK) AND SENECA RESOURCES #38282 (37-047-23885 – PAS2D026BELK) CLASS II DISPOSAL WELLS

February 2021

Introduction

ALL Consulting (ALL) has been requested by Seneca Resources Company, LLC (Seneca Resources) to prepare a 2020 annual summary of all activities associated with the Seismic Monitoring and Mitigation Plan (SMMP) submitted to the Pennsylvania Department of Environmental Protection (PA DEP) in March of 2017.The SMMP, which was developed for Seneca's Resources by ALL, was a permit condition requirements of the Class IID saltwater disposal permits issued for the Seneca Resources #38268 injection well (API No. 37-047-23835-PAS2D025BELK) and Seneca Resources #.38282 (API No. 37-047-23885 – PAS2D026BELK). Both of these injection wells are located in Highland Township of Elk County, Pennsylvania near James City. The annual summary of all activities associated with the SMMP includes any maintenance, system upgrades, downtime periods, and triggered event detections and are detailed in the following sections.

Maintenance and System Upgrades

Since installation of the seismic monitoring network (five seismic stations and one accelerometer) in late August of 2017, ALL has maintained the seismic network on a routine basis and has conducted inspections of the seismic stations as needed to ensure the system was active and sending the data to the Incorporated Research Institutions for Seismology (IRIS). Below is a summary of the maintenance and system upgrade activities performed by ALL on the seismic monitoring in 2020.

- 01/21/2020 – Updated firmware at ALL01 and ALL03 to version 3.4.8. Replaced batteries with cold-resistant AGM batteries.
- 01/31/2020 – Winston Wave Server update.
- 03/04/2020 – Replaced battery at ALL05 with cold-resistant AGM battery.
- 08/06/2020 – Replaced wiring harness at ALL04 & updated firmware to 3.4.8.
- 09/25/2020 – Pulled cable modem at ALL04 for manufacturer RMA. Replaced on 10/11/2020.

Seismic Station Downtime

The seismic monitoring network is monitored in real-time and did experience some station downtime in 2020, which normally was caused by weather-related conditions, but was also due to random equipment failure. Cold weather and heavy snow had the biggest impact on seismic station downtime due to snow cover on the solar panels or low voltage readings on the batteries due to cold weather and lack of sunlight. Whether it was weather conditions or random equipment failure, ALL would mobilize staff as quickly as possible to go out to the station sites and restore operating conditions at the seismic stations.

- 01/20/2020 to 01/21/2020 – Intermittent downtime at ALL01 and ALL03 due battery replacements.
- 01/31/2020 – Two-hour downtime at all stations due to server upgrade.
- 03/04/2020 – Intermittent downtime at ALL05 due to battery replacement.

- 07/22/2020 to 08/06/2020 – Intermittent downtime at ALL004 due to power short.
- 09/25/2020 to 10/11/2020 – Downtime at ALL04 due to maintenance on modem.
- 12/02/2020 – Two-hour downtime at ALL04 due to snow.
- 12/14/2020 to 12/15/2020 – Downtime at ALL00 and ALL01 due to snow.
- 12/22/2020 – Downtime at ALL03 and ALL04 due to snow.

Event Triggers and Detection

Since initiation of seismic monitoring at Seneca Resources Class IID disposal well in late 2017, there has been no detection of any seismic events due to the injection operations. During monitoring operations at this seismic network in 2020, no triggers were detected by the network and one small seismic event was recorded.

- 08/25/2020 – Small (M2.1) seismic event was recorded approximately 100 miles northwest of the seismic network location. Event did not trigger the seismic network notification system.

Conclusions

As discussed in the previous sections, the annual 2020 evaluation and assessment of Seneca Resources seismic monitoring network clearly demonstrates that there was no injection-induced seismic activity due to the operations at the Class IID disposal wells. There were no event detections that triggered the ALL seismic monitoring network.

Routine maintenance and replacement of equipment due to random failure occurred during the entire 2020 year. Most of the issues were caused by cold weather and snow, which were addressed by ALL by adding dielectric grease to the batteries, replacing some batteries, and upgrading modems.

ALL will continue performing routine maintenance and inspection per equipment manufacturer's recommendations in 2021.

SENECA RESOURCES COMPANY, LLC

2021 ANNUAL SEISMIC MONITORING SYSTEM ACTIVITIES REPORT FOR THE SENECA RESOURCES #38268 (37-047-23835 - PAS2D025BELK) AND SENECA RESOURCES #38282 (37-047-23885 – PAS2D026BELK) CLASS II DISPOSAL WELLS

January 2022

Introduction

ALL Consulting (ALL) has been requested by Seneca Resources Company, LLC (Seneca Resources) to prepare a 2021 annual summary of all activities associated with the Seismic Monitoring and Mitigation Plan (SMMP) submitted to the Pennsylvania Department of Environmental Protection (PA DEP) in March of 2017.The SMMP, which was developed for Seneca's Resources by ALL, was a permit condition requirements of the Class IID saltwater disposal permits issued for the Seneca Resources #38268 injection well (API No. 37-047-23835-PAS2D025BELK) and Seneca Resources #.38282 (API No. 37-047-23885 – PAS2D026BELK). Both of these injection wells are located in Highland Township of Elk County, Pennsylvania near James City. The annual summary of all activities associated with the SMMP includes any maintenance, system upgrades, downtime periods, and triggered event detections and are detailed in the following sections.

Maintenance and System Upgrades

Since installation of the seismic monitoring network (five seismic stations and one accelerometer) in late August of 2017, ALL has maintained the seismic network on a routine basis and has conducted inspections of the seismic stations as needed to ensure the system was active and sending the data to the Incorporated Research Institutions for Seismology (IRIS). Below is a summary of the maintenance and system upgrade activities performed by ALL on the seismic monitoring in 2021.

- 5/4/2021 – ALL04 site visit, modem no longer functioning, returned to manufacturer for replacement.
- 5/13/2021 – Firmware updated at all PA seismometers.
- 5/30/2021 – New modem installed at ALL04.
- 6/28/2021 – Site maintenance at all PA sites, brush cleanup and ant control.
- 7/16/2021 – Battery replaced at ALL00 & ALL01 with AGM cold resistant battery.

Seismic Station Downtime

The seismic monitoring network is monitored in real-time and did experience some station downtime in 2021, which normally was caused by weather-related conditions, but was also due to random equipment failure. Cold weather and heavy snow had the biggest impact on seismic station downtime due to snow cover on the solar panels or low voltage readings on the batteries due to cold weather and lack of sunlight. Whether it was weather conditions or random equipment failure, ALL would mobilize staff as quickly as possible to go out to the station sites and restore operating conditions at the seismic stations.

- 4/19/2021 – Two hours downtime at ALL04, modem issue.
- 5/4/2021 to 5/30/2021 – Downtime at ALL04 due to modem replacement.
- 8/27/2021 – Two hours downtime at ALL05, Verizon network issue.
- 9/1/2021 – One hour downtime at ALL04, Verizon network issue.
- 10/7/2021 – Four hours downtime at ALL03 and ALL04, Verizon network issue.

- 11/15/2021 – Three hours downtime at ALL04, low battery voltage.
- 11/22/2021 – Twelve hours downtime at ALL04, Verizon network issue.

Event Triggers and Detection

Since initiation of seismic monitoring at Seneca Resources Class IID disposal well in late 2017, there has been no detection of any seismic events due to the injection operations. During monitoring operations at this seismic network in 2021, no triggers were detected by the network.

Conclusions

As discussed in the previous sections, the annual 2021 evaluation and assessment of Seneca Resources seismic monitoring network clearly demonstrates that there was no injection-induced seismic activity due to the operations at the Class IID disposal wells. There were no event detections that triggered the ALL James City seismic monitoring network.

Routine maintenance and replacement of equipment due to random failure occurred during the entire 2021 year. Most of the issues were caused by cold weather and snow, which were addressed by ALL by adding dielectric grease to the batteries, replacing some batteries, and upgrading modems.

ALL will continue performing routine maintenance and inspection per equipment manufacturer's recommendations in 2022.

SENECA RESOURCES COMPANY, LLC

2022 ANNUAL SEISMIC MONITORING SYSTEM ACTIVITIES REPORT FOR THE SENECA RESOURCES #38268 (37-047-23835 - PAS2D025BELK) AND SENECA RESOURCES #38282 (37-047-23885 – PAS2D026BELK) CLASS II DISPOSAL WELLS

January 2023

Introduction

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Maintenance and System Upgrades

Since installation of the seismic monitoring network (five seismic stations and one accelerometer) in late August of 2017, ALL has maintained the seismic network on a routine basis and has conducted inspections of the seismic stations as needed to ensure the system was active and sending the data to the Incorporated Research Institutions for Seismology (IRIS). Below is a summary of the maintenance and system upgrade activities performed by ALL on the seismic monitoring in 2022.

- 1/22/2022 – Seismometer firmware updated to 3.9.0 at ALL00, ALL01, ALL02, ALL03, and ALL05. ALL04 inaccessible due to snow.
- 1/24/2022 – Reset and updated RTCC software on ALL Earthworm server due to unresponsive units following firmware updates. ALL02 remained unresponsive.
- 1/26/2022 – Site visit at ALL02. Power cycled and reset station configuration, ALL02 returned to normal functionality.
- 3/27/2022 – Site visit at ALL00 and ALL04. Power cycled modems and placed insecticide due to ants.
- 4/20/2022 – Visited and replaced SIM cards at all sites.
- 8/18/2022 – Visited and inspected all sites, no action required.
- 12/11/2022 – Visited sites ALL00, ALL01, ALL02, ALL03, and ALL05. Sites in good condition, no action required. ALL04 inaccessible due to snow.

Seismic Station Downtime

The seismic monitoring network is monitored in real-time and did experience some station downtime in 2022, which normally was caused by weather-related conditions, but was also due to random equipment failure. Cold weather and heavy snow had the biggest impact on seismic station downtime due to snow cover on the solar panels or low voltage readings on the batteries due to cold weather and lack of sunlight. Whether it was weather conditions or random equipment failure, ALL would mobilize staff as quickly as possible to go out to the station sites and restore operating conditions at the seismic stations.

- 1/22/2022 to 1/24/2022 – Units unresponsive following firmware update. Resolved via site visit on 1/24/2022, ALL02 remained unresponsive through 1/26/2022.
- 3/21/2022 to 3/27/2022 – Intermittent downtime at ALL00 and ALL04. Modems infested with ants.
- 11/17/2022 to 11/18/2022 – Downtime at ALL00 due to weather, solar panel covered with snow.
- 11/27/2022 to 11/28/2022 – Downtime at ALL00 and ALL04 due to weather, solar panels covered with snow.
- 11/29/2022 – Downtime at ALL00 due to weather, solar panel covered with snow.
- 12/24/2022 – 12/25/2022 – Intermittent downtime at ALL00 due to weather, solar panel covered with snow.
- 12/27/2022 to 12/29/2022 – Intermitted downtime on all stations due to RTPD software error.

Event Triggers and Detection

Since initiation of seismic monitoring at Seneca Resources Class IID disposal well in late 2017, there has been no detection of any seismic events due to the injection operations. During monitoring operations at this seismic network in 2022, no triggers were detected by the network.

Conclusions

As discussed in the previous sections, the annual 2022 evaluation and assessment of Seneca Resources seismic monitoring network clearly demonstrates that there was no injection-induced seismic activity due to the operations at the Class IID disposal wells. There were no event detections that triggered the ALL James City seismic monitoring network.

Routine maintenance and upgrades of equipment occurred during the entire 2022 year. Most of the issues were caused by cold weather, snow, ants, and software issues which were addressed by ALL via upgrading of SIM cards, upgrading of Earthworm server software, and placement of insecticide where ants were present.

ALL will continue performing routine maintenance and inspection per equipment manufacturer's recommendations in 2023.

Well #38268 Lab Data

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Chromium - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Cobalt - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Copper - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Hardness	BE	03/13	n/a	58691	mg/l	n/a	SM2340B	1
Iron - ICP	BE	03/13	n/a	59.800	mg/l	D	200.7/6010	1.000
n,Dissolved-ICP	BE	03/13	n/a	26.600	mg/l	D	200.7/6010	1.000
Lead-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Lithium - ICP	BE	03/13	n/a	98.200	mg/l	D	200.7/6010	50.000
Magnesium-ICP	BE	03/13	n/a	1939.000	mg/l	D	200.7/6010	50.000
Manganese - ICP	BE	03/13	n/a	9.100	mg/l	D	200.7/6010	0.500
Mercury	SS	03/09	n/a	ND	mg/l	n/a	245.1	0.0010
Molybedenum - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Nickel - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Selenium-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Silver-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Sodium - ICP	BE	03/15	n/a	35620.000	mg/l	D	200.7/6010	250.000
Strontium - ICP	BE	03/15	n/a	3242.500	mg/l	D	200.7/6010	5.000
Zinc - ICP	BE	03/13	n/a	0.800	mg/l	D	200.7/6010	0.500
Detergents, MBAS	LAW	02/29	8:30 AM	1.110	mg/l	n/a	SM5540C	0.200
Ethylene Glycol	EAC	03/01	n/a	ND	ug/L	D	SW846 8015B	2500

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: Gabriel J Tyler

Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Acidity to pH=8.3	BH	03/01	n/a	269	mg/l as CaCO3	n/a	SM2310B	2
Alkalinity to pH=4.5	BH	03/03	n/a	22	mg/l as CaCO3	n/a	SM2320B	20
Biological Oxygen Demand 05	CJ	02/29	9:44 AM	59.1	mg/l	n/a	SM5210B	2.0
Chemical Oxygen Demand	AJD	02/29	n/a	1162.5	mg/l	D	SM5220 D	500.0
'vdrogen Sulfide	SM	02/28	n/a	ND	mg/l	n/a	Hach	0.0
.mmonia as N / Distilled	BM	02/29	n/a	194.68	mg/l	n/a	SM4500NH3B & D	9.59
Bromide	BM	03/06	n/a	1910.00	mg/l	D	D1246-99	100.00
Chloride	KL	03/08	n/a	136446.00	mg/l	D	SM4500ClD	5.00
Dissolved Oxygen	SM	02/28	n/a	4.0	mg/l	n/a	SM4500 O-G	2.0
Kjeldahl Nitrogen as N	ZTR	03/14	n/a	320.8	mg/l	n/a	SM4500Norg-C,D	59.4
pH (SM)	BH	03/03	n/a	5.89	SU	R	SM 4500H-B	0.01
Sulfate ASTM	ZTR	03/13	n/a	ND	mg/l	D	D516-02	10
Total Nitrate + Nitrite as N	SR	03/01	n/a	0.08	mg/l	n/a	SM4500NO3E	0.05
Aluminum - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Arsenic-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Barium - ICP	BE	03/13	n/a	371.700	mg/l	D	200.7/6010	0.500
Beryllium - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Boron	ZTR	02/29	n/a	2.8	mg/l	D	SM 4500B-B	1.0
Cadmium - ICP	BE	03/14	n/a	ND	mg/l	D	200.7/6010	0.500
Calcium - ICP	BE	03/13	n/a	20307.000	mg/l	D	200.7/6010	50.000

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: [signature]

Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Oil and Grease - HEM	SGT	03/05	n/a	125.5	mg/l	n/a	1664A	5.0
Phenolics, as Phenol	SR	02/29	n/a	ND	mg/l	D	420.1	0.050
pH- Field	SM	02/28	n/a	5.76	SU	n/a	SM 4500H-B	0.00
Specific Conductance	BH	03/03	n/a	176784	umhos/cm	n/a	SM 2510B	1
Total Dissolved Solids (TDS)	LMB	02/29	n/a	212500	mg/l	n/a	SM2540C	25
tal Suspended Solids	LMB	02/29	n/a	238	mg/l	n/a	SM2540D	5
1) Benzene	RO	03/03	n/a	4.64	ug/L	n/a	624/8260B	1.00
47) Toluene	RO	03/03	n/a	4.00	ug/L	n/a	624/8260B	1.00

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: Gabriel J Tyler

Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08934
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/2/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Radium 226	Bnchmrk	03/21	n/a	*	pCi/L	n/a	RAD-CTDHS	0.000
Radium 228	Bnchmrk	03/13	n/a	*	pCi/L	n/a	RAD-CTDHS	0.000
Thorium	Bnchmrk	03/23	n/a	*	pCi/L	n/a	RAD-CTDHS	-1.000
Uranium	Bnchmrk	03/23	n/a	*	pCi/L	n/a	RAD-CTDHS	-1.000

Comments: Radiologicals done by Benchmark Analytical, PADEP Lab ID: 39-00401

ND=Not Detected

DEP Certification #s 32-00382

Approved By: Gabriel J Tagliaferro
Laboratory Supervisor

LAB ID: 39-00401 *CV

BENCHMARK ANALYTICS, INC.

4777 Saucon Creek Road
Center Valley, PA 18034-9004

PHONE (610) 974-8100
FAX (610) 974-8104

SEND DATA TO:

NAME: Jean M. Cole
COMPANY: Environmental Service Laboratories, Inc
ADDRESS: 1803 Philadelphia St
Indiana, PA 15701

WO#: 12030411
PAGE: 1 of 7
PO#:
PWS ID#

TEST REPORT

PHONE: (724) 463-8378
FAX: (724) 465-4209

12 08934-09155-09160-09166-09172-09190-09193
RECEIVED FOR LAB BY: GMD DATE: 03/05/2012 9:45

SAMPLE: **12 08934** Lab ID: 12030411-001A Grab
SAMPLED BY: Client Sample Time 02/28/2012 11:45

Test	Result	Uncert.	MDA	Units		Method	MCL	Analysis Start	Analysis End	Analyst *
Radium, Combined (Ra226 + Ra228)	5396			pCi/L	N	Calculation		03/26/12 10:38		BH-CV
Radium-226	4690	± 139.80	194.00	pCi/L		EPA 903.0		03/07/12 17:10	03/21/12	BH-CV
Carrier Recovery	108			%		EPA 903.0		03/07/12 17:10	03/21/12	BH-CV

SAMPLE: **12 08934** Lab ID: 12030411-001B Grab
SAMPLED BY: Client Sample Time 02/28/2012 11:45

Test	Result	Uncert.	MDA	Units	Method	MCL	Analysis Start	Analysis End	Analyst *
Radium-228	706.1	± 110.10	137.70	pCi/L	EPA 904.0		03/08/12 8:30	03/13/12	NLB-CV
Carrier Recovery	118			%	EPA 904.0		03/08/12 8:30	03/13/12	NLB-CV

REMARKS:

Where the analytical method has been performed under NELAP certification, the analysis has met all of the requirements of NELAP unless otherwise noted on the Analytical Report.

* CV = Benchmark Analytics, Inc. Center Valley, PA; SA = Benchmark Analytics, Inc. Sayre, PA

E \nalyte detected in the associated Method Blank

N Parameter is not NELAC certified

MANAGER *Chi Mek* DATE: 3/27/2012

LAB ID: 39-00401 *CV
LAB ID: 08-00380 *SA

Benchmark Analytics, Inc.

4777 Saucon Creek Road
Center Valley, PA 18034

Work Order: 12030411

Phone: (610) 974-8100
Fax: (610) 974-8104

SEND DATA TO:

NAME: Jean M. Cole
COMPANY: Environmental Service Laboratories, Inc
ADDRESS: 1803 Philadelphia St
Indiana, PA 15701

WO#: 12030411
PAGE: 1 of 2
PO#:
PWS ID#

TEST REPORT

PHONE: (724) 463-8378
FAX: (724) 465-4209

12 08934-09155-09160-09166-09172-09190-09193

RECEIVED FOR LAB BY: GMD DATE: 03/05/2012 9:45

SAMPLE: **12 08934** Lab ID: 12030411-001C Grab
SAMPLED BY: Client Sample Time: 02/28/2012 11:45

Test	Result	Method	Req Limit	Analysis Start	Analysis End	Analyst *
Thorium	< 12.50 µg/L	EPA 200.8		03/15/12 10:40	03/23/12	JRA-CV
Uranium	< 0.63 µg/L	EPA 200.8	30	03/15/12 10:40	03/23/12	JRA-CV
Uranium	< 0.43 pCi/L	EPA 200.8		03/15/12 10:40	03/23/12	JRA-CV

REMARKS:
Where the analytical method has been performed under NELAP certification, the analysis has met all of the requirements of NELAP unless otherwise noted on the Analytical Report.
* CV = Benchmark Analytics, Inc. Center Valley, PA; SA = Benchmark Analytics, Inc. Sayre, PA

MANAGER Chi Mel. DATE: 3/27/2012

ENVIRONMENTAL SERVICE LABORATORIES, INC.

SAMPLE REQUEST & CHAIN OF CUSTODY

HEADQUARTERS: 1803 Philadelphia St. Indiana, PA 15701 (724) 463-TEST (724) 465-4209 [X]

SOUTHERN DIVISION: 1276 Bentleyville Road Van Voorhis, PA 15366 (724) 258-TEST (724) 258-8376 [ ]

FOR INTERNAL LABORATORY USE ONLY

Sample Identification	ESL#	Composite Date on/off	Composite Time on/off	Grab Date	Grab Time	Matrix	# of Containers	Container Type Preservative	Analysis Requested
James SWD	12 08933			22812	1145	FIELD	FIELD	FIELD	pH 5.76 Hydrogen Sulfide Ø, DO 4.03
↓	↓			↓	↓	WW	1 ✓	Plastic Liter none	pH, SC, Chloride, Sulfate, Alkalinity, Acidity, Bromide
						WW	2 ✓	Plastic Liter none	TSS, TDS, Dissolved Iron, Boron, BOD, MBAS Surfactants
						WW	1 ✓	Plastic Liter HNO_3	Al, As, Ba, Be, Cd, Cr, Co, Cu, Fe, Pb, Mg, Mn, Hg, Ni, Se, Ag, Sr, Zn, Li, Na, Ca, Mo, Hardness pH<2
						WW	1 ✓	Plastic Liter H_2SO_4	Nitrate-Nitrite, TKN, Ammonia, COD pH<2
	12 08934					WW	3 ✓	Plastic Liter HNO_3	Radium 226, Radium 228 Thorium, Uranium pH<2
						WW	1 ✓	Amber Glass L HCl	Oil & Grease pH<2
						WW	1 ✓	Amber Glass L H_2SO_4	Total Phenolics pH<2
						WW	2 ✓	Amber VOA Vials none	Ethylene Glycol
↓	↓ 2-28 AK			↓	↓	WW	2 ✓	Amber VOA Vials HCl	Benzene, Toluene
TRIP BLANK	12 ~~08935~~					Water	2	Amber VOA Vials HCl	Benzene, Toluene

THE UNDERSIGNED PURCHASER HEREBY AGREES TO PAY SERVICE CHARGES ON ACCOUNTS OVER 31 DAYS OLD.
1. THESE SERVICE CHARGES WILL ACCRUE AT THE RATE OF 1 1/2% PER MONTH (18% PER ANNUM OR THE MAXIMUM ALLOWED BY LAW.)
2. THE UNDERSIGNED PURCHASER AGREES TO PAY, IN THE EVENT HIS ACCOUNT BECOMES DELINQUENT AND IS TURNED OVER TO ANY ATTORNEY FOR COLLECTION, REASONABLE ATTORNEY'S FEES PLUS ALL COURT AND ATTENDANT COLLECTION COSTS.

Project Notes: 26R Waste Profile

Sampled By: (Signature) [signature] Date/ Time 22812 1145

Relinquished By: (Signature) [signature] Date/ Time 22812 1410 — Received By: (Signature) [signature] Date/ Time 2-28-12 1419

Relinquished By: (Signature) Date/ Time — Received By: (Signature) Date/ Time

Relinquished By: (Signature) Date/ Time — Received By: (Signature) 2-28-12 Date/ Time

PRESERVATION Y / N CONTAINER Y / N TEMP 5.9 C Y / N / NA

Company/Name: Seneca Resources
Address: 51 Zents Boulevard, Brookville, PA 15825
Contact Person: Ms. Marisa Dollinger
Phone: (814) 849-4555
Fax: (814) 849-4795
Email: DollingerM@srcx.com

5.9

Maximum Injection Pressure Calculations

Maximum Injection Pressure (MIP) Calculations for Seneca Well #38268

1) Frac Gradient Based on Well #38268

FG = [ISIP + (.433 X SG X D)] /D
Where:
ISIP = 1580 psi
SG = 1.0
D = 2354

Well	ISIP (psi)*	Hydrostatic Factor (psi/ft)	SG	D (ft)	Fracture Gradient (psi/ft)
Well #38268	1580	0.433	1	2354	1.104

2) Maximum Injection Pressure (MIP) Using Average Frac Gradient From Well #38268

	FG	SG	Depth	MIP
MIP = [FG - (.433XSG)] X D	1.104	1.14	2354	1437

Top Perf	2354	Top of Perforations Used For Calculation
Bottom Perf	2403	

PADEP Technical Review (February 2017)

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

MEMO

TO S. Craig Lobins SCL

FROM Harry C. Wise, P.G. HCW

DATE February 8, 2017

RE Seneca Resources – Elk County Well #38268
Geological Review
EPA UIC Application Documents

MESSAGE:

Analysis
This technical review is in response to a request from John Ryder to assess the geologic structure and setting associated with Seneca Resources' (Seneca) gas well (Well #38368) in Highland Township, Elk County, Pennsylvania, API # 37-047-23835. The well formerly served as a production well and is a candidate for conversion to an underground injection control (UIC) well. The intent of the analysis is to determine the suitability for conversion.

I reviewed all the documents submitted by Seneca to the Pennsylvania Department of Environmental Protection's Office of Oil and Gas Management (Department) as part of the UIC permit package. The permit package is titled "Change of Use – Class II Injection Well Permit Application Supporting Documents, API #37-047-23835, United States Environment Protection Agency (EPA) UIC Permit PAS2D025BELK dated November 17, 2014". Various documents were identified as having information pertaining to local geologic structure and setting.

The discussion that follows is based on my experience as a Professional Geologist and environmental regulator.

The proposed UIC well (Well #38268) served as a former gas production well targeting the Elk 3 Sandstone. Seneca has indicated that the Upper Devonian siltstones, shales and sands between 635 feet and 2354 feet below existing site grades would effectively serve as a stratigraphic seal (confining zone). In EPA's Notice of Deficiency, further clarification regarding the confining zone for the proposed injection well was requested. Seneca noted in their response that the Elk 3 Shale, at a depth interval from 2,328 feet to 2,354 feet below existing site grades, would act as the confining zone for the proposed injection well. In addition, Seneca notes additional shales, silty shales and siltstones above the Elk 3 shale that would serve as confining zones, isolating the injection zone from the interval of the subsurface bearing fresh groundwater. Seneca Resources described the Elk 3 Shale as a silty shale zone.

The Department reviewed a petrophysical log as required by *§ 91.51. Potential pollution resulting from underground disposal* submitted via email by Seneca on June 6, 2015. The data corroborates Seneca's identification of a sandy injection zone and shows that there is a silty to shaly sequence of rocks directly above the injection zone (between 2,352 feet and 2,404 feet). The petrophysical log also identifies confining (shaly) zones that are present between 2,144 and 2,210 feet below site grades.

The Department's analysis of Alleghanian structures confirms the presence of an anticlinal trap structure – the Simpson Anticline is located within the quarter-mile and mile radius areas of review. The presence of anticlinal/synclinal pairs is commonly associated with structural deformation features throughout the Appalachian fold belt/plateau of Pennsylvania. (Figure 1).

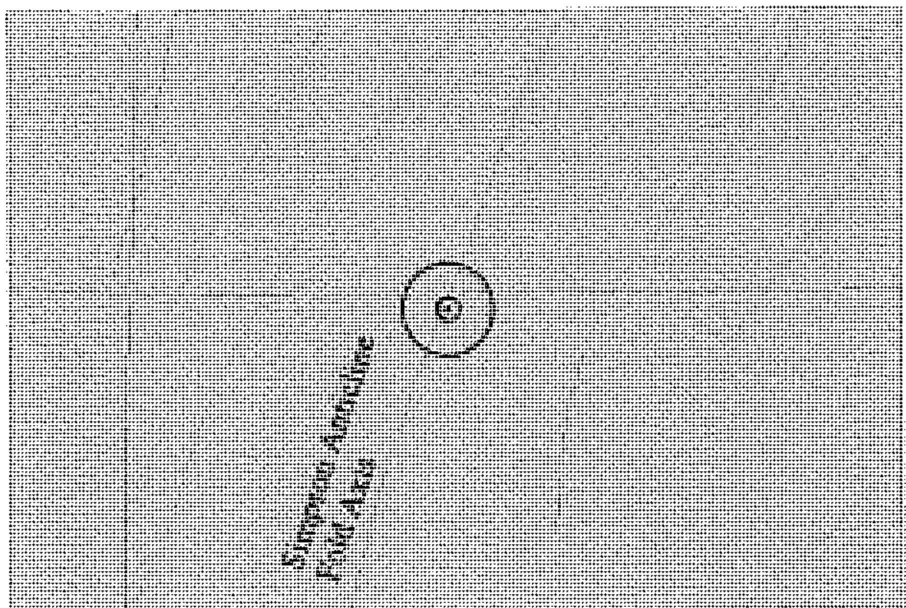

Figure 1. Alleghanian folds near well site. Well surrounded by quarter-mile and one-mile buffers.

It is my professional opinion that the injection horizon and surrounding strata result in suitable geologic structure and stratigraphy for waste disposal via underground injection. There are no concerns related to containment.

The Department's review of operating and plugged wells within a quarter-mile radial distance confirmed the information provided by Seneca in their application. The only operating well that penetrates the produced horizon is a Seneca owned well. This well is API# 047-23884, located 0.21 miles southwest of the site. This well extends to a total depth of 2,544 feet.

A plugged well, API# 047-00449/Seneca Well #01328; (the Department's eFACTS operator is listed as National Fuel Gas Supply Corporation) is located 0.21 miles east-southeast of the site. This well was plugged in February 1991 and the plugging certificate was approved by DEP in March 1991. Ninety (90) sacks of cement were used to plug the gas-bearing zone from 2,100 feet to 2,431 feet (Figure 2).

Seneca did not perform a one-mile radial review of wells in their application to EPA. EPA did not comment in their Notice of Deficiency that this was necessary. The Department's review identified 31 additional wells within a 1-mile radial search area. These wells include 14 active wells, 8 plugged wells, 4 DEP Orphan list wells and 5 wells that were reported as proposed but never drilled by the operator (Figure 2). Some wells just outside the quarter-mile radial review area are noted in Seneca's Preparedness, Prevention, and Contingency (PPC) Plan and Seneca's Response to Request for Additional Information dated May 8, 2013.

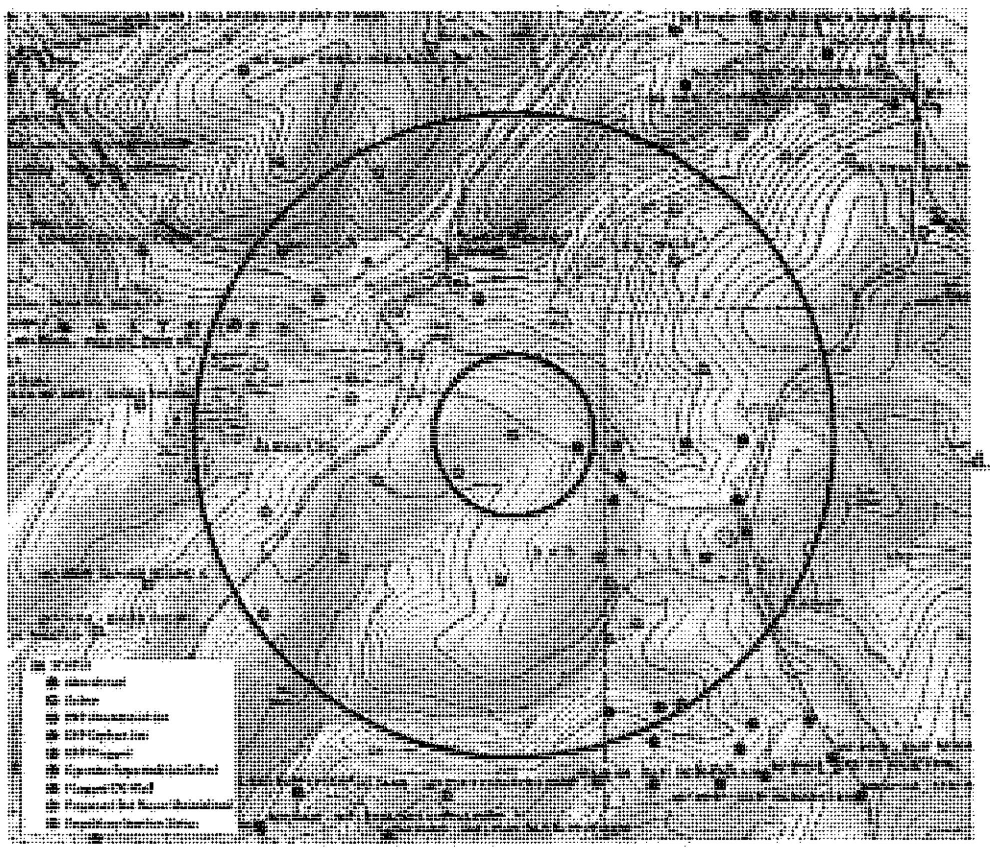

Figure 2. Surrounding conventional wells with the quarter-mile and one-mile buffers depicted.

A search was completed for historic and other well sites not in the Department's eFACTS database. No wells not already listed in eFACTS are located within the quarter mile-radial distance around the proposed injection site. There are four wells not listed in eFACTS that are within the one-mile radial distance of the proposed well site (Figure 3). Three of these wells (red symbols) are listed as plugged and abandoned (API #'s 047-21639, 047-21442 and 047-20609). The other well is listed as active (blue symbol) and the API# is 047-21054. This well is listed as belonging to Seneca.

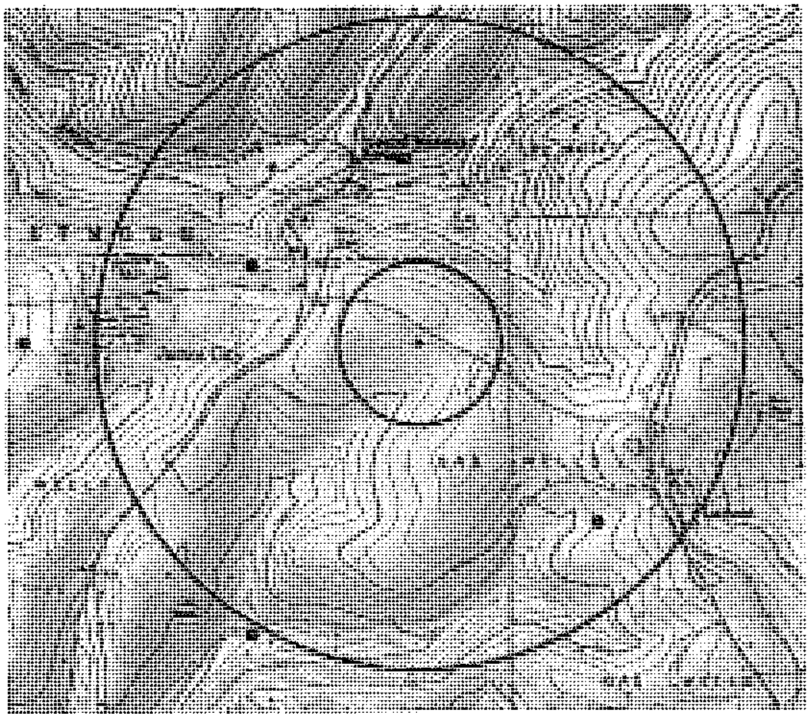

Figure 3. Historical well information with the quarter- and one-mile buffers depicted.

It is my professional opinion that there are no concerns related to the suitability of the caprock, or seal, created by ongoing and legacy oil and gas production activities in the vicinity of the proposed UIC well location.

The Department's review indicates there are no mapped faults or structural fronts in the quarter- and mile-radius areas of review (Figure 4). The Department could not find a review of the geologic structure in Seneca's application to EPA. The nearest fault is identified as an "Unnamed Structural Fault", approximately 13 miles to the southeast of the site. It appears the faulting is roughly coincidental with the folding classified as an anticlinal axis. Faulting is often noted in association with structural deformation features such as the anticline/syncline pairs common throughout the Appalachian fold belt/plateau of Pennsylvania.

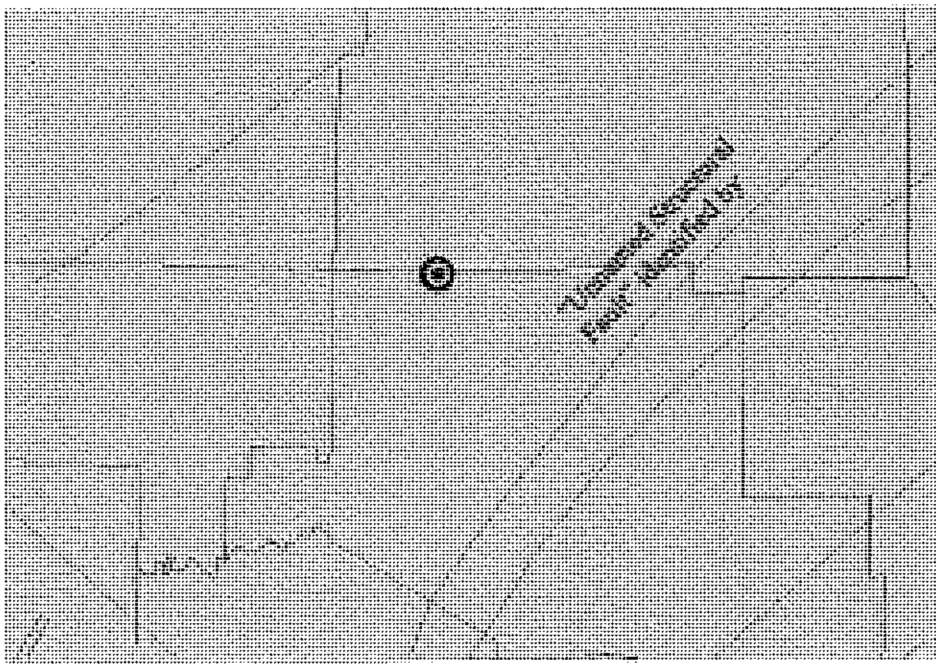

Figure 4. Faults located near the proposed well site.

The Department's review indicates there are no historical seismic events within the quarter- and one-mile radius area of review (Figure 5). There have been no recorded earthquakes of 2M or greater within Elk and McKean Counties.

It should be noted that EPA reports induced seismicity associated with injection wells in Ohio resulted from injection into Precambrian basement rock. These rocks are often cross-cut by blind faults and are crystalline in nature. Additional studies by the state of Oklahoma (http://earthquakes.ok.gov/) and within the geologic community appears to corroborate the belief that injecting fluid into brittle, crystalline basement rock can induce seismicity. The Department could not find where Seneca's application addressed any seismic concerns and the EPA did not address this in the Notice of Deficiency. As part of its review, the Department analyzed maps showing the basement rock (depth of approximately 12,000 feet to 13,000 feet) and the injection zone (depth of 2,328 feet to 2,354 feet) for this well and estimated a vertical offset distance of approximately 9,600 to 10,600 feet (Figure 6).

Induced seismicity relating to the operation of injection wells results from the interrelationship of factors such as depth to basement rock, distance to existing faults, fault plane orientation and pore pressure regimes. This geologic analysis has not revealed indicators suggestive of a heightened potential for induced seismicity. Based upon the review of all available information, it is my professional opinion that injection activities at this well pose a low risk with regard to induced seismicity. It is recommended that this risk be managed through the application of permit conditions addressing seismic monitoring and mitigation.

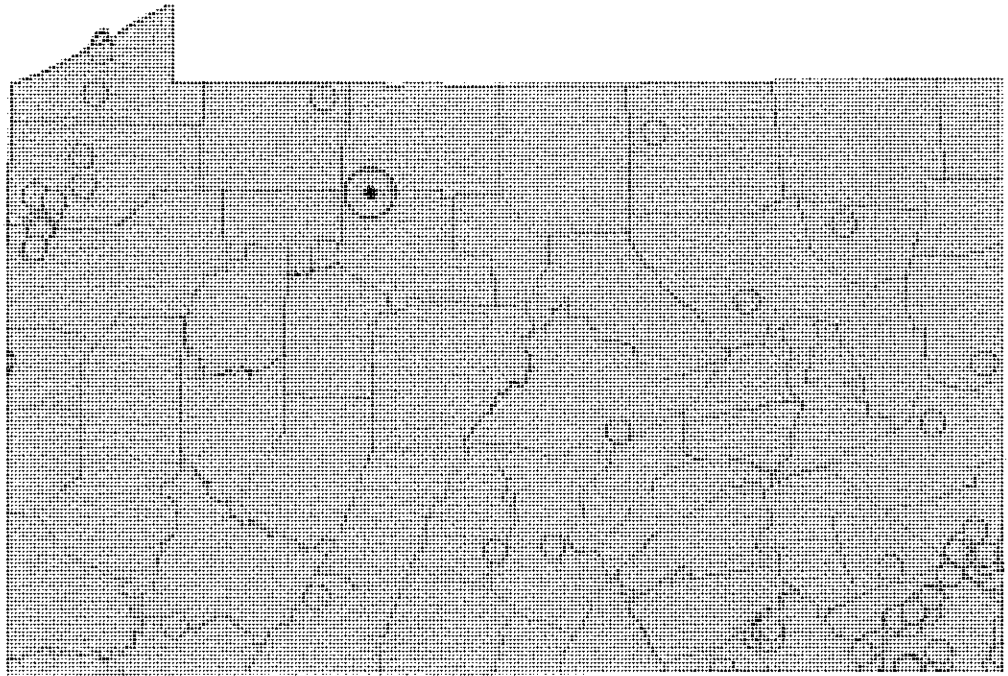

Figure 5. **Seismic activity map showing 3-mile buffers around Magnitude 2 or greater earthquakes.**

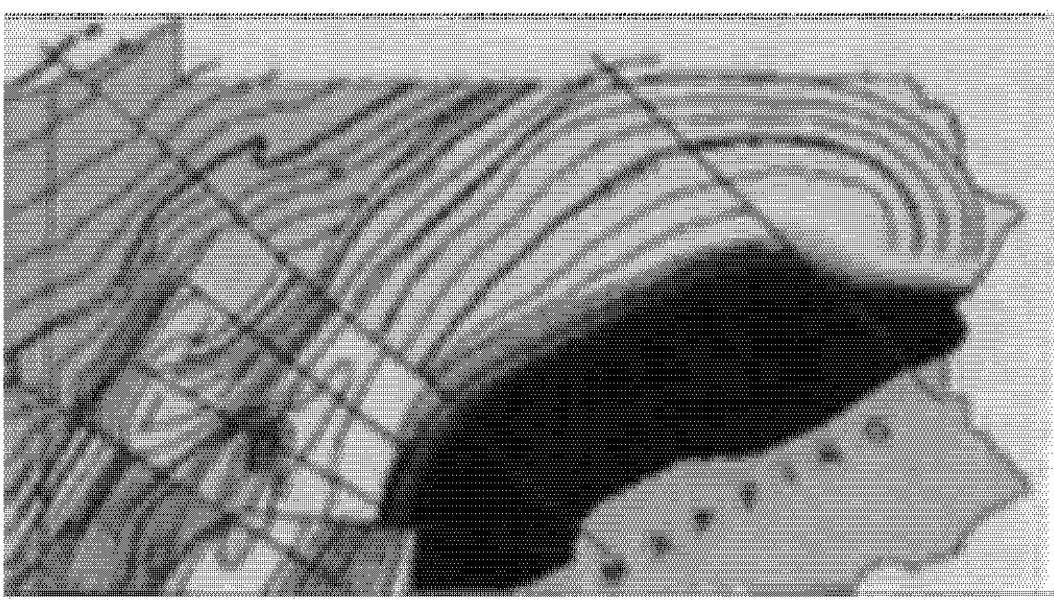

Figure 6. **Depth to Precambrian crystalline basement rock.** **UIC well site (pink circle)**

The Department's review indicates the closest storage well (API # 083-04492) is located approximately 5.7 miles northwest of the proposed injection well site. There is an active storage field (East Branch A) located approximately 6 miles northwest of the site and an abandoned storage field (McKinley) approximately 3 miles southwest of the site (Figure 7). Since the East Branch A Storage Field is approximately 6 miles northwest of the site, and outside the ¼ mile radius of review, it is not expected to be of concern. The Department's review indicated a proposed injection well within the 1-mile radius of review; however, this well is listed as proposed but was reportedly never drilled.

The Department's review indicates there is no surface or underground mining within the quarter- and one-mile radius area of review (Figure 8).

The Department's review indicates there are active municipal water wells/springs associated with Highland Township Municipal Authority within the 1-mile radius of review which were identified in Seneca's Addendum to Permit Application to EPA, dated October 2, 2012. These wells are located north to northwest of the site (Figure 9). In Seneca's application to EPA, two (2) alleged water wells were identified within the 1-mile radial area of review. The first of these was documented by Seneca as the deepest USDW well and it is completed at a depth of 130 feet below existing site grades and serves as a domestic water supply well belonging to Randy Klaiber. The second well, which is completed at a depth of 2,389 feet below existing site grades, belongs to National Fuel Gas Supply Corporation. Seneca identifies the latter well as a gas test well, and not a drinking water well. Additional private water wells were identified in Seneca's PPC Plan within the one-mile radial area of review. The Department could not find any discussion on these wells within the application or addendum. Seneca does note in the Addendum to Permit Application that they have reviewed water well depths throughout Highland and Jones Township of Elk County and Wetmore Township of McKean County and found the deepest groundwater well to be approximately 320 feet below site grades. The surface casing set depth for the proposed injection well is 553 feet below site grades. The Department concurs with Seneca's assessment that the casing set depth is adequate provided the casing and cementing requirements of 25 Pa. Code Chapter 78, Subchapter D are met.

<u>Regarding local water supplies:</u>

- It is recommended that the location, depth and use of any additional private water wells detailed in Seneca's PPC Plan be confirmed by the Department.
- It is recommended that the location and usage of the well identified by Seneca as belonging to National Fuel Gas Supply Corporation be confirmed by the Department as a test gas well and not a water well.

Once the location, depth and usage of the aforementioned wells are confirmed, the Department should ensure the casing and cementing design of the proposed injection well satisfies the requirements of 25 Pa. Code Chapter 78, Subchapter D by completing an engineering assessment of the well's construction characteristics and integrity. If no issues are noted during the review, it is my professional opinion that there is no expected risk to surrounding water supply wells provided injection well integrity is maintained per the requirements of EPA's UIC Program. This belief is due to the required construction of the well, the geology, and the distance of these features to the well and its injection horizon.

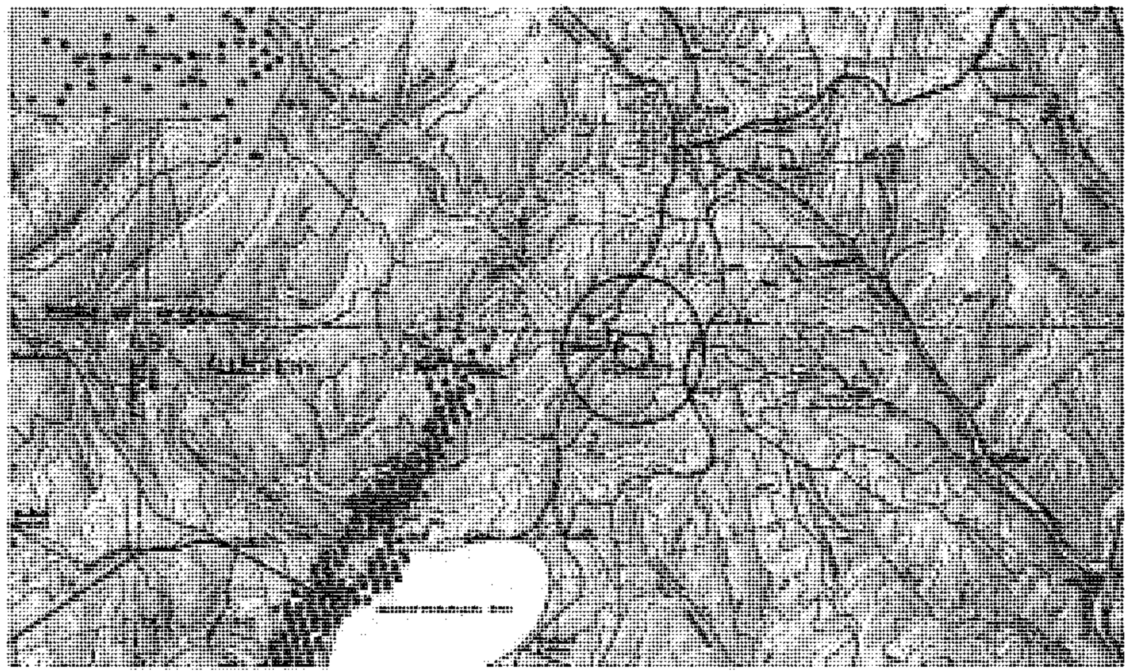

Figure 7. Map showing storage well locations. Quarter-mile and one-mile buffers depicted.

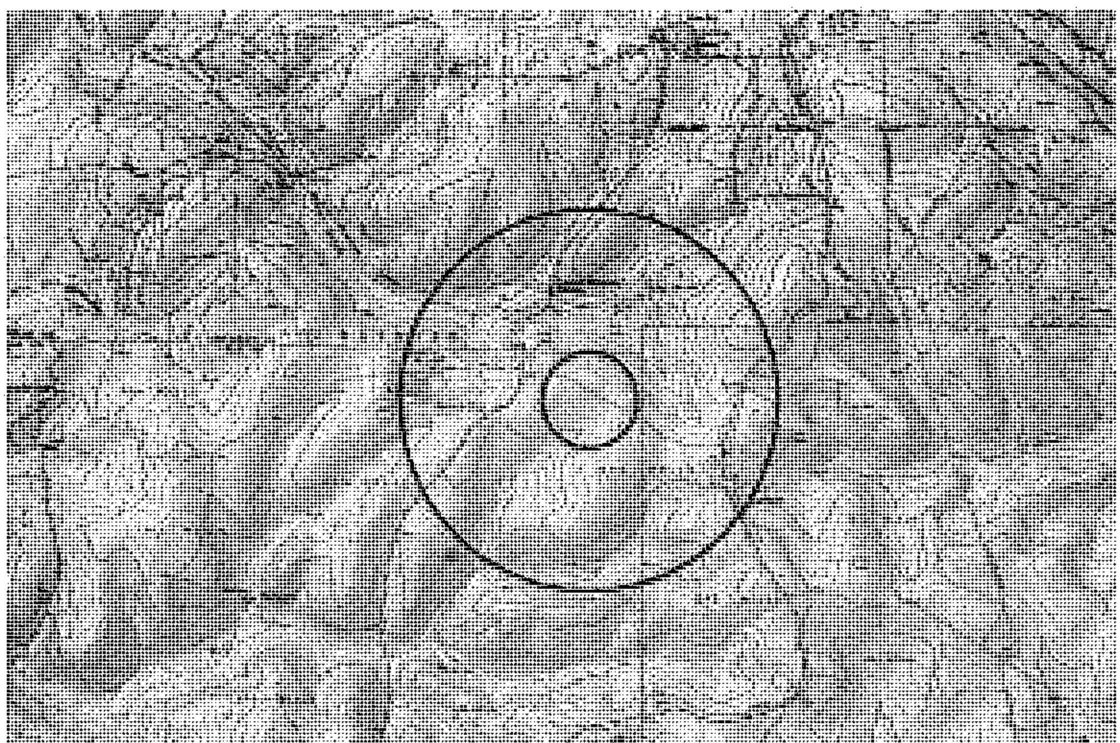

Figure 8. Map showing surface and underground mining activities in the area. Quarter-mile and one-mile buffers depicted.

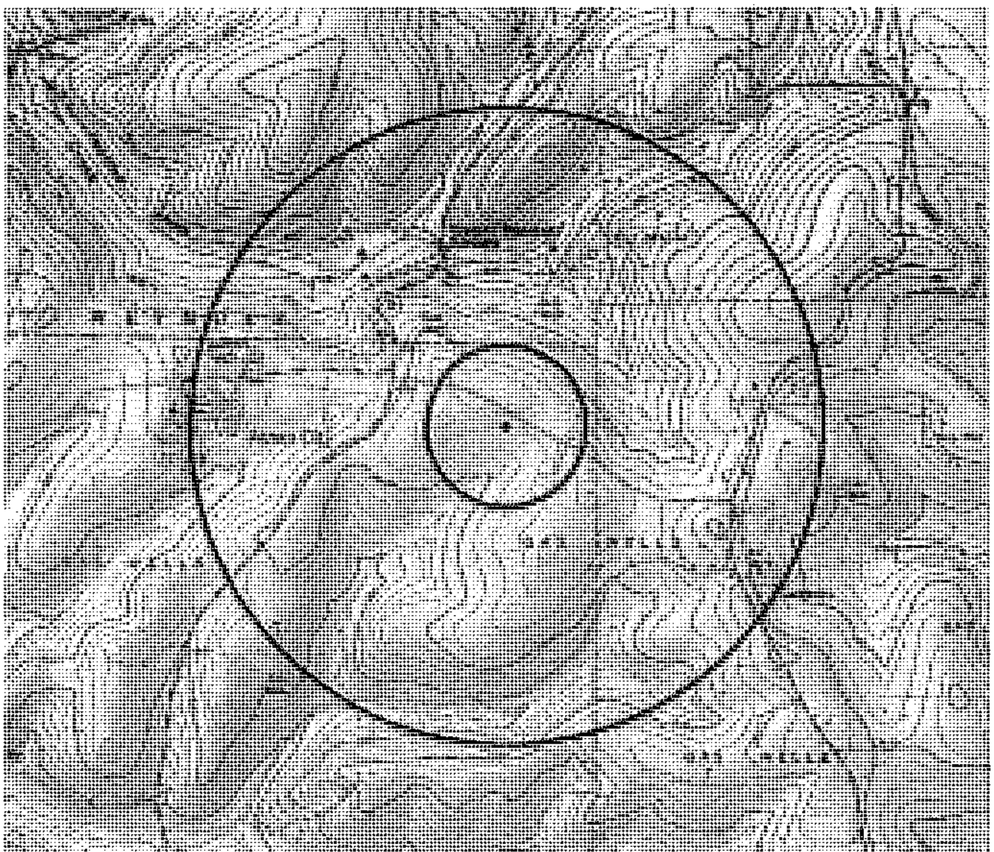

Figure 9. Map showing public water supply wells (municipal water wells shown as blue symbols and private supply wells as gold symbols). Quarter-mile and one-mile buffers depicted.

Summary of Geological Review/Assessment and Recommendations

Geological Assessment for the Seneca – Elk County Well #38268 gas well:

In my professional opinion, based on the data reviewed, the geological structure and setting associated with the Seneca – Elk County Well #38268 makes it a suitable candidate for conversion from a production well to an underground injection well.

The following recommendations are suggested:

(1) It is recommended that the location, depth and use of any additional private water wells detailed in Seneca's PPC Plan be confirmed by the Department.

(2) It is recommended that the location and usage of the well identified by Seneca as belonging to National Fuel Gas Supply Corporation be confirmed by the Department as a test gas well and not a water well.

Once the location, depth and usage of the aforementioned wells are confirmed, the Department must take steps to ensure the casing and cementing design of the proposed injection well satisfies the requirements of 25 Pa. Code Chapter 78, Subsection D. If this is the case, it is my professional opinion that there is no expected risk to these wells provided injection well integrity is maintained per the requirements of EPA's UIC Program.

cc: John Ryder
Douglas Moorhead
Keith Salador

End

Porosity and Permeability Information

delta p = 162.6 $Q\mu$ / kh * [(log(kt / $\Phi\mu Cr^2$) – 3.23] where:

delta p = pressure change (psi) at radius, r and time, t
Q = injection rate (barrels/day)
μ = injectate viscosity (centipoise)
k = formation permeability (millidarcies)
h = formation thickness (feet)
t = time since injection began (hours)
C = compressibility (total, sum of water and rock compressibility) (psi^{-1})
r = radial distance from wellbore to point of investigation (feet)
Φ = average formation porosity (decimal)

PARAMETERS USED IN THE ANALYSIS

The following parameters were used in the zone of endangerment analysis. The majority of the parameters are based on the analysis and results of the injection testing performed on well #38268 in March 2012 (Tetra Tech, 2012). The permeability value was based on the results from the injection testing analysis. For the depth to the lowest most USDW, a conservative estimate based on US EPA Region 3 guidance and review of site area hydrogeologic conditions was used (i.e., depth to USDW = 400 feet)

Input Parameters for Well #38268
Q = 3,000 barrels/day
t = 10 years = 87,600 hours
μ = 0.9457 centipoise
k = 190 md
h = 49 feet
C = 7.6e-06 psi^{-1}
Φ = 13.5%
Well radius = 0.29 feet
Specific gravity of injectate = 1.14
Surface elevation = 2040 feet
Depth to injection formation = 2354 feet
Base of lowest most USDW (elevation) = 1640 feet
Initial pressure at top of injection formation = 24 psi

RESULTS

The Matthews and Russell equation was solved for various distances from the wellbore based on the parameters listed above for permeability value determined from the injection test. The values of delta p were added to the existing pressure in the injection formation to obtain the total pressure in the formation. These values were then converted to feet of head of formation brine. The results are shown in Figure 1. The plot shows the calculated pressure surface within the injection formation, measured as feet of head of formation brine above the top of the injection formation. Also shown is the head of the

APPENDIX C

Tetra Tech June 2012 Injectivity Test Report

Tetra Tech Injectivity Test Report

A R M G r o u p L L

TETRA TECH

INJECTIVITY TEST REPORT

SENECA RESOURCES WELL #38268
(API# 37-047-23835)

Highland Township
Elk County, Pennsylvania

Seneca Resources Corporation
5800 Corporate Blvd.
Suite 300
Pittsburgh, PA 15237

June 2012

complex world CLEAR SOLUTIONS™

INJECTIVITY TEST REPORT

SENECA RESOURCES WELL # 38268
(API# 37-047-23835)

Highland Township
Elk County, Pennsylvania

Seneca Resources Corporation
5800 Corporate Blvd.
Suite 300
Pittsburgh, PA 15237

June 2012

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Figure 3 – Well Construction Diagram (#38281)

Figure 4 – Fluid Level Graph

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Figure 6 – Measured bottom-hole pressure and temperature versus elapsed time (#38268)

Figure 7 – Log-log plot of pressure and derivative curves versus elapsed time (#38268)

Figure 8 –Semi-log plot of measured bottom-hole pressure versus elapsed time (#38268)

Figure 9 – Semi-log plot of measured bottom-hole pressure versus superposition time (#38268)

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Appendix A – Well #38268 Wellhead Pressure and Injection Rate Field Measurements

Appendix B – Fluid Levels from Echo Meter Readings

1.0 INTRODUCTION AND BACKGROUND

This report summarizes the injectivity testing performed in March 2012 at the Seneca Resources Corporation's (Seneca's) Well # 38268 (API #37-047-23835), located in Highland Township, Elk County, Pennsylvania. Seneca is considering converting this well into a brine disposal well for disposal of produced water from its Marcellus Shale and other natural gas producing operations. Seneca retained Tetra Tech, Inc. (Tetra Tech) to investigate the hydraulic feasibility of utilizing Well #38268 for brine disposal. Tetra Tech designed and implemented a testing program to determine hydraulic parameters for this potential injection well, including information about reservoir characteristics such as transmissivity, bottom-hole injection pressure, reservoir static pressure, potential sustainable injection rates and geologic boundaries. This report summarizes the injectivity test procedures and results for the injectivity test conducted at Well #38268 in March 2012.

1.1 Site Location

Well #38268 is located in Highland Township, Elk County, Pennsylvania (see **Figure 1** – Site Map).

1.2 Test Well Construction and Background

Well #38268 was drilled in March 2007 and completed in the following intervals for natural gas production as shown below in **Table 1.**

Table 1 - Notched and Frac'd Intervals of Well #38268

Formation	Notched and Frac'd Interval	Thickness (h)	Comments
Speechley 5	1667	1 foot	Gas producing interval (situated above packer)
Speechley 6	1671.5 to 1676 feet	4.5 feet	Gas producing interval (situated above packer)
Speechley 7	1721	1 foot	Gas producing interval (situated above packer)
Tiona 1	1739.5	1 foot	Gas producing interval (situated above packer)
Elk 3	2354 to 2403 feet	49 feet	Gas producing interval Test injection interval

Figure 2 is a well construction diagram for the test well. As indicated, the well has 553.2 feet of cemented 7-inch surface casing, with the remaining portion of the well having open hole completion. In preparation for the injectivity test, tubing and packer were placed in the well, with the bottom of the packer placed at a depth of approximately 2304 ft., which is approximately 50 ft above the top of the targeted Elk 3 Sandstone injection interval. Also prior to injection, a bottom-hole pressure gauge was placed at 2275 feet. A surface pressure gauge was also placed at the wellhead. Both gauges had data storage capability.

A review of the neutron-density log for the test well indicates that a maximum porosity for the upper 6 ft of the Elk Sandstone is in the 18 percent range with the entire frac interval having an average porosity of 13.5%.

1.3 Observation Well Construction and Background

Seneca Well #38281 (API# 37-047-23884), located 1320 feet to the southwest of the subject test well, was utilized as an observation well and monitored during the injectivity testing of Well #38268. The location of this well is shown on **Figure 1**. **Figure 3** is a well construction diagram for Well #38281, which is an operating gas well producing from the Speechley, Tiona, Kane, and Elk 3 intervals (**Table 2**). As indicated, 602 feet of cemented surface casing is present followed by open hole completion. The well is configured with tubing and rods and a pump jack to remove accumulated water.

Table 2 - Notched and Frac'd Intervals of Well #38281

Formation	Notched and Frac'd Interval	Thickness (h)	Comments
Speechley 6	1650 to 1662	12 feet	Gas producing interval
Speechley 7	1704 to 1719 feet	15feet	Gas producing interval
Tiona Sandstone	1728 to 1734 feet	6 feet	Gas producing interval
Kane 1	2123 feet	1 foot	Gas producing interval
Kane 2	2133 to 2151 feet	18 feet	Gas producing interval
Kane 3	2156	1 foot	Gas producing interval
Elk 3	2339 to 2390 feet	51 feet	Gas producing interval

2.0 INJECTIVITY TESTING CONDITIONS AND IMPLEMENTATION

2.1 Injectivity Test Conditions

On February 28, 2012, Seneca provided EPA with an injectivity test request for performing the injection test at Well #38268 followed by an email dated February 29, 2012, which included additional information requested by EPA. In a letter dated March 12, 2012, EPA approved conducting the injectivity test under the following conditions:

1. **Injection Zone** – The well will be utilized to perform testing of the Elk 3 Sandstone. Injection into the Elk 3 will be conducted through tubing and packer set no more than 50 feet above the upper perforated (notched) interval in the Elk 3 which is located at 2354 feet.
2. **Duration of Test** – The duration of the injectivity test shall not exceed a maximum of thirty (30) consecutive days.
3. **Total Volume Limitation** – During the testing period, the total volume of fluid to be injected shall not exceed a maximum of 5000 barrels of produced fluid (brine).
4. **Maximum Injection Pressure** – The maximum injection pressure for the test into the Elk 3 is based on an instantaneous shut-in pressure of 1580 psi (based on the first stage fracture information), a specific gravity of the injection fluid of 1.14 and a packer setting depth of 2304 feet. The injection pressure for this test shall not exceed the maximum surface injection pressure of 1433 psi. If, during testing, it is observed that this pressure causes formation breakdown/fracturing to occur, the test shall be stopped and EPA contacted immediately to discuss possible alternative testing procedures.
5. **Injection Fluid** – Injection fluid shall consist of produced fluid (brine) obtained from Seneca's production operations with a specific gravity of 1.14.
6. **Monitoring** – Injection volume and pressure shall be monitored and recorded on a continuous basis. Both the injection pressure and annulus pressure, between the injection tubing and 7-inch casing, will be monitored. In addition, production Well #38281 shall be monitored throughout the injectivity test. Prior to testing, Well #38281 will be shut-in and the pressure and fluid level monitored. The pressure and fluid level in this well will also be monitored during the test and once following completion of the test. EPA encouraged the continuous monitoring of the formation pressure decline after injection has concluded. This data should further enhance analysis of the transmissivity and storage capacity of the proposed injection formation and allow for an estimation of the protracted effects on the formation. A final report must be submitted to EPA.

2.2 March 2012 Injection Test Implementation

The project team conducting the field work consisted of Seneca operations staff (overall test management, well access and brine mobilization), Eastern Reservoir Services (ERS) (wireline services, pressure gauges and flowmeter), WPD (Western Pump and Dredge) (filtering equipment and injection pumps), Champion (brine water treatment prior to injection), and Tetra Tech (test oversight and data evaluation). The brine utilized for the injection was obtained from Seneca's nearby James City Marcellus production area.

The injectivity test was performed on Well #38268 in March 2012 with the brine injection conducted on March 27 and 28, 2012. The test consisted of injection through tubing/packer into the frac'd intervals corresponding to the Elk 3 Sandstone while monitoring injection rates and well head and bottom hole pressure during the injection phase and the pressure falloff after the well was shut-in. Also as required by the EPA approval letter, annular pressure was monitored during the test for any evidence of packer failure or tubing leak.

The initial phase of injection consisted of "loading the well" with brine to establish wellhead pressure. This was necessary because the well was taking the brine on vacuum. The injectivity test work plan included a Step-Rate Test (SRT) which was to be performed once significant wellhead pressure was established in the well. Although the injection rate after the first 4.5 hours of injection was approximately 3 bpm (barrels/minute), no significant wellhead pressure was developing. (Approximately 1000 barrels of brine had been injected by that time.) Based on this condition and rate limitations of the injection pump available onsite, it was decided to forego the SRT and proceed directly to the Constant Rate Test (CRT). Initially, a 10 µm filter and a 25 µm filter were utilized to filter the brine water prior to being injected into the well. It was discovered that during the latter part of the test the injection rate could not be sustained with a 10 µm filter, and therefore two 25 µm filters were utilized for the last 8 hours of the injection test to maintain a relatively constant rate of 2.1 bpm.

Most of the data required for data analysis were recorded electronically during the injectivity test. An exception was injection rate and cumulative volume which was recorded manually in the field book based on readings taken from the in-line digital flow meter situated on the piping approximately 6 feet from the well head. In addition, field data sheets were used to record the most relevant data by hand to ensure these data were being recorded in an event of a failure of the electronic systems and to summarize test conditions for review to optimize field procedures as necessary.

The following data were measured and recorded by Tetra Tech staff during the injection test:

- Injection rate and time
- Wellhead pressure
- Annulus pressure

(It is noted there was no surface readout associated with the bottom hole pressure gauge, which was later retrieved for downloading the data.)

Injection was initiated on March 27, 2012 at 1003 hrs. Injection rates during the test varied from 1.1 to 7.1 bpm. During the final 8 hours of the injection period, the injection rate was held relatively constant at approximately 2.1 bpm. The average rate over the entire injection phase was 2.67 bpm.

Injection was halted on March 28, 2012 at 1856 hours and the well shut-in to begin the Falloff Test (FOT) portion of the injectivity test. A total of 5,000 barrels of brine were injected during the test over a cumulative injection time of 1973 minutes (approximately 33 hours). Pressure data was collected during the FOT portion of the test for approximately 116 hours (4.8 days). It is noted that there were only minor changes in the annulus pressure during the injectivity test, indicating there were no issues of packer failure or tubing leaks.

2.3 Surface Hydraulic Analysis of March 2012 Injection Test

The maximum pressure (surface) observed during the injection test was approximately 31.3 psi, which was approximately 1401.7 psi below the EPA specified MIP of 1433 psi. The average

surface pressure observed was 13.47 psi. Injection rate and surface pressure data recorded during the injectivity test are included in **Appendix A**.
During the injectivity test two samples of the brine were collected for field testing for density (specific gravity). **Table 3** summarizes the analytical results for the injectate samples.

Table 3 - Injectate Samples Analytical Results for Well #38268

Parameter	Units	3/27/12	3/28/12
Specific Gravity	Unitless (Relative ratio to density of water at 4°C)	1.16	1.14

2.4 Observation Well Results

Well #38281, located 1320 feet to the southwest of the subject test well, was utilized as an observation well. Well #38281 was shut-in for a period of approximately five days prior to the injectivity test to allow for equilibrium in pressures and fluid levels to be attained. Pressures and fluid levels (utilizing an Echometer) were measured in the annulus between the 7-inch casing and tubing prior to injection at Well #38268, daily during the injection at Well #38268; and during the falloff period of the test. Monitoring at the observation well was performed at the completion of the test, the day after the completion of the test, and five days after the completion of the test. The annulus pressure on the observation well held steady between 23 and 26 psi before, during, and after the injection. A comparison of wellhead pressures between the two wells is shown below on **Table 4**.

Table 4 – Injection and Observation Well Pressure Readings

Injection Well #38268

	Pre-Test	During Test		Post - Test				
Date	3/27/12 - AM	3/27/12 - PM	3/28/12	3/28/12	3/30/12	3/31/12	4/1/12	4/2/12
Annulus PSI	19.75	20.8	22.8	23.6	26.5	28.4	29.9	30
Wellhead PSI	22	17.3	28	-12	-11.3	-10.7	-5.3	29.1

Observation Well #38281

	Pre-Test					During Test		Post - Test				
Date	3/23/12	3/24/12	3/25/12	3/26/12	3/27/12	3/27/12	3/28/12	3/28/12	3/30/12	3/31/12	4/1/12	4/2/12
Annulus PSI	20	21	22	24	25	23	24	23	26	26	26	26

As indicated above, the pressure in the observation well was relatively constant before during and after injection at Well #38268. Based on the collected data, there is no apparent relationship between pressure changes in the injection and observations wells.

ERS staff conducted fluid level measurements in the injection well for the annulus and well head (tubing) prior to the injection test and then during the falloff portion of the test. The fluid levels in the observation well were also taken by ERS staff prior to the injection test, during the injection test and during the falloff period. **Appendix B** includes the fluid level data obtained from the

Echometer measurements. The results are summarized below in **Table 5**. It is noted that negative time values represent time prior to initiation of injection.

Table 5 – Liquid Level Measurements

Injection Well # 38268 - Casing	
Elapsed time (min)	**Depth to Liquid Level (ft)**
-1513	2201.55
8894	2185.24
Water level change	16.31

Injection Well # 38268 - Tubing	
Elapsed time (min)	**Depth to Liquid Level (ft)**
-1512	2452.81
8922	2439.65
Water level change	13.16

Observation Well # 38281	
Elapsed time (min)	**Depth to Liquid Level (ft)**
-1414	2172.57
-46	2167.41
491	2165.59
1377	2153.22
1444	2151.07
2015	2144.63
2840	2118.59
8950	2116.83
Water level change	55.74

When comparing pre- and post-injection fluid levels, the fluid level in the injection well rose 13.16 feet in the tubing and 16.31 feet in the casing (i.e., annular space between 7-inch and tubing). (There were no fluid level readings in the injection well during the injection phase.) The fluid level rose 55.74 feet in the observation well during this same period. Although the obersvation well was shut-in for use in injectivity test monitoirng, the observation well is an operating gas well with rods and a pump jack to remove accumulating water. It is not known whether the observed increase in fluid levels in this well is a result of influence from injection at Well #38268 or attributable to produced water from the various gas productive intervals in the observation well. As discussed above, there were no significant pressure changes in the observation well over the duration of the test which may indicate that the increase in fluid levels was from produced water intervals within the well. **Figure 4** illustrates the fluid level changes in both wells.

3.0 BOTTOM HOLE PRESSURE DATA ANALYSIS

The plot of measured bottom-hole pressure and injection rate versus time is shown in **Figure 5**, and the plot of measured bottom-hole pressure and temperature is shown in **Figure 6**.

Analysis of the falloff portion of the test was performed using Fekete F.A.S.T. WellTest™ (Version 7.4.3.161) software. F.A.S.T. WellTest™ allows for the identification of flow regime, computation of the pressure derivative function, and reservoir parameter analysis by both type curve matching (log-log plot) and superposition analysis (semilog plot). **Figure 7** shows the log-log plot of the pressure and derivative curve versus elapsed time for the falloff portion of the injection test. **Figure 8** shows the semilog plot of pressure versus elapsed time for the falloff portion of the injection test and **Figure 9** shows the semilog plot of pressure versus superposition radial time for the falloff portion of the injection test.

For the purposes of this analysis, it was assumed that only the Elk 3 Sandstone frac interval (from 2354 to 2503 ft, a thickness of 49 ft) was to be used as the representative thickness for the formation as the vast majority of the flow during the injection test was likely being taken by this interval. An average porosity of 13.5% was utilized based on log analysis.

Radial flow is flow in the horizontal radial direction and occurs during the infinite-acting time period of the falloff (before the pressure transient has reached boundaries of the reservoir). The purpose of analyzing radial flow data is to determine permeability (k). The signature of radial flow data on a derivative plot for a constant rate test is a straight line whose slope is at or approaching zero. This portion of the derivative curve is denoted on **Figure 7** and shows that radial flow occurs at approximately 19 hours after shut-in. The position of this line is used to calculate permeability. The value of the derivative of radial flow data corresponds to the vertical position of the horizontal straight line and is used to calculate permeability as follows:

$$k = 70.6 \bullet \frac{qB\mu}{Der \bullet h}$$

where k = permeability (md), q = final water rate (bbl/d), B = formation volume factor, μ = viscosity (cP), Der = derivative (psi), and h = net pay (ft).
Test data are shown in **Table 6**.

Table 6 - Test Data for #38268 Well March 2012 Test

Parameter	Value
Interval Thickness (Net Pay) (h)	49 ft
Porosity	13.5%
Formation Temperature (T)	72°F
Specific Gravity (G)	1.14
Viscosity (μ)	0.9457 cP
Final Flowing Pressure	1162.8 psi
Water Saturation (S_w)	100%
Final Water Rate (q)	2937.3 bbl/d
Corrected Flow Time (t_c)	40.7 hr
Well Radius (r_w)	0.29 ft
Total Compressibility (c_t)`	7.593e-06 psi^{-1}
Final Flowing Pressure (p_{wfo})	1162.8 psi
Extrapolated Pressure (p*)	-6.3 psi
Formation Volume Factor (B)	1.0

Based on the test data in Table 6, and a derivative value (Der) of 21.09 psi, the estimated permeability is equal to:

$$k = 70.6 \bullet \frac{(2937.3 \bullet 1.0 \bullet 0.9457)}{(21.09 \bullet 49)}$$

$$k = 190\, md$$

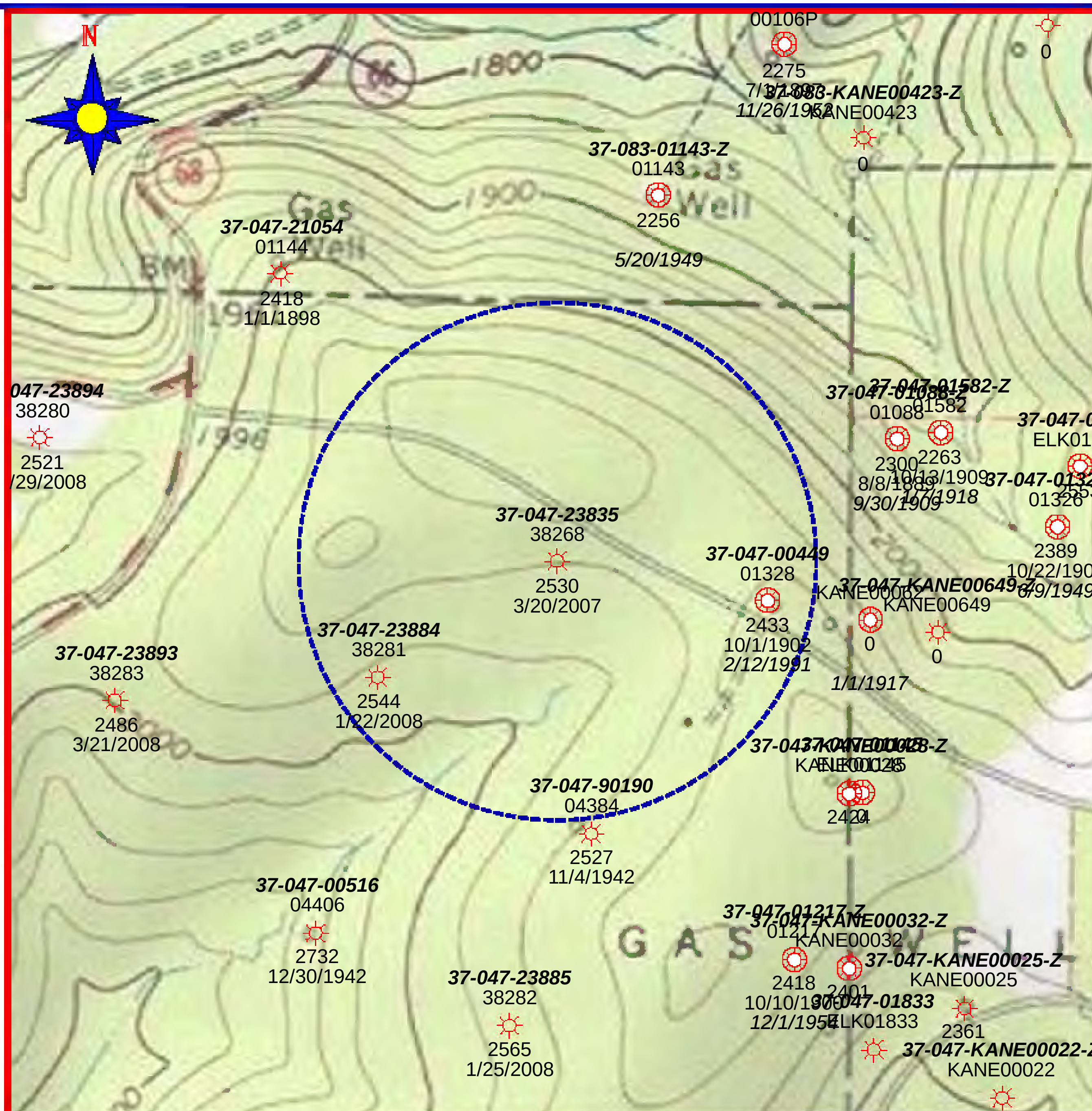
4.0 SUMMARY

The following are key findings based on injectivity testing performed on the Elk 3 Sandstone interval of Seneca Well #38268:

- During the injection portion of the test, the injection rate varied, but was maintained at approximately 2.1 bpm for the last 8 hours of injection. The average injection rate for the entire test period was 2.67 bpm.
- A total of 5,000 bbls were injected during the test.
- The maximum surface wellhead pressure recorded during the test was only approximately 31 psi, which is well below the MIP (surface) of 1433 psi approved by EPA for the test. This condition suggests the well would have been able to sustain higher injection rates during the test if not for the limits of the pumping system.
- The maximum bottom-hole pressure measured during the test was approximately 1163 psi.
- Falloff pressure data analysis indicates an estimated permeability of 190 md, based on a formation thickness of 49 feet, a porosity of 13.5%, and S_w = 100%
- No indications of significant geologic boundaries were identified during the test.
- An evaluation of fluid levels and pressure data from the observation well are inconclusive regarding the potential influence from injection at Well #38268. Although fluid levels rose approximately 56 feet in the observation well during the test, this increase may be attributable to accumulating produced water from the various gas producing intervals in the well.
- No evidence of formation breakdown/fracturing was observed during the test.

In summary, an evaluation of injectivity test data for the March 2012 test on Seneca Well #38268 indicates that the well has significant potential for brine disposal through injection into the Elk 3 Sandstone interval. This is consistent with the relatively thick, porous characteristics of the injection interval based on log analysis. It is not possible to accurately predict long-term injection well performance based on a relatively short duration test; however, the test results suggest that the well could sustain an injection rate of greater than 2 bpm (approximately 3000 bpd) with pressures remaining under the likely UIC Class IID permit limits for maximum injection pressure.

FIGURES



800 0 800 1600 ft

1 inch = 800 feet

Legend

Well Symbols

Well Status

AGAS

D&A

GAS

37-047-00449 — **API Number**
01328 — Seneca's Well ID
2433 — Well Depth
10/1/1902 — Spud Date
2/12/1991 — *Abandoned Date*

SENECA RESOURCES

Proposed Injection Test Well (38268)
James City, Elk County, PA

Author: A.M. Veazey		Date: February 22, 2012
	Scale: 1" = 800'	

Figure 2
Well Construction Diagram
Injection Test Well

Seneca Well #38268
Highland Township
Elk County, PA
37-047-23835

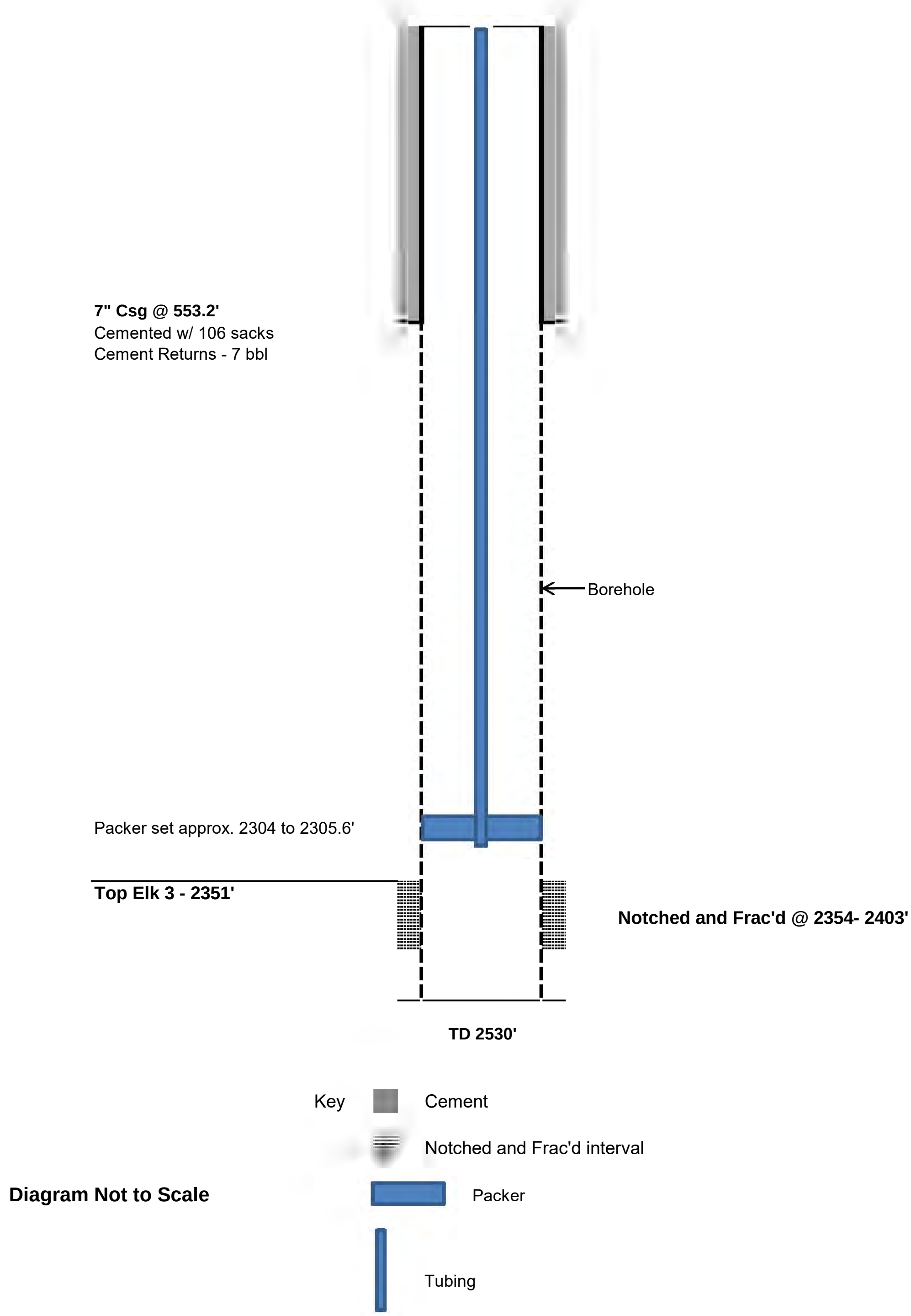
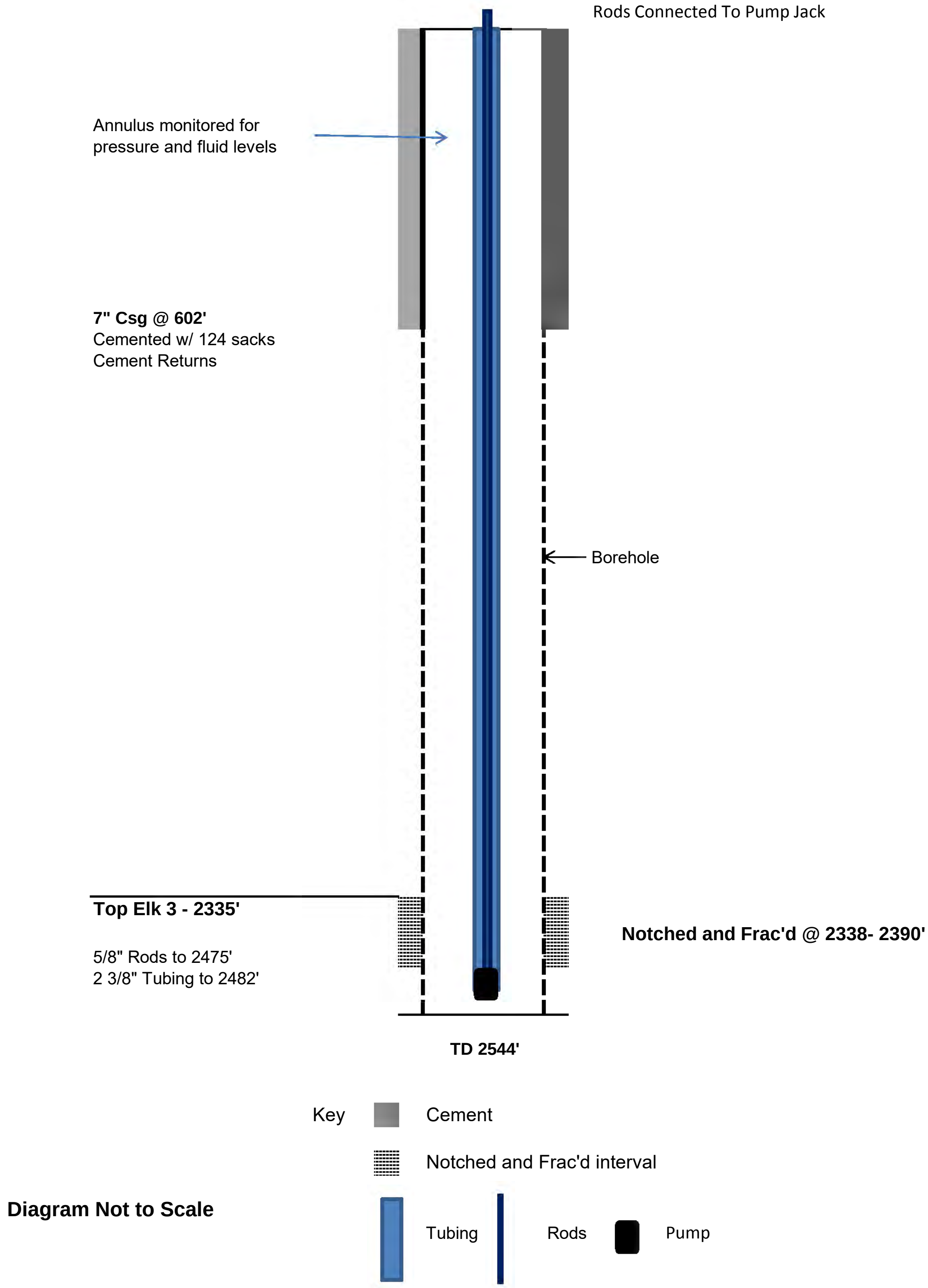


Figure 3
Well Construction Diagram
Observation Well
Seneca Well #38281
Highland Township
Elk County, PA
37-047-23884



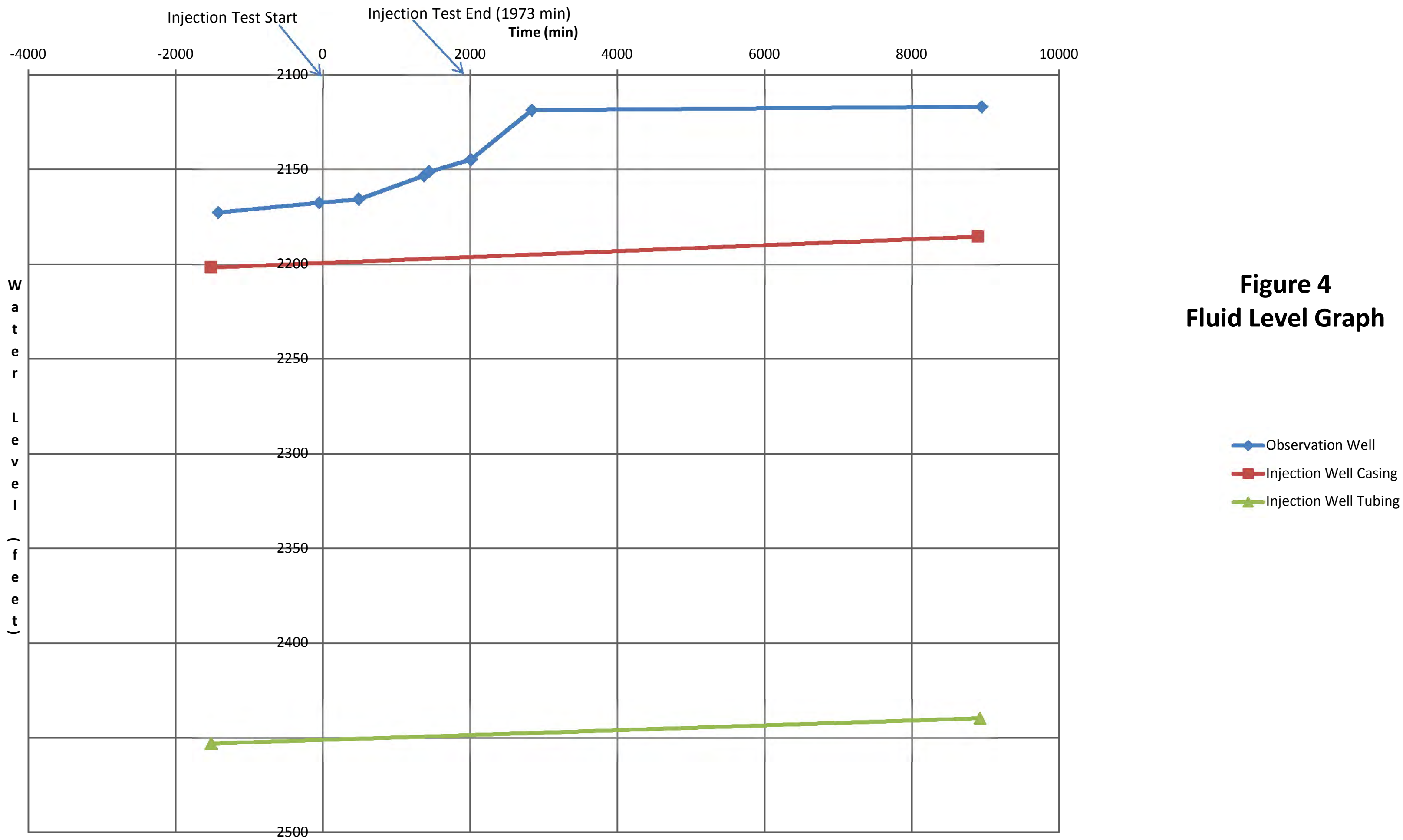


Figure 4
Fluid Level Graph

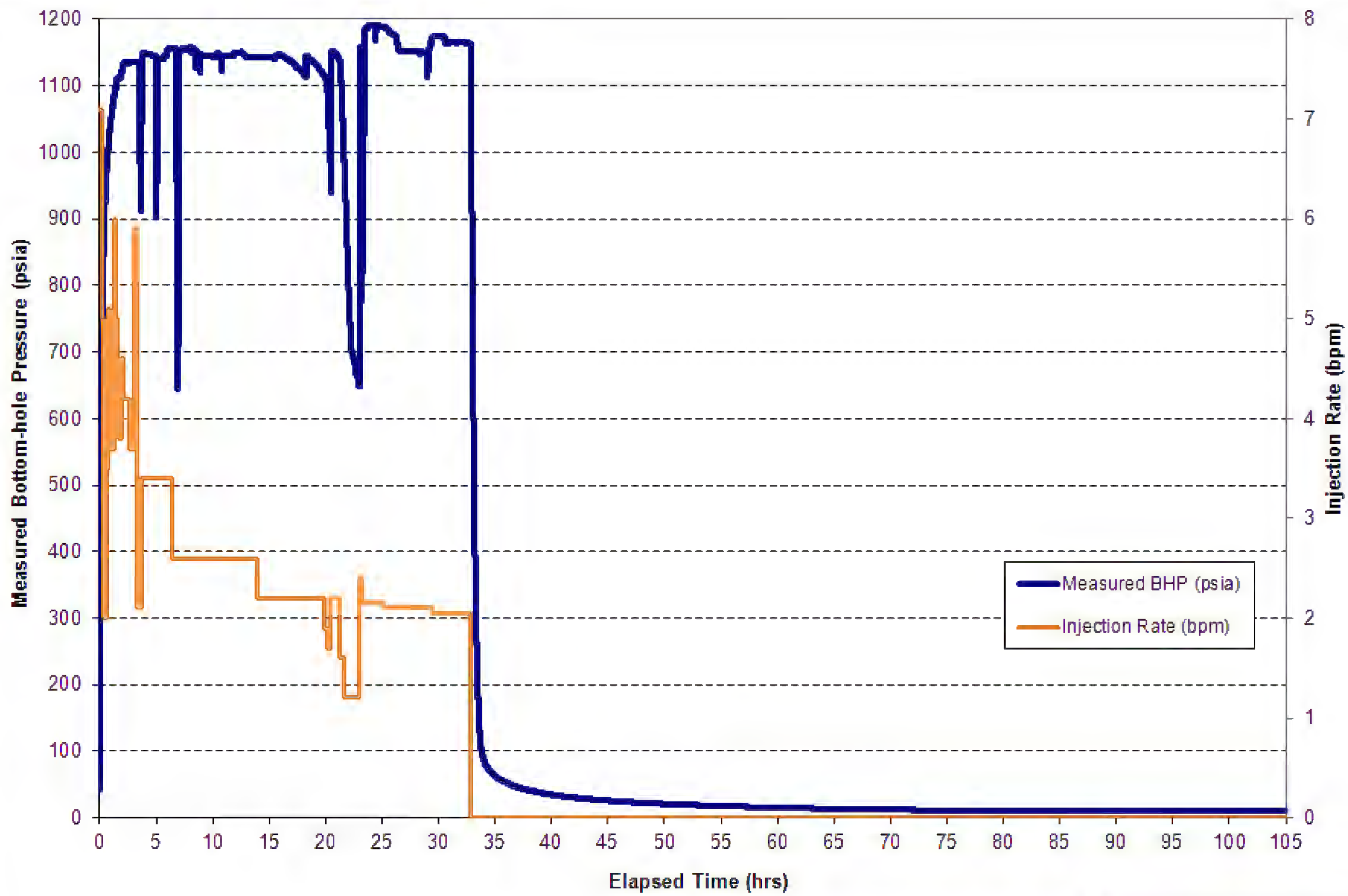


Figure 5. Measured bottom-hole pressure and injection rate versus elapsed time for Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

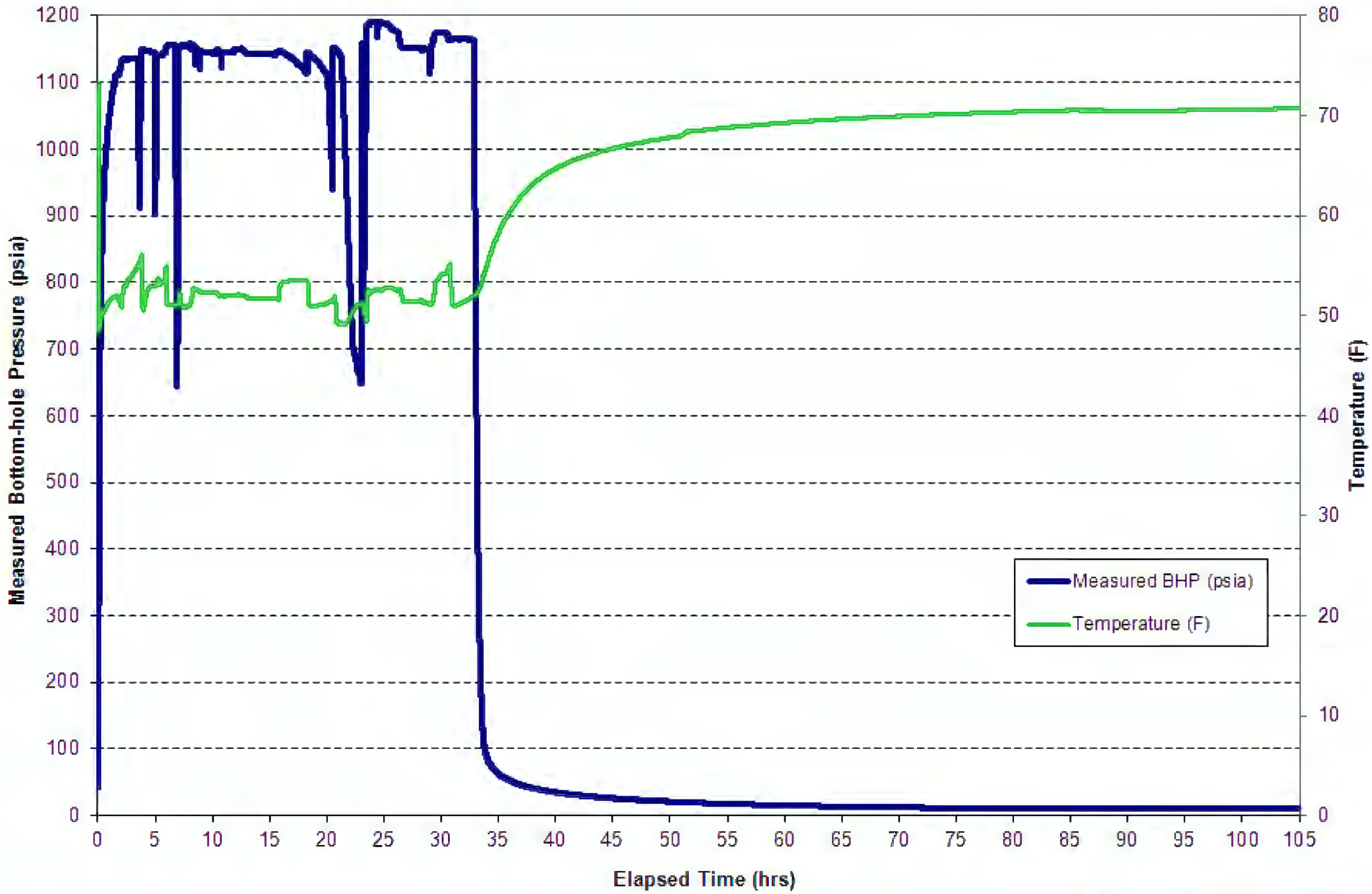


Figure 6. Measured bottom-hole pressure and temperature versus elapsed time for Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

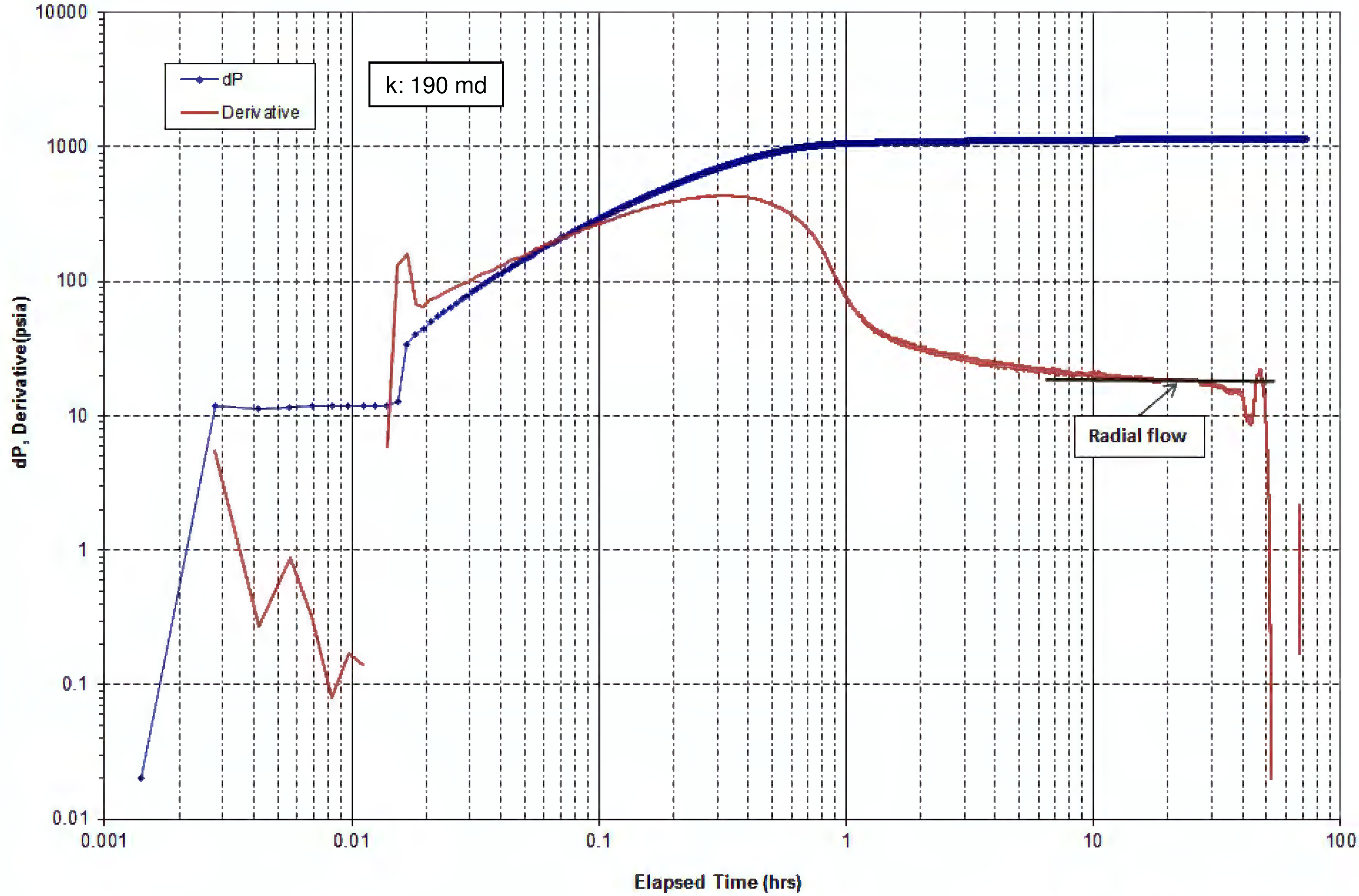


Figure 7. Log-log plot of pressure and derivative curves versus elapsed time for Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

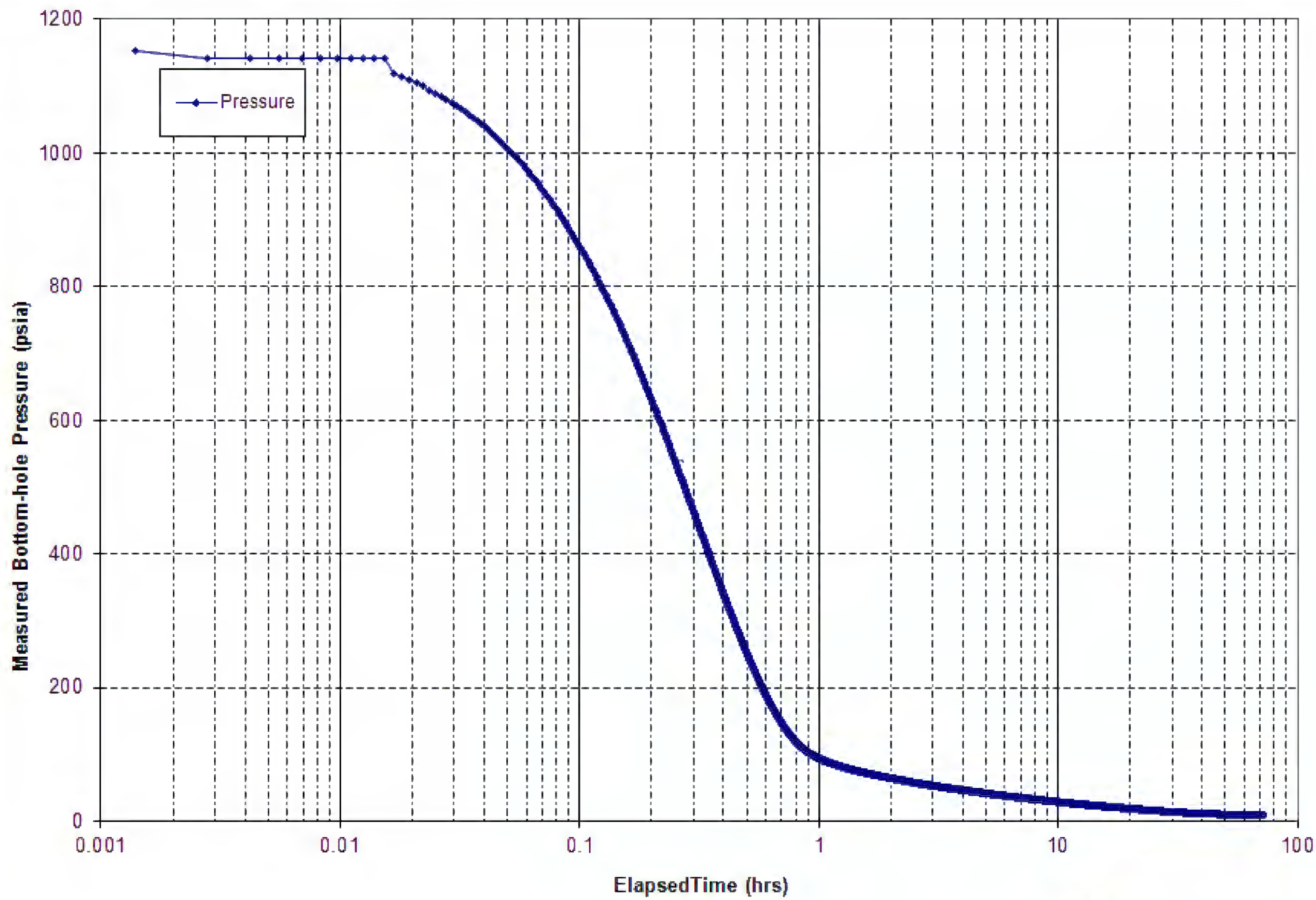


Figure 8. Semi-log plot of measured bottom-hole pressure versus elapsed time for falloff portion of Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

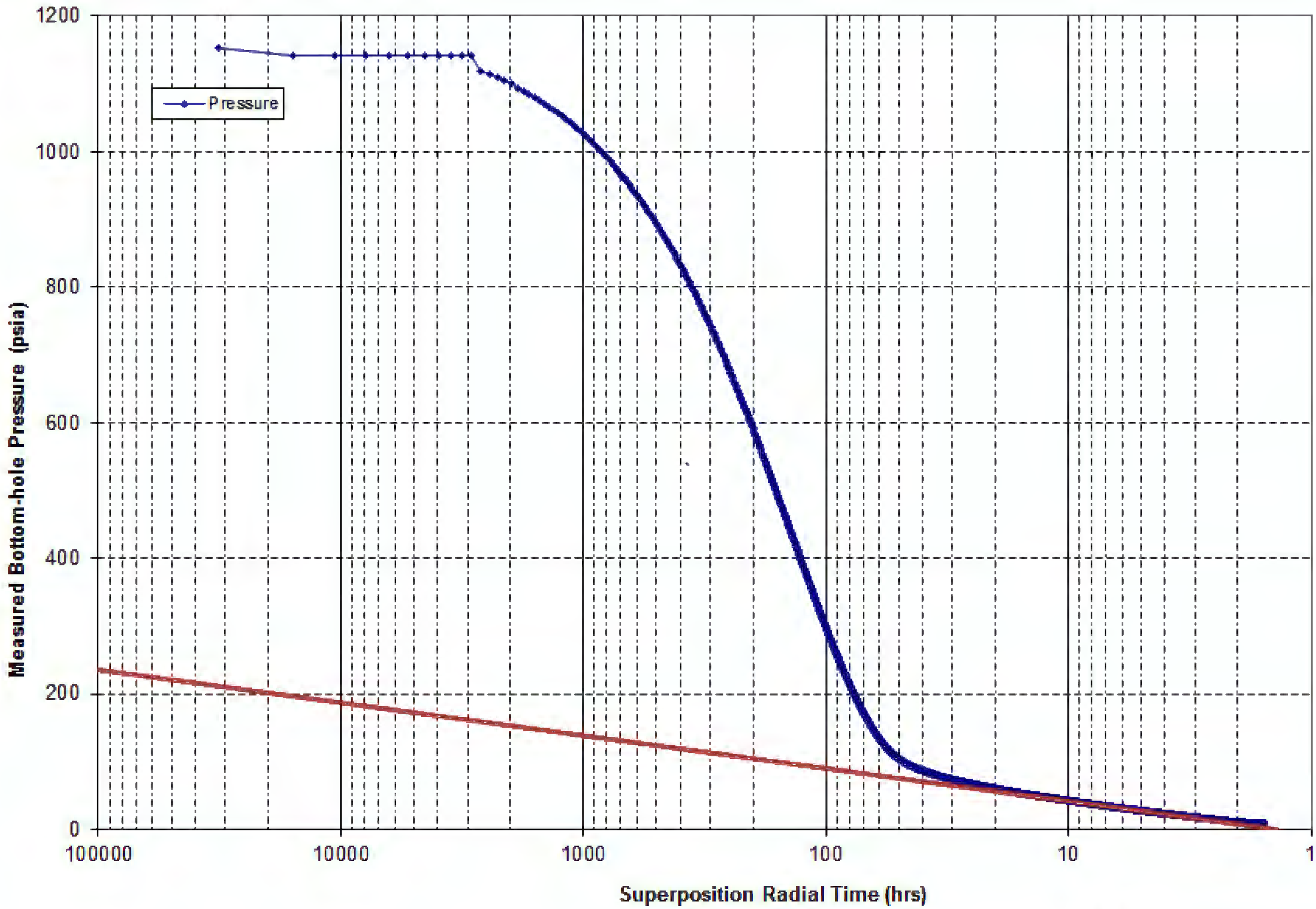


Figure 9. Semi-log plot of measured bottom-hole pressure versus superposition time for falloff portion of Seneca #38268 well injection test – March 2012 test.

TETRA TECH, INC.

APPENDIX A

Well #38268 Wellhead Pressure and Injection Rate Field Measurements

APPENDIX A - WELL # 38268 WELLHEAD PRESSURE AND INJECTION RATE FIELD MEASUREMENTS

Date	Eastern Standard Time	Time	Elapsed Time (min)	BBLs inj.	BBLM	Wellhead Pressure
3/27/2012	10:03 AM	1003	0	0	0	0
3/27/2012	10:13 AM	1013	10	71	7.1	-1.7
3/27/2012	10:27 AM	1027	24	106	5	-4
3/27/2012	10:37 AM	1037	34	127	2	-3.9
3/27/2012	10:47 AM	1047	44	162	3.5	-3.8
3/27/2012	10:57 AM	1057	54	213	5.1	-4
3/27/2012	11:07 AM	1107	64	253	4.3	-3.9
3/27/2012	11:17 AM	1117	74	290	3.7	-4.1
3/27/2012	11:27 AM	1127	84	350	6	-4.1
3/27/2012	11:37 AM	1137	94	400	5	-3.8
3/27/2012	11:47 AM	1147	104	445	4.5	-3
3/27/2012	11:57 AM	1157	114	483	3.8	1
3/27/2012	12:08 PM	1208	125	534	4.6	2
3/27/2012	12:18 PM	1218	135	579	4.5	2.2
3/27/2012	12:28 PM	1228	145	619	4	2.6
3/27/2012	12:38 PM	1238	155	660	4.1	2.3
3/27/2012	12:48 PM	1248	165	695	3.5	2.5
3/27/2012	12:58 PM	1258	175	734	3.9	2.7
3/27/2012	1:08 PM	1308	185	771	3.7	2.5
3/27/2012	1:18 PM	1318	195	830	5.9	2.8
3/27/2012	1:28 PM	1328	205	857	2.7	2.5
3/27/2012	1:48 PM	1348	225	893	1.8	7.4
3/27/2012	1:58 PM	1358	235	928	3.5	7.9
3/27/2012	2:08 PM	1408	245	968	4	7.4
3/27/2012	2:18 PM	1418	255	999	3.1	7
3/27/2012	2:28 PM	1428	265	1029	3	6.9
3/27/2012	2:38 PM	1438	275	1064	3.5	6.8
3/27/2012	2:48 PM	1448	285	1110	4.6	6.6
3/27/2012	2:58 PM	1458	295	1140	3	6.6
3/27/2012	3:12 PM	1512	309	1180	4	1.7
3/27/2012	3:30 PM	1530	327	1230	3.3	2.8
3/27/2012	3:45 PM	1545	342	1279	3.28	5.8
3/27/2012	4:00 PM	1600	357	1328	3.28	13.6
3/27/2012	4:15 PM	1615	372	1375	3.07	15.7
3/27/2012	4:30 PM	1630	387	1410	3	16
3/27/2012	4:45 PM	1645	402	1455	2.98	15.9
3/27/2012	5:05 PM	1705	422	1511	4.32	-1.7
3/27/2012	5:15 PM	1715	432	1544	2.97	13.9
3/27/2012	5:30 PM	1730	447	1589	2.92	13.8
3/27/2012	5:45 PM	1745	462	1632	2.9	13.6
3/27/2012	6:00 PM	1800	477	1677	2.92	17.3
3/27/2012	6:15 PM	1815	492	1716	2.87	17.8
3/27/2012	6:30 PM	1830	507	1762	2.9	17.7
3/27/2012	6:45 PM	1845	522	1803	2.82	17.6
3/27/2012	7:00 PM	1900	537	1844	2.81	17.2
3/27/2012	7:15 PM	1915	552	1886	2.79	17.1
3/27/2012	7:30 PM	1930	567	1927	2.77	16.7
3/27/2012	7:45 PM	1945	582	1970	2.76	16.5
3/27/2012	8:00 PM	2000	597	2008	2.75	16.3
3/27/2012	8:15 PM	2015	612	2045	2.75	18.2
3/27/2012	8:30 PM	2030	627	2086	2.73	18.1
3/27/2012	8:45 PM	2045	642	2145	2.67	18.8

APPENDIX A - WELL # 38268 WELLHEAD PRESSURE AND INJECTION RATE FIELD MEASUREMENTS

Date	Eastern Standard Time	Time	Elapsed Time (min)	BBLs inj.	BBLM	Wellhead Pressure
3/27/2012	9:00 PM	2100	657	2171	2.63	18.2
3/27/2012	9:15 PM	2115	672	2211	2.6	18.2
3/27/2012	9:30 PM	2130	687	2250	2.56	18.2
3/27/2012	9:45 PM	2145	702	2286	2.55	18.1
3/27/2012	10:00 PM	2200	717	2326	2.55	22.3
3/27/2012	10:15 PM	2215	732	2373	2.51	22.1
3/27/2012	10:30 PM	2230	747	2409	2.49	21.9
3/27/2012	10:45 PM	2245	762	2439	2.48	21.6
3/27/2012	11:00 PM	2300	777	2478	2.44	21.5
3/27/2012	11:15 PM	2315	792	2509	2.44	21.2
3/27/2012	11:30 PM	2330	807	2549	2.43	20.9
3/27/2012	11:45 PM	2345	822	2587	2.41	20.8
3/28/2012	12:00 AM	2400	837	2623	2.4	20.5
3/28/2012	12:15 AM	15	852	2656	2.39	20.2
3/28/2012	12:30 AM	30	867	2696	2.37	20
3/28/2012	12:45 AM	45	882	2729	2.37	19.8
3/28/2012	1:00 AM	100	897	2766	2.36	19.6
3/28/2012	1:15 AM	115	912	2800	2.35	19.6
3/28/2012	1:30 AM	130	927	2836	2.34	19.1
3/28/2012	1:45 AM	145	942	2873	2.36	22.5
3/28/2012	2:00 AM	200	957	2906	2.34	22.1
3/28/2012	2:15 AM	215	972	2940	2.31	20.8
3/28/2012	2:30 AM	230	987	2973	2.29	18.1
3/28/2012	2:45 AM	245	1002	3010	2.27	14.5
3/28/2012	3:00 AM	300	1017	3044	2.25	12.5
3/28/2012	3:15 AM	315	1032	3078	2.24	8.3
3/28/2012	3:30 AM	330	1047	3108	2.22	5.5
3/28/2012	3:45 AM	345	1062	3143	2.2	0.1
3/28/2012	4:00 AM	400	1077	3173	2.18	-11.3
3/28/2012	4:15 AM	415	1092	3200	2.15	-18
3/28/2012	4:22 AM	422	1099	3221	2.21	7.9
3/28/2012	4:30 AM	430	1107	3235	2.26	19.1
3/28/2012	4:45 AM	445	1122	3270	2.24	16.6
3/28/2012	5:00 AM	500	1137	3300	2.22	13.3
3/28/2012	5:15 AM	515	1152	3333	2.22	9.4
3/28/2012	5:30 AM	530	1167	3367	2.2	4.5
3/28/2012	5:45 AM	545	1182	3398	2.18	-0.4
3/28/2012	6:00 AM	600	1197	3431	2.16	-7.7

APPENDIX A - WELL # 38268 WELLHEAD PRESSURE AND INJECTION RATE FIELD MEASUREMENTS

Date	Eastern Standard Time	Time	Elapsed Time (min)	BBLs inj.	BBLM	Wellhead Pressure
3/28/2012	6:15 AM	615	1212	3463	1.9	-12
3/28/2012	6:30 AM	630	1227	3490	1.7	-12.2
3/28/2012	6:45 AM	645	1242	3530	2.36	4.2
3/28/2012	7:00 AM	700	1257	3560	2.2	-3.4
3/28/2012	7:15 AM	715	1272	3594	2.16	-10.4
3/28/2012	7:30 AM	730	1287	3626	1.77	-12.2
3/28/2012	7:45 AM	745	1302	3650	1.53	-12.5
3/28/2012	8:00 AM	800	1317	3671	1.27	-12.4
3/28/2012	8:15 AM	815	1332	3689	1.14	-12.5
3/28/2012	8:30 AM	830	1347	3707	1.24	-12.4
3/28/2012	8:45 AM	845	1362	3725	1.17	-12.5
3/28/2012	9:00 AM	900	1377	3743	1.12	-12.5
3/28/2012	9:15 AM	915	1392	3775	2.4	-13.3
3/28/2012	9:45 AM	945	1422	3844	2.23	26.5
3/28/2012	10:00 AM	1000	1437	3873	2.19	26.6
3/28/2012	10:15 AM	1015	1452	3905	2.17	27.2
3/28/2012	10:30 AM	1030	1467	3937	2.16	28
3/28/2012	10:45 AM	1045	1482	3972	2.14	27.8
3/28/2012	11:00 AM	1100	1497	4002	2.13	27.9
3/28/2012	11:15 AM	1115	1512	4033	2.10	27.4
3/28/2012	11:30 AM	1130	1527	4064	2.10	30
3/28/2012	11:45 AM	1145	1542	4096	2.10	29.5
3/28/2012	12:00 PM	1200	1557	4128	2.10	30.1
3/28/2012	12:15 PM	1215	1572	4159	2.10	30.6
3/28/2012	12:30 PM	1230	1587	4190	2.05	31.2
3/28/2012	12:45 PM	1245	1602	4223	2.13	30.2
3/28/2012	1:00 PM	1300	1617	4254	2.13	30
3/28/2012	1:15 PM	1315	1632	4286	2.12	29.8
3/28/2012	1:30 PM	1330	1647	4318	2.11	29.3
3/28/2012	2:45 PM	1445	1662	4349	2.11	30.1
3/28/2012	2:00 PM	1400	1677	4381	2.1	30
3/28/2012	2:15 PM	1415	1692	4412	2.1	29.5
3/28/2012	2:30 PM	1430	1707	4443	2.09	29.3
3/28/2012	2:45 PM	1445	1722	4474	2.09	29.2
3/28/2012	3:00 PM	1500	1737	4506	2.08	28.8
3/28/2012	3:15 PM	1515	1752	4538	2.1	26.1
3/28/2012	3:30 PM	1530	1767	4579	2.08	28.8
3/28/2012	3:45 PM	1545	1782	4611	2.07	29.9
3/28/2012	4:00 PM	1600	1797	4641	2.06	29.7
3/28/2012	4:15 PM	1615	1812	4671	2.05	29.4
3/28/2012	4:30 PM	1630	1827	4702	2.05	29.1
3/28/2012	4:45 PM	1645	1842	4734	2.02	31.3
3/28/2012	5:00 PM	1700	1857	4764	2.05	30.1
3/28/2012	5:15 PM	1715	1872	4795	2.05	30.4
3/28/2012	5:30 PM	1730	1887	4825	2.05	30.2
3/28/2012	5:45 PM	1745	1902	4855	2.05	30.7
3/28/2012	6:00 PM	1800	1917	4887	2.04	30.4
3/28/2012	6:15 PM	1815	1932	4917	2.04	30.1
3/28/2012	6:30 PM	1830	1947	4947	2.04	30
3/28/2012	6:45 PM	1845	1962	4978	2.03	29.7
3/28/2012	6:56 PM	1856	1973	5000	2.03	29.7

APPENDIX B

Fluid Levels from Echo Meter Readings

APPENDIX B - FLUID LEVELS FROM ECHOMETER READINGS

Well # / Shot #	Date/Time	Main Time To Liquid Level (sec)	Main Depth to Liquid Level (ft)	Analysis Method	Depth To Downhole Marker	Well State	Gas Gravity (Sp.Gr.AIR)
MyWells\Seneca 38268/001 Casing	3/26/2012 8:50	3.522	2201.55	Depth Marker	553.2	Static	0.78
MyWells\Seneca 38268/001 Tubing	3/26/2012 8:51	4.245	2452.81	Acoustic Velocity	X	Static	0.84
MyWells\Seneca 38281/001	3/26/2012 10:29	4.042	2172.57	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/002	3/27/2012 9:17	4.036	2167.41	Depth Marker	602	Static	0.56
MyWells\Seneca 38281/003	3/27/2012 18:14	4.029	2165.59	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/004	3/28/2012 9:00	4.006	2153.22	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/005	3/28/2012 10:07	4.002	2151.07	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/006	3/28/2012 19:38	3.99	2144.63	Depth Marker	602	Static	0.90
MyWells\Seneca 38281/007	3/29/2012 9:23	3.931	2118.59	Depth Marker	602	Static	0.89
MyWells\Seneca 38268/002 Casing	4/2/2012 14:17	3.424	2185.24	Depth Marker	553.2	Static	0.77
MyWells\Seneca 38268/012 Tubing	4/2/2012 14:45	4.051	2439.65	Acoustic Velocity	X	Static	0.78
MyWells\Seneca 38281/008	4/2/2012 15:13	3.875	2116.83	Depth Marker	602	Static	0.88

Injection Well # 38268 - Casing

Elapsed time (min)	Depth to Liquid Level (ft)
-1513	2201.55
8894	2185.24
Water level change	16.31

Injection Well # 38268 - Tubing

Elapsed time (min)	Depth to Liquid Level (ft)
-1512	2452.81
8922	2439.65
Water level change	13.16

Observation Well # 38281

Elapsed time (min)	Depth to Liquid Level (ft)
-1414	2172.57
-46	2167.41
491	2165.59
1377	2153.22
1444	2151.07
2015	2144.63
2840	2118.59
8950	2116.83
Water level change	55.74

APPENDIX D

Well Construction Diagram & Well Completion Report

Well #38268 Construction Detail

Figure 2

Well Construction Diagram

Injection Test Well

Seneca Well #38268
Highland Township
Elk County, PA
37-047-23835

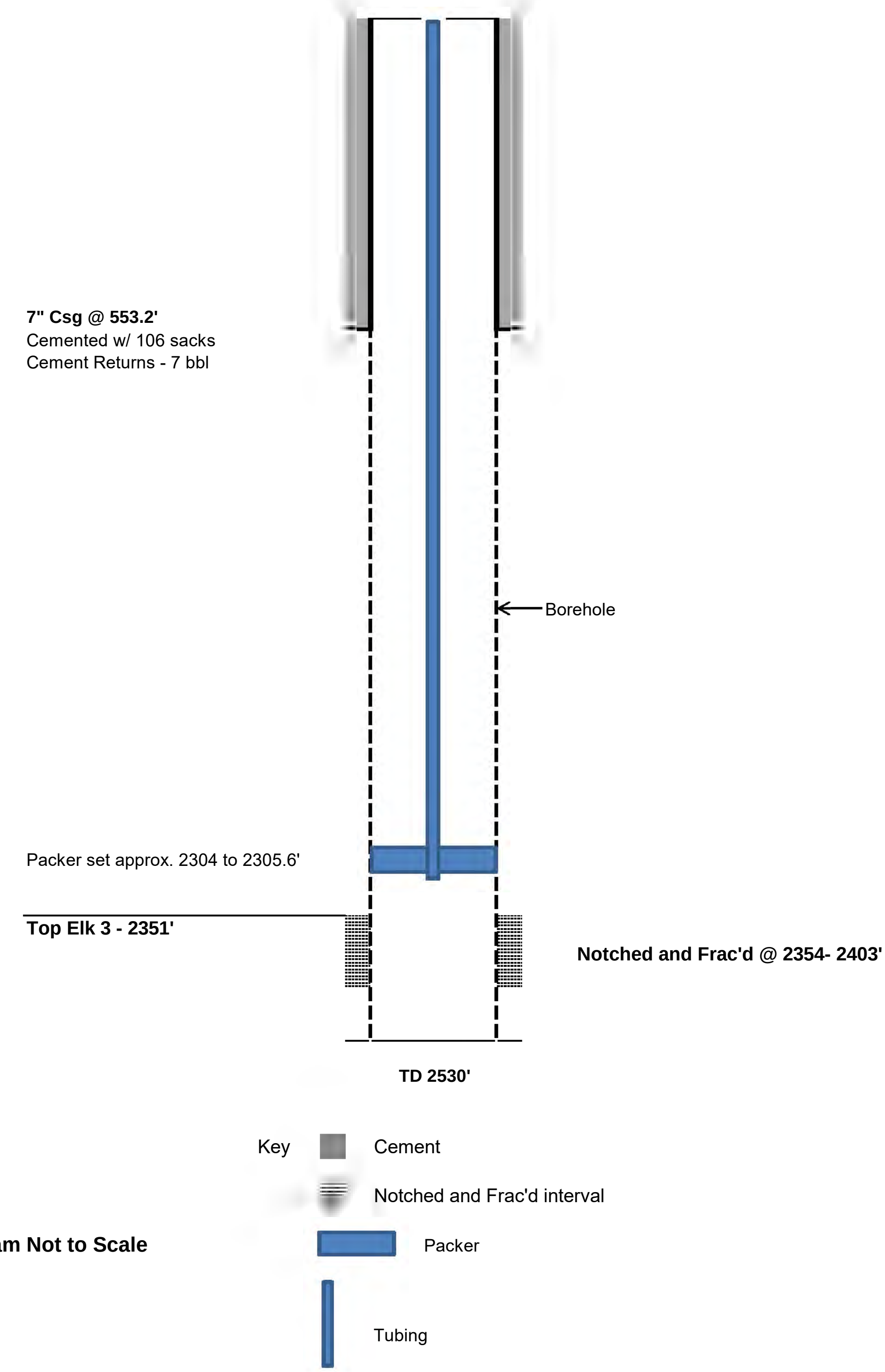


Diagram Not to Scale

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT 7 & C

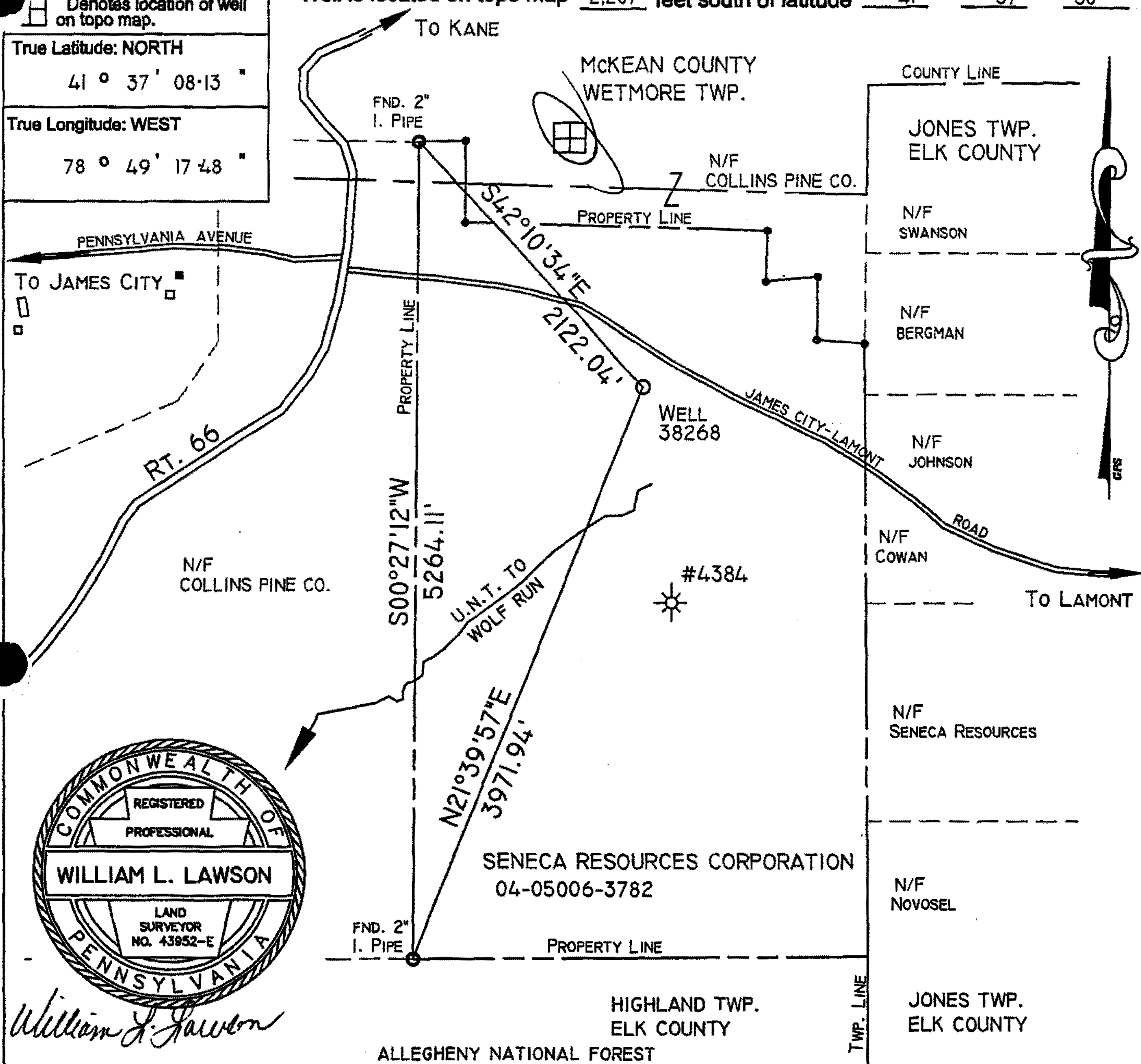
DEP USE ONLY	
DEP Application Tracking #	G:35 2/20/07
Permit #	047-23835
Project #	C:

Well is located on topo map 2,207 feet south of latitude 41 ° 37 ' 30 "

Denotes location of well on topo map.

True Latitude: NORTH
41 ° 37 ' 08.13 "

True Longitude: WEST
78 ° 49 ' 17.48 "



Well is located on topo map 8,163 feet west of longitude 78 ° 47 ' 30 "

COMMONWEALTH OF PENNSYLVANIA REGISTERED PROFESSIONAL WILLIAM L. LAWSON LAND SURVEYOR NO. 43952-E

William L. Lawson

Surveyor or Engineer: WILLIAM L. LAWSON	Phone # (814) 752-2291 Dwg. # P:/WELLFILES/38268.DWG	Date 02/09/07	Scale 1" = 1000'	Tract Acreage 299.6

Lat. & Long Metadata Method: GPSDF Accuracy +/- 3 ft. Datum: NAD - 27	Elevation Metadata Method: TOPO Accuracy +/- 10 ft. Datum: NGVD-29		Survey Date 01/30/07
Applicant / Well Operator Name: SENECA RESOURCES CORPORATION	Well (Farm) Name: FEE- SRC WT. 3771	Well # 38268	Serial #
Address: 286 OLD 36 ROAD SIGEL, PA 15860	County - Code: ELK - 24	Municipality: HIGHLAND TOWNSHIP	
Surface Landowner: SENECA RESOURCES CORPORATION	USGS 7 1/2 Quadrangle Map Name: JAMES CITY, PA 0615		Map Section "2"
Surface Lessor: NONE	Angle & Course of Deviation (Drilling): VERTICAL	Surface Elevation 2040 ft.	Anticipated Total Depth 2530 ft.
Surface Owner or Water Purveyor with a Water Supply within 1,000 feet: NONE	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated

HQ

Martin Run

WATERSHED

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil & Gas Management Program

LYNN AUG 15

WELL RECORD AND COMPLETION REPORT

DEP USE ONLY	
Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

Well Operator SENECA RESOURCES CORPORATION		DEP ID# 72993	Well API # (Permit / Reg) 37-047-23835-00	Project Number		Acres
Address 286 OLD 36 ROAD			Well Farm Name FEE SENECA RESOURCES WARRANT 3771		Well # 38268	Serial #
City SIGEL	State PA	Zip Code 15860	County Elk	Municipality Highland		
Phone 814-725-2291	Fax 814-752-6204		USGS 7 5 min quadrangle map James City 2			

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type ☒ Gas ☐ Oil ☐ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
3/20/07	3/22/07	2040'	2530'	2532'

Casing and Tubing

Cement returned on surface casing? ☒ Yes ~~No~~ See Drillers Log
Cement returned on coal protective casing? ☐ Yes No X N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	Material Behind Pipe Type and Amount	Packer / Hardware / Centralizers Type	Size	Depth	Date Run
11 ¼	9 5/8	26	T	63					
8 ¾	7	17	T	553	106 sks. Common Class A, 3% CaCl, ½#unicele			523, 349, 175	3/21/07
6 1/4	2 3/8		T	2498					7/03/07
	5/8		T	2475					7/03/07

COMPLETION REPORT

Perforation Record Date	Interval Perforated From	To	Stimulation Record Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			7/03/07	1667 0	Gel Water	8770 gal	20/40 sand	120 sks	19 8
				1671 5	Gel Water	11,040 gal	20/40 sand	160 sks	20
				1676 0	Gel Water	10,910 gal	20/40 sand	160 sks	20
				1721 0	Gel Water	8910 gal	20/40 sand	120 sks	20
				1739 5	Gel Water	9250 gal	20/40 sand	120 sks	20 3

Natural Open Flow mcfd	Natural Rock Pressure	Hours	Days
After Treatment Open Flow Mcfd 350	After Treatment Rock Pressure 125	Hours	Days 2

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name Dallas-Morris Drilling Co	Name Universal Well Services	Name Schlumberger
Address Morris Lane	Address P O Box 180	Address 95 Rutherford Run
City - State – Zip Bradford PA 16701	City - State – Zip Bradford, PA 16701	City - State – Zip Bradford, PA 16701
Phone (814) 362-6493	Phone (814) 368-6175	Phone (814) 362-7441

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NORTHWEST REGIONAL OFFICE

LOG OF FORMATIONS

Well API#: 37-053-23835-00

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

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WARREN DISTRICT OFFICE

Well Operator's Signature: Guy A. Shuey

Title: Superintendent / Prod. & Eng. Date: 7/26/07

DEP USE ONLY

Reviewed by: T Curry Date: 6-4-08

Comments.

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DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	
Bits Used:	12 ¼", 8 ¾", 6 ¼"				
Fuel Use:	Spud: 8057	T. D.: 8916	Rig Hours:	5051 - 5093	

TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock
5	15	Sand
15	40	Sand
40	55	Sand
55	70	Shale
70	95	Sand
95	120	Sand & Shale
120	225	Sand
225	415	Sand & Shale
415	558	Sand
558	635	Red Rock
635	650	Shale
650	820	Red Rock
820	865	Shale
865	915	Red Rock
915	1270	Sand & Shale
1270	1345	Sand
1345	1360	Red Rock
1360	1385	Sand & Shale
1385	1555	Base Warren 1.0
1555	1565	Red Rock
1565	1575	Sand
1575	1598	T-12 Marker
1598	1675	Speechley 2.0
1675	1725	Gas
1725	1750	Speechley 6.0 (gas)
1750	1765	Gas
1765	1875	Tiona 1.0
1875	1890	Red Rock (gas)
1890	1910	Sand
1910	1925	Gas
1925	1980	Cooper 4.0 & Sand
1980	2135	Cooper 6.0
2135	2275	Gas
2275	2295	Elk 1.0 (gas)
2295	2355	Sand (gas)
2355	2390	Gas
2390	2420	Elk 4.0
2420	2510	Sand (gas)
2510	2530	Sand
2530		Total Depth

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ENVIRONMENTAL PROTECTION
WARREN DISTRICT OFFICE

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AUG 0 6 2007
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	

Bits Used:	12 ¼", 8 ¾", 6 ¼"			
Fuel Use:	Spud: 8057	T. D.: 8916	Rig Hours:	5051 - 5093

TOP	BOTTOM	FORMATIONS	TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock	1910	1925	Gas
5	15	Sand	1925	1980	Cooper 4.0 & Sand
15	40	Sand	1980	2135	Cooper 6.0
40	55	Sand	2135	2275	Gas
55	70	Shale	2275	2295	Elk 1.0 (gas)
70	95	Sand	2295	2355	Sand (gas)
95	120	Sand & Shale	2355	2390	Gas
120	225	Sand	2390	2420	Elk 4.0
225	415	Sand & Shale	2420	2510	Sand (gas)
415	558	Sand	2510	2530	Sand
558	635	Red Rock	2530		Total Depth
635	650	Shale			
650	820	Red Rock			
820	865	Shale			
865	915	Red Rock			
915	1270	Sand & Shale			
1270	1345	Sand			
1345	1360	Red Rock			
1360	1385	Sand & Shale			
1385	1555	Base Warren 1.0			
1555	1565	Red Rock			
1565	1575	Sand			
1575	1598	T-12 Marker			
1598	1675	Speechley 2.0			
1675	1725	Gas			
1725	1750	Speechley 6.0 (gas)			
1750	1765	Gas			
1765	1875	Tiona 1.0			
1875	1890	Red Rock (gas)			
1890	1910	Sand			

For assistance in accessing this document, contact R3_UIC_Mailbox@epa.gov

INVOICE NO. 536463

PAGE NO.

UNIVERSAL WELL SERVICES INC

JOB LOG

CUSTOMER Seneca Res

LEASE NAME 38268

DATE 3-21-07

	NO. OF SACKS	COMPOSITION OF CEMENT	YIELD	GAL. WTR/SK	DENSITY	BBL. OF MIX WTR.	CU. FT. OF SLURRY	BBL. OF SLURRY
1.	106	class A, 3% cacl2, 1/2# sk unicele	1.18	5.2	15.6	13.1	125	22.2
2.								
3.								
					TOTAL	13.1	125	22.2

CIRCULATE CEMENT TO SURFACE

☒ Yes ☐ No ☐ Not Applicable

7 bbls return

JOB TYPE

☒ Surface ☐ Longstring ☐ Acid

☐ Other 7" Surface

	NEW USED	SIZE	FROM	TO	WEIGHT	MAXIMUM PSI ALLOWANCE
CASING	N	7"	0	553.2	17#	
TUBING						
OPEN HOLE		8 3/4	553.2	568		
~~PERFORATIONS~~ LJ			4'			

DISPLACEMENT CAPACITY 23.1 BBL.

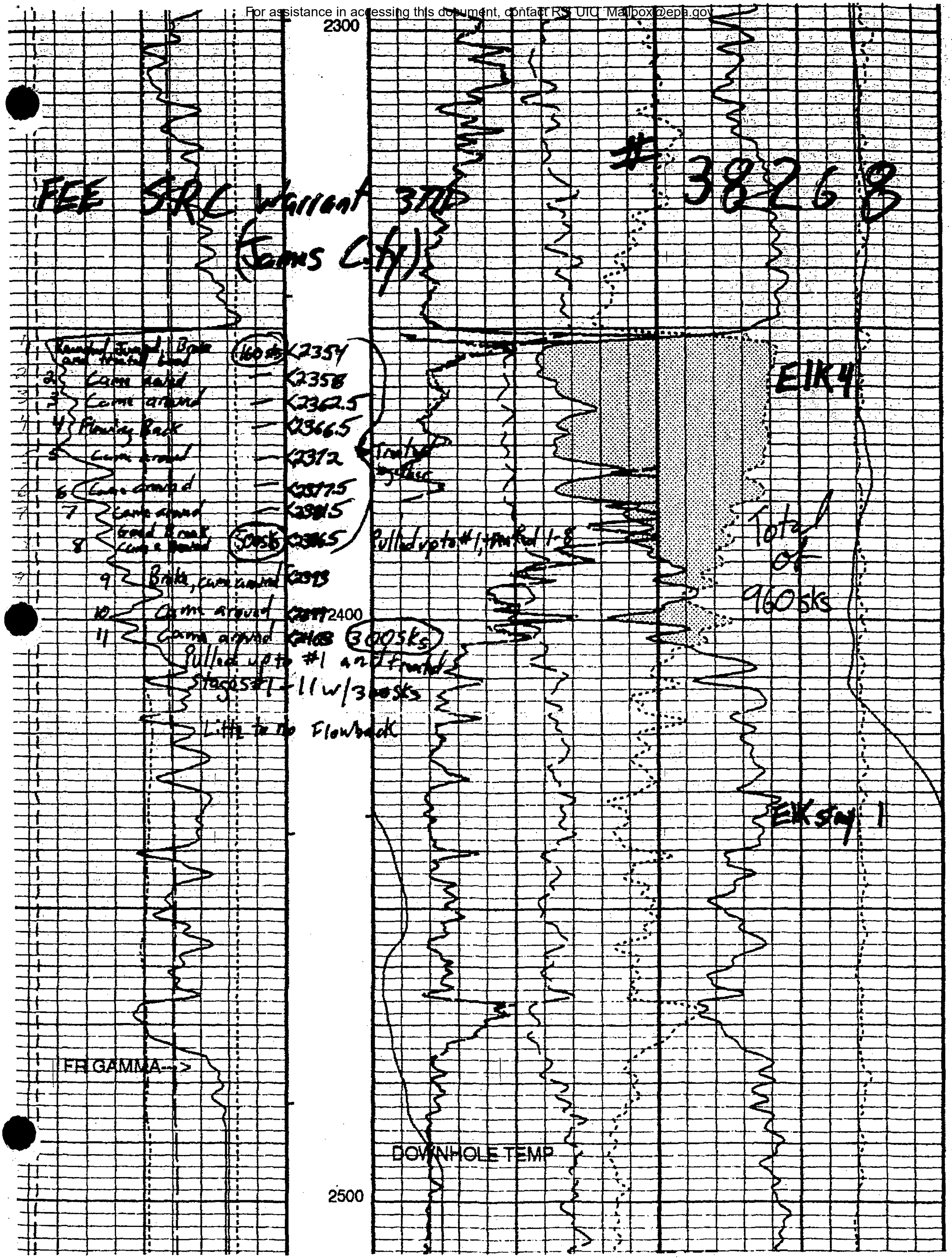
DISPLACEMENT DEPTH 557.2 FT.

TIME	RATE (BPM)	VOLUME (BBL)	PRESSURE (PSI) TUBING	PRESSURE (PSI) CASING	DESCRIPTION OF STAGE OR EVENT
1830					SPOT Truck, rig up
[illegible]55					Safety meeting
1900	2-3	10		0-50	Start H_2O
1903	3	10		50-100	Start Gel unicele
1906	3	5		100	Start spacer
1909	3-4	22.2		100-200	Start class A, 3% cacl2, 1/2# sk unicele
1916					SDTP
1918	4-2	23.1		0-550	Start H_2O displacement
1925					Plug Landed, closed manifold
1928				550-0	release pressure, wash up
1945					rig down
					Job complete

REMARKS Ph 7 H_2O 38 W&D sample

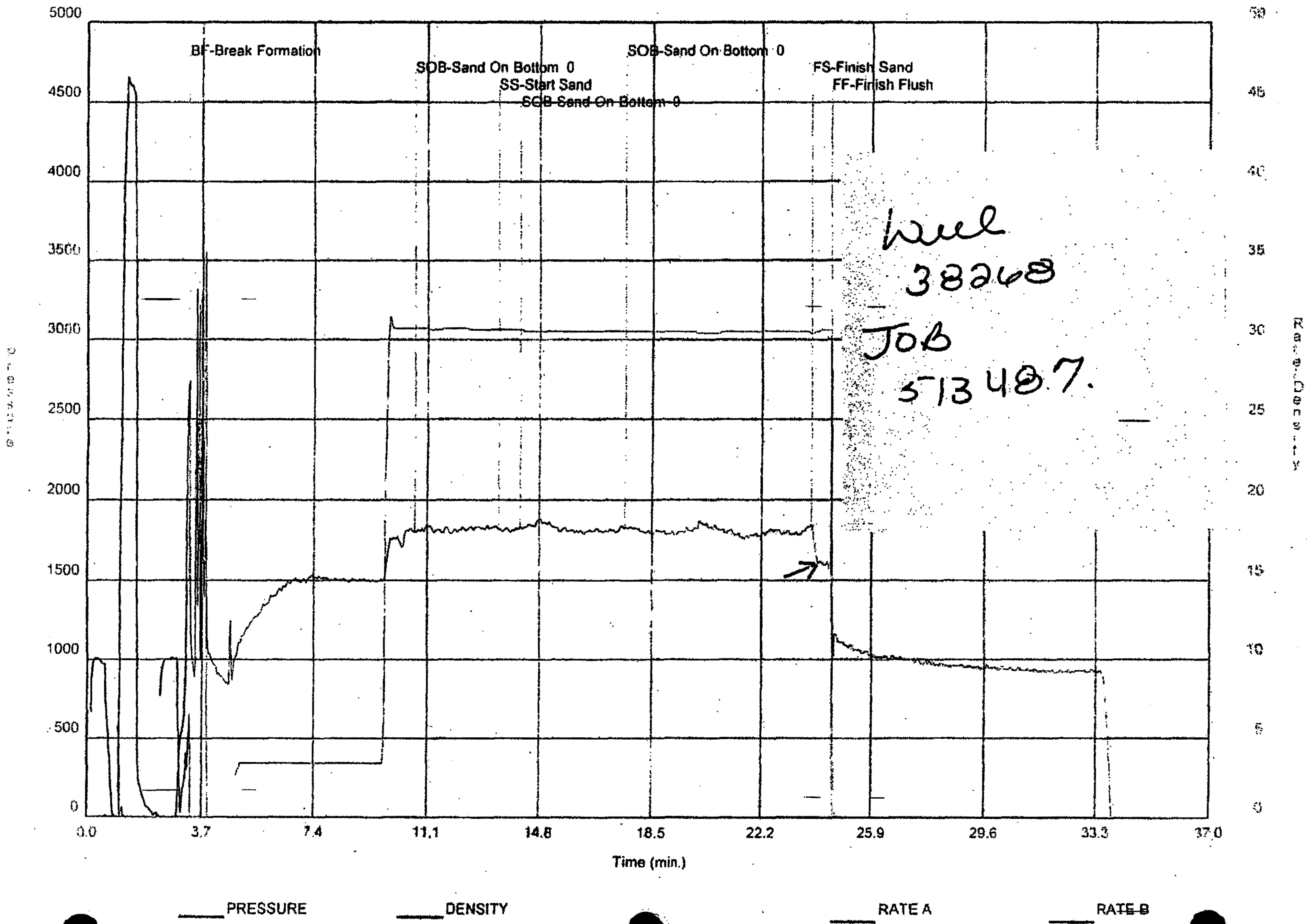
SERVICE ENGINEER Everly

CUSTOMER REPRESENTATIVE [signature]


2300
FEE SRC Warrant 37D
(Jams City)
38268
1 Rounded/Jumped, Broke and treated ... 160 sks <2354
2 Came around — <2358
3 Came around — <2362.5
4 Flowing Back — <2366.5
5 Came around — <2372
6 Came around — <2377.5
7 Came around — <2381.5
8 Good Break, Came around 500 sks <2385
Treated by zone
Pulled up to #1, treated 1-8
9 Broke, came around <2393
10 Came around <2397
2400
11 Came around <2403 300 sks
Pulled up to #1 and treated stages #1-11 w/300 sks
Little to no Flowback
Elk 4
Total of 960 sks
Elk stray 1
FR GAMMA-->
DOWNHOLE TEMP
2500

#1 100 sks 4/5/07
Elk 4

Frac Data



APPENDIX E

Tetra Tech June 2012 Permit Application

Tetra Tech UIC Well Permit Application

ARM Group LL

TETRA TECH

PITT-06-12-079

June 25, 2012

S. Stephen Platt
U.S. EPA Region III
Ground Water & Enforcement Branch (3WP22)
1650 Arch Street
Philadelphia, PA 19103

Subject: Underground Injection Control (UIC) Class IID Brine Disposal Well
Seneca Resources Corporation Well #38268 (API# 37-047-23835)
Higbland Townsbip, Elk County, Pennsylvania

Dear Mr. Platt:

On behalf of Seneca Resources Corporation (Seneca), enclosed please find two copies of the subject UIC Class IID Well permit application prepared by Tetra Tech, Inc. (Tetra Tech).

Your prompt review of the application would be greatly appreciated. Should you have any questions or comments, please feel free to contact Guy Shirey of Seneca at (412) 548-2514 or me at (412) 921-4006. Thank you very much for your assistance.

Sincerely,

Dale E. Skoff, P.G.
Oil and Gas Hydrogeologic Services Manager

cc: Dave Rectenwald – EPA (1 copy)
Guy Shirey – Sencea (2 copies)

TETRA TECH

BRINE DISPOSAL WELL PERMIT APPLICATION
SENECA WELL # 38268
(API# 37-047-23835)

Seneca Resources Corporation
5800 Corporate Boulevard
Pittsburgh, PA 15237

June 2012

complex world CLEAR SOLUTIONS™

OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

United States Environmental Protection Agency

Underground Injection Control Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number

	T/A	C
U		

Read Attached Instructions Before Starting

For Official Use Only

Application approved (mo day year)	Date received (mo day year)	Permit Number	Well ID	FINDS Number

II. Owner Name and Address

Owner Name		
Seneca Resources Corporation		
Street Address: 5800 Corporate Blvd. Suite 300	Phone Number: (412) 548-2500	
City: Pittsburgh	State: PA	ZIP CODE: 15237

III. Operator Name and Address

Owner Name		
Seneca Resources Corporation		
Street Address: 5800 Corporate Blvd. Suite 300	Phone Number: (412) 548-2500	
City: Pittsburgh	State: PA	ZIP CODE: 15237

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
☐ Yes ☒ No	☒ Private ☐ Federal ☐ Other	☐ Owner ☒ Operator	1389 - Oil and Gas Field services, Not elsewhere classified

VIII. Well Status (Mark "x")

☐ A. Operating	Date Started (mo day year)	☒ B. Modification/Conversion	☐ C. Proposed

IX. Type of Permit Requested (Mark "x" and specify if required)

	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
☒ A. Individual ☐ B. Area	1		Seneca Well #38268 API # 37-047-23835

X. Class and Type of Well (see reverse)

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
II	D		

XI. Location of Well(s) or Approximate Center of Field or Project

Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Township and Range Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
041	037	08.1	078	049	17.5								

XII. Indian Lands (Mark 'x')

☐ Yes
☒ No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title (Type or Print)	B. Phone No. (Area Code and No.)
Doug Kepler, Vice President, Environmental Engineering	(814) 771-0281
C. Signature: DAKep	D. Date Signed: 6/25/12

EPA Form 7520-6 (Rev. 12-11)

Well Class and Type Codes

Class I		Wells used to inject waste below the deepest underground source of drinking water.
Type	**"I"**	Nonhazardous industrial disposal well
	"M"	Nonhazardous municipal disposal well
	"W"	Hazardous waste disposal well injecting below USDWs
	"X"	Other Class I wells (not included in Type "I," "M," or "W")
Class II		Oil and gas production and storage related injection wells.
Type	**"D"**	Produced fluid disposal well
	"R"	Enhanced recovery well
	"H"	Hydrocarbon storage well (excluding natural gas)
	"X"	Other Class II wells (not included in Type "D," "R," or "H")
Class III		Special process injection wells.
Type	**"G"**	Solution mining well
	"S"	Sulfur mining well by Frasch process
	"U"	Uranium mining well (excluding solution mining of conventional mines)
	"X"	Other Class III wells (not included in Type "G," "S," or "U")
Other Classes		Wells not included in classes above. Class V wells which may be permitted under §144.12. Wells not currently classified as Class I, II, III, or V.

Attachments to Permit Application

Class	**Attachments**
I new well	A, B, C, D, F, H – S, U
existing	A, B, C, D, F, H – U
II new well	A, B, C, E, G, H, M, Q, R; optional – I, J, K, O, P, U
existing	A, E, G, H, M, Q, R, – U; optional – J, K, O, P, Q
III new well	A, B, C, D, F, H, I, J, K, M – S, U
existing	A, B, C, D, F, H, J, K, M – U
Other Classes	To be specified by the permitting authority

INSTRUCTIONS - Underground Injection Control (UIC) Permit Application

Paperwork Reduction Act: The public reporting and record keeping burden for this collection of information is estimated to average 224 hours for a Class I hazardous well application, 110 hours for a Class I non-hazardous well application, 67 hours for a Class II well application, and 132 hours for a Class III well application. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, DC 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

This form must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for permit by the Director.

I. **EPA I.D. NUMBER** - Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. **OWNER NAME AND ADDRESS** - Name of well, well field or company and address.

III. **OPERATOR NAME AND ADDRESS** - Name and address of operator of well or well field.

IV. **COMMERCIAL FACILITY** - Mark the appropriate box to indicate the type of facility.

V. **OWNERSHIP** - Mark the appropriate box to indicate the type of ownership.

VI. **LEGAL CONTACT** - Mark the appropriate box.

VII. **SIC CODES** - List at least one and no more than four Standard Industrial Classification (SIC) Codes that best describe the nature of the business in order of priority.

VIII. **WELL STATUS** - Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if wells(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

IX. **TYPE OF PERMIT** - Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field," submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

X. **CLASS AND TYPE OF WELL** - Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of the application. When selecting type X please explain in the space provided.

XI. **LOCATION OF WELL** - Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR Part 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

XII. **INDIAN LANDS** - Place an "X" in the box if any part of the facility is located on Indian lands.

XIII. **ATTACHMENTS** - Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, III are described on pages 4 and 5 of this document and listed by Class on page 2. Place EPA ID number in the upper right hand corner of each page of the Attachments.

XIV. **CERTIFICATION** - All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

Attachments to be submitted with permit application for Class I, II, III and other wells.

A. **AREA OF REVIEW METHODS** - Give the methods and, if appropriate, the calculationsused to determine the size of the area of review (fixed radius or equation).The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.

B. **MAPS OF WELL/AREA AND AREA OF REVIEW** - Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I

The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map;

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. This requirement does not apply to existing Class II wells;

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. **CORRECTIVE ACTION PLAN AND WELL DATA** - Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

Class I

A description of each well's types, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include thecorrective action proposed to be taken by the applicant under 40 CFR 144.55.

Class II

In addition to requirement for Class I, in the case of Class II wellsoperating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. **MAPS AND CROSS SECTION OF USDWs** - Submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. **NAME AND DEPTH OF USDWs (CLASS II)** - For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. **MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA** - Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

G. **GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (Class II)** - For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. **OPERATING DATA** - Submit the following proposed operating data for each well (including all those to be covered by area permits): (1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure; (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. **FORMATION TESTING PROGRAM** - Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the testing must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the program formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. **STIMULATION PROGRAM** - Outline any proposed stimulation program.

K. **INJECTION PROCEDURES** - Describe the proposed injection procedures including pump, surge, tank, etc.

L. **CONSTRUCTION PROCEDURES** - Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to packer for Class I.)

M. **CONSTRUCTION DETAILS** - Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. **CHANGES IN INJECTED FLUID** - Discuss expected changes in pressure, native fluid displacement, and direction of movement of injection fluid. (Class III wells only.)

O. **PLANS FOR WELL FAILURES** - Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or wells failures, so as to prevent migration of fluids into any USDW.

P. **MONITORING PROGRAM** - Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Q. **PLUGGING AND ABANDONMENT PLAN** - Submit a plan for plugging and abandonment of the well including: (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used; (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.

R. **NECESSARY RESOURCES** - Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available.

S. **AQUIFER EXEMPTIONS** - If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon production, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR Sections 144.7 and 146.04.

T. **EXISTING EPA PERMITS** - List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc.

U. **DESCRIPTION OF BUSINESS** - Give a brief description of the nature of the business.

Table of Contents
Underground Injection Control (UIC) Class II Well Permit Application
Seneca
Well #38268
Highland Township, Elk County, PA

Section 1 – Area of Review Methods/Calculations

Section 2 – Maps of Well Area and Area of Review

Section 3 – Corrective Action Plan and Well Data

Section 4 – Name and Depth of USDWs

Section 5 – Geologic Data on Injection and Confining Zones

Section 6 – Operating Data

Section 7 – Well Construction Details

Section 8 – Monitoring Program

Section 9 – Plugging and Abandonment Plan

Section 10 – Necessary Resources

Section 11 – Plan for Well Failures

Appendices

Appendix A – Groundwater Well Records

Appendix B – Surrounding Landowner Information

TETRA TECH

21335 Signal Hill Plaza, Suite 100, Sterling, VA 20164 703-444-7000 703-444-1685 (FAX)

TECHNICAL MEMORANDUM - DRAFT

TO: Dale Skoff, Tetra Tech NUS

FROM: Jeffrey Benegar

DATE: June 14, 2012

RE: Area of Review/Zone of Endangerment Analysis for Potential Brine Disposal Injection Well #38268

EXECUTIVE SUMMARY

This technical memorandum (TM) summarizes the analytical modeling we have performed for the area of review/zone of endangerment analysis for potential brine disposal injection well #38268 for Seneca Resources. Well #38268 is located in Highland Township, Elk County, PA. Brine disposal via injection well would take place into the Elk 3 Sandstone. Our analysis is described in more detail below.

OVERVIEW AND METHODOLOGY

There are several methods proposed for calculating the zone of endangerment of an injection well. The most simplistic method is the use of a fixed radius, based on the type of injection well being permitted. Other methods involve calculation of the radius based on well and formation properties. The method used here is the graphical method first used by US EPA Region 6. It involves the calculation of the increase of pressure in the formation due to injection, then converting that pressure into equivalent feet of head. The increase in head in the formation due to injection is then compared to the equivalent head of the lowest most underground source of drinking water (USDW). When plotted graphically, the intersection of those two curves at some distance, r, determines the radius of the zone of endangerment.

The increase in pressure in the formation due to injection depends on the properties of the injection fluid and the formation, the rate of fluid injection, and the length of time of injection. The most common mathematical expression to describe this increase in pressure was developed by Matthews and Russell (1967). Matthews and Russell assume that, for a single well injecting into an infinite, homogeneous and isotropic, non-leaking formation, the increase in pressure (delta p) can be described as:

delta p = 162.6 Qμ / kh * [(log(kt / ΦμCr^2) – 3.23] where:

delta p = pressure change (psi) at radius, r and time, t
Q = injection rate (barrels/day)
μ = injectate viscosity (centipoise)
k = formation permeability (millidarcies)
h = formation thickness (feet)
t = time since injection began (hours)
C = compressibility (total, sum of water and rock compressibility) (psi^{-1})
r = radial distance from wellbore to point of investigation (feet)
Φ = average formation porosity (decimal)

PARAMETERS USED IN THE ANALYSIS

The following parameters were used in the zone of endangerment analysis. The majority of the parameters are based on the analysis and results of the injection testing performed on well #38268 in March 2012 (Tetra Tech, 2012). The permeability value was based on the results from the injection testing analysis. For the depth to the lowest most USDW, a conservative estimate based on US EPA Region 3 guidance and review of site area hydrogeologic conditions was used (i.e., depth to USDW = 400 feet)

Input Parameters for Well #38268
Q = 3,000 barrels/day
t = 10 years = 87,600 hours
μ = 0.9457 centipoise
k = 190 md
h = 49 feet
C = 7.6e-06 psi^{-1}
Φ = 13.5%
Well radius = 0.29 feet
Specific gravity of injectate = 1.14
Surface elevation = 2040 feet
Depth to injection formation = 2354 feet
Base of lowest most USDW (elevation) = 1640 feet
Initial pressure at top of injection formation = 24 psi

RESULTS

The Matthews and Russell equation was solved for various distances from the wellbore based on the parameters listed above for permeability value determined from the injection test. The values of delta p were added to the existing pressure in the injection formation to obtain the total pressure in the formation. These values were then converted to feet of head of formation brine. The results are shown in Figure 1. The plot shows the calculated pressure surface within the injection formation, measured as feet of head of formation brine above the top of the injection formation. Also shown is the head of the lowest most USDW. Where the two lines intersect, the radius of the zone of endangerment can be estimated. For the permeability value of k = 190 md, the increase in head due to injection would remain below the elevation of the lowest most USDW. This permeability value was obtained from injection testing analysis of well #38268.

CONCLUSIONS

Our analysis of the area of review/zone of endangerment for the proposed brine disposal injection wells is based on a methodology typically used by US EPA. For the permeability value of k = 190 md (obtained from injection testing analysis of well #38268), increase in head due to injection would remain below the elevation of the lowest most USDW. Based on the results, we believe the well is an excellent candidate for use as a brine disposal well.

In summary, the default area of review of a ¼ mile radius from the proposed injection well is applicable for this application.

REFERENCES

Matthews, C.S., Russell, D.G., (1967) Pressure Buildup and Flow Tests in Wells, SPE Monograph Series, Volume 1, New York.

Tetra Tech, (2012) Injectivity Test Report, Seneca Resources Well #38268, Highland Township, Elk County, PA. May 2012.

FIGURES

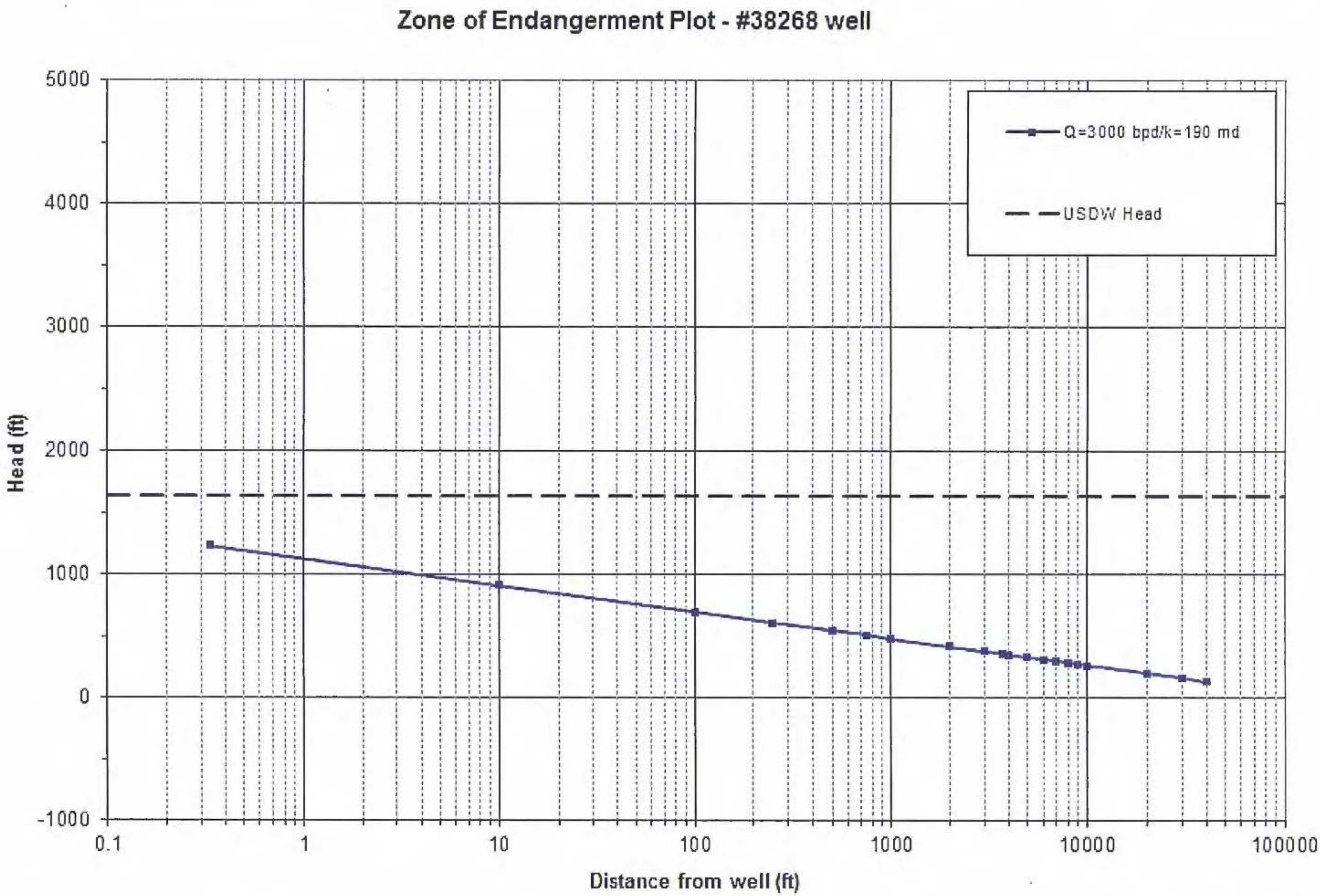


Figure 1. Feet of head of injection formation and USDW vs. distance from the well for #38268 well

TETRA TECH, INC.

Area of Review

According to publicly available records for the proposed injection well area, there are no intake or discharge structures, hazardous waste treatment, storage, or disposal facilities, mines, or quarries within one mile of Seneca Well #38268, the proposed injection well. A High Quality – Cold Water Fishery (HQ-CWF) designated unnamed tributary (UNT) to the East Branch of Tionesta Creek is located approximately 0.5 miles east, a HQ-CWF designated unnamed tributary (UNT) to Wolf Run is located approximately 0.1 miles south, and a HQ-CWF designated unnamed tributary (UNT) to Wolf Run is located approximately 0.6 miles west of Seneca Well #38268.

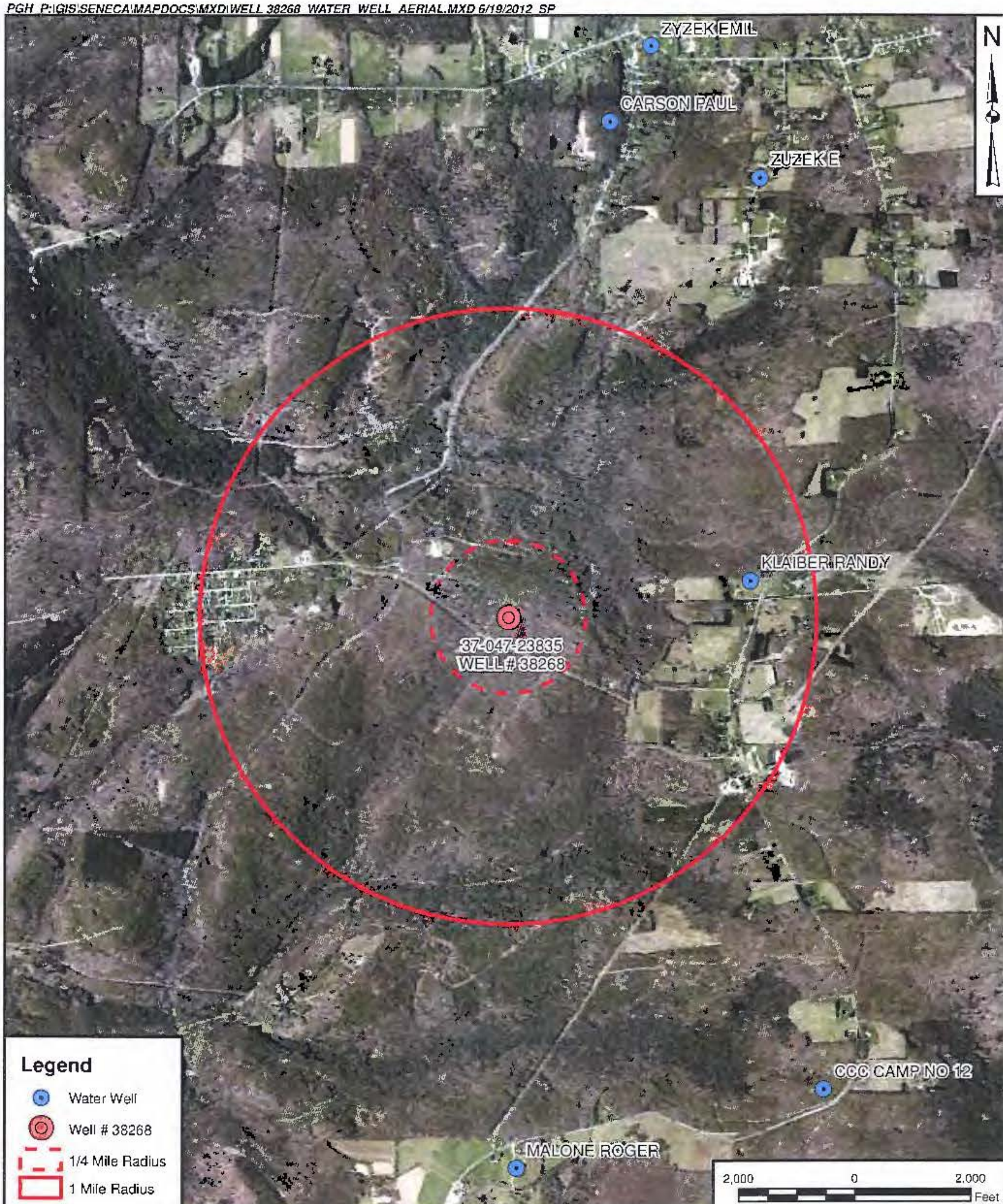
According to publicly available records, there are no groundwater wells within the ¼ mile Area of Review for Well #38268. The nearest groundwater well is located approximately 0.8 miles to the northeast (Randy Klaiber). The only active oil and gas well located within ¼ mile of the Seneca Well #38268 is Seneca Well #38281 located approximately 0.2 miles to the southwest. A plugged gas well, Seneca Well #01328, is located approximately 1320 ft southeast of the proposed injection well. This well is discussed in greater detail in the following section of this application.

The names and addresses of residents located within ¼ mile of the proposed injection well are provided in Appendix B.

AREA OF REVIEW MAPS

GROUNDWATER WELLS

PGH P:\GIS\SENECA\MAPDOCS\MXD\WELL 38268 WATER WELL AERIAL.MXD 6/19/2012 SP



TETRA TECH

FIGURE 1
#38268 WELL LOCATION
WITH WATER WELL LOCATIONS

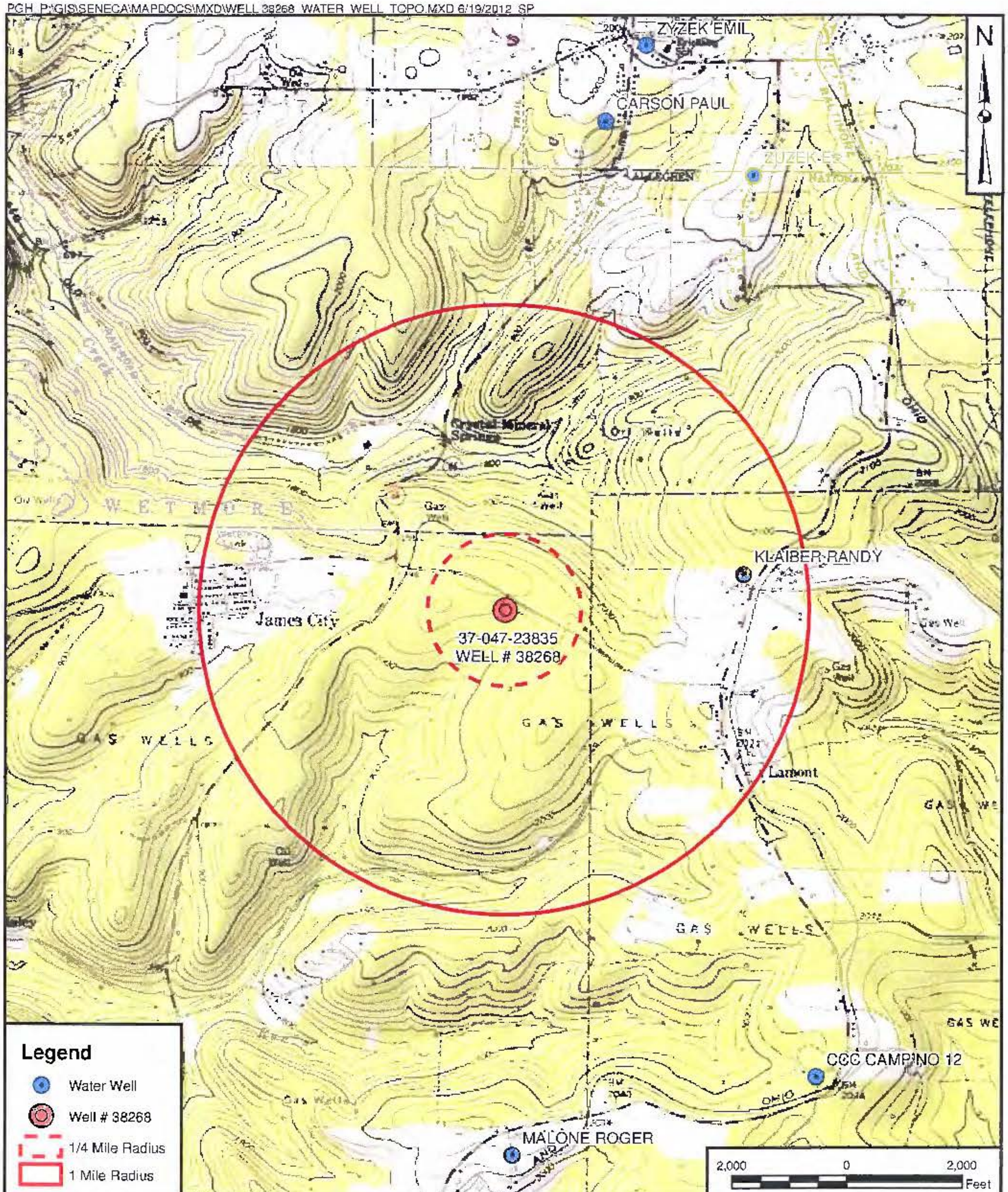
ELK COUNTY, PENNSYLVANIA

DRAWN BY: J. NOVAK 05/17/12
CHECKED BY: E. BERKLITE 06/19/12
APPROVED BY:

CONTRACT NUMBER: 112C04076

FIGURE NUMBER	REV
1	0

PGH P:\GIS\SENECA\MAPDOCS\MXD\WELL 38268 WATER WELL TOPO.MXD 6/19/2012 SP



TETRA TECH

FIGURE 2
#38268 WELL LOCATION
WITH WATER WELL LOCATIONS

ELK COUNTY, PENNSYLVANIA

DRAWN BY: J. NOVAK 05/17/12
CHECKED BY: E. BERKLITE 06/19/12
APPROVED BY:

CONTRACT NUMBER: 112C04078

FIGURE NUMBER	REV
2	0

AREA OF REVIEW MAPS

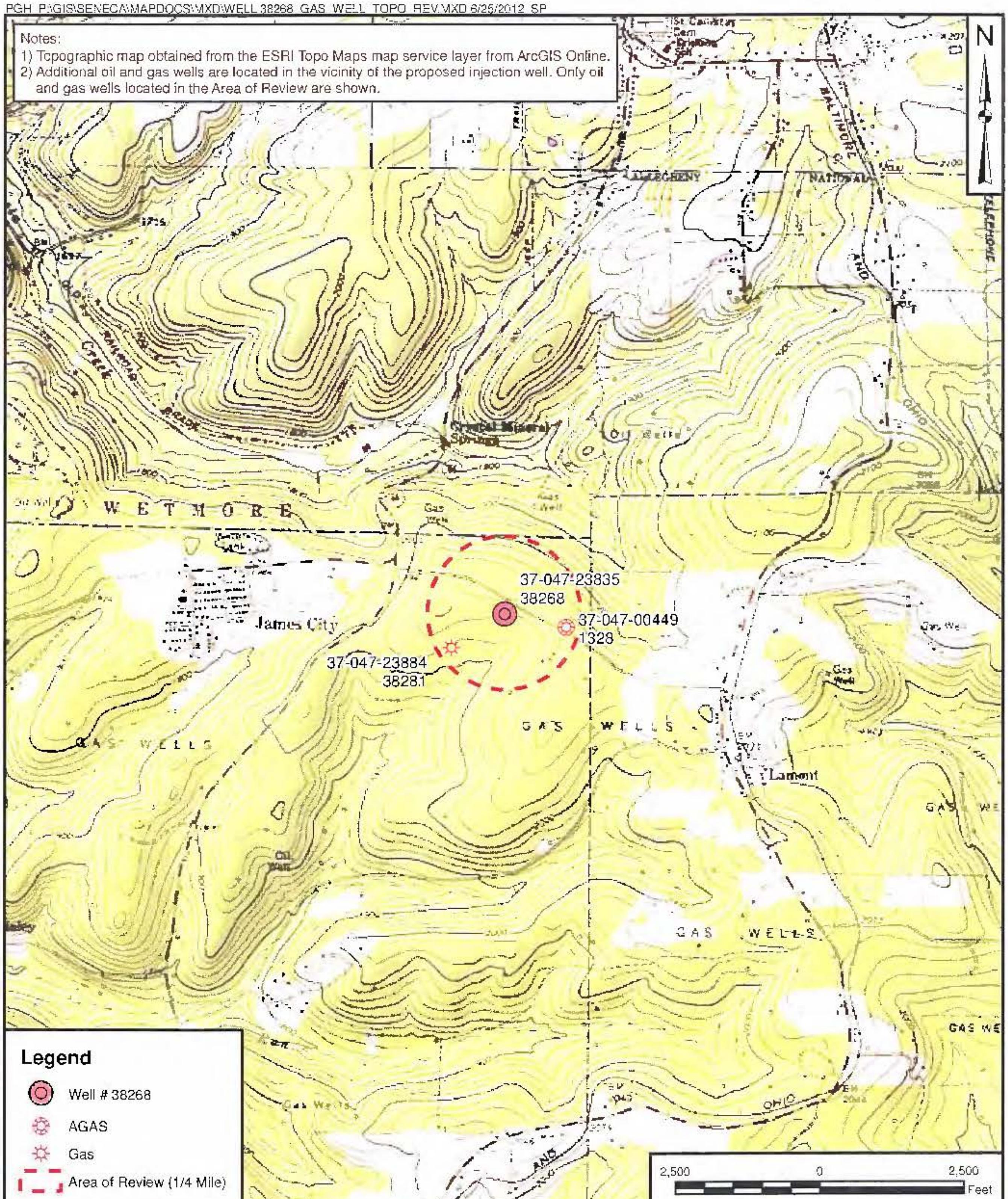
OIL AND GAS WELLS

PGH P:\GIS\SENECA\MAPDOCS\MXD\WELL 38268 GAS WELL AERIAL REV.MXD 6/25/2012 SP

TETRA TECH	FIGURE 3 #38268 WELL LOCATION WITH GAS WELL LOCATIONS ELK COUNTY, PENNSYLVANIA	DRAWN BY: J. NOVAK 05/17/12 CHECKED BY: D. SKOFF 06/25/12 APPROVED BY: CONTRACT NUMBER: 112C04078 FIGURE NUMBER 3 REV 0

PGH P:\GIS\SENECA\MAPDOCS\MXD\WELL 38268 GAS WELL TOPO REV.MXD 6/25/2012 SP

Notes:
1) Topographic map obtained from the ESRI Topo Maps map service layer from ArcGIS Online.
2) Additional oil and gas wells are located in the vicinity of the proposed injection well. Only oil and gas wells located in the Area of Review are shown.



TETRA TECH	FIGURE 4 #38268 WELL LOCATION WITH GAS WELL LOCATIONS ELK COUNTY, PENNSYLVANIA	DRAWN BY: J. NOVAK 05/17/12 CHECKED BY: D. SKOFF 06/25/12 APPROVED BY: CONTRACT NUMBER: 112C04078 FIGURE NUMBER 4 — REV 0

OIL AND GAS WELLS IN THE AOR

GROUNDWATER WELLS WITHIN 1 MILE

Proposed Injection and Monitoring Wells

Operator	Cmpl Date	API	WellID	Elevation (ft msl)	Total Depth (ft)	Last Csg (in)	Csg Depth (ft)	Completion	Comments
SENECA RESOURCES CORP	7/3/2007	37-047-23835	38268	2040	2530	7	553.2	Notched & Frac'd: 2354-2403'	Subject of UIC Class IID permit application
SENECA RESOURCES CORP	3/11/2008	37-047-23884	38281	2020	2544	7	602	Notched & Frac'd: 2338-2390'	Monitoring Well

Other Existing /Former Oil and Gas Wells Within Area of Review (1/4 Mile Radius)

Operator	CmplDate	API	WellID	Elevation	Total Depth (ft)	Last Csg (in)	Csg Depth (ft)	Completion	Comments
SENECA RESOURCES CORP	11/21/1902	N/A	1328	2049	2433	6.25	460	Shot with 100 qts. Nitroglycerin: 2370-2400'	Plugged and Abandoned Feb. 12, 1991

Water Wells Within 1 Mile Radius

PAWellID	DateDrilled	Owner	WellDepth	Depth To Bedrock	WellUse	Borehole Bottom	Bore Hole Diameter	Casing Bottom	Casing Diameter
100718	8/1/1987	KLAIBER RANDY	130	28	WITHDRAWAL				

Corrective Action Plan and Well Data

Two wells penetrated the same zone of injection within one-quarter mile of the subject well: Well #38281 and Well #01328. Both wells are owned by Seneca. Well #01328 is located approximately 1320 ft to the southeast and was properly plugged and abandoned in 1991. Well #38281 is located approximately 1030 ft to the southwest and is a gas producing well having productive intervals as shown in the table below.

Notched and Frac'd Intervals of Well #38281

Formation	Notched and Frac'd Interval	Thickness (h)	Comments
Speechley 6	1650 to 1662	12 feet	Gas producing interval
Speechley 7	1704 to 1719 feet	15feet	Gas producing interval
Tiona Sandstone	1728 to 1734 feet	6 feet	Gas producing interval
Kane 1	2123 feet	1 foot	Gas producing interval
Kane 2	2133 to 2151 feet	18 feet	Gas producing interval
Kane 3	2156	1 foot	Gas producing interval
Elk 3	2339 to 2390 feet	51 feet	Gas producing interval

Both wells are discussed further below.

Existing Oil and Gas Wells within the Area of Review

Well completion records are required to be submitted for all wells located within the area of review in order to evaluate the need for corrective action specific to each well. The well completion reports for the proposed injection well, Well #38268, and Well #38281 are attached. The well construction diagram for Well #38281 is included in Section 8, Monitoring Program. As discussed further in Section 8, Well #38281 will be utilized as a monitoring well and is properly constructed for that purpose.

Plugged and Abandoned Wells

As indicated above, there is one plugged and abandoned well (#01328) located within the ¼ mile area of review for Well #38268. This well has been properly plugged and abandoned; therefore, no additional corrective action is necessary within the AOR. The plugging report for this well is attached.

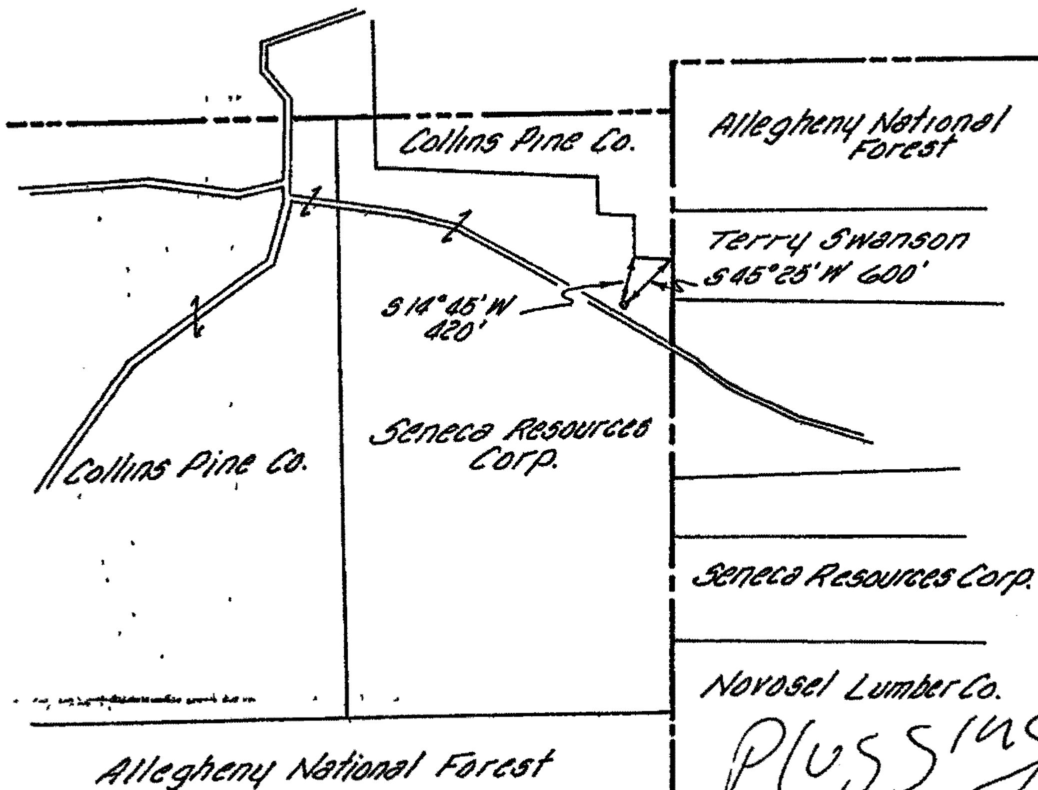
ER-OG-7, Rev. 3/85

WELL LOCATION PLAT

Well is located on topo map 2400 feet south of LATITUDE 41° 37' 30"

Well is located on topo map 7100 feet west of LONGITUDE 78° 47' 30"

047-00449



Plugging

Include description of the property and courses and distances of the well(s) location to two or more permanent identifiable points or land marks, all buildings and water supplies within 200', all springs, bodies of water and streams within 100' identified on the most current 7½" topographic map and wetlands within 100'.
Reference to buildings, springs, bodies of water and wetlands is not required for well plugging.

⊞ Denotes location of well on 7½" topo map Permit # 37-047-00449 Project # ______

National Fuel Gas Supply Corp Well Operator	Revision ☐ Re-Issue ☐ Alteration ☐ Storage Recondition ☐ New Location ☐ Drill Deeper ☐ Abandonment ■ Registration ☐ Plugging ☐	J Porterfield Surveyor/Engineer
308 Seneca St. Address		RS 15283-E Registration Number
Oil City, Penna. 16301		Aug. 6, 1986 Date
Seneca Resources Corp. Surface Owner		1" = 1320' Scale
— Surface Lessor (if any)	Surface landowner and water purveyor with water supply within 1,000'	Approximate course and distance to water supply
Seneca Resources Corp. Farm Name	None	RECEIVED JAN 31 1991
1328 Well No / 1328 Serial No		
310 Acres / 2049 Ground Elevation		
James City 06/5 Topo Quadrangle / #2 Section		
Elk County / Highland Twp. Political Subdivision	Owner/Operator	Workable Coal Seams Bureau of Oil & Gas Management Dept. of Environmental Resources
None Angle of Deviation / Anticipated TD		No Coal
	RK 2/4/91	FEB 12 1991
Commonwealth of Pennsylvania Department of Environmental Resources Bureau of Oil and Gas Management		PA GEOLOGICAL SURVEY (Oil & Gas Geology Division)

RE
2400' S 41°37'30"
7100' W 78°47'30"
(B)

BUREAU OF OIL AND GAS REGULATION

Date Approved 3-26-9

CERTIFICATE OF PLUGGING WELL

James City
047-1
00449-1

☐ Coal Operator ☐ Owner ☐ Lessee

Address

☐ Coal Operator ☐ Owner ☐ Lessee

Address

☐ Coal Operator ☐ Owner ☐ Lessee

Address

COMPLETE ABOVE SECTION IF APPLICABLE

Type of Well Natural Gas

Name of Well Operator National Fuel Gas Supply

1400 Gilbert Dr. P.O. Box 626 Titusville, PA 16354
Address

February 26 19 9
Date

Highland
Political Subdivision, Borough, City or Township

Elk Coun

Farm James Bros.

Well (Farm) No 1328 Serial No.

KANE FIELD, NANSEN POOL

We, the undersigned representatives of the Well Operator certify that we participated in the plugging of the abo well, and that the work was started Feb. 7 19 91, and that the well was plugged as follow

FILLING MATERIAL AND PLUGS	FROM	TO	Casing and Tubing SIZE	PULLED	LEFT
Solid Cavings	2433'	2431'	6¼"	336'	124
Cement 90 sacks	2431'	2100'	4"	497'	25
Cement 70 sacks	1850'	1500'			
Cement 20 sacks	600'	500'			
Cement 20 sacks	500'	346'			
SP/Mud	346	30'			
Cement 10 sacks	30'	surface	Depth of Coal Seam, If Any		
			NONE		
			Description of Monument		
NOTE: Gelled water between cement plugs.			Installed marker to extend 4' above ground.		

RECEIVED MAR 28 1991 Bureau of Oil and Gas Management Environmental Resources

RECEIVED MAR - 6 1991 WARREN DISTRICT OFFICE ENVIRONMENTAL RESOURCES

I certify that the work of plugging and filling said well was completed on the 12th day of Feb. 19 91 and that the above information is true and accurate.

RECEIVED APR 9 1991 GEOLOGICAL SURVEY

National Fuel Gas Supply Corporation
(Well Operator)

Karl Alberg
(Qualified Participant)

S.J. Stauffer
(Qualified Participant)

Bruce E Johnson
(Qualified Participant)

PERMIT/REGISTRATION NO. 37-047-00449

PROJECT NO.

GEOLOGIC DATA

38268 WELL RECORD

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT 7 & C

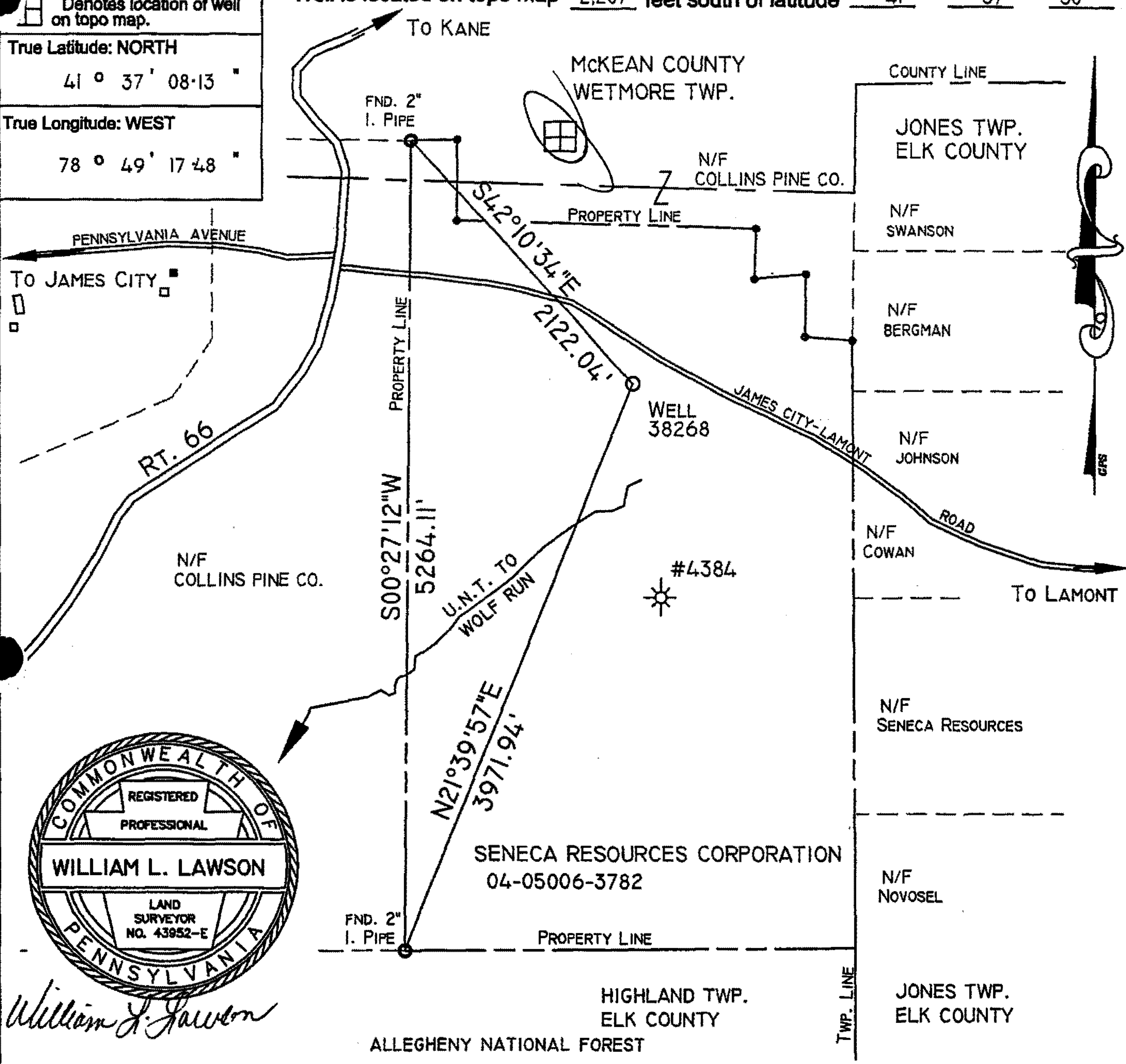
DEP USE ONLY	
DEP Application Tracking #	G: 35 2/20/07
Permit # 047-23835	C:
Project #	

Well is located on topo map 2,207 feet south of latitude 41 ° 37 ' 30 "

Denotes location of well on topo map.

True Latitude: NORTH
41 ° 37 ' 08.13 "

True Longitude: WEST
78 ° 49 ' 17.48 "



Well is located on topo map 8,163 feet west of longitude 78 ° 47 ' 30 "

COMMONWEALTH OF PENNSYLVANIA REGISTERED PROFESSIONAL WILLIAM L. LAWSON LAND SURVEYOR NO. 43952-E

William L. Lawson

Surveyor or Engineer WILLIAM L. LAWSON Phone # (814) 752-2291 Dwg. # P:/WELLFILES/38268.DWG Date 02/09/07 Scale 1" = 1000' Tract Acreage 299.6

Lat. & Long Metadata Method GPSDF Accuracy +/- 3 ft. Datum NAD - 27	Elevation Metadata Method TOPO Accuracy +/- 10 ft. Datum NGVD-29 Survey Date 01/30/07
Applicant / Well Operator Name SENECA RESOURCES CORPORATION	Well (Farm) Name FEE- SRC WT. 3771 — Well # 38268 — Serial #
Address 286 OLD 36 ROAD SIGEL, PA 15860	County - Code ELK - 24 — Municipality HIGHLAND TOWNSHIP
Surface Landowner SENECA RESOURCES CORPORATION	USGS 7 1/2 Quadrangle Map Name JAMES CITY, PA 0615 — Map Section "2"
Surface Lessor NONE	Angle & Course of Deviation (Drilling) VERTICAL — Surface Elevation 2040 ft. — Anticipated Total Depth 2530 ft.
Surface Owner or Water Purveyor with a Water Supply within 1,000 feet — Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam — Name of Coal Seam Owned, Leased, or Operated
NONE	
Martin Run	

HQ WATERSHED

RECEIVED
FEB 14 2007
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil & Gas Management Program

LYNN AUG 15

DEP USE ONLY	
Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

WELL RECORD AND COMPLETION REPORT

Well Operator SENECA RESOURCES CORPORATION	DEP ID# 72993		Well API # (Permit / Reg) 37-047-23835-00	Project Number	Acres
Address 286 OLD 36 ROAD			Well Farm Name FEE SENECA RESOURCES WARRANT 3771	Well # 38268	Serial #
City SIGEL	State PA	Zip Code 15860	County Elk	Municipality Highland	
Phone 814-725-2291	Fax 814-752-6204		USGS 7 5 min quadrangle map James City 2		

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type ☒ Gas ☐ Oil ☐ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
3/20/07	3/22/07	2040'	2530'	2532'

Casing and Tubing

Cement returned on surface casing? ☒ Yes ~~No~~ See Drillers Log
Cement returned on coal protective casing? ☐ Yes No X N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	Material Behind Pipe Type and Amount	Packer / Hardware / Centralizers Type	Size	Depth	Date Run
11 ¼	9 5/8	26	T	63					
8 ¾	7	17	T	553	106 sks. Common Class A, 3% CaCl, ½#unicele			523, 349, 175	3/21/07
6 1/4	2 3/8		T	2498					7/03/07
	5/8		T	2475					7/03/07

COMPLETION REPORT

Perforation Record Date	Interval Perforated From	To	Stimulation Record Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			7/03/07	1667 0	Gel Water	8770 gal	20/40 sand	120 sks	19 8
				1671 5	Gel Water	11,040 gal	20/40 sand	160 sks	20
				1676 0	Gel Water	10,910 gal	20/40 sand	160 sks	20
				1721 0	Gel Water	8910 gal	20/40 sand	120 sks	20
				1739 5	Gel Water	9250 gal	20/40 sand	120 sks	20 3

Natural Open Flow mcfd	Natural Rock Pressure	Hours	Days
After Treatment Open Flow Mcfd 350	After Treatment Rock Pressure 125	Hours	Days 2

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name Dallas-Morris Drilling Co	Name Universal Well Services	Name Schlumberger
Address Morris Lane	Address P O Box 180	Address 95 Rutherford Run
City - State – Zip Bradford PA 16701	City - State – Zip Bradford, PA 16701	City - State – Zip Bradford, PA 16701
Phone (814) 362-6493	Phone (814) 368-6175	Phone (814) 362-7441

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ENVIRONMENTAL PROTECTION
WARREN DISTRICT OFFICE

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ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

LOG OF FORMATIONS

Well API#: 37-053-23835-00

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

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ENVIRONMENTAL PROTECTION
WARREN DISTRICT OFFICE

Well Operator's Signature: Guy S. Shreig

Title: Superintendent / Prod. & Eng. Date: 7/26/07

DEP USE ONLY

Reviewed by: T. Cuny

Date: 6-4-08

Comments.

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NORTHWEST REGIONAL OFFICE

DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	
Bits Used:	12 ¼", 8 ¾", 6 ¼"				
Fuel Use:	Spud: 8057	T. D.: 8916	Rig Hours:	5051 - 5093	

TOP	BOTTOM	FORMATIONS	TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock	1910	1925	Gas
5	15	Sand	1925	1980	Cooper 4.0 & Sand
15	40	Sand	1980	2135	Cooper 6.0
40	55	Sand	2135	2275	Gas
55	70	Shale	2275	2295	Elk 1.0 (gas)
70	95	Sand	2295	2355	Sand (gas)
95	120	Sand & Shale	2355	2390	Gas
120	225	Sand	2390	2420	Elk 4.0
225	415	Sand & Shale	2420	2510	Sand (gas)
415	558	Sand	2510	2530	Sand
558	635	Red Rock	2530		Total Depth
635	650	Shale			
650	820	Red Rock			
820	865	Shale			
865	915	Red Rock			
915	1270	Sand & Shale			
1270	1345	Sand			
1345	1360	Red Rock			
1360	1385	Sand & Shale			
1385	1555	Base Warren 1.0			
1555	1565	Red Rock			
1565	1575	Sand			
1575	1598	T-12 Marker			
1598	1675	Speechley 2.0			
1675	1725	Gas			
1725	1750	Speechley 6.0 (gas)			
1750	1765	Gas			
1765	1875	Tiona 1.0			
1875	1890	Red Rock (gas)			
1890	1910	Sand			

DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	
Bits Used:	12 ¼", 8 ¾", 6 ¼"				
Fuel Use:	Spud: 8057	T. D.: 8916	Rig Hours:	5051 - 5093	

TOP	BOTTOM	FORMATIONS	TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock	1910	1925	Gas
5	15	Sand	1925	1980	Cooper 4.0 & Sand
15	40	Sand	1980	2135	Cooper 6.0
40	55	Sand	2135	2275	Gas
55	70	Shale	2275	2295	Elk 1.0 (gas)
70	95	Sand	2295	2355	Sand (gas)
95	120	Sand & Shale	2355	2390	Gas
120	225	Sand	2390	2420	Elk 4.0
225	415	Sand & Shale	2420	2510	Sand (gas)
415	558	Sand	2510	2530	Sand
558	635	Red Rock	2530		Total Depth
635	650	Shale			
650	820	Red Rock			
820	865	Shale			
865	915	Red Rock			
915	1270	Sand & Shale			
1270	1345	Sand			
1345	1360	Red Rock			
1360	1385	Sand & Shale			
1385	1555	Base Warren 1.0			
1555	1565	Red Rock			
1565	1575	Sand			
1575	1598	T-12 Marker			
1598	1675	Speechley 2.0			
1675	1725	Gas			
1725	1750	Speechley 6.0 (gas)			
1750	1765	Gas			
1765	1875	Tiona 1.0			
1875	1890	Red Rock (gas)			
1890	1910	Sand			

INVOICE NO. 536463

STAGE NO.

UNIVERSAL WELL SERVICES INC

JOB LOG

CUSTOMER Seneca Res

LEASE NAME 38268

DATE 3-21-07

	NO. OF SACKS	COMPOSITION OF CEMENT	YIELD	GAL. WTR/SK	DENSITY	BBL. OF MIX WTR.	CU. FT. OF SLURRY	BBL. OF SLURRY
1.	106	class A, 3% cacl2, ½#sk unicele	1.18	5.2	15.6	13.1	125	22.2
2.								
3.								
					TOTAL	13.1	125	22.2

CIRCULATE CEMENT TO SURFACE

☒ Yes ☐ No ☐ Not Applicable

7 bbls return

JOB TYPE

☒ Surface ☐ Longstring ☐ Acid

☐ Other 7" surface

	NEW USED	SIZE	FROM	TO	WEIGHT	MAXIMUM PSI ALLOWANCE
CASING	N	7"	0	553.2	17#	
TUBING						
OPEN HOLE		8¾	553.2	568		
~~PERFORATIONS~~ LJ			4'			

DISPLACEMENT CAPACITY 23.1 BBL.

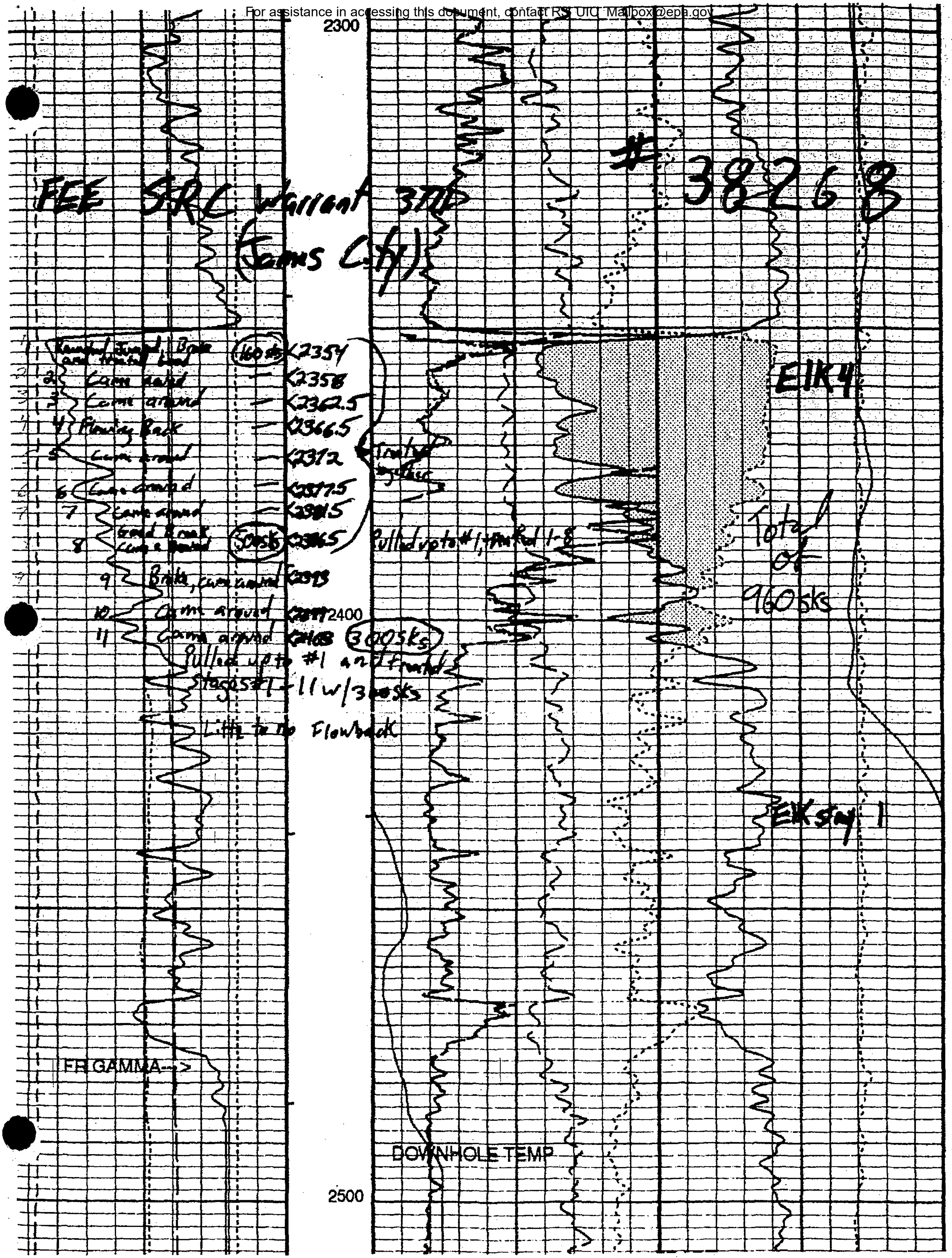
DISPLACEMENT DEPTH 557.2 FT.

TIME	RATE (BPM)	VOLUME (BBL)	PRESSURE (PSI) TUBING	PRESSURE (PSI) CASING	DESCRIPTION OF STAGE OR EVENT
1830					SPOT Truck, rig up
1855					Safety meeting
1900	2-3	10		0-50	Start H^2O
1903	3	10		50-100	Start Gel unicele
1906	3	5		100	Start spacer
1909	3-4	22.2		100-200	Start class A, 3% cacl2, ½#sk unicele
1916					SDTP
1918	4-2	23.1		0-550	Start H^2O displacement
1925					Plug Landed, closed manifold
1928				550-0	reless pressure, wash up
1945					rig down
					Job complete

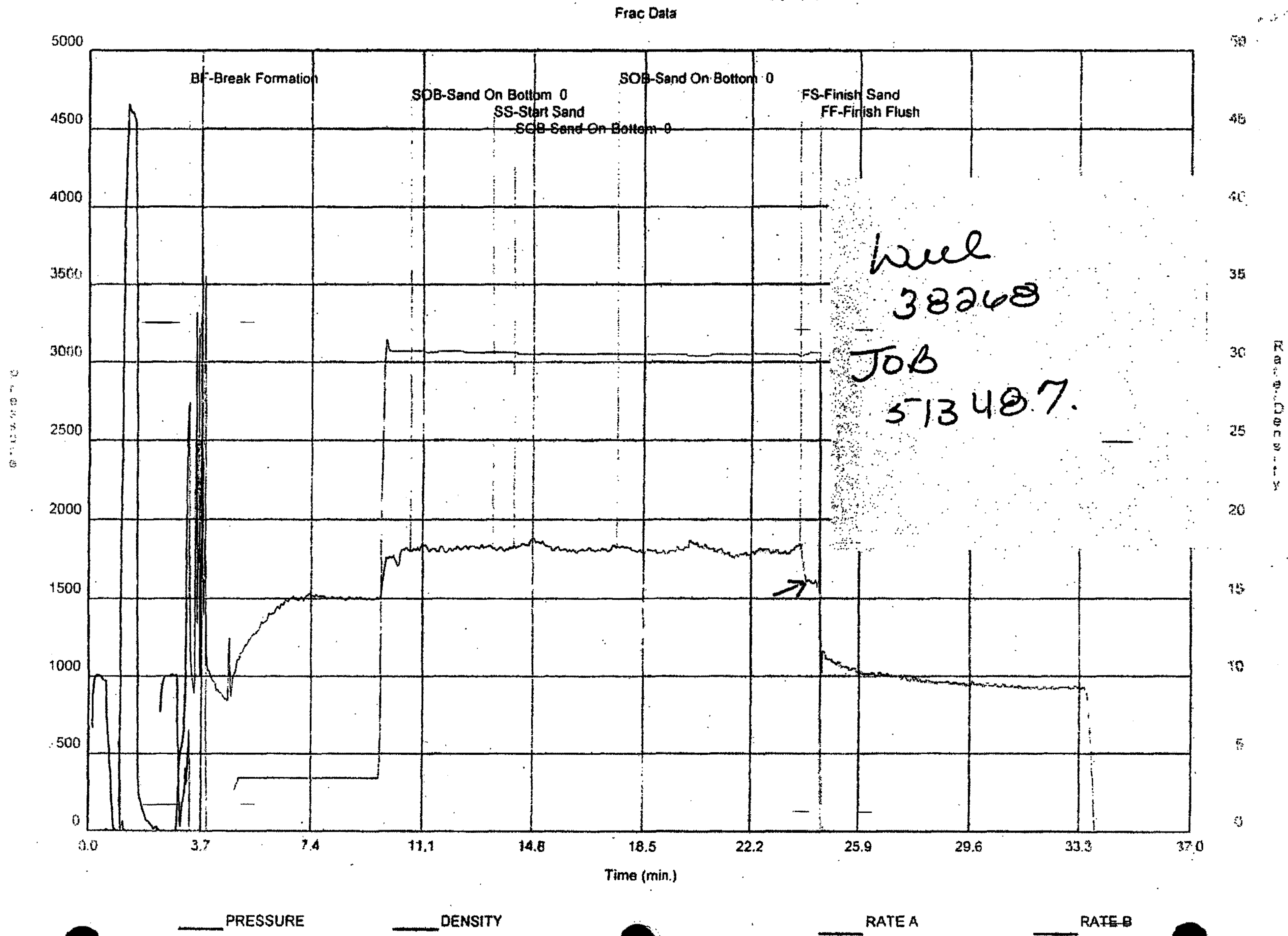
REMARKS Ph 7 H^2O 38 W&D sample

SERVICE ENGINEER Everly

CUSTOMER REPRESENTATIVE [signature]


2300
FEE SRC Warrant 37D
(James City)
38268
Elk 4
2 Came around <2358
3 Came around <2362.5
4 Flowing Back <2366.5
5 Came around <2372
6 Came around <2377.5
7 Came around
8 Good Break Came around 50 sks
9 Broke, came around
10 Came around
2400
11 Came around 300 sks
Pulled up to #1 and fraced Stages #1 - 11 w/300 sks
Little to no Flowback
Total of 960 sks
Elk stray 1
FR GAMMA-->
DOWNHOLE TEMP
2500

#1 100 SKS 4/5/07
Elk 4



GEOLOGIC DATA

38281 WELL RECORD

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program
WELL LOCATION PLAT

T ¢ o

DEP USE ONLY	DEP Application Tracking #	G: JS 5/10/07
	Permit # 047-23884	C:
	Project #	

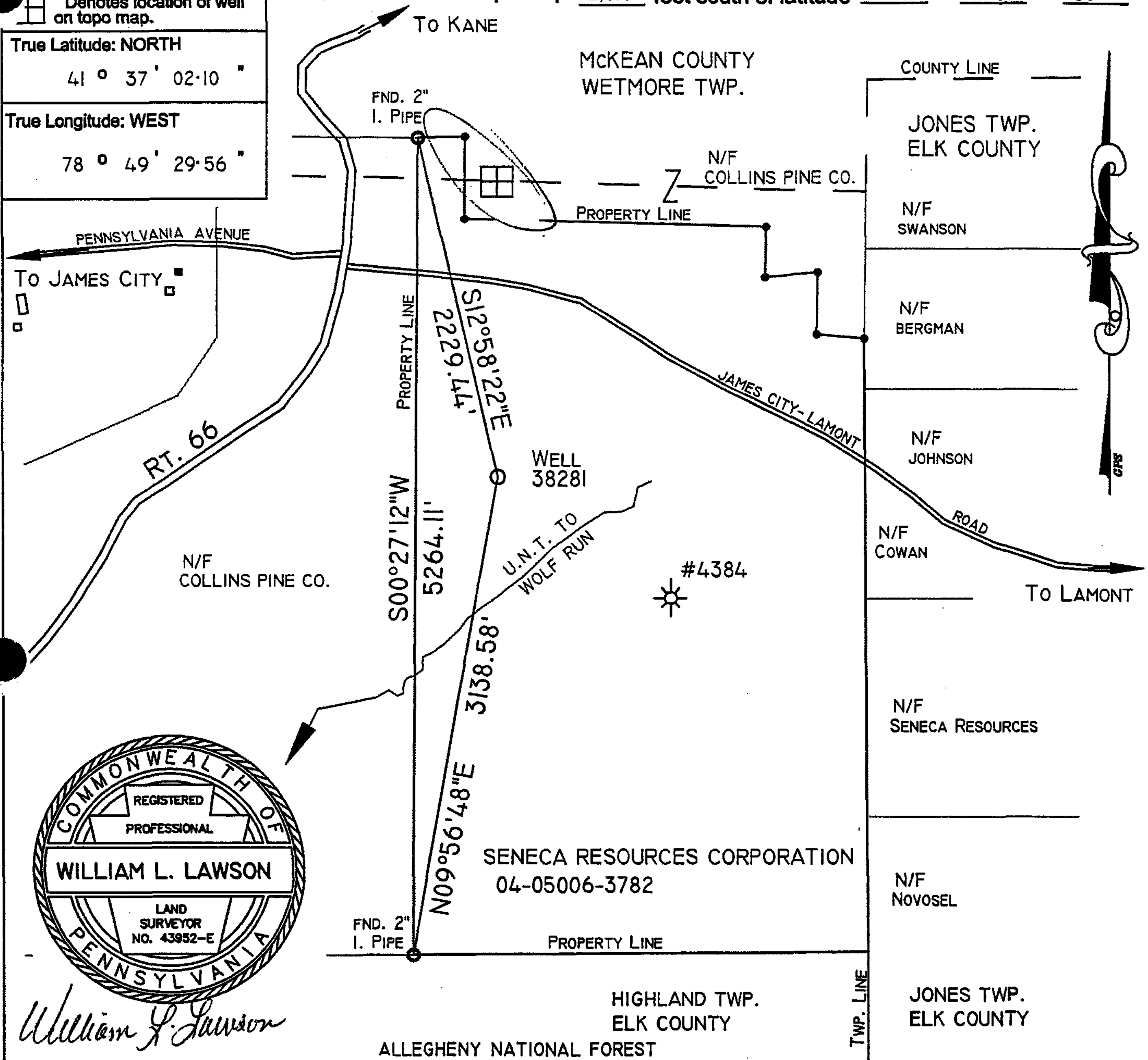
Denotes location of well on topo map.

True Latitude: NORTH 41° 37' 02.10"

True Longitude: WEST 78° 49' 29.56"

Well is located on topo map 2,815 **feet south of latitude** 41° 37' 30"

Well is located on topo map 9,081 **feet west of longitude** 78° 47' 30"



Surveyor or Engineer: WILLIAM L. LAWSON | Phone # (814) 752-2291 | Dwg. # P:/WELLFILES/38281.DWG | Date 04/09/07 | Scale 1" = 1000' | Tract Acreage 299.6

Lat. & Long Metadata		Elevation Metadata	
Method GPSDF · Accuracy +/- 3 ft. · Datum NAD - 27		Method TOPO · Accuracy +/- 10 ft. · Datum NGVD-29	Survey Date 02/30/07
Applicant / Well Operator Name: SENECA RESOURCES CORPORATION		Well (Farm) Name: FEE- SRC WT. 3771 · Well # 38281	Serial #
Address: 286 OLD 36 ROAD SIGEL, PA 15860		County - Code: ELK - 24	Municipality: HIGHLAND TOWNSHIP
Surface Landowner: SENECA RESOURCES CORPORATION		USGS 7 1/2 Quadrangle Map Name: JAMES CITY, PA 0615	Map Section "2"
Surface Lessor: NONE		Angle & Course of Deviation (Drilling): VERTICAL	Surface Elevation 2020 ft. · Anticipated Total Depth 2570 ft.
Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.: NONE	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated

HQ

WATERSHED Martin Run

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil & Gas Management Program

WELL RECORD AND COMPLETION REPORT

DEP USE ONLY	
Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

Well Operator: SENECA RESOURCES CORPORATION	DEP ID#: 72993	Well API # (Permit / Reg): 37-047-~~3288+~~ 23884	Project Number / Acres
Address: 51 Zents Blvd		Well Farm Name: FEE-SRC Wt 3771	Well #: 38281 / Serial #
City: Brookville	State: PA / Zip Code: 15825	County: McKean	Municipality: Highland
Phone: 814-849-4555	Fax: 814-849-4795	USGS 7 5 min quadrangle map	

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type ☐ Gas ☐ Oil ☒ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
01/22/08	01/24/08	2020	2544	2540

Casing and Tubing

Cement returned on surface casing? ☒ Yes ☐ No
Cement returned on coal protective casing? ☐ Yes ☐ No ☒ N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	Material Behind Pipe Type and Amount	Packer / Hardware / Centralizers Type	Size	Depth	Date Run
12 ¼	9 5/8	26	T	47					01/22/08
8 ¾	7	17	T	602	124 sks Class A Cement, 3% CaCl, ½# unicele/sk	3 centralizers			01/23/08
¼	2 3/8	4.9	T	2482					03/11/08
	5/8		T	2475					03/11/08

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NORTHWEST REGIONAL OFFICE

COMPLETION REPORT

Perforation Record / Stimulation Record

Perf. Date	Interval Perforated From	To	Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			03/11/08	1650	Gel Water	8460	20/40 sks	120	20
				1655	Gel Water	9620	20/40 sks	140	20
				1658	Gel Water	10728	20/40 sks	160	20
				1662	Gel Water	8672	20/40 sks	140	20
				1704	Gel Water	7401	20/40 sks	100	20
				1719	Gel Water	9111	20/40 sks	120	20

Natural Open Flow Mcfd 1	Natural Rock Pressure	Hours	Days
After Treatment Open Flow Mcfd 500	After Treatment Rock Pressure	Hours	Days

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name: Natural Oil and Gas	Name: Keane and Sons Drilling	Name: Schlumberger
Address: 1410 W Warren Road	Address: 12 Keane Lane	Address: 95 Rutherford Run
City - State – Zip: Bradford, PA 16701	City - State – Zip: Bradford, PA 16701	City - State – Zip: Bradford, PA 16701
Phone: 814-362-2543	Phone: 814-362-2659	Phone: 814-362-7441

COMPLETION REPORT API#37-047-32884

Perforation Record			Stimulation Record						
Date	*Interval Perforated* From	To	Date	Interval Treated	*Fluid* Type	Amount	*Propping Agent* Type	Amount	Average Injection Rate
			03/11/08	1728	Gel Water	8779	20/40 Sand	120	20
				1734	Gel Water	8779	20/40 Sand	120	20
				1893	Gel Water	7567	20/40 Sand	100	20
				2123	Gel Water	8770	20/40 Sand	120	17
				2133	Gel Water	9949	20/40 Sand	140	20
				2151	Gel Water	9903	20/40 Sand	140	19
				2156	Gel Water	10256	20/40 Sand	140	18
				2339-2390	Gel Water	23228	20/40 Sand	500	23
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		

5500-FM-OG0004 Rev 5/98

LOG OF FORMATIONS

Well API#: 37-047-32884

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

RECEI...
APR

Well Operator's Signatures

Guy A. Shuey

Title: Superintendent / Prod. & Eng. Date: 4/14/08

DEP USE ONLY

Reviewed by: T Curry

Date: 6-4-08

Comments:

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVAN
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL #	38281	PERMIT #	37-047-23884
SPUD DATE	1/22/2008	COUNTY	Elk
SPUD TIME	4:30 p.m.	TOWNSHIP	Highland
CONDUCTOR	47 ft.	LEASE	James City
CASING	603 ft.	TD DATE	1/24/2008
TOTAL DEPTH	2544 ft.	TD TIME	11:57 a.m.

PIPE TALLY

1	23.2 ft.	7	23.2 ft.	13	23.2 ft.	19	23.2 ft.	25	23.2 ft.
2	23.2 ft.	8	23.2 ft.	14	23.2 ft.	20	23.2 ft.	26	23.2 ft.
3	23.2 ft.	9	23.2 ft.	15	23.2 ft.	21	23.2 ft.	27	
4	23.2 ft.	10	23.2 ft.	16	23.2 ft.	22	23.2 ft.	28	
5	23.2 ft.	11	23.2 ft.	17	23.2 ft.	23	23.2 ft.	29	
6	23.2 ft.	12	23.2 ft.	18	23.2 ft.	24	23.2 ft.	30	

#JOINTS	26	CEMENT CO.	Universal
SACKS	124	RETURNS	6 Barrels
PLUG DOWN	9:45 a.m.	CEMENT DATE	1/23/2008

OPERATOR: Seneca WELL NAME: Fee-SRC WT 37

WELL # : 38281 PERMIT #: 37-047-23884-(

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVANIA 167
Telephone: (814) 362-6890 Fax (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
45	4:30		Gravel, Shale	645	10:40	10	Shale
75	4:56		Shale	675	8:02	12	Shale
105	6:00		Shale	705	8:11	9	Shale
135	6:11	11	SandStone	735	8:21	10	Shale
165	6:21	10	SS/Shale	765	8:31	10	RedRock
195	6:34	13	Shale	795	8:43	12	RR/Shale
225	6:45	11	Shale	825	8:53	10	Shale
[illegible]5	6:58	13	Sand	855	9:04	11	Shale
285	7:10	12	Shale	885	9:16	12	Shale
315	7:25	15	Sand	915	9:27	11	Shale
345	7:37	12	Shale	945	9:40	13	Shale
375	8:49	12	RedRock	975	9:55	15	RedRock
405	9:00	11	RedRock	1005	10:05	10	Shale
435	9:12	12	RR/Shale	1035	10:15	10	Shale
465	9:26	14	Sand/Shale	1065	10:26	11	RedRock
495	9:40	12	Shale	1095	10:37	11	RedRock
525	9:52	12	Shale	1125	10:50	13	RedRock
555	10:04	12	Shale	1155	11:02	12	Shale
585	10:17	13	Sand/Shale	1185	11:13	11	RR/Shale
[illegible]5	10:30	13	Shale	1215	11:23	10	Shale

COMMENTS:

OPERATOR: Seneca WELL NAME: Fee-SRC WT 37

WELL # : 38281 PERMIT #: 37-047-23884-

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVANIA 167
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
1245	11:33	10	RedRock	1845	7:25	11	Shale
1275	11:43	10	Shale	1875	7:39		Sand (Cooper 4-0)
1305	11:56	13	Shale	1905	7:52	13	Sand/Shale
1335	12:30		Shale	1935	8:03	11	Sand/Shale
1365	3:00		RR/Shale	1965	8:16		Sand (Cooper 6-0)
1395	4:20		Shale	1995	8:28	12	Sand/Shale
1425	4:30	10	Shale	2025	8:38	10	Shale
[illegible]65	4:43	13	Shale	2055	8:49	11	Shale
1485	4:55	12	Shale	2085	9:00	11	Shale
1515	5:05	10	Shale	2115	9:12	12	Shale
1545	5:20	15	Shale	2145	9:22	10	Shale
1575	5:34		Sand (Speechley 2-0)	2175	9:33	11	Shale
1605	5:45	11	Sand/Shale	2205	9:43	10	Shale
1635	5:58	13	Shale	2235	9:56	13	Sand (Elk 1-0)
1665	6:12		Sand (Speechley 6-0)	2265	10:09	13	Sand/Shale
1695	6:25	13	Sand/Shale	2295	10:20	11	Shale
1725	6:40	15	Sand (Tiona 1-0)	2325	10:31	11	Shale
1755	6:53	13	Sand/Shale	2355	10:45	14	Sand (Elk 3-0)
1785	7:04	11	RR/Shale	2385	10:48	13	Sand/Shale
[illegible]15	7:14	10	RR/Shale	2415	11:00	12	Sand/Shale

COMMENTS:

OPERATOR: Seneca WELL NAME: Fee-SRC WT 377

WELL # : 38281 PERMIT #: 37-047-23884-0

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVANIA 167
Telephone (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
2445	11:14	14	Shale				
2475	11:26	12	Shale				
2505	11:36	10	Shale				
2535	11:46	10	Shale				
2544	11:57	11	TD Shale				

COMMENTS:

Underground Sources of Drinking Water – Seneca Well #38268/Highland Township, Elk County, PA

The site lies within the Glaciated High Plateau section of the Appalachian Plateaus Physiographic province. The High Plateau Section consists of broad, rounded to flat uplands cut by deep angular valleys. The uplands are underlain by flat-lying sandstones and conglomerates. Local relief between valley bottoms and adjacent uplands can be as much as 1,000 feet, but is generally in the area of half that amount. Elevations in the area range from 980 to 2,360 feet. Drainage of the area has a dendritic pattern. The western boundary of the area is the Late Wisconsin glacial border. The area between this border and the Allegheny River a few miles to the east was glaciated by pre-Wisconsin glaciers. The area occurs in northwestern Pennsylvania and includes all of Forest County, most of Venango, Warren, and Elk Counties, and small parts of McKean, Jefferson, and Clarion Counties (http://www.dcnr.state.pa.us/topogeo/map13).

Bedrock is generally used for potable water in the project area. The well log for Well #38268 indicates that the uppermost bedrock unit at the site is the Allegheny Group of Pennsylvanian Age. The Allegheny Group consists of limestone, sandstone, shale, and coal deposits. At a depth of 30 to 35 feet below ground surface (bgs) the Pennsylvanian Age Pottsville Group also consists of limestone, sandstone, shale, and coal deposits. At approximately 200 feet bgs lies the Mississippian-Devonian Age Shenango through Oswayo undivided, which consist of sandstone, siltstone, and shale. The Upper Devonian siltstones, shale, and sands are present beneath the site beginning from approximately 500 feet bgs to the total depth of the borehole at 2530 feet bgs. (http://www.dcnr.state.pa.us/topogeo/index.aspx). The units are described further in Section 5.

The Pennsylvania Geologic Survey "Ground Water Inventory System" (PAGWIS) was accessed to determine the sources of groundwater in the site area. According to these publicly available records, there are no groundwater wells within ¼ mile of the Well #38268. The nearest groundwater well is located approximately 0.8 miles to the northeast (Randy Klaiber). The Randy Klaiber well has a listed depth of 130 feet bgs and is a domestic withdrawal well. The listed information for this well is provided in Appendix A. Although this is the only well listed, the well reporting requirement was established in 1968 and is not considered to be a complete record of water wells and other wells may be present. (PAGWIS, May 23, 2012). It is noted that PAGWIS also references a National Fuel Gas Supply Corporation well which is located approximately 0.75 miles to the southeast. The National Fuel Gas Supply Corporation Well depth is 2389 feet bgs, and according to PAGWIS, is classified as a "test well". This well is a natural gas well.

Well # 38268 is located in the northeastern corner of Highland Township of Elk County. To better understand the underground sources of drinking water, the PAGWIS was searched for all wells within Highland Township and Jones Township (bordering east of Highland Township) of Elk County, and Wetmore Township (bordering north of Highland Township) of McKean County. The PAGWIS indicated that there are 49 recorded wells in Highland Township. Twelve of these wells are owned by National Fuel Gas and according to PAGWIS are listed as test wells (i.e., natural gas wells) ranging from 1176 to 2348 feet deep. The deepest water withdrawal well is listed as 320 feet deep, with reported well depths ranging from 58 to 320 feet deep. The PAGWIS indicated that there are 155 recorded wells in Jones Township. Four of these wells are owned by National Fuel Gas and are listed as test wells ranging from 2331 to 2389 feet deep. The deepest water well is listed as 320 feet deep, with reported well depths ranging from 60 to 320 feet deep. The PAGWIS indicated that there are 41 recorded water wells in Wetmore Township. The deepest well is listed as 245 feet deep, with reported well depths ranging from 55 to 245 feet deep. Based on the available information, the Allegheny Group, Pottsville Formation, and Shenango Group are utilized as underground sources of drinking water in the site area.

In summary, PAGWIS indicates that the deepest ground water wells in the site area are approximately 320 feet deep. Based on this information and the site geologic conditions, 400 feet bgs has been identified as a conservative estimate of the base of the lowermost USDW for the proposed injection well area. It is noted that surface casing for the proposed injection well extends to 553 feet, which is greater than 200 feet deeper than the deepest groundwater drinking source in the Tri-Township Area.

Groundwater Wells within 1 mile of Seneca Well #38268
Highland Township, Elk County, PA

Water Wells									
PAWellID	DateDrilled	Owner	WellDepth	Depth To Bedrock	WellUse	Borehole Bottom	Bore Hole Diameter	Casing Bottom	Casing Diameter
100718	8/1/1987	KLAIBER RANDY	130	28	WITHDRAWAL				

Injection and Confining Zones

The proposed injection well is designed to inject into the Upper Devonian Elk 3 Sand, with injection into notched and frac'd intervals at a depth of 2354 to 2403 feet bgs.

As shown on the generalized stratigraphic column (attached), most of the geologic Groups and Formations overlying the Elk 3 Sand can be considered confining units totaling approximately 2,000 feet. Although many of these units are predominantly shale and siltstone, the Upper Devonian Speechley Sand also contains reservoir rock and this zone is highlighted yellow in the stratigraphic column.

The uppermost units at the site are mapped as the Allegheny Group of Pennsylvanian Age and the Pennsylvanian Age Pottsville Group of which both consist of limestone, sandstone, shale, and coal deposits. At approximately 200 feet bgs, the Mississippian-Devonian Age Shenango through Oswayo undivided consists of sandstone, siltstone, and shale to approximately 500 feet bgs. The Upper Devonian siltstones, shale, and sands are present beneath the site beginning from approximately 500 feet bgs.

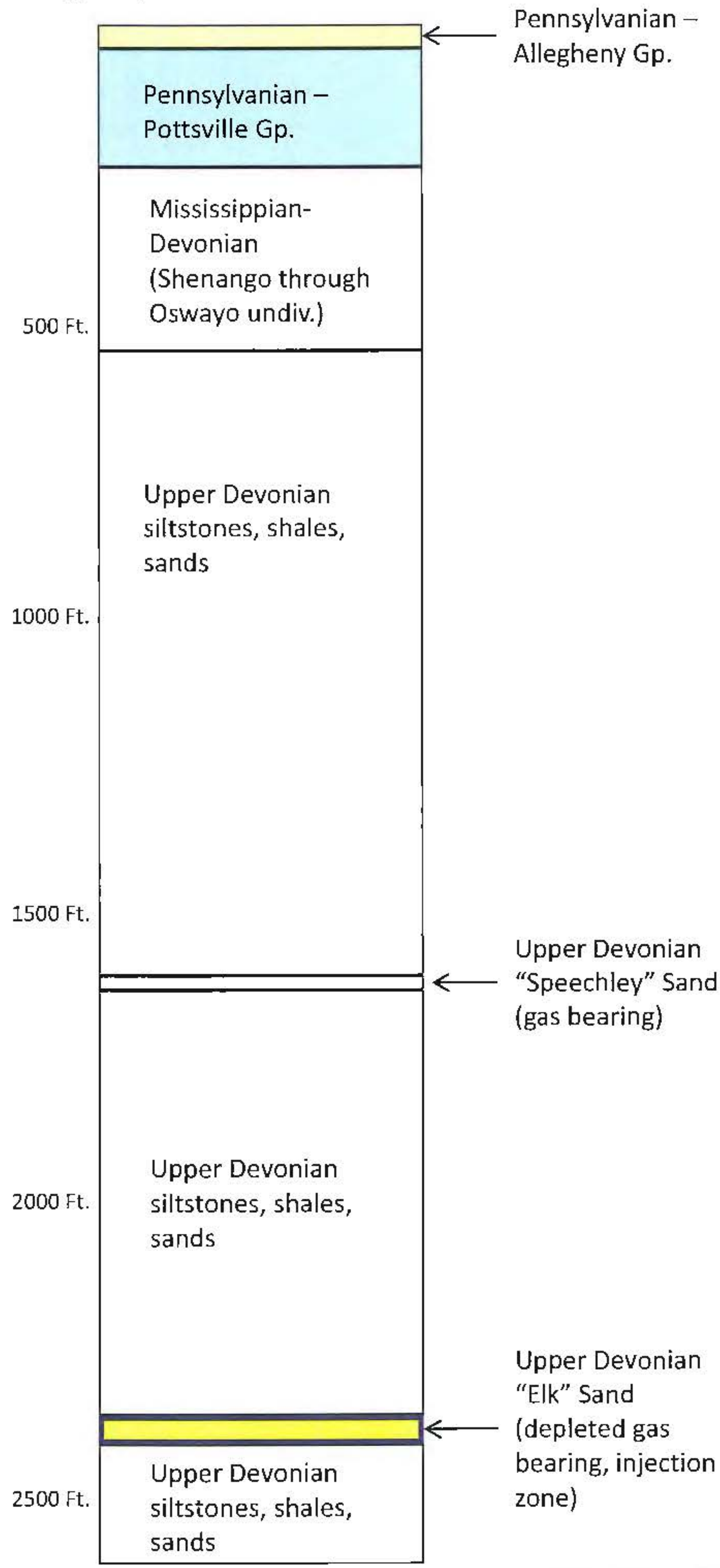
Also attached are the following:

- Seneca Well #38268 completion record, treatment record, service company job logs documenting cement returns, and geophysical log,
- Maximum Injection Pressure (MIP) calculations based on Instantaneous Shut-In Pressure (ISIP) data for Seneca Well #38268,
- Seneca #38281 (proposed monitoring well) completion record and treatment report.

GEOLOGIC DATA

GENERALIZED STRATIGRAPHIC COLUMN

Stratigraphic Column



GEOLOGIC DATA

38268 WELL RECORD

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT 7 &C

DEP USE ONLY	
DEP Application Tracking #	G: 2/20/07
Permit # 047-23835	C:
Project #	

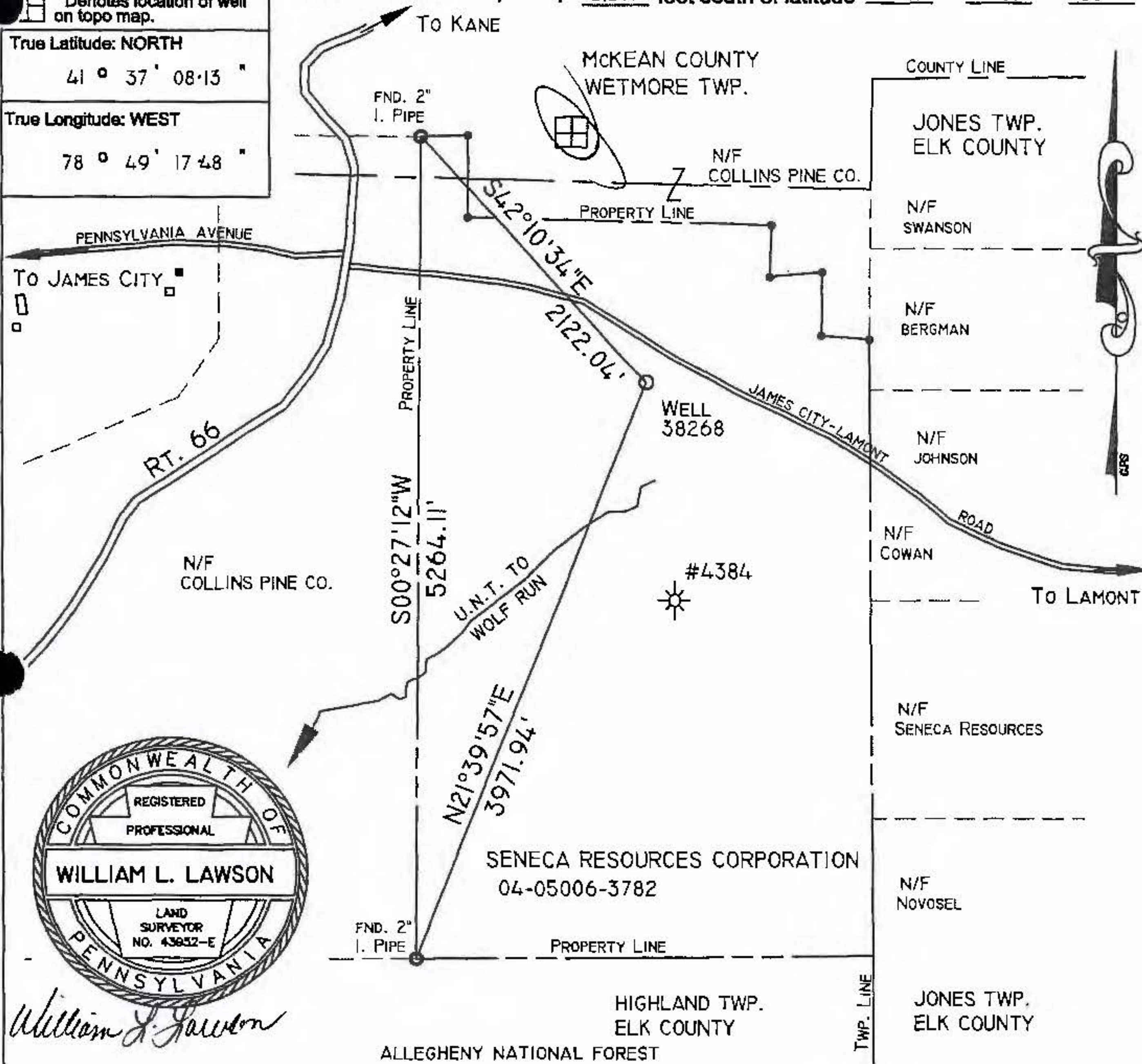
Well is located on topo map 2,207 feet south of latitude 41° 37' 30"

Denotes location of well on topo map.

True Latitude: NORTH 41° 37' 08.13"

True Longitude: WEST 78° 49' 17.48"

Well is located on topo map 8,163 feet west of longitude 78° 47' 30"



William L. Lawson

Surveyor or Engineer WILLIAM L. LAWSON | Phone # (814) 752-2291 | Dwg. # P:/WELLFILES/38268.DWG | Date 02/09/07 | Scale 1" = 1000' | Tract Acreage 299.6

Lat. & Long Metadata Method GPSDF Accuracy +/- 3 ft. Datum NAD - 27	Elevation Metadata Method TOPO Accuracy +/- 10 ft. Datum NGVD-29		Survey Date 01/30/07
Applicant / Well Operator Name SENECA RESOURCES CORPORATION	Well(Farm) Name FEE- SRC WT. 3771	Well # 38268	Serial #
Address 286 OLD 36 ROAD SIGEL, PA 15860	County - Code ELK - 24	Municipality HIGHLAND TOWNSHIP	
Surface Landowner SENECA RESOURCES CORPORATION	USGS 7 1/2 Quadrangle Map Name JAMES CITY, PA	0615	Map Section "2"
Surface Lessor NONE	Angle & Course of Deviation (Drilling) VERTICAL	Surface Elevation 2040 ft	Anticipated Total Depth 2530 ft
Surface Owner or Water Purveyor with a Water Supply within 1,000	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
NONE			

HQ

Martin Run

WATERSHED

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LYNN AUG 15

WELL RECORD AND COMPLETION REPORT

DEP USE ONLY

Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

Well Operator SENECA RESOURCES CORPORATION	DEP ID# 72993	Well API # (Permit / Reg) 37-047-23835-00	Project Number / Acres
Address 286 OLD 36 ROAD		Well Farm Name FEE SENECA RESOURCES WARRANT 3771	Well # 38268 / Serial #
City SIGEL	State PA / Zip Code 15860	County Elk	Municipality Highland
Phone 814-725-2291	Fax 814-752-6204	USGS 7.5 min quadrangle map James City 2	

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type ☒ Gas ☐ Oil ☐ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
3/20/07	3/22/07	2040'	2530'	2532'

Casing and Tubing

Cement returned on surface casing? ☒ Yes ~~No~~ See Drillers Log
Cement returned on coal protective casing? ☐ Yes No X N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	Material Behind Pipe Type and Amount	Packer / Hardware / Centralizers Type	Size	Depth	Date Run
11 ¼	9 5/8	26	T	63					
8 ¾	7	17	T	553	106 sks. Common Class A, 3% CaCl, ½#unicele			523, 349, 175	3/21/07
6 1/4	2 3/8		T	2498					7/03/07
	5/8		T	2475					7/03/07

COMPLETION REPORT

Perforation Record Date	Interval Perforated From	To	Stimulation Record Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			7/03/07	1667 0	Gel Water	8770 gal	20/40 sand	120 sks	19 8
				1671 5	Gel Water	11,040 gal	20/40 sand	160 sks	20
				1676 0	Gel Water	10,910 gal	20/40 sand	160 sks	20
				1721 0	Gel Water	8910 gal	20/40 sand	120 sks	20
				1739 5	Gel Water	9250 gal	20/40 sand	120 sks	20 3

Natural Open Flow mcfd	Natural Rock Pressure	Hours	Days
After Treatment Open Flow Mcfd 350	After Treatment Rock Pressure 125	Hours	Days 2

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name Dallas-Morris Drilling Co	Name Universal Well Services	Name Schlumberger
Address Morris Lane	Address P O Box 180	Address 95 Rutherford Run
City - State – Zip Bradford PA 16701	City - State – Zip Bradford, PA 16701	City - State – Zip Bradford, PA 16701
Phone (814) 362-6493	Phone (814) 368-6175	Phone (814) 362-7441

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LOG OF FORMATIONS

Well API#: 37-053-23835-00

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

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WARREN DISTRICT OFFICE

Well Operator's Signature: Guy A. Shuey

Title: Superintendent / Prod. & Eng. Date: 7/26/07

DEP USE ONLY

Reviewed by: Ceny Date: 6-4-08

Comments.

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ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	
Bits Used:	12 ¼", 8 ¾", 6 ¼"				
Fuel Use:	Spud: 8057	T. D.: 8916	Rig Hours:	5051 - 5093	

TOP	BOTTOM	FORMATIONS	TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock	1910	1925	Gas
5	15	Sand	1925	1980	Cooper 4.0 & Sand
15	40	Sand	1980	2135	Cooper 6.0
40	55	Sand	2135	2275	Gas
55	70	Shale	2275	2295	Elk 1.0 (gas)
70	95	Sand	2295	2355	Sand (gas)
95	120	Sand & Shale	2355	2390	Gas
120	225	Sand	2390	2420	Elk 4.0
225	415	Sand & Shale	2420	2510	Sand (gas)
415	558	Sand	2510	2530	Sand
558	635	Red Rock	2530		Total Depth
635	650	Shale			
650	820	Red Rock			
820	865	Shale			
865	915	Red Rock			
915	1270	Sand & Shale			
1270	1345	Sand			
1345	1360	Red Rock			
1360	1385	Sand & Shale			
1385	1555	Base Warren 1.0			
1555	1565	Red Rock			
1565	1575	Sand			
1575	1598	T-12 Marker			
1598	1675	Speechley 2.0			
1675	1725	Gas			
1725	1750	Speechley 6.0 (gas)			
1750	1765	Gas			
1765	1875	Tiona 1.0			
1875	1890	Red Rock (gas)			
1890	1910	Sand			

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WARREN DISTRICT OFFICE

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ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

DALLAS-MORRIS DRILLING, INC.

WELL OWNER: Seneca Resources Corporation	WELL NO.: 38268
LEASE: Fee-SRC Warrant 3771	SPUD DATE: 3/20/07
TOWNSHIP: Highland	T.D. DATE: 3/22/07
COUNTY: Elk	TOTAL DEPTH: 2530'
PERMIT NO.: 37-047-23835-00	RIG NO.: RD-23

62.6	FT	CONDUCTOR CASING	9 5/8"	SIZE	CEMENT
	FT	CONDUCTOR CASING		SIZE	106 sks
553.2	FT	SURFACE CASING	7"	SIZE	7 bbl cement returns
275	FT	FRESH WATER DEPTH	5 GPM	SIZE	
290	FT	FRESH WATER DEPTH	10 GPM	SIZE	
325	FT	FRESH WATER DEPTH	15 GPM	SIZE	
415	FT	FRESH WATER DEPTH	20 GPM	SIZE	
Bits Used:	12 ¼", 8 ¾", 6 ¼"				
Fuel Use:	Spud: 8057	T. D.: 8916	Rig Hours:	5051 - 5093	

TOP	BOTTOM	FORMATIONS	TOP	BOTTOM	FORMATIONS
0	5	Dirt & Rock	1910	1925	Gas
5	15	Sand	1925	1980	Cooper 4.0 & Sand
15	40	Sand	1980	2135	Cooper 6.0
40	55	Sand	2135	2275	Gas
55	70	Shale	2275	2295	Elk 1.0 (gas)
70	95	Sand	2295	2355	Sand (gas)
95	120	Sand & Shale	2355	2390	Gas
120	225	Sand	2390	2420	Elk 4.0
225	415	Sand & Shale	2420	2510	Sand (gas)
415	558	Sand	2510	2530	Sand
558	635	Red Rock	2530		Total Depth
635	650	Shale			
650	820	Red Rock			
820	865	Shale			
865	915	Red Rock			
915	1270	Sand & Shale			
1270	1345	Sand			
1345	1360	Red Rock			
1360	1385	Sand & Shale			
1385	1555	Base Warren 1.0			
1555	1565	Red Rock			
1565	1575	Sand			
1575	1598	T-12 Marker			
1598	1675	Speechley 2.0			
1675	1725	Gas			
1725	1750	Speechley 6.0 (gas)			
1750	1765	Gas			
1765	1875	Tiona 1.0			
1875	1890	Red Rock (gas)			
1890	1910	Sand			

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INVOICE NO. 536463

STAGE NO.

UNIVERSAL WELL SERVICES INC

JOB LOG

CUSTOMER Seneca Res

LEASE NAME 38268

DATE 3-21-07

	NO. OF SACKS	COMPOSITION OF CEMENT	YIELD	GAL. WTR/SK	DENSITY	BBL. OF MIX WTR.	CU. FT. OF SLURRY	BBL. OF SLURRY
1.	106	class A, 3% cacl2, ½# sk unicele	1.18	5.2	15.6	13.1	125	22.2
2.								
3.								
					TOTAL	13.1	125	22.2

CIRCULATE CEMENT TO SURFACE

☒ Yes ☐ No ☐ Not Applicable

7 bbls return

JOB TYPE

☒ Surface ☐ Longstring ☐ Acid

☐ Other

7" surface

	NEW USED	SIZE	FROM	TO	WEIGHT	MAXIMUM PSI ALLOWANCE
CASING	N	7"	0	553.2	17#	
TUBING						
OPEN HOLE		8¾	553.2	568		
~~PERFORATIONS~~ LJ			4'			

DISPLACEMENT CAPACITY 23.1 BBL.

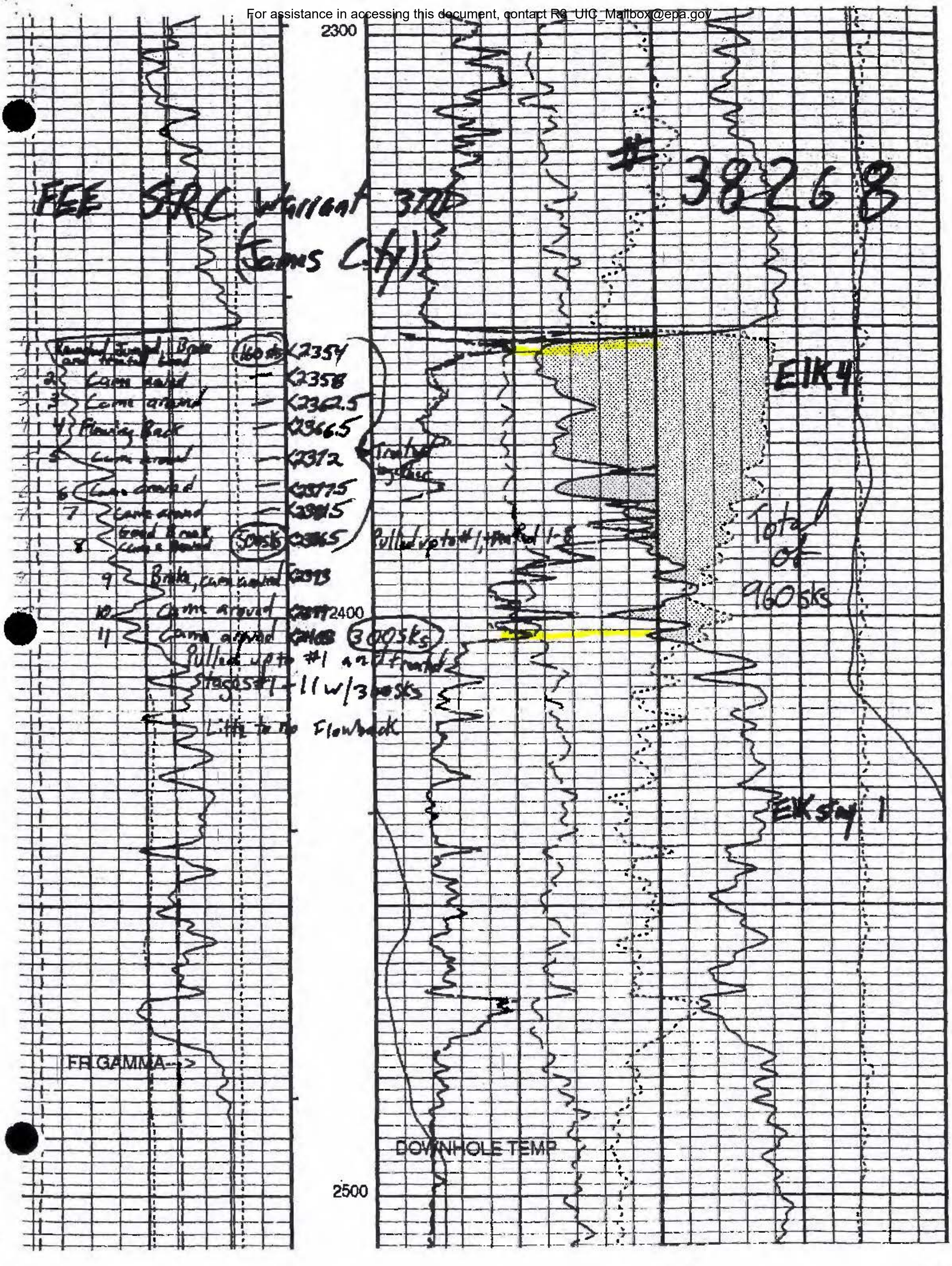
DISPLACEMENT DEPTH 557.2 FT.

TIME	RATE (BPM)	VOLUME (BBL)	PRESSURE (PSI) TUBING	PRESSURE (PSI) CASING	DESCRIPTION OF STAGE OR EVENT
1830					SPOT Truck, rig up
1855					Safety meeting
1900	2-3	10		0-50	Start H_2O
1903	3	10		50-100	Start Gel unicele
1906	3	5		100	Start spacer
1909	3-4	22.2		100-200	Start class A, 3% cacl2, ½# sk unicele
1916					SDTP
1918	4-2	23.1		0-550	Start H_2O displacement
1925					Plug Landed; closed manifold
1928				550-0	releis pressure, wash up
1945					rig down
					Job complete

REMARKS Ph 7 H_2O 38 W&D sample

SERVICE ENGINEER Everly

CUSTOMER REPRESENTATIVE Ryan Kentratt


2300
FEE SRC
(Jones City)
38268
160 sks
2354
2 Came around 2358
3 Came around 2362.5
4 Flowing Back 2366.5
5 Came around 2372
6 Came around 2377.5
7 Came around 2381.5
8 Good Break Came around 500 sks 2386.5
Pulled up to #1, treated 1-8
9 Broke, came around 2393
10 Came around 2400
11 Came around 2408 300 sks
Pulled up to #1 and treated stages #1-11 w/300 sks
Little to no Flowback
Elk 4
Total of 960 sks
Elk stg 1
FR GAMMA-->
DOWNHOLE TEMP
2500

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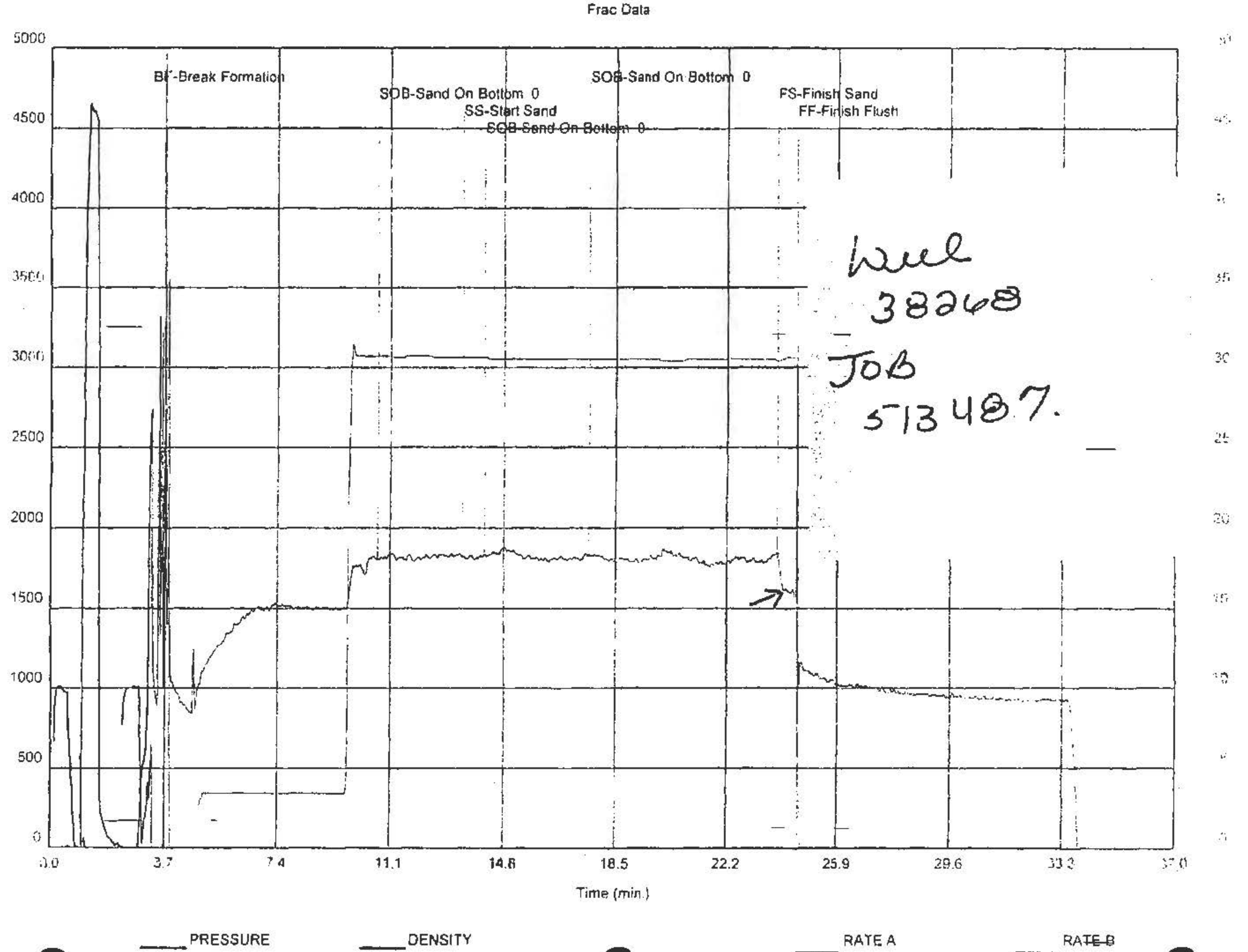
#1 (60 SKS) 4/5/07
Elk 4



Well 38268
JOB 513487.

GEOLOGIC DATA

38281 WELL RECORD

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program
WELL LOCATION PLAT

T & C

DEP USE ONLY	DEP Application Tracking #	G: 5/10/07
	Permit # 047-23884	
	Project #	C:

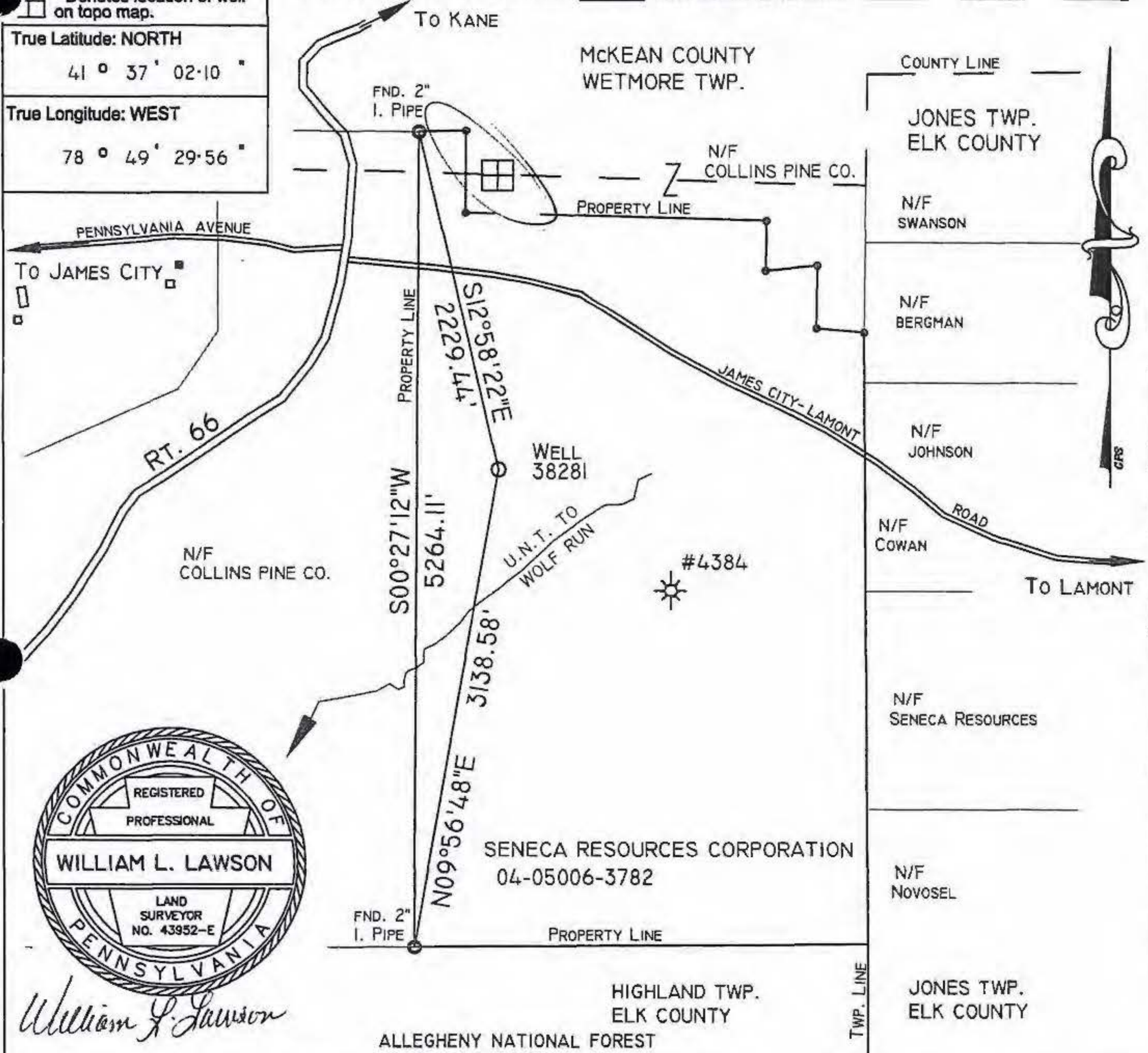
Well is located on topo map 2,815 feet south of latitude 41 ° 37 ' 30 "

Well is located on topo map 9,081 feet west of longitude 78 ° 47 ' 30 "

Denotes location of well on topo map.

True Latitude: NORTH
41 ° 37 ' 02.10 "

True Longitude: WEST
78 ° 49 ' 29.56 "



William L. Lawson

Surveyor or Engineer WILLIAM L. LAWSON Phone # (814) 752-2291 Dwg. # P:/WELLFILES/38281.DWG Date 04/09/07 Scale 1" = 1000' Tract Acreage 299.6

Lat. & Long Metadata Method GPSDF Accuracy +/- 3 ft. Datum NAD - 27	Elevation Metadata Method TOPO Accuracy +/- 10 ft. Datum NGVD-29	Survey Date 02/30/07
Applicant / Well Operator Name SENECA RESOURCES CORPORATION	Well(Farm) Name FEE- SRC WT. 3771	Well # 38281 / Serial #
Address 286 OLD 36 ROAD SIGEL, PA 15860	County - Code ELK - 24	Municipality HIGHLAND TOWNSHIP
Surface Landowner SENECA RESOURCES CORPORATION	USGS 7 1/2 Quadrangle Map Name JAMES CITY, PA 0615	Map Section "2"
Surface Lessor NONE	Angle & Course of Deviation (Drilling) VERTICAL	Surface Elevation 2020 ft. / Anticipated Total Depth 2570 ft.
Surface Owner or Water Purveyor with a Water Supply within 1,000 ft. NONE	Approximate Course and Distance to Water Supply / Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated

HQ

WATERSHED Martin Run

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5500-PM-OG0004 Rev 3/00

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil & Gas Management Program

WELL RECORD AND COMPLETION REPORT

DEP USE ONLY	
Auth #	APS #
Site #	Facility #
FIX Client #	Sub-fac #

Well Operator SENECA RESOURCES CORPORATION	DEP ID# 72993	Well API # (Permit / Reg) 37-047-~~32884~~ 23884	Project Number	Acres
Address 51 Zents Blvd		Well Farm Name FEE-SRC Wt 3771	Well # 38281	Serial #
City Brookville	State PA	Zip Code 15825	County McKean	Municipality Highland
Phone 814-849-4555	Fax 814-849-4795	USGS 7 5 min quadrangle map	

WELL RECORD Also complete Log of Formations on back (page 2)

Well Type ☐ Gas ☐ Oil ☒ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☒ Rotary - Air ☐ Rotary - Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
01/22/08	01/24/08	2020	2544	2540

Casing and Tubing

Cement returned on surface casing? ☒ Yes ☐ No
Cement returned on coal protective casing? ☐ Yes ☐ No ☒ N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	*Material Behind Pipe* Type and Amount	*Packer / Hardware / Centralizers* Type Size Depth	Date Run
12 ¼	9 5/8	26	T	47			01/22/08
8 ¾	7	17	T	602	124 sks Class A Cement, 3% CaCl, ½# unicele/sk	3 centralizers	01/23/08
¼	2 3/8	4.9	T	2482			03/11/08
	5/8		T	2475			03/11/08

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NORTHWEST REGIONAL OFFICE

COMPLETION REPORT

Perforation Record: Date	Interval Perforated From	To	Stimulation Record: Date	Interval Treated	Fluid Type	Fluid Amount	Propping Agent Type	Propping Agent Amount	Average Injection Rate
			03/11/08	1650	Gel Water	8460	20/40 sks	120	20
				1655	Gel Water	9620	20/40 sks	140	20
				1658	Gel Water	10728	20/40 sks	160	20
				1662	Gel Water	8672	20/40 sks	140	20
				1704	Gel Water	7401	20/40 sks	100	20
				1719	Gel Water	9111	20/40 sks	120	20

Natural Open Flow Mcfd 1 | Natural Rock Pressure | Hours | Days
After Treatment Open Flow Mcfd 500 | After Treatment Rock Pressure | Hours | Days

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name Natural Oil and Gas	Name Keane and Sons Drilling	Name Schlumberger
Address 1410 W Warren Road	Address 12 Keane Lane	Address 95 Rutherford Run
City - State – Zip Bradford, PA 16701	City - State – Zip Bradford, PA 16701	City - State – Zip Bradford, PA 16701
Phone 814-362-2543	Phone 814-362-2659	Phone 814-362-7441

COMPLETION REPORT API#37-047-32884

Perforation Record			Stimulation Record						
Date	Interval Perforated		Date	Interval Treated	Fluid		Propping Agent		Average
	From	To			Type	Amount	Type	Amount	Injection Rate
			03/11/08	1728	Gel Water	8779	20/40 Sand	120	20
				1734	Gel Water	8779	20/40 Sand	120	20
				1893	Gel Water	7567	20/40 Sand	100	20
				2123	Gel Water	8770	20/40 Sand	120	17
				2133	Gel Water	9949	20/40 Sand	140	20
				2151	Gel Water	9903	20/40 Sand	140	19
				2156	Gel Water	10256	20/40 Sand	140	18
				2339-2390	Gel Water	23228	20/40 Sand	500	23
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		
					Gel Water		20/40 Sand		

LOG OF FORMATIONS

Well API#: 37-047-32884

Formation Name	Top	Bottom	Gas at	Oil at	Water at (Fresh or Brine)	Source of Data
SEE ATTACHED						

RECEI[illegible]
APR

Well Operator's Signature:

Guy A. Shuey

Title: Superintendent / Prod. & Eng. Date: 4/14/08

DEP USE ONLY

Reviewed by: T Carney

Date: 6-4-08

Comments:

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVAN
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL #	38281	PERMIT #	37-047-23884
SPUD DATE	1/22/2008	COUNTY	Elk
SPUD TIME	4:30 p.m.	TOWNSHIP	Highland
CONDUCTOR	47 ft.	LEASE	James City
CASING	603 ft.	TD DATE	1/24/2008
TOTAL DEPTH	2544 ft.	TD TIME	11:57 a.m.

PIPE TALLY

1	23.2 ft.	7	23.2 ft.	13	23.2 ft.	19	23.2 ft.	25	23.2 ft.
2	23.2 ft.	8	23.2 ft.	14	23.2 ft.	20	23.2 ft.	26	23.2 ft.
3	23.2 ft.	9	23.2 ft.	15	23.2 ft.	21	23.2 ft.	27	
4	23.2 ft.	10	23.2 ft.	16	23.2 ft.	22	23.2 ft.	28	
5	23.2 ft.	11	23.2 ft.	17	23.2 ft.	23	23.2 ft.	29	
6	23.2 ft.	12	23.2 ft.	18	23.2 ft.	24	23.2 ft.	30	

#JOINTS	26	CEMENT CO.	Universal
SACKS	124	RETURNS	6 Barrels
PLUG DOWN	9:45 a.m.	CEMENT DATE	1/23/2008

OPERATOR: Seneca WELL NAME: Fee-SRC WT 37

WELL # : 38281 PERMIT #: 37-047-23884-(

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD, BRADFORD, PENNSYLVANIA 167
Telephone: (814) 362-6890 Fax (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
45	4:30		Gravel, Shale	645	10:40	10	Shale
75	4:56		Shale	675	8:02	12	Shale
105	6:00		Shale	705	8:11	9	Shale
135	6:11	11	SandStone	735	8:21	10	Shale
165	6:21	10	SS/Shale	765	8:31	10	RedRock
195	6:34	13	Shale	795	8:43	12	RR/Shale
225	6:45	11	Shale	825	8:53	10	Shale
255	6:58	13	Sand	855	9:04	11	Shale
285	7:10	12	Shale	885	9:16	12	Shale
315	7:25	15	Sand	915	9:27	11	Shale
345	7:37	12	Shale	945	9:40	13	Shale
375	8:49	12	RedRock	975	9:55	15	RedRock
405	9:00	11	RedRock	1005	10:05	10	Shale
435	9:12	12	RR/Shale	1035	10:15	10	Shale
465	9:26	14	Sand/Shale	1065	10:26	11	RedRock
495	9:40	12	Shale	1095	10:37	11	RedRock
525	9:52	12	Shale	1125	10:50	13	RedRock
555	10:04	12	Shale	1155	11:02	12	Shale
585	10:17	13	Sand/Shale	1185	11:13	11	RR/Shale
[illegible]15	10:30	13	Shale	1215	11:23	10	Shale

COMMENTS:

OPERATOR: Seneca WELL NAME: Fee-SRC WT 37

WELL # : 38281 PERMIT #: 37-047-23884-

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD. BRADFORD, PENNSYLVANIA 16
Telephone: (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
1245	11:33	10	RedRock	1845	7:25	11	Shale
1275	11:43	10	Shale	1875	7:39		Sand (Cooper 4-0)
1305	11:56	13	Shale	1905	7:52	13	Sand/Shale
1335	12:30		Shale	1935	8:03	11	Sand/Shale
1365	3:00		RR/Shale	1965	8:16		Sand (Cooper 6-0)
1395	4:20		Shale	1995	8:28	12	Sand/Shale
1425	4:30	10	Shale	2025	8:38	10	Shale
1455	4:43	13	Shale	2055	8:49	11	Shale
1485	4:55	12	Shale	2085	9:00	11	Shale
1515	5:05	10	Shale	2115	9:12	12	Shale
1545	5:20	15	Shale	2145	9:22	10	Shale
1575	5:34		Sand (Speechley 2-0)	2175	9:33	11	Shale
1605	5:45	11	Sand/Shale	2205	9:43	10	Shale
1635	5:58	13	Shale	2235	9:56	13	Sand (Elk 1-0)
1665	6:12		Sand (Speechley 6-0)	2265	10:09	13	Sand/Shale
1695	6:25	13	Sand/Shale	2295	10:20	11	Shale
1725	6:40	15	Sand (Tiona 1-0)	2325	10:31	11	Shale
1755	6:53	13	Sand/Shale	2355	10:45	14	Sand (Elk 3-0)
1785	7:04	11	RR/Shale	2385	10:48	13	Sand/Shale
[illegible]15	7:14	10	RR/Shale	2415	11:00	12	Sand/Shale

COMMENTS:

OPERATOR: Seneca

WELL NAME: Fee-SRC WT 37

WELL # : 38281

PERMIT #: 37-047-23884-(

NATURAL OIL & GAS CORP.

1410 WEST WARREN ROAD. BRADFORD. PENNSYLVANIA 167
Telephone (814) 362-6890 Fax: (814) 362-6120

WELL DEPTH	TIME	MINUTES	FORMATION	WELL DEPTH	TIME	MINUTES	FORMATION
2445	11:14	14	Shale				
2475	11:26	12	Shale				
2505	11:36	10	Shale				
2535	11:46	10	Shale				
2544	11:57	11	TD Shale				

COMMENTS:

GEOLOGIC DATA

MAXIMUM INJECTION PRESSURE CALCULATIONS

Maximum Injection Pressure (MIP) Calculations for Seneca Well #38268

1) Frac Gradient Based on Well #38268

FG = [ISIP + (.433 X SG X D)] /D
Where:
ISIP = 1580 psi
SG = 1.0
D = 2354

Well	ISIP (psi)*	Hydrostatic Factor (psi/ft)	SG	D (ft)	Fracture Gradient (psi/ft)
Well #38268	1580	0.433	1	2354	1.104

2) Maximum Injection Pressure (MIP) Using Average Frac Gradient From Well #38268

	FG	SG	Depth	MIP
MIP = [FG - (.433XSG)] X D	1.104	1.14	2354	1437

Top Perf	2354	Top of Perforations Used For Calculation
Bottom Perf	2403	

Operating Data

The proposed brine disposal well will primarily be utilized to inject produced and flowback water from wells completed in the Marcellus Shale, the Elk 3 Sand and other natural gas and oil producing formations. Other oil and gas related wastewaters associated with the production of oil and natural gas or natural gas storage operations, which are approved by EPA for injection under a UIC Class II D injection well, may also be injected. According to Title 40 Chapter I Sec. 144.6 (b)(1), such fluids include those "Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection."

Injection Rate

Injectivity testing performed on the proposed injection well (Seneca #38268 indicated the well may be capable of sustaining an injection rate of greater than 2 bpm (approximately 3000 bpd) with pressures remaining under the likely UIC Class IID permit limits for maximum injection pressure. A maximum injection rate of 3,000 bbl/day is proposed for operation of the facility, with an average injection rate of 2,000 bbl/day expected.

Maximum Allowable Surface Injection Pressure (MASIP) and Average Surface Injection Pressure

MASIP calculations based on EPA approved equations are included in the "Geologic Data" section of this application. Based on these calculations, the proposed MASIP is 1437 psi. It is estimated that the average surface injection pressure will be approximately 1000 psi.

Laboratory Analysis of Injection Fluid Samples

A summary of laboratory analytical results for samples representative of the types of brine which will be injected into the proposed injection well are attached. Samples were collected from produced water generated from gas wells in the vicinity of the injection well. The samples are characterized by an average specific gravity of approximately 1.14, pH of 6.08, and conductivity of 194.09.

Monitoring of Injection Fluid Samples and Well

The following identifies the UIC Class II underground injection well regulatory requirements and operational procedures which will be conducted to meet the subject requirements:

1. **Monitoring of the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics**. An initial sample of fluid will be collected and

analyzed from initial loads proposed for disposal. In addition, samples will be collected for analysis from new types of sources (e.g., from different geologic formations, geographic regions, etc.) which would be expected to differ significantly from brine previously characterized for disposal at the facility. Samples will be analyzed for the following parameters at a minimum: specific gravity, total dissolved solids, total organic carbon, and pH.

2. **Observation of injection pressure, flow rate, and cumulative volume at least weekly based on the regulatory requirements for produced fluid disposal operations.** Injection pressures, flow rate, and cumulative volume will be continuously recorded electronically.

3. **A demonstration of mechanical integrity pursuant to 40 CFR Sec. 146.8 at least once every five years during the life of the injection well.** A mechanical integrity test will be performed prior to initiating injection and at least once every five years.

4. **Maintenance of the results of all monitoring until the next permit review.** All monitoring records will be maintained throughout the life of the well.

Reporting requirements consist of the following:

An annual report will be submitted to EPA summarizing the results of the required monitoring, including monthly records of injected fluids, and any major changes in characteristics or sources of injected fluid.

Proposed Annulus Fluid

The proposed annulus fluid for the proposed injection well will consist of fresh water and a water soluble corrosion inhibitor. The corrosion inhibitor will be mixed in accordance with the manufacturer's recommendations then loaded into the well annulus prior to conducting injection operations. Product information for the type of corrosion inhibitor which will be utilized is attached. A similar type product may be used instead of the example product referenced.

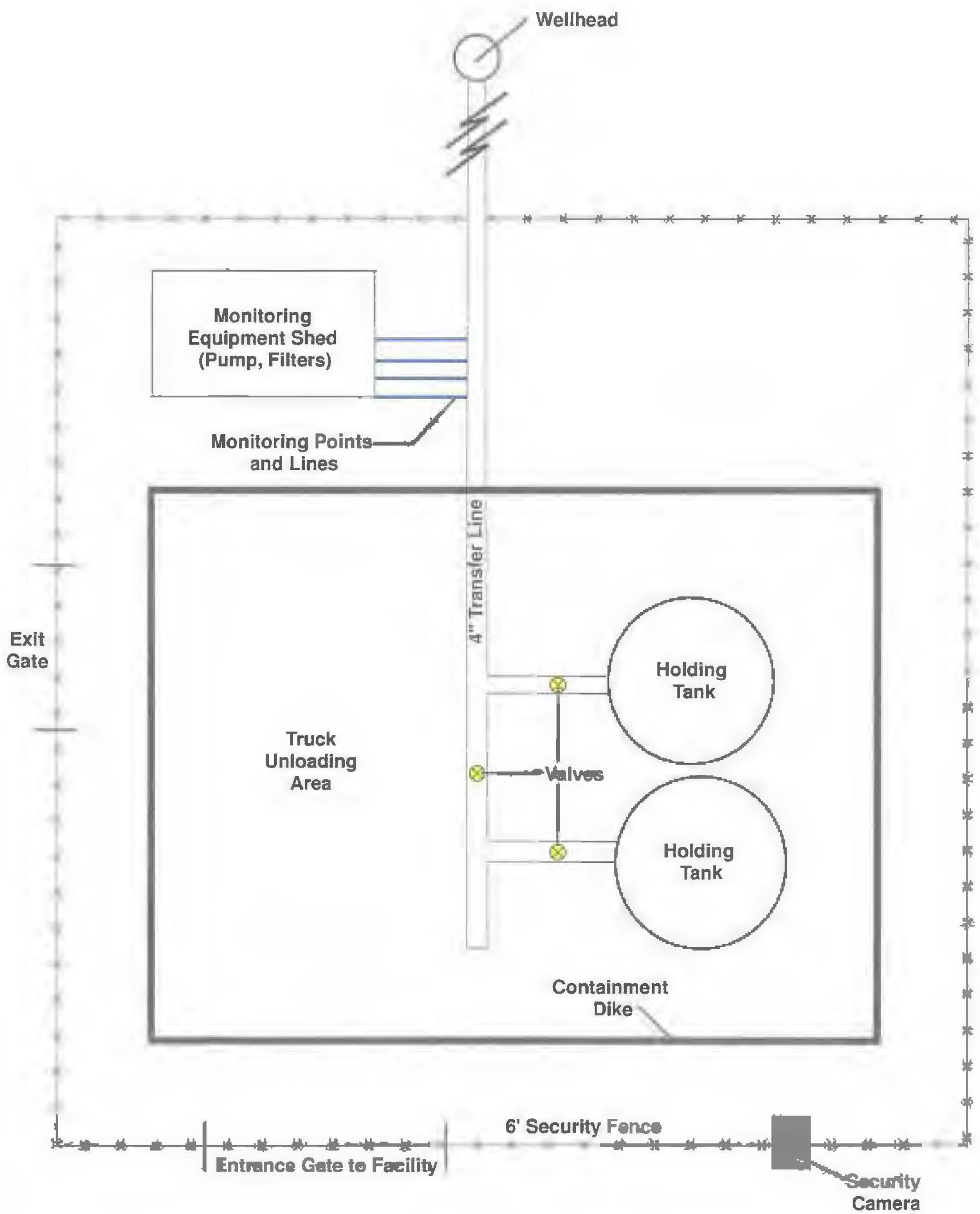
Facility Layout and Operation

As indicated in the attached facility layout diagram, the injection well facility will include a truck unloading area and holding tanks connected by piping with associated valves, all of which will be situated in a diked containment area. The containment area will be properly sized to account for the entire volume of the largest container, plus 10% freeboard, in the event of a leak. The brine will be transferred to the injection well utilizing injection pumps situated in the Equipment Shed along with filters and monitoring equipment. Automatic shut-off valves will be incorporated into the tank design to prevent overflow during filling operations. The facility will be surrounded by a fence having locking entrance and exit gates. A security camera will also be strategically situated on the site. The facility will be continually manned during unloading and injection operations. As indicated above, injection rate, cumulative volume and pressures will be continuously measured and recorded.

OPERATING DATA

SURFACE FACILITY SCHEMATIC

P:\GIS\SENECA\MAPDOCS\MXD\SCHEMATIC_DIAGRAM.MXD 06/04/12 SP



DRAWN BY S. PAXTON	DATE 06/04/12	TETRA TECH	CONTRACT NUMBER —	
CHECKED BY E. BERKLITE	DATE 06/04/12	SENECA RESOURCES CORPORATION SURFACE FACILITY SCHEMATIC WELL # 38268 ELK COUNTY, PENNSYLVANIA	APPROVED BY —	DATE —
REVISED BY —	DATE —		APPROVED BY —	DATE —
SCALE NOT TO SCALE			FIGURE NO. —	REV 0

OPERATING DATA

TYPICAL BRINE LABORATORY ANALYSIS

Date	W.O. #	Type Of Fluid	From	To	Well Hole	Secific Gravity	Weight (lb/gal)	pH	Conductivity
FO5323									
01/09/12	26757	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1 15	9.6	5 87	212
01/08/12	18693	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
N5963									
01/07/12	18497	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1 15	9 6	5.82	207
01/07/12	30558	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5314									
12/21/11	22010	Flowback	Collins Pine Pad G frac tanks	James City Pad A	Frac Tanks	1 13	9 4	7.51	184.1
12/21/11	22015	Flowback	Collins Pine Pad G frac tanks	James City Pad A	Frac Tanks				
FO5327									
01/06/12	18689	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.13	9.45	6 26	191
01/05/12	26756	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5324									
01/07/12	18691	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.16	9.65	5.77	210.2
01/07/12	18497	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5315									
01/11/12	18376	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1 11	9 2	6.01	158.3
01/11/12	18696	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
01/09/12	26757	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5215									
01/09/12	18500	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.125	9.35	5 94	183 9
FO5289									
01/05/12	30553	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1.135	9.45	5 92	193.6
01/05/12	30554	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
01/05/12	18684	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
01/08/12	15104	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5322									
01/08/12	18693	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks	1 15	9 6	5.96	205.2
01/08/12	18499	Flowback	Boone Mtn Pad A frac tanks	James City Pad A	Frac Tanks				
FO5316									
nothing						1 13	9 4	5 93	189 4
N5234									
12/20/11		Flowback	Collins Pine Pad G	James City Pad A		1.15	9 6	5 92	200.3

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name: Seneca Resources
51 Zents Boulevard
Brookville, PA 15825
Sample Start Date: 2/28/2012 11:45 AM
Receipt Date: 2/28/2012 2:10 PM
Report Date: 4/3/2012
Sample Site: 26R Waste Profile

Sample ID#: 12 08933
Sample Type: Water
Sample Source: Grab
Sampler: SM (Lab employee)
Client Sample ID: James SWD

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Acidity to pH=8.3	BH	03/01	n/a	269	mg/l as CaCO3	n/a	SM2310B	2
Alkalinity to pH=4.5	BH	03/03	n/a	22	mg/l as CaCO3	n/a	SM2320B	20
Biological Oxygen Demand 05	CJ	02/29	9:44 AM	59.1	mg/l	n/a	SM5210B	2.0
Chemical Oxygen Demand	AJD	02/29	n/a	1162.5	mg/l	D	SM5220 D	500.0
'vdrogen Sulfide	SM	02/28	n/a	ND	mg/l	n/a	Hach	0.0
.mmonia as N / Distilled	BM	02/29	n/a	194.68	mg/l	n/a	SM4500NH3B & D	9.59
Bromide	BM	03/06	n/a	1910.00	mg/l	D	D1246-99	100.00
Chloride	KL	03/08	n/a	136446.00	mg/l	D	SM4500ClD	5.00
Dissolved Oxygen	SM	02/28	n/a	4.0	mg/l	n/a	SM4500 O-G	2.0
Kjeldahl Nitrogen as N	ZTR	03/14	n/a	320.8	mg/l	n/a	SM4500Norg-C,D	59.4
pH (SM)	BH	03/03	n/a	5.89	SU	R	SM 4500H-B	0.01
Sulfate ASTM	ZTR	03/13	n/a	ND	mg/l	D	D516-02	10
Total Nitrate + Nitrite as N	SR	03/01	n/a	0.08	mg/l	n/a	SM4500NO3E	0.05
Aluminum - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Arsenic-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Barium - ICP	BE	03/13	n/a	371.700	mg/l	D	200.7/6010	0.500
Beryllium - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Boron	ZTR	02/29	n/a	2.8	mg/l	D	SM 4500B-B	1.0
Cadmium - ICP	BE	03/14	n/a	ND	mg/l	D	200.7/6010	0.500
Calcium - ICP	BE	03/13	n/a	20307.000	mg/l	D	200.7/6010	50.000

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: ________________
Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Chromium - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Cobalt - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Copper - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Hardness	BE	03/13	n/a	58691	mg/l	n/a	SM2340B	1
Iron - ICP	BE	03/13	n/a	59.800	mg/l	D	200.7/6010	1.000
n,Dissolved-ICP	BE	03/13	n/a	26.600	mg/l	D	200.7/6010	1.000
Lead-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Lithium - ICP	BE	03/13	n/a	98.200	mg/l	D	200.7/6010	50.000
Magnesium-ICP	BE	03/13	n/a	1939.000	mg/l	D	200.7/6010	50.000
Manganese - ICP	BE	03/13	n/a	9.100	mg/l	D	200.7/6010	0.500
Mercury	SS	03/09	n/a	ND	mg/l	n/a	245.1	0.0010
Molybedenum - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Nickel - ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Selenium-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	1.000
Silver-ICP	BE	03/13	n/a	ND	mg/l	D	200.7/6010	0.500
Sodium - ICP	BE	03/15	n/a	35620.000	mg/l	D	200.7/6010	250.000
Strontium - ICP	BE	03/15	n/a	3242.500	mg/l	D	200.7/6010	5.000
Zinc - ICP	BE	03/13	n/a	0.800	mg/l	D	200.7/6010	0.500
Detergents, MBAS	LAW	02/29	8:30 AM	1.110	mg/l	n/a	SM5540C	0.200
Ethylene Glycol	EAC	03/01	n/a	ND	ug/L	D	SW846 8015B	2500

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: Galal J Tyl[illegible]

Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name:	Seneca Resources 51 Zents Boulevard Brookville, PA 15825	**Sample ID#:**	12 08933
		Sample Type:	Water
		Sample Source:	Grab
Sample Start Date:	2/28/2012 11:45 AM	**Sampler:**	SM (Lab employee)
Receipt Date:	2/28/2012 2:10 PM	**Client Sample ID:**	James SWD
Report Date:	4/3/2012		
Sample Site:	26R Waste Profile		

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Oil and Grease - HEM	SGT	03/05	n/a	125.5	mg/l	n/a	1664A	5.0
Phenolics, as Phenol	SR	02/29	n/a	ND	mg/l	D	420.1	0.050
pH- Field	SM	02/28	n/a	5.76	SU	n/a	SM 4500H-B	0.00
Specific Conductance	BH	03/03	n/a	176784	umhos/cm	n/a	SM 2510B	1
Total Dissolved Solids (TDS)	LMB	02/29	n/a	212500	mg/l	n/a	SM2540C	25
tal Suspended Solids	LMB	02/29	n/a	238	mg/l	n/a	SM2540D	5
1) Benzene	RO	03/03	n/a	4.64	ug/L	n/a	624/8260B	1.00
47) Toluene	RO	03/03	n/a	4.00	ug/L	n/a	624/8260B	1.00

Comments: Due to matrix of sample, a 1:2 dilution was required for sulfate analysis resulting in a ND. ZTR 03/13/2012

ND=Not Detected

DEP Certification #s 32-00382

D - Indicates an identified compound in an analysis that has been diluted R - Received out of recommended hold time.

Approved By: [signature]
Laboratory Supervisor

ENVIRONMENTAL
SERVICE LABORATORIES, INC.
1803 Philadelphia St., Indiana, PA 15701
(724) 463-TEST (724) 465-4209

Report of Analysis

Name: Seneca Resources
51 Zents Boulevard
Brookville, PA 15825
Sample Start Date: 2/28/2012 11:45 AM
Receipt Date: 2/28/2012 2:10 PM
Report Date: 4/2/2012
Sample Site: 26R Waste Profile

Sample ID#: 12 08934
Sample Type: Water
Sample Source: Grab
Sampler: SM (Lab employee)
Client Sample ID: James SWD

Analyte	Analyst	Analysis Date	Analysis Time	Sample Result	Units	Data Qualifier	Method	RPL
Radium 226	Bnchmrk	03/21	n/a	*	pCi/L	n/a	RAD-CTDHS	0.000
Radium 228	Bnchmrk	03/13	n/a	*	pCi/L	n/a	RAD-CTDHS	0.000
Thorium	Bnchmrk	03/23	n/a	*	pCi/L	n/a	RAD-CTDHS	-1.000
Uranium	Bnchmrk	03/23	n/a	*	pCi/L	n/a	RAD-CTDHS	-1.000

Comments: Radiologicals done by Benchmark Analytical, PADEP Lab ID: 39-00401

ND=Not Detected

DEP Certification #s 32-00382

Approved By: Gabriel J Tagher
Laboratory Supervisor

LAB ID: 39-00401 *CV

BENCHMARK ANALYTICS, INC.
4777 Saucon Creek Road
Center Valley, PA 18034-9004

PHONE (610) 974-8100
FAX (610) 974-8104

SEND DATA TO:

NAME: Jean M. Cole
COMPANY: Environmental Service Laboratories, Inc
ADDRESS: 1803 Philadelphia St
Indiana, PA 15701

PHONE: (724) 463-8378
FAX: (724) 465-4209

WO#: 12030411
PAGE: 1 of 7
PO#:
PWS ID#

TEST REPORT

12 08934-09155-09160-09166-09172-09190-09193

RECEIVED FOR LAB BY: GMD DATE: 03/05/2012 9:45

SAMPLE: **12 08934** Lab ID: 12030411-001A Grab
SAMPLED BY: Client Sample Time 02/28/2012 11:45

Test	Result	Uncert.	MDA	Units		Method	MCL	Analysis Start	Analysis End	Analyst *
Radium, Combined (Ra226 + Ra228)	5396			pCi/L	N	Calculation		03/26/12 10:38		BH-CV
Radium-226	4690	± 139.80	194.00	pCi/L		EPA 903.0		03/07/12 17:10	03/21/12	BH-CV
Carrier Recovery	108			%		EPA 903.0		03/07/12 17:10	03/21/12	BH-CV

SAMPLE: **12 08934** Lab ID: 12030411-001B Grab
SAMPLED BY: Client Sample Time 02/28/2012 11:45

Test	Result	Uncert.	MDA	Units	Method	MCL	Analysis Start	Analysis End	Analyst *
Radium-228	706.1	± 110.10	137.70	pCi/L	EPA 904.0		03/08/12 8:30	03/13/12	NLB-CV
Carrier Recovery	118			%	EPA 904.0		03/08/12 8:30	03/13/12	NLB-CV

REMARKS:

Where the analytical method has been performed under NELAP certification, the analysis has met all of the requirements of NELAP unless otherwise noted on the Analytical Report.

* CV = Benchmark Analytics, Inc. Center Valley, PA; SA = Benchmark Analytics, Inc. Sayre, PA

E \nalyte detected in the associated Method Blank

N Parameter is not NELAC certified

MANAGER Cli Mel DATE: 3/27/2012

LAB ID: 39-00401 *CV
LAB ID: 08-00380 *SA

Benchmark Analytics, Inc.

4777 Saucon Creek Road
Center Valley, PA 18034

Work Order: 12030411

Phone: (610) 974-8100
Fax: (610) 974-8104

SEND DATA TO:

NAME: Jean M. Cole
COMPANY: Environmental Service Laboratories, Inc
ADDRESS: 1803 Philadelphia St
Indiana, PA 15701

PHONE: (724) 463-8378
FAX: (724) 465-4209

WO#: 12030411
PAGE: 1 of 2
PO#:
PWS ID#

TEST REPORT

12 08934-09155-09160-09166-09172-09190-09193

RECEIVED FOR LAB BY: GMD DATE: 03/05/2012 9:45

SAMPLE: **12 08934** Lab ID: 12030411-001C Grab
SAMPLED BY: Client Sample Time: 02/28/2012 11:45

Test	Result	Method	Req Limit	Analysis Start	Analysis End	Analyst *
Thorium	< 12.50 µg/L	EPA 200.8		03/15/12 10:40	03/23/12	JRA-CV
Uranium	< 0.63 µg/L	EPA 200.8	30	03/15/12 10:40	03/23/12	JRA-CV
Uranium	< 0.43 pCi/L	EPA 200.8		03/15/12 10:40	03/23/12	JRA-CV

ENVIRONMENTAL SERVICE LABORATORIES, INC.

HEADQUARTERS: X
1803 Philadelphia St.
Indiana, PA 15701
(724) 463-TEST
(724) 465-4209

SOUTHERN DIVISION:
1276 Bentleyville Road
Van Voorhis, PA 15366
(724) 258-TEST
(724) 258-8376

FOR INTERNAL LABORATORY USE ONLY

SAMPLE REQUEST & CHAIN OF CUSTODY

Sample Identification	ESL#	Composite Date on/off	Composite Time on/off	Grab Date	Grab Time	Matrix	# of Containers	Container Type / Preservative	Analysis Requested
James SWD	12 08933			22812	1145	FIELD	FIELD	FIELD	pH 5.76 Hydrogen Sulfide Ø DO 4.03
						WW	1 ✓	Plastic Liter none	pH, SC, Chloride, Sulfate, Alkalinity, Acidity, Bromide
						WW	2 ✓	Plastic Liter none	TSS, TDS, ~~Dissolved Iron~~, Boron, BOD, MBAS Surfactants
						WW	1 ✓	Plastic Liter HNO_3	Al, As, Ba, Be, Cd, Cr, Co, Cu, Fe, Pb, Mg, Mn, Hg, Ni, Se, Ag, Sr, Zn, Li, Na, Ca, Mo, Hardness pH<2
						WW	1 ✓	Plastic Liter H_2SO_4	Nitrate+Nitrite, TKN, Ammonia, COD pH<
	12 08934					WW	3 ✓	Plastic Liter HNO_3	Radium 226, Radium 228 Thorium, Uranium pH<2
						WW	1 ✓	Amber Glass L HCl	Oil & Grease pH<2
						WW	1 ✓	Amber Glass L H_2SO_4	Total Phenolics pH<2
						WW	2 ✓	Amber VOA Vials none	Ethylene Glycol
	2-28					WW	2 ✓	Amber VOA Vials HCl	Benzene, Toluene
TRIP BLANK	12 ~~08935~~					Water	2	Amber VOA Vials HCl	Benzene, Toluene

THE UNDERSIGNED PURCHASER HEREBY AGREES TO PAY SERVICE CHARGES ON ACCOUNTS OVER 31 DAYS OLD.
1. THESE SERVICE CHARGES WILL ACCRUE AT THE RATE OF 1 1/2% PER MONTH (18% PER ANNUM OR THE MAXIMUM ALLOWED BY LAW.)
2. THE UNDERSIGNED PURCHASER AGREES TO PAY, IN THE EVENT HIS ACCOUNT BECOMES DELINQUENT AND IS TURNED OVER TO ANY ATTORNEY FOR COLLECTION, REASONABLE ATTORNEY'S FEES PLUS ALL COURT AND ATTENDANT COLLECTION COSTS.

Sampled By: (Signature) [signature] Date/ Time 22812 1145

Relinquished By: (Signature) [signature] Date/ Time 22812 1410 — Received By: (Signature) [signature] Date/ Time 2-28-12 1419

Relinquished By: (Signature) Date/ Time — Received By: (Signature) Date/ Time

Relinquished By: (Signature) Date/ Time — Received By: (Signature) 2-28-12 Date/ Time

PRESERVATION Y / N   CONTAINER Y / N   TEMP ≤6°C Y / N / NA

Project Notes: 26R Waste Profile

Company/Name: Seneca Resources

Address: 51 Zents Boulevard, Brookville, PA 15825

Contact Person: Ms. Marisa Dollinger
Phone: (814) 849-4555
Fax: (814) 849-4795
Email: DollingerM@srcx.com

5.9

OPERATING DATA

TYPICAL CORROSION INHIBITOR

AQUACLEAR
PRODUCT INFORMATION




Corrosion Inhibitor SticksT

WHAT ARE CORROSION INHIBITOR STICKST?

Corrosion Inhibitor SticksT are water soluble or oil soluble sticks that contain a blend of Imidazolines which have excellent filming characteristics and low emulsion tendencies. This unique blend gives effective corrosion control for most oil field corrosion problems.

CORROSION INHIBITOR STICK™ USES

Corrosion Inhibitor Sticks ™ are primarily used to control common corrosion problems found in producing oil and gas well systems. They can be used to treat hard to reach 'dead' areas such as the annulus space above the packer, rat-hole, or the bottom of water supply tanks.

ADVANTAGES OF CORROSION INHIBITOR STICKST

Corrosion Inhibitor SticksT can provide corrosion control throughout the entire production system. Regular usage will help control corrosion at the point they begin - down-hole.

They are available in two different formulations (oil soluble and water dispersable) or (water soluble and oil dispersable). The oil soluble type is soluble in oil, condensate and wet gas and can slowly disperse inhibitor into the water phase. The water soluble type is soluble in water and can slowly disperse inhibitor into the oil phase.

Corrosion Inhibitor SticksT can effectively inhibit corrosion in wells that produce both water and distillate or oil phases. In this case, it may be desirable to treat the well with both types of sticks by first dropping water soluble sticks and allowing them to fall through the oil into the water, thus dissolving and releasing inhibitor in

TREATMENT DETERMINATION

The number of Corrosion Inhibitor SticksT used is based on the volume of total fluid produced (oil or condensate plus water). Field experience indicates that for most corrosive environments the best results are achieved by using a larger initial slug treatment (80 PPM daily) until the problem is under control then reduce to smaller periodic treatments (40 PPM daily) thereafter. EXAMPLE: An initial slug treatment of 80 PPM would require 0.64 lbs of Corrosion Inhibitor Stick™ per 24 BBL (1000 gallons) of total fluid produced.

COR. INH. STICK™ SIZES	STICKS PER BBL
SENIOR (1 5/8 " x 18")	**1 per 58 bbls**
JUNIOR (1 3/8 " x 16 ")	**1 per 40 bbls**
JUNIOR (1 1/4" x 15")	**1 per 29 bbls**
THRIFTY (1" x 15")	**1 per 18 bbls**
MIDGET (5/8" x 15")	**1 per 7 bbls**

NOTE: To successfully control any corrosion problem, the inhibitor insertion into the fluid stream must be constant. For intermittent treatment or extreme corrosive environments increase the number of sticks accordingly.

THE MOST COMMON PROCEDURE for producing wells is to shut-in well and drop sticks through lubricator. Leave well shut until sticks fall to the bottom. The time in minutes for the sticks to fall to the bottom (assuming well is shut-in with fluid at surface) is equal to the depth divided by 100. (Time, min. = Depth, ft / 100).

FOR WATER INJECTION SYSTEMS drop the sticks into the water supply tank to inhibit more of the system.

the water column). Then drop the oil soluble sticks which will "FLOAT" at where the oil and water contact thus slowly dissolving and releasing inhibitor in the oil column.

The sticks are economical when compared to conventional corrosion control operations and therefore save investment in pumps, drums of chemical, and equipment maintenance.

Corrosion Inhibitor SticksT may be used in wells with bottom hole temperatures (BHT) of up to 375 degrees Fahrenheit.

PRODUCTION SPECIFICATIONS

OIL SOLUBLE: The stick will dissolve in 20 to 120 minutes (in moving diesel) depending on temperature, salt content, and relative fluid motion. The stick will melt at 135 degrees Fahrenheit and the specific gravity is 0.95.

WATER SOLUBLE: The stick will dissolve in 12 to 24 hours (in 60,00 PPMmoving brine water) depending on temperature, salt content, and relative fluid motion. The stick will melt at 125 degrees Fahrenheit and the specific gravity is 1.10.

PRODUCT PACKAGING

SENIOR	1.55 lb/stick	24/case	31/pail	48/chest
JUNIOR(1)	1.20 lb/stick	36/case	n/a	72/chest
JUNIOR(2)	0.76 lb/stick	36/case	52/pail	72/chest
THRIFTY	0.49 lb/stick	49/case	72/pail	98/chest
MIDGET	0.19 lb/stick	108/case	204/pail	216/chest

WHERE TO BUY

All good oil field supply stores carry Aqua-Clear, Inc. Corrosion Inhibitor Sticks™, but you can also buy direct from us.

Ordering Information

Should you wish to speak to a sales representative about any of our products, you can call or email Tommy Halloran Jr., Ronald "Buster" Wilson, or Russell Cook directly:

Tommy Halloran Jr.
W 304-343-4792
H 304-345-5152
C 304-546-8526
tom@aquaclear-inc.com

Ronald "Buster" Wilson
W 304-546-8518
H 304-965-7996
Fax 304-965-2713
buster@aquaclear-inc.com

Russell Cook
W 304-546-2940
H 304-842-7050
Fax 304-842-7050
russell@aquaclear-inc.com

WELL CONSTRUCTION

INJECTION WELL CONFIGURATION

Well Construction Diagram
Proposed Injection Test Well
Seneca Well #38268
Highland Township
Elk County, PA
37-047-23835

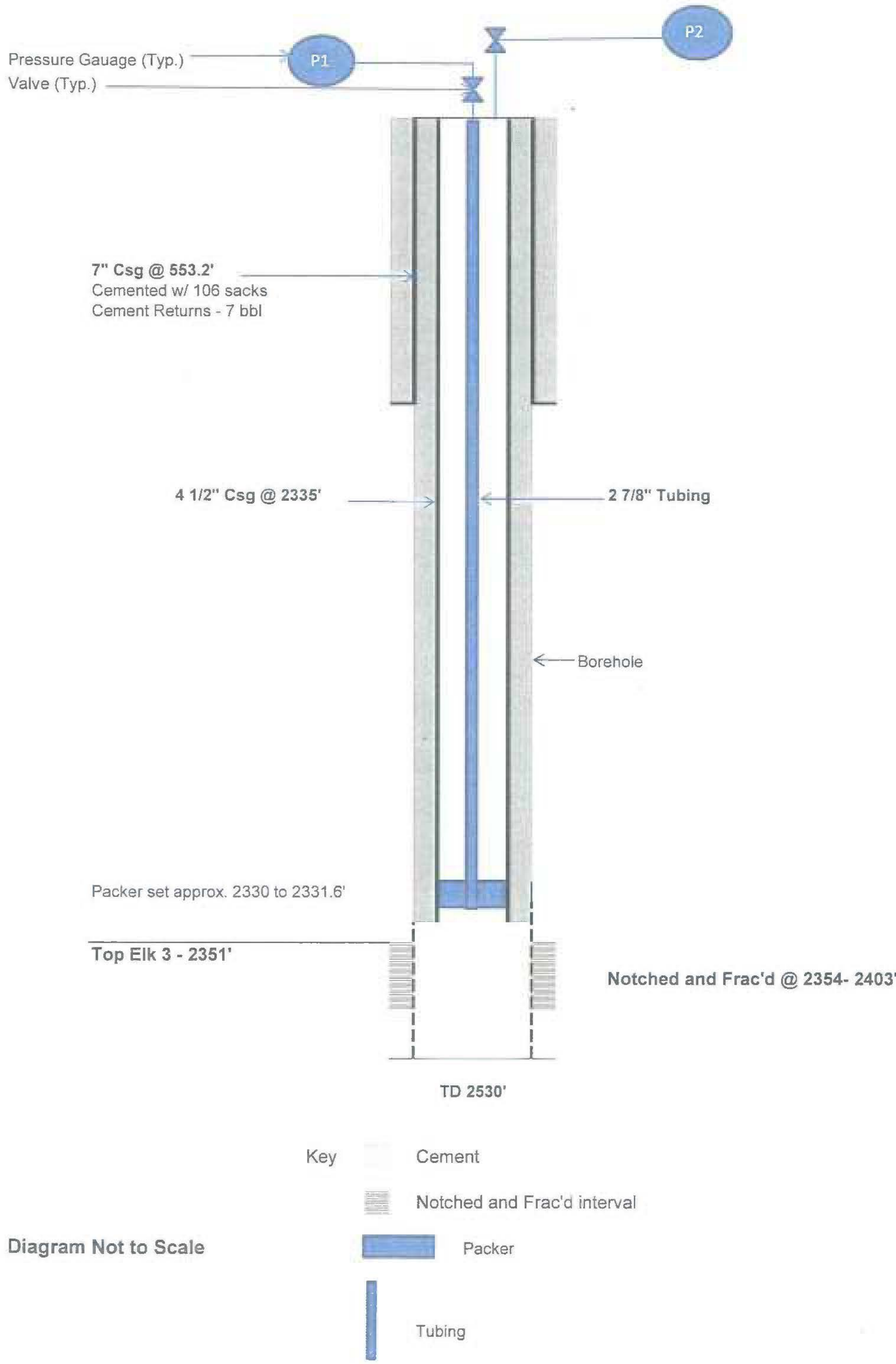


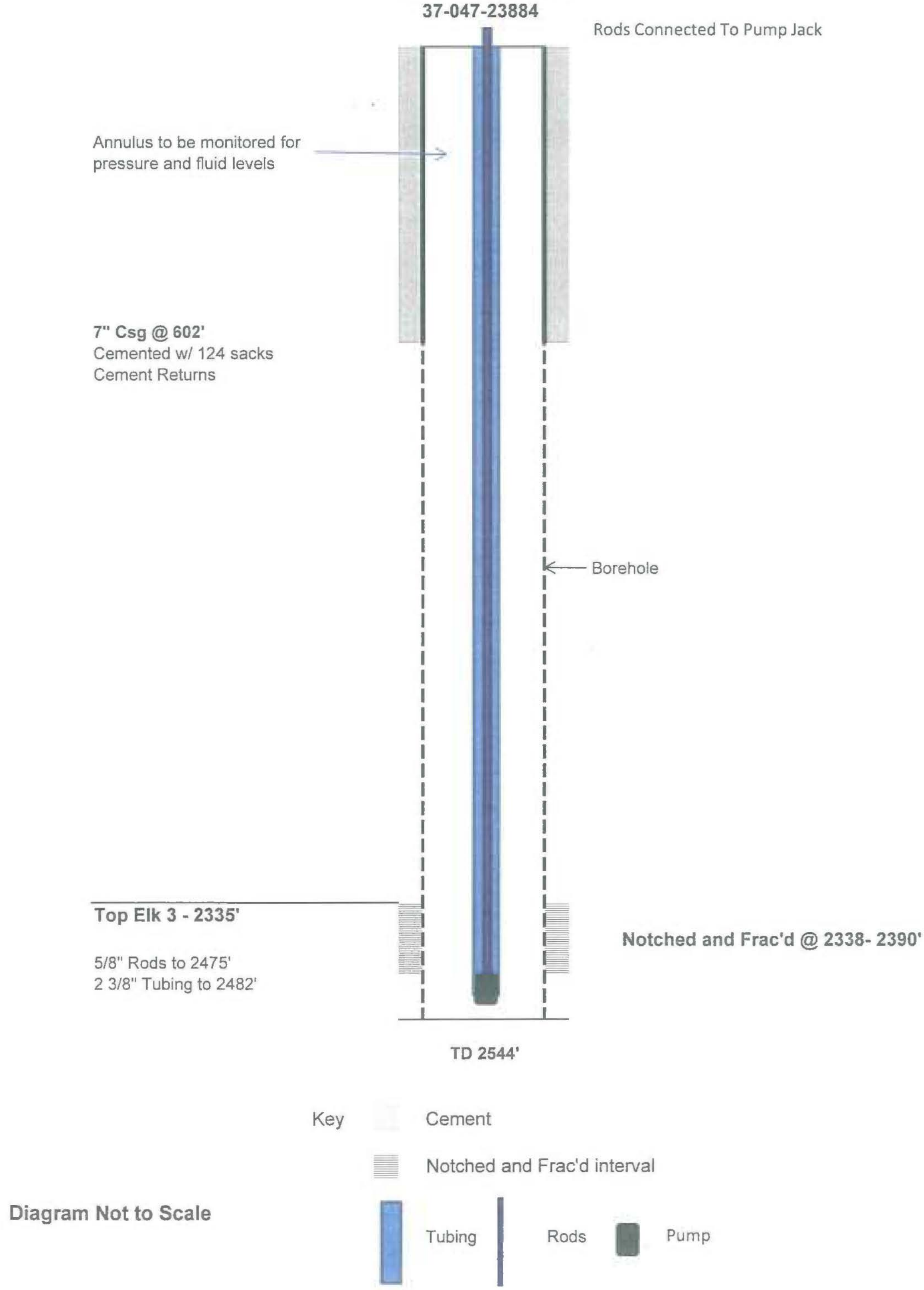
Diagram Not to Scale

Well Construction Diagram

Proposed Monitoring Well

Seneca Well #38281
Highland Township
Elk County, PA

37-047-23884



Monitoring Program

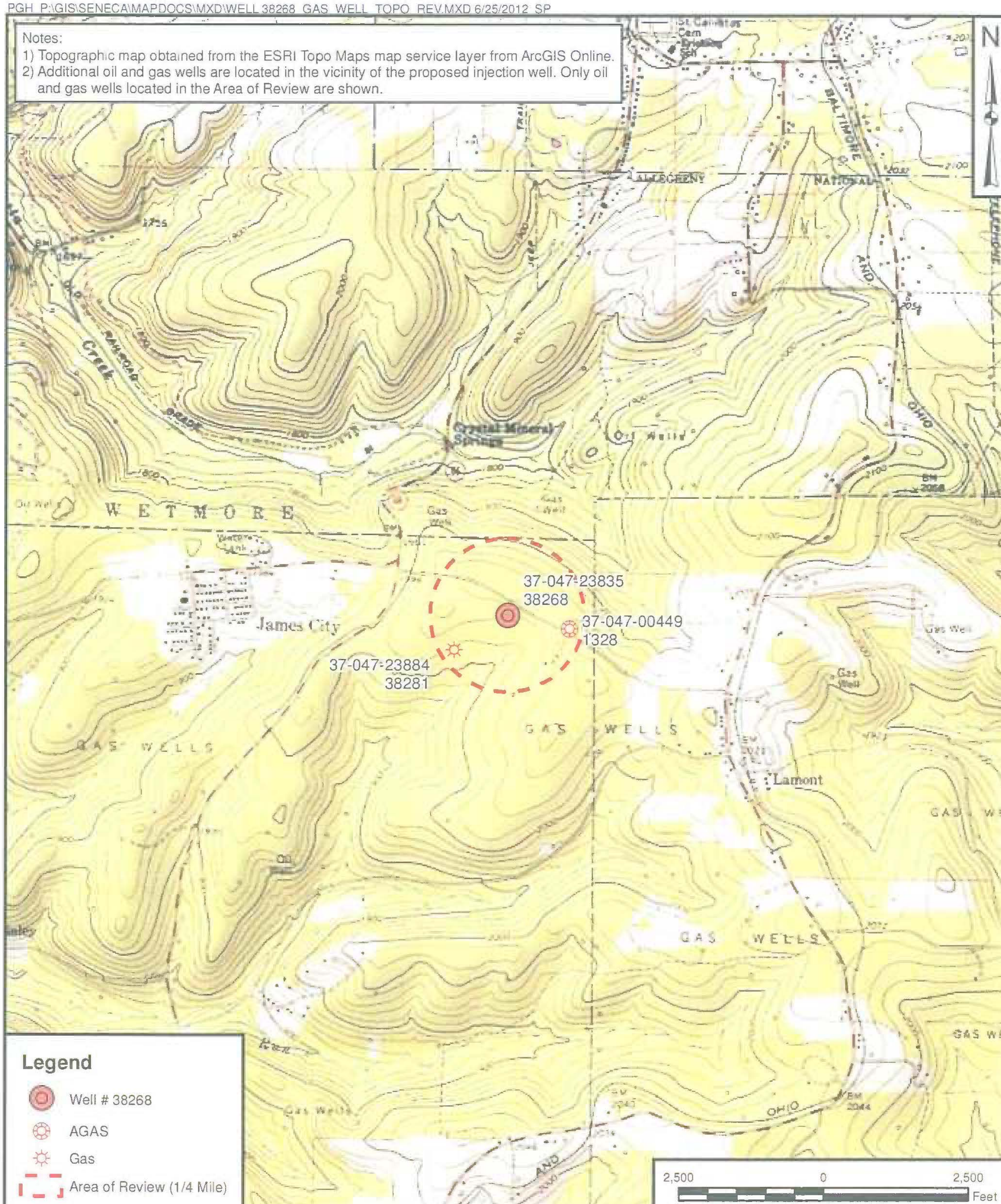
Well #38281, located 1320 feet to the southwest of the subject injecition well, will be utilized as a monitoring well for injection at Well #38268. The well construction diagram for this well is attached in Section 7. While being used as a monitoring well, if the fluid level in this well is observed to rise to within 100 feet of the base of the USDW, disposal operations in Well #38268 will be stopped immediately, EPA will be notified, and operating conditions will be evaluated in order to control the fluid levels.

Prior to monitoring being performed at Well #38281, the well will be shut-in for a period of approximately one week to allow for equilibrium in pressures and fluid levels to be attained in this producing well. Pressures and fluid levels (utilizing an Echometer) will be measured in the annulus between the 7-inch casing and tubing prior to initiation of injection at Well #38268 and semi-annually thereafter while injeciton is occurring at at Well #38268.

Injection Well	Monitoring Well	Approximate Distance and Direction From Injection Well
Seneca #38268	Seneca #38281	1320 feet southwest

PGH P:\GIS\SENECA\MAPDOCS\MXD\WELL 38268 GAS WELL TOPO REV.MXD 6/25/2012 SP

Notes:
1) Topographic map obtained from the ESRI Topo Maps map service layer from ArcGIS Online.
2) Additional oil and gas wells are located in the vicinity of the proposed injection well. Only oil and gas wells located in the Area of Review are shown.



TETRA TECH	FIGURE 4 #38268 WELL LOCATION WITH GAS WELL LOCATIONS ELK COUNTY, PENNSYLVANIA	DRAWN BY: J. NOVAK 05/17/12 CHECKED BY: D. SKOFF 06/25/12 APPROVED BY: CONTRACT NUMBER: 112C04078 FIGURE NUMBER: 4 / REV: 0

Plugging and Abandonment Plan

At the point when the well is no longer used, the well will be abandoned in accordance with EPA and PADEP regulations. With regard to PADEP regulations, this currently includes providing a "Notice of Intent to Plug a Well" no less than 3 days and no more than 30 days prior to abandoning the well, to allow a PADEP inspector to be present during the plugging procedure. The PADEP may waive the notification period. The notification will include well location plat, well logs, production logs, injection logs, construction details, and proposed abandonment method. After receiving approval from PADEP to proceed, the well will be abandoned and the abandonment procedures will be documented on a "Certificate of Plugging".

The USEPA will be notified of the plugging activity at least 45 days prior to commencing activities. This notification will include USEPA Form No. 7520-14. A proposed plugging plan (Form 7520-14) is attached based on the current PADEP and USEPA regulations. However, this may be modified prior to plugging in order to meet the requirements at the time of the plugging activity. A contractor cost estimate to perform plugging and abandonment according to the proposed plugging plan is attached. The contractor estimate is $14,650. In addition a $10,000 contingency has been added resulting in a total estimate of $24,650 for plugging and abandonment costs.

PLUGGING AND ABANDONMENT CONTRACTOR ESTIMATE

ALCO Well Services, Inc.
314 Interstate Parkway
Bradford, PA 16701

Sent via electronic mail to okunugal@srcx.com

June 22nd, 2012

Mr. Ladi Okanuga
Production Engineer
Seneca Resource, Inc.
51 Zents Boulevard
Brookville, PA 15825

Dear Mr. Okanuga:

On behalf of ALCO Well Services, Inc., we appreciate the opportunity to present ALCO's quotation for the plugging of Seneca Well #38268.

After reviewing the specifications provided and based on the assumptions outlined below, ALCO's turnkey fee for plugging Well #38268 amounts to $14,650.

This quotation is valid until September 30th, 2012 and the assumptions are as follows:

1. Cement between 7" casing and 4 ½" casing must be visible at surface.[1]
2. Cement between 9 5/8" casing and 7" casing must be visible at suface.[2]
3. The projected amount of cement and gel required to plug the well is based on PA DEP regulations and has a direct correlation to the depths indicated on the Well Construction Diagram provided to us by your office.

The quotation breaks down as follows:

Category	Unit	Total
Site Preparation/Restoration	Lump Sum	$ 1,500
Mobilization/Demobilization	Lump Sum	$ 1,500
Plugging Rig[3]	Hourly	$ 5,600
Cement Services	Per Sack	$ 4,300
Gravel and Non-Cement Mat'l	Lump Sum	$ 750
Disposal	Bbl	$ 1,000
Total		**$14,650**

[1] If cement is not visible between 7" and 4 ½" casing, a bond log must be run to find top of cement and 4" pipe must be shot off and removed.

[2] If cement is not visible between 9 5/8" and 7" casing, a bond log must be run to find top of cement and 4" pipe must be shot off and removed.

[3] Plugging Rig rate include $200 hourly rate and 3 laborers. Time estimate is 3.5 days max assuming no other changes to project.

In the event you have questions or concerns about this quotation, feel free to contact me at 814-598-2566. Again, we thank you for the opportunity to submit this quotation.

Sincerely,

Margaret M. Copeland

Margaret M Copeland

Margaret M. Copeland
President
ALCO Well Services, Inc.
mcopeland@alcowell.com

PLUGGING AND ABANDONMENT PLAN

EPA FORM 7520-14

OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
SENECA WELL # 38268 HIGHLAND TOWNSHIP, ELK COUNTY PA.	SENECA RESOURCES CORPORATION 5800 CORPORATE BLVD SUITE 300, PITTSBURGH PA 15237

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State	County	Permit Number
PENNSYLVANIA	ELK	37-047-23835

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

WELL ACTIVITY

- [ ] CLASS I
- [x] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Lease Name

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
9.62	2	62.6	62.6	11.25
.00	1	553.2	553.2	8.75
4.	1 .5	2335	2335	6.25
2.875	6.5	2335		6.25

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	6.25	4.052	4.052	4.052			
Depth to Bottom of Tubing or Drill Pipe (ft	2530	2335	578	2			
Sacks of Cement To Be Used (each plug)	39	133	N/A	0.15			
Slurry Volume To Be Pumped (cu. ft.)	42	157.4	51.6	0.179			
Calculated Top of Plug (ft.)	2335	578	2	0			
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.6	15.6	8.5	15.6			
Type Cement or Other Material (Class III)	CLS A	CLS A	GEL	CLS. A			

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
2335	2530		

Estimated Cost to Plug Wells

$24,650.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Guy Shirey; Mngr - Production	Guy A Shirey	6/25/12

Necessary Resources

Attached is the Seneca Resources Corporation Surety Bond Letter to demonstrate that the company has the resources necessary to plug and abandon the well.

Plan for Well Failures

Pressure will be measured in the annulus between the 4 1/2-inch casing and tubing and continuously monitored during injection at Well #38268. Should a pressure increase occur in the monitored space, injection will cease and EPA will be verbally notified within 24 hours and notified in writing within 7 days. The cause of the pressure increase will be investigated by Seneca and remedial measures implemented following discussions with EPA on the proposed approach.

Appendix A

Appendix A contains well records and information for groundwater wells in the area surrounding Well #38268. Groundwater wells located within 1 mile of Well #38268 are listed in the following table.

Groundwater Wells within 1 mile of Seneca Well #38268
Highland Township, Elk County, PA

Water Wells

PAWellID	DateDrilled	Owner	WellDepth	Depth To Bedrock	WellUse	Borehole Bottom	Bore Hole Diameter	Casing Bottom	Casing Diameter
100718	8/1/1987	KLAIBER RANDY	130	28	WITHDRAWAL				

Appendix B

Appendix B contains the names and address of residents located within ¼ mile of the proposed injection well. Other than Seneca, only Collins Pine Lumber Company, PO Box 807, Kane, PA 16735, is located within ¼ mile of the proposed injection well.

APPENDIX F

Well Flow Diagram & Layout

Well #38268 Well Flow Diagram & Layout

TWO–TRUCK OFFLOAD CONCRETE CONTAINMENT
BASKET STRAINER
OFFLOAD PUMP
BASKET STRAINER
OFFLOAD PUMP
SUMP PUMP
TANK & PUMP CONTAINMENT SPRAY LINER W/ GALVANIZED STEEL SIDES
SURGE TANK 400BBL
SURGE TANK 400BBL
SLOP TANK 100BBL
TRANSFER PUMP
FE 0000
M
BAG FILTER 100 MICRON
SETTLING TANK 400BBL
TRANSFER PUMP
ROLL–OFF DUMPSTER CONCRETE CONTAINMENT
SUMP PUMP
SUMP PUMP
INJECTION PUMP
INJECTION PUMP
FRAC TANK 500BBL CLEAN WATER
FRAC TANK 500BBL CLEAN WATER
FRAC TANK 500BBL CLEAN WATER
FRAC TANK 500BBL CLEAN WATER
FRAC TANK 500BBL CLEAN WATER
FRAC TANK 500BBL CLEAN WATER
AG
UG
DISPOSAL WELL

REV.	DESCRIPTION	BY	DATE
1		XXXXX	MM/DD/YYY

ENGINEER: XXXXX MM/DD/YY

CHECK BY: XXXXX MM/DD/YY

ISSUED FOR: REVIEW

LOCATION: TOWN

DRAWN BY: XXXXX MM/DD/YY

SCALE: AS NOTED

TITLE1
TITLE2
TITLE3
TITLE4
TITLE5

DRAWING NUMBER: DWG_NO

REV.: XX

DIR/FILE: C:\USERS\ENGLERD\DESKTOP\JAMES CITY INJECTION WELL\JCF-MECH-AS BUILT

SRC Well #38268 Monitoring Reports

A R M   G r o u p   L L C

OMB No. 2040-0042 Approval Expires 12/31/2018

EPA

United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee
Seneca Resources Company, LLC
5800 Corporate Drive, Suite 300; Pittsburgh, PA 15237

Name and Address of Surface Owner
Seneca Resources Company, LLC
5800 Corporate Drive, Suite 300; Pittsburgh, PA 15237

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State: PA
County: Elk
Permit Number: PAS2D025BELK

Surface Location Description
___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

RECEIVED
EPA REGION III
FEB 04 2019
GROUND WATER & ENFORCEMENT
(3WP22)

WELL ACTIVITY
- [x] Brine Disposal
- [ ] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT
- [x] Individual
- [ ] Area

Number of Wells ___

Lease Name: FEE - SRC WT 3771
Well Number: 38268

MONTH YEAR	INJECTION PRESSURE AVERAGE PSIG	INJECTION PRESSURE MAXIMUM PSIG	TOTAL VOLUME INJECTED BBL	TOTAL VOLUME INJECTED MCF	TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MINIMUM PSIG	TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MAXIMUM PSIG
January-2018	222	226	2098		-2	141
February-2018	0	0	7		0	2
March-2018	0	0	3		-5	178
April-2018	270	466	14358		0	170
May-2018	243	257	859		0	144
June-2018	239	242	4791		133	186
July-2018	617	926	27346		0	239
August-2018	841	1003	21929		111	245
September-2018	807	832	7222		105	195
October-2018	0	0	0		53	142
November-2018	470	693	8443		-1.5	148
December-2018	756	821	27036		-21	152

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*: Amanda Veazey, Advisor
Signature: Amanda Veazey
Date Signed: 1/25/2019

EPA Form 7520-11 (Rev. 12-11)

P-max - ~~[illegible]~~ 3,000 Total bbls = 114,092

Compliance Review Completed
WIMS Updated
Pdf to G:Drive rum 2/26/19

OMB No. 2040-0042 Approval Expires 4/30/2022

EPA

United States Environmental Protection Agency

ANNUAL CLASS II DISPOSAL/INJECTION WELL MONITORING REPORT

Name, Address, Phone and/or Email of Permittee

Seneca Resources Company, LLC
5800 Corporate Drive, Suite 300
Pittsburgh, PA 15237
(412) 548-2500

State: Pennsylvania

County: Elk

WELL TYPE
- [x] Brine Disposal
- [ ] Enhanced Recovery
- [ ] Hydrocarbon Storage

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

___ ft. from (N/S) ___ Line of quarter section
___ ft. from (E/W) ___ Line of quarter section.

Latitude 41.618992 Longitude -78.821267

Permit or EPA ID Number PAS2D025BELK API Number 37-047-23835 Full Well Name FEE - SRC WT 3771 38268

	INJECTION PRESSURE	TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (IF SPECIFIED IN PERMIT)
MONTH, YEAR	MAXIMUM PSIG	BBL	MCF	MAXIMUM PSIG
January-2019	1032	20287		158
February-2019	55	0		4
March-2019	917	24644		155
April-2019	1035	48548		140
May-2019	1154	34747		91
June-2019	1194	23297		115
July-2019	1186	3809		109
August-2019	1007	371		86
September-2019	1227	23048		102
October-2019	1298	14648		107
November-2019	1299	24110		78
December-2019	1264	11871		68

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Amanda Veazey, Advisor	Amanda Veazey	1/28/2020

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

ANNUAL CLASS II DISPOSAL/INJECTION WELL MONITORING REPORT

Name, Address, Phone and/or Email of Permittee

Seneca Resources Company, LLC
2000 Westinghouse Drive, Suite 400
Cranberry Twp., PA 16066
(412) 548-2500

State: Pennsylvania

County: Elk

WELL TYPE

- [x] Brine Disposal
- [ ] Enhanced Recovery
- [ ] Hydrocarbon Storage

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section

____ ft. from (E/W) ____ Line of quarter section.

Latitude 41.618992 Longitude -78.821267

Permit or EPA ID Number: PAS2D025BELK **API Number:** 37-047-23835 **Full Well Name:** FEE - SRC WT 3771 38268

	INJECTION PRESSURE	TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (IF SPECIFIED IN PERMIT)
MONTH, YEAR	MAXIMUM PSIG	BBL	MCF	MAXIMUM PSIG
January-2020	1293	23563		132
February-2020	1261	24713		37
March-2020	1257	10737		153
April-2020	1193	2701		162
May-2020	0	0		0
June-2020	921	427		200
July-2020	1026	442		212
August-2020	52	0		162
September-2020	84	0		161
October-2020	1149	5802		148
November-2020	1233	26588		168
December-2020	1223	13749		158

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*

Amanda Veazey
Advisor, Environmental Geology

Signature

Amanda Veazey

Date Signed

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

ANNUAL CLASS II DISPOSAL/INJECTION WELL MONITORING REPORT

Name, Address, Phone and/or Email of Permittee

Seneca Resources Company, LLC
2000 Westinghouse Drive, Suite 400
Cranberry Township, PA 16066
(412) 548-2533

State Pennsylvania

County Elk

WELL TYPE

✓ Brine Disposal
Enhanced Recovery
Hydrocarbon Storage

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

1/4 of 1/4 of Section Township Range

ft. from (N/S) Line of quarter section

ft. from (E/W) Line of quarter section.

Latitude 41.618992 **Longitude** -78.821267

Permit or EPA ID Number PAS2D025BELK **API Number** 37-047-23835 **Full Well Name** FEE SRC WT 3771 38268

	INJECTION PRESSURE	TOTAL VOLUME INJECTED		TUBING – CASING ANNULUS PRESSURE (IF SPECIFIED IN PERMIT)
MONTH, YEAR	MAXIMUM PSIG	BBL	MCF	MAXIMUM PSIG
January-2021	1127	3,714		152
February-2021	1118	5,979		70
March-2021	1170	14,450		103
April-2021	1174	4,595		93
May-2021	1189	5,350		120
June-2021	1233	14,346		154
July-2021	1225	9,461		193
August-2021	1204	25,578		201
September-2021	1203	12,088		156
October-2021	1203	9,888		121
November-2021	1202	6,878		93
December-2021	1210	11,973		71

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Amanda Veazey, Advisor	Amanda V	1/18/2022

EPA Form 7520-11 (Rev. 4-19)

For assistance in accessing this document, contact R3_UIC_Mailbox@epa.gov

OMB No. 2040-0042 Approval Expires 4/30/2022

EPA

United States Environmental Protection Agency

ANNUAL CLASS II DISPOSAL/INJECTION WELL MONITORING REPORT

Name, Address, Phone and/or Email of Permittee

Seneca Resources Company, LLC
2000 Westinghouse Drive, Suite 400
Cranberry Township, PA 16066
(412) 548-2533

State: Pennsylvania

County: Elk

WELL TYPE

- ✓ Brine Disposal
- Enhanced Recovery
- Hydrocarbon Storage

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location
____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section
____ ft. from (E/W) ____ Line of quarter section.

Latitude 41.618992 Longitude -78.821267

Permit or EPA ID Number PAS2D025BELK **API Number** 37-047-23835 **Full Well Name** FEE SRC WT 3771 38268

	INJECTION PRESSURE	TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (IF SPECIFIED IN PERMIT)
MONTH, YEAR	MAXIMUM PSIG	BBL	MCF	MAXIMUM PSIG
January-2022	1203	16,893		78
February-2022	1229	13,000		76
March-2022	1219	24,397		80
April-2022	1151	25,459		72
May-2022	1201	17,821		71
June-2022	0	0		69
July-2022	0	0		77
August-2022	1151	11,138		607
September-2022	0	0		152
October-2022	1	1		130
November-2022	1199	319		127
December-2022	0	0		116

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*: Amanda Veazey, Advisor

Signature: Amanda Veazey

Date Signed: 1/5/23

EPA Form 7520-11 (Rev. 4-19)

APPENDIX G

P&A Plan & Plugging Estimates

Plugging & Abandonment Plan(s)

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Seneca Resource Company, LLC
2000 Westinghouse Drive, Suite 400
Cranberry Township, PA 16066
Ms. Jennifer Nemitz, P.G.
nemitzj@srcx.com / (412) 548-2574

Permit or EPA ID Number	API Number	Full Well Name
PAS2D025BELK	37-047-23835	Seneca Well #38268

State	County
Pennsylvania	Elk County

Locate well in two directions from nearest lines of quarter section and drilling unit

Latitude 41.618913

Longitude -78.821541

Surface Location

____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

____ ft. from (N/S) ____ Line of quarter section
____ ft. from (E/W) ____ Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work Date Expected to Commence: Wells End Use	☐ Well Rework
☑ Class II		☑ Plugging and Abandonment
☐ Class III	☐ Report After Work Date Work Ended:	☐ Conversion to a Non-Injection Well
☐ Class V		

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Please refer to the June 2012 USEPA Form 7520-14 (Appendix E) for the conceptual abandonment plan for Well #38268.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
NA at this time		

INSTRUCTIONS FOR FORM 7520-19

This form replaces forms 7520-12 and 7520-14. Use this form only when work is planned or has occurred that affects the well's construction or operation as an injection well, including work on the casing, tubing or packer (or for shallow Class V wells, the subsurface fluid emplacement network). Use one form per injection well. While reports or other information developed by contractors or service companies may be attached, this form must be signed by a responsible entity as described at 40 CFR 144.32. Note: operators closing Class V wells should use Form 7520-17.

NAME, ADDRESS, PHONE AND/OR EMAIL OF PERMITTEE: Enter the name and street address, city/town, state, and ZIP code of the permittee. Also provide an email address (if available) and/or a phone number.

PERMIT OR EPA ID NUMBER: Enter the well identification number or permit number assigned to the well by the EPA or the permitting authority.

API NUMBER: Enter the number assigned by the local jurisdiction (usually a State Oil and Gas Agency) using the American Petroleum Institute standard numbering system.

FULL WELL NAME: Enter the full name of the well or project.

Enter the **STATE** and **COUNTY** where the well is located. For States that do not have counties, use the name of that State's equivalent jurisdiction at a more local level.

WELL LOCATION: Fill in the complete township, range, and section to the nearest quarter-quarter section. A township is north or south of the baseline, and a range is east or west of the principal meridian (e.g., T12N, R34W). Also include the distance, in feet, from the nearest north or south line and nearest east or west line of the quarter-section. Also, enter the **latitude** and **longitude** of the well in decimal degrees, to five or six places if possible; be sure to include a negative sign for the longitude of a well in the Western Hemisphere and a negative sign for the latitude of a well in the Southern Hemisphere.

Enter the **WELL CLASS,** i.e., the class of injection well as defined in 40 CFR 144.6.

TIMING OF THE ACTION: Check ***Notice prior to work*** if the activity has not yet occurred (i.e., is planned). Check ***Report after work*** if the activity described has already occurred. As appropriate, include the date the activity is expected to start or the date the activity was completed. (Note this may not be available, e.g., for a plugging plan submitted with a permit application.)

TYPE OF ACTION: Check the appropriate box to describe the kind of activity being reported. Check ***Well Rework*** for work that was/will be performed on the well after it has already been in operation as an injection well. Check ***Plugging and Abandonment*** to report on plans for or descriptions of final closure/plugging after use as an injection well. Check ***Conversion to a Non-Injection Well*** if the well is to be converted to something other than an injection well.

Provide a **NARRATIVE DESCRIPTION** of the work planned to be performed, or that was performed. The narrative should include a description of the main procedures planned or that occurred during the work activity. A service company report, daily report, or similar document may be attached if it includes all the requested information and is clear and legible.

For well reworks, include the following information: The reason for the well rework; depths of activity; type of activity; changes to injection well configuration, well casing, or cement behind casing; any plug added to the well and its depth; any newly drilled interval and its depth; method(s) to demonstrate that the well has mechanical integrity (as applicable); and any deviations from the approved rework plan (as applicable).

For a well plugging plan, include the following information: Reason for the well plugging; number of plugs placed, and their depths; materials used as plugs (e.g., cast iron bridge plug, cement, cement retainer); method to set plugs; and wait-on-cement times, if any. Also provide one or more cost estimates from an independent firm in the business of plugging and abandoning wells to plug the well as described in the plan.

For well plugging affidavit, include the following information: Reason for the well plugging; number of plugs placed, and their depths; materials used as plugs (e.g., cast iron bridge plug, cement, cement retainer); method to set plugs; wait-on-cement times, if any; and any deviations from the approved plugging plan (if applicable).

For conversion to a non-injection well, include the following information: Depths of activity; type of activity; changes to injection well configuration, well casing, or cement behind casing; any plug added to the well and its depth; any newly drilled interval and its depth; depths of new perforations; and method(s) to demonstrate that the well has mechanical integrity (as applicable).

For all of the above activities, include a well sketch depicting the work, results of well tests/logging performed, service company tickets, and any other available information demonstrating how the work was/is to be performed. Also, specify whether depths are below ground surface, relative to Kelly bushing, etc.

CERTIFICATION: This form must be signed and dated by either: a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, or by a principal executive or ranking elected official for a public agency.

ALCO Well Services, Inc.
314 Interstate Parkway
Bradford, PA 16701

Sent via electronic mail to okunugal@srcx.com

June 22nd, 2012

Mr. Ladi Okanuga
Production Engineer
Seneca Resource, Inc.
51 Zents Boulevard
Brookville, PA 15825

Dear Mr. Okanuga:

On behalf of ALCO Well Services, Inc., we appreciate the opportunity to present ALCO's quotation for the plugging of Seneca Well #38268.

After reviewing the specifications provided and based on the assumptions outlined below, ALCO's turnkey fee for plugging Well #38268 amounts to $14,650.

This quotation is valid until September 30th, 2012 and the assumptions are as follows:

1. Cement between 7" casing and 4 ½" casing must be visible at surface.[1]
2. Cement between 9 5/8" casing and 7" casing must be visible at suface.[2]
3. The projected amount of cement and gel required to plug the well is based on PA DEP regulations and has a direct correlation to the depths indicated on the Well Construction Diagram provided to us by your office.

The quotation breaks down as follows:

Category	Unit	Total
Site Preparation/Restoration	Lump Sum	$ 1,500
Mobilization/Demobilization	Lump Sum	$ 1,500
Plugging Rig[3]	Hourly	$ 5,600
Cement Services	Per Sack	$ 4,300
Gravel and Non-Cement Mat'l	Lump Sum	$ 750
Disposal	Bbl	$ 1,000
Total		**$14,650**

[1] If cement is not visible between 7" and 4 ½" casing, a bond log must be run to find top of cement and 4" pipe must be shot off and removed.

[2] If cement is not visible between 9 5/8" and 7" casing, a bond log must be run to find top of cement and 4" pipe must be shot off and removed.

[3] Plugging Rig rate include $200 hourly rate and 3 laborers. Time estimate is 3.5 days max assuming no other changes to project.

In the event you have questions or concerns about this quotation, feel free to contact me at 814-598-2566. Again, we thank you for the opportunity to submit this quotation.

Sincerely,

Margaret M. Copeland

Margaret M Copeland

Margaret M. Copeland
President
ALCO Well Services, Inc.
mcopeland@alcowell.com

OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
SENECA WELL # 38268 HIGHLAND TOWNSHIP, ELK COUNTY PA.	SENECA RESOURCES CORPORATION 5800 CORPORATE BLVD SUITE 300, PITTSBURGH PA 15237

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State	County	Permit Number
PENNSYLVANIA	ELK	37-047-23835

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

WELL ACTIVITY

- [ ] CLASS I
- [x] CLASS II
  - [x] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Lease Name

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
9.62	2	62.6	62.6	11.25
.00	1	553.2	553.2	8.75
4.	1 .5	2335	2335	6.25
2.875	6.5	2335		6.25

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	6.25	4.052	4.052	4.052			
Depth to Bottom of Tubing or Drill Pipe (ft	2530	2335	578	2			
Sacks of Cement To Be Used (each plug)	39	133	N/A	0.15			
Slurry Volume To Be Pumped (cu. ft.)	42	157.4	51.6	0.179			
Calculated Top of Plug (ft.)	2335	578	2	0			
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.6	15.6	8.5	15.6			
Type Cement or Other Material (Class III)	CLS A	CLS A	GEL	CLS. A			

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
2335	2530		

Estimated Cost to Plug Wells

$24,650.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title (Please type or print)	Signature	Date Signed
Guy Shirey; Mngr-Production	Guy A Shirey	6/25/12

Plugging & Abandonment Estimate (2023)

A R M G r o u p L L C

Plugging and Abandonment Estimate - Per State Plugging Regulations

Service Provider:
Coastal Well Service LLC
130 Meadow Ridge Road, Suite 26
Mt. Morris, PA 15349

Customer:
Seneca Resources
2000 Westinghouse Drvie Suite 400
Cranberry Twp, PA 16066

Quote	
Quote Number:	**Well# 38268 - After Disposal Well**
Quote Date:	9/12/2023
Well Number:	047-23835
Rig Number:	TBD
PO Number:	TBD
Start Date:	TBD
Finish Date:	TBD
County/State	Elk / PA

	DESCRIPTION	UNITS	QTY.	UNIT PRICE	EXTENDED PRICE	
Plugging And Abandonment Summary After Disposal Well						
1	Site Preparation Charges	**Estimated Total**	1	$10,750.00	$10,750.00	
2	Mobilization	**Estimated Total**	1	$6,500.00	$6,500.00	
3	Rig Charges	**Estimated Total**	1	$32,000.00	$29,500.00	
4	Wireline / Cement Charges	**Estimated Total**	1	$38,000.00	$31,500.00	
5	Reclamation Charges	**Estimated Total**	1	$16,000.00	$16,000.00	
6	Demobilization	**Estimated Total**	1	$6,500.00	$6,500.00	
				Estimated Total	**$100,750.00**	

Summary of Estimate - Per PA Regulations

APPENDIX H

SRC Financial Statement

SRC Financial Statement (2023)

National Fuel®

2022 Annual Report









David P. Bauer
President and Chief
Executive Officer

Dear Shareholders,

National Fuel's fiscal 2022 was an outstanding year for the Company, one in which we achieved several significant milestones that position us well for the future. Of note, we completed construction of the FM100 project at our Pipeline & Storage business, achieved record natural gas production and throughput from our Exploration & Production and Gathering businesses, and replaced more than 150 miles of pipeline mains as part of our Utility's long-standing modernization program.

These operational achievements, alongside an improved commodity price backdrop, drove an impressive 37% increase in our adjusted operating results per share from the prior year and further improved the strength of our investment-grade balance sheet. In addition, in line with our strong financial results, we increased our annual dividend rate by 4.4% — making this our 52nd year of consecutive dividend increases and 120th year of uninterrupted dividend payments.

Further, National Fuel took important steps to enhance our environmental, social and governance (ESG) initiatives, positioning our business to play a meaningful role in a lower-carbon economy. In March, we published our inaugural Climate Report, expanding our ESG reporting to better align with the recommendations of the Task Force on Climate-Related Financial Disclosures (TCFD), a well-recognized framework for climate-focused disclosure. Likewise, in September, we published our third annual Corporate Responsibility Report, which describes the Company's progress toward achieving its methane emissions intensity targets, with reductions across the natural gas value chain. In addition, the Company had another outstanding year advancing our safety culture, accomplishing an impressive 20% reduction in our Occupational Safety and Health Administration recordable injury rate over the past three years, excluding cases of workplace COVID transmission.

Improving diversity, equity and inclusion in the workplace continues to be a focus. This year we formed four employee resource groups to support ethnically diverse, veteran, LGBTQ+ and female employees. And with the pandemic behind us, we reenergized our efforts to connect with our communities at deeper levels through corporate volunteerism and stewardship programs. In this regard, National Fuel launched an inaugural "Days of Doing" event in October 2022 in which employees provided more than 1,200 volunteer hours at various nonprofits within our operating footprint.

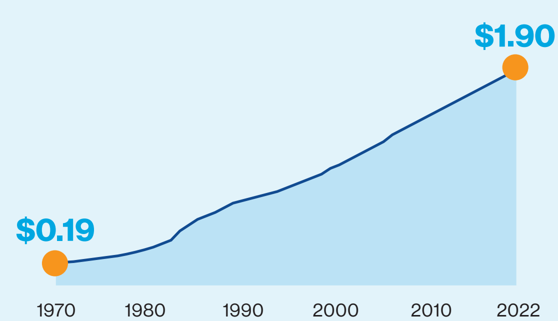
We believe these undertakings, in conjunction with our high-quality assets, talented workforce and organizational focus on continuous improvement across all aspects of our operations, leave National Fuel well positioned for success in the years ahead.

Operational Highlights

Record performance from our Appalachian Development program

In 2022, our Exploration & Production business, Seneca Resources Company, LLC (Seneca), grew its production by approximately 8% to 353 billion cubic feet equivalent (Bcfe), a Company record. On the heels of Seneca's growth, our Gathering business, National Fuel Gas Midstream Company, LLC (Midstream), which gathers 100% of our production, experienced an approximately 11% revenue increase from the prior year, evidencing the value of our integrated approach to Appalachian development. Throughout the year, we continued to leverage our high-quality acreage position within the Utica and Marcellus shales and our valuable marketing portfolio to take advantage of improved natural gas pricing, driving strong operational and financial results.

Fifty-Two Years of Dividend Growth
Annual Rate at Fiscal Year-End



Seneca transitioned to a pure-play natural gas producer in 2022, completing the divestiture of our California properties to Sentinel Peak Resources in June. Just as the spring of 2020 was an optimal time for us to acquire natural gas assets, this was an opportunistic time for Seneca to sell our California assets. These were great assets for National Fuel, generating over $1 billion in cash flow over the past decade that funded significant upstream and midstream growth in Appalachia; however, given the challenging regulatory environment in California, which made it difficult to grow these operations, the time was right to sell. We expect that Sentinel Peak will be a great owner of these assets, maintaining the focus on environmental stewardship that Seneca has long established.

As we move forward, Seneca is focused on its substantial development potential in the Appalachian basin. This tightened focus will continue to position us well for future growth, while significantly improving our expected per-unit cash operating costs and further reducing Seneca's emissions profile.

During fiscal 2022, Seneca made great progress advancing several key environmental and emissions-focused programs across our operations. Seneca's principal focus is reducing methane emissions by replacing natural gas actuated pneumatic devices with compressed air to eliminate vented emissions. Seneca also conducted its first facility-scale monitoring pilot using aerial light detection and ranging (LIDAR) technology to provide real-time assessments of facility emissions, enabling us to identify opportunities to improve our emissions profile.

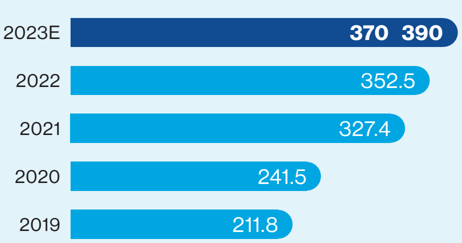
In addition, over the past year, Seneca received multiple responsibly sourced gas certifications, demonstrating our commitment to environmental stewardship and sustainability. In January 2022, Seneca announced the certification of 100% of our natural gas production under Equitable Origin's EO100™ Standard for Responsible Energy Development — a series of rigorous ESG performance metrics. Likewise, in March, Seneca achieved certification under Project Canary's TrustWell™ program for a pilot of 121 wells, all of which received Platinum or Gold ratings. Similarly, in August, Seneca announced its achievement of an "A" certification grade — the highest available certification level — for 100% of its production under MiQ's Standard for Methane Emissions Performance. These accreditations, along with ongoing investments and efforts to achieve emission reduction targets, position National Fuel to differentiate our production in the marketplace.

Looking ahead, in fiscal 2023, we expect to maintain our current activity levels in Appalachia, operating two drilling rigs with a focus on developing our highly economic Eastern Development Area (EDA) assets which, assuming the midpoint of our production guidance, should drive natural gas production growth of 8% over fiscal 2022. Additionally, Seneca plans to deploy a full-time, fully integrated electric hydraulic fracturing fleet in early calendar 2023, which is expected to deliver optimal performance while decreasing emissions.

Seneca employee speaks with a contractor about a Well Done Foundation (WDF) plugging project in Bradford, PA. Seneca provided funding to WDF, a nonprofit aimed at plugging orphaned and abandoned wells, to support WDF's first orphaned well plugging in PA.

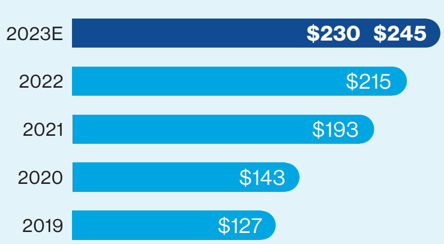
Seneca Resources Production

(Bcfe)



Gathering Revenues

($ millions)



Successful completion of the FM100 project

National Fuel's FERC-regulated Pipeline & Storage subsidiaries, National Fuel Gas Supply Corporation (Supply) and Empire Pipeline, Inc. (Empire), continue to leverage our existing asset footprint to drive growth opportunities in Appalachia. In December 2021, Supply placed into service the $230 million FM100 project. This project, the largest in the Company's history, was completed on time and substantially under budget, which is a testament to the hard work of our dedicated workforce. On an annual basis, we expect the FM100 project to add approximately $50 million in revenues to our Pipeline & Storage business, while also providing, in conjunction with a companion third-party pipeline expansion, 330,000 dekatherms per day (Dth/d) of high-value firm transportation capacity for Seneca's production.

Supply employee inspects an upgraded compressor unit in Mercer County, PA. New unit equipment helps to improve efficiency and lower emissions.

As we move into fiscal 2023, we will continue to pursue opportunities to expand our pipeline system, leveraging our interconnectivity to other long-haul pipelines and proximity to producers, while further investing in the safety, integrity and reliability of our transmission and storage assets through our ongoing modernization program. Over the last five years, Supply and Empire have invested more than $450 million on safety and modernization efforts, helping to drive a 24% reduction in methane intensity in calendar year 2021 from 2020, when methane intensity reduction targets were established at each of our businesses.

Significant progress in Utility modernization

Our Utility business, National Fuel Gas Distribution Corporation (Distribution), remains focused on safely and reliably providing natural gas service to more than 2 million residents in Western New York and Northwestern Pennsylvania. Over the past five years, our Utility has invested approximately $380 million on system modernization efforts, replacing 770 miles of pipeline mains over this period. These investments are a win-win for our customers and the Company, furthering the safety and reliability of our distribution network while driving additional reductions in EPA-reported greenhouse gas (GHG) emissions. Since 1990, our modernization program has driven a more than 65% reduction in delivery system GHG emissions, keeping the Company on track to achieve its targeted 75% reduction by 2030 and 90% reduction by 2050, which exceeds the requirements of New York State's Climate Leadership and Community Protection Act.

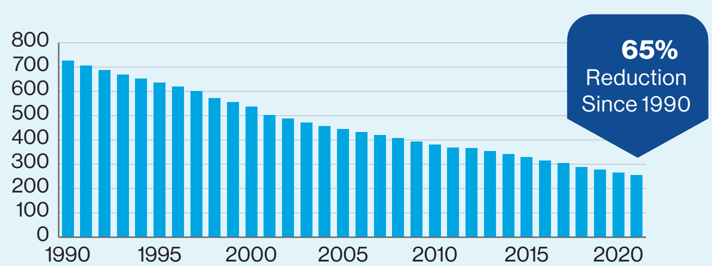
As we move ahead, we believe our multi-pronged approach to reducing our carbon footprint — focused on operational emissions reductions, energy conservation and embracing new and emerging technology, as well as leveraging our highly reliable and weather-hardened pipeline network for the delivery of low and no-carbon fuels — provides a solid foundation for National Fuel's long-term role in the energy complex. We expect that Distribution will continue to make significant investments

Utility Investment in Safety

(Fiscal Year — $ millions)

Utility Delivery System GHG Emissions

*(Calendar Year - Thousand Metric Tons, CO2e)**



**EPA Subpart W, using AR5 Global Warming Potential* to ensure the long-term safety, reliability and resilience of its system, while remaining steadfastly committed to the sustainability of our operations.

Our Continued and Important Role in the Energy Complex

The importance of an "all-of-the-above" approach

The affordability, reliability and security offered by natural gas is unmatched by any other source of energy today. Fortunately, the United States has an abundant supply of this low-cost and low-emissions-intensity energy readily available in the Marcellus and Utica shales. Natural gas and its safe, reliable and resilient delivery network, should continue to be a central component in an "all-of-the-above" approach to energy policy. One need only look to the challenges facing Europe to see the perils of going "all-in" on intermittent resources.

Nevertheless, we continue to see policymakers in New York and elsewhere pushing the narrative that growth in wind and solar alone can meet the needs of a fully electric world — including for winter heating in cold climates like Buffalo — without sacrificing affordability and reliability. They fully believe the electric grid can nearly triple in size without impacting cost, and they have complete faith that massive amounts of dispatchable, emissions-free generation solutions will be developed when no such technologies exist today at scale. The gap between aspirations and reality is truly remarkable.

Internationally, there is a growing and renewed appreciation for the role of natural gas. The European Union, which is several years ahead of the U.S. in its efforts to decarbonize its economy, now has committed to building new natural gas facilities and included natural gas to its taxonomy of "green energy."

National Fuel Utility employees tour a customer site of facilities that control the blending of hydrogen and natural gas to demonstrate reduced boiler emissions in Tonawanda, NY.

I am optimistic that one day the U.S. will reach this same level of appreciation and affirm natural gas as an essential component of an "all-of-the-above" approach to energy that ensures reliability, affordability and security.

The natural gas industry stands ready and willing to do its part to help alleviate the ongoing energy challenge both domestically and globally. I firmly believe increased natural gas production and pipeline infrastructure will be needed if the U.S. is serious about achieving its emission reduction goals and ensuring energy security. National Fuel is well positioned to play a long-term role in developing this resource and building the facilities needed to move critical energy supplies to markets.

Our Bright Future

Fiscal 2022 was undoubtedly a great year for National Fuel — a year which further built upon the strong foundation of our business and positioned the Company for continued success. As we look ahead, we expect that our significant footprint of high-quality assets in one of the lowest-emissions-intensity basins in the world will provide the Company with meaningful opportunities to further grow the business.

Our strong operational execution has laid the groundwork for National Fuel to generate significant and durable free cash flow across our businesses. We believe this puts us in the very enviable position in which we can simultaneously grow the business, strengthen our investment-grade balance sheet and increase the amount of capital we return to shareholders through our dividend, all of which we expect will deliver considerable value to shareholders over the long-term.

David P. Bauer
President and Chief Executive Officer
January 6, 2023

Directors

From left to right:

David H. Anderson
President and Chief Executive Officer of Northwest Natural Holding Company and Northwest Natural Gas Company

David P. Bauer
President and Chief Executive Officer of National Fuel Gas Company

Barbara M. Baumann
President and Owner of Cross Creek Energy Corporation

David C. Carroll
Former President and Chief Executive Officer of GTI Energy

Steven C. Finch
President, Manufacturing and Director of Community Engagement at Viridi Parente, Inc.

Joseph N. Jaggers
Former President, Chairman, and Chief Executive Officer of Jagged Peak Energy Inc.

Rebecca Ranich
Former Director at Deloitte Consulting, LLP

Jeffrey W. Shaw
Former Director and Chief Executive Officer of Southwest Gas Corporation

Thomas E. Skains
Former President, Chairman, and Chief Executive Officer of Piedmont Natural Gas Company, Inc.

David F. Smith
Chairman of the Board and former Chief Executive Officer of the Company

Ronald J. Tanski
Former President and Chief Executive Officer of the Company

Officers

David P. Bauer
President and Chief Executive Officer

Ronald C. Kraemer
Chief Operating Officer
President, National Fuel Gas Supply Corporation and Empire Pipeline, Inc.

Donna L. DeCarolis
President, National Fuel Gas Distribution Corporation

Justin I. Loweth
President, Seneca Resources Company, LLC and National Fuel Gas Midstream Company, LLC

Karen M. Camiolo
Treasurer and Principal Financial Officer

Elena G. Mendel
Controller and Principal Accounting Officer

Martin A. Krebs
Chief Information Officer

Sarah J. Mugel
General Counsel, Secretary and Corporate Responsibility Officer

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended September 30, 2022

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to
Commission File Number 1-3880

National Fuel Gas Company

(Exact name of registrant as specified in its charter)

New Jersey	**13-1086010**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6363 Main Street	
Williamsville, New York	**14221**
(Address of principal executive offices)	*(Zip Code)*

(716) 857-7000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, par value $1.00 per share	NFG	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $6,253,478,000 as of March 31, 2022.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2022: 91,485,294 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2023 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2022, are incorporated by reference into Part III of this report.

Glossary of Terms

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation National Fuel Gas Distribution Corporation
Empire Empire Pipeline, Inc.
Midstream Company National Fuel Gas Midstream Company,

National Fuel National Fuel Gas Company
NFR National Fuel Resources, Inc.
Registrant National Fuel Gas Company
Seneca Seneca Resources Company, LLC
Supply Corporation National Fuel Gas Supply Corporation

Regulatory Agencies

CFTC Commodity Futures Trading Commission
EPA United States Environmental Protection Agency
FASB Financial Accounting Standards Board
FERC Federal Energy Regulatory Commission
IRS Internal Revenue Service
NYDEC New York State Department of Environmental Conservation
NYPSC State of New York Public Service Commission
PaDEP Pennsylvania Department of Environmental Protection
PaPUC Pennsylvania Public Utility Commission
PHMSA Pipeline and Hazardous Materials Safety Administration
SEC Securities and Exchange Commission

Other

Bbl Barrel (of oil)
Bcf Billion cubic feet (of natural gas)
Bcfe (or Mcfe) — represents Bcf (or Mcf) Equivalent The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.
Capital expenditure Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.
CLCPA Legislation referred to as the "Climate Leadership & Community Protection Act," enacted by the State of New York on July 18, 2019.
Degree day A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.
Development costs Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.
Development well A well drilled to a known producing formation in a previously discovered field.
Dodd-Frank Act Dodd-Frank Wall Street Reform and Consumer Protection Act.
Dth Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploitation Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.
Exploration costs Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
Exploratory well A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.
FERC 7(c) application An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
Firm transportation and/or storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP Accounting principles generally accepted in the United States of America
Goodwill An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
ICE Intercontinental Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Interruptible transportation and/or storage The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LDC Local distribution company
LIBOR London Interbank Offered Rate
LIFO Last-in, first-out
Marcellus Shale A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl Thousand barrels (of oil)
Mcf Thousand cubic feet (of natural gas)
MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations
MDth Thousand decatherms (of natural gas)
MMBtu Million British thermal units (heating value of one decatherm of natural gas)
MMcf Million cubic feet (of natural gas)
MMcfe Million cubic feet equivalent

NGA The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
OPEB Other Post-Employment Benefit
Open Season A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
PCB Polychlorinated Biphenyl
Precedent Agreement An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called "conditions precedent") happen, usually within a specified time.
Proved developed reserves Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make those reserves productive.
PRP Potentially responsible party
Reliable technology Technology that a company may use to establish reserves estimates and categories that has been proven empirically to lead to correct conclusions.
Reserves The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Restructuring Generally referring to partial "deregulation" of the pipeline and/or utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or "unbundling") of gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.
Revenue decoupling mechanism A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P Standard & Poor's Ratings Service
SAR Stock appreciation right
Service Agreement The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
SOFR Secured Overnight Financing Rate
Spot gas purchases The purchase of natural gas on a short-term basis.
Stock acquisitions Investments in corporations.
Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
Utica Shale A Middle Ordovician-age geological formation lying several thousand feet below the Marcellus Shale in the Appalachian region of the United States, including much of Ohio, Pennsylvania, West Virginia and southern New York.
VEBA Voluntary Employees' Beneficiary Association
WNC/WNA Weather normalization clause/adjustment; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

For the Fiscal Year Ended September 30, 2022

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PART I

Item 1 *Business*

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. The Registrant owns directly or indirectly all of the outstanding securities of its subsidiaries. Reference to "the Company" in this report means the Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company's fiscal year ended September 30 of that year unless otherwise noted.

The Company is a diversified energy company engaged principally in the production, gathering, transportation, storage and distribution of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being used for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current natural gas production development activities are focused in the Marcellus and Utica shales, geological shale formations that are present nearly a mile or more below the surface in the Appalachian region of the United States. Pipeline development activities are designed to transport natural gas production to both existing and new markets. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian basin to markets in the eastern United States and Canada. The Company reports financial results for four business segments: Exploration and Production, Pipeline and Storage, Gathering, and Utility.

1. The Exploration and Production segment operations are carried out by Seneca Resources Company, LLC (Seneca), a Pennsylvania limited liability company. Seneca is engaged in the exploration for, and the development and production of, primarily natural gas in the Appalachian region of the United States. At September 30, 2022, Seneca had proved developed and undeveloped reserves of 4,170,662 MMcf of natural gas and 250 Mbbl of oil.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation, and Empire Pipeline, Inc. (Empire), a New York corporation. Supply Corporation and Empire provide interstate natural gas transportation services for affiliated and nonaffiliated companies through integrated gas pipeline systems in Pennsylvania and New York. Supply Corporation also provides storage services through its underground natural gas storage fields, and Empire provides storage service (via lease with Supply Corporation) to a nonaffiliated company.

3. The Gathering segment operations are carried out by wholly-owned subsidiaries of National Fuel Gas Midstream Company, LLC (Midstream Company), a Pennsylvania limited liability company. Through these subsidiaries, Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region.

4. The Utility segment operations are carried out by National Fuel Gas Distribution Corporation (Distribution Corporation), a New York corporation. Distribution Corporation provides natural gas utility services to approximately 754,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

Financial information about each of the Company's business segments can be found in Item 7, MD&A and also in Item 8 at Note M — Business Segment Information.

Seneca's Northeast Division is included in the Company's All Other category for 2021 and 2020. This division marketed timber from Appalachian land holdings. On August 5, 2020, the Company entered into a purchase and sale agreement to sell substantially all timber and other assets, which at September 30, 2020, accounted for the Company's ownership of approximately 95,000 acres of timber property and management of approximately 2,500 additional acres of timber cutting rights. The transaction closed on December 10, 2020.

For additional discussion of the purchase and sale agreement to sell these assets, see Item 8 at Note B — Asset Acquisitions and Divestitures.

Revenues from three customers of the Company's Exploration and Production segment, exclusive of hedging losses transacted with separate parties, represented approximately $850 million, or 38.9%, of the Company's consolidated revenue for the year ended September 30, 2022. These three customers were also customers of the Company's Pipeline and Storage segment, accounting for an additional $15 million, or 0.7%, of the Company's consolidated revenue for the year ended September 30, 2022.

Rates and Regulation

The Company's businesses are subject to regulation under a wide variety of federal, state and local laws, regulations and policies. This includes federal and state agency regulations with respect to rate proceedings, project permitting and environmental requirements.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. The operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Supply Corporation, Empire or Distribution Corporation are unable to obtain approval from these regulators for the rates they are requesting to charge customers, particularly when necessary to cover increased costs, earnings may decrease. For additional discussion of the Pipeline and Storage and Utility segments' rates, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note F — Regulatory Matters.

The discussion under Item 8 at Note F — Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company's Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company's Consolidated Balance Sheets and such accounting treatment would be discontinued.

The FERC also exercises jurisdiction over the construction and operation of interstate gas transmission and storage facilities and possesses significant penalty authority with respect to violations of the laws and regulations it administers. The Company is also subject to the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA issues regulations and conducts evaluations, among other things, that set safety standards for pipelines and underground storage facilities. PHMSA may delegate this authority to a state, as it has in New York and Pennsylvania, and that state may choose to institute more stringent safety regulations for the construction, operation and maintenance of intrastate facilities. In addition to this state safety authority program, the NYPSC imposes additional requirements on the construction of certain utility facilities. Increased regulation by these agencies, and other regulators, or requested changes to construction projects, could lead to operational delays or restrictions and increase compliance costs that the Company may not be able to recover fully through rates or otherwise offset.

For additional discussion of the material effects of compliance with government environmental regulation, see Item 7, MD&A under the heading "Environmental Matters."

The Exploration and Production Segment

The Exploration and Production segment contributed net income of $306.1 million in 2022.

Additional discussion of the Exploration and Production segment appears below in this Item 1 under the headings "Sources and Availability of Raw Materials" and "Competition: The Exploration and Production Segment," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Pipeline and Storage Segment

The Pipeline and Storage segment contributed net income of $102.6 million in 2022.

The Pipeline and Storage segment generated approximately 30% of its revenues in 2022 from services provided to the Utility segment or Exploration and Production segment.

Additional discussion of the Pipeline and Storage segment appears below under the headings “Sources and Availability of Raw Materials,” “Competition: The Pipeline and Storage Segment” and “Seasonality,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Gathering Segment

The Gathering segment contributed net income of $101.1 million in 2022.

The Gathering segment generated approximately 94% of its revenues in 2022 from services provided to the Exploration and Production segment.

Additional discussion of the Gathering segment appears below under the headings “Sources and Availability of Raw Materials” and “Competition: The Gathering Segment,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Utility Segment

The Utility segment contributed net income of $68.9 million in 2022.

Additional discussion of the Utility segment appears below under the headings “Sources and Availability of Raw Materials,” “Competition: The Utility Segment” and “Seasonality,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss of $12.7 million in 2022.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Sources and Availability of Raw Materials

The Exploration and Production segment seeks to discover and produce raw materials (natural gas and hydrocarbon liquids) as further described in this report in Item 7, MD&A and Item 8 at Note M — Business Segment Information and Note N — Supplementary Information for Oil and Gas Producing Activities.

The Pipeline and Storage segment transports and stores natural gas owned by its customers, whose gas primarily originates in the Appalachian region of the United States, as well as other gas supply regions in the United States and Canada. Additional discussion of proposed pipeline projects appears below under “Competition: The Pipeline and Storage Segment” and in Item 7, MD&A.

The Gathering segment gathers, processes and transports natural gas that is, in large part, produced by Seneca in the Appalachian region of the United States.

Natural gas is the principal raw material for the Utility segment. In 2022, the Utility segment purchased 76.0 Bcf of gas (including 74.2 Bcf for delivery to retail customers and 1.8 Bcf used in operations) pursuant to its purchase contracts with firm delivery requirements. Gas purchased from producers and suppliers in the United States under multi-month contracts accounted for 48% of these purchases. Purchases of gas in the spot market (contracts of one month or less) accounted for 52% of the Utility segment’s 2022 purchases. Purchases from DTE Energy Trading, Inc. (33%), Emera Energy Services, Inc. (12%), Chevron Natural Gas (8%), EQT Energy, LLC (7%), Vitol Inc. (6%), Tenaska Marketing Ventures (6%), and Shell Energy North America US (6%), accounted for nearly 78% of the Utility segment's 2022 gas purchases. No other producer or supplier provided the Utility segment with more than 5% of its gas requirements in 2022. The Utility segment does not directly purchase gas from affiliates.

Competition

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy, such as fuel oil and electricity. Management believes that the reliability and affordability, along with the environmental advantages of natural gas have enhanced its competitive position relative to other fuels.

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this "Competition" heading, do not compete with the Company to any significant extent.

Competition: The Exploration and Production Segment

The Exploration and Production segment competes with other natural gas producers and marketers with respect to sales of natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other natural gas producers with respect to exploration and development prospects and mineral leaseholds.

To compete in this environment, Seneca originates and acts primarily as operator on its prospects, seeks to minimize the risk of exploratory efforts through partnership-type arrangements, utilizes technology for both exploratory studies and drilling operations, and seeks prospect and partnership opportunities based on size, operating expertise and financial criteria.

Competition: The Pipeline and Storage Segment

Supply Corporation competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position. Most of Supply Corporation's facilities are in or near areas overlying the Marcellus and Utica shale production areas in Pennsylvania, and it has established interconnections with producers and other pipelines that provide access to these supplies and to premium off-system markets. Its facilities are also located adjacent to the Canadian border at the Niagara River providing access to markets in Canada and the northeastern and midwestern United States via the TC Energy pipeline system. Supply Corporation has developed and placed into service a number of pipeline expansion projects designed to transport natural gas to key markets in New York, Pennsylvania, the northeastern United States, Canada, and to long-haul pipelines with access to the U.S. Midwest and the Gulf Coast. For further discussion of Pipeline and Storage projects, refer to Item 7, MD&A under the heading "Investing Cash Flow."

Empire competes for natural gas market growth with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is well situated to provide transportation of Appalachian shale gas as well as gas supplies available at Empire's interconnect with TC Energy at Chippawa. Empire's geographic location provides it the opportunity to compete for service to its on-system LDC markets, as well as for a share of the gas transportation markets into Canada (via Chippawa) and into the northeastern United States. The Empire Connector, along with other subsequent projects, has expanded Empire's footprint and capability, allowing Empire to serve new markets in New York and elsewhere in the Northeast, and to attach to prolific Marcellus and Utica supplies principally from Tioga and Bradford Counties in Pennsylvania. Like Supply Corporation, Empire's expanded system facilitates transportation of natural gas to key markets within New York State, the northeastern United States and Canada.

Competition: The Gathering Segment

The Gathering segment provides gathering services for Seneca and, to a lesser extent, other producers. It competes with other companies that gather and process natural gas in the Appalachian region.

Competition: The Utility Segment

With respect to gas commodity service, in New York and Pennsylvania, both of which have implemented "unbundling" policies that allow customers to choose their gas commodity supplier, Distribution Corporation has retained a substantial majority of small sales customers. In both New York and Pennsylvania, approximately 8% of Distribution Corporation's small-volume residential and commercial customers purchase their supplies from unregulated marketers. In contrast, almost all large-volume load is served by unregulated retail marketers. However, retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation, because in both jurisdictions, utility cost of service is recovered through rates and charges for gas delivery service, not gas commodity service.

Competition for transportation service to large-volume customers continues with local producers or pipeline companies attempting to sell or transport gas directly to end-users located within the Utility segment's service territories without use of the utility's facilities (i.e., bypass). In addition, while competition with fuel oil suppliers exists, natural gas retains its competitive position despite recent commodity pricing.

The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible, high quality services. The Utility segment continues to advance programs promoting the efficient use of natural gas.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation in jurisdictions that impact the Utility segment. In addition to the Inflation Reduction Act, New York, for example, adopted the Climate Leadership & Community Protection Act (CLCPA) in July 2019, which could ultimately result in increased competition from electric and geothermal forms of energy. However, given the extended time frames associated with the CLCPA's emission reduction mandates as discussed in Item 7, MD&A under the heading "Environmental Matters" and subheading "Environmental Regulation," any meaningful competition resulting from the CLCPA cannot be determined.

Seasonality

Variations in weather conditions can materially affect the volume of natural gas delivered by the Utility segment, as virtually all of its residential and commercial customers use natural gas for space heating. The effect that this has on Utility segment margins in New York is largely mitigated by a weather normalization clause (WNC), which covers the eight-month period from October through May. Weather that is warmer than normal results in an upward adjustment to customers' current bills, while weather that is colder than normal results in a downward adjustment, so that in either case projected delivery revenues calculated at normal temperatures will be largely recovered.

Volumes transported and stored by Supply Corporation and by Empire may vary significantly depending on weather, without materially affecting the revenues of those companies. Supply Corporation's and Empire's allowed rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover only the variable costs associated with actual transportation or storage of gas.

Capital Expenditures

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

Environmental Matters

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Environmental Matters" and in Item 8, Note L — Commitments and Contingencies.

Miscellaneous

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities. When necessary, the Utility segment renews such franchises.

The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company's website, www.nationalfuelgas.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. The information available at the Company's website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

Human Capital

The Company aims to attract the best employees, to retain those employees through offering competitive benefits, career development and training opportunities, while also prioritizing their safety and wellness, and to create a safe, inclusive and productive work environment for everyone. Human capital measures and objectives that the Company focuses on in managing its business include the safety of its employees, its voluntary attrition rate, the number of work stoppages, its employee benefits, employee development, and diversity and inclusion. Additional information regarding the Company's human capital measures and objectives is contained in the Company's recently published Corporate Responsibility Report, which is available on the Company's website, www.nationalfuelgas.com. The information on the Company's website is not, and will not be deemed to be, a part of this annual report on Form 10-K or incorporated into any of the Company's other filings with the SEC.

Employees and Collective Bargaining Agreements

The Company and its wholly-owned subsidiaries had a total of 2,132 full-time employees at September 30, 2022.

As of September 30, 2022, 48% of the Company's active workforce was covered under collective bargaining agreements. The Company has agreements in place with collective bargaining units in New York into February 2025, as well as with collective bargaining units in Pennsylvania into April 2026.

Safety

Safety is one of the Company's guiding principles. In managing the business, the Company focuses on the safety of its employees and contractors and has implemented safety programs and management practices to promote a culture of safety. This includes required trainings for both field and office employees, as well as specific qualifications and certifications for field employees. The Company also ties executive compensation to safety related goals to emphasize the importance of and focus on safety at the Company.

Voluntary Attrition Rate

The Company measures the voluntary attrition rate of its employees in assessing the Company's overall human capital. The Company's voluntary attrition rate (not including retirements and excluding the severance related to the sale of Seneca's assets in California) was 8%. Additionally, throughout the COVID-19 pandemic, the Company did not institute any furloughs or workforce reductions.

No Work Stoppages

During the Company's fiscal year, the Company did not incur any work stoppages (strikes or lockouts) and therefore experienced zero idle days for the fiscal year.

Employee Benefits

To attract employees and meet the needs of the Company's workforce, the Company offers market-competitive benefits packages to employees of its subsidiaries. The Company's benefits package options may vary depending on type of employee and date of hire. Additionally, the Company continuously looks for ways to improve employee work-life balance and well-being.

Employee Development

The Company provides its employees with tools and development resources to enhance their skills and careers at the Company, including: (i) encouraging employees to discuss their professional development and identify interests or possible cross-training areas during annual performance reviews with their supervisors; (ii) offering corporate and technical training programs based on position, regulatory environment, and employee needs; (iii) providing a tuition aid program for educational pursuits related to present work or possible future positions; (iv) providing talent review and succession planning; (v) providing opportunities for on-the-job growth, through stretch assignments or temporary projects outside of an employee's typical responsibilities; and

(vi) offering one-on-one meetings for supervisory employees at the Company's subsidiaries to discuss career pathing and employee development.

Diversity, Equity and Inclusion

The Company recognizes that a diverse talent pool provides the opportunity to gain a diversity of perspectives, ideas and solutions to help the Company succeed. As such, the Company approaches diversity from the top-down, which is reflected in the makeup of our Board of Directors and senior leadership team: three out of eleven directors are diverse, and four of the Company's eight designated executive officers are women. The Company's Corporate Governance Guidelines incorporate the "Rooney Rule." As a result, when identifying independent director candidates for nomination to the Board, the Nominating/Corporate Governance Committee is committed to including in any initial candidate pool qualified racially, ethnically and/or gender diverse candidates. Beginning in fiscal 2021, the Compensation Committee adopted specific diversity and inclusion performance goals as part of the Company's Annual at Risk Compensation Incentive Plan and Executive Annual Compensation Incentive Program to link executive compensation to the Company's focus on diversity.

During fiscal 2022, the Company furthered numerous initiatives to increase the diversity of our workforce and create a more inclusive environment. The Company's Director of Diversity and Inclusion ("D&I Director") continued to spearhead diversity and inclusion initiatives across the organization. Additional resources were added to the Diversity and Inclusion team with the creation of a Diversity and Inclusion Specialist ("D&I Specialist") role to assist and expand the Company's proactive efforts of creating a more inclusive organization. These efforts include initiatives to focus on diversity when making hiring and promotional decisions. To attract diverse candidates, the Company works with community groups and organizations to help promote awareness of our job opportunities within diverse communities. The D&I Director maintains close partnerships with the employment teams, cultivates the Company's relationships with community organizations, and focuses on initiatives to attract diverse candidates, vendors and suppliers. The executive team receives a monthly report about the composition of the Company's salaried applicant pools to encourage the recruiting team to focus recruiting in diverse communities and identify resources needed to do so. The Company has also focused on encouraging diverse suppliers to receive the necessary certifications to participate in the industry and has added new diverse suppliers to its list of vendors in an effort to promote diversity.

The D&I Director and D&I Specialist also spearhead inclusion initiatives throughout the organization. To promote a more inclusive work environment, the Company has continued to provide training opportunities to employees relating to Unconscious Bias, Inclusivity, and Micro-aggressions. In addition, four new Employee Resource Groups, focused towards ethnically diverse, veteran, LGBTQ and female employees, were developed. These Employee Resource Groups provide an opportunity to engage and connect with underrepresented employees, and each group has an executive sponsor which helps facilitate communication directly to senior management. In addition, the Company has several policies that reinforce its commitment to diversity and inclusion within the workplace. The Company's Employee Handbook Policy includes equal employment opportunity commitments and nondiscrimination and anti-harassment disclosures, which communicate the Company's expectations with respect to maintaining a professional workplace free of harassment. The Company prohibits discrimination or harassment against any employee or applicant on the basis of sex, race/ethnicity, or the other protected categories listed within the Company's Non-Discrimination and Anti-Harassment Policy. This policy is mailed to employees annually with an employee survey, and employees must acknowledge that they have received the policy. The Company reiterates its commitment to a harassment free workplace through this process, as well as through prevention training for employees. Annually, the Company's Chief Executive Officer reinforces the Company's commitment to harassment prevention and equal employment opportunity by signing corporate Equal Employment Opportunity and Non-Discrimination and Anti-Harassment policy statements. These statements are then displayed at Company locations, included in employee handbooks, and discussed with new hires during their onboarding process.

Executive Officers of the Company as of November 15, 2022(1)

Name and Age (as of November 15, 2022)	Current Company Positions and Other Material Business Experience During Past Five Years
David P. Bauer (53)	Chief Executive Officer of the Company since July 2019. President of Supply Corporation from February 2016 through June 2019. Treasurer and Principal Financial Officer of the Company from July 2010 through June 2019. Treasurer of Seneca from April 2015 through June 2019. Treasurer of Distribution Corporation from April 2015 through June 2019. Treasurer of Midstream Company from April 2013 through June 2019. Treasurer of Supply Corporation from June 2007 through June 2019. Treasurer of Empire from June 2007 through June 2019.
Donna L. DeCarolis (63)	President of Distribution Corporation since February 2019. Ms. DeCarolis previously served as Vice President of Business Development of the Company from October 2007 through January 2019.
Ronald C. Kraemer (66)	Chief Operating Officer of the Company since March 2021, President of Supply Corporation since July 2019 and President of Empire since August 2008. Mr. Kraemer previously served as Senior Vice President of Supply Corporation from June 2016 through June 2019.
Karen M. Camiolo (63)	Treasurer and Principal Financial Officer of the Company since July 2019. Treasurer of Seneca Resources Company since July 2019. Ms. Camiolo previously served as Treasurer of Distribution Corporation, Supply Corporation, Empire and Midstream Company from July 2019 through June 2021. Ms. Camiolo previously served as Controller and Principal Accounting Officer of the Company from April 2004 through June 2019. Vice President of Distribution Corporation from April 2015 through June 2019. Controller of Midstream Company from April 2013 through June 2019. Controller of Empire from June 2007 through June 2019. Controller of Distribution Corporation and Supply Corporation from April 2004 through June 2019.
Elena G. Mendel (56)	Controller and Principal Accounting Officer of the Company since July 2019. Controller of Distribution Corporation, Supply Corporation, Empire, and Midstream Company since July 2019. Assistant Controller of Distribution Corporation, Supply Corporation and Empire from February 2017 through June 2019.
Martin A. Krebs (52)	Chief Information Officer of the Company since December 2018. Prior to joining the Company, Mr. Krebs served as Chief Information Officer and Chief Information Security Officer of Fidelis Care, a health insurance provider for New York State residents, from January 2012 to June 2018. Centene Corporation acquired Fidelis Care in July 2018, and Mr. Krebs served as the Chief Information Officer of the Fidelis Plan and Senior Vice President of Information Technology and Security from the acquisition to November 2018. Mr. Krebs' prior employers are not subsidiaries or affiliates of the Company.
Sarah J. Mugel (58)	Corporate Responsibility Officer of the Company since April 2022. General Counsel of the Company since May 2020 and Secretary of the Company since July 2018. Ms. Mugel has been Vice President of Supply Corporation since April 2015 and General Counsel and Secretary of Supply Corporation since April 2016. Ms. Mugel has been Secretary of Empire Pipeline and Secretary of Midstream Company, and has served as the General Counsel of both entities, since April 2016. Ms. Mugel previously served as Assistant Secretary of the Company from June 2016 through June 2018.
Justin I. Loweth (44)	President of Midstream Company since April 2022 and President of Seneca Resources Company since May 2021. Mr. Loweth previously served as Senior Vice President of Seneca Resources Company from October 2017 through April 2021.

(1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers also have served, or currently serve, as officers or directors of other subsidiaries of the Company.

Item 1A *Risk Factors*

STRATEGIC RISKS

The Company is dependent on capital and credit markets to successfully execute its business strategies.

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Turmoil in credit markets may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance existing debt. These difficulties could adversely affect the Company's growth strategies, operations and financial performance.

The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indentures, depend on the Company's compliance with its obligations under the facilities, agreements and indentures. For example, to issue incremental long-term debt, the Company must meet an interest coverage test under its 1974 indenture. In general, the Company's operating income, subject to certain adjustments, over a consecutive 12-month period within the 15 months preceding the debt issuance, must be not less than two times the total annual interest charges on the Company's long-term debt, taking into account the incremental issuance. In addition, taking into account the incremental issuance, and using a pro forma balance sheet as of the last day of the 12-month period used in the interest coverage test, the Company must maintain a ratio of long-term debt to consolidated assets (as defined under the 1974 indenture) of not more than 60%. The 1974 indenture defines consolidated assets as total assets less a number of items, including current and accrued liabilities. Depending on their magnitude, factors that reduce the Company's operating income and/or total assets, including impairments (i.e., write-downs) of the Company's natural gas properties, or that increase current and accrued liabilities, like short-term borrowings and "out of the money" derivative financial instruments, could contribute to the Company's inability to meet the interest coverage test or debt-to-assets ratio.

In addition, the Company's short-term bank loans and commercial paper are in the form of floating rate debt or debt that may have rates fixed for very short periods of time, resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans and commercial paper and the ability of the Company to issue commercial paper are affected by its credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings, Inc. A downgrade in the Company's credit ratings could increase borrowing costs, restrict or eliminate access to commercial paper markets, negatively impact the availability of capital from uncommitted sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. Additionally, $1.1 billion of the Company's outstanding long-term debt would be subject to an interest rate increase if certain fundamental changes occur that involve a material subsidiary and result in a downgrade of a credit rating assigned to the notes below investment grade. In addition to the $1.1 billion, another $500 million of the Company's outstanding long-term debt would be subject to an interest rate increase based solely on a downgrade of a credit rating assigned to the notes below investment grade, regardless of any additional fundamental changes.

Climate change, and the regulatory, legislative, consumer behaviors and capital access developments related to climate change, may adversely affect operations and financial results.

Climate change, and the laws, regulations and other initiatives to address climate change, may impact the Company's financial results. In early 2021, the U.S. rejoined the Paris Agreement, the international effort to establish emissions reduction goals for signatory countries. Under the Paris Agreement, signatory countries are expected to submit their nationally determined contributions to curb greenhouse gas emissions and meet the agreed temperature objectives every five years. On April 22, 2021, the federal administration announced the U.S. nationally determined contribution to achieve a fifty to fifty-two percent reduction from 2005 levels in economy-wide net greenhouse gas pollution by 2030. In addition to the federal reentry into the Paris

Agreement, state and local governments, non-governmental organizations, investment firms, and financial institutions have made, and will likely continue to make, more aggressive efforts to reduce emissions and advance the objectives of the Paris Agreement. Executive orders from the federal administration, in addition to federal, state and local legislative and regulatory initiatives proposed or adopted in an attempt to limit the effects of climate change, including greenhouse gas emissions, could have significant impacts on the energy industry including government-imposed limitations, prohibitions or moratoriums on the use and/or production of gas, establishment of a carbon tax and/or methane fee, lack of support for system modernization, as well as accelerated depreciation of assets and/or stranded assets.

Federal and state legislatures have from time to time considered bills that would establish a cap-and-trade program, methane fee or carbon tax to incent the reduction of greenhouse gas emissions. For example, in August 2022, the federal Inflation Reduction Act was signed into law, which includes a methane charge that is expected to be applicable to the reported annual methane emissions of certain oil and gas facilities, above specified methane intensity thresholds, starting in calendar year 2024. In addition, the New York State legislature, in early 2021, proposed a bill known as the Climate and Community Investment Act, which proposed an escalating fee starting at $55 per short ton of carbon dioxide equivalent on any carbon-based fuels sold, used or brought into the state. That bill did not pass, but similar legislation may be proposed in the future. If the Company becomes subject to new or revised cap-and-trade programs, methane charges, fees for carbon-based fuels or other similar costs or charges, the Company may experience additional costs and incremental operating expenses, which would impact our future earnings and cash flows.

A number of states have also adopted energy strategies or plans with goals that include the reduction of greenhouse gas emissions. For example, Pennsylvania has a methane reduction framework for the natural gas industry which has resulted in permitting changes with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. In addition, the NYPSC initiated a proceeding to consider climate-related financial disclosures at the utility operating level, and in 2019, the New York State legislature passed the CLCPA, which created emission reduction and electric generation mandates, and could ultimately impact the Utility segment's customer base and business. Pursuant to the CLCPA, New York's Climate Action Council issued for comment a draft scoping plan that includes recommendations to decommission substantial portions of the natural gas system and curtail use of natural gas and natural gas appliances.

Legislation or regulation that aims to reduce greenhouse gas emissions could also include natural gas bans, greenhouse gas emissions limits and reporting requirements, carbon taxes and/or similar fees on carbon dioxide, methane or equivalent emissions, restrictive permitting, increased efficiency standards requiring system remediation and/or changes in operating practices, and incentives or mandates to conserve energy or use renewable energy sources. NYDEC finalized its Part 203 Oil and Gas Sector Rule in March 2022, which significantly increases leak detection and repair inspections, recordkeeping, reporting, and notification requirements for multiple sources along city gates, transmission pipelines, compressor stations, storage facilities, and gathering lines.

Additionally, the trend toward increased energy conservation, change in consumer behaviors, competition from renewable energy sources, and technological advances to address climate change may reduce the demand for natural gas. For further discussion of the risks associated with environmental regulation to address climate change, refer to Item 7, MD&A under the heading "Environmental Matters."

Further, recent trends directed toward a low-carbon economy could shift funding away from, or limit or restrict certain sources of funding for, companies focused on fossil fuel-related development or carbon-intensive investments. To the extent financial markets view climate change and greenhouse gas emissions as a financial risk, the Company's cost of and access to capital could be negatively impacted.

Organized opposition to the natural gas industry could have an adverse effect on Company operations.

Organized opposition to the natural gas industry, including exploration and production activity, pipeline expansion and replacement projects, and the extension and continued operation of natural gas distribution systems, may continue to increase as a result of, among other things, safety incidents involving natural gas facilities, and concerns raised by politicians, financial institutions and advocacy groups about greenhouse gas emissions, hydraulic fracturing, or fossil fuels generally. This opposition may lead to increased regulatory and legislative initiatives that could place limitations, prohibitions or moratoriums on the use of natural gas, impose costs tied to carbon emissions, provide cost advantages to alternative energy sources, or impose mandates that increase operational costs associated with new natural gas infrastructure and technology. There are also increasing litigation risks associated with climate change concerns and related disclosures. Increased litigation could cause operational delays or restrictions, and increase the Company's operating costs. In turn, these factors could impact the competitive position of natural gas, ultimately affecting the Company's results of operations and cash flows.

Delays or changes in plans or costs with respect to Company projects, including regulatory delays or denials with respect to necessary approvals, permits or orders, could delay or prevent anticipated project completion and may result in asset write-offs and reduced earnings.

Construction of planned distribution, gathering, and transmission pipeline and storage facilities, as well as the expansion and replacement of existing facilities, and the development of new natural gas wells, is subject to various regulatory, environmental, political, legal, economic and other development risks, including the ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on acceptable terms, or at all. Existing or potential third-party opposition, such as opposition from landowner and environmental groups, which are beyond our control, could materially affect the anticipated construction of a project. In addition, third parties could impede the Company's acquisition, expansion or renewal of rights-of-way or land rights on a timely basis and on acceptable terms. Any delay in project development or construction may prevent a planned project from going into service when anticipated, which could cause a delay in the receipt of revenues from those facilities, result in asset write-offs and materially impact operating results or anticipated results. Additionally, delays in pipeline construction projects or gathering facility completion could impede the Exploration and Production segment's ability to transport its production to premium markets, or to fulfill obligations to sell at contracted delivery points.

FINANCIAL RISKS

As a holding company, the Company depends on its operating subsidiaries to meet its financial obligations.

The Company is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, the Company relies exclusively on repayments of principal and interest on intercompany loans made by the Company to its operating subsidiaries and income from dividends. Such operating subsidiaries may not generate sufficient net income to pay dividends to the Company or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

The Company may be adversely affected by economic conditions and their impact on our suppliers and customers.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect the Company's revenues and cash flows or restrict its future growth. Additionally, supply chain disruptions, and the associated costs and inflation related thereto, could have an impact on the Company's operations. Economic conditions in the Company's utility service territories, along with legislative and regulatory prohibitions and/or limitations on terminations of service, also impact its collections of accounts receivable. Customers of the Company's Utility segment may have particular trouble paying their bills during periods of declining economic activity, high inflation, or high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. Similarly, if reductions were to occur in funding of the federal Low Income Home Energy Assistance Program, bad debt expense could increase and earnings could decrease. In addition, oil and natural gas exploration and production companies that are customers of the Company's Pipeline and Storage segment may decide not to renew contracts for the same transportation capacity. Certain customers of the Company's Exploration and Production segment can represent a concentrated risk during times of high commodity prices and high hedge losses. Any of these events or circumstances could have or contribute to a material adverse effect on the Company's results of operations, financial condition and cash flows.

Changes in interest rates may affect the Company's financing and its regulated businesses' rates of return.

Rising interest rates may impair the Company's ability to cost-effectively finance capital expenditures and to refinance maturing debt. In addition, the Company's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, the Company's authorized rate of return could be reduced. If interest rates are higher than assumed rates, the Company's ability to earn its authorized rate of return may be adversely impacted.

Loans to the Company under its committed credit facilities may be alternate base rate loans or term SOFR loans. SOFR is a reference rate (the Secured Overnight Financing Rate) published by the Federal Reserve Bank of New York. SOFR is one available replacement for LIBOR (the London Interbank Offered Rate), which the U.K.'s Financial Conduct Authority is phasing out as a benchmark. The change from LIBOR to SOFR could expose the Company's borrowings to less favorable rates. If the change to SOFR results in increased interest rates or if the Company's lenders have increased costs due to the change, then the Company's debt that uses benchmark rates could be affected and, in turn, the Company's cash flows and interest expense could be adversely impacted.

Fluctuations in natural gas prices could adversely affect revenues, cash flows and profitability.

Financial results in the Company's Exploration and Production segment are materially dependent on prices received for its natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, and gathering natural gas. Natural gas prices can be volatile and can be affected by various factors, including weather conditions, natural disasters, the level of consumer product demand, national and worldwide economic conditions, economic disruptions caused by terrorist activities, acts of war or major accidents, political conditions in foreign countries, the price and availability of alternative fuels, the proximity to, and availability of, sufficient capacity on transportation and liquefaction facilities, regional and global levels of supply and demand, energy conservation measures, and government regulations. The Company sells the natural gas that it produces at a combination of current market prices, indexed prices or through fixed-price contracts. The Company hedges a significant portion of future sales that are based on indexed prices utilizing the physical sale counter-party and/or the financial markets. The prices the Company receives depend upon factors beyond the Company's control, including the factors affecting price mentioned above. The Company believes that any prolonged reduction in natural gas prices could restrict its ability to continue the level of exploration and production activity the Company otherwise would pursue, which could have a material adverse effect on its future revenues, cash flows and results of operations.

In the Company's Pipeline and Storage segment, significant changes in the price differential between equivalent quantities of natural gas at different geographic locations could adversely impact the Company. For example, if the price of natural gas at a particular receipt point on the Company's pipeline system increases relative to the price of natural gas at other locations, then the volume of natural gas received by the Company at the relatively more expensive receipt point may decrease, or the Company may need to discount the approved tariff rate for that transportation path in the future in order to maintain the existing volumes on its system. Changes in price differentials can cause shippers to seek alternative lower priced natural gas supplies and, consequently, alternative transportation routes. In some cases, shippers may decide not to renew transportation contracts due to changes in price differentials. While much of the impact of lower volumes under existing contracts would be offset by the straight fixed-variable rate design, this rate design does not protect Supply Corporation or Empire where shippers do not contract for expiring capacity at the same quantity and rate. If contract renewals were to decrease, revenues and earnings in this segment may decrease. Significant changes in the price differential between futures contracts for gas having different delivery dates could also adversely impact the Company. For example, if the prices of natural gas futures contracts for winter deliveries to locations served by the Pipeline and Storage segment decline relative to the prices of such contracts for summer deliveries (as a result, for instance, of increased production of gas within the segment's geographic area or other factors), then demand for the Company's natural gas storage services driven by that price differential could decrease. These changes could adversely affect future revenues, cash flows and results of operations.

In the Company's Utility segment, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills, which could increase bad debt expenses and ultimately reduce earnings. Additionally, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of the Company's capital resources.

The Company has significant transactions involving price hedging of its natural gas production as well as its fixed price sale commitments.

To protect itself to some extent against price volatility and to lock in fixed pricing on natural gas production for certain periods of time, the Company's Exploration and Production segment regularly enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may extend over multiple years, covering a substantial majority of the Company's expected energy production over the course of the current fiscal year, and lesser percentages of subsequent years' expected production. These contracts reduce exposure to subsequent price drops but can also limit the Company's ability to benefit from increases in commodity prices.

The nature of these hedging contracts could lead to potential liquidity impacts in scenarios of significantly increased natural gas prices if the Company has hedged its current production at prices below the current market price. Hedging collateral deposits represent the cash, letters of credit, or other eligible instruments held in Company funded margin accounts to serve as collateral for hedging positions used in the Company's Exploration and Production segment. A significant increase in natural gas prices may cause the Company's outstanding derivative instrument contracts to be in a liability position creating margin calls on the Company's hedging arrangements, which could require the Company to temporarily post significant amounts of cash collateral with our hedge counterparties. That collateral could be in excess of the Company's available short-term liquidity under its committed credit facility and other uncommitted sources of capital, leading to potential default under certain of its hedging arrangements. That interest-bearing cash collateral is returned to us in whole or in part upon a reduction in forward market prices, depending on the amount of such reduction, or in whole upon settlement of the related derivative contract.

Use of energy commodity price hedges also exposes the Company to the risk of nonperformance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements.

In the Exploration and Production segment, under the Company's hedging guidelines, commodity derivatives contracts must be confined to the price hedging of existing and forecast production. The Company maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose the Company to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of natural gas falls short of hedged forecast production, the Company may incur substantial losses to cover its hedges.

The Dodd-Frank Act increased federal oversight and regulation of the over-the-counter derivatives markets and certain entities that participate in those markets. Although regulators have issued certain regulations, other rules that may be relevant to the Company have yet to be finalized. For discussion of the risks associated with the Dodd-Frank Act, refer to Item 7, MD&A under the heading "Market Risk Sensitive Instruments."

You should not place undue reliance on reserve information because such information represents estimates.

This Form 10-K contains estimates of the Company's proved natural gas reserves and the future net cash flows from those reserves, which the Company's petroleum engineers prepared and independent petroleum engineers audited. Petroleum engineers consider many factors and make assumptions in estimating natural gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Changes in natural gas prices impact the quantity of economic natural gas reserves. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to the Company’s reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of the Company’s reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then the Company is reasonably certain that its reserve estimates represent economically recoverable natural gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from the Company’s proved reserves is the current market value of the Company’s estimated natural gas reserves. In accordance with SEC requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on a 12-month average of historical prices for natural gas (based on first day of the month prices and adjusted for hedging) and on costs as of the date of the estimate, which are all discounted at the SEC mandated discount rate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of the Company’s reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating natural gas reserves is complex. The process involves significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to the Company’s reserve estimates in the future. Estimates of economically recoverable natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of natural gas that are ultimately recovered, the timing of the recovery of natural gas reserves, the production and operating costs to be incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

Financial accounting requirements regarding exploration and production activities may affect the Company's profitability.

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must perform a "ceiling test" calculation, comparing the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses a 12-month historical average price for oil and natural gas (based on first day of the month prices and adjusted for hedging) as well as the SEC mandated discount rate. If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost authoritative accounting and reporting guidance require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. Under the Company's existing indenture covenants, an impairment could restrict the Company's ability to issue incremental long-term unsecured indebtedness for a period of time, beginning with the fourth calendar month following the impairment. In addition, because an impairment results in a charge to retained earnings, it lowers the Company's total capitalization, all other things being equal, and increases the Company's debt to capitalization ratio. As a result, an impairment can impact the Company's ability to maintain compliance with the debt to capitalization covenant set forth in its credit facilities. For example, for the fiscal year ended September 30, 2020 and the quarter ended December 31, 2020, the Company recognized non-cash, pre-tax impairment charges on its oil and natural gas properties of $449.4 million and $76.2 million, respectively.

OPERATIONAL RISKS

The nature of the Company's operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.

The Company's operations in its various reporting segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, the Company's facilities, machinery, and equipment may be subject to sabotage. These events, in turn, could lead to governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, the Company maintains insurance coverage against some, but not all, potential losses. The Company also seeks, but may be unable, to secure written indemnification agreements with contractors that adequately protect the Company against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to the Company. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

Hazards and risks faced by the Company, and insurance and indemnification obtained or provided by the Company, may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against the Company or be resolved on unfavorable terms, the result of which could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

Our businesses depend on natural gas gathering, storage, and transmission facilities, which, if unavailable, could adversely affect the Company's results of operations, financial condition, and cash flows.

Our businesses depend on natural gas gathering, storage, and transmission facilities, including third-party midstream facilities that are not within our control. Our Exploration and Production and Utility segments have entered into long-term agreements with midstream providers for natural gas gathering, storage, and/or transportation services. The disruption or unavailability of the midstream facilities required to provide these services, due to maintenance, mechanical failures, accidents, weather, regulatory requirements and/or other operational hazards, could negatively impact our ability to market and/or deliver our products, especially if such disruption were to last for an extended period of time. In addition, any substantial disruptions to the services provided by our midstream providers could cause us to curtail a significant amount of our production or could impair our ability to deliver natural gas to our utility customers and could have a material adverse effect on the Company's results of operations, financial condition, and cash flows. Furthermore, as substantially all of our production is transported from the well pad to interconnections with various FERC-regulated pipelines though our affiliated gathering facilities, such a production curtailment could result in significantly reduced throughput on those facilities, adversely affecting revenues and cash flows of our Gathering business.

The disruption of the Company's information technology and operational technology systems, including third party attempts to breach the Company's network security, could adversely affect the Company's financial results.

The Company relies on information technology and operational technology systems to process, transmit, and store information, to manage and support a variety of business processes and activities, and to comply with regulatory, legal, and tax requirements. The Company's information technology and operational technology systems, some of which are dependent on services provided by third parties, may be vulnerable to damage, interruption, or shutdown due to any number of causes outside of our control such as catastrophic events, natural disasters, fires, power outages, systems failures, telecommunications failures, and employee error or malfeasance. In addition, the Company's information technology and operational technology systems are subject to attempts by others to gain unauthorized access, or to otherwise introduce malicious software. These attempts might be the result of industrial or other espionage, or actions by hackers seeking to harm the Company, its services or customers. These more sophisticated cyber-related attacks, as well as cybersecurity failures resulting from human error, pose a risk to the security of the Company's systems and networks and the confidentiality, availability and integrity of the Company's and its customers' data. That data may be considered sensitive, confidential, or personal information that is subject to privacy and security laws, regulations and directives. While the Company employs reasonable and appropriate controls to maintain and protect its information technology and operational technology systems, the Company may be vulnerable to material disruptions, material security breaches, lost or corrupted data, programming errors and employee errors and/or malfeasance that could lead to interruptions to the Company's business operations or the unauthorized access, use, disclosure, modification or destruction of sensitive, confidential or personal information. Attempts to breach the Company's network security may result in disruption of the Company's business operations and services, delays in production, theft of sensitive and valuable data, damage to our physical systems, and reputational harm. Significant expenditures may be required to remedy system disruptions or breaches, including restoration of customer service and enhancement of information technology and operational technology systems.

The Company seeks to prevent, detect and investigate security incidents, but in some cases the Company might be unaware of an incident or its magnitude and effects. In addition to existing risks, the adoption of new technologies may also increase the Company's exposure to data breaches or the Company's ability to detect and remediate effects of a breach. The Company has experienced attempts to breach its network security and has received notifications from third-party service providers who have experienced disruptions to services or data breaches where Company data was potentially impacted. Although the scope of such incidents is sometimes unknown, they could prove to be material to the Company. Even though insurance coverage is in place for cyber-related risks, if a material disruption or breach were to occur, the Company's operations, earnings, cash flows and financial condition could be adversely affected to the extent not fully covered by such insurance.

The amount and timing of actual future natural gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce the Company's earnings.

There are many risks in developing natural gas, including numerous uncertainties inherent in estimating quantities of proved natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of the Company's Exploration and Production and Gathering segments depends on its ability to develop additional natural gas reserves that are economically recoverable, and its failure to do so may reduce the Company's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. The Company's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, completion crew and related equipment availability, geology, and other factors. Drilling for natural gas can be unprofitable, not only from non-productive wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, competition and cost to acquire mineral rights, weather conditions, governmental requirements, including completion of environmental impact analyses and compliance with other environmental laws and regulations, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is significant and often uncertain, and new wells may not be productive or the Company may not recover all or any portion of its investment. Production can also be delayed or made uneconomic if there is insufficient gathering, processing and transportation capacity available at an economic price to get that production to a location where it can be profitably sold. Without continued successful exploitation or acquisition activities, the Company's reserves and revenues will decline as a result of its current reserves being depleted by production. The Company cannot make assurances that it will be able to find or acquire additional reserves at acceptable costs.

The physical risks associated with climate change may adversely affect the Company's operations and financial results.

Climate change could create acute and/or chronic physical risks to the Company's operations, which may adversely affect financial results. Acute physical risks include more frequent and severe weather events, which may result in adverse physical effects on portions of U.S. natural gas infrastructure, and could disrupt the Company's supply chain and ultimately its operations. Disruption of production activities, as well as natural gas transportation and distribution systems, could result in reduced operational efficiency, and customer service interruption. Severe weather events could also cause physical damage to facilities, all of which could lead to reduced revenues, increased insurance premiums or increased operational costs. To the extent the Company's regulated businesses are unable to recover those costs, or if the recovery of those costs results in higher rates and reduced demand for Company services, the Company's future financial results could be adversely impacted. Chronic physical risks include long-term shifts in climate patterns resulting in new storm patterns or chronic increased temperatures, which could cause demand for gas to increase or decrease as a result of warmer weather and less degree days, and adversely impact the Company's future financial results.

Disputes with collective bargaining units representing the Company's workforce, and work stoppage (e.g. strike or lockout), could adversely affect the Company's operations as well as its financial results.

Approximately half of the Company's active workforce is represented by collective bargaining units in New York and Pennsylvania. These labor agreements are negotiated periodically, and therefore, the Company is subject to the risk that such agreements may not be able to be renewed on reasonably satisfactory terms, on anticipated timelines, or at all. In connection with the negotiation of such collective bargaining agreements, or in future matters involving collective bargaining units representing the Company's workforce, the Company could experience, among other things, strikes, work stoppages, slowdowns or lockouts, which could cause a disruption of the Company's operations and have a material adverse effect on the Company's results of operations and financial condition.

<u>REGULATORY RISKS</u>

The Company's need to comply with comprehensive, complex, and the sometimes unpredictable enforcement of government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

The Company's businesses are subject to regulation under a wide variety of federal and state laws, regulations and policies. Existing statutes and regulations, including current tax rates, may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, which may increase the Company's costs, require refunds to customers or affect its business in ways that the Company cannot predict. Administrative agencies may apply existing laws and regulations in unanticipated, inconsistent or legally unsupportable ways, making it difficult to develop and complete projects, and harming the economic climate generally.

Various aspects of the Company's operations are subject to regulation by a variety of federal and state agencies with respect to permitting and environmental requirements. In some areas, the Company's operations may also be subject to locally adopted ordinances. Administrative proceedings or increased regulation by these agencies could lead to operational delays or restrictions and increased expense for one or more of the Company's subsidiaries.

The Company is subject to the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA). The PHMSA issues regulations and conducts evaluations, among other things, that set safety standards for pipelines and underground storage facilities. If as a result of these or similar new laws or regulations the Company incurs material compliance costs that it is unable to recover fully through rates or otherwise offset, the Company's financial condition, results of operations, and cash flows could be adversely affected.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. Pursuant to the petition of a customer or state commission, or on the FERC's own initiative, the FERC has the authority to investigate whether Supply Corporation's and Empire's rates are still "just and reasonable" as required by the NGA, and if not, to adjust those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to adjust the rates it charges its gas transportation and/or storage customers, or if either Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease. In addition, the FERC exercises jurisdiction over the construction and operation of interstate natural gas transmission and storage facilities and also possesses significant penalty authority with respect to violations of the laws and regulations it administers.

The operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is unable to obtain approval from these regulators for the rates it is requesting to charge utility customers, particularly when necessary to cover increased costs, earnings and/or cash flows may decrease.

Environmental regulation significantly affects the Company's business.

The Company's business operations are subject to federal, state, and local laws, regulations and agency policies relating to environmental protection including obtaining and complying with permits, leases, approvals, consents and certifications from various governmental and permit authorities. These laws, regulations and policies concern the generation, storage, transportation, disposal, emission or discharge of pollutants, contaminants, hazardous substances and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. For example, currently applicable environmental laws and regulations restrict the types, quantities and concentrations of materials that can be released into the environment in connection with regulated activities, limit or prohibit activities in certain protected areas, and may require the Company to investigate and/or remediate contamination at certain current and former properties regardless of whether such contamination resulted from the Company's actions or whether such actions were in compliance with applicable laws and regulations at the time they were taken. Moreover, spills or releases of regulated substances or the discovery of currently unknown contamination could expose the Company to material losses, expenditures and environmental, health and safety liabilities. Such liabilities could include penalties, sanctions or claims for damages to persons, property or natural resources brought on behalf of the government or private litigants that could cause the Company to incur substantial costs or uninsured losses.

Costs of compliance and liabilities could negatively affect the Company's results of operations, financial condition and cash flows. In addition, compliance with environmental laws, regulations or permit conditions could require unexpected capital expenditures at the Company's facilities, temporarily shut down the Company's facilities or delay or cause the cancellation of expansion projects or natural gas drilling activities. Because the costs of such compliance are significant, additional regulation could negatively affect the Company's business.

Increased regulation of exploration and production activities, including hydraulic fracturing, could adversely impact the Company.

Various state legislative and regulatory initiatives regarding the exploration and production business have been proposed or adopted in the northeast United States affecting the Marcellus and Utica Shale gas plays. These initiatives include potential new or updated statutes and regulations governing the drilling, casing, cementing, testing, monitoring and abandonment of wells, the protection of water supplies and restrictions on water use and water rights, hydraulic fracturing operations, surface owners' rights and damage compensation, the spacing of wells, use and disposal of potentially hazardous materials, and environmental and safety issues regarding gas pipelines. New permitting fees and/or severance taxes for natural gas production are also possible.

Additionally, legislative initiatives in the U.S. Congress and regulatory studies, proceedings or rule-making initiatives at federal, state or local agencies focused on the hydraulic fracturing process, the use of underground injection control wells for produced water disposal, and related operations could result in operational delays or prohibitions and/or additional permitting, compliance, reporting and disclosure requirements, which could lead to increased operating costs and increased risks of litigation for the Company.

The Company could be adversely affected by the delayed recovery or disallowance of purchased gas costs incurred by the Utility segment.

Tariff rate schedules in each of the Utility segment's service territories contain purchased natural gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased natural gas. Assuming those rate adjustments are granted, increases in the cost of purchased natural gas have no direct impact on profit margins. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased natural gas. Extreme weather events, variations in seasonal weather, and other events disrupting supply and/or demand could cause the Company to experience unforeseeable and unprecedented increases in the costs of purchased natural gas. Any prudently incurred natural gas costs could be subject to deferred recovery if regulators determine such costs are detrimental to customers in the short-term. Furthermore, there is a risk of disallowance of full recovery of these costs if regulators determine that Distribution Corporation was imprudent in making its natural gas purchases. Any material delayed recovery or disallowance of purchased natural gas costs could have a material adverse effect on cash flow and earnings.

GENERAL RISKS

The Company's credit ratings may not reflect all the risks of an investment in its securities.

The Company's credit ratings are an independent assessment of its ability to pay its obligations. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the specific debt instruments that are rated, as well as the market value of the Company's common stock. The Company's credit ratings, however, may not reflect the potential impact on the value of its common stock of risks related to structural, market or other factors discussed in this Form 10-K.

The increasing costs of certain employee and retiree benefits could adversely affect the Company's results.

The Company's earnings and cash flow may be impacted by the amount of income or expense it expends or records for employee benefit plans. This is particularly true for pension and other post-retirement benefit plans, which are dependent on actual plan asset returns and factors used to determine the value and current costs of plan benefit obligations. In addition, if medical costs rise at a rate faster than the general inflation rate, the Company might not be able to mitigate the rising costs of medical benefits. Increases to the costs of pension, other post-retirement and medical benefits could have an adverse effect on the Company's financial results.

Significant shareholders or potential shareholders may attempt to effect changes at the Company or acquire control over the Company, which could adversely affect the Company's results of operations and financial condition.

Shareholders of the Company may from time to time engage in proxy solicitations, advance shareholder proposals or otherwise attempt to effect changes or acquire control over the Company. Campaigns by shareholders to effect changes at publicly traded companies are sometimes led by investors seeking to increase short-term shareholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. Additionally, activist shareholders may submit proposals to promote an environmental, social, and/or governance position. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupting the Company's operations and diverting the attention of the Company's Board of Directors and senior management from the pursuit of business strategies. As a result, shareholder campaigns could adversely affect the Company's results of operations and financial condition.

Item 1B ***Unresolved Staff Comments***

None.

Item 2 ***Properties***

General Information on Facilities

The net investment of the Company in property, plant and equipment was $6.6 billion at September 30, 2022. The Exploration and Production segment constitutes 31.2% of this investment, and is primarily located in the Appalachian region of the United States. Approximately 56.1% of the Company's investment in net property, plant and equipment was in the Utility and Pipeline and Storage segments, whose operations are located primarily in western and central New York and western Pennsylvania. The Gathering segment constitutes 12.6% of the Company's investment in net property, plant and equipment, and is located in northwestern and central Pennsylvania. The remaining 0.1% of the Company's net investment in property, plant and equipment falls within All Other and Corporate operations. During the past five years, the Company has made significant additions to property, plant and equipment in order to expand its exploration and production and gathering operations in the Appalachian region of the United States and to expand and modernize transmission and distribution facilities for customers in New York and Pennsylvania. Net property, plant and equipment has increased $1.9 billion, or 40.5%, since September 30, 2017. The five year increase is net of impairments of oil and gas producing properties recorded in 2020 and 2021 ($449 million and $76 million, respectively).

The Exploration and Production segment had a net investment in property, plant and equipment of $2.1 billion at September 30, 2022.

The Pipeline and Storage segment had a net investment of $2.0 billion in property, plant and equipment at September 30, 2022. Transmission pipeline represents 37% of this segment's total net investment and includes 2,301 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 13% of this segment's total net investment and consist of 387 miles of pipeline, as well as 30 storage fields operating at a combined working gas level of 77.2 Bcf, three of which are jointly owned and operated with other interstate gas pipeline companies. Net investment in storage facilities includes $79.7 million of gas stored underground-noncurrent, representing the cost of the gas utilized to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 34 compressor stations with 262,393 installed horsepower that represent 32% of this segment's total net investment in property, plant and equipment.

The Pipeline and Storage segment's facilities provided the capacity to meet Supply Corporation's 2022 peak day sendout for transportation service of 2,092 MMcf, which occurred on January 10, 2022. Withdrawals from storage of 718 MMcf provided approximately 34% of the requirements on that day.

The Gathering segment had a net investment of $0.8 billion in property, plant and equipment at September 30, 2022. Gathering lines and related compressor stations represent substantially all of this segment's total net investment, including 368 miles of pipelines utilized to move Appalachian production (including Marcellus and Utica shales) to various transmission pipeline receipt points. The Gathering segment has 25 compressor stations with 119,980 installed horsepower.

The Utility segment had a net investment in property, plant and equipment of $1.7 billion at September 30, 2022. The net investment in its gas distribution network (including 15,040 miles of distribution pipeline) and its service connections to customers represent approximately 49% and 32%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2022.

Company maps are included in Exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

Exploration and Production Activities

The Company is engaged in the exploration for and the development of natural gas reserves in the Appalachian region of the United States. The Company's development activities in the Appalachian region are focused primarily in the Marcellus and Utica shales. Further discussion of oil and gas producing activities is included in Item 8, Note N — Supplementary Information for Oil and Gas Producing Activities. Note N sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2022, 2021 and 2020 reserves shown in Note N are valued using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. The reserves were estimated by Seneca's petroleum engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Note N discusses the qualifications of the Company's petroleum engineers, internal controls over the reserve estimation process and audit of the reserve estimates and changes in proved developed and undeveloped oil and natural gas reserves year over year.

Seneca's proved developed and undeveloped natural gas reserves increased from 3,723 Bcf at September 30, 2021 to 4,171 Bcf at September 30, 2022. This increase is attributed to extensions and discoveries of 838 Bcf and revisions of previous estimates of 3 Bcf, partially offset by production of 343 Bcf. Upward revisions included 3 Bcf of price-related revisions and 13 Bcf of revisions related to positive performance improvements including reduced operating expenses. The additions and upward revisions were partially offset by divestures of 50 Bcf as well as downward revisions of 13 Bcf from the removal of 1 PUD location related to pad layout changes. The Company has no near term plans to develop the reserves at this PUD location.

Seneca's proved developed and undeveloped oil reserves decreased from 21,537 Mbbl at September 30, 2021 to 250 Mbbl at September 30, 2022. The decrease of 21,287 Mbbl is attributed to production of 1,604 Mbbl and the sale of Seneca's West Coast region (i.e., California assets) of 20,766 Mbbl. These decreases were partially offset by positive performance revisions of 787 Mbbl and extensions and discoveries of 296 Mbbl.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 3,853 Bcfe at September 30, 2021 to 4,172 Bcfe at September 30, 2022. This increase is attributed to extensions and discoveries of 839 Bcfe and upward revisions of previous estimates of 8 Bcfe, partially offset by production of 353 Bcfe and divestures, primarily from the sale of the West Coast region (i.e., California assets), of 175 Bcfe.

Seneca's proved developed and undeveloped natural gas reserves increased from 3,325 Bcf at September 30, 2020 to 3,723 Bcf at September 30, 2021. This increase was attributed to extensions and discoveries of 689 Bcf and revisions of previous estimates of 23 Bcf, partially offset by production of 314 Bcf. Upward revisions included 74 Bcf of price-related revisions and 29 Bcf of revisions related to positive performance improvements including reduced operating expenses. Downward revisions of 80 Bcf from the removal of 8 PUD locations were due to continued integration of the Tioga assets acquired in July 2020, as well as other operational optimizations that resulted in pad layout and development schedule changes.

Seneca's proved developed and undeveloped oil reserves decreased from 22,100 Mbbl at September 30, 2020 to 21,537 Mbbl at September 30, 2021. The decrease of 563 Mbbl was attributed to production of 2,235 Mbbl and downward revisions of previous estimates of 579 Mbbl, partially offset by positive price-related revisions of 1,210 Mbbl and extensions and discoveries of 1,041 Mbbl, primarily occurring in the West Coast region.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 3,458 Bcfe at September 30, 2020 to 3,853 Bcfe at September 30, 2021. This increase was attributed to extensions and discoveries of 696 Bcfe and upward revisions of previous estimates of 26 Bcfe, partially offset by production of 327 Bcfe.

At September 30, 2022, the Company's Exploration and Production segment had delivery commitments for natural gas production of 2,390 Bcf. The Company expects to meet those commitments through the future production of reserves that are currently classified as proved reserves and future extensions and discoveries.

The following is a summary of certain oil and gas information taken from Seneca's records. All monetary amounts are expressed in U.S. dollars.

Production

	For The Year Ended September 30		
	2022	2021	2020
United States			
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 5.03 (1)	$ 2.46 (1)	$ 1.75 (1)
Average Sales Price per Barrel of Oil	$ 97.82	$ 48.02	$ 45.69
Average Sales Price per Mcf of Gas (after hedging)	$ 2.69	$ 2.22	$ 2.05
Average Sales Price per Barrel of Oil (after hedging)	$ 97.82	$ 48.02	$ 45.69
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.68 (1)	$ 0.67 (1)	$ 0.68 (1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	936 (1)	856 (1)	616 (1)
West Coast Region			
Average Sales Price per Mcf of Gas	$ 10.03	$ 6.34	$ 3.82
Average Sales Price per Barrel of Oil	$ 94.06	$ 60.50	$ 45.94
Average Sales Price per Mcf of Gas (after hedging)	$ 10.03	$ 6.34	$ 3.82
Average Sales Price per Barrel of Oil (after hedging)	$ 70.53	$ 56.55	$ 56.97
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 4.83	$ 3.74	$ 3.14
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	39 (2)	41	44
Total Company			
Average Sales Price per Mcf of Gas	$ 5.05	$ 2.49	$ 1.77
Average Sales Price per Barrel of Oil	$ 94.10	$ 60.49	$ 45.94
Average Sales Price per Mcf of Gas (after hedging)	$ 2.71	$ 2.25	$ 2.07
Average Sales Price per Barrel of Oil (after hedging)	$ 70.80	$ 56.54	$ 56.96
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.81	$ 0.82	$ 0.84
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	966	897	660

(1) Average sales prices per Mcf of gas reflect sales of gas in the Marcellus and Utica Shale fields. The Marcellus Shale fields (which exceed 15% of total reserves at September 30, 2022, 2021 and 2020) contributed 574 MMcfe, 597 MMcfe and 463 MMcfe of daily production in 2022, 2021 and 2020, respectively. The average lifting costs (per Mcfe) were $0.71 in 2022, $0.70 in 2021 and $0.70 in 2020. The Utica Shale fields (which exceed 15% of total reserves at September 30, 2022, 2021 and 2020) contributed 357 MMcfe, 255 MMcfe and 151 MMcfe of daily production in 2022, 2021 and 2020, respectively. The average lifting costs (per Mcfe) were $0.63 in 2022, $0.62 in 2021 and $0.62 in 2020.

(2) West Coast region properties were sold at June 30, 2022.

Productive Wells

At September 30, 2022	Appalachian Region		West Coast Region		Total Company	
	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	996	—	—	—	996	—
Productive Wells — Net	870	—	—	—	870	—

Developed and Undeveloped Acreage

At September 30, 2022	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
— Gross	655,433	—	655,433
— Net	643,381	—	643,381
Undeveloped Acreage			
— Gross	675,886	—	675,886
— Net	636,523	—	636,523
Total Developed and Undeveloped Acreage			
— Gross	1,331,319	—	1,331,319
— Net	1,279,904 (1)	—	1,279,904

(1) Of the 1,279,904 Total Developed and Undeveloped Net Acreage in the Appalachian region as of September 30, 2022, there are a total of 1,208,976 net acres in Pennsylvania. Of the 1,208,976 total net acres in Pennsylvania, shale development in the Marcellus, Utica or Geneseo shales has occurred on approximately 121,411 net acres, or 10% of Seneca's total net acres in Pennsylvania. Developed Acreage in the table reflects previous development activities in the Upper Devonian formation, but does not include the potential for development beneath this formation in areas of previous development, which includes the Marcellus, Utica and Geneseo shales.

As of September 30, 2022, the aggregate amounts of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 2,569 acres in 2023 (2,368 net acres), 15,203 acres in 2024 (14,310 net acres), 1,547 acres in 2025 (1,388 net acres) and 192,105 acres thereafter (187,765 net acres). The remaining 464,462 gross acres (430,692 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2023, 2024 and 2025, Seneca has 80.2 Bcf of associated proved undeveloped gas reserves. As a part of its management approved development plan, Seneca generally commences development of these reserves prior to the expiration of the leases and/or proactively extends/renews these leases.

Drilling Activity

For the Year Ended September 30	Productive 2022	Productive 2021	Productive 2020	Dry 2022	Dry 2021	Dry 2020
United States						
Appalachian Region						
Net Wells Completed						
— Exploratory	—	—	—	—	—	1.00
— Development(1)	43.00	47.83	39.84	2.50	2.00	6.50
West Coast Region						
Net Wells Completed						
— Exploratory	—	—	—	—	—	—
— Development	23.00	10.00	34.00	—	—	—
Total Company						
Net Wells Completed						
— Exploratory	—	—	—	—	—	1.00
— Development	66.00	57.83	73.84	2.50	2.00	6.50

(1) Fiscal 2022, 2021 and 2020 Appalachian region dry wells include 2.5, 2 and 4.5 net wells, respectively, drilled prior to 2012 that were never completed under a joint venture in which the Company was the nonoperator. The Company became the operator of the properties in 2017 and plugged and abandoned the wells in 2022, 2021 and 2020 after the Company determined it would not continue development activities. The remaining 2 dry wells in fiscal 2020 relate to plugged and abandoned well locations where preparatory top-hole drilling operations had commenced but further development activities (e.g., vertical and horizontal drilling, hydraulic fracturing, etc.) did not proceed as a result of changes to the Company's development plans.

Present Activities

At September 30, 2022	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	49.00	—	49.00
— Net	46.50	—	46.50

(1) Includes wells awaiting completion.

Item 3 ***Legal Proceedings***

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note L — Commitments and Contingencies.

For a discussion of certain rate matters involving the NYPSC, refer to Part II, Item 7, MD&A of this report under the heading "Other Matters - Rate Matters."

Item 4 ***Mine Safety Disclosures***

Not Applicable.

PART II

Item 5 *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

At September 30, 2022, there were 9,236 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange under the trading symbol "NFG". Information regarding the market for the Company's common equity and related stockholder matters appears under Item 12 at Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and Item 8 at Note H — Capitalization and Short-Term Borrowings.

On July 1, 2022, the Company issued a total of 6,560 unregistered shares of Company common stock to non-employee directors of the Company then serving on the Board of Directors of the Company (or, in the case of non-employee directors who elected to defer receipt of such shares pursuant to the Company's Deferred Compensation Plan for Directors and Officers (the "DCP"), to the DCP trustee), consisting of 656 shares per director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended September 30, 2022. The Company issued an additional 273 unregistered shares in the aggregate on July 15, 2022, pursuant to the dividend reinvestment feature of the DCP, to the six non-employee directors who defer the shares issued for the quarter ended September 30, 2022. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

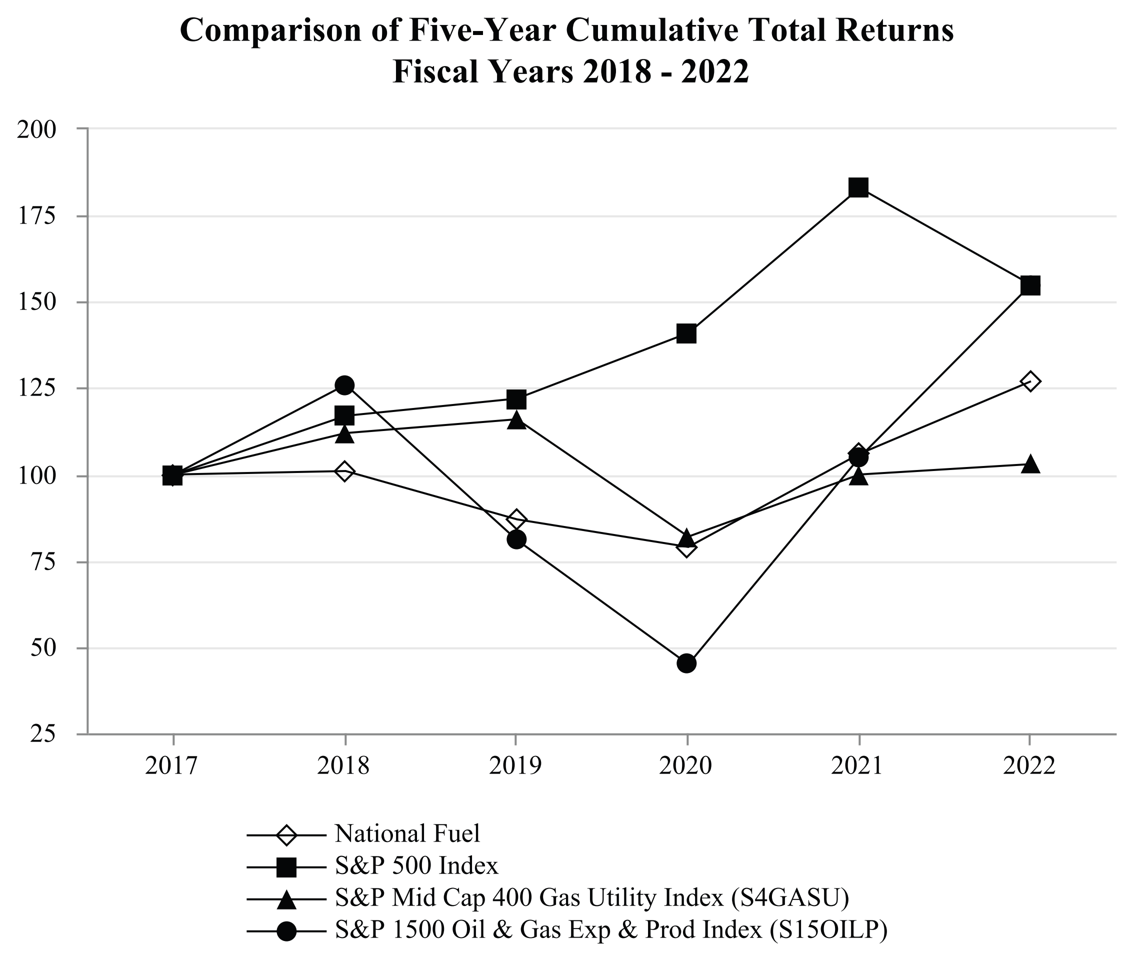
Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b)
July 1-31, 2022	12,420	$ 65.24	—	6,971,019
Aug. 1-31, 2022	10,598	$ 72.22	—	6,971,019
Sept. 1-30, 2022	9,387	$ 71.18	—	6,971,019
Total	32,405	$ 69.37	—	6,971,019

(a) Represents (i) shares of common stock of the Company purchased with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock-based compensation awards for the payment of applicable withholding taxes. During the quarter ended September 30, 2022, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 32,405 shares purchased other than through a publicly announced share repurchase program, 29,440 were purchased for the Company's 401(k) plans and 2,965 were purchased as a result of shares tendered to the Company by holders of stock-based compensation awards.

(b) In September 2008, the Company's Board of Directors authorized the repurchase of eight million shares of the Company's common stock. The Company has not repurchased any shares since September 17, 2008. The repurchase program has no expiration date and management would discuss with the Company's Board of Directors any future repurchases under this program.

Performance Graph

The following graph compares the Company's common stock performance with the performance of the S&P 500 Index, the S&P Mid Cap 400 Gas Utility Index and the S&P 1500 Oil & Gas Exploration & Production Index for the period September 30, 2017 through September 30, 2022. The graph assumes that the value of the investment in the Company's common stock and in each index was $100 on September 30, 2017 and that all dividends were reinvested.



	2017	2018	2019	2020	2021	2022
National Fuel	$100	$101	$87	$79	$106	$127
S&P 500 Index	$100	$117	$122	$141	$183	$155
S&P Mid Cap 400 Gas Utility Index (S4GASU)	$100	$112	$116	$82	$100	$103
S&P 1500 Oil & Gas Exp & Prod Index (S15OILP)	$100	$126	$81	$45	$105	$155

Source: Bloomberg

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

Item 6 ***(Reserved)***

Item 7 ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

OVERVIEW

The Company is a diversified energy company engaged principally in the production, gathering, transportation, storage and distribution of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused primarily in the Marcellus and Utica shales. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian basin to markets in the eastern United States and Canada. The Company's efforts in this regard are not limited to affiliated projects. The Company has also been designing and building pipeline projects for the transportation of natural gas for non-affiliated natural gas customers in the Appalachian basin. The Company reports financial results for four business segments: Exploration and Production, Pipeline and Storage, Gathering, and Utility.

Corporate Responsibility

The Board of Directors and management recognize that the long-term interests of stockholders are served by considering the interests of customers, employees and the communities in which the Company operates. The Board retains risk oversight and general oversight of corporate responsibility, including environmental, social and governance ("ESG") concerns, and any related health and safety issues that might arise from the Company's operations. The Board's Nominating/Corporate Governance Committee oversees and provides guidance concerning the Company's practices and reporting with respect to corporate responsibility and ESG factors that are of significance to the Company and its stakeholders, and may also make recommendations to the Board regarding ESG initiatives and strategies, including the Company's progress on integrating ESG factors into business strategy and decision-making.

Part of the Board and management's strategic and capital spending decision process includes identifying and assessing climate-related risks and opportunities. Management reports quarterly to the Board on critical and potentially emerging risks, including climate-related risks, as part of the Enterprise Risk Management process. Since the Company operates an integrated business with assets being utilized for, and benefiting from, the production, transportation and consumption of natural gas, the Board and management consider physical and transitional climate risks, including policy and legal risks, technological developments, shifts in market conditions, including future natural gas usage, and reputational risks, and the impact of those risks on the Company's business. In March 2022, the Company published its inaugural Climate Report, analyzing climate-related transitional and physical risks, and describing our strategy for addressing those risks, as well as the resiliency of that strategy under a carbon constrained scenario. The Company reviews and considers adjustments to its approach to capital investment in response to these transitional developments, with its long-term, returns-focused approach.

The Company recognizes the important role of ongoing system modernization and efficiency in reducing greenhouse gas emissions and remains focused on reducing the Company's carbon footprint, with these efforts positioning natural gas, and the Company's related infrastructure, to remain an important part of the energy complex. In 2021, the Company set methane intensity reduction targets at each of its businesses, an absolute greenhouse gas emissions reduction target for the consolidated Company, and greenhouse gas reduction targets associated with the Company's utility delivery system. In 2022, the Company began measuring progress against these reduction targets. The Company also incorporated short-term and long-term executive compensation goals designed to incentivize and reward performance if reduction targets are met or exceeded. The Company's ability to estimate accurately the time, costs and resources necessary to meet these emissions reduction targets may change as environmental exposures and opportunities change, technology advances, and legislative and regulatory updates are issued.

Fiscal 2022 Highlights

This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, “Results of Operations;”
3. Operating, investing and financing cash flows under the heading “Capital Resources and Liquidity” and;
4. Other Matters, including: (a) 2022 and projected 2023 funding for the Company’s pension and other post-retirement benefits; (b) disclosures and tables concerning market risk sensitive instruments; (c) rate matters in the Company’s New York, Pennsylvania and FERC-regulated jurisdictions; (d) environmental matters; and (e) effects of inflation.

The information in MD&A should be read in conjunction with the Company’s financial statements in Item 8 of this report, which includes a comparison of our Results of Operations and Capital Resources and Liquidity for fiscal 2022 and fiscal 2021. For a discussion of the Company's earnings, refer to the Results of Operations section below. A discussion of changes in the Company’s results of operations from fiscal 2020 to fiscal 2021 has been omitted from this Form 10-K, but may be found in Item 7, MD&A, of the Company’s Form 10-K for the fiscal year ended September 30, 2021, filed with the SEC on November 19, 2021.

On June 30, 2022, the Company completed the sale of Seneca’s California assets to Sentinel Peak Resources California LLC for a total sale price of $253.5 million, consisting of $240.9 million in cash and contingent consideration valued at $12.6 million at closing. The Company pursued this sale given the strong commodity price environment and the Company's strategic focus in the Appalachian Basin. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The sale price, which reflected an effective date of April 1, 2022, was reduced for production revenues less expenses that were retained by Seneca from the effective date to the closing date. Under the full cost method of accounting for oil and natural gas properties, $220.7 million of the sale price at closing was accounted for as a reduction of capitalized costs since the disposition did not alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center. The remainder of the sale price ($32.8 million) was applied against assets that are not subject to the full cost method of accounting, with the Company recognizing a gain of $12.7 million on the sale of such assets. The majority of this gain related to the sale of emission allowances.

The Company has continued to pursue development projects to expand its Pipeline and Storage segment. One project on Supply Corporation's system, referred to as the FM100 Project, upgraded a 1950’s era pipeline in northwestern Pennsylvania and created approximately 330,000 Dth per day of additional transportation capacity in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County, Pennsylvania to the Transcontinental Gas Pipe Line Company, LLC ("Transco") system at Leidy, Pennsylvania. Construction activities on the expansion portion of the FM100 Project are complete and the project was placed into service in December 2021. This project will provide incremental annual transportation revenues of approximately $50 million. The FM100 Project is discussed in more detail in the Capital Resources and Liquidity section that follows. For further discussion of the Pipeline and Storage segment's revenues and earnings, refer to the Results of Operations section below.

The Company's Exploration and Production segment continues to grow, as evidenced by an 8% growth in proved reserves from the prior year to a total of 4,172 Bcfe at September 30, 2022. Production increased 25.1 Bcfe during the fiscal year ended September 30, 2022 to a total of 352.5 Bcfe, and is expected to increase again in fiscal 2023. The December 2021 commencement of service for Seneca’s 330,000 Dth per day of incremental pipeline capacity on the Leidy South Project, which was the companion project of the Company's FM100 Project, contributed to the production growth in fiscal 2022. This incremental pipeline capacity provides Seneca with the ability to reach premium Transco Zone 6 (Non-New York) markets.

On February 28, 2022, the Company entered into a Credit Agreement (as amended from time to time, the "Credit Agreement") with a syndicate of twelve banks. The Credit Agreement replaced the previous Fourth Amended and Restated Credit Agreement and a previous 364-Day Credit Agreement. The Credit Agreement provides a $1.0 billion unsecured committed revolving credit facility with a maturity date of February 26, 2027.

On June 30, 2022, the Company entered into a new 364-Day Credit Agreement (the "364-Day Credit Agreement") with a syndicate of five banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional $250.0 million unsecured committed delayed draw term loan credit facility with a maturity date of June 29, 2023. The Company elected to draw $250.0 million under the facility on October 27, 2022. The Company is using the proceeds for general corporate purposes, which will include the redemption in November of a portion of the Company's outstanding long-term debt maturing in March 2023. The Company does not anticipate long-term refinancing for the $250.0 million drawn under the facility or the maturing long-term debt in March 2023.

CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company’s most critical accounting estimates, which are defined as those estimates whereby judgments or uncertainties could affect the application of accounting policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company’s significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

Oil and Gas Exploration and Development Costs. In the Company's Exploration and Production segment, gas and oil property acquisition, exploration and development costs are capitalized under the full cost method of accounting, with natural gas properties in the Appalachian region being the primary component of these capitalized costs after the June 30, 2022 sale of the Company's California oil and natural gas properties. That sale is discussed in more detail in Item 8 at Note B — Asset Acquisitions and Divestitures. Under this accounting methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

Proved reserves are estimated quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be producible under existing economic and operating conditions. Such estimates of proved reserves are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The estimates involved in determining proved reserves are critical accounting estimates because they serve as the basis over which capitalized costs are depleted under the full cost method of accounting (on a units-of-production basis). Unproved properties are excluded from the depletion calculation until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unproved properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in natural gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment charge must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. At September 30, 2022, the ceiling exceeded the book value of the oil and gas properties by approximately $3.2 billion. The 12-month average of the first day of the month price for natural gas for each month during 2022, based on the quoted Henry Hub spot price for natural gas, was $6.13 per MMBtu. (Note — because actual pricing of the Company's producing properties vary depending on their location and hedging, the prices used to calculate the ceiling may differ from the Henry Hub price, which is only indicative of 12-month average prices for 2022. Actual realized pricing includes adjustments for regional market differentials, transportation fees and contractual arrangements.) In regard to the sensitivity of the ceiling test calculation to commodity price changes, if natural gas prices were $0.25 per MMBtu lower than the average prices used at September 30, 2022 in the ceiling test calculation, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $2.9 billion (after-tax), which would not have resulted in an impairment charge. This calculated amount is based solely on price changes and does not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates.

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. As discussed above, fluctuations in or subtractions from proved reserves, increases in development costs for undeveloped reserves and significant fluctuations in natural gas prices have an impact on the amount of the ceiling at any point in time.

As discussed above, the full cost method of accounting provides a ceiling to the amount of costs that can be capitalized in the full cost pool. In accordance with current authoritative guidance, the future cash outflows associated with plugging and abandoning wells are excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation.

Regulation. The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to the FASB authoritative guidance regarding accounting for certain types of regulations, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting principles for certain types of rate-regulated activities provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note F — Regulatory Matters.

RESULTS OF OPERATIONS

EARNINGS

2022 Compared with 2021

The Company's earnings were $566.0 million in 2022 compared with earnings of $363.6 million in 2021. The increase in earnings of $202.4 million was primarily a result of higher earnings in all reportable segments, slightly offset by losses in the Corporate and All Other categories. In the discussion that follows, all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings were impacted by the following events in 2022 and 2021:

2022 Events

- The reversal of a deferred tax valuation allowance of $24.9 million recorded in the Exploration and Production and Gathering segments.
- A $28.4 million remeasurement of accumulated deferred income taxes, primarily in the Exploration and Production and Gathering segments, related to a reduction in the Pennsylvania state corporate income tax rate that was signed into law in July 2022.
- A gain recognized on the sale of Seneca's California assets of $12.7 million ($9.5 million after-tax) recorded during 2022 in the Exploration and Production segment related to a portion of the sale price that was applied to assets that were not subject to the full cost method of accounting.
- A loss of $44.6 million ($33.3 million after-tax) recorded during 2022 in the Exploration and Production segment related to the termination of this segment's remaining crude oil derivative contracts as a result of the sale of Seneca's California assets.
- Transaction and severance costs of $9.7 million ($7.2 million after-tax) incurred during 2022 in the Exploration and Production segment related to the sale of Seneca's California assets.
- The reduction of an OPEB regulatory liability that increased earnings by $18.5 million ($14.6 million after-tax) recorded during 2022 in the Utility segment in accordance with a regulatory proceeding in Distribution Corporation's Pennsylvania service territory.

2021 Events

- Non-cash impairment charges of $76.2 million ($55.2 million after-tax) recorded during 2021 for the Exploration and Production segment's oil and gas producing properties.
- A gain recognized on the sale of timber properties of $51.1 million ($37.0 million after-tax) recorded during 2021 in the Company's All Other category.
- A loss of $15.7 million ($11.4. million after-tax) recorded in the Exploration and Production and Gathering segments during 2021 for the premium paid on early redemption of long-term debt.

Earnings (Loss) by Segment

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Exploration and Production	$ 306,064	$ 101,916	$ (326,904)
Pipeline and Storage	102,557	92,542	78,860
Gathering	101,111	80,274	68,631
Utility	68,948	54,335	57,366
Total Reported Segments	578,680	329,067	(122,047)
All Other	(9)	37,645	(269)
Corporate	(12,650)	(3,065)	(1,456)
Total Consolidated	$ 566,021	$ 363,647	$ (123,772)

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30	
	2022	2021
	(Thousands)	
Gas (after Hedging)	$ 930,130	$ 705,326
Oil (after Hedging)(1)	113,588	126,369
Gas Processing Plant	3,511	2,960
Other	(36,765)	2,042
Operating Revenues	$ 1,010,464	$ 836,697

Production

	Year Ended September 30	
	2022	2021
Gas Production *(MMcf)*		
Appalachia	341,700	312,300
West Coast	1,211	1,720
Total Production	342,911	314,020
Oil Production *(Mbbl)*		
Appalachia	16	2
West Coast	1,588	2,233
Total Production	1,604	2,235

Average Prices

	Year Ended September 30	
	2022	2021
Average Gas Price/Mcf		
Appalachia	$ 5.03	$ 2.46
West Coast	$ 10.03	$ 6.34
Weighted Average	$ 5.05	$ 2.49
Weighted Average After Hedging(2)	$ 2.71	$ 2.25
Average Oil Price/Barrel (Bbl)		
Appalachia	$ 97.82	$ 48.02
West Coast	$ 94.06	$ 60.50
Weighted Average	$ 94.10	$ 60.49
Weighted Average After Hedging(1)(2)	$ 70.80	$ 56.54

(1) Oil revenue and weighted average oil price after hedging for the year ended September 30, 2022 excludes a loss on discontinuance of crude oil cash flow hedges of $44.6 million. This loss is presented in other revenue in the table above.

(2) Refer to further discussion of hedging activities below under “Market Risk Sensitive Instruments” and in Note J — Financial Instruments in Item 8 of this report.

2022 Compared with 2021

Operating revenues for the Exploration and Production segment increased $173.8 million in 2022 as compared with 2021. Gas production revenue after hedging increased $224.8 million primarily due to a $0.46 per Mcf increase in the weighted average price of gas after hedging coupled with a 28.9 Bcf increase in gas production. The increase in gas production was largely due to new Marcellus and Utica wells in the Appalachian region. Oil production revenue after hedging decreased $12.8 million primarily due to a 631 Mbbl decrease in crude oil production, partially offset by a $14.26 per Bbl increase in the weighted average price of oil after hedging. The decrease in oil production is mainly attributed to the sale of California assets at June 30, 2022. In addition, other revenue decreased $38.8 million and plant revenue increased $0.6 million. The decrease in other revenue was primarily attributed to a loss on the discontinuance of crude oil cash flow hedges related to the sale of California assets combined with royalty shut-in payments made in accordance with lease agreements. These were partially offset by a temporary capacity release of Leidy South and TC Pipeline transportation contracts. Finally, other revenue also increased from Highland Field Services water treatment plants acquired at the end of fiscal 2021.

Refer to further discussion of derivative financial instruments in the “Market Risk Sensitive Instruments” section that follows. Refer to the tables above for production and price information.

Earnings

2022 Compared with 2021

The Exploration and Production segment’s earnings for 2022 were $306.1 million, an increase of $204.2 million when compared with earnings of $101.9 million for 2021. The increase in earnings was primarily attributable to higher natural gas prices after hedging ($126.3 million), higher natural gas production ($51.3 million), and higher oil prices after hedging ($18.1 million). Additionally, a $55.2 million impairment was recorded during 2021 that did not recur during 2022. Certain deferred tax adjustments during 2022 also contributed to the earnings increase. The Exploration and Production segment reversed a valuation allowance ($28.6 million) on deferred tax assets related to certain state net operating loss and credit carryforwards as these deferred tax assets are now expected to be realized in the future. The Exploration and Production segment also recorded an income tax benefit ($16.2 million) from the remeasurement of deferred income taxes related to a state corporate income tax rate reduction in Pennsylvania that was signed into law in July 2022. The law reduces the Pennsylvania corporate income tax rate to 8.99% for fiscal 2024, and starting with fiscal 2025, the rate is further reduced by 0.5% annually until it reaches 4.99% for fiscal 2032.

In addition to the factors discussed above, the Exploration and Production segment's earnings were also impacted by the following factors. Factors that increased earnings included a 2022 gain ($9.5 million) that was recognized on the sale of the Exploration and Production segment's California non-full cost pool assets as well as a 2021 loss ($10.7 million) recognized for this segment's share of the premium paid by the Company to redeem $500 million of the Company's 4.90% notes that were scheduled to mature in December 2021. Factors that reduced earnings included a loss related to the discontinuance of this segment's crude oil cash flow hedges ($33.3 million), which was driven by the sale of the California assets, lower crude oil production ($28.2 million), higher lease operating and transportation expenses ($13.1 million), higher depletion expense ($20.3 million), higher other operating expenses ($5.4 million), an unrealized loss on a derivative asset ($3.2 million), higher other taxes ($2.5 million) and a higher effective tax rate ($6.3 million). The Company also recorded transaction and severance costs ($7.2 million) during 2022 associated with the sale of the California assets. The increase in lease operating and transportation expenses was primarily due to increased gathering and transportation costs in the Appalachian region offset by lower costs in the West Coast region due to selling the assets on June 30, 2022. The increase in depletion expense was primarily due to the increase in production, combined with a $0.03 per Mcfe increase in the depletion rate. The increase in other operating expenses was primarily attributed to abandonment costs related to certain offshore Gulf of Mexico wells formally owned by the Company. In addition, the increase in other operating expenses was attributed to operating costs associated with the Highland Field Services water treatment plants acquired at the end of fiscal 2021. The unrealized loss on a derivative asset represents an adjustment to the contingent consideration received for the sale of the California assets. The increase in other taxes was mainly attributed to increased Impact Fees in the Appalachian region as a result of an increase in natural gas prices. The Impact Fees are calculated annually based on calendar year NYMEX natural gas prices. The increase in the effective tax rate was primarily driven by a reduction to the valuation allowance recorded in fiscal 2021.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30	
	2022	2021
	(Thousands)	
Firm Transportation	$ 287,486	$ 254,853
Interruptible Transportation	2,481	996
	289,967	255,849
Firm Storage Service	84,565	83,032
Interruptible Storage Service	—	48
	84,565	83,080
Other	2,512	4,628
	$ 377,044	$ 343,557

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30	
	2022	2021
Firm Transportation	790,417	770,284
Interruptible Transportation	5,612	1,460
	796,029	771,744

2022 Compared with 2021

Operating revenues for the Pipeline and Storage segment increased $33.5 million in 2022 as compared with 2021. The increase in operating revenues was primarily due to an increase in transportation revenues of $34.1 million and an increase in storage revenues of $1.5 million, partially offset by a decrease in other revenue of $2.1 million. The increase in transportation revenues was primarily attributable to new demand charges for transportation service from Supply Corporation's FM100 Project, which was placed into service in December 2021. The increase from the FM100 Project includes the impact of a negotiated revenue step-up to Period 2 Rates that went into effect April 1, 2022, as specified in Supply Corporation's 2020 rate case settlement. This increase was partially offset by a decline in revenues associated with miscellaneous contract terminations and revisions. The increase in storage revenues was partially due to the Period 2 Rates that went into effect April 1, 2022 related to the FM100 Project, as discussed above. In addition, the Pipeline Safety and Greenhouse Gas Regulatory Costs (PS/GHG Regulatory Costs) surcharge that went into effect in November 2020 associated with Supply Corporation's 2020 rate case settlement also contributed to the increase in both transportation and storage revenues. The decrease in other revenue primarily reflects the non-recurrence of revenue associated with a contract buyout that occurred during the quarter ended December 31, 2020, combined with lower electric surcharge true-up revenues, partially offset by higher cashout revenues. Revenues collected through the electric surcharge mechanism are completely offset by electric power costs recorded in operation and maintenance expense. Cashout revenues are completely offset by purchased gas expense.

Transportation volume increased by 24.3 Bcf in 2022 as compared with 2021, primarily due to incremental volume from the FM100 Project, which was brought online in December 2021, as well as an increase in short-term contracts. These were partially offset by lower capacity utilization with certain contract shippers. Volume fluctuations, other than those caused by the addition or termination of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The majority of Supply Corporation's and Empire's transportation and storage contracts allow either party to terminate the contract upon six or twelve months' notice effective at the end of the primary term and include "evergreen" language that allows for annual term extension(s). The amount of firm transportation capacity contracted on the Pipeline and Storage segment's facilities is expected to decrease in fiscal 2023, primarily due to the termination of two long-term contracts with a nonaffiliated party totaling 300 MDth per day. Lower contracted quantities at the time of a future rate proceeding would be taken into account and would be the basis for setting new rates. The timing of Supply Corporation's next rate filing is discussed below under Rate Matters.

Earnings

2022 Compared with 2021

The Pipeline and Storage segment’s earnings in 2022 were $102.6 million, an increase of $10.1 million when compared with earnings of $92.5 million in 2021. The increase in earnings was primarily due to the impact of higher operating revenues of $26.5 million, as discussed above, which was partially offset by an increase in depreciation expense ($4.2 million), higher property taxes ($0.8 million), an increase in operating expenses ($7.6 million) and higher income tax expense ($2.3 million). The increase in depreciation expense was primarily due to incremental depreciation from the FM100 Project going into service in December 2021. The increase in property taxes was primarily due to the first-time assessment of property taxes for the Empire North project's Farmington compressor station. The increase in operating expenses was primarily due to a decrease in the reserve for preliminary project costs recorded during fiscal 2021 that did not recur in fiscal 2022, as well as an increase in personnel and technology-related costs and higher vehicle fuel costs. This was partially offset by lower power costs related to Empire's electric motor drive compressor station. The Pipeline and Storage segment also experienced higher purchased gas costs ($0.7 million), largely related to Empire's natural gas-driven compressor stations. The electric power costs and purchased gas costs are offset by an equal amount of revenue, as discussed above. The increase in income tax expense was mainly due to a reduction in benefits associated with the tax sharing agreement with affiliated companies combined with higher state income tax expense due to higher pre-tax earnings for fiscal 2022.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30	
	2022	**2021**
	(Thousands)	
Gathering	$ 214,843	$ 193,264

Gathering Volume — (MMcf)

	Year Ended September 30	
	2022	**2021**
Gathered Volume	419,332	366,033

2022 Compared with 2021

Operating revenues for the Gathering segment increased $21.6 million in 2022 as compared with 2021, which was driven primarily by a 53.3 Bcf increase in gathered volume. The increase in gathered volume can be attributed primarily to an increase in natural gas production on the Covington, Wellsboro, Clermont and Trout Run gathering systems, which recorded increases of 17.9 Bcf, 11.7 Bcf, 10.1 Bcf and 13.6 Bcf, respectively. The increase in gathered volume can be attributed to the increase in gross natural gas production in the Appalachian region by producers connected to the aforementioned gathering systems.

Earnings

2022 Compared with 2021

The Gathering segment's earnings in 2022 were $101.1 million, an increase of $20.8 million when compared with earnings of $80.3 million in 2021. The increase in earnings was primarily attributable to higher gathering revenues ($17.0 million) driven by the increase in gathered volume (discussed above). Additionally, the Gathering segment recorded an income tax benefit ($11.9 million) from the remeasurement of deferred income taxes related to a state corporate income tax rate reduction in Pennsylvania that was signed into law in July 2022 (as discussed above, in the Exploration and Production segment). Earnings also increased as a result of the Gathering segment's recognition of a loss during the quarter end March 31, 2021 ($0.7 million) for its share of the premium paid by the Company to redeem $500 million of the Company's 4.90% notes that were scheduled to mature in December 2021. However, the Gathering segment's earnings were negatively impacted by the recording of deferred income tax expense ($3.7 million) as an offset to the reversal of the valuation allowance recorded by the Exploration and Production segment during the quarter ended September 30, 2022. This offset is a result of the Gathering and Exploration and Production segments' subsidiaries filing a combined state tax return. Earnings also decreased due to higher operating expenses ($3.2 million), higher depreciation expense ($1.3 million) and higher income tax expense ($0.6 million). The increase in operating expenses was largely due to higher costs for labor, major overhaul maintenance of compressor units at Trout Run gathering system compressor stations during fiscal 2022 and higher costs for material used to operate the compressor stations at the Trout Run, Covington and Clermont gathering systems. The increase in depreciation expense was largely due to higher plant balances associated with the Clermont and Covington gathering systems. The increase in income tax expense was primarily driven by a higher effective state income tax rate.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30	
	2022	2021
	(Thousands)	
Retail Revenues:		
Residential	$ 691,034	$ 497,244
Commercial	95,120	63,954
Industrial	4,913	3,089
	791,067	564,287
Transportation	111,072	108,213
Other	(3,918)	(5,249)
	$ 898,221	$ 667,251

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30	
	2022	2021
Retail Sales:		
Residential	64,011	61,038
Commercial	9,621	8,741
Industrial	541	475
	74,173	70,254
Transportation	65,993	66,012
	140,166	136,266

Degree Days

				Percent (Warmer) Colder Than	
Year Ended September 30		Normal	Actual	Normal(1)	Prior Year(1)
2022	Buffalo, NY	6,617	5,769	(12.8)%	0.7 %
	Erie, PA	6,147	5,368	(12.7)%	2.8 %
2021	Buffalo, NY	6,617	5,731	(13.4)%	(6.1)%
	Erie, PA	6,147	5,221	(15.1)%	(4.2)%

(1) Percents compare actual degree days to normal degree days and actual degree days to actual prior year degree days.

2022 Compared with 2021

Operating revenues for the Utility segment increased $231.0 million in 2022 compared with 2021. The increase resulted from a $226.8 million increase in retail gas sales revenues, which was primarily due to a significant increase in the cost of gas sold (per Mcf). In addition, there was a $2.9 million increase in transportation revenues and a $1.3 million increase in other revenues. The increase in transportation revenues, despite a small decrease in throughput, was largely due to an increase in marketer sales cashouts and an increase in the system modernization tracker allocation to transportation customers, which was partially offset by the migration of residential transportation customers previously served by marketers to retail service provided by the Utility segment. The increase in other revenues was primarily due to higher capacity release revenues and higher late payment charges billed to customers.

Purchased Gas

The cost of purchased gas is one of the Company's largest operating expenses. Annual variations in purchased gas costs are attributed directly to changes in gas sales volume, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded $498.0 million and $274.8 million of Purchased Gas expense during 2022 and 2021, respectively. Under its purchased gas adjustment clauses in New York and Pennsylvania, Distribution Corporation is not allowed to profit from fluctuations in gas costs. Purchased Gas expense recorded on the consolidated income statement matches the revenues collected from customers, a component of Operating Revenues on the consolidated income statement. Under mechanisms approved by the NYPSC in New York and the PaPUC in Pennsylvania, any difference between actual purchased gas costs and what has been collected from the customer is deferred on the consolidated balance sheet as either an asset, Unrecovered Purchased Gas Costs, or a liability, Amounts Payable to Customers. These deferrals are subsequently collected from the customer or passed back to the customer, subject to review by the NYPSC and the PaPUC. Absent disallowance of full recovery of Distribution Corporation's purchased gas costs, such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation's purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

Distribution Corporation contracts for firm long-term transportation and storage capacity with rights-of-first-refusal from ten upstream pipeline companies including Supply Corporation for transportation and storage and Empire for transportation. Distribution Corporation contracts for firm gas supplies on term and spot bases with various producers, marketers and two local distribution companies to meet its gas purchase requirements. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

2022 Compared with 2021

The Utility segment's earnings in 2022 were $68.9 million, an increase of $14.6 million when compared with earnings of $54.3 million in 2021. The increase was primarily attributable to the conclusion of a regulatory proceeding by the PaPUC in February 2022, which resulted in the reduction of an OPEB-related regulatory liability that increased earnings ($14.6 million). While the regulatory proceeding reduced base rates in Pennsylvania by $5.6 million, this impact was more than offset by a decrease in non-service post-retirement benefit costs ($11.5 million) as Distribution Corporation's Pennsylvania service territory recognized OPEB income during fiscal 2022, compared to the prior year when it recognized OPEB expenses to match against the OPEB amounts collected in base rates. Additional details related to the regulatory proceeding are discussed in Note F — Regulatory Matters.

Other factors contributing to the increase in earnings included the positive earnings impact of a system modernization tracker in New York ($3.6 million), which is a rate mechanism that provides recovery of qualified leak prone pipe replacement costs, higher usage and the impact of weather on customer margins ($2.9 million), and a decrease in income tax expense ($0.6 million). These increases were partially offset by higher operating expenses ($9.5 million), which were primarily the result of higher personnel costs, transportation fuel costs, and outside services partially offset by a decrease in the provision for uncollectible accounts. The decrease in the provision for uncollectible accounts reflects the recording of incremental expense in 2021 due to the potential for future customer non-payment as a result of the COVID-19 pandemic. In addition, earnings were negatively impacted by higher interest expense ($2.0 million), which was largely the result of a higher weighted average interest rate on intercompany short-term borrowings, and higher depreciation expense ($1.8 million), primarily due to higher plant balances.

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is largely mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For 2022, the WNC contributed approximately $4.8 million to earnings, as the weather was warmer than normal. In 2021, the WNC contributed approximately $4.5 million to earnings, as the weather was warmer than normal.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Seneca's Northeast Division and corporate operations. Seneca's Northeast Division previously marketed timber from its New York and Pennsylvania land holdings. On December 10, 2020, the Company completed the sale of substantially all timber properties. Please refer to Item 8 at Note B — Asset Acquisitions and Divestitures for further discussion of the sale of timber properties.

Earnings

2022 Compared with 2021

All Other and Corporate operations recorded a loss of $12.7 million in 2022, a decrease of $47.3 million when compared with earnings of $34.6 million in 2021. The decrease was primarily attributable to the non-recurrence of a $51.1 million gain ($37.0 million gain after-tax) on the sale of timber properties recorded by Seneca's Northeast Division in 2021. Changes in unrealized gains and losses on investments in equity securities also contributed to the decrease. In 2022, the Company recorded unrealized losses of $9.2 million, while in 2021, the Company recorded unrealized gains of $0.1 million.

OTHER INCOME (DEDUCTIONS)

Although most of the variances in Other Income (Deductions) are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis (amounts below are pre-tax amounts):

Net other deductions on the Consolidated Statement of Income decreased $13.7 million in 2022 as compared to 2021. This change is primarily attributable to non-service pension and post-retirement benefit income of $3.6 million for 2022 compared to non-service pension and post-retirement benefit costs of $31.3 million for 2021. As discussed above in the Utility segment, this is largely related to the February 2022 conclusion of the regulatory proceeding in Distribution Corporation's Pennsylvania service territory that addressed Distribution Corporation's recovery of OPEB expenses. In addition, there was an increase in other interest income of $1.7 million. This was partially offset by changes in unrealized gains and losses on investments in equity securities. During 2022, the Company recorded pre-tax unrealized losses of $13.8 million. During 2021, the Company recorded pre-tax unrealized gains of $0.2 million. Other income (deductions) was also impacted by a decrease in the cash surrender value of life insurance policies of $1.9 million, as well as a decrease in allowance for funds used during construction (equity component) of $2.5 million primarily as a result of the FM100 Project being placed into service in December 2021. There was also a mark-to-market revaluation that decreased contingent consideration by $4.4 million from the sale of Seneca's California assets. For further discussion, refer to Note J — Financial Instruments.

INTEREST CHARGES

Although most of the variances in Interest Charges are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis (amounts below are pre-tax amounts):

Interest on long-term debt decreased $21.0 million in 2022 as compared to 2021. The Company redeemed $500.0 million of 4.90% notes in March 2021 and paid an early redemption premium of $15.7 million that was recorded as interest expense on long-term debt. The remaining decrease is due largely to a lower weighted average interest rate on long-term debt, stemming from the Company's issuance of $500.0 million of 2.95% notes in February 2021, which replaced $500.0 million of 4.90% notes that were retired in March 2021.

Other interest expense increased $5.0 million in 2022 as compared to 2021. The increase was primarily due to higher average interest rates for 2022 combined with higher average short-term debt balances in 2022 compared to 2021.

CAPITAL RESOURCES AND LIQUIDITY

The primary sources and uses of cash during the last two years are summarized in the following condensed statement of cash flows:

	Year Ended September 30	
	2022	2021
	(Millions)	
Provided by Operating Activities	$ 812.5	$ 791.6
Capital Expenditures	(811.8)	(751.7)
Net Proceeds from Sale of Oil and Gas Producing Properties	254.4	—
Net Proceeds from Sale of Timber Properties	—	104.6
Sale of Fixed Income Mutual Fund Shares in Grantor Trust	30.0	—
Other Investing Activities	8.7	13.8
Reduction of Long-Term Debt	—	(515.7)
Change in Notes Payable to Banks and Commercial Paper	(98.5)	128.5
Net Proceeds from Issuance of Long-Term Debt	—	495.3
Net Repurchases of Common Stock	(9.6)	(3.7)
Dividends Paid on Common Stock	(168.1)	(163.1)
Net Increase in Cash, Cash Equivalents, and Restricted Cash	$ 17.6	$ 99.6

The Company expects to have adequate amounts of cash available to meet both its short-term and long-term cash requirements for at least the next twelve months and for the foreseeable future thereafter. During 2023, cash provided by operating activities is expected to increase over the amount of cash provided by operating activities during 2022 and will be used to fund the Company's capital expenditures. There are two long-term debt maturities in March 2023, totaling $549 million. The Company expects to repay those securities through the use of cash on hand at the date of maturity and short-term borrowings. Looking at 2023 and 2024, based on current commodity prices, cash provided by operating activities is expected to exceed capital expenditures in each of those years. This is expected to provide the Company with the option to consider additional growth investments, further reductions in short-term or long-term debt, and increasing the amount of cash flow returned to shareholders, either through increases to the Company’s dividend or via repurchases of common stock. These cash flow projections do not reflect the impact of acquisitions or divestitures that may arise in the future.

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income, gains and losses associated with investing and financing activities, and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, deferred income taxes, the reduction of an other post-retirement regulatory liability and stock-based compensation.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from year to year because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs and weather may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment’s New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by the straight fixed-variable rate design used by Supply Corporation and Empire.

Cash provided by operating activities in the Exploration and Production segment may vary from year to year as a result of changes in the commodity prices of natural gas as well as changes in production. The Company uses various derivative financial instruments, including price swap agreements and no cost collars, in an attempt to manage this energy commodity price risk.

The Company, in its Utility segment and Exploration and Production segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Refer to Item 8 at Note L —

Commitments and Contingencies under the heading "Other" for additional discussion concerning these contractual commitments as well as the amounts of future gas purchase, transportation and storage contract commitments expected to be incurred during the next five years and thereafter. Also refer to Item 8 at Note D — Leases for a discussion of the Company's operating lease arrangements and a schedule of lease payments during the next five years and thereafter.

Net cash provided by operating activities totaled $812.5 million in 2022, an increase of $20.9 million compared with the $791.6 million provided by operating activities in 2021. The increase in cash provided by operating activities primarily reflects higher cash provided by operating activities in the Exploration and Production segment and the Gathering segment, partially offset by lower cash provided by operating activities in the Utility segment. The increase in the Exploration and Production segment and the Gathering segment was primarily due to higher cash receipts from natural gas production and gathering services in the Appalachian region. The decrease in Utility segment is primarily due to lower rates in the Utility segment's Pennsylvania service territory that went into effect October 1, 2021 combined with the timing of gas cost recovery, timing of gas receivables and other regulatory true-ups. The rates that went into effect included a one-time customer bill credit of $25 million in October 2021 for previously overcollected OPEB expenses and the beginning of a 5-year pass back of an additional $29 million in previously overcollected OPEB expenses. Please refer to the Rate Matters section that follows for additional discussion of this matter.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets, including non-cash capital expenditures, totaled $829.4 million and $769.9 million in 2022 and 2021, respectively. The table below presents these expenditures:

	Year Ended September 30	
	2022	2021
	(Millions)	
Exploration and Production:		
Capital Expenditures	$ 565.8 (1)	$ 381.4 (2)
Pipeline and Storage:		
Capital Expenditures	95.8 (1)	252.3 (2)
Gathering:		
Capital Expenditures	55.5 (1)	34.7 (2)
Utility:		
Capital Expenditures	111.0 (1)	100.8 (2)
All Other and Corporate:		
Capital Expenditures	1.3	0.5
Eliminations	—	0.2
Total Expenditures	$ 829.4	$ 769.9

(1) 2022 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $83.0 million, $15.2 million, $10.7 million and $11.4 million, respectively, of non-cash capital expenditures.

(2) 2021 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $47.9 million, $39.4 million, $4.8 million and $10.6 million, respectively, of non-cash capital expenditures.

Exploration and Production

In 2022, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $547.1 million for the Appalachian region (including $161.4 million in the Marcellus Shale area and $370.6 million in the Utica Shale area) and $18.7 million for the West Coast region. These amounts included approximately $154.3 million spent to develop proved undeveloped reserves.

In 2021, the majority of the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $368.1 million for the Appalachian region (including $117.2 million in the Marcellus Shale area and $213.8 million in the Utica Shale area) and $13.3 million for the West Coast region. These amounts included approximately $81.2 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The Pipeline and Storage segment’s capital expenditures for 2022 were primarily for additions, improvements and replacements to this segment's transmission and gas storage systems, which included system modernization expenditures that enhance the reliability and safety of the systems and reduce emissions. In addition, the Pipeline and Storage segment capital expenditures for 2022 include expenditures related to Supply Corporation's FM100 Project ($25.2 million). The FM100 Project upgraded a 1950's era pipeline in northwestern Pennsylvania and created approximately 330,000 Dth per day of additional transportation capacity in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County to the Transcontinental Gas Pipe Line Company, LLC (“Transco”) system at Leidy, Pennsylvania. Supply Corporation and Transco executed a precedent agreement whereby Transco has leased this additional capacity as part of a Transco expansion project ("Leidy South"), creating incremental transportation capacity to Transco Zone 6 (Non-New York) markets. Seneca is an anchor shipper on Leidy South, which provides it with an outlet to premium markets from both its Eastern and Western development areas. Construction activities on the expansion portion of the FM100 Project are complete and the project commenced partial in-service on December 1, 2021, with full in-service on December 19, 2021. Abandonment activities on the project continue in calendar year 2022. As of September 30, 2022, approximately $211.3 million has been spent on the FM100 Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2022.

The Pipeline and Storage segment’s capital expenditures for 2021 were primarily for expenditures related to Supply Corporation's FM100 Project ($179.0 million). In addition, the Pipeline and Storage segment capital expenditures for 2021 included additions, improvements and replacements to this segment's transmission and gas storage systems.

Gathering

The majority of the Gathering segment's capital expenditures for 2022 included expenditures related to the continued expansion of Midstream Company's Clermont, Covington, Trout Run and Wellsboro gathering systems, as discussed below. Midstream Company spent $20.9 million, $27.0 million, $4.9 million and $2.3 million in 2022 on the development of the Clermont, Covington, Trout Run and Wellsboro gathering systems, respectively. These expenditures were largely attributable to the installation of new in-field gathering pipelines in the Clermont gathering system, as well as the continued expansion of centralized station facilities, including increased compression horsepower at the Clermont, Trout Run, and Wellsboro gathering systems. In the Tioga gathering system, which is part of Midstream Covington, expenditures were largely attributable to the installation of in-field gathering pipelines and upgraded station facilities related to new development.

The majority of the Gathering segment's capital expenditures for 2021 included expenditures related to the continued expansion of Midstream Company's Clermont, Covington and Wellsboro gathering systems. Midstream Company spent $23.1 million, $4.4 million and $3.7 million in 2021 on the development of the Clermont, Covington and Wellsboro gathering systems, respectively. These expenditures were largely attributable to new Clermont gathering pipelines, a new tie-in between the legacy Covington gathering system and the midstream gathering assets acquired from SWEPI LP, a subsidiary of Royal Dutch Shell plc ("Shell"), which is now referred to as the Tioga gathering system, as well as the continued development of centralized station facilities, including increased compression horsepower at the Clermont and Wellsboro gathering systems and additional dehydration on the Clermont gathering system.

Utility

The majority of the Utility segment’s capital expenditures for 2022 and 2021 were made for main and service line improvements and replacements that enhance the reliability and safety of the system and reduce emissions. Expenditures were also made for main extensions.

Other Investing Activities

On December 10, 2020, the Company completed the sale of substantially all timber properties in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for net proceeds of $104.6 million. After purchase price adjustments and transaction costs, a gain of $51.1 million was recognized on the sale of these assets ($37.0 million after-tax). The sale of the timber properties completed a reverse like-kind exchange pursuant to Section 1031 of the Internal Revenue Code, as amended ("Reverse 1031 Exchange"). On July 31, 2020, the Company completed its acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from Shell for total consideration of $506.3 million. The purchase and sale agreement with Shell was structured, in part, as a Reverse 1031 Exchange. Refer to Item 8 at Note B — Asset Acquisitions and Divestitures for additional information concerning the Company's acquisition of certain upstream assets and midstream gathering assets from Shell.

In October 2021, the Company sold $30 million of fixed income mutual fund shares held in a grantor trust that was established for the benefit of Pennsylvania ratepayers. The proceeds were used in the Utility segment's Pennsylvania service territory to fund a one-time customer bill credit of $25 million in October 2021 for previously overcollected OPEB expenses and the first year installment of a 5-year pass back of an additional $29 million in previously overcollected OPEB expenses in accordance with new rates that went into effect on October 1, 2021. Please refer to the Rate Matters section that follows for additional discussion of this matter.

In March 2022, the Company completed the sale of certain oil and gas assets located in Tioga County, Pennsylvania, effective as of October 1, 2021. The Company received net proceeds of $13.5 million from this sale. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

On June 30, 2022, the Company completed the sale of Seneca's California assets to Sentinel Peak Resources California LLC for a total sale price of $253.5 million, consisting of $240.9 million in cash and contingent consideration valued at $12.6 million at closing. The Company pursued this sale given the strong commodity price environment and the Company's strategic focus in the Appalachian Basin. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The sale price, which reflected an effective date of April 1, 2022, was reduced for production revenues less expenses that were retained by Seneca from the effective date to the closing date. Under the full cost method of accounting for oil and natural gas properties, $220.7 million of the sale price at closing was accounted for as a reduction of capitalized costs since the disposition did not alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center. The remainder of the sale price ($32.8 million) was applied against assets that are not subject to the full cost method of accounting, with the Company recognizing a gain of $12.7 million on the sale of such assets. The majority of this gain related to the sale of emission allowances.

Estimated Capital Expenditures

The Company's estimated capital expenditures for the next three years are:

	Year Ended September 30		
	2023	2024	2025
		(Millions)	
Exploration and Production(1)	$ 550	$ 525	$ 515
Pipeline and Storage	120	105	90
Gathering	95	110	95
Utility(2)	120	135	135
All Other	—	—	—
	$ 885	$ 875	$ 835

(1) Includes estimated expenditures for the years ended September 30, 2023, 2024 and 2025 of approximately $308 million, $95 million and $82 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting.

(2) Includes estimated expenditures for the years ended September 30, 2023, 2024, and 2025 of approximately $95 million, $100 million and $100 million, respectively, for system modernization and safety to enhance the reliability and safety of the system and reduce emissions.

Exploration and Production

Capital expenditures for the Exploration and Production segment in 2023 through 2025 are expected to be primarily well drilling and completion expenditures in the Appalachian region.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2023 through 2025 are expected to include: the replacement and modernization of transmission and storage facilities, the reconditioning of storage wells, improvements of compressor stations and emissions reduction initiatives.

In addition, due to the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia, specifically in the Marcellus and Utica Shale producing areas, Supply Corporation and Empire have completed and continue to pursue expansion projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to on-system markets, and markets beyond the Supply Corporation and Empire pipeline systems. Capital expenditures in 2023 through 2025 include minimal capital expenditures related to system expansion and forecasted amounts will be adjusted in the future to incorporate any new projects that are expected to be developed by the Company.

Gathering

The majority of the Gathering segment capital expenditures in 2023 through 2025, included in the table above, are expected to be for construction and expansion of gathering systems, as discussed below. The Gathering segment primarily invests capital to support Seneca's drilling and completion activity in their long-term development plan. Seneca has been in the process of shifting a larger share of its activity from its Western Development Area to Tioga County, Pennsylvania. As a result, the Gathering segment is expecting to see near-term increases in capital expenditures as it constructs the necessary infrastructure to support Seneca's activity in the region.

NFG Midstream Covington, LLC, a wholly-owned subsidiary of Midstream Company, operates its Covington gathering system as well as the Tioga gathering system acquired from Shell on July 31, 2020, both in Tioga County, Pennsylvania. The current Covington gathering system consists of two compressor stations and backbone and in-field gathering pipelines. The Tioga gathering system consists of 16 compressor stations and backbone and in-field gathering pipelines. Estimated capital expenditures in 2023 through 2025 include anticipated expenditures in the range of $150 million to $180 million for continued expansion of the Tioga gathering system.

NFG Midstream Clermont, LLC, a wholly-owned subsidiary of Midstream Company, continues to develop an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The Clermont gathering system was initially placed in service in July 2014. The current system consists of three compressor stations and backbone and in-field gathering pipelines. The total cost estimate for the continued buildout will be dependent on the nature and timing of Seneca's long-term plans. Estimated capital expenditures in 2023 through 2025 include anticipated expenditures in the range of $50 million to $70 million for the continued expansion of the Clermont gathering system.

NFG Midstream Wellsboro, LLC, a wholly-owned subsidiary of Midstream Company, continues to develop its Wellsboro gathering system in Tioga County, Pennsylvania. The current system consists of one compressor station and backbone and in-field gathering pipelines. Estimated capital expenditures in 2023 through 2025 include anticipated expenditures in the range of $50 million to $60 million for the continued expansion of the Wellsboro gathering system.

NFG Midstream Trout Run, LLC, a wholly-owned subsidiary of Midstream Company, continues to develop its Trout Run gathering system in Lycoming County, Pennsylvania. The Trout Run gathering system was initially placed in service in May 2012. The current system consists of three compressor stations and backbone and in-field gathering pipelines. Estimated capital expenditures in 2023 through 2025 include anticipated expenditures in the range of $15 million to $25 million for the continued expansion of the Trout Run gathering system.

Utility

Capital expenditures for the Utility segment in 2023 through 2025 are expected to be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment. Additionally, capital expenditures are expected to increase after 2023 largely due to the anticipated implementation of a Distribution System Improvement Charge (DSIC) mechanism in the Utility's Pennsylvania Division upon completion of the rate proceeding initiated on October 28, 2022.

Project Funding

Over the past two years, the Company has been financing capital expenditures with cash from operations, short-term and long-term debt, common stock, and proceeds from the sale of timber properties and the Company's California assets. During fiscal 2022, capital expenditures were funded with cash from operations, short-term debt and proceeds from the sale of the Company's California assets. The Company issued long-term debt and common stock in June 2020 to help finance the acquisition of upstream assets and midstream gathering assets from Shell. The financing of the asset acquisition from Shell was completed in December 2020 when the Company completed the sale of substantially all of its timber properties, through the completion of the Reverse 1031 Exchange discussed above. Going forward, the Company expects to use cash on hand, cash from operations and short-term borrowings to finance capital expenditures. The level of short-term borrowings will depend upon the amount of cash provided by operations, which, in turn, will likely be most impacted by the timing of gas cost recovery in the Utility segment. It will also depend on natural gas production, and the associated commodity price realizations, as well as the level of hedging collateral deposits in the Exploration and Production segment.

In the Exploration and Production segment, the Company has entered into contractual obligations to support its development activities and operations in Pennsylvania, including hydraulic fracturing and other well completion services, well tending services, well workover activities, tubing and casing purchases, production equipment purchases, water hauling services and contracts for drilling rig services. Refer to Item 8 at Note L — Commitments and Contingencies under the heading “Other” for the amounts of contractual obligations expected to be incurred during the next five years and thereafter to support the Company’s exploration and development activities. These amounts are largely a subset of the estimated capital expenditures for the Exploration and Production segment shown above.

The Company, in its Pipeline and Storage segment, Gathering segment and Utility segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system modernization and expansion projects. Refer to Item 8 at Note L — Commitments and Contingencies under the heading “Other” for the amounts of contractual commitments expected to be incurred during the next five years and thereafter associated with the Company's pipeline, compressor and gathering system modernization and expansion projects. These amounts are a subset of the estimated capital expenditures for the Pipeline and Storage segment, Gathering segment and Utility segment that are shown above.

The Company continuously evaluates capital expenditures and potential investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive natural gas properties, quicker development of existing natural gas properties, natural gas storage and transmission facilities, natural gas gathering and compression facilities and the expansion of natural gas transmission line capacities, regulated utility assets and other opportunities as they may arise. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's other business segments depends, to a large degree, upon market and regulatory conditions as well as legislative actions.

FINANCING CASH FLOW

Consolidated short-term debt decreased \$98.5 million, to a total of \$60.0 million, when comparing the balance sheet at September 30, 2022 to the balance sheet at September 30, 2021. The maximum amount of short-term debt outstanding during the year ended September 30, 2022 was \$675.4 million. In addition to cash provided by operating activities, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. For example, elevated commodity prices relative to its existing portfolio of derivative financial instruments led to the Company posting margin of \$91.7 million with a number of its derivative counterparties as of September 30, 2022. The maximum amount of margin posted during the year ended September 30, 2022 was \$430.6 million. The Company's margin deposits are reflected on the balance sheet as a current asset titled Hedging Collateral Deposits. To meet these margin requirements and other near-term cash flow needs, the Company utilized short-term debt in the form of commercial paper and borrowings under its revolving credit facility. At September 30, 2022, the Company had outstanding short-term notes payable to banks of \$60.0 million. The Company did not have any commercial paper outstanding at September 30, 2022.

On February 28, 2022, the Company entered into the Credit Agreement with a syndicate of twelve banks. The Credit Agreement replaced the previous Fourth Amended and Restated Credit Agreement and a previous 364-Day Credit Agreement. The Credit Agreement provides a \$1.0 billion unsecured committed revolving credit facility with a maturity date of February 26, 2027.

On June 30, 2022, the Company entered into the 364-Day Credit Agreement with a syndicate of five banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional \$250.0 million unsecured committed delayed draw term loan credit facility with a maturity date of June 29, 2023. The Company elected to draw \$250.0 million under the facility on October 27, 2022. The Company is using the proceeds for general corporate purposes, which will include the redemption in November of a portion of the Company's outstanding long-term debt maturing in March 2023.

The Company also has uncommitted lines of credit with financial institutions for general corporate purposes. Borrowings under these uncommitted lines of credit would be made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institution and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future.

The total amount available to be issued under the Company's commercial paper program is \$500.0 million. The commercial paper program is backed by the Credit Agreement, which provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $400 million. Since July 1, 2018, the Company recorded non-cash, after-tax ceiling test impairments totaling $381.4 million. As a result, at September 30, 2022, $190.7 million was added back to the Company's total capitalization for purposes of the calculation under the Credit Agreement and 364-Day Credit Agreement. On May 3, 2022, the Company entered into Amendment No. 1 to the Credit Agreement with the same twelve banks under the initial Credit Agreement. The amendment further modified the definition of consolidated capitalization, for purposes of calculating the debt to capitalization ratio under the Credit Agreement, to exclude, beginning with the quarter ended June 30, 2022, all unrealized gains or losses on commodity-related derivative financial instruments and up to $10 million in unrealized gains or losses on other derivative financial instruments included in Accumulated Other Comprehensive Income (Loss) within Total Comprehensive Shareholders' Equity on the Company's consolidated balance sheet. Under the Credit Agreement, such unrealized losses will not negatively affect the calculation of the debt to capitalization ratio, and such unrealized gains will not positively affect the calculation. The 364-Day Credit Agreement includes the same debt to capitalization covenant and the same exclusions of unrealized gains or losses on derivative financial instruments as the Credit Agreement. At September 30, 2022, the Company's debt to capitalization ratio, as calculated under the Credit Agreement and 364-Day Credit Agreement, was .49. The constraints specified in the Credit Agreement and 364-Day Credit Agreement would have permitted an additional $2.56 billion in short-term and/or long-term debt to be outstanding at September 30, 2022 (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources.

The Credit Agreement and 364-Day Credit Agreement contain a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement and 364-Day Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity.

On February 24, 2021, the Company issued $500.0 million of 2.95% notes due March 1, 2031. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.3 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to adjustment from time to time, with a maximum adjustment of 2.00%, such that the coupon will not exceed 4.95%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to a rating below investment grade. A downgrade with a resulting increase to the coupon does not preclude the coupon from returning to its original rate if the Company's credit rating is subsequently upgraded. The proceeds of this debt issuance were used for general corporate purposes, including the redemption of $500.0 million of the Company's 4.90% notes on March 11, 2021 that were scheduled to mature in December 2021. The Company redeemed those notes for $515.7 million, plus accrued interest.

The Current Portion of Long-Term Debt at September 30, 2022 consists of $500.0 million of 3.75% notes and $49.0 million of 7.395% notes, that each mature in March 2023. The Company does not anticipate long-term refinancing for these maturities. None of the Company's long-term debt as of September 30, 2021 had a maturity date within the following twelve-month period. As of September 30, 2022, the future contractual obligations related to aggregate principal amounts of long-term debt, including interest expense, maturing during the next five years and thereafter are as follows: $654.1 million in 2023, $95.4 million in 2024, $589.4 million in 2025, $548.9 million in 2026, $340.4 million in 2027, and $863.5 million thereafter. Refer to Item 8 at Note H — Capitalization and Short-Term Borrowings, as well as the table under Interest Rate Risk in the Market Risk Sensitive Instruments section below, for the amounts excluding interest expense. Principal payments of long-term debt are a component of cash used in financing activities while interest payments on long-term debt are a component of cash used in operating activities.

The Company’s embedded cost of long-term debt was 4.48% at both September 30, 2022 and September 30, 2021. Refer to “Interest Rate Risk” in this Item for a more detailed breakdown of the Company’s embedded cost of long-term debt.

Under the Company's existing indenture covenants at September 30, 2022, the Company would have been permitted to issue up to a maximum of approximately $2.0 billion in additional unsubordinated long-term indebtedness at then current market interest rates, in addition to being able to issue new indebtedness to replace existing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. It is possible, depending on amounts reported in various income statement and balance sheet line items, that the indenture covenants could, for a period of time, prevent the Company from issuing incremental unsubordinated long-term debt, or significantly limit the amount of such debt that could be issued. Losses incurred as a result of significant impairments of oil and gas properties have in the past resulted in such temporary restrictions. The indenture covenants would not preclude the Company from issuing new long-term debt to replace existing long-term debt, or from issuing additional short-term debt. Please refer to the Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.

The Company’s 1974 indenture pursuant to which $99.0 million (or 3.7%) of the Company’s long-term debt (as of September 30, 2022) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note L — Commitments and Contingencies, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company’s present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

Supply Corporation and Empire have developed a project which would move significant prospective Marcellus and Utica production from Seneca's Western Development Area at Clermont to an Empire interconnection with the TC Energy pipeline at Chippawa and an interconnection with TGP's 200 Line in East Aurora, New York (the “Northern Access project”). The Northern Access project would provide an outlet to Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast. The Northern Access project involves the construction of approximately 99 miles of largely 24” pipeline and approximately 27,500 horsepower of compression on the two systems. Supply Corporation, Empire and Seneca executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa and 140,000 Dth per day of firm transportation capacity to a new interconnection with TGP's 200 Line on this project. The Company remains committed to the project and, on June 29, 2022, received an extension of time from FERC, until December 31, 2024, to construct the project. The Company will update the $500 million preliminary cost estimate and expected in-service date for the project when there is further clarity on the timing of receipt of necessary regulatory approvals. As of September 30, 2022, approximately $55.8 million has been spent on the Northern Access project, including $24.2 million that has been spent to study the project. The remaining $31.6

million spent on the project is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2022.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan). The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it may continue making contributions to the Retirement Plan in the future. During 2022, the Company contributed $20.4 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2023 will be in the range of zero to $8.0 million. For further discussion of the Company's Retirement Plan, including actuarial assumptions, refer to Item 8 at Note K — Retirement Plan and Other Post-Retirement Benefits. As noted in that footnote, the Retirement Plan has been closed to new participants since 2003. In that regard, the average remaining service life of active participants in the Retirement Plan is approximately 6 years.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company has been making contributions to its VEBA trusts and/or 401(h) accounts over the last several years and does not anticipate making contributions to the VEBA trusts and/or 401(h) accounts in the near term. However, this will be subject to future review. During 2022, the Company contributed $2.8 million to its VEBA trusts. In addition, the Company made direct payments of $0.3 million to retirees not covered by the VEBA trusts and 401(h) accounts during 2022. The Company does not expect to make any contributions to its VEBA trusts in 2023. For further discussion of the Company's other post-retirement benefits, including actuarial assumptions, refer to Item 8 at Note K — Retirement Plan and Other Post-Retirement Benefits. As noted in that footnote, the other post-retirement benefits provided by the Company have been closed to new participants since 2003. In that regard, the average remaining service life of active participants is approximately 4 years for those eligible for other post-retirement benefits.

The Company has made certain guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading "Critical Accounting Estimates - Accounting for Derivative Financial Instruments"); and (ii) other obligations which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company uses various derivative financial instruments (derivatives), including price swap agreements and no cost collars, as part of the Company's overall energy commodity price risk management strategy in its Exploration and Production segment. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from, or pay to, the respective counterparties at September 30, 2022 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas transactions that are related to the financial instruments.

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act required the CFTC, SEC and other regulatory agencies to promulgate rules and regulations implementing the legislation, and includes provisions related to the swaps and over-the-counter derivatives markets that are designed to promote transparency, mitigate systemic risk and protect against market abuse. Although regulators have issued certain regulations, other rules that may impact the Company have yet to be finalized. Rules developed by the CFTC and other regulators could impact the Company. While many of those rules place specific conditions on the operations of swap dealers and major swap participants, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from final rules through higher transaction costs and prices or other direct or indirect costs. Additionally, given the enforcement authority granted to the CFTC on anti-market manipulation, anti-fraud and disruptive trading practices, it is difficult to predict how the evolving enforcement priorities of the CFTC will impact our business. Should the Company violate any laws or regulations applicable to our hedging activities, it could be subject to CFTC enforcement action and material penalties and sanctions. The Company continues to monitor these enforcement and other regulatory developments, but cannot predict the impact that evolving application of the Dodd-Frank Act may have on its operations.

The authoritative guidance for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2022, the Company determined that nonperformance risk associated with the price swap agreements, no cost collars and foreign currency contracts would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

The following tables disclose natural gas price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2022. At September 30, 2022, the Company had not entered into any natural gas price swap agreements extending beyond 2026.

Natural Gas Price Swap Agreements

	Expected Maturity Dates				
	2023	2024	2025	2026	Total
Notional Quantities (Equivalent Bcf)	112.8	65.7	26.8	2.0	207.3
Weighted Average Fixed Rate (per Mcf)	$ 2.88	$ 3.07	$ 3.16	$ 3.18	$ 2.98
Weighted Average Variable Rate (per Mcf)	$ 6.02	$ 4.86	$ 4.55	$ 4.32	$ 5.45

At September 30, 2022, the Company would have paid its respective counterparties an aggregate of approximately $512.3 million to terminate the natural gas price swap agreements outstanding at that date.

At September 30, 2021, the Company had natural gas price swap agreements covering 398.8 Bcf at a weighted average fixed rate of $2.84 per Mcf.

No Cost Collars

The following table discloses the notional quantities, the weighted average ceiling price and the weighted average floor price for the no cost collars used by the Company to manage natural gas price risk. The no cost collars provide for the Company to receive monthly payments from (or make payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). At September 30, 2022, the Company had not entered into any natural gas no cost collars extending beyond 2027.

	Expected Maturity Dates					
	2023	2024	2025	2026	2027	Total
Natural Gas						
Notional Quantities (Equivalent Bcf)	68.3	57.5	42.7	41.5	3.5	213.5
Weighted Average Ceiling Price (per Mcf)	$ 3.75	$ 3.89	$ 4.79	$ 4.90	$ 4.90	$ 4.24
Weighted Average Floor Price (per Mcf)	$ 3.20	$ 3.30	$ 3.60	$ 3.63	$ 3.63	$ 3.40

At September 30, 2022, the Company would have had to pay an aggregate of approximately $270.5 million to terminate the natural gas no cost collars outstanding at that date.

At September 30, 2021, the Company had no cost collars agreements covering 20.9 Bcf at a weighted average ceiling price of $3.25 per Mcf and a weighted average floor price of $2.81 per Mcf.

Foreign Exchange Risk

The Company uses foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. All of these transactions are forecasted.

The following table discloses foreign exchange contract information by expected maturity dates. The Company receives a fixed price in exchange for paying a variable price as noted in the Canadian to U.S. dollar forward exchange rates. Notional amounts (Canadian dollars) are used to calculate the contractual payments to be exchanged under contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2022. At September 30, 2022, the Company had not entered into any foreign currency exchange contracts extending beyond 2030.

	Expected Maturity Dates						
	2023	2024	2025	2026	2027	Thereafter	Total
Notional Quantities (Canadian Dollar in millions)	$14.7	$12.9	$10.9	$ 3.1	$ 2.4	$ 5.4	$49.4
Weighted Average Fixed Rate ($Cdn/$US)	$1.29	$1.29	$1.28	$1.32	$1.33	$ 1.34	$1.29
Weighted Average Variable Rate ($Cdn/$US)	$1.34	$1.33	$1.32	$1.34	$1.34	$ 1.34	$1.33

At September 30, 2022, absent other positions with the same counterparties, the Company would have paid to its respective counterparties an aggregate of $1.9 million to terminate these foreign exchange contracts.

Refer to Item 8 at Note J — Financial Instruments for a discussion of the Company's exposure to credit risk related to its derivative financial instruments.

Interest Rate Risk

The fair value of long-term fixed rate debt is $2.5 billion at September 30, 2022. This fair value amount is not intended to reflect principal amounts that the Company will ultimately be required to pay. The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company's long-term fixed rate debt:

	Principal Amounts by Expected Maturity Dates						
	2023	2024	2025	2026	2027	Thereafter	Total
	(Dollars in millions)						
Long-Term Fixed Rate Debt	$ 549.0	$ —	$ 500.0	$ 500.0	$ 300.0	$ 800.0	$2,649.0
Weighted Average Interest Rate Paid	4.1%	—	5.4%	5.5%	4.0%	3.6%	4.5%

RATE MATTERS

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states' respective public utility commissions and typically are changed only when approved through a procedure known as a "rate case." As noted below, the Pennsylvania division currently has a rate case on file. In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated "supply charge" on the customer bill.

New York Jurisdiction

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on April 20, 2017 with rates becoming effective May 1, 2017. The order provided for a return on equity of 8.7%, and directed the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018. The order also authorized the Company to recover approximately $15 million annually for pension and other post-employment benefit ("OPEB") expenses from customers. Because the Company's future pension and OPEB costs were projected to be satisfied with existing funds held in reserve, in July, Distribution Corporation made a filing with the NYPSC to effectuate a pension and OPEB surcredit to customers to offset these amounts being collected in base rates effective October 1, 2022. On September 16, 2022, the NYPSC issued an order approving the filing. With the implementation of this surcredit, Distribution Corporation will no longer be funding the pension from its New York jurisdiction and it will not be funding its VEBA trusts in its New York jurisdiction.

On August 13, 2021, the NYPSC issued an order extending the date through which qualified pipeline replacement costs incurred by the Company can be recovered using the existing system modernization tracker for two years (until March 31, 2023). The extension is contingent on the Company not filing a base rate case that would result in new rates becoming effective prior to April 1, 2023.

Pennsylvania Jurisdiction

Distribution Corporation's current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007. On October 28, 2022, Distribution Corporation made a filing with the PaPUC seeking an increase in its annual base rate operating revenues of $28.1 million with a proposed effective date of December 27, 2022. The Company is also proposing, among other things, to implement a weather normalization adjustment mechanism and a new energy efficiency and conservation pilot program for residential customers. The filing will be suspended for seven months by operation of law unless directed otherwise by the PaPUC.

Effective October 1, 2021, pursuant to a tariff supplement filed with the PaPUC, Distribution Corporation reduced base rates by $7.7 million in order to stop collecting OPEB expenses from customers. It also began to refund to customers overcollected OPEB expenses in the amount of $50.0 million. Certain other matters in the tariff supplement were unresolved. These matters were resolved with the PaPUC's approval of an Administrative Law Judge's Recommended Decision on February 24, 2022. Concurrent with that decision, the Company discontinued regulatory accounting for OPEB expenses and recorded an $18.5 million adjustment during the quarter ended March 31, 2022 to reduce its regulatory liability for previously deferred OPEB income amounts through September 30, 2021 and to increase Other Income (Deductions) on the consolidated financial statements by a like amount. The Company also increased customer refunds of overcollected OPEB expenses from $50.0 million to 54.0 million. All refunds specified in the tariff supplement are being funded entirely by grantor trust assets held by the Company, most of which are included in a fixed income mutual fund that is a component of Other Investments on the Company's Consolidated Balance Sheet. With the elimination of OPEB expenses in base rates, Distribution Corporation is no longer funding the grantor trust or its VEBA trusts in its Pennsylvania jurisdiction.

Pipeline and Storage

Supply Corporation's 2020 rate settlement provides that no party may make a rate filing for new rates to be effective before February 1, 2024, except that Supply Corporation may file an NGA general Section 4 rate case to change rates if the corporate federal income tax rate is increased. If no case has been filed, Supply Corporation must file for rates to be effective February 1, 2025.

Empire's 2019 rate settlement provides that Empire must make a rate case filing no later than May 1, 2025.

ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory requirements. In 2021, the Company set methane intensity reduction targets at each of its businesses, an absolute greenhouse gas emissions reduction target for the consolidated Company, and greenhouse gas reduction targets associated with the Company's utility delivery system. In 2022, the Company began measuring progress against these reduction targets. The Company's ability to estimate accurately the time, costs and resources necessary to meet emissions targets may change as environmental exposures and opportunities change and regulatory updates are issued.

For further discussion of the Company's environmental exposures, refer to Item 8 at Note L — Commitments and Contingencies under the heading "Environmental Matters."

While changes in environmental laws and regulations could have an adverse financial impact on the Company, legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

Environmental Regulation

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation in the United States. These efforts include legislation, legislative proposals and new regulations at the state and federal level, and private party litigation related to greenhouse gas emissions. Legislation or regulation that aims to reduce greenhouse gas emissions could also include emissions limits, reporting requirements, carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources. For example, the Inflation Reduction Act of 2022 (IRA) legislation was signed into law on August 16, 2022. The IRA includes a methane charge that is expected to be applicable to the reported annual methane emissions of certain oil and gas facilities, above specified methane intensity thresholds, starting in calendar year 2024. This portion of the IRA is to be administered by the EPA and potential fees will begin with emissions reported for calendar year 2024. The EPA regulates greenhouse gas emissions pursuant to the Clean Air Act. The regulations implemented by the EPA impose more stringent leak detection and repair requirements, and further address reporting and control of methane and volatile organic compound emissions. The Company must continue to comply with all applicable regulations. Additionally, a number of states have adopted energy strategies or plans with aggressive goals for the reduction of greenhouse gas emissions. Pennsylvania has a methane reduction framework with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. Pennsylvania's Governor also entered the Commonwealth into a cap-and-trade program known as the Regional Greenhouse Gas Initiative, however, the Commonwealth's participation is currently stayed due to ongoing litigation. Federal, state or local governments may provide tax advantages and other subsidies to support alternative energy sources, mandate the use of specific fuels or technologies, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The NYPSC, for example, initiated a proceeding to consider climate-related financial disclosures at the utility operating company level, and the New York State legislature passed the CLCPA that mandates reducing greenhouse gas emissions by 40% from 1990 levels by 2030, and by 85% from 1990 levels by 2050, with the remaining emission reduction achieved by controlled offsets. The CLCPA also requires electric generators to meet 70% of demand with renewable energy by 2030 and 100% with zero emissions generation by 2040. These climate change and greenhouse gas initiatives could impact the Company's customer base and assets depending on the promulgation of final regulations and on regulatory treatment afforded in the process. Thus far, the only regulations promulgated in connection with the CLCPA are greenhouse gas emissions limits established by the NYDEC in 6 NYCRR Part 496, effective December 30, 2020. The NYDEC has until January 1, 2024 to issue further rules and regulations implementing the statute. The above-enumerated initiatives could also increase the Company’s cost of environmental compliance by increasing reporting requirements, requiring retrofitting of existing equipment, requiring installation of new equipment, and/or requiring the purchase of emission allowances. They could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals. Changing market conditions and new regulatory requirements, as well as unanticipated or inconsistent application of existing laws and regulations by administrative agencies, make it difficult to predict a long-term business impact across twenty or more years.

EFFECTS OF INFLATION

The Company’s operations are sensitive to increases in the rate of inflation because of its operational and capital spending requirements in both its regulated and non-regulated businesses. For the regulated businesses, recovery of increasing costs from customers can be delayed by the regulatory process of a rate case filing. For the non-regulated businesses, prices received for services performed or products produced are determined by market factors that are not necessarily correlated to the underlying costs required to provide the service or product.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new authoritative accounting and reporting guidance, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words “anticipates,” “estimates,” “expects,” “forecasts,” “intends,” “plans,” “predicts,” “projects,” “believes,” “seeks,” “will,” “may,” and similar expressions, are “forward-looking statements” as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management’s expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;
2. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design, retained natural gas and system modernization), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
3. The Company’s ability to estimate accurately the time and resources necessary to meet emissions targets;
4. Governmental/regulatory actions and/or market pressures to reduce or eliminate reliance on natural gas;
5. Changes in economic conditions, including inflationary pressures, supply chain issues, liquidity challenges, and global, national or regional recessions, and their effect on the demand for, and customers’ ability to pay for, the Company’s products and services;
6. Changes in the price of natural gas;
7. The creditworthiness or performance of the Company’s key suppliers, customers and counterparties;
8. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company’s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company’s credit ratings and changes in interest rates and other capital market conditions;
9. Impairments under the SEC’s full cost ceiling test for natural gas reserves;
10. Increased costs or delays or changes in plans with respect to Company projects or related projects of other companies, as well as difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
11. The Company's ability to complete planned strategic transactions;
12. The Company's ability to successfully integrate acquired assets and achieve expected cost synergies;

13. Changes in price differentials between similar quantities of natural gas sold at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations;
14. The impact of information technology disruptions, cybersecurity or data security breaches;
15. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas reserves, including among others geology, lease availability and costs, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;
16. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits;
17. Other changes in price differentials between similar quantities of natural gas having different quality, heating value, hydrocarbon mix or delivery date;
18. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
19. Negotiations with the collective bargaining units representing the Company's workforce, including potential work stoppages during negotiations;
20. Uncertainty of gas reserve estimates;
21. Significant differences between the Company's projected and actual production levels for natural gas;
22. Changes in demographic patterns and weather conditions (including those related to climate change);
23. Changes in the availability, price or accounting treatment of derivative financial instruments;
24. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;
25. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war, as well as economic and operational disruptions due to third-party outages;
26. Significant differences between the Company's projected and actual capital expenditures and operating expenses; or
27. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Forward-looking and other statements in this Annual Report on Form 10-K regarding methane and greenhouse gas reduction plans and goals are not an indication that these statements are necessarily material to investors or required to be disclosed in our filings with the SEC. In addition, historical, current and forward-looking statements regarding methane and greenhouse gas emissions may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve and assumptions that are subject to change in the future.

INDUSTRY AND MARKET DATA DISCLOSURE

The market data and certain other statistical information used throughout this Form 10-K are based on independent industry publications, government publications or other published independent sources. Some data is also based on the Company's good faith estimates. Although the Company believes these third-party sources are reliable and that the information is accurate and complete, it has not independently verified the information.

Item 7A ***Quantitative and Qualitative Disclosures About Market Risk***

Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A.

Item 8 ***Financial Statements and Supplementary Data***

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All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Supplementary Data

Supplementary data that is included in Note N — Supplementary Information for Oil and Gas Producing Activities (unaudited), appears under this Item, and reference is made thereto.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of National Fuel Gas Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, of National Fuel Gas Company and its subsidiaries (the "Company") as listed in the accompanying index (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of September 30, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of September 30, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Natural Gas Reserves on Natural Gas Properties, Net

As described in Note A to the consolidated financial statements, the Exploration and Production segment includes capitalized costs relating to natural gas producing activities, net of depreciation, depletion, and amortization (DD&A) of $1.9 billion as of September 30, 2022. The Exploration and Production segment follows the full cost method of accounting. Under this method, all costs associated with property acquisition, exploration and development activities are capitalized and DD&A is computed based on quantities produced in relation to proved reserves using the units of production method. As disclosed by management, in addition to DD&A under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. If capitalized costs, net of accumulated DD&A and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. There were no ceiling test impairment charges for the year ended September 30, 2022. As of September 30, 2022, the ceiling exceeded the book value of the natural gas properties by approximately $3.2 billion. Estimates of the Company's proved natural gas reserves and the future net cash flows from those reserves were prepared by the Company's petroleum engineers and audited by independent petroleum engineers (together referred to as "management's specialists"). Petroleum engineering involves significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Estimates of economically recoverable natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including quantities of natural gas that are ultimately recovered, the timing of the recovery of natural gas reserves, the production and operating costs to be incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The principal considerations for our determination that performing procedures relating to the impact of proved natural gas reserves on natural gas properties, net is a critical audit matter are the significant judgment by management, including the use of management's specialists, when developing the estimates of proved natural gas reserves, which in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of quantities of proved natural gas that are ultimately recovered.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved natural gas reserves that are utilized in the DD&A expense and ceiling test calculations. These procedures also included, among others, evaluating the reasonableness of the significant assumptions used by management related to the quantities of natural gas that are ultimately recovered. Evaluating the reasonableness of the significant assumptions included evaluating information on additional development activity, production history, if the assumptions used were reasonable considering the past performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved natural gas reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood and the Company's relationship with the specialists assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists' findings.

/s/ PRICEWATERHOUSECOOPERS LLP
Buffalo, New York
November 18, 2022

We have served as the Company's auditor since 1941.

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2022	2021	2020
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues:			
Utility and Energy Marketing Revenues	$ 897,916	$ 667,549	$ 728,336
Exploration and Production and Other Revenues	1,010,629	837,597	611,885
Pipeline and Storage and Gathering Revenues	277,501	237,513	206,070
	2,186,046	1,742,659	1,546,291
Operating Expenses:			
Purchased Gas	392,093	171,827	233,890
Operation and Maintenance:			
Utility and Energy Marketing	193,058	179,547	181,051
Exploration and Production and Other	191,572	173,041	148,856
Pipeline and Storage and Gathering	136,571	123,218	108,640
Property, Franchise and Other Taxes	101,182	94,713	88,400
Depreciation, Depletion and Amortization	369,790	335,303	306,158
Impairment of Oil and Gas Producing Properties	—	76,152	449,438
	1,384,266	1,153,801	1,516,433
Gain on Sale of Assets	12,736	51,066	—
Operating Income	814,516	639,924	29,858
Other Income (Expense):			
Other Income (Deductions)	(1,509)	(15,238)	(17,814)
Interest Expense on Long-Term Debt	(120,507)	(141,457)	(110,012)
Other Interest Expense	(9,850)	(4,900)	(7,065)
Income (Loss) Before Income Taxes	682,650	478,329	(105,033)
Income Tax Expense	116,629	114,682	18,739
Net Income (Loss) Available for Common Stock	566,021	363,647	(123,772)
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,191,175	991,630	1,272,601
	1,757,196	1,355,277	1,148,829
Dividends on Common Stock	(170,111)	(164,102)	(156,249)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	(950)
Balance at End of Year	$ 1,587,085	$ 1,191,175	$ 991,630
Earnings (Loss) Per Common Share:			
Basic:			
Net Income (Loss) Available for Common Stock	$ 6.19	$ 3.99	$ (1.41)
Diluted:			
Net Income (Loss) Available for Common Stock	$ 6.15	$ 3.97	$ (1.41)
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	91,410,625	91,130,941	87,968,895
Used in Diluted Calculation	92,107,066	91,684,583	87,968,895

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2022	2021	2020
	(Thousands of dollars)		
Net Income (Loss) Available for Common Stock	$ 566,021	$ 363,647	$(123,772)
Other Comprehensive Income (Loss), Before Tax:			
Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	9,561	17,862	(19,214)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	11,054	16,229	15,361
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(1,050,831)	(665,371)	9,862
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	882,581	83,711	(93,295)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	1,313
Other Post-Retirement Adjustment for Regulatory Proceeding	(7,351)	—	—
Other Comprehensive Income (Loss), Before Tax	(154,986)	(547,569)	(85,973)
Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	2,169	4,072	(4,357)
Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	2,574	3,762	3,566
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(287,608)	(179,028)	2,578
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	241,559	22,465	(25,521)
Income Tax Benefit (Expense) on Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	363
Income Tax Expense (Benefit) Related to Other Post-Retirement Adjustment for Regulatory Proceeding	(1,544)	—	—
Income Taxes — Net	(42,850)	(148,729)	(23,371)
Other Comprehensive Income (Loss)	(112,136)	(398,840)	(62,602)
Comprehensive Income (Loss)	$ 453,885	$ (35,193)	$(186,374)

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2022	At September 30 2021
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 12,551,909	$ 13,103,639
Less — Accumulated Depreciation, Depletion and Amortization	5,985,432	6,719,356
	6,566,477	6,384,283
Current Assets		
Cash and Temporary Cash Investments	46,048	31,528
Hedging Collateral Deposits	91,670	88,610
Receivables — Net of Allowance for Uncollectible Accounts of $40,228 and $31,639, Respectively	361,626	205,294
Unbilled Revenue	30,075	17,000
Gas Stored Underground	32,364	33,669
Materials, Supplies and Emission Allowances	40,637	53,560
Unrecovered Purchased Gas Costs	99,342	33,128
Other Current Assets	59,369	59,660
	761,131	522,449
Other Assets		
Recoverable Future Taxes	106,247	121,992
Unamortized Debt Expense	8,884	10,589
Other Regulatory Assets	67,101	60,145
Deferred Charges	77,472	59,939
Other Investments	95,025	149,632
Goodwill	5,476	5,476
Prepaid Pension and Post-Retirement Benefit Costs	196,597	149,151
Fair Value of Derivative Financial Instruments	9,175	—
Other	2,677	1,169
	568,654	558,093
Total Assets	$ 7,896,262	$ 7,464,825
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value; Authorized - 200,000,000 Shares; Issued and Outstanding - 91,478,064 Shares and 91,181,549 Shares, Respectively	$ 91,478	$ 91,182
Paid In Capital	1,027,066	1,017,446
Earnings Reinvested in the Business	1,587,085	1,191,175
Accumulated Other Comprehensive Loss	(625,733)	(513,597)
Total Comprehensive Shareholders' Equity	2,079,896	1,786,206
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,083,409	2,628,687
Total Capitalization	4,163,305	4,414,893
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	60,000	158,500
Current Portion of Long-Term Debt	549,000	—
Accounts Payable	178,945	171,655
Amounts Payable to Customers	419	21
Dividends Payable	43,452	41,487
Interest Payable on Long-Term Debt	17,376	17,376
Customer Advances	26,108	17,223
Customer Security Deposits	24,283	19,292
Other Accruals and Current Liabilities	257,327	194,169
Fair Value of Derivative Financial Instruments	785,659	616,410
	1,942,569	1,236,133
Other Liabilities		
Deferred Income Taxes	698,229	660,420
Taxes Refundable to Customers	362,098	354,089
Cost of Removal Regulatory Liability	259,947	245,636
Other Regulatory Liabilities	188,803	200,643
Pension and Other Post-Retirement Liabilities	3,065	7,526
Asset Retirement Obligations	161,545	209,639
Other Liabilities	116,701	135,846
	1,790,388	1,813,799
Commitments and Contingencies (Note L)	—	—
Total Capitalization and Liabilities	$ 7,896,262	$ 7,464,825

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2022	2021	2020
	(Thousands of dollars)		
Operating Activities			
Net Income (Loss) Available for Common Stock	$ 566,021	$ 363,647	$ (123,772)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Gain on Sale of Assets	(12,736)	(51,066)	—
Impairment of Oil and Gas Producing Properties	—	76,152	449,438
Depreciation, Depletion and Amortization	369,790	335,303	306,158
Deferred Income Taxes	104,415	105,993	54,313
Premium Paid on Early Redemption of Debt	—	15,715	—
Stock-Based Compensation	19,506	17,065	14,931
Reduction of Other Post-Retirement Regulatory Liability	(18,533)	—	—
Other	31,983	10,896	6,527
Change in:			
Receivables and Unbilled Revenue	(168,769)	(61,413)	(2,578)
Gas Stored Underground and Materials, Supplies and Emission Allowances	3,109	(2,014)	(6,625)
Unrecovered Purchased Gas Costs	(66,214)	(33,128)	2,246
Other Current Assets	291	(11,972)	49,367
Accounts Payable	11,907	31,352	(4,657)
Amounts Payable to Customers	398	(10,767)	6,771
Customer Advances	8,885	1,904	2,275
Customer Security Deposits	4,991	2,093	989
Other Accruals and Current Liabilities	34,260	34,314	5,001
Other Assets	(58,924)	1,250	(24,203)
Other Liabilities	(17,859)	(33,771)	4,628
Net Cash Provided by Operating Activities	812,521	791,553	740,809
Investing Activities			
Capital Expenditures	(811,826)	(751,734)	(716,153)
Net Proceeds from Sale of Oil and Gas Producing Properties	254,439	—	—
Net Proceeds from Sale of Timber Properties	—	104,582	—
Sale of Fixed Income Mutual Fund Shares in Grantor Trust	30,000	—	—
Acquisition of Upstream Assets and Midstream Gathering Assets	—	—	(506,258)
Other	8,683	13,935	(1,205)
Net Cash Used in Investing Activities	(518,704)	(633,217)	(1,223,616)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	(98,500)	128,500	(25,200)
Net Proceeds from Issuance of Long-Term Debt	—	495,267	493,007
Reduction of Long-Term Debt	—	(515,715)	—
Net Proceeds from Issuance (Repurchase) of Common Stock	(9,590)	(3,702)	161,603
Dividends Paid on Common Stock	(168,147)	(163,089)	(153,322)
Net Cash Provided by (Used in) Financing Activities	(276,237)	(58,739)	476,088
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	17,580	99,597	(6,719)
Cash, Cash Equivalents and Restricted Cash At Beginning of Year	120,138	20,541	27,260
Cash, Cash Equivalents and Restricted Cash At End of Year	$ 137,718	$ 120,138	$ 20,541
Supplemental Disclosure of Cash Flow Information			
Cash Paid (Refunded) For:			
Interest	$ 124,312	$ 135,136	$ 103,479
Income Taxes	$ 16,680	$ 6,374	$ (82,876)
Non-Cash Investing Activities:			
Non-Cash Capital Expenditures	$ 120,262	$ 102,700	$ 87,328
Non-Cash Contingent Consideration for Asset Sale	$ 12,571	$ —	$ —

See Notes to Consolidated Financial Statements

Note A — Summary of Significant Accounting Policies

Principles of Consolidation

The Company consolidates all entities in which it has a controlling financial interest. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Regulation

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to GAAP, as applied to regulated enterprises, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. Reference is made to Note F — Regulatory Matters for further discussion.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance, the majority of which is in the Utility segment, is determined based on historical experience, the age of customer accounts, other specific information about customer accounts, and the economic and regulatory environment. Account balances are charged off against the allowance approximately twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered.

Activity in the allowance for uncollectible accounts are as follows:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Balance at Beginning of Year	$ 31,639	$ 22,810	$ 25,788
Additions Charged to Costs and Expenses	13,209	14,940	12,339
Add: Discounts on Purchased Receivables	1,314	1,168	1,353
Deduct: Net Accounts Receivable Written-Off	5,934	7,279	16,670
Balance at End of Year	$ 40,228	$ 31,639	$ 22,810

Regulatory Mechanisms

The Company's rate schedules in the Utility segment contain clauses that permit adjustment of revenues to reflect price changes from the cost of purchased gas included in base rates. Differences between amounts currently recoverable and actual adjustment clause revenues, as well as other price changes and pipeline and storage company refunds not yet includable in adjustment clause rates, are deferred and accounted for as either unrecovered purchased gas costs or amounts payable to customers. Such amounts are generally recovered from (or passed back to) customers during the following fiscal year.

Estimated refund liabilities to ratepayers represent management's current estimate of such refunds. Reference is made to Note F — Regulatory Matters for further discussion.

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a WNC, which covers the eight-month period from October through May. The WNC is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is warmer than normal results in a surcharge being added to customers' current bills, while weather that is colder than normal results in a refund being credited to customers' current bills. Since the Utility segment's Pennsylvania rate jurisdiction does not have a WNC, weather variations have a direct impact on the Pennsylvania rate jurisdiction's revenues.

The impact of weather normalized usage per customer account in the Utility segment's New York rate jurisdiction is tempered by a revenue decoupling mechanism. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. Weather normalized usage per account that exceeds the average weather normalized usage per customer account results in a refund being credited to customers' bills. Weather normalized usage per account that is below the average weather normalized usage per account results in a surcharge being added to customers' bills. The surcharge or credit is calculated over a twelve-month period ending March 31st, and applied to customer bills annually, beginning July 1st.

In the Pipeline and Storage segment, the allowed rates that Supply Corporation and Empire bill their customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs, including return on equity and income taxes, through fixed monthly reservation charges. Because of this rate design, changes in throughput due to weather variations do not have a significant impact on the revenues of Supply Corporation or Empire.

Asset Acquisition and Business Combination Accounting

In accordance with authoritative guidance issued by the FASB that clarifies the definition of a business, when the Company executes an acquisition, it will perform an initial screening test as of the acquisition date that, if met, results in the conclusion that the set of activities and assets is not a business. If the initial screening test is not met, the Company evaluates whether the set is a business based on whether there are inputs and a substantive process in place. The definition of a business impacts whether the Company consolidates an acquisition under business combination guidance or asset acquisition guidance.

When the Company acquires assets and liabilities deemed to be an asset acquisition, the fair value of the purchase consideration, including the transaction costs of the asset acquisition, is assumed to be equal to the fair value of the net assets acquired. The purchase consideration, including the transaction costs, is allocated to the individual assets and liabilities assumed based on their relative fair values. Transaction costs associated with asset acquisitions are capitalized as part of the costs of the group of assets acquired.

When the Company acquires assets and liabilities deemed to be a business combination, the acquisition method is applied. Goodwill is measured as the fair value of the consideration transferred less the net recognized fair value of the identifiable assets acquired and the liabilities assumed, all measured at the acquisition date. Transaction costs that the Company incurs in connection with a business combination, such as finders' fees, legal fees, due diligence fees and other professional and consulting fees are expensed as incurred.

Property, Plant and Equipment

In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Company's capitalized costs relating to oil and gas producing activities, net of accumulated depreciation, depletion and amortization, were $1.9 billion at September 30, 2022 and 2021.

For further discussion of capitalized costs, refer to Note N — Supplementary Information for Oil and Gas Producing Activities.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unproved properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent non-cash impairment is required to be charged to earnings in that quarter. At September 30, 2022, the ceiling exceeded the book value of the oil and gas properties by approximately $3.2 billion. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2022, 2021 and 2020, estimated future net cash flows were decreased by $1.0 billion, decreased by $76.1 million and increased by $180.0 million, respectively.

The principal assets of the Utility, Pipeline and Storage and Gathering segments, consisting primarily of gas distribution pipelines, transmission pipelines, storage facilities, gathering lines and compressor stations, are recorded at historical cost. There were no indications of any impairments to property, plant and equipment in the Utility, Pipeline and Storage and Gathering segments at September 30, 2022.

Maintenance and repairs of property and replacements of minor items of property are charged directly to maintenance expense. The original cost of the regulated subsidiaries' property, plant and equipment retired, and the cost of removal less salvage, are charged to accumulated depreciation.

Depreciation, Depletion and Amortization

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unproved oil and gas properties is excluded from this computation. Depreciation, depletion and amortization expense for oil and gas properties was $202.4 million, $177.1 million and $166.8 million for the years ended September 30, 2022, 2021 and 2020, respectively. For all other property, plant and equipment, depreciation and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated service lives of property in service. The following is a summary of depreciable plant by segment:

	As of September 30	
	2022	2021
	(Thousands)	
Exploration and Production	$ 6,088,476	$ 6,827,122
Pipeline and Storage	2,747,948	2,467,891
Gathering	971,665	932,583
Utility	2,411,707	2,306,603
All Other and Corporate	13,712	13,585
	$ 12,233,508	$ 12,547,784

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2022	2021	2020
Exploration and Production, per Mcfe(1)	$ 0.59	$ 0.56	$ 0.71
Pipeline and Storage	2.7 %	2.6 %	2.4 %
Gathering	3.6 %	3.6 %	3.2 %
Utility	2.7 %	2.7 %	2.7 %
All Other and Corporate	1.4 %	3.4 %	3.6 %

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note N — Supplementary Information for Oil and Gas Producing Activities, depletion of oil and gas producing properties amounted to $0.57, $0.54 and $0.69 per Mcfe of production in 2022, 2021 and 2020, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2022 and 2021 on its Consolidated Balance Sheets related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2022, 2021 and 2020, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

Financial Instruments

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and to manage a portion of the risk of currency fluctuations associated with transportation costs denominated in Canadian currency. These instruments include natural gas price swap agreements and no cost collars and foreign currency forward contracts. The Company accounts for these instruments as cash flow hedges for which the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled Fair Value of Derivative Financial Instruments. Reference is made to Note I — Fair Value Measurements for further discussion concerning the fair value of derivative financial instruments.

For cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues on the Consolidated Statements of Income. Reference is made to Note J — Financial Instruments for further discussion concerning cash flow hedges.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) and changes for the years ended September 30, 2022 and 2021, net of related tax effects, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Funded Status of the Pension and Other Post-Retirement Benefit Plans	Total
Year Ended September 30, 2022			
Balance at October 1, 2021	$ (449,962)	$ (63,635)	$ (513,597)
Other Comprehensive Gains and Losses Before Reclassifications	(763,223)	7,392	(755,831)
Amounts Reclassified From Other Comprehensive Income (Loss)	641,022	8,480	649,502
Other Post-Retirement Adjustment for Regulatory Proceeding	—	(5,807)	(5,807)
Balance at September 30, 2022	$ (572,163)	$ (53,570)	$ (625,733)
Year Ended September 30, 2021			
Balance at October 1, 2020	$ (24,865)	$ (89,892)	$ (114,757)
Other Comprehensive Gains and Losses Before Reclassifications	(486,343)	13,790	(472,553)
Amounts Reclassified From Other Comprehensive Income (Loss)	61,246	12,467	73,713
Balance at September 30, 2021	$ (449,962)	$ (63,635)	$ (513,597)

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company's pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service cost was $0.4 million and $0.7 million at September 30, 2022 and 2021, respectively. The total amount for accumulated losses was $53.2 million and $62.9 million at September 30, 2022 and 2021, respectively.

During the quarter ended March 31, 2022, the PaPUC concluded a regulatory proceeding that addressed the recovery of OPEB expenses in Distribution Corporation's Pennsylvania service territory. As a result of that proceeding, Distribution Corporation discontinued regulatory accounting for OPEB expenses in Pennsylvania and a regulatory deferral of $7.4 million ($5.8 million after tax) related to the funded status of Distribution Corporation's other post-retirement benefit plans in Pennsylvania was reclassified to accumulated other comprehensive loss. For further discussion of this regulatory proceeding, refer to Note F — Regulatory Matters under the heading "Pennsylvania Jurisdiction."

Reclassifications Out of Accumulated Other Comprehensive Income (Loss)

The details about the reclassification adjustments out of accumulated other comprehensive income (loss) for the years ended September 30, 2022 and 2021 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) for the Year Ended September 30,		Affected Line Item in the Statement Where Net Income is Presented
	2022	2021	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	($882,594)	($83,973)	Operating Revenues
Foreign Currency Contracts	13	262	Operating Revenues
Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans:			
Prior Service Cost	(103)	(208)	(1)
Net Actuarial Loss	(10,951)	(16,021)	(1)
	(893,635)	(99,940)	Total Before Income Tax
	244,133	26,227	Income Tax Expense
	($649,502)	($73,713)	Net of Tax

(1) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost. Refer to Note K — Retirement Plan and Other Post-Retirement Benefits for additional details.

Gas Stored Underground

In the Utility segment, gas stored underground in the amount of $32.4 million is carried at lower of cost or net realizable value, on a LIFO method. Based upon the average price of spot market gas purchased in September 2022, including transportation costs, the current cost of replacing this inventory of gas stored underground exceeded the amount stated on a LIFO basis by approximately $178.5 million at September 30, 2022.

Materials, Supplies and Emission Allowances

The components of the Company's materials, supplies and emission allowances are as follows:

	Year Ended September 30	
	2022	2021
	(Thousands)	
Materials and Supplies — at average cost	$ 40,637	$ 34,880
Emission Allowances	—	18,680
	$ 40,637	$ 53,560

Unamortized Debt Expense

Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment. At September 30, 2022, the remaining weighted average amortization period for such costs was approximately 5 years.

Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return. State tax returns are filed on a combined or separate basis depending on the applicable laws in the jurisdictions where tax returns are filed.

The Company follows the asset and liability approach in accounting for income taxes, which requires the recognition of deferred income taxes for the expected future tax consequences of net operating losses, credits and temporary differences between the financial statement carrying amounts and the tax basis of assets and liabilities. A valuation allowance is provided on deferred tax assets if it is determined, within each taxing jurisdiction, that it is more likely than not that the asset will not be realized.

The Company reports a liability or a reduction of deferred tax assets for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. When applicable, the Company recognizes interest relating to uncertain tax positions in Other Interest Expense and penalties in Other Income (Deductions).

Consolidated Statement of Cash Flows

The components, as reported on the Company's Consolidated Balance Sheets, of the total cash, cash equivalents, and restricted cash presented on the Statement of Cash Flows are as follows (in thousands):

	Year Ended September 30			
	2022	**2021**	**2020**	**2019**
Cash and Temporary Cash Investments	$ 46,048	$ 31,528	$ 20,541	$ 20,428
Hedging Collateral Deposits	91,670	88,610	—	6,832
Cash, Cash Equivalents, and Restricted Cash	$137,718	$120,138	$ 20,541	$ 27,260

The Company considers all highly liquid debt instruments purchased with a maturity date of generally three months or less to be cash equivalents. The Company's restricted cash is composed entirely of amounts reported as Hedging Collateral Deposits on the Consolidated Balance Sheets. Hedging Collateral Deposits is an account title for cash held in margin accounts funded by the Company to serve as collateral for derivative financial instruments in an unrealized loss position. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instruments liability or asset balances.

Other Current Assets

The components of the Company's Other Current Assets are as follows:

	Year Ended September 30	
	2022	**2021**
	(Thousands)	
Prepayments	$ 17,757	$ 14,164
Prepaid Property and Other Taxes	14,321	14,788
State Income Taxes Receivable	5,933	1,502
Regulatory Assets	21,358	29,206
	$ 59,369	$ 59,660

Other Accruals and Current Liabilities

The components of the Company's Other Accruals and Current Liabilities are as follows:

	Year Ended September 30	
	2022	2021
	(Thousands)	
Accrued Capital Expenditures	$ 64,720	$ 42,541
Regulatory Liabilities	31,293	60,860
Liability for Royalty and Working Interests	86,206	31,483
Non-Qualified Benefit Plan Liability	17,474	15,408
Other	57,634	43,877
	$ 257,327	$ 194,169

Customer Advances

The Company, primarily in its Utility segment, has balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2022 and 2021, customers in the balanced billing programs had advanced excess funds of $26.1 million and $17.2 million, respectively.

Customer Security Deposits

The Company, primarily in its Utility and Pipeline and Storage segments, oftentimes requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2022 and 2021, the Company had received customer security deposits amounting to $24.3 million and $19.3 million, respectively.

Earnings Per Common Share

Basic earnings per common share is computed by dividing income or loss by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the potentially dilutive securities the Company had outstanding were SARs, restricted stock units and performance shares. For the years ended September 30, 2022 and September 30, 2021, the diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 2,858 securities excluded as being antidilutive for the year ended September 30, 2022 and 320,222 securities excluded as being antidilutive for the year ended September 30, 2021. As the Company recognized a net loss for the year ended September 30, 2020, the aforementioned potentially dilutive securities, amounting to 411,890 securities, were not recognized in the diluted earnings per share calculation for 2020.

Stock-Based Compensation

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares. The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments. SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no SAR is exercisable less than one year or more than ten years after the date of each grant. The Company has chosen the Black-Scholes-Merton closed form model to calculate the compensation expense associated with SARs. For all Company stock awards, forfeitures are recognized as they occur.

Restricted stock units are subject to restrictions on vesting and transferability. Restricted stock units represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. The restricted stock units do not entitle the participants to dividend and voting rights. The fair value at the date of grant of the restricted stock units (represented by the market value of Company common stock on the date of the award) must be reduced by the present value of forgone dividends over the vesting term of the award. The fair value of restricted stock units on the date of award is recorded as compensation expense over the vesting period.

Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period. For performance shares based on a return on capital goal and greenhouse gas emissions reductions, the fair value at the date of grant of the performance shares is determined by multiplying the expected number of performance shares to be issued by the market value of Company common stock on the date of grant reduced by the present value of forgone dividends. For performance shares based on a total shareholder return goal, the Company uses the Monte Carlo simulation technique to estimate the fair value price at the date of grant.

Refer to Note H — Capitalization and Short-Term Borrowings under the heading “Stock Award Plans” for additional disclosures related to stock-based compensation awards for all plans.

Note B — Asset Acquisitions and Divestitures

On June 30, 2022, the Company completed the sale of Seneca’s California assets, all of which are in the Exploration and Production segment, to Sentinel Peak Resources California LLC for a total sale price of $253.5 million, consisting of $240.9 million in cash and contingent consideration valued at $12.6 million at closing. The Company pursued this sale given the strong commodity price environment and the Company’s strategic focus in the Appalachian Basin. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The sale price, which reflected an effective date of April 1, 2022, was reduced for production revenues less expenses that were retained by Seneca from the effective date to the closing date. Under the full cost method of accounting for oil and natural gas properties, $220.7 million of the sale price at closing was accounted for as reduction of capitalized costs since the disposition did not alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center. The remainder of the sale price ($32.8 million) was applied against assets that are not subject to the full cost method of accounting, with the Company recognizing a gain of $12.7 million on the sale of such assets. The majority of this gain related to the sale of emission allowances. The Company also eliminated the asset retirement obligation associated with Seneca’s California oil and gas assets. This obligation amounted to $50.1 million and was accounted for as a reduction of capitalized costs under the full cost method of accounting.

On July 31, 2020, the Company completed its acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from SWEPI LP, a subsidiary of Royal Dutch Shell plc (“Shell”) for total consideration of $506.3 million. The purchase price, which reflected an effective date of January 1, 2020, was reduced for production revenues less expenses that were retained by Shell from the effective date to the closing date. As part of the transaction, the Company acquired over 400,000 net acres in Appalachia, including approximately 200,000 net acres in Tioga County, Pennsylvania. The proved developed and undeveloped natural gas reserves associated with this acquisition amounted to 684,141 MMcf. In addition, the Company acquired gathering pipelines and related compression, water pipelines, and associated water handling infrastructure, all of which support the acquired Tioga County production operations. These gathering facilities are interconnected with various interstate pipelines, including the Company's Empire pipeline system, with the potential to tie into the Company's existing Covington gathering system. Post-closing, the Company has integrated the assets into its existing operations in Tioga County, which has resulted in cost synergies. This transaction was accounted for as an asset acquisition as substantially all the fair value of the gross assets acquired is concentrated in a single asset under the screen test comprised of Proved Developed Producing Reserves and the attached Gathering Property, Plant and Equipment. The purchase consideration, including the transaction costs, has been allocated to the individual assets acquired based on their relative fair values. The following is a summary of the asset acquisition (in thousands):

Purchase Price	$	503,908
Transaction Costs		2,350
Total Consideration	$	506,258

	Allocation of Cost of Asset Acquisition:						
	Exploration and Production Reporting Segment			Gathering Reporting Segment			Total
Property, Plant and Equipment	$	281,648	(1)(2)	$	223,369	(2)	$	505,017
Inventory		1,132			109			1,241
Total Accounting	$	282,780		$	223,478		$	506,258

(1) Includes $241,134 in Proved Developed Producing Properties and $277,832 capitalized in the full cost pool.

(2) The Company utilized an income approach and market based approach to determine the fair value of the acquired property, plant and equipment in the Exploration and Production reporting segment. The Company utilized a cost approach and an income approach to determine the fair value of the acquired property, plant and equipment in the Gathering reporting segment.

The acquisition of the upstream assets and midstream gathering assets from Shell was financed with a combination of debt and equity, as discussed in Note H — Capitalization and Short-Term Borrowings. The purchase and sale agreement with Shell was structured, in part, as a reverse like-kind exchange pursuant to Section 1031 of the Internal Revenue Code, as amended ("Reverse 1031 Exchange").

On December 10, 2020, the Company completed the sale of substantially all timber properties in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for net proceeds of $104.6 million. These assets were a component of the Company's All Other category and did not have a major impact on the Company's operations or financial results. After purchase price adjustments and transaction costs, a gain of $51.1 million was recognized on the sale of these assets. Since the sale did not represent a strategic shift in focus for the Company, the financial results associated with operating these assets as well as the gain on sale have not been reported as discontinued operations.

The sale of the timber properties completed the Reverse 1031 Exchange related to the Company's acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from Shell, as discussed above. In connection with the Reverse 1031 Exchange, the Company, through a subsidiary, assigned the rights to acquire legal title to certain oil and natural gas properties to a Variable Interest Entity ("VIE") formed by an exchange accommodation titleholder. The Company evaluated the VIE to determine whether the Company should be considered as the primary beneficiary having a controlling financial interest. It was determined that the Company had the power to direct the activities of the VIE and the obligation to absorb significant losses of that entity or the right to receive significant benefits from that entity. Therefore, the Company was considered to be the primary beneficiary. From July 31, 2020 to December 10, 2020, a subsidiary of the Company operated the properties pursuant to a lease agreement with the VIE. As the Company was deemed to be the primary beneficiary of the VIE, the VIE was included in the consolidated financial statements of the Company. Upon completion of the sale of the timber properties on December 10, 2020, the affected properties were conveyed to the Company and the VIE structure was terminated.

On August 1, 2020, the Company completed the sale of NFR’s commercial and industrial gas contracts in New York and Pennsylvania and certain other assets to Marathon Power LLC. This sale, in conjunction with the turn back of NFR's residential customers to Distribution Corporation, effectively ended NFR's operations. The sale did not have a material impact to the Company’s financial statements. The divestiture reflects the Company’s decision to focus on other strategic areas of the energy market.

Note C — Revenue from Contracts with Customers

The following tables provide a disaggregation of the Company's revenues for the years ended September 30, 2022 and 2021, presented by type of service from each reportable segment.

	Year Ended September 30, 2022							
Revenues by Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
					(Thousands)			
Production of Natural Gas	$ 1,730,723	$ —	$ —	$ —	$ 1,730,723	$ —	$ —	$ 1,730,723
Production of Crude Oil	150,957	—	—	—	150,957	—	—	150,957
Natural Gas Processing	3,511	—	—	—	3,511	—	—	3,511
Natural Gas Gathering Service	—	—	214,843	—	214,843	—	(202,757)	12,086
Natural Gas Transportation Service	—	289,967	—	106,495	396,462	—	(74,749)	321,713
Natural Gas Storage Service	—	84,565	—	—	84,565	—	(36,382)	48,183
Natural Gas Residential Sales	—	—	—	688,271	688,271	—	—	688,271
Natural Gas Commercial Sales	—	—	—	95,114	95,114	—	—	95,114
Natural Gas Industrial Sales	—	—	—	4,902	4,902	—	—	4,902
Other	7,867	2,512	—	(3,918)	6,461	6	(644)	5,823
Total Revenues from Contracts with Customers	1,893,058	377,044	214,843	890,864	3,375,809	6	(314,532)	3,061,283
Alternative Revenue Programs	—	—	—	7,357	7,357	—	—	7,357
Derivative Financial Instruments	(882,594)	—	—	—	(882,594)	—	—	(882,594)
Total Revenues	$ 1,010,464	$ 377,044	$ 214,843	$ 898,221	$ 2,500,572	$ 6	$ (314,532)	$ 2,186,046

	Year Ended September 30, 2021							
Revenues by Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Production of Natural Gas	$ 780,477	$ —	$ —	$ —	$ 780,477	$ —	$ —	$ 780,477
Production of Crude Oil	135,191	—	—	—	135,191	—	—	135,191
Natural Gas Processing	2,960	—	—	—	2,960	—	—	2,960
Natural Gas Gathering Service	—	—	193,264	—	193,264	—	(190,148)	3,116
Natural Gas Transportation Service	—	255,849	—	103,141	358,990	—	(72,920)	286,070
Natural Gas Storage Service	—	83,080	—	—	83,080	—	(35,841)	47,239
Natural Gas Residential Sales	—	—	—	492,567	492,567	—	—	492,567
Natural Gas Commercial Sales	—	—	—	62,634	62,634	—	—	62,634
Natural Gas Industrial Sales	—	—	—	3,071	3,071	—	—	3,071
Natural Gas Marketing	—	—	—	—	—	678	(49)	629
Other	2,042	4,628	—	(5,249)	1,421	544	(374)	1,591
Total Revenues from Contracts with Customers	920,670	343,557	193,264	656,164	2,113,655	1,222	(299,332)	1,815,545
Alternative Revenue Programs	—	—	—	11,087	11,087	—	—	11,087
Derivative Financial Instruments	(83,973)	—	—	—	(83,973)	—	—	(83,973)
Total Revenues	$ 836,697	$ 343,557	$ 193,264	$ 667,251	$ 2,040,769	$ 1,222	$ (299,332)	$ 1,742,659

The Company records revenue related to its derivative financial instruments in the Exploration and Production segment. The Company also records revenue related to alternative revenue programs in its Utility segment. Revenue related to derivative financial instruments and alternative revenue programs are excluded from the scope of the authoritative guidance regarding revenue recognition since they are accounted for under other existing accounting guidance.

Exploration and Production Segment Revenue

The Company's Exploration and Production segment records revenue from the sale of the natural gas and oil that it produces and natural gas liquids (NGLs) processed based on entitlement, which means that revenue is recorded based on the actual amount of natural gas or oil that is delivered to a pipeline, or upon pick-up in the case of NGLs, and the Company's ownership interest. Prior to the completion of the sale of the Company's California assets on June 30, 2022, natural gas production occurred primarily in the Appalachian region of the United States and crude oil production occurred primarily in the West Coast region of the United States. Subsequent to June 30, 2022, substantially all Exploration and Production segment production consists of natural gas production from the Appalachian region of the United States. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance. The sales contracts generally require the Company to deliver a specific quantity of a commodity per day for a specific number of days at a price that is either fixed or variable and considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery.

The transaction price for the sale of natural gas, oil and NGLs is contractually agreed upon based on prevailing market pricing (primarily tied to a market index with certain adjustments based on factors such as delivery location and prevailing supply and demand conditions) or fixed pricing. The Company allocates the transaction price to each performance obligation on the basis of the relative standalone selling price of each distinct unit sold. Revenue is recognized at a point in time when the transfer of the commodity occurs at the delivery point per the contract. The amount billable, as determined by the contracted quantity and price, indicates the value to the customer, and is used for revenue recognition purposes by the Exploration and Production segment as specified by the "invoice practical expedient" (the amount that the Exploration and

Production segment has the right to invoice) under the authoritative guidance for revenue recognition. The contracts typically require payment within 30 days of the end of the calendar month in which the natural gas and oil is delivered, or picked up in the case of NGLs.

The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment related to sales of the natural gas that it produces. Gains or losses on such derivative financial instruments are recorded as adjustments to revenue; however, they are not considered to be revenue from contracts with customers.

Pipeline and Storage Segment Revenue

The Company's Pipeline and Storage segment records revenue for natural gas transportation and storage services in New York and Pennsylvania at tariff-based rates regulated by the FERC. Customers secure their own gas supply and the Pipeline and Storage segment provides transportation and/or storage services to move the customer-supplied gas to the intended location, including injections into or withdrawals from the storage field. This performance obligation is satisfied over time. The rate design for the Pipeline and Storage segment's customers generally includes a combination of volumetric or commodity charges as well as monthly "fixed" charges (including charges commonly referred to as capacity charges, demand charges, or reservation charges). These types of fixed charges represent compensation for standing ready over the period of the month to deliver quantities of gas, regardless of whether the customer takes delivery of any quantity of gas. The performance obligation under these circumstances is satisfied based on the passage of time and meter reads, if applicable, which correlates to the period for which the charges are eligible to be invoiced. The amount billable, as determined by the meter read and the "fixed" monthly charge, indicates the value to the customer, and is used for revenue recognition purposes by the Pipeline and Storage segment as specified by the "invoice practical expedient" (the amount that the Pipeline and Storage segment has the right to invoice) under the authoritative guidance for revenue recognition. Customers are billed after the end of each calendar month, with payment typically due by the 25th day of the month in which the invoice is received.

The Company's Pipeline and Storage segment expects to recognize the following revenue amounts in future periods related to "fixed" charges associated with remaining performance obligations for transportation and storage contracts: $212.4 million for fiscal 2023; $191.0 million for fiscal 2024; $166.9 million for fiscal 2025; $143.8 million for fiscal 2026; $121.1 million for fiscal 2027; and $691.7 million thereafter.

Gathering Segment Revenue

The Company's Gathering segment provides gathering and processing services in the Appalachian region of Pennsylvania, primarily for Seneca. The Gathering segment's primary performance obligation is to deliver gathered natural gas volumes from Seneca's wells, and to a lesser extent, other producers' wells, into interstate pipelines at contractually agreed upon per unit rates. This obligation is satisfied over time. The performance obligation is satisfied based on the passage of time and meter reads, which correlates to the period for which the charges are eligible to be invoiced. The amount billable, as determined by the meter read and the contracted volumetric rate, indicates the value to the customer, and is used for revenue recognition purposes by the Gathering segment as specified by the "invoice practical expedient" (the amount that the Gathering segment has the right to invoice) under the authoritative guidance for revenue recognition. Customers are billed after the end of each calendar month, with payment typically due by the 10th day after the invoice is received.

Utility Segment Revenue

The Company's Utility segment records revenue for natural gas sales and natural gas transportation services in western New York and northwestern Pennsylvania at tariff-based rates regulated by the NYPSC and the PaPUC, respectively. Natural gas sales and transportation services are provided largely to residential, commercial and industrial customers. The Utility segment's performance obligation to its customers is to deliver natural gas, an obligation which is satisfied over time. This obligation generally remains in effect as long as the customer consumes the natural gas provided by the Utility segment. The Utility segment recognizes revenue when it satisfies its performance obligation by delivering natural gas to the customer. Natural gas is delivered and consumed by the customer simultaneously. The satisfaction of the performance obligation is measured by the turn of the meter dial. The amount billable, as determined by the meter read and the tariff-based rate, indicates the value to the customer, and is used for revenue recognition purposes by the Utility segment as specified by the "invoice practical expedient" (the amount that the Utility segment has the right to invoice) under the authoritative guidance for revenue recognition. Since the Utility segment bills its customers in cycles having billing dates that do not generally coincide with the end of a calendar month, a receivable is recorded for natural gas delivered but not yet billed to customers based on an estimate of the amount of natural gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets. The Utility segment's tariffs allow customers to utilize budget billing. In this situation, since the amount billed may differ from the amount of natural gas delivered to the customer in any given month, revenue is recognized monthly based on the amount of natural gas consumed. The differential between the amount billed and the amount consumed is recorded as a component of Receivables or Customer Advances on the Consolidated Balance Sheets. All receivables or advances related to budget billing are settled within one year.

Utility Segment Alternative Revenue Programs

As indicated in the revenue table shown above, the Company's Utility segment has alternative revenue programs that are excluded from the scope of the authoritative guidance regarding revenue recognition. The NYPSC has authorized alternative revenue programs that are designed to mitigate the impact that weather and conservation have on margin. The NYPSC has also authorized additional alternative revenue programs that adjust billings for the effects of broad external factors or to compensate the Company for demand-side management initiatives. These alternative revenue programs primarily allow the Company and customer to share in variances from imputed margins due to migration of transportation customers, allow for adjustments to the gas cost recovery mechanism for fluctuations in uncollectible expenses associated with gas costs, and allow the Company to pass on to customers costs associated with customer energy efficiency programs. In general, revenue is adjusted monthly for these programs and is collected from or passed back to customers within 24 months of the annual reconciliation period.

Note D — Leases

On October 1, 2019, the Company adopted authoritative guidance regarding lease accounting, which requires entities that lease the use of property, plant and equipment to recognize on the balance sheet the assets and liabilities for the rights and obligations created by all leases, including leases classified as operating leases. The Company implemented the new standard using the optional transition method and elected to apply the following practical expedients provided in the authoritative guidance:

1. For contracts that commenced prior to and existed as of October 1, 2019, a package of practical expedients to not reassess whether a contract is or contains a lease, lease classification, and initial direct costs under the new authoritative guidance;
2. An election not to apply the recognition requirements in the new authoritative guidance to short-term leases (a lease that at commencement date has a lease term of one year or less);
3. A practical expedient to not reassess certain land easements that existed prior to October 1, 2019 and were not previously accounted for as leases under the prior authoritative guidance; and
4. A practical expedient that permits combining lease and non-lease components in a contract and accounting for the combination as a lease (elected by asset-class).

Upon adoption, the Company increased assets and liabilities on its Consolidated Balance Sheet by \$19.7 million. The adoption did not result in a cumulative effect adjustment to earnings reinvested in the business or have a material impact on the Company's Consolidated Statement of Income or Consolidated

Statement of Cash Flows. Comparative periods, including disclosures relating to those periods, were not restated.

Nature of Leases

The Company primarily leases building space and drilling rigs, and on a limited basis, compressor equipment and other miscellaneous assets. The Company determines if an arrangement is a lease at the inception of the arrangement. To the extent that an arrangement represents a lease, the Company classifies that lease as an operating or a finance lease in accordance with the authoritative guidance. The Company did not have any material finance leases as of September 30, 2022 or September 30, 2021. Aside from a sublease of office space at the Company's corporate headquarters, which terminated April 30th, 2022, the Company does not have any material arrangements where the Company is the lessor.

Buildings and Property

The Company enters into building and property rental agreements with third parties for office space, certain field locations and other properties used in the Company's operations. Building and property leases include the Company's corporate headquarters in Williamsville, New York, and Exploration and Production segment offices in Houston, Texas, and Pittsburgh, Pennsylvania. The primary non-cancelable terms of the Company's building and property leases range from two months to seventeen years. Most building leases include one or more options to renew, generally at the Company's sole discretion, with renewal terms that can extend the lease terms from one year to eighteen years. Renewal options are included in the lease term if they are reasonably certain to be exercised. The agreements do not contain any material restrictive covenants.

Drilling Rigs

The Company enters into contracts for drilling rig services with third party contractors to support Seneca's development activities in Pennsylvania. Seneca's drilling rig arrangements are structured with a non-cancelable primary term that exceeds one year. Upon mutual agreement with the contractor, Seneca has the option to extend contracts with amended terms and conditions, including a renegotiated day rate fee.

Drilling rig lease costs are capitalized as part of natural gas properties on the Consolidated Balance Sheet when incurred.

Compressor Equipment

The Company enters into contracts for compressor services with third parties primarily to support its gathering system in Pennsylvania. The primary non-cancelable terms of the Company's compressor equipment leases range from 21 months to 4 years. Most compressor equipment leases include one or more options to renew or to continue past the primary term on a month-to-month basis, generally at the Company's sole discretion. Renewal options are included in the lease term if they are reasonably certain to be exercised.

Significant Judgments

Lease Identification

The Company uses judgment when determining whether or not an arrangement is or contains a lease. A contract is or contains a lease if the contract conveys the right to use an explicitly or implicitly identified asset that is physically distinct and the Company has the right to control the use of the identified asset for a period of time. When determining right of control, the Company evaluates whether it directs the use of the asset and obtains substantially all of the economic benefits from the use of the asset.

Discount Rate

The Company uses a discount rate to calculate the present value of lease payments in order to determine lease classification and measurement of the lease asset and liability. In the absence of a rate of interest that is readily determinable in the contract, the Company estimates the incremental borrowing rate (IBR) for each lease. The IBR reflects the rate of interest that the Company would pay on the lease commencement date to borrow an amount equal to the lease payments on a collateralized basis over a similar term in similar economic environments.

Firm Transportation and Storage Contracts

The Company's subsidiaries enter into long-term arrangements to both reserve firm transportation capacity on third party pipelines and provide firm transportation and storage services to third party shippers. The Company's firm capacity contracts with non-affiliated entities do not provide rights to use substantially all of the underlying pipeline or storage asset. As such, the Company has concluded that these arrangements are not leases under the authoritative guidance.

Gas Leases

The authoritative guidance does not apply to leases to explore for or use natural gas resources, including the right to explore for those resources and rights to use the land in which those resources are contained. As such, the Company has concluded that its gas exploration and production leases and gas storage leases are not leases under the authoritative guidance.

Amounts Recognized in the Financial Statements

Operating lease costs, excluding those relating to drilling rig leases that are capitalized as part of oil and natural gas properties under full cost pool accounting, are presented in Operations and Maintenance expense on the Consolidated Statement of Income. The following table summarizes the components of the Company's total operating lease costs (in thousands):

	Year Ended September 30	
	2022	2021
Operating Lease Expense	$ 4,909	$ 5,268
Variable Lease Expense(1)	462	537
Short-Term Lease Expense(2)	461	1,279
Sublease Income	(166)	(356)
Total Lease Expense	$ 5,666	$ 6,728
Lease Costs Recorded to Property, Plant and Equipment(3)	$ 19,839	$ 14,188

(1) Variable lease payments that are not dependent on an index or rate are not included in the lease liability.
(2) Short-term lease costs exclude expenses related to leases with a lease term of one month or less.
(3) Lease costs relating to drilling rig leases that are capitalized as part of oil and natural gas properties under full cost pool accounting as well as certain equipment leases used on construction projects.

Right-of-use assets and lease liabilities are recognized at the commencement date of a leasing arrangement based on the present value of lease payments over the lease term. The weighted average remaining lease term was 6.0 years and 8.8 years as of September 30, 2022 and 2021, respectively. The weighted average discount rate was 3.92% and 4.24% as of September 30, 2022 and 2021, respectively.

The Company's right-of-use operating lease assets are reflected as Deferred Charges on the Consolidated Balance Sheet. The corresponding operating lease liabilities are reflected in Other Accruals and Current Liabilities (current) and Other Liabilities (noncurrent). Short-term leases that have a lease term of one year or less are not recorded on the Consolidated Balance Sheet.

The following amounts related to operating leases were recorded on the Company's Consolidated Balance Sheet (in thousands):

	Year Ended September 30	
	2022	2021
Assets:		
Deferred Charges	$ 37,120	$ 23,601
Liabilities:		
Other Accruals and Current Liabilities	$ 14,239	$ 3,963
Other Liabilities	$ 22,881	$ 19,638

Cash paid for lease liabilities, and reported in cash provided by operating activities on the Company's Consolidated Statement of Cash Flows, was $5.7 million and $6.7 million for the years ended September 30, 2022 and 2021, respectively. The Company did not record any right-of-use assets in exchange for new lease liabilities during the years ended September 30, 2022 or 2021.

The following schedule of operating lease liability maturities summarizes the undiscounted lease payments owed by the Company to lessors pursuant to contractual agreements in effect as of September 30, 2022 (in thousands):

	At September 30, 2022
2023	$ 14,420
2024	5,353
2025	4,828
2026	3,578
2027	2,889
Thereafter	11,656
Total Lease Payments	42,724
Less: Interest	(5,604)
Total Lease Liability	$ 37,120

Note E — Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with the authoritative guidance that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. An asset retirement obligation is defined as a legal obligation associated with the retirement of a tangible long-lived asset in which the timing and/or method of settlement may or may not be conditional on a future event that may or may not be within the control of the Company. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. The Company estimates the fair value of its asset retirement obligations based on the discounting of expected cash flows using various estimates, assumptions and judgments regarding certain factors such as the existence of a legal obligation for an asset retirement obligation; estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements as the inputs used to measure the fair value are unobservable.

The Company has recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment's natural gas wells and has capitalized such costs in property, plant and equipment (i.e. the full cost pool). During fiscal 2021, this segment's Appalachian operations were required to implement additional water testing on a portion of its assets, which contributed to an increase in the asset retirement obligation. This increase is the primary component of the Revisions of Estimates amount for fiscal 2021 shown in the table below.

In addition to the asset retirement obligation recorded in the Exploration and Production segment, the Company has recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. Asset retirement obligation costs related to storage tanks have been recorded in the Utility, Pipeline and Storage, and Gathering segments. The Company has also recorded asset retirement obligations for certain costs connected with the retirement of the distribution mains, services and other components of the pipeline system in the Utility segment, the transmission mains and other components in the pipeline system in the Pipeline and Storage segment, and the gathering lines and other components in the Gathering segment. The retirement costs within the distribution, transmission and gathering systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

As discussed in Note B — Asset Acquisitions and Divestitures, on June 30, 2022, the Company completed the sale of Seneca's California oil and gas assets to Sentinel Peak Resources California LLC. With the divestiture of these assets, the Company reduced its Asset Retirement Obligation at June 30, 2022 by $50.1 million. This reduction is reflected in Liabilities Settled in the table below.

As discussed in Note B — Asset Acquisitions and Divestitures, on July 31, 2020, the Company completed its acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from Shell. With the acquisition of these assets, the Company recorded an additional $57.2 million to its Asset Retirement Obligation at September 30, 2020, which is reflected in Liabilities Incurred in the table below. The following is a reconciliation of the change in the Company's asset retirement obligations:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Balance at Beginning of Year	$ 209,639	$ 192,228	$ 127,458
Liabilities Incurred	2,401	7,035	61,246
Revisions of Estimates	10,700	14,509	3,267
Liabilities Settled	(71,171)	(14,270)	(7,268)
Accretion Expense	9,976	10,137	7,525
Balance at End of Year	$ 161,545	$ 209,639	$ 192,228

Note F — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30 2022	At September 30 2021
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note K)	$ 11,677	$ 21,655
Post-Retirement Benefit Costs(2) (Note K)	6,814	10,075
Recoverable Future Taxes (Note G)	106,247	121,992
Environmental Site Remediation Costs(2) (Note L)	3,646	7,256
Asset Retirement Obligations(2) (Note E)	18,517	16,799
Unamortized Debt Expense (Note A)	8,884	10,589
Other(3)	47,805	33,566
Total Regulatory Assets	203,590	221,932
Less: Amounts Included in Other Current Assets	(21,358)	(29,206)
Total Long-Term Regulatory Assets	$ 182,232	$ 192,726

	At September 30 2022	At September 30 2021
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	$ 259,947	$ 245,636
Taxes Refundable to Customers (Note G)	362,098	354,089
Post-Retirement Benefit Costs(5) (Note K)	167,305	213,112
Pension Costs(4) (Note K)	8,242	—
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	419	21
Other(6)	44,549	48,391
Total Regulatory Liabilities	842,560	861,249
Less: Amounts included in Current and Accrued Liabilities	(31,712)	(60,881)
Total Long-Term Regulatory Liabilities	$ 810,848	$ 800,368

(1) The Company recovers the cost of its regulatory assets but generally does not earn a return on them. There are a few exceptions to this rule. For example, the Company does earn a return on Unrecovered Purchased Gas Costs and, in the New York jurisdiction of its Utility segment, earns a return, within certain parameters, on the excess of cumulative funding to the pension plan over the cumulative amount collected in rates.

(2) Included in Other Regulatory Assets on the Consolidated Balance Sheets.

(3) $21,358 and $29,206 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $26,447 and $4,360 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively.

(4) Included in Other Regulatory Liabilities on the Consolidated Balance Sheets.

(5) $5,800 and $30,000 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively, since such amounts are expected to be passed back to ratepayers in the next 12 months. $161,505 and $183,112 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively.

(6) $25,493 and $30,860 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively, since such amounts are expected to be passed back to ratepayers in the next 12 months. $19,056 and $17,531 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively.

If for any reason the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheets and included in income of the period in which the discontinuance of regulatory accounting treatment occurs.

Cost of Removal Regulatory Liability

In the Company’s Utility and Pipeline and Storage segments, costs of removing assets (i.e. asset retirement costs) are collected from customers through depreciation expense. These amounts are not a legal retirement obligation as discussed in Note E — Asset Retirement Obligations. Rather, they are classified as a regulatory liability in recognition of the fact that the Company has collected dollars from customers that will be used in the future to fund asset retirement costs.

New York Jurisdiction

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on April 20, 2017 with rates becoming effective May 1, 2017. The order provided for a return on equity of 8.7%, and directed the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018. The order also authorized the Company to recover approximately $15 million annually for pension and OPEB expenses from customers. Because the Company’s future pension and OPEB costs were projected to be satisfied with existing funds held in reserve, in July, Distribution Corporation made a filing with the NYPSC to effectuate a pension and OPEB surcredit to customers to offset these amounts being collected in base rates effective October 1, 2022. On September 16, 2022, the NYPSC issued an order approving the filing. With the implementation of this surcredit, Distribution Corporation will no longer be funding the pension from its New York jurisdiction and it will not be funding its VEBA trusts in its New York jurisdiction.

Pennsylvania Jurisdiction

Distribution Corporation’s current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007. On October 28, 2022, Distribution Corporation made a filing with the PaPUC seeking an increase in its annual base rate operating revenues of $28.1 million with a proposed effective date of December 27, 2022. The Company is also proposing, among other things, to implement a weather normalization adjustment mechanism and a new energy efficiency and conservation pilot program for residential customers. The filing will be suspended for seven months by operation of law unless directed otherwise by the PaPUC.

Effective October 1, 2021, pursuant to a tariff supplement filed with the PaPUC, Distribution Corporation reduced base rates by $7.7 million in order to stop collecting OPEB expenses from customers. It also began to refund customers overcollected OPEB expenses in the amount of $50.0 million. Certain other matters in the tariff supplement were unresolved. These matters were resolved with the PaPUC’s approval of an Administrative Law Judge’s Recommended Decision on February 24, 2022. Concurrent with that decision, the Company discontinued regulatory accounting for OPEB expenses and recorded an $18.5 million adjustment during the quarter ended March 31, 2022 to reduce its regulatory liability for previously deferred OPEB income amounts through September 30, 2021 and to increase Other Income (Deductions) on the consolidated financial statements by a like amount. The Company also increased customer refunds of overcollected OPEB expenses from $50.0 million to $54.0 million. All refunds specified in the tariff supplement are being funded entirely by grantor trust assets held by the Company, most of which are included in a fixed income mutual fund that is a component of Other Investments on the Company's Consolidated Balance Sheet. With the elimination of OPEB expenses in base rates, Distribution Corporation is no longer funding the grantor trust or its VEBA trusts in its Pennsylvania jurisdiction.

FERC Jurisdiction

Supply Corporation's 2020 rate settlement provides that no party may make a rate filing for new rates to be effective before February 1, 2024, except that Supply Corporation may file an NGA general Section 4 rate case to change rates if the corporate federal income tax rate is increased. If no case has been filed, Supply Corporation must file for rates to be effective February 1, 2025.

Empire's 2019 rate settlement provides that Empire must make a rate case filing no later than May 1, 2025.

Note G — Income Taxes

The components of federal and state income taxes included in the Consolidated Statements of Income are as follows:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Current Income Taxes —			
Federal	$ —	$ (10)	$ (42,548)
State	12,214	8,699	6,974
Deferred Income Taxes —			
Federal	137,025	90,970	4,538
State	(32,610)	15,023	49,775
Total Income Taxes	$ 116,629	$ 114,682	$ 18,739

On March 27, 2020, the "Coronavirus Aid, Relief and Economic Security (CARES) Act" was signed into law. The CARES Act, among other things, includes provisions relating to alternative minimum tax (AMT) credit refunds, refundable payroll tax credits, deferment of employer side social security payments, net operating loss carryback periods, and modifications to the net interest deduction limitation. The Company filed for the acceleration of the remaining AMT credit refunds (under CARES) of $42.5 million, which were received in June 2020.

On July 8, 2022, House Bill 1342 was signed into law in Pennsylvania. The law reduces the corporate income tax rate to 8.99% for fiscal 2024. Starting with fiscal 2025, the rate is reduced by 0.5% annually until it reaches 4.99% for fiscal 2032. Under GAAP, the tax effects of a change in tax law must be recognized in the period in which the law is enacted. GAAP also requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. The Company's deferred income taxes were re-measured based upon the new tax rates. For the Company's non-rate regulated activities, the change in deferred income taxes was $28.4 million as of the enactment date and was recorded as a reduction to income tax expense. For the Company's rate regulated activities, the reduction in deferred income taxes of $37.2 million was recorded as a decrease to Recoverable Future Taxes of $19.8 million and an increase to Taxes Refundable to Customers of $17.4 million.

On August 16, 2022, the "Inflation Reduction Act" (IRA) was signed into law. The IRA, among other things, includes provisions to expand energy incentives and impose a corporate minimum tax. The provisions of the IRA did not have a material impact on the fiscal 2022 financial statements, although some of the provisions may be applicable in future years.

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income (loss) before income taxes. The following is a reconciliation of this difference:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
U.S. Income (Loss) Before Income Taxes (1)	$ 682,650	$ 478,327	$ (105,046)
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 21%	$ 143,357	$ 100,449	$ (22,060)
State Valuation Allowance (2)	(24,850)	(5,560)	63,205
State Income Taxes (Benefit) (3)	8,736	24,300	(18,374)
Amortization of Excess Deferred Federal Income Taxes	(5,184)	(5,215)	(4,749)
Plant Flow Through Items	(814)	(1,503)	(2,848)
Stock Compensation	820	2,239	3,867
Federal Tax Credits	(5,701)	(310)	(217)
Miscellaneous	265	282	(85)
Total Income Taxes	$ 116,629	$ 114,682	$ 18,739

(1) Amounts include the impact of deferred investment tax credits reported in Other Income (Deductions) on the Consolidated Statements of Income.

(2) During fiscal 2020, a valuation allowance was recorded against certain state deferred tax assets. During fiscal 2022, the valuation allowance was removed. See discussion below.

(3) The state income tax expense (benefit) shown above includes adjustments to the estimated state effective tax rates utilized in the calculation of deferred income taxes, including the Pennsylvania rate change discussed above.

Significant components of the Company’s deferred tax liabilities and assets were as follows:

	At September 30	
	2022	2021
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 954,757	$ 920,692
Pension and Other Post-Retirement Benefit Costs	30,132	23,240
Other	48,893	35,081
Total Deferred Tax Liabilities	1,033,782	979,013
Deferred Tax Assets:		
Unrealized Hedging Losses	(215,187)	(170,155)
Tax Loss and Credit Carryforwards	(50,686)	(120,725)
Pension and Other Post-Retirement Benefit Costs	(37,250)	(53,765)
Other	(32,430)	(31,593)
Total Gross Deferred Tax Assets	(335,553)	(376,238)
Valuation Allowance	—	57,645
Total Deferred Tax Assets	(335,553)	(318,593)
Total Net Deferred Income Taxes	$ 698,229	$ 660,420

The following is a summary of changes in valuation allowances for deferred tax assets:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Balance at Beginning of Year	$ 57,645	$ 63,205	$ —
Additions	—	—	63,205
Deductions	57,645	5,560	—
Balance at End of Year	$ —	$ 57,645	$ 63,205

A valuation allowance for deferred tax assets, including net operating losses and tax credits, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized. The Company, at each reporting date, assesses the realizability of its deferred tax assets, including factors such as future taxable income, reversal of existing temporary differences, and tax planning strategies. The Company considers both positive and negative evidence related to the likelihood of the realization of the deferred tax assets. As of March 31, 2020, the Company recorded a valuation allowance against certain state deferred tax assets based on its conclusion, considering all available objective evidence and the Company's history of subsidiary state tax losses, that it was more likely than not that the deferred tax assets would not be realized. On June 30, 2022, the Company completed the sale of Seneca's California oil and gas assets to Sentinel Peak Resources California, LLC. As a result of the sale of the California oil and gas assets, the remaining deferred tax assets and valuation allowance of approximately $27.2 million related to the California net operating loss and tax credit carryforwards were written off. The deferred tax assets and valuation allowance were written off as the Company determined that there was a remote possibility for use as the Company no longer has California operations. During the quarter ended September 30, 2022, the valuation allowance was adjusted because of the Pennsylvania corporate income tax rate change remeasurement described above and for current activity for a cumulative adjustment of $5.5 million. In addition, the Company determined there was sufficient positive evidence, despite a prior history of subsidiary tax losses, to conclude that it was more likely than not that the remaining state deferred tax assets would be realized. The conclusion was primarily related to the use of net operating losses in Pennsylvania in the current year due to sustained strong operating results as well as the expectation for future forecasted earnings in Pennsylvania due to increased natural gas prices. The sale of California assets will also result in higher apportionment of income to Pennsylvania on a prospective basis, further supporting realization of existing Pennsylvania net operating loss deferred tax assets. Accordingly, the Company reversed the remaining valuation allowance and recognized an income tax benefit of approximately $24.9 million.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $362.1 million and $354.1 million at September 30, 2022 and 2021, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of ratemaking practices, amounted to $106.2 million and $122.0 million at September 30, 2022 and 2021, respectively.

The Company is in the Bridge Phase of the IRS Compliance Assurance Process ("CAP") for fiscal 2022. The Bridge Phase is intended for taxpayers with a low risk of non-compliance who are cooperative and transparent with few, if any, material issues that require resolution. The IRS will not accept any disclosures, conduct any reviews, or provide any letters of assurance for the Bridge year. The federal statute of limitations remains open for fiscal 2019 and later years. The Company is also subject to various routine state income tax examinations. The Company's principal subsidiaries have state statutes of limitations that generally expire between three to four years from the date of filing of the income tax return. Net operating losses being carried forward from prior years remain subject to examination on a future return until they are utilized, upon which time the statute of limitation begins. The Company has no unrecognized tax benefits as of September 30, 2022, 2021, or 2020.

During fiscal 2009, preliminary consent was received from the IRS National Office approving the Company's application to change its tax method of accounting for certain capitalized costs relating to its utility property, subject to final guidance. The Company is awaiting the issuance of IRS guidance addressing the issue for natural gas utilities.

Tax carryforwards available, prior to valuation allowance, at September 30, 2022, were as follows:

Jurisdiction	Tax Attribute	Amount (Thousands)	Expires
Pennsylvania	Net Operating Loss	$ 378,631	2030-2042
Federal	General Business Credits	20,677	2035-2042

Note H — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock		Paid In Capital	Earnings Reinvested in the Business		Accumulated Other Comprehensive Loss
	Shares	Amount				
	(Thousands, except per share amounts)					
Balance at September 30, 2019	86,315	$86,315	$ 832,264	$1,272,601		$ (52,155)
Net Loss Available for Common Stock				(123,772)		
Dividends Declared on Common Stock ($1.76 Per Share)				(156,249)		
Cumulative Effect of Adoption of Authoritative Guidance for Hedging				(950)		
Other Comprehensive Loss, Net of Tax						(62,602)
Share-Based Payment Expense(1)			13,180			
Common Stock Issued from Sale of Common Stock	4,370	4,370	161,399			
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	270	270	(2,685)			
Balance at September 30, 2020	90,955	90,955	1,004,158	991,630		(114,757)
Net Income Available for Common Stock				363,647		
Dividends Declared on Common Stock ($1.80 Per Share)				(164,102)		
Other Comprehensive Loss, Net of Tax						(398,840)
Share-Based Payment Expense(1)			15,297			
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	227	227	(2,009)			
Balance at September 30, 2021	91,182	91,182	1,017,446	1,191,175		(513,597)
Net Income Available for Common Stock				566,021		
Dividends Declared on Common Stock ($1.86 Per Share)				(170,111)		
Other Comprehensive Loss, Net of Tax						(112,136)
Share-Based Payment Expense(1)			17,699			
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	296	296	(8,079)			
Balance at September 30, 2022	91,478	$91,478	$1,027,066	$1,587,085	(2)	$ (625,733)

(1) Paid in Capital includes compensation costs associated with performance shares and/or restricted stock awards. The expense is included within Net Income Available for Common Stock, net of tax benefits.

(2) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2022, $1.4 billion of accumulated earnings was free of such limitations.

Common Stock

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent. During 2022, the Company did not issue any original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan or the Company's 401(k) plans.

During 2022, the Company issued 30,769 original issue shares of common stock as a result of SARs exercises, 129,169 original issue shares of common stock for restricted stock units that vested and 265,607 original issue shares of common stock for performance shares that vested. Holders of stock-based compensation awards will often tender shares of common stock to the Company for payment of applicable withholding taxes. During 2022, 157,812 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

The Company also has a director stock program under which it issues shares of Company common stock to the non-employee directors of the Company who receive compensation under the Company's 2009 Non-Employee Director Equity Compensation Plan, including the reinvestment of dividends for certain non-employee directors who elected to defer their shares pursuant to the dividend reinvestment feature of the Company's Deferred Compensation Plan for Directors and Officers, as partial consideration for the directors' services during the fiscal year. Under this program, the Company issued 28,782 original issue shares of common stock during 2022.

On June 2, 2020, the Company completed a public offering and sale of 4,370,000 shares of the Company's common stock, par value $1.00 per share, at a price of $39.50 per share. After deducting fees, commissions and other issuance costs, the net proceeds to the Company amounted to $165.8 million. The proceeds of this issuance were used to fund a portion of the purchase price of the acquisition of Shell's upstream assets and midstream gathering assets in Pennsylvania that closed on July 31, 2020. Refer to Note B — Asset Acquisitions and Divestitures for further discussion.

Stock Award Plans

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares.

Stock-based compensation expense for the years ended September 30, 2022, 2021 and 2020 was approximately $17.6 million, $15.2 million and $13.1 million, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statements of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2022, 2021 and 2020 was approximately $2.5 million, $2.4 million and $2.1 million, respectively. A portion of stock-based compensation expense is subject to capitalization under IRS uniform capitalization rules. Stock-based compensation of $0.1 million was capitalized under these rules during each of the years ended September 30, 2022, 2021 and 2020. The tax benefit related to stock-based compensation exercises and vestings was $0.6 million for the year ended September 30, 2022.

Pursuant to registration statements for these plans, there were 2,149,203 shares available for future grant at September 30, 2022. These shares include shares available for future options, SARs, restricted stock and performance share grants.

SARs

Transactions for 2022 involving SARs for all plans are summarized as follows:

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2021	318,445	$ 53.60		
Granted in 2022	—	$ —		
Exercised in 2022	(241,437)	$ 55.73		
Forfeited in 2022	—	$ —		
Expired in 2022	(5,000)	$ 55.09		
Outstanding at September 30, 2022	72,008	$ 53.05	0.22	$ 612
SARs exercisable at September 30, 2022	72,008	$ 53.05	0.22	$ 612

The Company did not grant any SARs during the years ended September 30, 2021 and 2020. The Company's SARs include both performance based and nonperformance-based SARs, but the performance conditions associated with the performance based SARs at the time of grant have all been subsequently met. The SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for SARs is the same as the accounting for stock options.

The total intrinsic value of SARs exercised during the years ended September 30, 2022 totaled approximately $2.0 million. During the years ended September 30, 2021 and 2020, no SARs were exercised. There were no SARs that became fully vested during the years ended September 30, 2022, 2021 and 2020, and all SARs outstanding have been fully vested since fiscal 2017.

Restricted Stock Units

Transactions for 2022 involving nonperformance-based restricted stock units for all plans are summarized as follows:

	Number of Restricted Stock Units	Weighted Average Fair Value per Award
Outstanding at September 30, 2021	365,481	$ 41.45
Granted in 2022	128,950	$ 54.10
Vested in 2022	(129,169)	$ 45.24
Forfeited in 2022	(17,835)	$ 44.61
Outstanding at September 30, 2022	347,427	$ 44.58

The Company also granted 172,513 and 150,839 nonperformance-based restricted stock units during the years ended September 30, 2021 and 2020, respectively. The weighted average fair value of such nonperformance-based restricted stock units granted in 2021 and 2020 was $37.98 per share and $40.38 per share, respectively. As of September 30, 2022, unrecognized compensation expense related to nonperformance-based restricted stock units totaled approximately $6.4 million, which will be recognized over a weighted average period of 2.2 years.

Vesting restrictions for the nonperformance-based restricted stock units outstanding at September 30, 2022 will lapse as follows: 2023 — 119,612 units; 2024 — 97,614 units; 2025 — 73,797 units; 2026 — 37,052 units; and 2027 — 19,352 units.

Performance Shares

Transactions for 2022 involving performance shares for all plans are summarized as follows:

	Number of Performance Shares	Weighted Average Fair Value per Award
Outstanding at September 30, 2021	600,634	$ 45.13
Granted in 2022	195,397	$ 65.39
Vested in 2022	(265,607)	$ 55.93
Forfeited in 2022	(23,414)	$ 49.84
Change in Units Based on Performance Achieved	100,169	$ 56.36
Outstanding at September 30, 2022	607,179	$ 48.60

The Company also granted 309,470 and 254,608 performance shares during the years ended September 30, 2021 and 2020, respectively. The weighted average grant date fair value of such performance shares granted in 2021 and 2020 was $39.19 per share and $43.32 per share, respectively. As of September 30, 2022, unrecognized compensation expense related to performance shares totaled approximately $11.3 million, which will be recognized over a weighted average period of 1.8 years. Vesting restrictions for the outstanding performance shares at September 30, 2022 will lapse as follows: 2023 — 199,842 shares; 2024 — 220,914 shares; and 2025 — 186,423 shares.

The performance shares granted during the years ended September 30, 2022, 2021 and 2020 include awards that must meet a performance goal related to either relative return on capital over a three-year performance cycle ("ROC performance shares"), methane intensity and greenhouse gas emissions reductions over a three-year performance cycle ("ESG performance shares") or relative shareholder return over a three-year performance cycle ("TSR performance shares"). The performance goal over the respective performance cycles for the ROC performance shares granted during 2022, 2021 and 2020 is the Company's total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee ("Report Group"). Total return on capital for a given company means the average of the Report Group companies' returns on capital for each twelve-month period corresponding to each of the Company's fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these ROC performance shares that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value of the ROC performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award.

The performance goal over the performance cycle for the ESG performance shares granted during 2022 consists of two parts: reductions in the rates of intensity of methane emissions for each of the Company's operating segments, and reduction of the consolidated Company's total greenhouse gas emissions. The Company's Compensation Committee set specific target levels for methane intensity rates and total greenhouse gas emissions, and the performance goal is intended to incentivize and reward performance that helps position the Company to meet or exceed its 2030 methane intensity and greenhouse gas reduction targets. The number of these ESG performance shares that will vest and be paid out will depend upon the number of methane intensity segment targets achieved and whether the Company meets the total greenhouse gas emissions target. The fair value of these ESG performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award. There were no ESG performance shares granted in 2021 and 2020.

The performance goal over the respective performance cycles for the TSR performance shares granted during 2022, 2021 and 2020 is the Company's three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year total shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company's securities at each ex-dividend date) in the Bloomberg database. The number of these TSR performance shares that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value price at the date of grant for the TSR performance shares is determined using a Monte Carlo simulation technique, which includes a reduction in value for the present value of forgone dividends over the vesting term of the award. This price is multiplied by the number of TSR performance shares awarded, the result of which is recorded as compensation expense over the vesting term of the award. In calculating the fair value of the award, the risk-free interest rate is based on the yield of a Treasury Note with a term commensurate with the remaining term of the TSR performance shares. The remaining term is based on the remainder of the performance cycle as of the date of grant. The expected volatility is based on historical daily stock price returns. For the TSR performance shares, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees. The following assumptions were used in estimating the fair value of the TSR performance shares at the date of grant:

	Year Ended September 30		
	2022	2021	2020
Risk-Free Interest Rate	0.85 %	0.19 %	1.63 %
Remaining Term at Date of Grant (Years)	2.80	2.80	2.81
Expected Volatility	29.7 %	29.1 %	19.3 %
Expected Dividend Yield (Quarterly)	N/A	N/A	N/A

Redeemable Preferred Stock

As of September 30, 2022, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

Long-Term Debt

The outstanding long-term debt is as follows:

	At September 30	
	2022	2021
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	$ 99,000	$ 99,000
Notes(1)(2)(3):		
2.95% to 5.50% due March 2023 to March 2031	2,550,000	2,550,000
Total Long-Term Debt	2,649,000	2,649,000
Less Unamortized Discount and Debt Issuance Costs	16,591	20,313
Less Current Portion(4)	549,000	—
	$ 2,083,409	$ 2,628,687

(1) The Medium-Term Notes and Notes are unsecured.

(2) The holders of these notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade.

(3) The interest rate payable on $300.0 million of 4.75% notes, $300.0 million of 3.95% notes and $500.0 million of 2.95% notes will be subject to adjustment from time to time, with a maximum of 2.00%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to below investment grade (or if the credit rating assigned to the notes is subsequently upgraded). The interest rate payable on $500.0 million of 5.50% notes will be subject to adjustment from time to time, with a maximum adjustment of 2.00%, such that the coupon will not exceed 7.50%, if there is a downgrade of the credit rating assigned to the notes to a rating below investment grade. A downgrade with a resulting increase to the coupon does not preclude the coupon from returning to its original rate if the Company's credit rating is subsequently upgraded.

(4) Current Portion of Long-Term Debt at September 30, 2022 consists of $500.0 million of 3.75% notes and $49.0 million of 7.395% notes that each mature in March 2023. The Company has committed to redeeming $150.0 million of the 3.75% notes on November 25, 2022. None of the Company's long-term debt as of September 30, 2021 had a maturity date within the following twelve-month period.

On February 24, 2021, the Company issued $500.0 million of 2.95% notes due March 1, 2031. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.3 million. The proceeds of this debt issuance were used for general corporate purposes, including the redemption of $500.0 million of 4.90% notes on March 11, 2021 that were scheduled to mature in December 2021. The Company redeemed those notes for $515.7 million, plus accrued interest. The early redemption premium of $15.7 million was recorded to Interest Expense on Long-Term Debt on the Consolidated Income Statement during the quarter ended March 31, 2021.

On June 3, 2020, the Company issued $500.0 million of 5.50% notes due January 15, 2026. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $493.0 million. The proceeds of this debt issuance were used for general corporate purposes, which included the payment of a portion of the purchase price of the acquisition of Shell's upstream assets and midstream gathering assets in Pennsylvania that closed on July 31, 2020 and the repayment and refinancing of short-term debt.

As of September 30, 2022, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $549.0 million in 2023, zero in 2024, $500.0 million in 2025, $500.0 million in 2026, $300.0 million in 2027, and $800.0 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. On February 28, 2022, the Company entered into a Credit Agreement (as amended from time to time, the "Credit Agreement") with a syndicate of twelve banks. The Credit Agreement replaced the previous Fourth Amended and Restated Credit Agreement and a previous 364-Day Credit Agreement. The Credit Agreement provides a $1.0 billion unsecured committed revolving credit facility with a maturity date of February 26, 2027.

On June 30, 2022, the Company entered into a new 364-Day Credit Agreement (the "364-Day Credit Agreement") with a syndicate of five banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional $250.0 million unsecured committed delayed draw term loan credit facility with a maturity date of June 29, 2023. The Company elected to draw $250.0 million under the facility on October 27, 2022. The Company is using the proceeds for general corporate purposes, which will include the redemption in November of a portion of the Company's outstanding long-term debt maturing in March 2023.

The Company also has uncommitted lines of credit with financial institutions for general corporate purposes. Borrowings under these uncommitted lines of credit would be made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institution and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future. The total amount available to be issued under the Company's commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement.

At September 30, 2022, the Company had outstanding short-term notes payable to banks of $60.0 million, all of which was issued under the Credit Agreement, with an interest rate of 4.02%. The Company did not have any outstanding commercial paper at September 30, 2022. The Company had outstanding commercial paper of $158.5 million at September 30, 2021, with a weighted average interest rate on the commercial paper of 0.40%. The Company did not have any outstanding short-term notes payable to banks at September 30, 2021.

Debt Restrictions

The Credit Agreement provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $400 million. Since July 1, 2018, the Company recorded non-cash, after-tax ceiling test impairments totaling $381.4 million. As a result, at September 30, 2022, $190.7 million was added back to the Company's total capitalization for purposes of the calculation under the Credit Agreement and 364-Day Credit Agreement. On May 3, 2022, the Company entered into Amendment No. 1 to the Credit Agreement with the same twelve banks under the initial Credit Agreement. The amendment further modified the definition of consolidated capitalization, for purposes of calculating the debt to capitalization ratio under the Credit Agreement, to exclude, beginning with the quarter ended June 30, 2022, all unrealized gains or losses on commodity-related derivative financial instruments and up to $10 million in unrealized gains or losses on other derivative financial instruments included in Accumulated Other Comprehensive Income (Loss) within Total Comprehensive Shareholders' Equity on the Company's consolidated balance sheet. Under the Credit Agreement, such unrealized losses will not negatively affect the calculation of the debt to capitalization ratio, and such unrealized gains will not positively affect the calculation. The 364-Day Credit Agreement includes the same debt to capitalization covenant and the same exclusions of unrealized gains or losses on derivative financial instruments as the Credit Agreement. At September 30, 2022, the Company's debt to capitalization ratio, as calculated under the Credit Agreement and 364-Day Credit Agreement, was .49. The constraints specified in the Credit Agreement and 364-Day Credit Agreement would have permitted an additional $2.56 billion in short-term and/or long-term debt to be outstanding at September 30, 2022 (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources.

The Credit Agreement and 364-Day Credit Agreement contain a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement and 364-Day Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity.

In order to issue incremental long-term debt, the Company must meet an interest coverage test under its existing indenture covenants. In general, the Company’s operating income, subject to certain adjustments, over a consecutive 12-month period within the 15 months preceding the debt issuance, must be not less than two times the total annual interest charges on the Company’s long-term debt, taking into account the incremental issuance. In addition, taking into account the incremental issuance, and using a pro forma balance sheet as of the last day of the 12-month period used in the interest coverage test, the Company must maintain a ratio of long-term debt to consolidated assets (as defined under the indenture) of not more than 60%. Under the Company's existing indenture covenants at September 30, 2022, the Company would have been permitted to issue up to a maximum of approximately $2.0 billion in additional unsubordinated long-term indebtedness at then current market interest rates, in addition to being able to issue new indebtedness to replace existing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. It is possible, depending on amounts reported in various income statement and balance sheet line items, that the indenture covenants could, for a period of time, prevent the Company from issuing incremental unsubordinated long-term debt, or significantly limit the amount of such debt that could be issued. Losses incurred as a result of significant impairments of oil and gas properties have in the past resulted in such temporary restrictions. The indenture covenants would not preclude the Company from issuing new long-term debt to replace existing long-term debt, or from issuing additional short-term debt. Please refer to Part II, Item 7, Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.

The Company’s 1974 indenture pursuant to which $99.0 million (or 3.7%) of the Company’s long-term debt (as of September 30, 2022) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

Note I — Fair Value Measurements

The FASB authoritative guidance regarding fair value measurements establishes a fair-value hierarchy and prioritizes the inputs used in valuation techniques that measure fair value. Those inputs are prioritized into three levels. Level 1 inputs are unadjusted quoted prices in active markets for assets or liabilities that the Company can access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly at the measurement date. Level 3 inputs are unobservable inputs for the asset or liability at the measurement date. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following table sets forth, by level within the fair value hierarchy, the Company’s financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of September 30, 2022 and 2021. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over-the-counter swaps combines gas and oil swaps because a significant number of the counterparties have historically entered into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At Fair Value as of September 30, 2022				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$ 35,015	$ —	$ —	$ —	$ 35,015
Hedging Collateral Deposits	91,670	—	—	—	91,670
Derivative Financial Instruments:					
Over the Counter Swaps — Gas	—	5,177	—	(4,178)	999
Contingent Consideration for Asset Sale	—	8,176	—	—	8,176
Foreign Currency Contracts	—	128	—	(128)	—
Other Investments:					
Balanced Equity Mutual Fund	19,506	—	—	—	19,506
Fixed Income Mutual Fund	33,348	—	—	—	33,348
Total	$ 179,539	$ 13,481	$ —	$ (4,306)	$ 188,714
Liabilities:					
Derivative Financial Instruments:					
Over the Counter Swaps — Gas	$ —	$ 517,464	$ —	$ (4,178)	$ 513,286
Over the Counter No Cost Collars — Gas	—	270,453	—	—	270,453
Foreign Currency Contracts	—	2,048	—	(128)	1,920
Total	$ —	$ 789,965	$ —	$ (4,306)	$ 785,659
Total Net Assets/(Liabilities)	$ 179,539	$(776,484)	$ —	$ —	$(596,945)

Recurring Fair Value Measures	At Fair Value as of September 30, 2021				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$ 22,269	$ —	$ —	$ —	$ 22,269
Hedging Collateral Deposits	88,610	—	—	—	88,610
Derivative Financial Instruments:					
Over the Counter Swaps — Gas and Oil	—	1,802	—	(1,802)	—
Foreign Currency Contracts	—	938	—	(938)	—
Other Investments:					
Balanced Equity Mutual Fund	34,433	—	—	—	34,433
Fixed Income Mutual Fund	70,639	—	—	—	70,639
Total	$ 215,951	$ 2,740	$ —	$ (2,740)	$ 215,951
Liabilities:					
Derivative Financial Instruments:					
Over the Counter Swaps — Gas and Oil	$ —	$ 601,551	$ —	$ (1,802)	$ 599,749
Over the Counter No Cost Collars — Gas	—	17,385	—	—	17,385
Foreign Currency Contracts	—	214	—	(938)	(724)
Total	$ —	$ 619,150	$ —	$ (2,740)	$ 616,410
Total Net Assets/(Liabilities)	$ 215,951	$(616,410)	$ —	$ —	$(400,459)

(1) Netting Adjustments represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties. The net asset or net liability for each counterparty is recorded as an asset or liability on the Company's balance sheet.

Derivative Financial Instruments

At September 30, 2022, the derivative financial instruments reported in Level 2 consist of natural gas price swap agreements, natural gas no cost collars, and foreign currency contracts, all of which are used in the Company's Exploration and Production segment. The derivative financial instruments reported in Level 2 at September 30, 2021 consist of the same type of instruments in addition to crude oil price swap agreements. The use of crude oil price swap agreements was discontinued during the year ended September 30, 2022 in conjunction with the sale of the Exploration and Production segment's California assets. Hedging collateral deposits of $91.7 million (at September 30, 2022) and $88.6 million (at September 30, 2021), which were associated with the price swap agreements, no cost collars and foreign currency contracts, have been reported in Level 1.

The fair value of the Level 2 price swap agreements and no cost collars is based on an internal cash flow model that uses observable inputs (i.e. LIBOR based discount rates for the price swap agreements and basis differential information, if applicable, at active natural gas and crude oil trading markets). The fair value of the Level 2 foreign currency contracts at September 30, 2022 and September 30, 2021 are determined using the market approach based on observable market transactions of forward Canadian currency rates.

The authoritative guidance for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2022, the Company determined that nonperformance risk associated with the price swap agreements, no cost collars and foreign currency contracts would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company’s (assuming the derivative is in a loss position) credit default swaps rates.

Derivative financial instruments reported in Level 2 at September 30, 2022 also includes the contingent consideration associated with the sale of the Exploration and Production segment's California assets on June 30, 2022, which is discussed at Note B — Asset Acquisitions and Divestitures and at Note J — Financial Instruments. The fair value of the contingent consideration was calculated using a Monte Carlo simulation model that uses observable inputs, including the ICE Brent closing price as of the valuation date, initial and max trigger price, volatility, risk free rate, time of maturity and counterparty risk.

For the years ended September 30, 2022 and 2021, there were no assets or liabilities measured at fair value and classified as Level 3.

Note J — Financial Instruments

Long-Term Debt

The fair market value of the Company’s debt, as presented in the table below, was determined using a discounted cash flow model, which incorporates the Company’s credit ratings and current market conditions in determining the yield, and subsequently, the fair market value of the debt. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows:

	At September 30			
	2022 Carrying Amount	2022 Fair Value	2021 Carrying Amount	2021 Fair Value
	(Thousands)			
Long-Term Debt	$ 2,632,409	$ 2,453,209	$ 2,628,687	$ 2,898,552

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company’s Consolidated

Balance Sheets approximate fair value. The fair value of long-term debt was calculated using observable inputs (U.S. Treasuries for the risk-free component and company specific credit spread information — generally obtained from recent trade activity in the debt). As such, the Company considers the debt to be Level 2.

Any temporary cash investments, notes payable to banks and commercial paper are stated at cost. Temporary cash investments are considered Level 1, while notes payable to banks and commercial paper are considered to be Level 2. Given the short-term nature of the notes payable to banks and commercial paper, the Company believes cost is a reasonable approximation of fair value.

Other Investments

The components of the Company's Other Investments are as follows (in thousands):

	At September 30	
	2022	2021
	(Thousands)	
Life Insurance Contracts	$ 42,171	$ 44,560
Equity Mutual Fund	19,506	34,433
Fixed Income Mutual Fund	33,348	70,639
	$ 95,025	$ 149,632

Investments in life insurance contracts are stated at their cash surrender values or net present value. Investments in an equity mutual fund and a fixed income mutual fund are stated at fair value based on quoted market prices with changes in fair value recognized in net income. The insurance contracts and equity mutual fund are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees. The fixed income mutual fund is primarily an informal funding mechanism for certain regulatory obligations that the Company has to Utility segment customers in its Pennsylvania jurisdiction, as discussed in Note F — Regulatory Matters, and for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment. The Company enters into over-the-counter no cost collars and over-the-counter swap agreements for natural gas to manage the price risk associated with forecasted sales of natural gas. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. These instruments are accounted for as cash flow hedges. The duration of the Company's cash flow hedges does not typically exceed 5 years while the foreign currency forward contracts do not exceed 8 years.

On June 30, 2022, the Company completed the sale of Seneca's California assets. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The Company has determined that this contingent consideration meets the definition of a derivative under the authoritative accounting guidance. Changes in the fair value of this contingent consideration are marked-to-market each reporting period, with changes in fair value recognized in Other Income (Deductions) on the Consolidated Statement of Income. The fair value of this contingent consideration was estimated to be $12.6 million and $8.2 million at June 30, 2022 and September 30, 2022, respectively. A $4.4 million mark-to-market adjustment was recorded during the quarter ended September 30, 2022.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at September 30, 2022 and September 30, 2021.

Cash Flow Hedges

For derivative financial instruments that are designated and qualify as a cash flow hedge, the gain or loss on the derivative is reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings.

As of September 30, 2022, the Company had 420.8 Bcf of natural gas commodity derivative contracts (swaps and no cost collars) outstanding.

As of September 30, 2022, the Company was hedging a total of $49.4 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts.

As of September 30, 2022, the Company had $784.7 million ($572.2 million after-tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that $476.7 million ($347.6 million after-tax) of such unrealized losses will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transactions are recorded in earnings.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2022 and 2021 (Dollar Amounts in Thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) for the Year Ended September 30,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income for the Year Ended September 30,	
	2022	2021		2022	2021
Commodity Contracts	$ (1,048,200)	$ (668,074)	Operating Revenue	$ (882,594) (1)	$ (83,973)
Foreign Currency Contracts	(2,631)	2,703	Operating Revenue	13	262
Total	$ (1,050,831)	$ (665,371)		$ (882,581)	$ (83,711)

(1) On June 30, 2022, the Company completed the sale of Seneca's California assets. Because of this sale, the Company terminated its remaining crude oil derivative contracts and discontinued hedge accounting for such contracts. A loss of $44.6 million was reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet to Operating Revenues on the Consolidated Statement of Income for the year ended September 30, 2022. This loss is included in the reported reclassification amounts.

Credit Risk

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over the-counter swap positions, no cost collars and applicable foreign currency forward contracts with nineteen counterparties of which one is in a net gain position. The Company had $1.0 million of credit exposure with the counterparty in a gain position at September 30, 2022. As of September 2022, no collateral was received from the counterparties by the Company. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

As of September 30, 2022, seventeen of the nineteen counterparties to the Company's outstanding derivative financial contracts (specifically the over-the-counter swaps, over-the-counter no cost collars and applicable foreign currency forward contracts) had a common credit-risk related contingency feature. In the event the Company’s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company’s credit rating, in and of itself, would not cause the Company to be required to post or increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company’s outstanding derivative financial instrument contracts with a credit-risk contingency feature were in a liability position (or if the liability were larger) and/or the Company’s credit rating declined, then hedging collateral deposits or an increase to such deposits could be required. At September 30, 2022, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $564.3 million according to the Company's internal model (discussed in Note I — Fair Value Measurements) and the Company posted $91.7 million in hedging collateral deposits. Depending on the movement of commodity prices in the future, it is possible that these liability positions could swing into asset positions, at which point the Company would be exposed to credit risk on its derivative financial instruments. In that case, the Company's counterparties could be required to post hedging collateral deposits.

The Company’s requirement to post hedging collateral deposits and the Company's right to receive hedging collateral deposits is based on the fair value determined by the Company’s counterparties, which may differ from the Company’s assessment of fair value.

Note K — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan). The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Certain non-collectively bargained employees hired after June 30, 2003 and certain collectively bargained employees hired after October 31, 2003 are eligible for a Retirement Savings Account benefit provided under the Company’s defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were $5.3 million, $4.8 million and $4.2 million for the years ended September 30, 2022, 2021 and 2020, respectively. Costs associated with the Company’s contributions to the Tax-Deferred Savings Plans, exclusive of the costs associated with the Retirement Savings Account, were $7.8 million, $7.2 million, and $6.7 million for the years ended September 30, 2022, 2021 and 2020, respectively.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The other post-retirement benefits cover certain non-collectively bargained employees hired before January 1, 2003 and certain collectively bargained employees hired before October 31, 2003.

The Company’s policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established VEBA trusts for its other post-retirement benefits. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees’ other post-retirement benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its other post-retirement benefits. They are separate accounts within the Retirement Plan trust used to pay retiree medical benefits for the associated participants in the Retirement Plan. Although these accounts are in the Retirement Plan trust, for funding status purposes as shown below, the 401(h) accounts are included in Fair Value of Assets under Other Post-Retirement Benefits. Contributions are tax-deductible when made, subject to limitations contained in the Internal Revenue Code and regulations.

The expected return on Retirement Plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is the market value as of the measurement date adjusted for variances between actual returns and expected returns (from previous years) that have not been reflected in net periodic benefit costs. The expected return on other post-retirement benefit assets (i.e. the VEBA trusts and 401(h) accounts), which is a component of net periodic benefit cost shown in the tables below, is applied to the fair value of assets as of the measurement date.

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The components of net periodic benefit cost other than service cost are presented in Other Income (Deductions) on the Consolidated Statements of Income. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30 for fiscal years 2022, 2021 and 2020.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2022	2021	2020	2022	2021	2020
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 1,098,456	$ 1,139,105	$ 1,097,625	$ 431,213	$ 476,722	$ 468,163
Service Cost	8,758	9,865	9,318	1,328	1,602	1,609
Interest Cost	22,827	21,686	29,930	9,066	9,303	12,913
Plan Participants' Contributions	—	—	—	3,271	3,216	3,058
Retiree Drug Subsidy Receipts	—	—	—	312	1,244	1,411
Actuarial (Gain) Loss	(251,173)	(8,141)	65,908	(120,276)	(34,729)	16,396
Benefits Paid	(65,040)	(64,059)	(63,676)	(25,631)	(26,145)	(26,828)
Benefit Obligation at End of Period	$ 813,828	$ 1,098,456	$ 1,139,105	$ 299,283	$ 431,213	$ 476,722
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 1,095,729	$ 1,016,796	$ 968,449	$ 575,565	$ 547,885	$ 524,127
Actual Return on Plan Assets	(205,884)	122,992	87,402	(94,849)	47,541	44,448
Employer Contributions	20,400	20,000	24,621	3,082	3,068	3,080
Plan Participants' Contributions	—	—	—	3,271	3,216	3,058
Benefits Paid	(65,040)	(64,059)	(63,676)	(25,631)	(26,145)	(26,828)
Fair Value of Assets at End of Period	$ 845,205	$ 1,095,729	$ 1,016,796	$ 461,438	$ 575,565	$ 547,885
Net Amount Recognized at End of Period (Funded Status)	$ 31,377	$ (2,727)	$ (122,309)	$ 162,155	$ 144,352	$ 71,163
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	$ —	$ (2,727)	$ (122,309)	$ (3,065)	$ (4,799)	$ (4,872)
Non-Current Assets	31,377	—	—	165,220	149,151	76,035
Net Amount Recognized at End of Period	$ 31,377	$ (2,727)	$ (122,309)	$ 162,155	$ 144,352	$ 71,163
Accumulated Benefit Obligation	$ 793,555	$ 1,060,659	$ 1,096,427	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	5.57 %	2.75 %	2.66 %	5.56 %	2.76 %	2.71 %
Rate of Compensation Increase	4.60 %	4.70 %	4.70 %	4.60 %	4.70 %	4.70 %

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2022	2021	2020	2022	2021	2020
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$ 8,758	$ 9,865	$ 9,318	$ 1,328	$ 1,602	$ 1,609
Interest Cost	22,827	21,686	29,930	9,066	9,303	12,913
Expected Return on Plan Assets	(52,294)	(58,148)	(60,063)	(29,359)	(28,964)	(29,232)
Amortization of Prior Service Cost (Credit)	537	631	729	(429)	(429)	(429)
Recognition of Actuarial (Gain) Loss(1)	26,405	36,814	39,384	(7,610)	849	535
Net Amortization and Deferral for Regulatory Purposes	16,854	14,063	5,359	21,340	28,010	25,596
Net Periodic Benefit Cost (Income)	$ 23,087	$ 24,911	$ 24,657	$ (5,664)	$ 10,371	$ 10,992
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Effective Discount Rate for Benefit Obligations	2.75 %	2.66 %	3.15 %	2.76 %	2.71 %	3.17 %
Effective Rate for Interest on Benefit Obligations	2.14 %	1.96 %	2.81 %	2.17 %	2.01 %	2.84 %
Effective Discount Rate for Service Cost	2.95 %	3.01 %	3.31 %	3.00 %	3.20 %	3.39 %
Effective Rate for Interest on Service Cost	2.70 %	2.60 %	3.12 %	2.93 %	2.98 %	3.30 %
Expected Return on Plan Assets	5.20 %	6.00 %	6.40 %	5.20 %	5.40 %	5.70 %
Rate of Compensation Increase	4.70 %	4.70 %	4.70 %	4.70 %	4.70 %	4.70 %

(1) Distribution Corporation's New York jurisdiction calculates the amortization of the actuarial loss on a vintage year basis over 10 years, as mandated by the NYPSC. All the other subsidiaries of the Company utilize the corridor approach.

The Net Periodic Benefit Cost (Income) in the table above includes the effects of regulation. The Company recovers pension and other post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and other post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under the existing authoritative guidance as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and other post-retirement regulatory assets and liabilities) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In addition to the Retirement Plan discussed above, the Company also has Non-Qualified benefit plans that cover a group of management employees whose income level has exceeded certain IRS thresholds or who have been designated as participants by the Chief Executive Officer of the Company. These plans provide for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit costs associated with these plans were $8.9 million, $8.3

million and $8.9 million in 2022, 2021 and 2020, respectively. The components of net periodic benefit cost other than service costs associated with these plans are presented in Other Income (Deductions) on the Consolidated Statements of Income. The accumulated benefit obligations for the plans were $64.9 million, $76.9 million and $78.7 million at September 30, 2022, 2021 and 2020, respectively. The projected benefit obligations for the plans were $77.2 million, $95.8 million and $98.1 million at September 30, 2022, 2021 and 2020, respectively. At September 30, 2022, $17.5 million of the projected benefit obligation is recorded in Other Accruals and Current Liabilities and the remaining $59.7 million is recorded in Other Liabilities on the Consolidated Balance Sheets. At September 30, 2021, $15.4 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $80.4 million was recorded in Other Liabilities on the Consolidated Balance Sheets. At September 30, 2020, $14.5 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $83.6 million was recorded in Other Liabilities on the Consolidated Balance Sheets. The weighted average discount rates for these plans were 5.49%, 2.15% and 1.92% as of September 30, 2022, 2021 and 2020, respectively and the weighted average rate of compensation increase for these plans was 8.00% as of September 30, 2022, 2021 and 2020.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2022, as well as the changes in such amounts during 2022, are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits	Non-Qualified Benefit Plans
		(Thousands)	
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Gain (Loss)	$ (86,133)	$ 14,569	$ (18,718)
Prior Service (Cost) Credit	(2,472)	1,543	—
Net Amount Recognized	$ (88,605)	$ 16,112	$ (18,718)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2022(1)			
Decrease (Increase) in Actuarial Loss, excluding amortization(2)	$ (7,006)	$ (3,932)	$ 8,222
Change due to Amortization of Actuarial Loss	26,405	(7,610)	6,301
Prior Service (Cost) Credit	537	(429)	—
Net Change	$ 19,936	$ (11,971)	$ 14,523

(1) Amounts presented are shown before recognizing deferred taxes.

(2) Amounts presented include the impact of actuarial gains/losses related to return on assets, as well as the Actuarial (Gain) Loss amounts presented in the Change in Benefit Obligation.

In order to adjust the funded status of its pension (tax-qualified and non-qualified) and other post-retirement benefit plans at September 30, 2022, the Company recorded a $1.9 million decrease to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $20.6 million (pre-tax) increase to Accumulated Other Comprehensive Income.

The effect of the discount rate change for the Retirement Plan in 2022 was to decrease the projected benefit obligation of the Retirement Plan by $262.2 million. The mortality improvement projection scale was updated, which increased the projected benefit obligation of the Retirement Plan in 2022 by $1.8 million. Other actuarial experience increased the projected benefit obligation for the Retirement Plan in 2022 by $9.2 million. The effect of the discount rate change for the Retirement Plan in 2021 was to decrease the projected benefit obligation of the Retirement Plan by $11.2 million. The effect of the discount rate change for the Retirement Plan in 2020 was to increase the projected benefit obligation of the Retirement Plan by $61.3 million.

The Company made cash contributions totaling $20.4 million to the Retirement Plan during the year ended September 30, 2022. The Company expects that the annual contribution to the Retirement Plan in 2023 will be in the range of zero to $8.0 million.

The following Retirement Plan benefit payments, which reflect expected future service, are expected to be paid by the Retirement Plan during the next five years and the five years thereafter: $67.6 million in 2023; $67.7 million in 2024; $67.3 million in 2025; $66.9 million in 2026; $66.2 million in 2027; and $316.1 million in the five years thereafter.

The effect of the discount rate change in 2022 was to decrease the other post-retirement benefit obligation by $98.9 million. The mortality improvement projection scale was updated, which increased the other post-retirement benefit obligation in 2022 by $1.1 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2022 by $22.5 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2021 was to decrease the other post-retirement benefit obligation by $2.5 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2021 by $2.0 million. The health care cost trend rates were updated, which decreased the other post-retirement benefit obligation in 2021 by $3.7 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2021 by $26.6 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2020 was to increase the other post-retirement benefit obligation by $25.4 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2020 by $2.5 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2020 by $6.5 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 provides for a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

The estimated gross other post-retirement benefit payments and gross amount of Medicare Part D prescription drug subsidy receipts are as follows (dollars in thousands):

	Benefit Payments	Subsidy Receipts
2023	$ 26,221	$ (1,829)
2024	$ 26,337	$ (1,929)
2025	$ 26,376	$ (2,014)
2026	$ 26,291	$ (2,096)
2027	$ 26,140	$ (2,162)
2028 through 2032	$ 125,765	$ (11,391)

Assumed health care cost trend rates as of September 30 were:

	2022	2021	2020
Rate of Medical Cost Increase for Pre Age 65 Participants	5.30 % (1)	5.38 % (1)	5.42 % (2)
Rate of Medical Cost Increase for Post Age 65 Participants	4.84 % (1)	4.84 % (1)	4.75 % (2)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	6.29 % (1)	6.53 % (1)	6.80 % (2)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	4.84 % (1)	4.84 % (1)	4.75 % (2)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	5.96 % (1)	6.15 % (1)	6.20 % (2)

(1) It was assumed that this rate would gradually decline to 4% by 2046.
(2) It was assumed that this rate would gradually decline to 4.5% by 2039.

The Company made cash contributions totaling $2.8 million to its VEBA trusts during the year ended September 30, 2022. In addition, the Company made direct payments of $0.3 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2022. The Company does not expect to make any contributions to its VEBA trusts in 2023.

Investment Valuation

The Retirement Plan assets and other post-retirement benefit assets are valued under the current fair value framework. See Note I — Fair Value Measurements for further discussion regarding the definition and levels of fair value hierarchy established by the authoritative guidance.

The inputs or methodologies used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2022 and 2021, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall, based on the lowest level input that is significant to the fair value measurement in its entirety (dollars in thousands):

	At September 30, 2022				
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	$ 41,633	$ 41,633	$ —	$ —	$ —
International Equities(2)	1,363	—	—	—	1,363
Global Equities(3)	44,434	—	—	—	44,434
Domestic Fixed Income(4)	658,833	—	579,606	—	79,227
International Fixed Income(5)	7,782	—	7,782	—	—
Real Estate	140,739	—	—	—	140,739
Cash Held in Collective Trust Funds	17,388	—	—	—	17,388
Total Retirement Plan Investments	912,172	41,633	587,388	—	283,151
401(h) Investments	(73,044)	(3,310)	(46,694)	—	(23,040)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 839,128	$ 38,323	$ 540,694	$ —	$ 260,111
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	6,077				
Total Retirement Plan Assets	$ 845,205				

	At September 30, 2021				
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	$ 56,511	$ 146	$ —	$ —	$ 56,365
International Equities(2)	28,917	—	—	—	28,917
Global Equities(3)	95,865	—	—	—	95,865
Domestic Fixed Income(4)	818,361	1,447	758,417	—	58,497
International Fixed Income(5)	13,773	—	13,773	—	—
Global Fixed Income(6)	42,454	—	—	—	42,454
Real Estate	119,451	—	—	319	119,132
Cash Held in Collective Trust Funds	27,471	—	—	—	27,471
Total Retirement Plan Investments	1,202,803	1,593	772,190	319	428,701
401(h) Investments	(90,429)	(121)	(58,840)	(24)	(31,444)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 1,112,374	$ 1,472	$ 713,350	$ 295	$ 397,257
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(16,645)				
Total Retirement Plan Assets	$ 1,095,729				

(1) Domestic Equities include mostly collective trust funds, common stock, and exchange traded funds.
(2) International Equities are comprised of collective trust funds.
(3) Global Equities are comprised of collective trust funds.
(4) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.
(5) International Fixed Income securities are comprised mostly of corporate/government bonds.
(6) Global Fixed Income securities are comprised of a collective trust fund.
(7) Reflects the authoritative guidance related to investments measured at net asset value (NAV).

	At September 30, 2022				
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(1)
Other Post-Retirement Benefit Assets held in VEBA Trusts					
Collective Trust Funds — Global Equities	$ 104,554	$ —	$ —	$ —	$ 104,554
Exchange Traded Funds — Fixed Income	270,581	270,581	—	—	—
Cash Held in Collective Trust Funds	10,635	—	—	—	10,635
Total VEBA Trust Investments	385,770	270,581	—	—	115,189
401(h) Investments	73,044	3,310	46,694	—	23,040
Total Investments (including 401(h) Investments)	$ 458,814	$ 273,891	$ 46,694	$ —	$ 138,229
Miscellaneous Accruals (including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	2,624				
Total Other Post-Retirement Benefit Assets	$ 461,438				

	At September 30, 2021				
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(1)
Other Post-Retirement Benefit Assets held in VEBA Trusts					
Collective Trust Funds — Global Equities	$ 165,226	$ —	$ —	$ —	$165,226
Exchange Traded Funds — Fixed Income	313,392	313,392	—	—	—
Cash Held in Collective Trust Funds	9,700	—	—	—	9,700
Total VEBA Trust Investments	488,318	313,392	—	—	174,926
401(h) Investments	90,429	121	58,840	24	31,444
Total Investments (including 401(h) Investments)	$ 578,747	$ 313,513	$ 58,840	$ 24	$206,370
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(3,182)				
Total Other Post-Retirement Benefit Assets	$ 575,565				

(1) Reflects the authoritative guidance related to investments measured at net asset value (NAV).

The fair values disclosed in the above tables may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

The following tables provide a reconciliation of the beginning and ending balances of the Retirement Plan and other post-retirement benefit assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3). For the years ended September 30, 2022 and September 30, 2021, there were no transfers from Level 1 to Level 2. In addition, as shown in the following tables, there were no transfers in or out of Level 3.

	Retirement Plan Level 3 Assets (Thousands)		
	Real Estate	Excluding 401(h) Investments	Total
Balance at September 30, 2020	$ 471	$ (35)	$ 436
Unrealized Gains/(Losses)	(152)	11	(141)
Sales	—	—	—
Balance at September 30, 2021	319	(24)	295
Unrealized Gains/(Losses)	234	(18)	216
Sales	(553)	42	(511)
Balance at September 30, 2022	$ —	$ —	$ —

	Other Post-Retirement Benefit Level 3 Assets (Thousands)
	401(h) Investments
Balance at September 30, 2020	$ 35
Unrealized Gains/(Losses)	(11)
Sales	—
Balance at September 30, 2021	24
Unrealized Gains/(Losses)	18
Sales	(42)
Balance at September 30, 2022	$ —

The Company's assumption regarding the expected long-term rate of return on plan assets is 6.90% (Retirement Plan) and 5.70% (other post-retirement benefits), effective for fiscal 2023. The return assumption reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes projected capital market conditions and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trust, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity. In fiscal 2021 and fiscal 2022, capital market conditions led to significant improvements in the funded status of the Retirement Plan. As a result, the Company reduced the return seeking portion of its assets during both years, particularly equity securities and return seeking fixed income securities, held in the Retirement Plan, and increased its allocation to hedging fixed income securities in conjunction with the Company's liability driven investment strategy. The actual asset allocations as of September 30, 2022 are noted in the table above, and such allocations are subject to change, but the majority of the assets will remain hedging fixed income assets. Given the level of the VEBA trust and 401(h) assets in relation to the Other Post-Retirement Benefits, the majority of those assets are and will remain in fixed income securities.

Investment managers are retained to manage separate pools of assets. Comparative market and peer group performance of individual managers and the total fund are monitored on a regular basis, and reviewed by the Company's Retirement Committee on at least a quarterly basis.

The Company determines the service and interest cost components of net periodic benefit cost using the spot rate approach, which uses individual spot rates along the yield curve that correspond to the timing of each benefit payment in order to determine the discount rate. The individual spot rates along the yield curve are determined by an above mean methodology in that the coupon interest rates that are in the lower 50th percentile are excluded based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities.

Note L — Commitments and Contingencies

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory requirements.

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2022, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $3.6 million. The Company's liability for such clean-up costs has been recorded in Other Liabilities on the Consolidated Balance Sheet at September 30, 2022. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately one year and is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could have an adverse financial impact on the Company.

Northern Access Project

On February 3, 2017, Supply Corporation and Empire received FERC approval of the Northern Access project described herein. Shortly thereafter, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received in January of 2017). Subsequently, FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. FERC denied rehearing requests associated with its Order and FERC's decisions were appealed. The Second Circuit Court of Appeals issued an order upholding the FERC waiver orders. In addition, in the Company's state court litigation challenging the NYDEC's actions with regard to various state permits, the New York State Supreme Court issued a decision finding these permits to be preempted. The Company remains committed to the project and, on June 29, 2022, received an extension of time from FERC, until December 31, 2024, to construct the project. As of September 30, 2022, the Company has spent approximately $55.8 million on the project, all of which is recorded on the balance sheet.

Other

The Company, in its Utility segment and Exploration and Production segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $458.2 million in 2023, $98.6 million in 2024, $135.6 million in 2025, $150.7 million in 2026, $142.1 million in 2027 and $1,001.0 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company, in its Pipeline and Storage segment, Gathering segment and Utility segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system modernization and expansion projects. As of September 30, 2022, the future contractual commitments related to the system modernization and expansion projects are $68.9 million in 2023, $8.5 million in 2024, $8.1 million in 2025, $6.9 million in 2026, $5.8 million in 2027 and $5.8 million thereafter.

The Company, in its Exploration and Production segment, has entered into contractual obligations to support its development activities and operations in Pennsylvania, including hydraulic fracturing and other well completion services, well tending services, well workover activities, tubing and casing purchases, production equipment purchases, water hauling services and contracts for drilling rig services. The future contractual commitments are $282.5 million in 2023, $180.4 million in 2024 and $153.8 million in 2025, and $43.8 million in 2026. There are no contractual commitments extending beyond 2026.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note F — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, an estimate of the possible loss or range of loss, if any, cannot be made at this time.

Note M — Business Segment Information

The Company reports financial results for four segments: Exploration and Production, Pipeline and Storage, Gathering, and Utility. The division of the Company's operations into reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

The Exploration and Production segment, through Seneca, is engaged in exploration for and development of natural gas reserves in the Appalachian region of the United States.

The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers, exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports and stores natural gas for major industrial companies, utilities (including Distribution Corporation) and power producers in New York State. Empire also transports natural gas for natural gas marketers and exploration and production companies (including Seneca) from natural gas producing areas in Pennsylvania to markets in New York and to interstate pipeline delivery points with access to additional markets in the northeastern United States and Canada.

The Gathering segment is comprised of Midstream Company's operations. Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region and currently provides gathering services primarily to Seneca.

The Utility segment operations are regulated by the NYPSC and the PaPUC and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.

The data presented in the tables below reflects financial information for the segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A — Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. The Company evaluates segment performance based on income before discontinued operations (when applicable). When this is not applicable, the Company evaluates performance based on net income.

	Year Ended September 30, 2022							
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)(2)	$ 1,010,464	$ 265,415	$ 12,086	$ 897,916	$ 2,185,881	$ —	$ 165	$ 2,186,046
Intersegment Revenues	$ —	$ 111,629	$ 202,757	$ 305	$ 314,691	$ 6	$ (314,697)	$ —
Interest Income	$ 1,929	$ 2,275	$ 198	$ 2,730	$ 7,132	$ 3	$ (1,024)	$ 6,111
Interest Expense	$ 53,401	$ 42,492	$ 16,488	$ 24,115	$ 136,496	$ 4	$ (6,143)	$ 130,357
Depreciation, Depletion and Amortization	$ 208,148	$ 67,701	$ 33,998	$ 59,760	$ 369,607	$ —	$ 183	$ 369,790
Income Tax Expense (Benefit)	$ 43,898	$ 35,043	$ 24,949	$ 17,165	$ 121,055	$ 3	$ (4,429)	$ 116,629
Significant Item: Gain on Sale of Assets	$ 12,736	$ —	$ —	$ —	$ 12,736	$ —	$ —	$ 12,736
Segment Profit: Net Income (Loss)	$ 306,064	$ 102,557	$ 101,111	$ 68,948	$ 578,680	$ (9)	$ (12,650)	$ 566,021
Expenditures for Additions to Long-Lived Assets	$ 565,791	$ 95,806	$ 55,546	$ 111,033	$ 828,176	$ —	$ 1,212	$ 829,388
	At September 30, 2022							
	(Thousands)							
Segment Assets	$ 2,507,541	$2,394,697	$ 878,796	$2,299,473	$ 8,080,507	$ 2,036	$ (186,281)	$ 7,896,262

	Year Ended September 30, 2021							
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Elimination	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 836,697	$ 234,397	$ 3,116	$ 666,920	$ 1,741,130	$ 1,173	$ 356	$ 1,742,659
Intersegment Revenues	$ —	$ 109,160	$ 190,148	$ 331	$ 299,639	$ 49	$ (299,688)	$ —
Interest Income	$ 211	$ 1,085	$ 259	$ 2,117	$ 3,672	$ 230	$ 486	$ 4,388
Interest Expense	$ 69,662	$ 40,976	$ 17,493	$ 21,795	$ 149,926	$ —	$ (3,569)	$ 146,357
Depreciation, Depletion and Amortization	$ 182,492	$ 62,431	$ 32,350	$ 57,457	$ 334,730	$ 394	$ 179	$ 335,303
Income Tax Expense (Benefit)	$ 33,370	$ 28,812	$ 28,876	$ 14,007	$ 105,065	$ 11,438	$ (1,821)	$ 114,682
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$ 76,152	$ —	$ —	$ —	$ 76,152	$ —	$ —	$ 76,152
Significant Item: Gain on Sale of Assets	$ —	$ —	$ —	$ —	$ —	$ 51,066	$ —	$ 51,066
Segment Profit: Net Income (Loss)	$ 101,916	$ 92,542	$ 80,274	$ 54,335	$ 329,067	$ 37,645	$ (3,065)	$ 363,647
Expenditures for Additions to Long-Lived Assets	$ 381,408	$ 252,316	$ 34,669	$ 100,845	$ 769,238	$ —	$ 673	$ 769,911
	At September 30, 2021							
	(Thousands)							
Segment Assets	$ 2,286,058	$2,296,030	$ 837,729	$2,148,267	$ 7,568,084	$ 4,146	$ (107,405)	$ 7,464,825

	Year Ended September 30, 2020							
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 607,453	$ 205,998	$ 72	$ 642,855	$ 1,456,378	$ 89,435	$ 478	$ 1,546,291
Intersegment Revenues	$ —	$ 103,606	$ 142,821	$ 9,443	$ 255,870	$ 836	$ (256,706)	$ —
Interest Income	$ 698	$ 1,475	$ 545	$ 2,262	$ 4,980	$ 860	$ (833)	$ 5,007
Interest Expense	$ 58,098	$ 32,731	$ 10,877	$ 22,150	$ 123,856	$ 66	$ (6,845)	$ 117,077
Depreciation, Depletion and Amortization	$ 172,124	$ 53,951	$ 22,440	$ 55,248	$ 303,763	$ 1,716	$ 679	$ 306,158
Income Tax Expense (Benefit)	$ (41,472)	$ 28,613	$ 18,191	$ 13,274	$ 18,606	$ 210	$ (77)	$ 18,739
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$ 449,438	$ —	$ —	$ —	$ 449,438	$ —	$ —	$ 449,438
Segment Profit: Net Income (Loss)	$ (326,904)	$ 78,860	$ 68,631	$ 57,366	$ (122,047)	$ (269)	$ (1,456)	$ (123,772)
Expenditures for Additions to Long-Lived Assets	$ 670,455	$ 166,652	$ 297,806	$ 94,273	$ 1,229,186	$ 39	$ (608)	$ 1,228,617
	At September 30, 2020							
	(Thousands)							
Segment Assets	$ 1,979,028	$2,204,971	$ 945,199	$2,067,852	$ 7,197,050	$ 113,571	$ (345,686)	$ 6,964,935

(1) All Revenue from External Customers originated in the United States.

(2) Revenues from three customers of the Company's Exploration and Production segment, exclusive of hedging losses transacted with separate parties, represented approximately $850 million of the Company's consolidated revenue for the year ended September 30, 2022. These three customers were also customers of the Company's Pipeline and Storage segment, accounting for an additional $15 million of the Company's consolidated revenue for the year ended September 30, 2022.

Geographic Information	At September 30		
	2022	2021	2020
	(Thousands)		
Long-Lived Assets:			
United States	$ 7,135,131	$ 6,942,376	$ 6,597,313

Note N — Supplementary Information for Oil and Gas Producing Activities (unaudited, except for Capitalized Costs Relating to Oil and Gas Producing Activities)

The Company follows authoritative guidance related to oil and gas exploration and production activities that aligns the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also follows. The SEC rules require companies to value their year-end reserves using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve month period prior to the end of the reporting period.

The following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about oil and gas producing activities and related SEC authoritative guidance. All monetary amounts are expressed in U.S. dollars. As discussed in Note B — Asset Acquisitions and Divestitures, the Company completed the sale of its California assets on June 30, 2022. With the completion of this sale, the Company no longer has any oil or gas reserves in the West Coast region of the U.S.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30	
	2022	2021
	(Thousands)	
Proved Properties(1)	$ 5,915,807	$ 6,652,341
Unproved Properties	65,994	103,759
	5,981,801	6,756,100
Less — Accumulated Depreciation, Depletion and Amortization	4,034,266	4,881,972
	$ 1,947,535	$ 1,874,128

(1) Includes asset retirement costs of $120.8 million and $152.8 million at September 30, 2022 and 2021, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Although the timing of the ultimate evaluation or disposition of the unproved properties cannot be determined, the Company expects the majority of its acquisition costs associated with unproved properties to be transferred into the amortization base by 2027. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2025. Following is a summary of costs excluded from amortization at September 30, 2022:

	Total as of September 30, 2022	Year Costs Incurred			
		2022	2021	2020	Prior
			(Thousands)		
Acquisition Costs	$ 41,831	$ —	$ —	$ 29,698	$ 12,133
Development Costs	24,163	17,590	4,085	2,488	—
Exploration Costs	—	—	—	—	—
Capitalized Interest	—	—	—	—	—
	$ 65,994	$ 17,590	$ 4,085	$ 32,186	$ 12,133

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 2,491	$ 1,801	$ 245,976
Unproved	10,665	5,102	42,922
Exploration Costs(1)	9,631	15,413	3,891
Development Costs(2)	528,684	329,368	355,742
Asset Retirement Costs	9,768	20,194	62,080
	$ 561,239	$ 371,878	$ 710,611

(1) Amounts for 2022, 2021 and 2020 include capitalized interest of zero, $0.1 million and zero respectively.
(2) Amounts for 2022, 2021 and 2020 include capitalized interest of $0.6 million, $0.4 million and $1.0 million, respectively.

For the years ended September 30, 2022, 2021 and 2020, the Company spent $154.3 million, $81.2 million and $219.9 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2022	2021	2020
United States	(Thousands, except per Mcfe amounts)		
Operating Revenues:			
Gas (includes transfers to operations of $5,696, $3,061 and $1,921, respectively)(1)	$ 1,730,723	$ 780,477	$ 402,447
Oil, Condensate and Other Liquids	150,957	135,191	107,844
Total Operating Revenues(2)	1,881,680	915,668	510,291
Production/Lifting Costs	283,914	267,316	203,670
Franchise/Ad Valorem Taxes	25,112	22,128	15,582
Purchased Emission Allowance Expense	1,305	2,940	2,930
Accretion Expense	7,530	7,743	5,237
Depreciation, Depletion and Amortization ($0.57, $0.54 and $0.69 per Mcfe of production, respectively)	202,418	177,055	166,759
Impairment of Oil and Gas Producing Properties	—	76,152	449,438
Income Tax Expense	368,925	98,593	(92,820)
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$ 992,476	$ 263,741	$ (240,505)

(1) There were no revenues from sales to affiliates for all years presented.
(2) Exclusive of hedging gains and losses. See further discussion in Note J — Financial Instruments.

Reserve Quantity Information

The Company's proved oil and gas reserve estimates are prepared by the Company's petroleum engineers who meet the qualifications of Reserve Estimator per the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007. The Company maintains comprehensive internal reserve guidelines and a continuing education program designed to keep its staff up to date with current SEC regulations and guidance.

The Company's Senior Manager of Reservoir Engineering is the primary technical person responsible for overseeing the Company's reserve estimation process and engaging and overseeing the third party reserve audit. His qualifications include a Bachelor of Science Degree in Petroleum Engineering and over 13 years of Petroleum Engineering experience with independent oil and gas companies, licensure as a Professional Engineer and is a member of the Society of Petroleum Engineers.

The Company maintains a system of internal controls over the reserve estimation process. Management reviews the price, heat content, lease operating cost and future investment assumptions used in the economic model to determine the reserves. The Senior Manager of Reservoir Engineering reviews and approves all new reserve assignments and significant reserve revisions. Access to the reserve database is restricted. Significant changes to the reserve report are reviewed by senior management on a quarterly basis. Periodically, the

Company's internal audit department assesses the design of these controls and performs testing to determine the effectiveness of such controls.

All of the Company's reserve estimates are audited annually by Netherland, Sewell & Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (consulting at NSAI since 2011 and with over 4 years of prior industry experience in petroleum engineering) and a professional geoscientist registered in the State of Texas (consulting at NSAI since 2008 and with over 11 years of prior industry experience in petroleum geosciences). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2022 and did not identify any problems which would cause it to take exception to those estimates.

The reliable technologies that were utilized in estimating the reserves include wire line open-hole log data, performance data, log cross sections, core data, 2D and 3D seismic data and statistical analysis. The statistical method utilized production performance from both the Company's and competitors' wells. Geophysical data includes data from the Company's wells, third-party wells, published documents and state data-sites, and 2D and 3D seismic data. These were used to confirm continuity of the formation.

	Gas MMcf			
	U.S.			
	Appalachian Region		West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2019	2,915,886		33,633	2,949,519
Extensions and Discoveries	7,246	(1)	—	7,246
Revisions of Previous Estimates	(85,647)		(2,772)	(88,419)
Production	(225,513)	(2)	(1,889)	(227,402)
Purchases of Minerals in Place	684,141		—	684,141
September 30, 2020	3,296,113		28,972	3,325,085
Extensions and Discoveries	689,395	(1)	—	689,395
Revisions of Previous Estimates	19,940		3,033	22,973
Production	(312,300)	(2)	(1,720)	(314,020)
September 30, 2021	3,693,148		30,285	3,723,433
Extensions and Discoveries	837,510	(1)	—	837,510
Revisions of Previous Estimates	2,882		71	2,953
Production	(341,700)	(2)	(1,211)	(342,911)
Sale of Minerals in Place	(21,178)		(29,145)	(50,323)
September 30, 2022	4,170,662		—	4,170,662
Proved Developed Reserves:				
September 30, 2019	1,901,162		33,633	1,934,795
September 30, 2020	2,744,851		28,972	2,773,823
September 30, 2021	3,061,178		30,285	3,091,463
September 30, 2022	3,312,568		—	3,312,568
Proved Undeveloped Reserves:				
September 30, 2019	1,014,724		—	1,014,724
September 30, 2020	551,262		—	551,262
September 30, 2021	631,970		—	631,970
September 30, 2022	858,094		—	858,094

(1) Extensions and discoveries include 7 Bcf (during 2020), 180 Bcf (during 2021) and 301 Bcf (during 2022), of Marcellus Shale gas (which exceed 15% of total reserves) in the Appalachian region. Extensions and discoveries include 0 Bcf (during 2020), 497 Bcf (during 2021) and 537 Bcf (during 2022), of Utica Shale gas (which exceed 15% of total reserves) in the Appalachian region.

(2) Production includes 169,453 MMcf (during 2020), 218,016 MMcf (during 2021) and 209,463 MMcf (during 2022), from Marcellus Shale fields. Production includes 55,392 MMcf (during 2020), 93,253 MMcf (during 2021) and 130,240 MMcf (during 2022), from Utica Shale fields.

	Oil Mbbl		
	U.S.		
	Appalachian Region	West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:			
September 30, 2019	13	24,860	24,873
Extensions and Discoveries	—	288	288
Revisions of Previous Estimates	2	(715)	(713)
Production	(3)	(2,345)	(2,348)
September 30, 2020	12	22,088	22,100
Extensions and Discoveries	—	1,041	1,041
Revisions of Previous Estimates	1	630	631
Production	(2)	(2,233)	(2,235)
September 30, 2021	11	21,526	21,537
Extensions and Discoveries	—	296	296
Revisions of Previous Estimates	255	532	787
Production	(16)	(1,588)	(1,604)
Sales of Minerals in Place	—	(20,766)	(20,766)
September 30, 2022	250	—	250
Proved Developed Reserves:			
September 30, 2019	13	24,246	24,259
September 30, 2020	12	22,088	22,100
September 30, 2021	11	20,930	20,941
September 30, 2022	250	—	250
Proved Undeveloped Reserves:			
September 30, 2019	—	614	614
September 30, 2020	—	—	—
September 30, 2021	—	596	596
September 30, 2022	—	—	—

The Company’s proved undeveloped (PUD) reserves increased from 636 Bcfe at September 30, 2021 to 858 Bcfe at September 30, 2022. PUD reserves in the Utica Shale increased from 411 Bcfe at September 30, 2021 to 503 Bcfe at September 30, 2022. PUD reserves in the Marcellus Shale increased from 220 Bcfe at September 30, 2021 to 355 Bcfe at September 30, 2022. PUD reserves in the West Coast region decreased from 5 Bcfe at September 30, 2021 to zero at September 30, 2022. The Company’s total PUD reserves were 20.6% of total proved reserves at September 30, 2022, up from 16.5% of total proved reserves at September 30, 2021.

The Company’s PUD reserves increased from 551 Bcfe at September 30, 2020 to 636 Bcfe at September 30, 2021. PUD reserves in the Utica Shale increased from 265 Bcfe at September 30, 2020 to 411 Bcfe at September 30, 2021. PUD reserves in the Marcellus Shale decreased from 287 Bcfe at September 30, 2020 to 220 Bcfe at September 30, 2021. The Company’s total PUD reserves were 16.5% of total proved reserves at September 30, 2021, roughly flat from 16% of total proved reserves at September 30, 2020.

The increase in PUD reserves in 2022 of 222 Bcfe is a result of 502 Bcfe in new PUD reserve additions and 23 Bcfe in upward revisions to remaining PUD reserves, partially offset by 287 Bcfe in PUD conversions to developed reserves (55 Bcfe from the Marcellus Shale, 231 Bcfe from the Utica Shale and 1 Bcfe from the West Coast region), and 13 Bcfe in PUD reserves removed for one Utica PUD location due to pad layout changes. The remaining change of 3 Bcf was due to removing West Coast region PUDs included in the beginning of year balances through development and divesture of Seneca's California assets.

The increase in PUD reserves in 2021 of 85 Bcfe is a result of 344 Bcfe in new PUD reserve additions and 9 Bcfe in upward revisions to remaining PUD reserves, partially offset by 188 Bcfe in PUD conversions to developed reserves (82 Bcfe from the Marcellus Shale and 106 Bcfe from the Utica Shale), and 80 Bcfe in PUD reserves removed for eight PUD locations, half of these due to pad layout changes, and the other half due to schedule changes. Six of these wells removed were in the Marcellus Shale (54 Bcfe) and two were in the Utica Shale (26 Bcfe).

The Company invested $154 million during the year ended September 30, 2022 to convert 287 Bcfe (333 Bcfe after revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 45% of the net PUD reserves recorded at September 30, 2021. In the Appalachian region, 31 of 65 PUD locations were developed while the West Coast region developed 6 of 17 PUD locations prior to the divesture. PUD expenditures in 2022 were lower than the 2021 estimate primarily due to changes in the development schedule.

The Company invested $81 million during the year ended September 30, 2021 to convert 188 Bcfe (198 Bcfe after revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 34% of the net PUD reserves recorded at September 30, 2020. In the Appalachian region, 18 of 53 PUD locations were developed. PUD expenditures in 2021 were lower than the 2020 estimate primarily due to changes in the development schedule.

In 2023, the Company estimates that it will invest approximately $308 million to develop its PUD reserves. The Company is committed to developing its PUD reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting. Since that rule was adopted, and over the last five years, the Company developed 51% of its beginning year PUD reserves in fiscal 2018, 39% of its beginning year PUD reserves in fiscal 2019, 36% of its beginning year PUD reserves in fiscal 2020, 34% of its beginning year PUD reserves in fiscal 2021 and 45% of its beginning year PUD reserves in fiscal 2022.

At September 30, 2022, the Company does not have any proved undeveloped reserves that have been on the books for more than five years at the corporate level, country level or field level. All of the Company's proved reserves are in the United States.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, in accordance with the SEC's final rule on Modernization of Oil and Gas Reporting, it is based on the unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period and costs adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

The standardized measure is intended instead to provide a means for comparing the value of the Company's proved reserves at a given time with those of other oil- and gas-producing companies than is provided by a simple comparison of raw proved reserve quantities.

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
United States			
Future Cash Inflows	$19,209,099	$10,175,182	$ 6,493,362
Less:			
Future Production Costs	3,138,226	3,423,629	3,149,857
Future Development Costs	781,847	597,662	501,678
Future Income Tax Expense at Applicable Statutory Rate	3,876,272	1,397,175	454,553
Future Net Cash Flows	11,412,754	4,756,716	2,387,274
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	5,964,424	2,403,144	1,164,804
Standardized Measure of Discounted Future Net Cash Flows	$ 5,448,330	$ 2,353,572	$ 1,222,470

The principal sources of change in the standardized measure of discounted future net cash flows were as follows:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
United States			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	$ 2,353,572	$ 1,222,470	$ 1,736,319
Sales, Net of Production Costs	(1,572,402)	(626,132)	(290,975)
Net Changes in Prices, Net of Production Costs	4,132,889	1,478,995	(1,109,101)
Extensions and Discoveries	1,355,257	462,040	4,236
Changes in Estimated Future Development Costs	(32,160)	48,247	99,884
Purchases of Minerals in Place	—	—	170,363
Sales of Minerals in Place	(311,308)	—	—
Previously Estimated Development Costs Incurred	154,253	81,239	219,938
Net Change in Income Taxes at Applicable Statutory Rate	(1,180,349)	(415,993)	248,182
Revisions of Previous Quantity Estimates	3,316	(52,383)	(28,337)
Accretion of Discount and Other	545,262	155,089	171,961
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$ 5,448,330	$ 2,353,572	$ 1,222,470

Item 9 ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2022.

Management's Annual Report on Internal Control over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2022. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework,* published in 2013. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2022.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2022. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended September 30, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B ***Other Information***

None.

Item 9C ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

None.

PART III

Item 10 ***Directors, Executive Officers and Corporate Governance***

The Company will file the definitive Proxy Statement with the SEC no later than 120 days after September 30, 2022. The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for One-Year Terms to Expire in 2024," and

"Continuing Directors Whose Terms Expire in 2024," and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

The Company has adopted a Code of Business Conduct and Ethics that applies to the Company's directors, officers and employees and has posted such Code of Business Conduct and Ethics on the Company's website, www.nationalfuelgas.com, together with certain other corporate governance documents. Copies of the Company's Code of Business Conduct and Ethics, charters of important committees, and Corporate Governance Guidelines will be made available free of charge upon written request to Investor Relations, National Fuel Gas Company, 6363 Main Street, Williamsville, New York 14221.

The Company intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, and that relates to any element of the code of ethics definition enumerated in paragraph (b) of Item 406 of the SEC's Regulation S-K, by posting such information on its website, www.nationalfuelgas.com.

Item 11 *Executive Compensation*

The information concerning executive compensation will be set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," is incorporated herein by reference.

Item 12 *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Equity Compensation Plan Information

The equity compensation plan information will be set forth in the definitive Proxy Statement under the heading "Equity Compensation Plan Information" and is incorporated herein by reference.

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information concerning security ownership of certain beneficial owners will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(b) Security Ownership of Management

The information concerning security ownership of management will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(c) Changes in Control

None.

Item 13 *Certain Relationships and Related Transactions, and Director Independence*

The information regarding certain relationships and related transactions will be set forth in the definitive Proxy Statement under the headings "Compensation Committee Interlocks and Insider Participation" and "Related Person Transactions" and is incorporated herein by reference. The information regarding director independence will be set forth in the definitive Proxy Statement under the heading "Director Independence" and is incorporated herein by reference.

Item 14 *Principal Accountant Fees and Services*

The information concerning principal accountant fees and services will be set forth in the definitive Proxy Statement under the heading "Audit Fees" and is incorporated herein by reference.

PART IV

Item 15 *Exhibits and Financial Statement Schedules*

(a)1. Financial Statements

Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)2. Financial Statement Schedules

All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

(a)3. Exhibits

All documents referenced below were filed pursuant to the Securities Exchange Act of 1934 by National Fuel Gas Company (File No. 1-3880), unless otherwise noted.

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:
•	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 2012)
•	Certificate of Amendment of Restated Certificate of Incorporation, as amended, of National Fuel Gas Company (Exhibit 3.1, Form 8-K dated March 16, 2021)
3(ii)	By-Laws:
•	By-Laws of National Fuel Gas Company, as amended June 15, 2022 (Exhibit 3.1, Form 8-K dated June 17, 2022)
	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Description of Securities (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 2019)
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992)
•	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999)

Exhibit Number	Description of Exhibits
•	Officers Certificate establishing 3.75% Notes due 2023, dated February 15, 2023 (Exhibit 4.1.1, Form 8-K dated February 15, 2013)
•	Officers Certificate establishing 5.20% Notes due 2025, dated June 25, 2015 (Exhibit 4.1.1, Form 8-K dated June 25, 2015)
•	Officers Certificate establishing 3.95% Notes due 2027, dated September 27, 2017 (Exhibit 4.1.1, Form 8-K dated September 27, 2017)
•	Officers Certificate establishing 4.75% Notes due 2028, dated August 17, 2018 (Exhibit 4.1.1, Form 8-K dated August 17, 2018)
•	Officers Certificate establishing 5.50% Notes due 2026, dated June 3, 2020 (Exhibit 4.1.1, Form 8-K dated June 3, 2020)
•	Officer's Certificate establishing 2.95% Notes due 2031, dated February 24, 2021 (Exhibit 4.1.1, Form 8-K dated February 24, 2021)
10	Material Contracts:
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006)
•	Purchase and Sale Agreement, dated as of May 4, 2020, by and among SWEPI LP, Seneca Resources Company, LLC, NFG Midstream Covington, LLC, National Fuel Gas Midstream Company, LLC and National Fuel Gas Company (Exhibit 10.1, Form 8-K dated May 4, 2020)
•	Credit Agreement, dated as of February 28, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent (Exhibit 10.1, Form 8-K dated February 28, 2022)
•	Amendment No. 1 to Credit Agreement, dated as of May 3, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent (Exhibit 10.1, Form 10-Q dated May 6, 2022)
•	364-Day Credit Agreement, dated as of June 30, 2022, among the Company, the Lenders party thereto, and Wells Fargo Bank, National Association as Administrative Agent (Exhibit 10.1, Form 8-K dated July 1, 2022)
10.1	Amendment No. 1 to 364-Day Credit Agreement, dated as of September 27, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent
	Management Contracts and Compensatory Plans and Arrangements:
•	Standard Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and executive officers (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008)
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2011)
•	National Fuel Gas Company 2010 Equity Compensation Plan, as amended and restated December 5, 2018 (Exhibit 10.1, Form 8-K dated March 11, 2019)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010)
•	National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012)

Exhibit Number	Description of Exhibits
•	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective June 9, 2016 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2016)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated December 14, 2020 (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2020)
•	National Fuel Gas Company Deferred Compensation Plan for Directors and Officers (Amended and Restated Effective September 1, 2021) (Exhibit 10.1, Form 8-K dated June 23, 2021)
•	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007)
•	Amendment to National Fuel Gas Company Tophat Plan, dated December 14, 2020 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2020)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999)
•	National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated August 13, 2015 (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2015)

Exhibit Number	Description of Exhibits
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 14, 2020 (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2020)
•	National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan, as amended and restated March 11, 2020 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2020)
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2021)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2021)
•	Form of Award Notice for ESG Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2021)
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2020)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2020)
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2019)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2019)
21	Subsidiaries of the Registrant
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC
99.2	Company Maps

Exhibit Number	Description of Exhibits
101	Interactive data files submitted pursuant to Regulation S-T, formatted in Inline XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the years ended September 30, 2022, 2021 and 2020, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2022, 2021 and 2020 (iii) the Consolidated Balance Sheets at September 30, 2022 and September 30, 2021, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2022, 2021 and 2020 and (v) the Notes to Consolidated Financial Statements.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)
•	Incorporated herein by reference as indicated.
	All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K.
••	In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference.

Item 16 ***Form 10-K Summary***

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

National Fuel Gas Company
(Registrant)

By /s/ D. P. Bauer
D. P. Bauer
President and Chief Executive Officer

Date: November 18, 2022

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	
/s/ D. F. Smith D. F. Smith	Chairman of the Board and Director	Date: November 18, 2022
/s/ D. H. Anderson D. H. Anderson	Director	Date: November 18, 2022
/s/ B. M. Baumann B. M. Baumann	Director	Date: November 18, 2022
/s/ D. C. Carroll D. C. Carroll	Director	Date: November 18, 2022
/s/ S. C. Finch S.C. Finch	Director	Date: November 18, 2022
/s/ J. N. Jaggers J. N. Jaggers	Director	Date: November 18, 2022
/s/ R. Ranich R. Ranich	Director	Date: November 18, 2022
/s/ J. W. Shaw J. W. Shaw	Director	Date: November 18, 2022
/s/ T. E. Skains T. E. Skains	Director	Date: November 18, 2022
/s/ R. J. Tanski R. J. Tanski	Director	Date: November 18, 2022
/s/ D. P. Bauer D. P. Bauer	President and Chief Executive Officer and Director	Date: November 18, 2022
/s/ K. M. Camiolo K. M. Camiolo	Treasurer and Principal Financial Officer	Date: November 18, 2022
/s/ E. G. Mendel E. G. Mendel	Controller and Principal Accounting Officer	Date: November 18, 2022

Investor Information

Common Stock Transfer Agent and Registrar

EQ Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
Telephone: 800-648-8166
Web: http://www.shareowneronline.com
Email: stocktransfer@equiniti.com

Change of address notices and inquiries about dividends should be sent to the Transfer Agent at the address listed above.

National Fuel Direct Stock Purchase and Dividend Reinvestment Plan

National Fuel offers a simple, cost-effective method for purchasing shares of National Fuel stock. A prospectus, which includes details of the Plan, can be obtained by calling, writing or emailing the administrator of the Plan, EQ Shareowner Services, at the address listed above.

Investor Relations

Investors or financial analysts desiring information should contact:

Karen M. Camiolo, Treasurer
Telephone: 716-857-7344

Brandon J. Haspett,
Director of Investor Relations
Telephone: 716-857-7697
Email: HaspettB@natfuel.com

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Additional Shareholder Reports

Additional copies of this report, the 2022 Form 10-K and the 2022 Financial and Statistical Report can be obtained without charge by writing to or calling:

Sarah J. Mugel, Corporate Secretary
Telephone: 716-857-7163

Brandon J. Haspett,
Director of Investor Relations
Telephone: 716-857-7697

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Stock Exchange Listing

New York Stock Exchange
(Stock Symbol: NFG)

Trustee for Debentures

The Bank of New York Mellon
Corporate Trust
240 Greenwich Street, 7 East
New York, NY 10286

Annual Meeting

The Annual Meeting of Stockholders will be held on Thursday, March 9, 2023 conducted via live webcast at www.virtualshareholdermeeting.com/NFG2023. Stockholders of record as of the close of business on January 9, 2023, will receive a formal notice of the meeting, proxy statement, and proxy.

Units of Measure

Bbl	Barrel *(of oil)*
Bcf	Billion cubic feet *(of natural gas)*
Bcfe	Bcf equivalent *(of natural gas and oil)*
Dth	Dekatherm (*approx. 1 Mcf of natural gas)*
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet *(of natural gas)*
Mcfe	Mcf equivalent *(of natural gas and oil)*
MMcf	Million cubic feet *(of natural gas)*
MMcfe	Million cubic feet equivalent

This Annual Report contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in the Company's Form 10-K at Item 7, MD&A, under the heading "Safe Harbor for Forward-Looking Statements," and with the "Risk Factors" included in the Company's Form 10-K at Item 1A. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of gas quantities, estimates of the time and resources necessary to meet emissions targets, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction and other projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may" and similar expressions. Forward-looking statements include estimates of gas quantities. Proved gas reserves are those quantities of gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. Other estimates of gas quantities, including estimates of probable reserves, possible reserves, and resource potential, are by their nature more speculative than estimates of proved reserves. Accordingly, estimates other than proved reserves are subject to substantially greater risk of being actually realized. This Annual Report and the statements contained herein are submitted for the general information of stockholders and employees of the Company and are not intended to induce any sale or purchase of securities or to be used in connection therewith. For up-to-date investor information, please visit the Investor Relations section of National Fuel Gas Company's Corporate Web site at http://www.nationalfuel.com. If you would like to receive news releases automatically by email, simply visit the News section and subscribe.

Design by addison.com

Revegetated FM100 right of way in Elk State Forest in PA. Supply will plant additional trees on this portion of right of way as part of its reclamation efforts.

National Fuel®

National Fuel Gas Company
6363 Main Street
Williamsville, New York 14221
716 857 7000
www.nationalfuel.com
NYSE: NFG

APPENDIX I

SRC PPC Plan

SRC PPC Plan

Class II Injection Well Preparedness, Prevention, and Contingency (PPC) Plan

Seneca Resources Corporation

The PPC Plan for Seneca Resources Corporation's Class II Injection well (#38268), located in Highland Township, Elk County, Pennsylvania

July 2017

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A. General Description of the Facility and Operations

A.1. Location of Facility

Seneca Resources Corporation (Seneca) owns and operates a Class II Injection well (facility) for disposal of fluids produced by Seneca's oil and gas wells. The facility, found on the James City, PA USGS 7.5 minute topographic map, is located at 36 Mustang Road in Highland Township, Elk County, Pennsylvania and is located in the Middle Allegheny-Tionesta Watershed (HUC 05010003) (**Figure 1 – Site Map** and **Figure 2 – Detail Map**).

The facility is located approximately 1 mile east of the village of James City, PA and approximately 0.5 miles east of the intersection of PA Route 66 and Lamont Road. It is located near the headwaters of an unnamed tributary to Wolf Run. Private groundwater wells are located approximately 0.8 to 1.0 mile east of the injection well. Highland Township's municipal water supply, consisting of two springs and two backup water wells, is located approximately 0.6 to 0.8 miles north/northwest of the injection well. There are no known public or private surface water intakes downstream from the site.

The injection well, identified as Seneca Well #38268, is permitted by Pennsylvania Department of Environmental Protection (API #37-047-23835) and by the U.S. Environmental Protection Agency (PAD2D025BELK).

A.2. Description of Activities

The facility is designed to accept produced water from Seneca's oil and gas wells. The fluid is minimally processed and stored onsite for a short period before injection into the subsurface via the permitted well. Processing activities include oil-water separation, de-sanding, and adding corrosion inhibitor and biocide to the produced water. Oil separated from the produced water will be collected and sent to a local refinery for sale and processing. Sand and other materials removed from the produced water will be recycled in the hydraulic fracturing process at other Seneca well locations, or will be properly disposed at permitted landfills. The facilities on-site consist of a truck unloading pad, piping, above-ground storage tanks, an oil-water separator, pumps, meters, control shed, and injection well (**Figure 3 – Site Layout**).

A.3. Site Layout

A general layout of the site is shown in **Figure 3 – Site Layout** and **Figure 4 – Facility Layout**. **Figure 5** shows the tank inventory. Incoming produced water is delivered to the site via an entrance/exit road off of Lamont Road. Access is controlled by a fence surrounding the site and a keypad-activated gate. Produced water is offloaded at the Truck Unloading Pads and pumped into a receiving tank (T12). The truck unloading pads are constructed of concrete sloped to a sump drain. The sump is piped to the receiving tank (T12). All tanks are located inside a concrete containment. Corrosion inhibitor and biocide are also stored inside the concrete containment. There are no outfall pipes or drains at this facility.

B. Description of Existing Emergency Response Plan

This is a new facility. Therefore, there are no existing emergency response plans for this site.

C. Organizational Structure for Developing, Implementing, and Maintaining the PPC Plan

C.1. Responsible Personnel for Implementation

Seneca's Environmental Engineering department is responsible for developing, modifying, and implementing this Plan. Amanda Veazey, Seneca geologist, prepared the plan with input from Ladi Okunuga, Seneca engineer. This PPC Plan was reviewed by Seneca Environmental Health and Safety staff. The plan was approved by Doug Kepler, Vice President of Environmental Engineering. The plan will be implemented and modified as needed by Seneca Environmental Engineering staff.

The Seneca personnel responsible for this PPC plan have the overall responsibility for periodically reviewing and evaluating the plan and instituting appropriate changes at regular intervals. They are also responsible for the review of new construction and process changes at the site relative to the PPC plan.

D. Material and Waste Inventory

D.1. Material and Waste Inventory Overview

The primary material to be managed at this site is produced water, which comes from Seneca's conventional and unconventional gas or combination oil and gas wells located in several counties throughout northwestern and north central Pennsylvania. The produced water will be stored in tanks located inside the concrete containment. Biocide, corrosion and scale inhibitor will be used to treat the produced water before injecting the produced water downhole at this facility. The biocide will be stored in a chemical tote within the concrete containment of the tank farm. This chemical tote will have secondary containment and a shield to prevent the accumulation of rainwater in the secondary containment. The scale and corrosion inhibitor will be stored in individual chemical totes and secondary containment in the pump room.

The desanding process used to remove sand and other particles from the produced water before it is pumped into the injection well will create a slurry of sand and water. This will be stored in a container in the tank farm (Trap Skid).

After the desanding process, the oil-water separator will remove oil from the produced water prior to injection. The oil will be stored in tank 11 (T11) until it is hauled away from the site via tanker truck.

D.2. Material and Waste Inventory Details

Health and safety information on the substances stored onsite is summarized in the table below. Safety Data Sheets for each substance are located in **Appendix A –Safety Data Sheets**. Each tank and/or container storing these and any other materials will be properly and clearly labeled.

Material Name	CAS Number	Location	Source	Maximum Quantity Onsite
Produced Water	See SDS	T1-10, T12	Seneca's conventional and unconventional wells	2,580 barrels
Desander slurry	See SDS	Trap Skid, Tank Farm	Desanding process	<500 lbs.
Crude Oil	See SDS	T11	Oil-water separator	100 barrels
Bactron K-139 (Biocide, glutaraldehyde, quaternary ammonium	See SDS	Tank Farm	Supplier*	110 gallons (2.4 barrels)

Material Name	CAS Number	Location	Source	Maximum Quantity Onsite
compounds, ethanol)				
Gyptron T-315 (Scale inhibitor, methanol)	See SDS	Pump & Filtration Room	Supplier*	110 gallons (2.4 barrels)
Cortron RN-211 (Corrosion inhibitor, methanol, surfactants)	See SDS	Pump & Filtration Room	Supplier*	110 gallons (2.4 barrels)

*Current supplier is Champion Technologies. Supplier is subject to change.

E. Spill and Leak Prevention and Response

E.1. Potential Spill and Leak Sources

Spills and leaks have the potential to occur in the following places at the site:

- Truck unloading pads
- Along pipes, at joints, and at valves
- Produced water tanks
- Chemicals storage totes
- Injection well wellhead

E.2. Pollution Prevention Measures

Leaks of motor oil, hydraulic oil, or fuel at the truck unloading station will be contained using clay absorbents. Spills of produced water at the truck unloading station or at other locations at the facility will be contained using clay absorbents or will be washed into the sump for placement into the storage tank for disposal. In addition, emergency shutoff switches are located at the facility entrance, the truck unloading area, pump room and wellhead.

The truck unloading area is a concrete pad, sloped towards a sump at the center of the pad. The sump has a pump to move pooled fluid into the primary receiving tank (T12). The produced water tanks are located inside a large, concrete containment area designed to hold 3,550 barrels of fluid. There are no drains in this containment.

All spills will be contained onsite. The facility is designed with a containment system large enough to hold 110% of the volume of all storage tanks located onsite. **Appendix B – Facility Design Summary** contains details regarding facility design and containment specifications.

The storage tote for the biocide is located within secondary containment, inside the primary tank farm containment area. The storage totes for the scale and corrosion inhibitors are located inside the pump room within secondary containment.

As required by the US EPA Class II Underground Injection Control Permit, Seneca constantly monitors the injection pressure, specific gravity of injected fluid, and annular pressure at the injection well. If injection pressure exceeds 1416 pounds per square inch (psi) at the surface, operations will cease immediately and must be reported to US EPA Region 3. Additionally, if annular pressure changes significantly, suggesting mechanical integrity failure, the well will automatically shut in, injection will cease, and US EPA must be notified per the permit requirements.

Fires will be extinguished using fire extinguishers available at the facility. In the event a fire cannot be quickly extinguished, the fire department will be contacted by phone.

F. Material Compatibility

Seneca uses tanks and pipes which are compatible with the materials used and stored onsite.

Material compatibility between produced water and process chemicals was evaluated on behalf of Seneca by Tetra Tech. Tetra Tech is an environmental and engineering consulting firm, with expertise in geochemistry and its application to the oil and gas industry. No compatibility issues between the produced water and chemicals used for scale, corrosion, or biological control were identified. Please see **Appendix C – Material Compatibility Report** for more details.

G. Inspection and Monitoring Program

Seneca will regularly inspect all equipment associated with this facility using the following schedule:

a. Pipes, pumps, values, and fittings for leaks – visual inspection weekly.
b. Tanks for corrosion – visual inspection weekly.
c. Tanks supports and foundations for deterioration – visual inspection quarterly.
d. Evidence of spilled materials along drainage ditches – visual inspection weekly.
e. Effectiveness of housekeeping practices –quarterly review with office and field personnel.
f. Damage to chemical storage containers – visual inspection weekly.
g. Leaks, seeps, or overflows outside of containment – inspection weekly.

Liquid levels in the tanks will be monitored electronically via computer displays in the control shed and at Seneca offices in Pittsburgh and Brookville. The tanks are equipped with valve control devices to prevent overfilling.

H. Preventive Maintenance

Preventive maintenance will be performed on equipment related to fluid storage and fluid movement. This will be done in a systematic manner, depending on equipment service time and manufacturers' recommendations.

Maintenance logs for tanks, pumps, and piping will be kept in the Pump and Filtration room for review.

I. Housekeeping Program

Good housekeeping will reduce the possibility of accidental spills and safety hazards to Seneca employees, contractors, and authorized site visitors. Seneca will employ the following strategies for good housekeeping:

- Neat and orderly storage of chemicals,
- Prompt removal of small spills,
- Regular refuse pickup and disposal,
- Storing containers and/or drums in locations away from open walkways, pathways, or roads,
- Maintenance of spill response kits, and
- Maintenance of clean/dry floors.

J. Security

Seneca employs several security strategies to maintain control of the site and prevent unauthorized or accidental entry that could result in injury to persons or wildlife or could result in a violation of DEP regulations.

- There is a chain link fence around the perimeter of the site. Gate access to the site is controlled by a PIN activated keypad at the entrance of the facility.
- There are closed-circuit cameras monitoring activities on location 24 hours a day. These cameras provide video feed to Seneca offices in Pittsburgh and Brookville. They also record video footage. This video footage is stored for a period of time.
- Motion activated lights are installed onsite to illuminate the unloading pads, the tank farm, and the pump/filtration room.
- Entry into the pump room will be restricted via access code to prevent unauthorized entry.
- An alarm system will notify Seneca personnel in the event of an unauthorized entry to the facility. The alarm system will also notify Seneca personnel in the event of equipment failure.
- The entry road to the site from Lamont Road accommodates two-way traffic, but converts to a one-way loop into and out of the truck unloading facility. Before vehicles can leave the location, they must come to a complete stop at a stop sign to prevent traffic incidents.

K. External Factors

Seneca acknowledges that certain external factors outside its control may impact site operations. Power outages, snowstorms and heavy rain/flooding have the potential to negatively affect operations.

The pumps used to move fluids at the facility run off electricity provided by the local electric utility. In the event of a power outage, the facility will not be able to move fluids between tanks or pump brine into the disposal well. The alarm and communication system has a battery backup system to supply power for approximately 24 hours in case the facility loses power. Therefore all monitoring devices should be functional during a power outage.

During a snowstorm, the site may experience high winds and/or heavy snow. The tanks and piping are designed to withstand winds and heavy snow. Detailed information regarding design specification will be provided by the manufacturer to Seneca for approval prior to installation.

The facility is designed to operate without continuous personnel presence. If the facility is running low on brine, the pumps will shut down preventing further disposal into the injection well.

During a significant rain event, water may accumulate in the tank farm containment. Should this occur, water will be collected in the containment's sump and will be pumped into the initial receiving tank (T12) for disposal on-site. The containment is designed to hold 149,200 gallons (3,550 barrels) of fluid.

The pumps and scale and corrosion inhibitor totes are located in a pump room. The amount of chemicals in the pump room is limited to 220 gallons. The pump and filtration room floor is sloped with a sump drain to contain any spills or releases. The sump is piped directly to the facility receiving tank (T12).

L. Internal and External Communications or Alarm Systems

Seneca will employ various methods to communicate emergency conditions at the facility to internal and external personnel.

Color coordinated flashing lights at the entrance and tank farm are used to indicate a potential event on location such as brine/water accumulation within containment of the tank farm.

An ultrasonic sound detector will be mounted on location to listen for high frequency sounds which are abnormal to regular operations. For example, if there is an explosion in the pump room, the ultrasonic sound detector will be triggered and all operations will shut down.

Seneca personnel in Pittsburgh and Brookville will have remote access to all site control panels and will be able to remotely shut down operations. Specific Seneca personnel will be automatically notified in the event of an emergency situation such as a security breach or equipment failure.

Seneca personnel and its onsite contractors will use the Elk County Emergency Management's 911 system to summon emergency assistance from local police or fire departments.

Below is a list of telephone numbers for first responders, regulatory agencies, and local government entities which will be notified by the Emergency Coordinator or appointed on-site designee in the event of an emergency.

Highland Township Fire Department	911
Elk County Sheriff's Department	911
PA DEP Northwest Regional Office	(814) 332-6945 or (800) 373-3398
US Environmental Protection Agency	(215) 814-5464 or (215) 814-5445
National Response Center	(800) 424-8802

M. Employee Training Program

Each employee and contractor responsible for operating the facility will be required to attend site-specific safety and operations training. This training will enable employees and contractors to understand the processes and materials involved in the operation of the facility. The training will also incorporate information about health and safety hazards, as well as the methods for preventing spills and the procedures for properly and quickly responding to them if they occur.

The training program will include the following topics:

- Proper operation of all pumps, valves, pipes, tanks, etc.
- Preventive maintenance, facility inspection, and housekeeping practices
- Response to spills and leaks.
- Procedures for using, inspecting, repairing, and replacing emergency and monitoring equipment.
- Key parameters for automatic shutoff systems, communications, and alarm systems.
- Response to fires, explosions, and medical emergencies.
- Site evacuation procedures.
- Operations shutdowns.
- Reporting emergencies and other non-scheduled incidents.

A training log will be maintained at Seneca’s Pittsburgh and Brookville offices.

Employees and contractors will not be given the key code for the gate to the facility until they have successfully completed this training.

N. List of Emergency Coordinators

In the event of an emergency at the Facility, the following Seneca employees are authorized to act as emergency coordinators:

Role	Name	Work Phone	Cell Phone
Primary Emergency Coordinator	Jeff Passerrello	814-220-1582	814-715-6782
Secondary Emergency Coordinator	Andy Woodward		814-715-5525
Seneca Facilities Senior Advisor	Terry Dunmyre	412-548-2642	412-742-1273
Seneca Geologist	Amanda Veazey	412-548-2533	412-709-1715
Seneca Vice President, Environmental Engineering	Doug Kepler		814-771-0281

O. Duties and Responsibilities of Emergency Coordinators and Other Employees

The emergency coordinator (EC) is responsible for assessing any spill or emergency situation. In the event of a fire that cannot be extinguished using onsite fire extinguishers, the EC shall contact the Highland Township Fire Department by calling 911. In the event of a major spill, the EC shall contact appropriate emergency response personnel as needed. The EC shall ensure that all used absorbent materials are cleaned up and properly disposed, that emergency supplies are replaced, and that tanks, pipes, valves, and emergency equipment are inspected and repaired or replaced as needed. The EC shall prepare and submit any information required for reporting to the US EPA or PA DEP to Amanda Veazey or alternate Seneca contact. The EC shall train new employees and contractors involved with the operation of the facility on this plan.

Other employees and approved contractors will inspect the facility for spills any time trucks are unloading or pumps are operating. Any spill will be promptly reported to the EC and cleaned up by the employee or contractor.

P. Chain of Command

In the event of an emergency or spill, the following key Seneca employees will be contacted:

Role	Name	Work Phone	Cell Phone
Primary Emergency Coordinator	Jeff Passerrello	814-220-1582	814-715-6782
Secondary Emergency Coordinator	Andy Woodward		814-715-5525
Seneca Facilities Senior Advisor	Terry Dunmyre	412-548-2642	412-742-1273
Seneca Geologist	Amanda Veazey	412-548-2533	412-709-1715
Seneca Vice President, Environmental Engineering	Doug Kepler		814-771-0281

This list will be posted inside the Pump and Filtration building.

Q. Emergency Notification List

Below is a list of telephone numbers for first responders, regulatory agencies, and local government entities which will be notified by the Emergency Coordinator or appointed on-site designee in the event of an emergency.

Facility & Operator Information	Key Emergency Numbers
Location Information: **36 Mustang Road James City, PA** **Highland Township, Elk County** Operator: **Seneca Resources Corporation EHS:** **Jeff Passerrello**, Environmental, Health & Safety Representative- Pipeline & Facilities, Water Management and Highland Field Services **(814) 715-6782** **Andy Woodward,** Environmental, Health and Safety Representative –Completions and Well Intervention Departments **(814) 715-5525** Environmental Engineering: **Doug Kepler**, Vice President, Environmental Engineering **(814) 771-0281** Environmental Geology: **Amanda Veazey,** Advisor, Environmental Geology **(412) 709-1715** Construction: **Ben Williams**, Manager, Construction **(814) 389-7318**	Closest Fire Station: **911** Highland Township Fire Dept Police Station **911** Elk County Sheriff's Department Closest Hospital: **911** Kane Community Hospital, 4372 US-6, Kane, PA 16735 USCG/National Response Center (NRC): **(800) 424-8802** Pennsylvania Dept. of Environmental Protection Northwest 24-hour Emergency No.: **(814) 332-6945** **After hours: (800) 373-3398** The Pennsylvania Emergency Management Agency (PEMA) **(800) 424-7362 or (717) 651-2001** Elk County Office of Emergency Management Department: **911 or ((814) 7764600** **NOTE:** Some cell phones do not support 911 calls. Phones should be tested on location prior to operations.

R. Emergency Equipment and Supplies Inventory

The following equipment is available at this facility in the Pump and Filtration Building:

- First aid kit,
- Emergency eye wash station,
- Fire extinguishers,
- Clay absorbent,
- Brooms, and
- Shovels.

The level of clay absorbent in the drum will be checked weekly or after any non-routine use. Any time the level drops below half full, new absorbent will be ordered. Fire extinguishers will also be inspected weekly. If a fire extinguisher is noted to have low pressure or was used for any purpose, it will be replaced within 24 hours.

S. Evacuation Plan for Facility Personnel

In the event of a serious emergency at the facility which requires site evacuation, personnel will muster at the entrance to the location at the gate near Lamont Road. The muster point is noted on **Figure 3 – Site Layout**.

T. Arrangements with Emergency Response Contractors

Seneca has made arrangements with the following contractors to respond to spills:

EAP Industries, Inc.
701 East Spring Street
Titusville, PA 16354
Primary contact: John Straub
Cell: (412) 999-1676
Email: Jstraub1676@verizon.net
24 Hour Emergency #: (814) 827-9902

ECS&R
3237 US Highway 19
Cochranton, PA 16314
Primary contact: Mike Liscinski
Cell: (814) 573-0445
Email: mikeliscinski@ecsr.net
24 Hour Emergency #: (866) 815-0016

Rapid Response, Inc. (an affiliate of Environmental Waste Minimization, Inc. (EWMI))
14 Brick Kiln Court
Northampton, PA 18067
24 Hour Emergency Number: (877) 460-1038

U. Agreements with Local Emergency Response Agencies and Hospitals

Seneca has notified Highland Township's Fire Department and Kane Community Hospital regarding the chemicals and crude oil stored onsite. Should a significant event occur which requires emergency responders and/or hospital care, these entities are aware of the chemicals used and stored onsite.

<u>Directions from the Facility to Kane Community Hospital</u>:

From James City SWD site 36 Mustang Lane
Head northwest on Lamont Rd/T319 toward PA-66 S - 0.4 mile
Turn right onto PA-66 N - 3.0 miles
Continue onto US-6 W/N Fraley St - 1.0 mile
Arrive at Kane Community Hospital on left.

Refer to the following page for a map of the hospital route.

V. Pollution Incident History

This is a new facility. There is no pollution incident history to report.

W. Implementation Schedule

This PPC plan will be implemented prior to first operation.

Figures

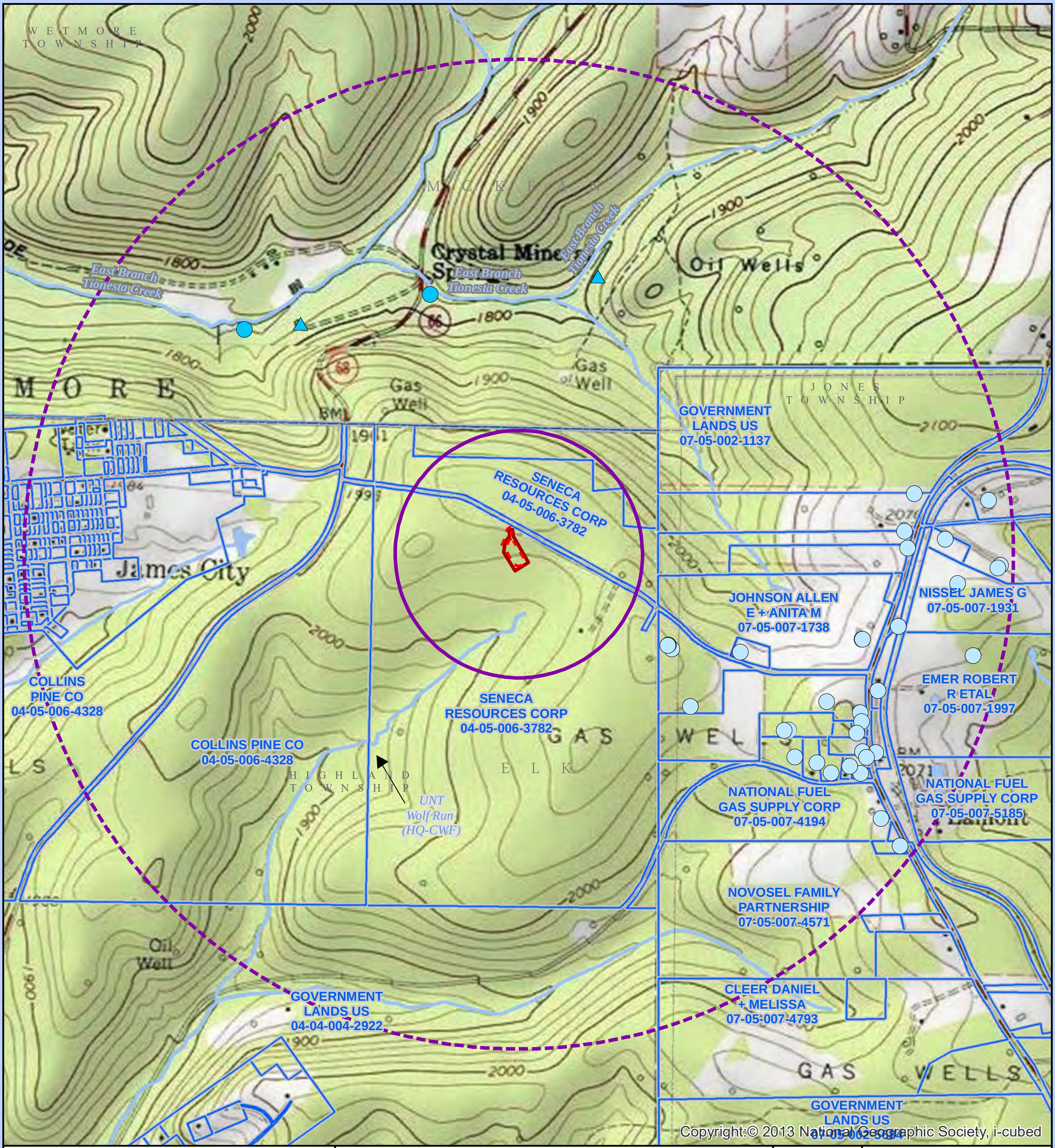
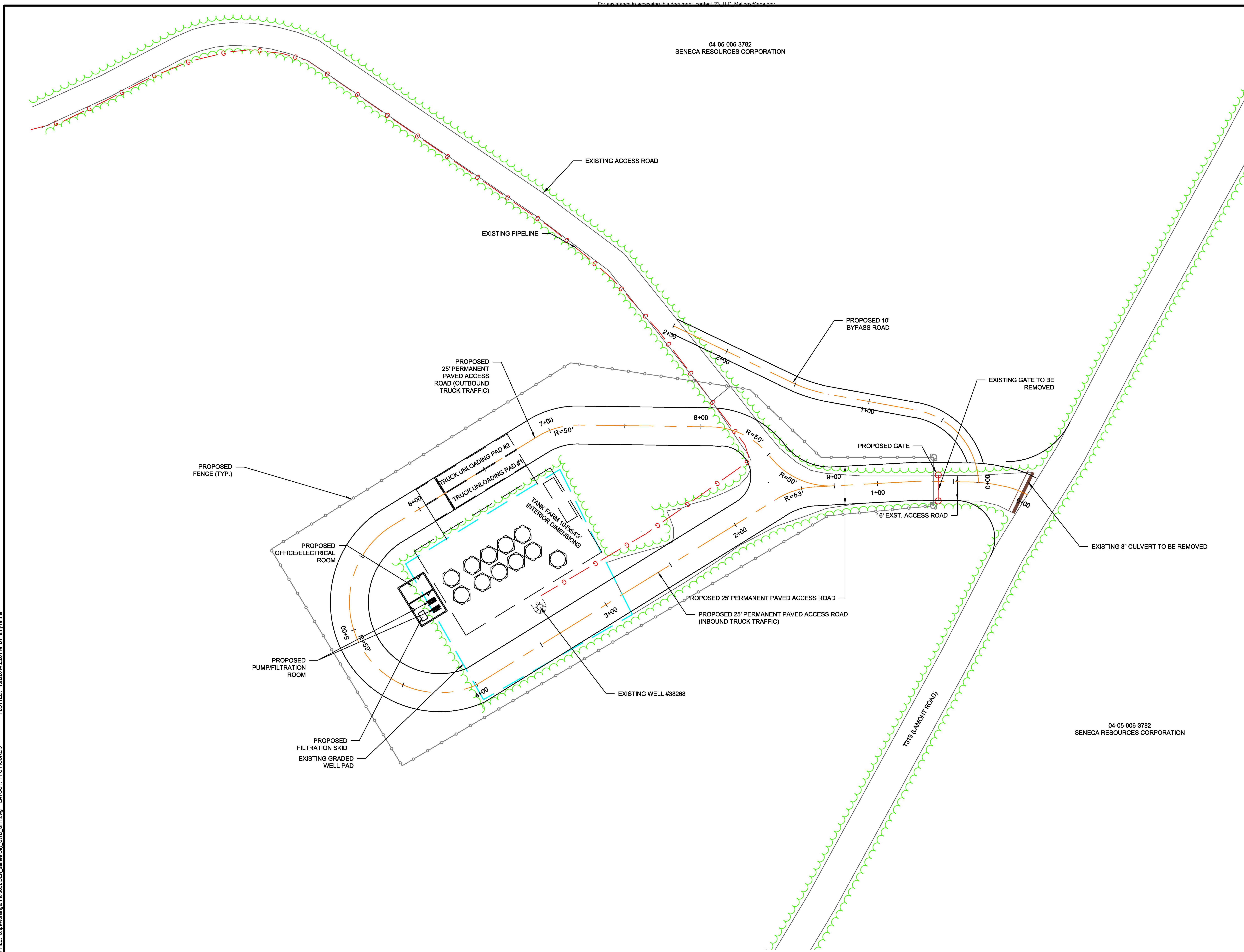

WETMORE TOWNSHIP
MCKEAN
Crystal Mineral Spring
East Branch Tionesta Creek
East Branch Tionesta Creek
East Branch Tionesta Creek
Oil Wells
Gas Well
Gas Well
WETMORE
JONES TOWNSHIP
GOVERNMENT LANDS US 07-05-002-1137
SENECA RESOURCES CORP 04-05-006-3782
James City
JOHNSON ALLEN E + ANITA M 07-05-007-1738
NISSEL JAMES G 07-05-007-1931
EMER ROBERT R ETAL 07-05-007-1997
COLLINS PINE CO 04-05-006-4328
SENECA RESOURCES CORP 04-05-006-3782
COLLINS PINE CO 04-05-006-4328
GAS
ELK
HIGHLAND TOWNSHIP
UNT Wolf Run (HQ-CWF)
WELLS
NATIONAL FUEL GAS SUPPLY CORP 07-05-007-4194
NATIONAL FUEL GAS SUPPLY CORP 07-05-007-5185
Lamont
NOVOSEL FAMILY PARTNERSHIP 07-05-007-4571
Oil Well
CLEER DANIEL + MELISSA 07-05-007-4793
GOVERNMENT LANDS US 04-04-004-2922
GAS WELLS
GOVERNMENT LANDS US 07-05-002-3694
Copyright:© 2013 National Geographic Society, i-cubed

Figure 2 - Detail Map

Highland Township, Elk County, PA

October 01, 2014 | Drawn By: AKH



KLEINFELDER
Bright People. Right Solutions.
230 Executive Drive, Suite 122
Cranberry Township, PA 16066
Phone: 724-772-7072
www.kleinfelder.com

Signed By: MICHAEL E. ARCHER, P.E. # PE-056060

REVISIONS

REV	DESCRIPTION	DSN / DWN	CHK / APP	DATE

SCALE VERIFICATION

THIS BAR IS 1 INCH IN LENGTH ON ORIGINAL DRAWING

0 1"

IF IT'S NOT 1 INCH ON THIS SHEET ADJUST YOUR SCALES ACCORDINGLY

0 30 60 90

SCALE IN FEET

ORIGINAL DRAWING SIZE IS 22 x 34

FACILITY LAYOUT

UNDERGROUND INJECTION CONTROL PERMIT
PAS2D025BELK - WELL #38268
HIGHLAND TOWNSHIP, ELK COUNTY, PA

SENECA RESOURCES
SENECA RESOURCES CORPORATION
5800 CORPORATE DRIVE, SUITE 300
PITTSBURGH, PA 15237
(412) 548-2500

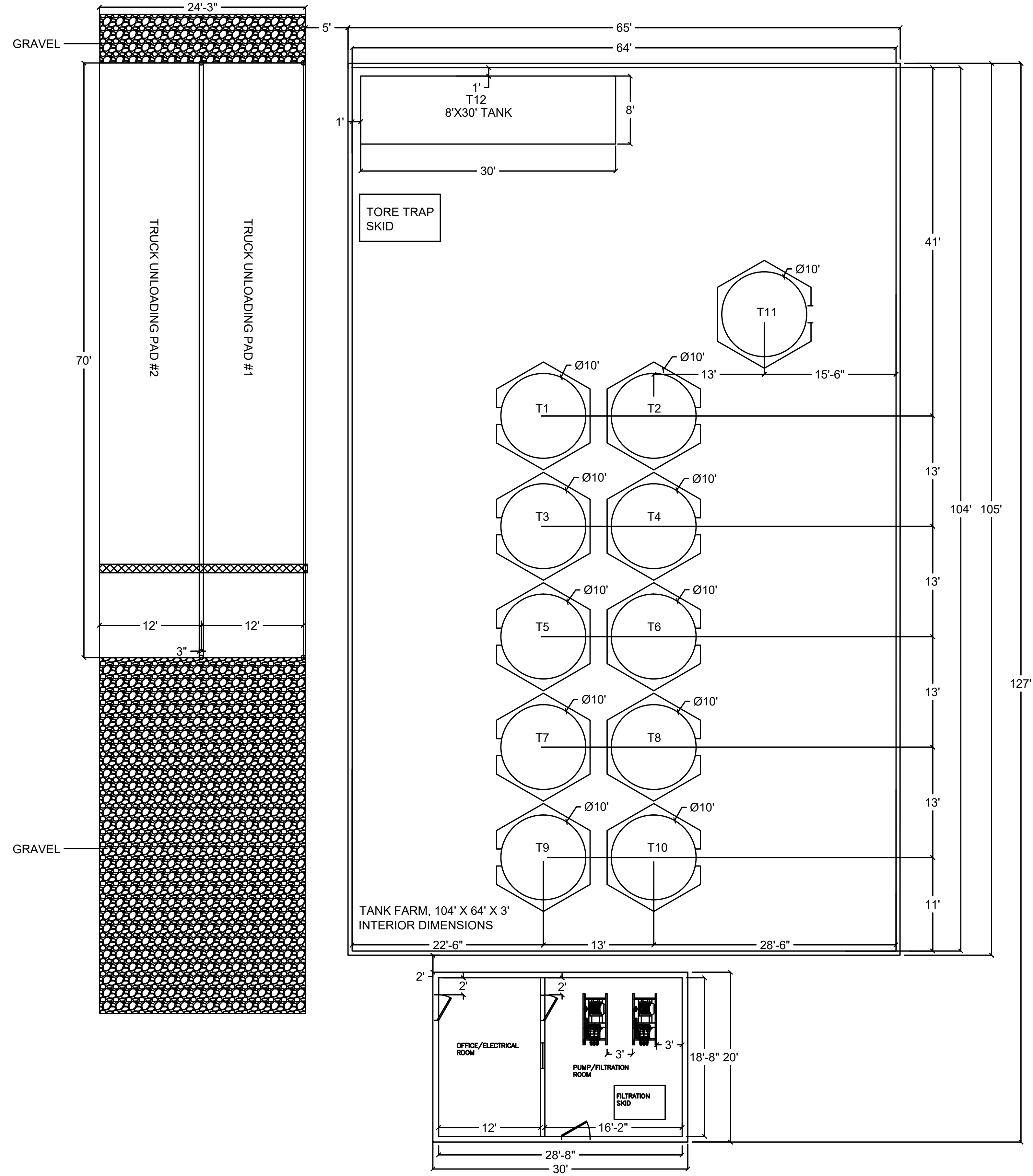
PPC FIGURE 3

PROJECT NO.	20143854
ISSUE DATE	10/02/2014
CURRENT REVISION	----
DESIGNED BY	AER
DRAWN BY	AER
CHECKED BY	-
APPROVED BY	-

1

SHEET 1 of 1

CAD FILE: C:\pwworking\dms78632\SEN_James City_SWD_SHT.dwg LAYOUT: PPC FIGURE 3 PLOTTED: 10/2/2014 2:28 PM BY: amy reimer



NOTES:

1. TANK FARM CONTAINMENT TO BE CONCRETE CONSTRUCTION, INTERIOR DIMENSIONS OF 104'LX64'WX3'.
2. TRUCK UNLOADING PAD TO BE CONSTRUCTED OF CONCRETE WITH A SLOPE OF 12:1 TO SUMP DRAIN.
3. ALL TANKS TO BE SET ON CONCRETE HOUSEKEEPING PADS, NO LESS THAN 6" THICKNESS.

GENERAL NOTES

NOTE 1: LISTING FOR DISCUSSION/APPROVAL ONLY

REFERENCE DRAWINGS

DWG. NO.	DESCRIPTION
D-1610001-A	SENECA KANE JAMES SWD PDF
D-1610002-A	SENECA KANE JAMES SWD BOM
D-1610003-A	SENECA KANE JAMES SWD SITE LAYOUT

REFERENCE DRAWINGS

DWG. NO.	DESCRIPTION

DRAWING STATUS

NO.	DATE	BY	DESCRIPTION

REVISIONS

NO.	DATE	DESCRIPTION
1	08/12/14	TANK FARM LAYOUT

SCALE
DRAWN BAM DATE 08/12/2014
CHK'D DATE
APPROVED DATE
FMS JOB NO.
AFE/P.O.NO.
CLIENT FILE NO.
FMS FILE NO. 1610000

FMS

Ph: 812/431-7314

SENECA RESOURCES

KANE JAMES CITY INJECTION FACILITY

SITE LAYOUT

NO. D-1610003-C

REV.

Tank #	QTY	DESCRIPTION	CAPACITY
T1	1	Gun Barrel, Steel, API, 10' x 20'	300 bbl
T2	1	Gun Barrel, Steel, API, 10' x 20'	300 bbl
T3	1	Dirty Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T4	1	Dirty Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T5	1	Dirty Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T6	1	Dirty Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T7	1	Dirty Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T8	1	Dirty Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T9	1	Clean Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T10	1	Clean Water Tank, Steel, Lined, API, 10' x 15'	210 bbl
T11	1	Oil Tank, Steel, API, 10' x 9'	100 bbl
T12	1	Truck Receiving Tank, Steel, Horizontal, 8' x 30'	300 bbl

Figure 5 – Listing of Tanks Shown in Figure 4.

Appendix A –Safety Data Sheets

SENECA RESOURCES

Safety Data Sheet

1. IDENTIFICATION

Seneca Resources Corporation
1201 Louisiana Suite 2600
Houston, TX 77002

Phone Number: (713)654-2600
Emergency Number - East: (800) 526-2608
Emergency Number – West: (888)595-8595

Product Name: **Produced Water**
SDS Number: PRO111

Synonyms: Formation Water, Salt Water, H_2O, Brine Water
Product Description: Water extracted from oil and natural gas well production with residual mineral contents and residual hydrocarbons

2. HAZARDS IDENTIFICATION

Classification:
H350 – Carcinogenicity – Category 1B

Hazards not Otherwise Classified:
May contain or release poisonous hydrogen sulfide gas

Label Elements:

DANGER
May contain or release poisonous hydrogen sulfide gas
May cause cancer. (H350)

Emergency Overview: This product has the potential to be a flammable liquid which may be harmful if ingested, inhaled, comes in contact with skin or eyes, or is released into the environment. Please read entire contents of Section 3 of this SDS for details.

Note: This product has not been tested by Seneca Resources Corporation to determine its specific health hazards. Therefore, the information provided in this section includes health hazard information on the potential product components.

Carcinogenicity:	**NTP**	**IARC Monographs**	**OSHA Regulated**
Benzene	Yes (1)	Yes (1)	Yes

3. COMPOSITION & INFORMATION ON INGREDIENTS

Product/ Components	CAS No.	Wt. % (1)	Occupational Exposure Limits			Units
			OSHA(2)	ACGIH(2)	NIOSH(3)	
Produced Water	Mixture	>68	N/A	N/A	N/A	---
Mineral Variety	N/A	<32	N/A	N/A	N/A	---
Gas Condensate	8002-05-9	<1	500 ppm	N/A	350 mg/m^3	
Benzene	71-43-2	<1	1 5^{STEL}	0.5 2.5^{STEL}	0.1 1^{STEL}	ppm
Hydrogen Sulfide	7783-06-4	<1	20^{Ceiling} 50^{STEL}	1 5^{STEL}	10^{Ceiling}	ppm

(1) Normal composition ranges are shown. Exceptions may occur depending upon the source of the produced water.
(2) 8-hour Total Weight Average (TWA) unless otherwise specified
(3) 10-hour TWA unless otherwise specified
(4) ACGIH has established a Biological Exposure Index (BEI) for this substance due to its carcinogenicity
N/A = Not Applicable
STEL (Short Term Exposure Limit): 15 minutes

Note: Composition will vary with geographic location, geologic formation, temperature, and pressure. Although, in Marcellus Shale Gas Development H_2S has not been found as a predominant characteristic in produced water, it has been included as a precautionary measure if it were to develop in future applications.

4. FIRST AID MEASURES

Potential Health Effects from Overexposure:

Acute Effects:

Eyes: Eye contact with vapors may cause eye irritation. Eye contact with liquid may cause irritation, and pain. Eye contact with Hydrogen Sulfide (H_2S) gas may cause painful irritation and may be indicative of exposure above applicable H_2S standards.

Skin: Skin contact may cause skin irritation and redness. Repeated or prolonged skin contact may cause dermatitis.

Inhalation:	Breathing the mist and vapors may be irritating to the respiratory tract. H_2S is irritating and highly toxic if inhaled.
Ingestion:	Ingestion may cause irritation of the digestive tract that may result in nausea, vomiting and diarrhea. In addition, signs and symptoms of H_2S toxicity may be present.

Chronic Effects: Skin, eye and respiratory tract irritation. Gastrointestinal and vascular effects and death may occur at high concentrations. May cause nervous system effects, such as headache, nausea and drowsiness. May contain high concentration of H_2S, from which respiratory paralysis and death may occur.

Additional Medical and Toxicological Information: Natural gas condensate and some of its fractions, which can contaminate produced water, have been shown to cause skin irritation, damage and even cancers when applied directly and repeatedly to the skin. When laboratory animals inhale oil vapors at high concentration or ingest in repeated doses, various tumors have developed.

This product may contain benzene, which can cause degeneration in blood forming bone marrow leading to anemia which may further degrade to leukemia, a type of cancer (see 29 CFR 1910.1028 for standard). Acute benzene poisoning causes central nervous system depression. Chronic exposure affects the hematopoietic system causing blood disorders including anemia and pancytopenia. Benzene is recognized as a human carcinogen by OSHA, NTP, ACGIH and IARC.

Recommended Treatments:

Eye Contact:	Flush eyes immediately with clean, low-pressure water for at least 15 minutes, occasionally lifting the eyelids. If pain or redness persists after flushing, seek medical attention. If eye is exposed to hot liquid, cover eyes with cloth and seek medical attention immediately.
Skin Contact:	In case of hot liquid exposure, do not remove clothing or treat, wash only unburned area and seek medical attention immediately.
Inhalation:	Immediately remove person to area of fresh air. Call 911, emergency medical service, or emergency phone number(s) provided in Section 1. Give artificial respiration if victim is not breathing. Do not use mouth-to-mouth method if victim ingested or inhaled the substance; give artificial respiration with the aid of a pocket mask equipped with a one-way valve or other proper respiratory medical device. Administer oxygen if breathing is difficult.
Ingestion:	Do not induce vomiting. If spontaneous vomiting occurs, hold the victim's head lower than hips to prevent aspiration of liquid into the lungs. Have exposed individual rinse mouth thoroughly with water. Never give anything by mouth to an unconscious person. Obtain medical assistance immediately.
Medical Providers:	Medical providers are urged to contact a Regional Poison Center at 800-222-1222.

5. FIRE FIGHTING MEASURES

Flash Point: Varies widely depending on hydrocarbon content
Flammable Limits in Air, % by Volume: No Data
Autoignition Temperature: N/A
Extinguishing Media: Class B fire extinguisher, dry chemical, foam, carbon dioxide, or water spray. For large fires, use unmanned hoses with water spray or fog. If unable to fight fire safely, withdraw from area and let fire burn.
NFPA Ratings: Health: 1, Flammability: 1, Reactivity: 0

General Hazard: Flammable. May react with strong oxidizing materials and a wide variety of chemicals. May form explosive mixtures with air.

Fire Fighting Instructions: Any fire would be associated with any natural gas condensate floating on the surface of the produced water. Water used for extinguishing may be ineffective on flames but should be used to keep fire exposed containers cool. Keep the surrounding areas cool by using water mists. Firefighters should wear self-contained breathing apparatus and full protective clothing. Refer to Section 8 for appropriate Personal Protective Equipment (PPE) selection.

6. ACCIDENTAL RELEASE MEASURES

As an immediate precautionary measure, isolate spill or leak area for at least 50 meters (150 feet) in all directions. Keep unauthorized personnel away. Stay upwind. Keep out of low areas. Ventilate closed spaces before entering.

Eliminate sources of heat or ignition including internal combustion engines and power tools. Stop gas flow. If indoors, ventilate the affected area. Evacuate building and all affected areas, downwind areas first. Prevent spreading of vapors through sewers, ventilation systems and confined areas. Isolate area until gas has dispersed. For emergency information and procedures to follow in case of an accidental release, call the emergency telephone number(s) listed in Section 1. In case of spillage, absorb with inert material and dispose of in accordance with applicable regulations. Dike far ahead of liquid spill for later disposal. Never discharge releases directly into sewers or surface waters. Remove any ignition sources and protect from ignition. Water spray may reduce vapor; but may not prevent ignition in closed spaces. A vapor suppressing foam may be used to reduce vapors. Provide sufficient ventilation in the affected area(s) and wear appropriate personal protective equipment as indicated in Section 8 when handling spill material.

Note: Large releases may require the notification of local emergency response agencies. Wear self-contained breathing apparatus if conditions warrant.

7. HANDLING & STORAGE

Handle in accordance with good industrial hygiene and safety practices. These practices include, but are not limited to, avoiding unnecessary exposure and prompt removal of material from eyes, skin, and clothing. If needed, take first aid actions as indicated in Section 4.

H_2S and other hazardous vapors may evolve and collect in the headspace of storage tanks or other enclosed vessels. H_2S is an extremely flammable and highly toxic gas.

Handling: Use only with adequate ventilation. Wear appropriate PPE and use exposure controls as indicated in Section 8. Avoid all contact with skin and eyes. Avoid breathing product vapors. Use explosion-proof electrical (ventilating, lighting and material handling) equipment. Remove contaminated clothing immediately. Wash with soap and water after working with this product.

Storage: Keep container in a well-ventilated area. Ground all containers during transfer. Store away from incompatible materials. Cylinders should be separated from oxygen cylinders or other oxidizers by a minimum distance of 20 ft., or by a barrier of non-combustible material at least 5 ft. high having a fire resistance rating of at least 1/2 hour. Store in the original container or an approved alternative made from compatible material. Treat empty containers in a similar fashion as residual product may exist. Use appropriate containment to avoid environmental contamination.

8. EXPOSURE CONTROLS & PERSONAL PROTECTION

Component	ACGIH	OSHA
Hydrogen Sulfide	STEL: 5 ppm TWA: 1 ppm	Ceiling: 20 ppm

Eye Protection: Chemical goggles or face shield should be worn when handling product if the possibility of spray exists.

Skin Protection: Consider wearing long-sleeve, Fire Resistant Clothing (FRC), otherwise normal working clothes should be worn. Wash contaminated clothing prior to reuse. If gloves are required for job operations involving this product, wear nitrile rubber or polyvinylalcohol (PVAL) gloves.

Inhalation: Respiratory protection is not required for normal use. In non-emergency situations, use NIOSH approved respiratory protective equipment in situations where airborne concentrations may meet or exceed occupational exposure levels. At excessive concentrations, wear a NIOSH approved full-face self-contained breathing apparatus (SCBA) with supplied air.

Ventilation: Work in well ventilated areas. Use non-sparking tools where liquids or vapors from the condensate contamination may be generated at flammable concentrations. Note: This product may release gases or vapors that can displace oxygen in enclosed areas.

9. PHYSICAL & CHEMICAL PROPERTIES

Boiling Point @760 mmHg: Varies widely depending on hydrocarbon content
Freezing Point: <32 °F
Vapor Pressure mmHg @100°F: N/A
Vapor Density (Air=1): 1.2
% Solubility in H_2O: N/A
pH at 25°C: Approximately 5.0 – 6.5
Specific Gravity 60/60F: >1@0°C
Evaporation Rate: N/A
% Volatile by Volume: Negligible
Odor: Possible slight hydrocarbon/rotten egg odor
Viscosity (method, temp.): N/A
Appearance: Clear or opaque liquid

10. STABILITY & REACTIVITY

Stability: Stable under normal conditions of use.
Hazardous Polymerization: Will not occur.
Conditions to Avoid/Incompatibilities: Keep material away from heat, sparks, open flames, and oxidizers such as chlorine and concentrated nitric acid.
Hazardous Decomposition Products: Normal combustion of H_2S creates sulfur oxides.

11. TOXICOLOGICAL INFORMATION

Benzene: This product may contain benzene, which can cause degeneration in blood forming bone marrow leading to anemia which may further degrade to leukemia, a type of cancer. Acute benzene poisoning causes central nervous system depression. Chronic exposure affects the hematopoietic system causing blood disorders including anemia and pancytopenia. Mutagenic and clastogenic in mammalian and non-mammalian test systems. Reproductive or developmental toxicant only at doses that are maternally toxic, based on tests with animals.

Hydrogen Sulfide (H_2S): This product may contain H_2S, which may be fatal if inhaled. Inhalation of a single breath at a concentration of 1000 ppm (0.1%) may cause coma. Hydrogen sulfide is corrosive when moist. Skin contact may cause burns. There is a rapid loss of sense of smell on exposure to gas concentrations above 150 ppm, thus the extent of exposure may be underestimated. Perception threshold ranges from 0.5 ppt to 0.1 ppm. Product is an irritant and asphyxiant.

12. ECOLOGICAL INFORMATION

Do not discharge into or allow runoff to flow into sewers and natural waterways. Contain spill material and dike for proper disposal. May be hazardous to waterways/wildlife.

13. DISPOSAL CONSIDERATIONS

This product is not a "listed" hazardous waste. But when disposed of in containers, it may meet the criteria of being an "ignitable" waste. It is the responsibility of the user to determine if the material disposed of meets federal, state, or local criteria to be defined as a hazardous waste and dispose of accordingly.

14. TRANSPORT INFORMATION

Proper Shipping Name: Residual Waste

15. REGULATORY INFORMATION

EPA SARA TITLE III

Section 302 EPCRA Extremely Hazardous Substances (EHS):

Product Component	*CAS No.*	*Wt%*	*RQ, lb*	*TPQ, lb*
None				

Section 304 CERCLA Hazardous Substances:

Product Component	*CAS No.*	*Wt%*	*RQ, lb*
Benzene	71-43-2	<1	10
Hydrogen Sulfide	7783-06-4	<1	100

Section 311/312 Hazard Categorization:

Acute:	*Chronic:*	*Fire:*	*Pressure:*	*Reactive:*
Yes	Yes	Yes	No	No

Section 313 EPCRA Toxic Substances:

Ingredient	*CAS No.*	*Wt.%*
Benzene	71-43-2	<1
Hydrogen Sulfide	7783-06-4	<1

Key RQ = Reportable Quantity
TPQ = Threshold Planning Quantity of EHS

Federal Regulatory Summary

Chemical Name	% Vol	CAS	CAA Accidental Release Prevention Substance	RCRA Hazardous Waste	SARA Extremely Hazardous Substance	SARA Toxic Release Chemical
Produced Water	>68	Mixture	N/A	N/A	N/A	N/A
Mineral Variety	<32	N/A	N/A	N/A	N/A	N/A
Gas Condensate	<1	8802-05-9				
Benzene	0 - 2	71-43-2	NO	YES	NO	YES
Hydrogen Sulfide	0.1 - 2	7783-06-4	YES	YES	YES	YES

Pennsylvania Regulatory Summary

Chemical Name	% Vol	CAS	Hazardous Substance
Produced Water	>68	Mixture	N/A
Mineral Variety	<32	N/A	N/A
Gas Condensate	<1	8002-05-9	
Benzene	<1	71-43-2	YES
Hydrogen Sulfide	<1	7783-06-4	YES

16. OTHER INFORMATION

Date of Issue:	02-Nov-2017
Statues:	Final
Previous Issue Date:	12-July-2016
Revised Sections or Basis for Revision:	Modified NFPA hazard class

THIS INFORMATION RELATES ONLY TO THE SPECIFIC MATERIAL DESIGNATED AND MAY NOT BE VALID FOR SUCH MATERIAL USED IN COMBINATION WITH ANY OTHER MATERIALS OR IN ANY PROCESS. SUCH INFORMATION IS TO THE BEST OF THIS COMPANY'S KNOWLEDGE AND BELIEVED ACCURATE AND RELIABLE AS OF THE DATE INDICATED. HOWEVER, NO REPRESENTATION, WARRANTY OR GUARANTEE IS MADE AS TO THE ACCURACY, RELIABILITY OR COMPLETENESS. IT IS THE USER'S RESPONSIBILITY TO SATISFY THEMSELVES AS TO THE SUITABILITY AND COMPLETENESS OF SUCH INFORMATION FOR HIS OWN PARTICULAR USE.

KEY / LEGEND

ACGIH - American Conference of Governmental Industrial Hygienists
ADR - Agreement on Dangerous Goods by Road
CAA - Clean Air Act
CAS - Chemical Abstracts Service Registry Number
CDG - Carriage of Dangerous Goods By Road and Rail Manual
CERCLA - Comprehensive Environmental Response, Compensation, and Liability Act
CFR - Code of Federal Regulations
EINECS - European Inventory of Existing Chemical Substances Registry Number

ERG - Emergency Response Guidebook
EPCRA - Emergency Planning and Community Right-to-Know Act
GHS - Globally Harmonized System of Classification and Labeling of Chemicals
IARC - International Agency for Research on Cancer
IATA - International Air Transport Association
ICAO - International Civil Aviation Organization
IMDG - International Maritime Dangerous Goods Code
IMO - International Maritime Organization
N/E - Not Established
NTP - National Toxicology Program
OSHA - Occupational Safety and Health Administration
PEL - Permissible Exposure Limit
PPE - Personal Protective Equipment
RCRA - Resource Conversation and Recovery Act
RID - Regulations Concerning the International Transport of Dangerous Goods by Rail
RQ - Reportable Quantities
SARA - Superfund Amendments and Reauthorization Act of 1986
SDS - Safety Data Sheet
TCC - Tag Closed Cup
TDG - Transportation of Dangerous Goods
TLV - Threshold Limit Value
TSCA - Toxic Substance Control Act
TWA - Total Weight Average
UN/NA - United Nations / North American Number
UNECE - United Nations Economic Commission for Europe
US DOT - United States Department of Transportation
US EPA - United States Environmental Protection Agency
Vol. - Volume
WHMIS - Workplace Hazardous Materials Information System

Safety Data Sheet

1. IDENTIFICATION

Seneca Resources Corporation
1201 Louisiana Suite 2600
Houston, TX 77002

Phone Number: (713)654-2600
Emergency Number - East: (800) 526-2608
Emergency Number – West: (888)595-8595

Product Name: **Crude Oil**
SDS Number: OIL111

Synonyms: Crude, Sweet Crude Oil, Sour Crude Oil, Light Crude Oil, Heavy Crude Oil
Product Description: Petroleum hydrocarbon used as refinery feedstock

2. HAZARDS IDENTIFICATION

Classification:
H224 - Flammable Liquids: Category 1
H340 - Germ Cell Mutagenicity: Category 1B
H350 – Carcinogenicity – Category 1A
H304 – Aspiration Hazard – Category 1
H319 – Eye hazard – Category 2A
H336 - Specific target organ toxicity, single exposure – Category 3
H373 - Specific target organ toxicity, repeated exposure – Category 2
H411 - Hazardous to the aquatic environment, chronic toxicity – Category 2

Hazards not Otherwise Classified:
May contain or release poisonous hydrogen sulfide gas

Label Elements:

DANGER

Hazard Statements

Extremely flammable liquid and vapor (H224)
May contain or release poisonous hydrogen sulfide gas
May cause cancer (H350)
May cause genetic defects (H340)
May be fatal if swallowed and enters airways (H304)
Causes serious eye irritation (H319)
May cause drowsiness or dizziness (H336)
May cause damage to organs (central nervous system, other organs) through prolonged or repeated exposure (H373)
Toxic to aquatic life with long lasting effects (H411)

Precautionary Statements

Obtain special instructions before use (P201)
Do not handle until all safety precautions have been read and understood (P202)
Keep away from heat/sparks/open flames/hot surfaces – no smoking (P210)
Keep container tightly closed (P233)
Ground/bond container and receiving equipment (P240)
Use explosion-proof electrical/ventilating/lighting equipment (P241)
Use only non-sparking tools (P242)
Take precautionary measures against static discharge (P243)
Avoid breathing dust/fume/gas/mist/vapours/spray (P261)
Wash thoroughly after handling (P264)
Use only outdoors or in a well-ventilated area (P271)
Avoid release to the environment (P273)
Wear protective gloves / protective clothing / eye protection / face protection (P280)
IF ON SKIN OR HAIR: Remove/take off immediately all contaminated clothing. Wash with plenty of soap and water. Take off contaminated clothing and wash before reuse. (P361, P352, P362)
IF IN EYES: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing (P305, P351, P338)
If eye irritation persists, get medical advice/attention (P313)
IF SWALLOWED: Immediately call a POISON CENTER or doctor/physician (P301, P310)
Do NOT induce vomiting (P331)
IF INHALED: Remove victim to fresh air and keep at rest in a position comfortable for Breathing (P304, P340)
Call a POISON CENTER or doctor/physician if you feel unwell (P312)
In case of fire: Use dry chemical, carbon dioxide, or foam for extinction
Collect spillage (P370, P378)
Store locked up (P405)
Store in a well-ventilated place. Keep container tightly closed, Keep cool (P403, P233, P235)
Dispose of contents/container to approved facility (P501)

3. COMPOSITION & INFORMATION ON INGREDIENTS

Product/ Components	CAS No.	Wt. % (1)	Occupational Exposure Limits			Units
			OSHA(2)	ACGIH(2)	NIOSH(3)	
Crude Oil	8002-05-9	100%	500 ppm	N/A	350 mg/m^3	
Benzene	71-43-2	<5	1 5^{STEL}	0.5 2.5^{STEL}	0.1 1^{STEL}	ppm
Hydrogen Sulfide	7783-06-4	0.00-3.5	20^{Ceiling} 50^{STEL}	1 5^{STEL}	10^{Ceiling}	ppm
Xylene, all isomers	1330-20-7	<3	100 150^{STEL} 300^{Ceiling}	100 150^{STEL}	100 150^{STEL}	ppm
Toluene	108-88-3	<2	10 150^{STEL} 300^{Ceiling}	20	100 150^{STEL}	ppm
Polycyclic Aromatic Hydrocarbons	mixture	Variable	0.2	0.2	80^{IDLH}	mg/m^3
Naphthalene	91-20-3	<2	10 15^{STEL}	10 15^{STEL}	10 15^{STEL}	ppm
Ethylbenzene	100-41-4	<3	100 125^{STEL}	20	100 125^{STEL}	ppm

(1) Normal composition ranges are shown. Exceptions may occur depending upon the source of the crude oil.
(2) 8-hour Total Weight Average (TWA) unless otherwise specified
(3) 10-hour TWA unless otherwise specified
N/A = Not Applicable
STEL (Short Term Exposure Limit): 15 minutes
IDLH=Immediately Dangerous to Live and Health

Note: Composition will vary with geographic location, geologic formation, temperature, and pressure.

4. FIRST AID MEASURES

Inhalation (Breathing)
Move the exposed person to fresh air. If not breathing, clear airways and give artificial respiration. If breathing is difficult, humidified oxygen should be administered by qualified personnel. Seek medical attention if breathing difficulties continue.

Eye Contact
Flush eyes with water for at least 15 minutes. Hold eyelids apart to ensure complete irrigation of the eye. Remove contact lenses, if worn, after initial flushing. Do not use eye ointment. Seek medical attention.

<u>Skin Contact</u>
Remove contaminated shoes and clothing, and flush affected areas with large amounts of water. If skin surface is damaged, apply a clean dressing and seek medical attention. If skin surface is not damaged, clean affected area thoroughly with mild soap and water. Seek medical attention if tissue appears damaged or if pain or irritation persists. Launder or discard contaminated clothing.

<u>Ingestion (Swallowing)</u>
Aspiration hazard. Do not induce vomiting or give anything by mouth because the material can enter the lungs and cause severe lung damage. If spontaneous vomiting is about to occur, place victim's head below knees. If victim is drowsy or unconscious, place on the left side with head down. Do not leave victim unattended and observe closely for adequacy of breathing. Seek medical attention.

<u>Most Important Symptoms and Effects</u>
Acute: Headache, drowsiness, dizziness, loss of coordination, disorientation and fatigue
Delayed: Dry skin and possible irritation with repeated or prolonged exposure

<u>Potential Acute Health Effects</u>
<u>Inhalation:</u> Breathing high concentrations may be harmful. Mist or vapor can irritate the throat and lungs. Breathing this material may cause central nervous system depression with symptoms including nausea, headache, dizziness, fatigue, drowsiness or unconsciousness. This material may contain or liberate hydrogen sulfide, a poisonous gas with the smell of rotten eggs. Hydrogen sulfide and other hazardous vapors may evolve and collect in the headspace of storage tanks or other enclosed vessels. The smell disappears rapidly because of olfactory fatigue so odor may not be a reliable indicator of exposure. Effects of overexposure include irritation of the eyes, nose, throat and respiratory tract, blurred vision, photophobia (light sensitivity) and pulmonary edema (fluid accumulation in lungs). Severe exposures can result in nausea, vomiting, muscle weakness or convulsions, respiratory failure and death.
<u>Eye Contact:</u> This product can cause eye irritation from short-term contact with liquid, mists or vapors. Symptoms include stinging, watering, redness and swelling. Effects may be more serious with repeated or prolonged contact. Hydrogen sulfide vapors may cause moderate to severe eye irritation and photophobia (light sensitivity).
<u>Skin Contact:</u> This product is a skin irritant. Contact may cause redness, itching, burning and skin damage. This material may contain polynuclear aromatic hydrocarbons that have been known to produce a phototoxic reaction when contaminated skin is exposed to sunlight. The effect is similar in appearance to an exaggerated sunburn, and is temporary in duration if exposure is discontinued. Continued exposure to sunlight can result in more serious skin problems including pigmentation (discoloration), skin eruptions (pimples) and possible skin cancers.
<u>Ingestion:</u> Ingestion may result in nausea, vomiting, diarrhea and restlessness. Aspiration (inadvertent suction) of liquid into the lungs must be avoided as even small quantities in the lungs can produce chemical pneumonitis, pulmonary edema or hemorrhage and even death.

<u>Potential Chronic Health Effects</u>
Chronic effects of overexposure are similar to acute effects including central nervous system (CNS) effects and CNS depression. Effects may also include irritation of the digestive tract, irritation of the respiratory tract, nausea, vomiting and skin dermatitis.

<u>Notes to Physician</u>

This material may contain or liberate hydrogen sulfide. In high doses, hydrogen sulfide may produce pulmonary edema and respiratory depression or paralysis. The first priority in treatment should be providing adequate ventilation and administering 100% oxygen. If unresponsive to supportive care, nitrites (amyl nitrite by inhalation or sodium nitrite by I.V.) may be an effective antidote, if delivered within the first few minutes of exposure. For adults, the dose is 10 ml of a 3NaNO2 solution (0.5 gm NaNO2 in 15 ml water) IV over 2 to 4 minutes. The dosage should be adjusted in children or in the presence of anemia and methemoglobin levels, arterial blood gases, and electrolytes should be monitored.

Epinephrine and other sympathomimetic drugs may initiate cardiac arrhythmias in persons exposed to high concentrations of hydrocarbon solvents (e.g., in enclosed spaces or with deliberate abuse). The use of other drugs with less arrhythmogenic potential should be considered. If sympathomimetic drugs are administered, observe for the development of cardiac arrhythmias.

Ingestion of this product or subsequent vomiting may result in aspiration of light hydrocarbon liquid, which may cause pneumonitis. Inhalation overexposure can produce toxic effects, monitor for respiratory distress. If cough or breathing difficulties develop, evaluate for upper respiratory tract inflammation, bronchitis and pneumonitis.

Skin contact may aggravate an existing dermatitis. High pressure injection injuries may cause necrosis of underlying tissue regardless of superficial appearance.

Federal regulations (29 CFR 1910.1028) specify medical surveillance programs for certain exposures to benzene above the action level or PEL (specified in Section (i)(1)(i) of the Standard). In addition, employees exposed in an emergency situation shall, as described in Section (i)(4)(i), provide a urine sample at the end of the shift for measurement of urine phenol.

5. FIRE FIGHTING MEASURES

Flash Point: Variable. Generally 73-200°F
Flammable Limits in Air, % by Volume: 100%
Autoignition Temperature: Variable. Generally 590°F
Extinguishing Media: Class B fire extinguisher, dry chemical, foam, carbon dioxide, water spray or Halon. Carbon dioxide can displace oxygen. Use caution when applying carbon dioxide in confined spaces. Water may be ineffective for extinguishment, unless used under favorable conditions by experienced fire fighters.
NFPA Ratings: Health: 2, Flammability: 3, Reactivity: 0, Flammable Liquid.

General Hazards: This material is extremely flammable and can be ignited by heat, sparks, flames or other sources of ignition (e.g., static electricity, pilot lights, mechanical/electrical equipment and electronic devices such as cell phones, computers, calculators and pagers which have not been certified as intrinsically safe). Vapors are heavier than air and can accumulate in low areas. May create vapor/air explosion hazard indoors, in confined spaces, outdoors or in sewers. Vapors may travel considerable distances to a remote source of ignition where they can ignite, flash back or explode. Product can accumulate a static charge that may cause a fire or explosion. A product container, if not properly cooled, can rupture in the heat of a fire.

Fire Fighting Instructions: Long duration fires involving crude or residual oil stored in tanks may result in a boilover. The contents of the tank may be expelled beyond the containment dikes or ditches. All personnel should be kept back a safe distance when a boilover is anticipated. Use water spray to cool fire-exposed containers and to protect personnel. Isolate immediate hazard area and keep unauthorized personnel out. Water spray may be useful in minimizing or dispersing vapors and to protect personnel. Cool equipment exposed to fire with water. Avoid spreading burning liquid with water used for cooling. For fires beyond the incipient stage, emergency responders in the immediate hazard area should wear protective clothing. When the potential chemical hazard is unknown, in enclosed or confined spaces, or when explicitly required by regulations, a self-contained breathing apparatus should be worn. Wear other appropriate protective equipment as conditions warrant.

6. ACCIDENTAL RELEASE MEASURES

Personal Precautions
Extremely Flammable. Spillage of liquid product will create a fire hazard and may form an explosive atmosphere. Keep all sources of ignition and hot metal surfaces away from spill/release. The use of explosion-proof electrical equipment is recommended.

Product may contain or release poisonous hydrogen sulfide gas. If the presence of dangerous amounts of H2S around the spilled product is suspected, additional or special actions may be warranted including access restrictions and the use of protective equipment. Stay upwind and away from spill/release. Isolate immediate hazard area and keep unauthorized personnel out. Wear appropriate protective equipment as conditions warrant per Exposure Controls/Personal Protection guidelines.

Environmental Precautions
Stop the leak if it can be done without risk. Prevent spilled material from entering waterways, sewers, basements or confined areas. Contain release to prevent further contamination of soils, surface water or groundwater. Clean up spill as soon as possible using appropriate techniques such as applying non-combustible absorbent materials or pumping. All equipment used when handling the product must be grounded. A vapor suppressing foam may be used to reduce vapors. Use clean non-sparking tools to collect absorbed material. Where feasible and appropriate, remove contaminated soil.

Methods for Containment and Clean Up
Immediate cleanup of any spill is recommended. Build dike far ahead of spill for containment and later recovery or disposal of spilled material. Absorb spill with inert material such as sand or vermiculite and place in suitable container for disposal. If spilled on water, remove with appropriate equipment like skimmers, booms or absorbents. In case of soil contamination, remove contaminated soil for remediation or disposal in accordance with applicable regulations.

Reporting
Report spills/releases as required, to appropriate local, state and federal authorities. US Coast Guard and Environmental Protection Agency regulations require immediate reporting of spills/release that

could reach any waterway including intermittent dry creeks. Report spill/release to the National Response Center at (800) 424-8802.

7. HANDLING & STORAGE

Precations for Safe Handling

Extremely flammable. May vaporize easily at ambient temperatures. The vapor is heavier than air and may create an explosive mixture of vapor and air. Beware of accumulation in confined spaces and low lying areas.

Use non-sparking tools and explosion-proof equipment. Open container slowly to relieve any pressure. Bond and ground all equipment when transferring from one vessel to another. Can accumulate static charge by flow or agitation. Can be ignited by static discharge. Explosion-proof electrical equipment is recommended and may be required by fire codes.

To prevent and minimize fire or explosion risk from static accumulation and discharge, effectively bond and/or ground product transfer system. Electrical equipment and fittings should comply with local fire codes.

Precautions for Safe Storage

Keep away from flame, sparks, excessive temperatures and open flame. Use approved vented containers. Keep containers closed and clearly labeled. Empty product containers or vessels may contain explosive vapors. Do not pressurize, cut, heat, weld or expose containers to sources of ignition. Store in a well ventilated area. This storage area should comply with NFPA 30 "Flammable and Combustible Liquid Code". Avoid storage near incompatible materials. The cleaning of tanks previously containing this product should follow API Recommended Practice (RP) 2013 "Cleaning Mobile Tanks In Flammable and Combustible Liquid Service" and API RP 2015 "Cleaning Petroleum Storage Tanks".

8. EXPOSURE CONTROLS & PERSONAL PROTECTION

Product/ Components	CAS No.	Wt. % (1)	Occupational Exposure Limits			Units
			OSHA(2)	ACGIH(2)	NIOSH(3)	
Crude Oil	8002-05-9	100%	500 ppm	N/A	350 mg/m^3	
Benzene	71-43-2	<5	1 5 STEL	0.5 2.5 STEL	0.1 1 STEL	ppm
Hydrogen Sulfide	7783-06-4	0.00-3.5	20 Ceiling 50 STEL	1 5 STEL	10 Ceiling	ppm
Xylene, all isomers	1330-20-7	<3	100 150 STEL 300 Ceiling	100 150 STEL	100 150 STEL	ppm
Toluene	108-88-3	<2	10	20	100	ppm

			150^{STEL} 300^{Ceiling}		150^{STEL}	
Polycyclic Aromatic Hydrocarbons	mixture	Variable	0.2	0.2	80^{IDLH}	mg/m^3
Naphthalene	91-20-3	<2	10 15^{STEL}	10 15^{STEL}	10 15^{STEL}	ppm
Ethylbenzene	100-41-4	<3	100 125^{STEL}	20	100 125^{STEL}	ppm

Personal Protective Equipment

1. General Considerations: Consider the potential hazards of this material, applicable exposure limits, job activities and other substances in the work place when designing engineering controls and selecting personal protective equipment.
2. Engineering Controls: Use process enclosures, local exhaust ventilation or other engineering controls to maintain airborne levels below the recommended exposure limits. An emergency eye wash station and safety shower should be located near the work station.
3. Personal Protective Equipment: If engineering controls or work practices are not adequate to prevent exposure to harmful levels of this material, personal protective equipment (PPE) is recommended. A hazard assessment of the work should be conducted by a qualified professional to determine what PPE is required.
4. Respiratory Protection: A respiratory protection program that meets or exceeds OSHA 29 CFR 1910.134 and ANSI Z.88.2 should be followed whenever workplace conditions warrant the use of a respirator. When airborne concentrations are expected to exceed the established exposure limits given in Section 8, use a NIOSH approved air purifying respirator equipped with organic vapor cartridges/canisters. Use a full-face positive-pressure supplied air respirator in circumstances where air-purifying respirators may not provide adequate protection or where there may be the potential for airborne exposure above the exposure limits. If exposure concentration is unknown, IDLH conditions exist or there is a potential for exposure to hydrogen sulfide above exposure limits, use a NIOSH approved self contained breathing apparatus (SCBA) or equivalent operated in a pressure demand or other positive pressure mode.
5. Eye Protection: Eye protection that meets or exceeds ANSI Z.87.1 is recommended if there is a potential for liquid contact to the eyes. Safety glasses equipped with side shields are recommended as minimum protection in industrial settings. Chemical goggles should be worn during transfer operations or when there is a likelihood of misting, splashing or spraying of this material. A face shield may be necessary depending on conditions of use.
6. Skin and Body Protection: Avoid skin contact. Wear long-sleeved fire-retardant garments while working with flammable and combustible liquids. Additional chemical-resistant protective gear may be required if splashing or spraying conditions exist. This may include an apron, arm covers, impervious gloves, boots and additional facial protection.
7. Hand Protection: Avoid skin contact. Use impervious gloves (e.g., PVC, neoprene, nitrile rubber). Check with glove suppliers to confirm the breakthrough performance of gloves. PVC and neoprene may be suitable for incidental contact. Nitrile rubber should be used for longer term protection when prolonged or frequent contact may occur. Gloves should be worn on clean hands and hands should be washed after removing gloves. Also wash hands with plenty of mild soap and water before eating, drinking, smoking, using toilet facilities or leaving work.

9. PHYSICAL & CHEMICAL PROPERTIES

Boiling Point: 100-1000°F
Freezing Point: <32 °F
Flash Point: 73-200°F
Vapor Density (Air=1): >1
pH: Neutral
Specific Gravity 60/60F: <1
Autoignition Temperature: 590°F
Pour point: >47°F
Evaporation Rate: Variable
Odor: Strong hydrocarbon, possible sulfurous odor
Viscosity: 45-1000cP (water=1)
Appearance: Thick, dark yellow, brown, or greenish black liquid

10. STABILITY & REACTIVITY

Stability: Stable under normal conditions of use.
Hazardous Polymerization: Will not occur.
Conditions to Avoid/Incompatibilities: Keep material away from heat, sparks, open flames, and oxidizers such as chlorine and concentrated nitric acid.
Hazardous Decomposition Products: Carbon monoxide, carbon dioxide, non-combusted hydrocarbons. Normal combustion of H_2S creates sulfur oxides.

11. TOXICOLOGICAL INFORMATION

Toxicological Information of the Material

1. Acute Toxicity
   a. Dermal: Low Toxicity: LD50 > 2000 mg/kg (rabbit). Causes mild skin irritation. Repeated exposure may cause skin dryness or cracking that can lead to dermatitis.

   b. Inhalation: Hydrogen Sulfide is Extremely Toxic: LC100 = 600 ppm(v), 30 min (man)
   Product expected to have low degree of toxicity by inhalation: LC 50 > 5 mg/l (vapor)
   Effect of overexposure may include irritation of the digestive tract, irritation of the respiratory tract, nausea, vomiting, diarrhea and signs of central nervous system depression (e.g., headache, drowsiness, dizziness, loss of coordination, disorientation and fatigue). Continued inhalation may result in unconsciousness and/or death.

   c. Ingestion: Product expected to have low degree of toxicity by ingestion: Oral LD50 > 5 g/kg (rat), > 10 g/kg (mice)
   Aspiration into the lungs when swallowed or vomited may cause chemical pneumonitis which can be fatal.
2. Eye damage/irritation/sensitization: Causes serious eye irritation

3. Skin: Not expected to be a skin sensitizer
4. Respiratory: Not expected to be a respiratory sensitizer
5. Specific target organ toxicity
    a. Single exposure: High concentrations may cause irritation of the skin, eyes, digestive tract, irritation of the respiratory tract, nausea, vomiting, diarrhea and signs of central nervous system depression (e.g., headache, drowsiness, dizziness, loss of coordination, disorientation and fatigue). Continued inhalation may result in unconsciousness and/or death.
    b. Repeated exposure: May cause damage to organs or organ systems through prolonged or repeated exposure. Laboratory animal studies of dermal and inhalation exposure routes have demonstrated toxicity to the liver, bone marrow, blood, spleen and thymus.
6. Conditions aggravated by overexposure
    a. Disorders of the organs or organ systems that may be aggravated by significant exposure to this material or its components include the skin, respiratory system, liver, kidneys, CNS, cardiovascular system and blood-forming system.
7. Carcinogenicity
    a. May cause cancer
    b. Causes cancer in laboratory animals. Chronic application of crude oil to mouse skin resulted in an increased incidence of skin tumors.
    c. The International Agency for Research on Cancer (IARC) concluded in its Crude Oil Monograph that there is limited evidence of carcinogenicity in animals, and that crude oil is not classifiable as to its carcinogenicity in humans (Group 3). It has not been listed as a carcinogen by NTP or OSHA.
8. Germ cell mutagenicity
    a. Inadequate information available, not expected to be mutagenic.
9. Reproductive and developmental toxicity
    a. Inadequate information available. Dermal exposure to crude oil during pregnancy resulted in limited evidence of developmental toxicity in laboratory animals. Decreased fetal weight and increased resorptions were noted at maternally toxic doses. No significant effects on pup growth or other developmental landmarks were observed postnatally.

Toxicological Information of Components

1. Benzene 71-43-2
    a. Acute Data:
        i. Dermal LD50 > 9400 mg/kg (Rabbit), (Guinea Pig
        ii. LC50 = 9980 ppm (Mouse); 10000 ppm/7hr (Rat)
        iii. Oral LD50 = 4700 mg/kg (Mouse); 930 mg/kg (Rat); 5700 mg/kg (Mammal)
    b. Carcinogenicity: Benzene is an animal carcinogen and is known to produce acute myelogenous leukemia (a form of cancer) in humans. Benzene has been identified as a human carcinogen by NTP, IARC and OSHA.
    c. Target Organs: Prolonged or repeated exposures to benzene vapors has been linked to bone marrow toxicity which can result in blood disorders such as leukopenia, thrombocytopenia, and aplastic anemia. All of these diseases can be fatal.
    d. Developmental: Exposure to benzene during pregnancy demonstrated limited evidence of developmental toxicity in laboratory animals. The effects seen include decreased body eight and increased skeletal variations in rodents. Alterations in hematopoeisis have been observed in the fetuses and offspring of pregnant mice.

   e. Mutagenicity: Benzene exposure has resulted in chromosomal aberrations in human lymphocytes and animal bone marrow cells, and DNA damage in mammalian cells in vitro
2. Ethyl Benzene 100-41-4
   a. Acute Toxicity:
      i. Dermal LD50 = 17800 mg/kg (Rabbit)
      ii. LC50 = 4000 ppm/4 hr; 13367 ppm (Rat)
      iii. Oral LD50 = 3500 mg/kg (Rat)
   b. Carcinogenicity: Rats and mice exposed to 0, 75, 250, or 750 ppm ethyl benzene in a two year inhalation study demonstrated limited evidence of kidney, liver, and lung cancer. Ethyl benzene has been listed as a possible human carcinogen by IARC. Ethyl benzene has not been listed as a carcinogen by NTP or OSHA.
   c. Target Organs: In rats and mice exposed to 0, 75, 250, or 750 ppm ethyl benzene in a two year inhalation study there was mild damage to the kidney (tubular hyperplasia), liver (eosinophilio foci,hypertrophy, necrosis), thyroid (hyperplasia) and pituitary (hyperplasia).
3. Hydrogen Sulfide 7783-06-4
   a. Acute Toxicity:
      i. Dermal - No data
      ii. LCLo= 600 ppm, 30 min (Human)
   b. Hydrogen sulfide concentrations will vary significantly depending on the source and sulfur content of the crude. Sweet crudes (<0.5% sulfur) may contain toxicologically significant levels of hydrogen sulfide in the vapor spaces of bulk storage tanks and transport compartments. Concentrations of H2S as low as 10 ppm over an 8 hour workshift may cause eye or throat irritation. Prolonged breathing of 50-100 ppm H2S vapors can produce significant eye and respiratory irritation. Sour crudes commonly contain extremely high concentrations of H2S (500-70,000 ppm) in the vapor spaces of bulk storage vessels. Exposure to 250-600 ppm for 15-30 minutes can produce headache, dizziness, nervousness, staggering gait, nausea and pulmonary edema or bronchial pneumonia. Concentrations >1,000 ppm will cause immediate unconsciousness and death through respiratory paralysis. Rats and mice exposed to 80 ppm H2S, 6 hrs/day, 5 days/week for 10 weeks, did not produce any toxicity except for irritation of nasal passages. H2S did not affect reproduction and development (birth defects or neurotoxicity) in rats exposed to concentrations of 75-80 ppm or 150 ppm H2S, respectively. Over the years a number of acute cases of H2S poisonings have been reported. Complete and rapid recovery is the general rule. However, if the exposure was sufficiently intense and sustained causing cerebral hypoxia (lack of oxygen to the brain), neurologic effects such as amnesia, intention tremors or brain damage are possible.
4. Naphthalene 91-20-3
   a. Acute Toxicity:
      i. Dermal LD50 = >2.5 g/kg (rat)
      ii. LC50 = >340 mg/m3/1H (rat)
      iii. Oral LD50 = 490 mg/kg; 2.6 g/kg (rat)
   b. Carcinogenicity: Naphthalene has been evaluated in two year inhalation studies in both rats and rice. The National Toxicology Program (NTP) concluded that there is clear evidence of carcinogenicity in male and female rats based on increased incidences of respiratory epithelial adenomas and olfactory epithelial neuroblastomas of the nose. NTP found some evidence of carcinogenicity in female mice (alveolar adenomas) and no

evidence of carcinogenicity in male mice. Naphthalene has been identified as a carcinogen by IARC and NTP.

5. Toluene 108-88-3
    a. Acute Toxicity:
        i. Dermal LD50 = 14 g/kg (Rabbit)
        ii. LC50 = 8,000 ppm (4-hr, Rat)
        iii. Oral LD50 = 2.5 - 7.9 g/kg (Rat)
    b. Target Organs: Epidemiology studies suggest that chronic occupational overexposure to toluene may damage color vision. Subchronic and chronic inhalation studies with toluene produced kidney and liver damage, hearing loss and central nervous system (brain) damage in laboratory animals. Intentional misuse by deliberate inhalation of high concentrations of toluene has been shown to cause liver, kidney, and central nervous system damage, including hearing loss and visual disturbances.
    c. Developmental: Exposure to toluene during pregnancy has demonstrated limited evidence of developmental toxicity in laboratory animals. The effects seen include decreased fetal body weight and increased skeletal variations in both inhalation and oral studies.
6. Xylenes 1330-20-7
    a. Acute Toxicity:
        i. Dermal LD50 >3.16 ml/kg (Rabbit)
        ii. LC50= 5000 ppm/4 hr. (Rat)
        iii. Oral LD50 = 4300 mg/kg (Rat)
    b. Target Organs: A six week inhalation study with xylene produced hearing loss in rats.
    c. Developmental: Both mixed xylenes and the individual isomers produced limited evidence of developmental toxicity in laboratory animals. Inhalation and oral administration of xylene resulted in decreased fetal weight, increased incidences of delayed ossification, skeletal variations and resorptions.

12. ECOLOGICAL INFORMATION

Do not discharge into or allow runoff to flow into sewers and natural waterways. Contain spill material and dike for proper disposal. May be hazardous to waterways/wildlife.

Toxicity

This material is expected to be toxic to aquatic organisms. A range of measurements of aquatic toxicity has been obtained in laboratory studies of crude oils. Variability in results may be related in part to the source of the crude oil, or it may reflect different approaches to testing. However, those studies using dispersions of whole oil, employing water soluble fractions, and water accommodated fractions have generally given LC50 or EC50 values in the range 10 to 100 mg/l or greater when expressed in terms of oil loading rate. These values are consistent with the predicted aquatic toxicity of these substances based on their hydrocarbon compositions.
Classification H411, Chronic Category 2
LL/EL/IL50 – 10 to 100 mg/l (fish, aquatic invertebrates, algae, microorganisms)

Coating action of oil can kill birds, plankton, aquatic life, algae and fish.

Persistence and Degradability
Most crude oils are not regarded as readily biodegradable. Most of the nonvolatile constituents are inherently biodegradable. Some of the highest molecular weight components are persistent in water. The individual hydrocarbon components of this material are differentially soluble in water with aromatic hydrocarbons tending to be more water soluble than aliphatic hydrocarbons. If spilled, the lighter components of crude oil will generally evaporate but depending on local environmental conditions (temperature, wind, soil type, mixing or wave action in water, etc), photo-oxidation and biodegradation, the remainder may become dispersed in the water column or absorbed to soil or sediment. Because of their differential solubility, the occurrence of hydrocarbons in groundwater will be at different proportions than the parent material. Under anaerobic conditions, such as in anoxic sediments, rates of biodegradation are negligible.

Persistence per IOPC Fund Definition
Persistent

Bioaccumulative Potential
Contains components with the potential to bioaccumulate. The octanol water coefficient values measured for the hydrocarbon components of this material range from less than 2 to greater than 6, and therefore would be considered as having the potential to bioaccumulate. Based upon spill investigation analysis, oils containing polynuclear aromatic hydrocarbon compounds similar to this material were shown to bioaccumulate in tissues of various aquatic organisms.

Mobility
Air: Contains volatile components. Lighter components will volatilize in the air. In air, the volatile hydrocarbons undergo photodegradation by reaction with hydroxyl radicals with half-lives varying from 0.5 days for n-dodecane to 6.5 days for benzene.

Water: Spreads on a film on the surface of water. Significant proportion of spill will remain after one day. Lower molecular weight aromatic hydrocarbons and some polar compounds have low but significant water solubility. Some higher molecular weight compounds are removed by emulsification and these also slowly biodegrade while others adsorb to sediment and sink. Heavier fractions agglomerate to form tars, some of which sink.

Soil: Some constituents may be mobile and contaminate groundwater.

Other Adverse Effects
Films form on water and may affect oxygen transfer and damage organisms.

13. DISPOSAL CONSIDERATIONS

Recover or recycle if possible. It is the responsibility of the generator to determine the toxicity and physical properties of the material generated so as to properly classify the waste and ensure disposal methods comply with applicable regulations.

This material, if discarded as produced, is not a RCRA "listed" hazardous waste. However, it should be fully characterized for ignitability (D001), reactivity (D003) and benzene (D018) prior to disposal (40 CFR 261). Use which results in chemical or physical change or contamination may subject it to regulation as a hazardous waste. Along with properly characterizing all waste materials, consult state and local regulations regarding the proper disposal of this material.

Do not dispose of tank water bottoms by draining onto the ground. This will result in soil and groundwater contamination. Waste arising from spillage or tank cleaning should be disposed of in accordance with applicable regulations.

Container contents should be completely used and containers should be emptied prior to discard. Container rinsate could be considered a RCRA hazardous waste and must be disposed of with care and in full compliance with federal, state and local regulations. Larger empty containers, such as drums, should be returned to the distributor or to a qualified drum reconditioner. To assure proper disposal of smaller empty containers, consult with state and local regulations and disposal authorities.

14. TRANSPORT INFORMATION

United States Department of Transportation (US DOT)
Shipping Description: Petroleum Crude Oil, 3, UN1267, I or II
Shipping Name: Petroleum Crude Oil
Hazard Class and Division: 3

15. REGULATORY INFORMATION

TSCA Status: On TSCA inventory

Section 311/312 Hazard Categorization:

Acute:	*Chronic:*	*Fire:*	*Pressure:*	*Reactive:*
Yes	*Yes*	*Yes*	*No*	*No*

CERCLA: The CERCLA definition of hazardous substances contains a “petroleum exclusion” clause which exempts crude oil. Fractions of crude oil, and products (both finished and intermediate) from the crude oil refining process and any indigenous components of such from the CERCLA Section 103 reporting requirements. However, other federal reporting requirements, including SARA Section 304, as well as the Clean Water Act may still apply.

Federal Regulatory Summary

Chemical Name	% Vol	CAS	CAA Accidental Release Prevention Substance	RCRA Hazardous Waste	SARA Extremely Hazardous Substance	SARA Toxic Release Chemical
Crude Oil	100%	8002-05-9	N/A	N/A	N/A	N/A
Benzene	<5	71-43-2	N/A	YES	N/A	YES
Hydrogen Sulfide	0.00-3.5	7783-06-4	YES	YES	YES	YES
Xylene, all isomers	<3	1330-20-7	N/A	YES	N/A	YES
Toluene	<2	108-88-3	N/A	YES	N/A	YES
Naphthalene	<2	91-20-3	N/A	YES	N/A	YES
Ethylbenzene	<3	100-41-4	N/A	N/A	N/A	YES

TQ = Threshold Quantity
TPQ = Threshold Planning Quantity

Pennsylvania Regulatory Summary

Chemical Name	% Vol	CAS	Hazardous Substance
Crude Oil	100%	8002-05-9	YES
Benzene	<5	71-43-2	YES
Hydrogen Sulfide	0.00-3.5	7783-06-4	YES
Xylene, all isomers	<3	1330-20-7	YES
Toluene	<2	108-88-3	YES
Naphthalene	<2	91-20-3	YES
Ethylbenzene	<3	100-41-4	YES

California Regulatory Summary

Proposition 65 Warning: Chemicals known to the State of California to cause cancer, birth defects, or other reproductive harm may be found in crude oil and petroleum products. Although it is possible to sufficiently refine a crude oil or its end products to remove the potential for cancer, we are advising that one or more of the listed chemicals may be present in some detectable quantities. Read and follow directions and use care when handling crude oil and petroleum products.

16. OTHER INFORMATION

Date of Issue: 12-July-2016
Statues: Final
Previous Issue Date: New
Revised Sections or Basis for Revision: NA

THIS INFORMATION RELATES ONLY TO THE SPECIFIC MATERIAL DESIGNATED AND MAY NOT BE VALID FOR SUCH MATERIAL USED IN COMBINATION WITH ANY OTHER MATERIALS OR IN ANY PROCESS. SUCH INFORMATION IS TO THE BEST OF THIS COMPANY'S KNOWLEDGE AND BELIEVED ACCURATE AND RELIABLE AS OF THE DATE INDICATED. HOWEVER, NO REPRESENTATION, WARRANTY OR GUARANTEE IS MADE AS TO THE ACCURACY, RELIABILITY OR COMPLETENESS. IT IS THE USER'S RESPONSIBILITY TO

SATISFY THEMSELVES AS TO THE SUITABILITY AND COMPLETENESS OF SUCH INFORMATION FOR HIS OWN PARTICULAR USE.

KEY / LEGEND
ACGIH - American Conference of Governmental Industrial Hygienists
ADR - Agreement on Dangerous Goods by Road
CAA - Clean Air Act
CAS - Chemical Abstracts Service Registry Number
CDG - Carriage of Dangerous Goods By Road and Rail Manual
CERCLA - Comprehensive Environmental Response, Compensation, and Liability Act
CFR - Code of Federal Regulations
EINECS - European Inventory of Existing Chemical Substances Registry Number
ERG - Emergency Response Guidebook
EPCRA - Emergency Planning and Community Right-to-Know Act
GHS - Globally Harmonized System of Classification and Labeling of Chemicals
IARC - International Agency for Research on Cancer
IATA - International Air Transport Association
ICAO - International Civil Aviation Organization
IDLH – Immediately Dangerous to Life and Health
IMDG - International Maritime Dangerous Goods Code
IMO - International Maritime Organization
N/E - Not Established
NTP - National Toxicology Program
OSHA - Occupational Safety and Health Administration
PEL - Permissible Exposure Limit
PPE - Personal Protective Equipment
RCRA - Resource Conversation and Recovery Act
RID - Regulations Concerning the International Transport of Dangerous Goods by Rail
RQ - Reportable Quantities
SARA - Superfund Amendments and Reauthorization Act of 1986
SDS - Safety Data Sheet
TCC - Tag Closed Cup
TDG - Transportation of Dangerous Goods
TLV - Threshold Limit Value
TSCA - Toxic Substance Control Act
TWA - Total Weight Average
UN/NA - United Nations / North American Number
UNECE - United Nations Economic Commission for Europe
US DOT - United States Department of Transportation
US EPA - United States Environmental Protection Agency
Vol. - Volume
WHMIS - Workplace Hazardous Materials Information System

Material Safety Data Sheet
Cortron® RN-211

1. PRODUCT AND COMPANY IDENTIFICATION

Product name Cortron® RN-211

Product use Corrosion Inhibitor

Manufacturer Champion Technologies, Inc.
P.O. Box 450499
Houston, TX, 77245
USA

Telephone 1-281-431-2561 (Champion)

In case of emergency 1-800-424-9300 (CHEMTREC)
1-703-527-3887 (CHEMTREC - International)

2. HAZARDS IDENTIFICATION

Physical state liquid

Color Clear. yellow.

Odor sharp, Hydrocarbon.

Emergency overview DANGER!
Corrosive. Flammable. Harmful. Keep away from heat, sparks and flame.

Potential health effects

Inhalation Possible risk of irreversible effects. May give off gas, vapor or dust that is very irritating or corrosive to the respiratory system.

Ingestion Possible risk of irreversible effects. May cause burns to mouth, throat and stomach.

Skin Corrosive to the skin. Causes burns. Possible risk of irreversible effects.

Eyes Corrosive to eyes. Causes burns.

Chronic effects No known significant effects or critical hazards.

See toxicological information (section 11)

3. COMPOSITION/INFORMATION ON INGREDIENTS

Name	CAS no.	Weight %
Methanol	67-56-1	30 - 60
Ionic Surfactants	Proprietary	10 - 30

4. FIRST AID MEASURES

Eye contact Get medical attention immediately. Immediately flush eyes with plenty of water, occasionally lifting the upper and lower eyelids. Check for and remove any contact lenses. Chemical burns must be treated promptly by a physician.

Skin contact Get medical attention immediately. Flush contaminated skin with plenty of water. Remove contaminated clothing and shoes. Continue to rinse for at least 10 minutes. Chemical burns must be treated promptly by a physician.

Inhalation Get medical attention immediately. Move exposed person to fresh air. If not breathing, if breathing is irregular or if respiratory arrest occurs, provide artificial respiration or oxygen by trained personnel. If unconscious, place in recovery position and get medical attention

	immediately. Maintain an open airway.
Ingestion	Get medical attention immediately. Wash out mouth with water. If material has been swallowed and the exposed person is conscious, give small quantities of water to drink. Do not induce vomiting unless directed to do so by medical personnel. Chemical burns must be treated promptly by a physician. Never give anything by mouth to an unconscious person.
Protection of first-aiders	No action shall be taken involving any personal risk or without suitable training. If it is suspected that fumes are still present, the rescuer should wear an appropriate mask or self-contained breathing apparatus. It may be dangerous to the person providing aid to give mouth-to-mouth resuscitation. Wash contaminated clothing thoroughly with water before removing it, or wear gloves.
Notes to physician	No specific treatment. Treat symptomatically. Contact poison treatment specialist immediately if large quantities have been ingested or inhaled.

5. FIRE-FIGHTING MEASURES

Flash point	76 °F (24.4 °C), Pensky-Martens. Closed cup
Flammability of the product	Flammable liquid. In a fire or if heated, a pressure increase will occur and the container may burst, with the risk of a subsequent explosion. Runoff to sewer may create fire or explosion hazard.

Extinguishing media

Suitable	Use dry chemical, CO_2, water spray (fog) or foam.
Not suitable	Do not use water jet.
Special exposure hazards	Promptly isolate the scene by removing all persons from the vicinity of the incident if there is a fire. No action shall be taken involving any personal risk or without suitable training. Move containers from fire area if this can be done without risk. Use water spray to keep fire-exposed containers cool.
Hazardous combustion products	carbon dioxide, carbon monoxide, nitrogen oxides, halogenated compounds
Special protective equipment for fire-fighters	Fire-fighters should wear appropriate protective equipment and self-contained breathing apparatus (SCBA) with a full face-piece operated in positive pressure mode.
Special remarks on fire hazards	Not available.

6. ACCIDENTAL RELEASE MEASURES

Personal precautions	No action shall be taken involving any personal risk or without suitable training. Evacuate surrounding areas. Keep unnecessary and unprotected personnel from entering. Do not touch or walk through spilled material. Shut off all ignition sources. No flares, smoking or flames in hazard area. Do not breathe vapor or mist. Provide adequate ventilation. Wear appropriate respirator when ventilation is inadequate. Put on appropriate personal protective equipment (see section 8).
Environmental precautions	Avoid contact of spilled material with soil and prevent runoff entering surface waterways. Inform the relevant authorities if the product has caused environmental pollution (sewers, waterways, soil or air).

Methods for cleaning up

Small spill	Stop leak if without risk. Move containers from spill area. Dilute with water and mop up if water-soluble or absorb with an inert dry material and place in an appropriate waste disposal container. Use spark-proof tools and explosion-proof equipment. Dispose of via a licensed waste disposal contractor.

Large spill Stop leak if without risk. Move containers from spill area. Approach release from upwind. Prevent entry into sewers, water courses, basements or confined areas. Contain and collect spillage with non-combustible, absorbent material e.g. sand, earth, vermiculite or diatomaceous earth and place in container for disposal according to local regulations (see section 13). Use spark-proof tools and explosion-proof equipment. Contaminated absorbent material may pose the same hazard as the spilled product. Note: see section 1 for emergency contact information and section 13 for waste disposal.

7. HANDLING AND STORAGE

Handling Use only with adequate ventilation. Put on appropriate personal protective equipment (see section 8). Wear appropriate respirator when ventilation is inadequate. Eating, drinking and smoking should be prohibited in areas where this material is handled, stored and processed. Do not get in eyes or on skin or clothing. Do not breathe vapor or mist. Do not enter storage areas and confined spaces unless adequately ventilated. Eliminate all ignition sources. Use explosion-proof electrical (ventilating, lighting and material handling) equipment. To avoid fire or explosion, dissipate static electricity during transfer by grounding and bonding containers and equipment before transferring material. Empty containers retain product residue and can be hazardous. Do not reuse container. Workers should wash hands and face before eating, drinking and smoking.

Storage Store in accordance with local regulations. Store in a segregated and approved area. Keep container in a well-ventilated area. Store in the original container or an approved alternative made from a compatible material. Keep tightly closed when not in use. Separate from oxidizing materials. Do not store in unlabeled containers. Use appropriate containment to avoid environmental contamination.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Personal protection

Hands Use chemical-resistant, impervious gloves.

Eyes Goggles, face shield or other full-face protection should be worn if there is a risk of direct exposure to aerosols or splashes.

Body Personal protective equipment for the body should be selected based on the task being performed and the risks involved and should be approved by a specialist before handling this product.

Respiratory If during normal use the material presents a respiratory hazard, use only with adequate ventilation or wear appropriate respirator. Respirator selection must be based on known or anticipated exposure levels, the hazards of the product and the safe working limits of the selected respirator.

Occupational exposure limits

Component	Source	Type	PPM	MG/M3	Notes
Methanol					
	OSHA PEL	TWA	200 ppm	260 mg/m3	
	NIOSH REL	TWA	200 ppm	260 mg/m3	SKIN
	NIOSH REL	STEL	250 ppm	325 mg/m3	SKIN
	ACGIH TLV	TWA	200 ppm	262 mg/m3	SKIN
	ACGIH TLV	STEL	250 ppm	328 mg/m3	SKIN

SKIN - Skin absorption can contribute significantly to overall exposure.

Engineering measures Use only with adequate ventilation. Use process enclosures, local exhaust ventilation or other engineering controls to keep worker exposure to airborne contaminants below any recommended or statutory limits. The engineering controls also need to keep gas, vapor or dust concentrations below any lower explosive limits. Use explosion-proof ventilation equipment.

Hygiene measures Wash hands, forearms and face thoroughly after handling chemical products, before eating, smoking and using the lavatory and at the end of the working period. Wash contaminated

	clothing before reusing. Emergency baths, showers, or other equipment appropriate for the potential level of exposure should be located close to the workstation location.
Environmental exposure controls	Emissions from ventilation or work process equipment should be checked to ensure they comply with the requirements of environmental protection legislation. In some cases, fume scrubbers, filters or engineering modifications to the process equipment will be necessary to reduce emissions to acceptable levels.

9. PHYSICAL AND CHEMICAL PROPERTIES

Physical state	liquid
Color	Clear. yellow.
Odor	sharp, Hydrocarbon.
Odor threshold	Not available.
Boiling/condensation point	Not available.
Pour point	-25 °F (-31.7 °C)
Flash point	76 °F (24.4 °C), Pensky-Martens. Closed cup
Flammable limits	Lower: Not available. Upper: Not available.
Auto-ignition temperature	Not available.
pH	6.0 - 7.0, Method (1:1 in Deionized Water)
Evaporation rate	Not available.
Solubility	Water
Vapor density	Not available.
Relative density	0.9170 - 0.9270 @ 60 °F (15.6 °C)
Vapor pressure	Not available.
Viscosity	Dynamic: 4 - 8 cPs @ 75 °F (23.9 °C)
Octanol/water partition coefficient (LogPow)	Not available.

Note: Typical values only - not to be interpreted as sales specifications

10. STABILITY AND REACTIVITY

Stability	The product is stable.
Hazardous polymerization	Under normal conditions of storage and use, hazardous polymerization will not occur.
Conditions to avoid	Avoid all possible sources of ignition (spark or flame). Do not pressurize, cut, weld, braze, solder, drill, grind or expose containers to heat or sources of ignition.
Materials to avoid	oxidizing materials
Hazardous decomposition products	Under normal conditions of storage and use, hazardous decomposition products should not be produced.

11. TOXICOLOGICAL INFORMATION

Acute toxicity

Substance	Test type	Species	Dose	Classification

Methanol				
	LD50 Oral	Rat	5,600 mg/kg	Not applicable
	LD50 Oral	Mouse	5,800 mg/kg	Not applicable
	LD50 Oral	Rabbit	14,200 mg/kg	Not applicable
	LC50 inhalation	Mouse	41000 ppm	Not applicable
	LC50 inhalation	Rat	64000 ppm	Not applicable
	LC50 inhalation	Rabbit	81,000 mg/m3	Not applicable
	LD50 Dermal	Rabbit	15,800 mg/kg	Not applicable
Ionic Surfactants				
	LD50 Oral	Rat	426 mg/kg	Not applicable
	LD50 Oral	Mouse	919 mg/kg	Not applicable

Irritation/Corrosion

Not available.

Target organ effects Methanol: Ingestion may cause blindness.

Carcinogenicity

None of the components are listed.

12. ECOLOGICAL INFORMATION

Environmental effects No known significant effects or critical hazards.

Aquatic ecotoxicity

Conclusion/Summary Not available.

Other adverse effects No known significant effects or critical hazards.

13. DISPOSAL CONSIDERATIONS

Waste disposal The generation of waste should be avoided or minimized wherever possible. Empty containers or liners may retain some product residues. This material and its container must be disposed of in a safe way. Dispose of surplus and non-recyclable products via a licensed waste disposal contractor. Disposal of this product, solutions and any by-products should at all times comply with the requirements of environmental protection and waste disposal legislation and any regional local authority requirements. Avoid dispersal of spilled material and runoff and contact with soil, waterways, drains and sewers.

Disposal should be in accordance with applicable regional, national and local laws and regulations. Refer to Section 7: HANDLING AND STORAGE and Section 8: EXPOSURE CONTROLS/PERSONAL PROTECTION for additional handling information and protection of employees.

14. TRANSPORT INFORMATION

Refer to the bill of lading or container label for DOT or other transportation hazard classification. Additionally, be aware that shipping descriptions may vary based on mode of transport, shipment volume or weight, container size or type, and/or origin and destination. Consult your company's Hazardous Materials / Dangerous Goods expert or your legal counsel for information specific to your situation.

15. REGULATORY INFORMATION

HCS Classification

Component	Classification
Methanol	Irritant., Target organ effects, Occupational exposure limits
Ionic Surfactants	Harmful., Corrosive

U.S. Federal regulations

CERCLA: Hazardous substances - Reportable quantity:

Substance	Reportable quantity

Methanol	5000 lbs

Product Reportable quantity	**Substance**
12,468 lb, 1,617 gal US	Methanol

Product spills equal to or exceeding the threshold above trigger the reporting requirements under CERCLA for the listed hazardous substance. Report the spill or release to the National Response Center (NRC) at (800) 424-8802.

SARA Title III Section 302 Extremely hazardous substances (40 CFR Part 355):
None of the components are listed.

SARA 311/312 MSDS distribution - chemical inventory - hazard identification:
Immediate (acute) health hazard. Delayed (chronic) health hazard. Fire hazard.

SARA 313 - Supplier notification

Component	CAS no.	Weight %
Methanol	67-56-1	30 - 60

Clean Water Act (CWA) 307:
None of the components are listed.

Clean Water Act (CWA) 311:
None of the components are listed.

Clean Air Act (CAA) 112 accidental release prevention:
None of the components are listed.

Clean Air Act (CAA) 112 regulated flammable substances:
None of the components are listed.

Clean Air Act (CAA) 112 regulated toxic substances:
None of the components are listed.

State regulations

Massachusetts Substances: The following components are listed: Methanol.

New Jersey Hazardous Substances: The following components are listed: Methanol.

Pennsylvania RTK Hazardous Substances: The following components are listed: Methanol.

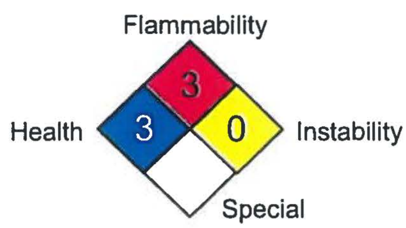
California Prop. 65
Not available.

International regulations

United States inventory (TSCA 8b):	All components are listed or exempted.
Canada inventory (DSL):	All components are listed or exempted.

16. OTHER INFORMATION

National Fire Protection Association (U.S.A.):



Date of issue	10/19/2009
Date of previous issue	08/17/2007
Version	3.0
Prepared by	Product Stewardship

Disclaimer

To the best of our knowledge, the information contained herein is accurate. However, neither the above-named supplier, nor any of its subsidiaries, assumes any liability whatsoever for the accuracy or completeness of the information contained herein. Final determination of suitability of any material is the sole responsibility of the user. All materials may present unknown hazards and should be used with caution. Although certain hazards are described herein, we cannot guarantee that these are the only hazards that exist.

Material Safety Data Sheet
Gyptron® T-315

1. PRODUCT AND COMPANY IDENTIFICATION

Product name Gyptron® T-315

Product use Scale Inhibitor

Manufacturer Champion Technologies, Inc.
P.O. Box 450499
Houston, TX, 77245
USA

Telephone 1-281-431-2561 (Champion)

In case of emergency 1-800-424-9300 (CHEMTREC)
1-703-527-3887 (CHEMTREC - International)

2. HAZARDS IDENTIFICATION

Physical state liquid

Color Clear. yellow.

Emergency overview WARNING!
Combustible. Keep away from heat, sparks and flame.

Potential health effects

Inhalation Over-exposure by inhalation may cause respiratory irritation.

Ingestion Ingestion may cause gastrointestinal irritation and diarrhea.

Skin May cause skin irritation.

Eyes May cause eye irritation.

Chronic effects No known significant effects or critical hazards.

See toxicological information (section 11)

3. COMPOSITION/INFORMATION ON INGREDIENTS

Name	CAS no.	Weight %
Methanol	67-56-1	5 - 10

4. FIRST AID MEASURES

Eye contact Immediately flush eyes with plenty of water, occasionally lifting the upper and lower eyelids. Check for and remove any contact lenses. Get medical attention if irritation occurs.

Skin contact Flush contaminated skin with plenty of water. Remove contaminated clothing and shoes. Get medical attention if symptoms occur.

Inhalation Move exposed person to fresh air. If not breathing, if breathing is irregular or if respiratory arrest occurs, provide artificial respiration or oxygen by trained personnel. Get medical attention if adverse health effects persist or are severe. If unconscious, place in recovery position and get medical attention immediately. Maintain an open airway.

Ingestion Wash out mouth with water. If material has been swallowed and the exposed person is conscious, give small quantities of water to drink. Do not induce vomiting unless directed to do so by medical personnel. Get medical attention if symptoms occur. Never give anything by mouth to an unconscious person.

Protection of No action shall be taken involving any personal risk or without suitable training. It may be

first-aiders	dangerous to the person providing aid to give mouth-to-mouth resuscitation.
Notes to physician	No specific treatment. Treat symptomatically. Contact poison treatment specialist immediately if large quantities have been ingested or inhaled.

5. FIRE-FIGHTING MEASURES

Flash point	115 °F (46.1 °C), Pensky-Martens. Closed cup
Flammability of the product	Flammable liquid. In a fire or if heated, a pressure increase will occur and the container may burst, with the risk of a subsequent explosion. Runoff to sewer may create fire or explosion hazard.

Extinguishing media

Suitable	Use dry chemical, CO2, water spray (fog) or foam.
Not suitable	Do not use water jet.
Special exposure hazards	Promptly isolate the scene by removing all persons from the vicinity of the incident if there is a fire. No action shall be taken involving any personal risk or without suitable training. Move containers from fire area if this can be done without risk. Use water spray to keep fire-exposed containers cool.
Hazardous combustion products	carbon dioxide, carbon monoxide
Special protective equipment for fire-fighters	Fire-fighters should wear appropriate protective equipment and self-contained breathing apparatus (SCBA) with a full face-piece operated in positive pressure mode.
Special remarks on fire hazards	Not available.

6. ACCIDENTAL RELEASE MEASURES

Personal precautions	No action shall be taken involving any personal risk or without suitable training. Evacuate surrounding areas. Keep unnecessary and unprotected personnel from entering. Do not touch or walk through spilled material. Shut off all ignition sources. No flares, smoking or flames in hazard area. Avoid breathing vapor or mist. Provide adequate ventilation. Wear appropriate respirator when ventilation is inadequate. Put on appropriate personal protective equipment (see section 8).
Environmental precautions	Avoid contact of spilled material with soil and prevent runoff entering surface waterways. Inform the relevant authorities if the product has caused environmental pollution (sewers, waterways, soil or air).

Methods for cleaning up

Small spill	Stop leak if without risk. Move containers from spill area. Dilute with water and mop up if water-soluble or absorb with an inert dry material and place in an appropriate waste disposal container. Use spark-proof tools and explosion-proof equipment. Dispose of via a licensed waste disposal contractor.
Large spill	Stop leak if without risk. Move containers from spill area. Approach release from upwind. Prevent entry into sewers, water courses, basements or confined areas. Contain and collect spillage with non-combustible, absorbent material e.g. sand, earth, vermiculite or diatomaceous earth and place in container for disposal according to local regulations (see section 13). Use spark-proof tools and explosion-proof equipment. Contaminated absorbent material may pose the same hazard as the spilled product. Note: see section 1 for emergency contact information and section 13 for waste disposal.

7. HANDLING AND STORAGE

Handling Use only with adequate ventilation. Put on appropriate personal protective equipment (see section 8). Wear appropriate respirator when ventilation is inadequate. Eating, drinking and smoking should be prohibited in areas where this material is handled, stored and processed. Avoid contact with eyes, skin and clothing. Avoid breathing vapor or mist. Do not enter storage areas and confined spaces unless adequately ventilated. Eliminate all ignition sources. Use explosion-proof electrical (ventilating, lighting and material handling) equipment. To avoid fire or explosion, dissipate static electricity during transfer by grounding and bonding containers and equipment before transferring material. Empty containers retain product residue and can be hazardous. Do not reuse container. Workers should wash hands and face before eating, drinking and smoking.

Storage Store in accordance with local regulations. Store in a segregated and approved area. Keep container in a well-ventilated area. Store in the original container or an approved alternative made from a compatible material. Keep tightly closed when not in use. Separate from oxidizing materials. Do not store in unlabeled containers. Use appropriate containment to avoid environmental contamination.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Personal protection

Hands Use chemical-resistant, impervious gloves.

Eyes Safety eyewear should be used when there is a likelihood of exposure.

Body Personal protective equipment for the body should be selected based on the task being performed and the risks involved and should be approved by a specialist before handling this product.

Respiratory If during normal use the material presents a respiratory hazard, use only with adequate ventilation or wear appropriate respirator. Respirator selection must be based on known or anticipated exposure levels, the hazards of the product and the safe working limits of the selected respirator.

Occupational exposure limits

Component	Source	Type	PPM	MG/M3	Notes
Methanol					
	OSHA PEL	TWA	200 ppm	260 mg/m3	
	NIOSH REL	TWA	200 ppm	260 mg/m3	SKIN
	NIOSH REL	STEL	250 ppm	325 mg/m3	SKIN
	ACGIH TLV	TWA	200 ppm	262 mg/m3	SKIN
	ACGIH TLV	STEL	250 ppm	328 mg/m3	SKIN

SKIN - Skin absorption can contribute significantly to overall exposure.

Engineering measures Use only with adequate ventilation. Use process enclosures, local exhaust ventilation or other engineering controls to keep worker exposure to airborne contaminants below any recommended or statutory limits. The engineering controls also need to keep gas, vapor or dust concentrations below any lower explosive limits. Use explosion-proof ventilation equipment.

Hygiene measures Wash hands, forearms and face thoroughly after handling chemical products, before eating, smoking and using the lavatory and at the end of the working period. Wash contaminated clothing before reusing. Emergency baths, showers, or other equipment appropriate for the potential level of exposure should be located close to the workstation location.

Environmental exposure controls Emissions from ventilation or work process equipment should be checked to ensure they comply with the requirements of environmental protection legislation. In some cases, fume scrubbers, filters or engineering modifications to the process equipment will be necessary to reduce emissions to acceptable levels.

9. PHYSICAL AND CHEMICAL PROPERTIES

Physical state liquid

Color	Clear. yellow.
Odor	Not available.
Odor threshold	Not available.
Boiling/condensation point	Not available.
Pour point	10 °F (-12.2 °C)
Flash point	115 °F (46.1 °C), Pensky-Martens. Closed cup
Flammable limits	Lower: Not available. Upper: Not available.
Auto-ignition temperature	Not available.
pH	2.5 - 3.5, Method (neat)
Evaporation rate	Not available.
Solubility	Water
Vapor density	Not available.
Relative density	1.0530 - 1.0830 @ 60 °F (15.6 °C)
Vapor pressure	Not available.
Viscosity	Dynamic: 15 - 25 cPs @ 75 °F (23.9 °C)
Octanol/water partition coefficient (LogPow)	Not available.

Note: Typical values only - not to be interpreted as sales specifications

10. STABILITY AND REACTIVITY

Stability	The product is stable.
Hazardous polymerization	Under normal conditions of storage and use, hazardous polymerization will not occur.
Conditions to avoid	Avoid all possible sources of ignition (spark or flame). Do not pressurize, cut, weld, braze, solder, drill, grind or expose containers to heat or sources of ignition.
Materials to avoid	oxidizing materials
Hazardous decomposition products	Under normal conditions of storage and use, hazardous decomposition products should not be produced.

11. TOXICOLOGICAL INFORMATION

Acute toxicity

Substance	Test type	Species	Dose
Methanol			
	LD50 Oral	Rat	5,600 mg/kg
	LD50 Oral	Mouse	5,800 mg/kg
	LD50 Oral	Rabbit	14,200 mg/kg
	LC50 Inhalation	Mouse	41000 ppm
	LC50 Inhalation	Rat	64000 ppm
	LC50 Inhalation	Rabbit	81,000 mg/m3
	LD50 Dermal	Rabbit	15,800 mg/kg

Irritation/Corrosion

Not available.

Target organ effects Methanol: Ingestion may cause blindness.

Carcinogenicity

None of the components are listed.

12. ECOLOGICAL INFORMATION

Environmental effects No known significant effects or critical hazards.

Other adverse effects None known.

13. DISPOSAL CONSIDERATIONS

Waste disposal The generation of waste should be avoided or minimized wherever possible. Empty containers or liners may retain some product residues. This material and its container must be disposed of in a safe way. Dispose of surplus and non-recyclable products via a licensed waste disposal contractor. Disposal of this product, solutions and any by-products should at all times comply with the requirements of environmental protection and waste disposal legislation and any regional local authority requirements. Avoid dispersal of spilled material and runoff and contact with soil, waterways, drains and sewers.

Disposal should be in accordance with applicable regional, national and local laws and regulations. Refer to Section 7: HANDLING AND STORAGE and Section 8: EXPOSURE CONTROLS/PERSONAL PROTECTION for additional handling information and protection of employees.

14. TRANSPORT INFORMATION

Refer to the bill of lading or container label for DOT or other transportation hazard classification. Additionally, be aware that shipping descriptions may vary based on mode of transport, shipment volume or weight, container size or type, and/or origin and destination. Consult your company's Hazardous Materials / Dangerous Goods expert or your legal counsel for information specific to your situation.

15. REGULATORY INFORMATION

HCS Classification

Component	Classification
Methanol	Irritant., Target organ effects, Occupational exposure limits

U.S. Federal regulations

CERCLA: Hazardous substances - Reportable quantity:

Substance	Reportable quantity
Methanol	5000 lbs

Product Reportable quantity	Substance
50,251 lb, 5,651 gal US	Methanol

Product spills equal to or exceeding the threshold above trigger the reporting requirements under CERCLA for the listed hazardous substance. Report the spill or release to the National Response Center (NRC) at (800) 424-8802.

SARA Title III Section 302 Extremely hazardous substances (40 CFR Part 355):

None of the components are listed.

SARA 311/312 MSDS distribution - chemical inventory - hazard identification:

Fire hazard.

SARA 313 - Supplier notification

Component	CAS no.	Weight %
Methanol	67-56-1	5 - 10

Clean Water Act (CWA) 307:

None of the components are listed.

Clean Water Act (CWA) 311:
None of the components are listed.

Clean Air Act (CAA) 112 accidental release prevention:
None of the components are listed.

Clean Air Act (CAA) 112 regulated flammable substances:
None of the components are listed.

Clean Air Act (CAA) 112 regulated toxic substances:
None of the components are listed.

State regulations

Massachusetts Substances: The following components are listed: Methanol.

New Jersey Hazardous Substances: The following components are listed: Methanol.

Pennsylvania RTK Hazardous Substances: The following components are listed: Methanol.

California Prop. 65

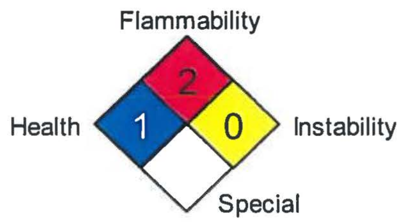
Not available.

International regulations

United States inventory (TSCA 8b):	All components are listed or exempted.
Canada inventory (DSL):	All components are listed or exempted.

16. OTHER INFORMATION

National Fire Protection Association (U.S.A.):



Prepared by	Product Stewardship (1-281-431-2561)
Date of issue	06/02/2010
Date of previous issue	07/30/2008
Version	3.0

Disclaimer

To the best of our knowledge, the information contained herein is accurate. However, neither the above-named supplier, nor any of its subsidiaries, assumes any liability whatsoever for the accuracy or completeness of the information contained herein. Final determination of suitability of any material is the sole responsibility of the user. All materials may present unknown hazards and should be used with caution. Although certain hazards are described herein, we cannot guarantee that these are the only hazards that exist.

Material Safety Data Sheet
Bactron® K-139

1. PRODUCT AND COMPANY IDENTIFICATION

Product name Bactron® K-139

Product use Biocide

Manufacturer Champion Technologies, Inc.
P.O. Box 450499
Houston, TX, 77245
USA

Telephone 1-281-431-2561 (Champion)

In case of emergency 1-800-424-9300 (CHEMTREC)
1-703-527-3887 (CHEMTREC - International)

2. HAZARDS IDENTIFICATION

Physical state liquid

Color Clear. colorless.

Odor sharp, pungent

Emergency overview WARNING!
Harmful. Irritant. May cause sensitization by inhalation. Not considered to be flammable.

Potential health effects

Inhalation Harmful by inhalation. Irritating to respiratory system. May cause sensitization by inhalation.

Ingestion Harmful if swallowed. Irritating to mouth, throat and stomach.

Skin Irritating to skin.

Eyes Severely irritating to eyes. Risk of serious damage to eyes.

Chronic effects Once sensitized, a severe allergic reaction may occur when subsequently exposed to very low levels.

See toxicological information (section 11)

3. COMPOSITION/INFORMATION ON INGREDIENTS

Name	CAS no.	Weight %
Glutaraldehyde	111-30-8	1 - 5
Quaternary ammonium compounds, benzyl-C12-16-alkyldimethyl, chlorides	68424-85-1	5 - 10
Ethanol	64-17-5	1 - 5

4. FIRST AID MEASURES

Eye contact Get medical attention immediately. Immediately flush eyes with plenty of water, occasionally lifting the upper and lower eyelids. Check for and remove any contact lenses. Chemical burns must be treated promptly by a physician.

Skin contact Flush contaminated skin with plenty of water. Remove contaminated clothing and shoes. Continue to rinse for at least 10 minutes. Get medical attention.

Inhalation Move exposed person to fresh air. If not breathing, if breathing is irregular or if respiratory arrest occurs, provide artificial respiration or oxygen by trained personnel. Get medical attention. If unconscious, place in recovery position and get medical attention immediately. Maintain an open airway. In the event of any complaints or symptoms, avoid further exposure.

Ingestion	Wash out mouth with water. If material has been swallowed and the exposed person is conscious, give small quantities of water to drink. Do not induce vomiting unless directed to do so by medical personnel. Get medical attention. Never give anything by mouth to an unconscious person.
Protection of first-aiders	No action shall be taken involving any personal risk or without suitable training. If it is suspected that fumes are still present, the rescuer should wear an appropriate mask or self-contained breathing apparatus. It may be dangerous to the person providing aid to give mouth-to-mouth resuscitation.
Notes to physician	No specific treatment. Treat symptomatically. Contact poison treatment specialist immediately if large quantities have been ingested or inhaled.

5. FIRE-FIGHTING MEASURES

Flash point	> 200 °F (> 93.3 °C), Pensky-Martens.
Flammability of the product	In a fire or if heated, a pressure increase will occur and the container may burst.

Extinguishing media

Suitable	Use an extinguishing agent suitable for the surrounding fire.
Special exposure hazards	Promptly isolate the scene by removing all persons from the vicinity of the incident if there is a fire. No action shall be taken involving any personal risk or without suitable training.
Hazardous combustion products	carbon dioxide, carbon monoxide
Special protective equipment for fire-fighters	Fire-fighters should wear appropriate protective equipment and self-contained breathing apparatus (SCBA) with a full face-piece operated in positive pressure mode.
Special remarks on fire hazards	Not available.

6. ACCIDENTAL RELEASE MEASURES

Personal precautions	No action shall be taken involving any personal risk or without suitable training. Evacuate surrounding areas. Keep unnecessary and unprotected personnel from entering. Do not touch or walk through spilled material. Avoid breathing vapor or mist. Provide adequate ventilation. Wear appropriate respirator when ventilation is inadequate. Put on appropriate personal protective equipment (see section 8).
Environmental precautions	Avoid contact of spilled material with soil and prevent runoff entering surface waterways. Inform the relevant authorities if the product has caused environmental pollution (sewers, waterways, soil or air).

Methods for cleaning up

Small spill	Stop leak if without risk. Move containers from spill area. Dilute with water and mop up if water-soluble or absorb with an inert dry material and place in an appropriate waste disposal container. Dispose of via a licensed waste disposal contractor.
Large spill	Stop leak if without risk. Move containers from spill area. Approach release from upwind. Prevent entry into sewers, water courses, basements or confined areas. Contain and collect spillage with non-combustible, absorbent material e.g. sand, earth, vermiculite or diatomaceous earth and place in container for disposal according to local regulations (see

section 13). Contaminated absorbent material may pose the same hazard as the spilled product. Note: see section 1 for emergency contact information and section 13 for waste disposal.

7. HANDLING AND STORAGE

Handling Use only with adequate ventilation. Put on appropriate personal protective equipment (see section 8). Wear appropriate respirator when ventilation is inadequate. Eating, drinking and smoking should be prohibited in areas where this material is handled, stored and processed. Persons with a history of asthma, allergies or chronic or recurrent respiratory disease should not be employed in any process in which this product is used. Do not get in eyes or on skin or clothing. Avoid breathing vapor or mist. Empty containers retain product residue and can be hazardous. Do not reuse container. Workers should wash hands and face before eating, drinking and smoking.

Storage Store in accordance with local regulations. Keep container in a well-ventilated area. Store in the original container or an approved alternative made from a compatible material. Keep tightly closed when not in use. Do not store in unlabeled containers. Use appropriate containment to avoid environmental contamination.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Personal protection

Hands Use chemical-resistant, impervious gloves.

Eyes Safety eyewear should be used when there is a likelihood of exposure.

Body Personal protective equipment for the body should be selected based on the task being performed and the risks involved and should be approved by a specialist before handling this product.

Respiratory If during normal use the material presents a respiratory hazard, use only with adequate ventilation or wear appropriate respirator. Respirator selection must be based on known or anticipated exposure levels, the hazards of the product and the safe working limits of the selected respirator.

Occupational exposure limits

Component	Source	Type	PPM	MG/M3	Notes
Glutaraldehyde					
	NIOSH REL	CEIL	0.2 ppm	0.8 mg/m3	
	ACGIH TLV	CEIL	0.05 ppm		
Ethanol					
	OSHA PEL	TWA	1,000 ppm	1,900 mg/m3	
	NIOSH REL	TWA	1,000 ppm	1,900 mg/m3	
	ACGIH TLV	TWA	1,000 ppm	1,880 mg/m3	

Engineering measures Use only with adequate ventilation. If user operations generate dust, fumes, gas, vapor or mist, use process enclosures, local exhaust ventilation or other engineering controls to keep worker exposure to airborne contaminants below any recommended or statutory limits.

Hygiene measures Wash hands, forearms and face thoroughly after handling chemical products, before eating, smoking and using the lavatory and at the end of the working period. Wash contaminated clothing before reusing. Emergency baths, showers, or other equipment appropriate for the potential level of exposure should be located close to the workstation location.

Environmental exposure controls Emissions from ventilation or work process equipment should be checked to ensure they comply with the requirements of environmental protection legislation. In some cases, fume scrubbers, filters or engineering modifications to the process equipment will be necessary to reduce emissions to acceptable levels.

9. PHYSICAL AND CHEMICAL PROPERTIES

Physical state liquid

Color	Clear. colorless.
Odor	sharp, pungent
Odor threshold	Not available.
Boiling/condensation point	Not available.
Pour point	< 32 °F (< 0.0 °C)
Flash point	> 200 °F (> 93.3 °C), Pensky-Martens.
Flammable limits	Lower: Not available. Upper: Not available.
Auto-ignition temperature	Not available.
pH	5.0 - 6.5, Method (neat)
Evaporation rate	Not available.
Solubility	Water
Vapor density	Not available.
Relative density	0.9896 - 1.0196 @ 68 °F (20.0 °C)
Vapor pressure	Not available.
Viscosity	Dynamic: 10 - 100 cPs
Octanol/water partition coefficient (LogPow)	Not available.

Note: Typical values only - not to be interpreted as sales specifications

10. STABILITY AND REACTIVITY

Stability	The product is stable.
Hazardous polymerization	Under normal conditions of storage and use, hazardous polymerization will not occur.
Conditions to avoid	No specific data.
Materials to avoid	No specific data.
Hazardous decomposition products	Under normal conditions of storage and use, hazardous decomposition products should not be produced.

11. TOXICOLOGICAL INFORMATION

Acute toxicity

Substance	Test type	Species	Dose	Classification
Product	LD50 Oral	Rat	511 mg/kg	Harmful.
Product	LC50 Inhalation	Rat	1.86 mg/l	Harmful.
Product	LD50 Dermal	Rat	2,020 mg/kg	Practically non-toxic in contact with skin.

Irritation/Corrosion

Substance	Test type	Species	Exposure	Classification
Product	skin	Rabbit	4 hrs	Irritating to skin.
	eyes	Rabbit	24 hrs	Corrosive to eyes.

Sensitization

Substance	Route of exposure	Species	Classification

Product	skin	Guinea pig	Non-sensitizer.

Carcinogenicity

None of the components are listed.

Conclusion/Summary

12. ECOLOGICAL INFORMATION

Environmental effects No known significant effects or critical hazards.

Other adverse effects None known.

13. DISPOSAL CONSIDERATIONS

Waste disposal The generation of waste should be avoided or minimized wherever possible. Empty containers or liners may retain some product residues. This material and its container must be disposed of in a safe way. Dispose of surplus and non-recyclable products via a licensed waste disposal contractor. Disposal of this product, solutions and any by-products should at all times comply with the requirements of environmental protection and waste disposal legislation and any regional local authority requirements. Avoid dispersal of spilled material and runoff and contact with soil, waterways, drains and sewers.

Disposal should be in accordance with applicable regional, national and local laws and regulations. Refer to Section 7: HANDLING AND STORAGE and Section 8: EXPOSURE CONTROLS/PERSONAL PROTECTION for additional handling information and protection of employees.

14. TRANSPORT INFORMATION

Refer to the bill of lading or container label for DOT or other transportation hazard classification. Additionally, be aware that shipping descriptions may vary based on mode of transport, shipment volume or weight, container size or type, and/or origin and destination. Consult your company's Hazardous Materials / Dangerous Goods expert or your legal counsel for information specific to your situation.

15. REGULATORY INFORMATION

HCS Classification

Component	Classification
Ethanol	Occupational exposure limits
Glutaraldehyde	Toxic., Corrosive, Sensitizer, Occupational exposure limits
Quaternary ammonium compounds, benzyl-C12-16-alkyldimethyl, chlorides	Harmful., Corrosive

U.S. Federal regulations

CERCLA: Hazardous substances - Reportable quantity:

None of the components are listed.

SARA Title III Section 302 Extremely hazardous substances (40 CFR Part 355):

None of the components are listed.

SARA 311/312 MSDS distribution - chemical inventory - hazard identification:

Immediate (acute) health hazard. Delayed (chronic) health hazard.

SARA 313 - Supplier notification

None of the components are listed.

Clean Water Act (CWA) 307:

None of the components are listed.

Clean Water Act (CWA) 311:

None of the components are listed.

Clean Air Act (CAA) 112 accidental release prevention:

None of the components are listed.

Clean Air Act (CAA) 112 regulated flammable substances:
None of the components are listed.

Clean Air Act (CAA) 112 regulated toxic substances:
None of the components are listed.

State regulations

Massachusetts Substances: The following components are listed: Glutaraldehyde. Ethanol.

New Jersey Hazardous Substances: The following components are listed: Ethanol. Glutaraldehyde.

Pennsylvania RTK Hazardous Substances: The following components are listed: Ethanol. Glutaraldehyde.

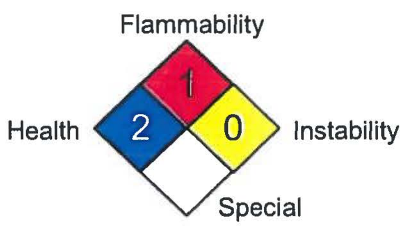
California Prop. 65
Not available.

International regulations

United States inventory (TSCA 8b):	All components are listed or exempted.
Canada inventory (DSL):	All components are listed or exempted.

16. OTHER INFORMATION

National Fire Protection Association (U.S.A.):



Prepared by	Product Stewardship (1-281-431-2561)
Date of issue	08/10/2010
Date of previous issue	10/01/2009
Version	1.1

Disclaimer
To the best of our knowledge, the information contained herein is accurate. However, neither the above-named supplier, nor any of its subsidiaries, assumes any liability whatsoever for the accuracy or completeness of the information contained herein. Final determination of suitability of any material is the sole responsibility of the user. All materials may present unknown hazards and should be used with caution. Although certain hazards are described herein, we cannot guarantee that these are the only hazards that exist.

Material Safety Data Sheet

1. PRODUCT AND COMPANY IDENTIFICATION

PRODUCT NAME	Methanol
PRODUCT USE	Solvent
COMPANY MAILING ADDRESS	Champion Technologies, Inc. P.O. Box 450499 Houston, TX, 77245 USA
EMERGENCY TELEPHONE NUMBERS 24 HRS.	1-800-424-9300 (CHEMTREC) 1-703-527-3887 (CHEMTREC - International) 1-613-996-6666 (CANUTEC - Canada) 1-281-431-2561 (Champion)

2. COMPOSITION/INFORMATION ON INGREDIENTS

SUBSTANCE	CAS-NO.	WEIGHT %
Methanol	67-56-1	80.0 - 100.0

3. HAZARDS IDENTIFICATION

EMERGENCY OVERVIEW
DANGER!

APPEARANCE & ODOR	Colorless, Liquid , Mild Sweet
HEALTH HAZARDS	Harmful, Irritant
PHYSICAL HAZARDS	Flammable, Material may be ignited by heat, sparks or flames.

HEALTH HAZARDS

SKIN	Harmful in contact with skin. Irritating to skin.
EYE	Irritating to eyes.
INHALATION	Harmful by inhalation. Irritating to respiratory system.
INGESTION	Harmful if swallowed.
POTENTIAL ENVIRONMENTAL EFFECTS	Prevent product from entering drains (waterways).

4. FIRST AID MEASURES

SKIN	Wash off immediately with soap and plenty of water while removing all contaminated clothes and shoes. If symptoms persist, call a physician.
EYE	Rinse immediately with plenty of water, also under the eyelids, for at least 15 minutes. Call a physician immediately.
INHALATION	Move to fresh air. If symptoms persist, call a physician.

INGESTION	Obtain medical attention. Immediately give large quantities of water to drink. Never give anything by mouth to an unconscious person.

5. FIRE-FIGHTING MEASURES

FLASH POINT	54 °F (12 °C) TCC
EXTINGUISHING MEDIA	Water spray, alcohol-resistant foam, dry chemical or carbon dioxide.
SPECIAL HAZARDS	Vapors are heavier than air and may travel considerable distance along the ground or be moved by ventilation to ignition sources. Empty product containers may contain product residue. Do not pressurize, cut, heat, weld or expose containers to flame or other sources of ignition.
SPECIAL PROTECTIVE EQUIPMENT FOR FIRE FIGHTERS	Wear positive-pressure self-contained breathing apparatus (SCBA) and full protective fire fighting gear. Equipment should be thoroughly decontaminated after use.
HAZARDOUS COMBUSTION PRODUCTS	Combustion products may include carbon monoxide, carbon dioxide and nitrogen oxides.
FIRE FIGHTING / FURTHER ADVICE	Evacuate area and fight fire from safe distance. Use water spray to cool fire exposed structures and to protect personnel. Shut off source of flow if possible. If a leak or spill has not ignited, use water spray to disperse the vapors.

6. ACCIDENTAL RELEASE MEASURES

CLEAN UP METHODS	Eliminate all ignition sources. No flares, smoking or flames in hazard area. Stop leak if you can do it without risk. Liquids may need to be neutralized before collection begins. Take up spill with sand or other noncombustible absorbent material and place in containers for later disposal. Always wear proper personal protective equipment when addressing spill or leak.
ENVIRONMENTAL PRECAUTIONS	Prevent product from entering drains (waterways).

7. HANDLING AND STORAGE

GENERAL PRECAUTIONS	Handle in accordance with good industrial hygiene and safety practices. These practices include avoiding unnecessary exposure and removal of material from eyes, skin and clothing. Wash thoroughly after handling. Avoid breathing vapor. Use only with adequate ventilation. Keep away from heat and sources of ignition. Take precautionary measures against static discharges.
STORAGE	Keep container closed when not in use. Store in cool, dry place.

8. EXPOSURE CONTROLS / PERSONAL PROTECTION

OCCUPATIONAL EXPOSURE LIMITS

NAME	SOURCE	TYPE	PPM	MG/M3	NOTATION

Methanol	ACGIH	STEL	250		
		SKIN			*
	NIOSH	REL	200	260	
		STEL	250	325	
		SKIN			*
	OSHA	PEL	200	260	
	ACGIH	TWA	200		

*** = Can be absorbed through the skin.**

ENGINEERING MEASURES Provide general and/or local exhaust ventilation, process enclosures or other engineering controls to control airborne levels below exposure guidelines.

RESPIRATORY PROTECTION When respiratory protection is required, use an approved air purifying respirator or positive-pressure supplied-air respirator depending on potential airborne concentration.

HAND PROTECTION Wear chemical-resistant gloves to prevent skin contact. Glove/protective clothing suppliers can provide recommendations for your specific applications. Wash immediately if skin is contaminated. Good personal hygiene practices such as properly handling contaminated clothing, using wash facilities before eating, drinking or smoking are essential for preventing personal chemical contamination. Contaminated gloves should be replaced.

EYE PROTECTION Use chemical splash goggles, safety glasses and/or face shield. An emergency eye wash fountain should be located in immediate work area.

BODY PROTECTION A safety shower should be located in the immediate work area. Remove contaminated clothing, wash skin with soap and water and launder clothing before reuse or dispose of properly.

9. PHYSICAL AND CHEMICAL PROPERTIES

FORM	Liquid
COLOR	Colorless
ODOR	Mild Sweet
ODOR THRESHOLD	Not available
BOILING POINT	149 °F (65 °C)
FLASH POINT	54 °F (12 °C) TCC
LOWER EXPLOSION LIMIT	Not available
UPPER EXPLOSION LIMIT	Not available
AUTOIGNITION TEMPERATURE	Not available
EVAPORATION RATE	2.1 Butyl acetate =1
pH	Not available
SOLUBILITY	Water
RELATIVE VAPOR DENSITY (AIR = 1)	1.11
SPECIFIC GRAVITY (H2O = 1)	0.7950
VAPOR PRESSURE	21.7 mmHg

PARTITION COEFFICIENT (N-OCTANOL/WATER)	Not available

10. STABILITY AND REACTIVITY

STABILITY	Stable
CONDITIONS TO AVOID	Open flames, Sparks
MATERIALS TO AVOID	Strong oxidizers
HAZARDOUS DECOMPOSITION PRODUCTS	Oxides of carbon
HAZARDOUS POLYMERIZATION	Will not occur

11. TOXICOLOGICAL INFORMATION

No data is available on the product itself.

CARCINOGENICITY

Product:	Not available

TARGET ORGAN TOXICITY

Methanol	Ingestion may cause blindness.

12. ECOLOGICAL INFORMATION

No data is available on the product itself.

13. DISPOSAL CONSIDERATIONS

ADVICE ON DISPOSAL Dispose of in accordance with local regulations.

14. TRANSPORT INFORMATION

Refer to the bill of lading or container label for DOT or other transportation hazard classification. Additionally, be aware that shipping descriptions may vary based on mode of transport, shipment volume or weight, container size or type, and/or origin and destination. Consult your company's Hazardous Materials / Dangerous Goods expert or your legal counsel for information specific to your situation.

15. REGULATORY INFORMATION

FEDERAL REGULATORY STATUS

CERCLA

SUBSTANCE	**REPORTABLE QUANTITY**
Methanol	5000 lbs

STATE REGULATORY STATUS

STATE RIGHT TO KNOW

NEW JERSEY RIGHT-TO-KNOW CHEMICAL LIST
Methanol

MASSACHUSETTS RIGHT-TO-KNOW CHEMICAL LIST
Methanol

PENNSYLVANIA RIGHT-TO-KNOW CHEMICAL LIST
Methanol

NOTIFICATION STATUS	**INVENTORY STATUS**
TSCA	Listed or Exempt

16. OTHER INFORMATION

NFPA RATING

HEALTH	1
FLAMMABILITY	3
INSTABILITY	0

Prepared By:	Product Stewardship
Preparation Date:	11/30/2007

The data and information contained herein are being furnished for informational purposes only, upon the express condition that each customer shall make its own assessment of appropriate use and appropriate shipping, transfer and storage materials and procedures for Champion Technologies, Inc. products. Although based on information sources which Champion Technologies, Inc. considers accurate and reliable, Champion Technologies Inc. makes no warranty, either express or implied, including any warranties or merchantability or fitness for a particular purpose, regarding the validity of this information, the information sources upon which the same are based, or the results to be obtained, and expressly disclaims liabilities for damages or injuries resulting from the use thereof.

Appendix B – Facility Design Summary

FLUID MOVING SOLUTIONS LLC

Date: August 11, 2014

To: Ladi Okunuga
Senior Engineer, Production
McCandless Corporate Center
5800 Corporate Drive, Suite 300
Pittsburgh, PA 15237
Office: (412) 548-2521
Cell: (814) 715-4681
okunugal@srcx.com

From: Don Tron
Fluid Moving Solutions LLC
4400 Stonegarden Lane
Newburgh, IN 47630
Cell: (812) 431 7314
E-mail: DTron@fluidmovingsolutions.com

RE: Seneca Resources Kane James City SWD Revised Facility
Surface Facility Permit

Dear Mr. Okunuga,

Seneca Resources to build a surface injection facility in Kane James City, PA and has tasked Fluid Moving Solutions with the job of designing this facility.

This report has been revised from the original sent on August 2, 2014 and will detail the following:

- Facility Performance Specifications
- Number and Capacity of Storage Tanks
- Volume Calculations and Containment Requirements
- Containment Dimensional Data and Construction Specifications
- Truck Unloading Pad Design and Containment Data

This packet contains all necessary items to properly detail the design and construction of the surface facility. If you require additional information or need further detail, please contact me at 812/431-7314 (mobile) or e-mail @ dtron@fluidmovingsolutions.com.

Best Regards,

Don Tron
Fluid Moving Solutions LLC

FACILITY PERFORMANCE SPECIFICATIONS

The facility will be designed to achieve the following performance:

Maximum Daily Injection: 3000 bpd
(Two Pumps rated for 1500 BPD each)

Maximum Facility Pressure: 1500 psi

Maximum Projected Truck Incoming Rate: 520 bph

Of Truck Bays: 2

NUMBER & CAPACITY OF STORAGE TANKS

The number, capacity, and description of storage tanks are as follows:

Tank #	QTY	DESCRIPTION	CAPACITY
T1	1	Gun Barrel, Steel, API, 10’ x 20’	300 bbl
T2	1	Gun Barrel, Steel, API, 10’ x 20’	300 bbl
T3	1	Dirty Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T4	1	Dirty Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T5	1	Dirty Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T6	1	Dirty Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T7	1	Dirty Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T8	1	Dirty Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T9	1	Clean Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T10	1	Clean Water Tank, Steel, Lined, API, 10’ x 15’	210 bbl
T11	1	Oil Tank, Steel, API, 10’ x 9’	100 bbl
T12	1	Truck Receiving Tank, Steel, Horizontal, 8’ x 30’	300 bbl

Total Water Storage Capacity: 2580

The tank farm layout segregates tanks into different “systems”. These systems will be piped as independent. A system list is as follows:

- Truck Receiving - Total Capacity = 300 bbl
- Gun Barrels - Total Capacity = 600 bbl
- Dirty Water Tanks - Total Capacity = 1260 bbl

- Clean Water Tanks - Total Capacity = 420 bbl
- Oil Tanks - Total Capacity = 100 bbl

The maximum volume will be in the dirty water tank system which is eight (6) – 210 bbl tanks all connected together.

Seneca Resources has requested a tank farm containment that will hold 110% of storage capacity.

CONTAINMENT CALCULATIONS

Maximum Storage Volume: = 2580 bbl = 108,360 gallons
= 14,485.67 ft^3

110% of Maximum Volume: = 15,934.24 ft^3

Volume Deducts:
(Defined as the non-usable space in the containment facility due to space usage)

<u>Housekeeping Pads – Vertical Tanks</u>
Formula: $\pi r^2 h$(# of pads) = (3.14)(11'/2)^2(.75')(14)
= 783.63 ft^3

<u>Tank Volumes – Vertical Tanks</u>
Formula: $\pi r^2 h$(# of tanks) =(3.14)(5')^2(2.25')(14)
= 1942.88 ft^3

Tank Volumes – Horizontal Tank
Formula: LxWxH(# of tanks) =(30')(8')(3')
= 720 ft^3

Total Used/Displaced Volume = 3,446.51ft^3

CORRECTED CONTAINMENT VOLUME

Required for Largest Volume:	15,934.24 ft^3
Adder For Used/Displaced Volume:	3,446.51 ft^3
100 bbl Oil Tank	561.46 ft^3

Total Volume Required: 19,942.21 ft^3

CONTAINMENT DIMENSIONS – PER REVISED DRAWING

Interior Dimensions

64ft Width x 104ft Length x 3ft height
= 19,968 ft^3

Total Volume Available: 19,968 ft^3

CONTAINMENT DIMENSIONS & CONSTRUCTION DATA

As detailed in the calculation section of this report the containment will be built with interior dimensions of 64' Width x 104' Length x 3' Height. This yields a containment volume of 19,968 cubic feet. The containment will be constructed as follows:

- Containment will be constructed in concrete
- Containment floor will be a minimum of 6" thickness in the middle and 12" thickness on the outside with a minimal of two layers of rebar, overlapped.
- Containment walls will be concrete and a minimum thickness of 6" and a minimum height of 3' from the containment floor.
- Containment walls will be rebar reinforced and rebar will project out of the floor and into the center of the walls.
- The containment floor and walls will be as one piece.
- A water stop will be constructed at the wall/floor connection to prevent fluid from migrating into the joint.
- A sump trench 18" width and 18" depth will be poured into the center of the containment floor. The containment floor will be slopped so all fluid moves to the trench as detailed on the drawing.
- A sump pit approximately 2' x 2' x 30" will be located at one end of the sump trench to transfer collected water into the truck receiving tank.

The containment area will be designed and concrete poured to prevent any possible leakage from the tank containment area.

TRUCK UNLOADING PAD & CONTAINMENT DESIGN

The facility will have a two truck unloading bay. This unloading bay will be designed and built with the following specifications:

- The truck pad will be concrete
- The truck pad will be 70’ length
- Two bays will be 12’ wide each
- Each bay will have a 6” wide x 8” high curb to divide the lanes
- The two outer bays will have a 6” wide x 8” high curb to contain fluid inside the truck pad.
- A sump trench with approximate dimensions of 18” width, 18” depth will be poured in the concrete spanning the entire with of the truck pad.
- The sump trench will be covered by a 2 ½” steel grate.
- The sump trench will contain discharge piping as well as direct flow toward a collections pit.
- A sump collections pit will be located at one end of the sump trench and will have approximate dimensions of 2’ x 2’ x 30”. A sump pump will be installed in the pit to evacuate out liquid and transfer into the truck receiving tank.
- The truck pad will be poured with a slope to direct flow toward the sump trench.
- The truck pad will be constructed as to contain all liquid within the concrete containment area.

CONCLUSION

The drawings for the site plot plan and site layout will be revised to show the security fencing as well as the addition of two tanks. These drawings will be send to Vavco, LLC. For PE Stamp. The drawings that will need revision are as follows:

- Kane James City Plot Plan
- Kane James City Site Layout
- Kane James City PFD
- Dennison #1 Tank Farm Containment Side View

Should you require additional information please contact me. The contact information is as follows:

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Appendix C - Material Compatibility Report

TETRA TECH

October 3, 2013

Mr. Ladi Okunuga
Production Engineer
Seneca Resources Corporation
McCandless Corporate Center
5800 Corporate Drive, Suite 300
Pittsburgh, Pennsylvania 15237

Subject: Compatibility Evaluation to Support Injection Facility Design – Seneca Well #38268, Elk County, Pennsylvania

Dear Mr. Okunuga:

The information provided by this brief Letter Report summarizes: 1) the chemical composition of water that will be potentially disposed by injection well as determined by samples collected in August 2013; 2) the scaling potential of these sources if injected into Elk Sandstone as the receiving formation; and 3) the predicted reactions related to mineral precipitation as injected water mixes with the native Elk Sandstone Formation water. The source water is expected to originate as produced water from the Marcellus, Utica, and Upper Devonian well fields.

1.0 INTRODUCTION

Seneca Resources Corporation (Seneca) has received a draft UIC Class IID well permit from the US Environmental Protection Agency (EPA) for converting to brine disposal Seneca's Well No. 38268, a depleted Elk Sandstone gas well located in Elk County, Pennsylvania. The well will be utilized for disposal of flowback and produced water from Seneca's Marcellus Shale and Utica Shale operations as well as produced water from Seneca's Upper Devonian wells.

Injected water may have a potential for reaction yielding precipitation of secondary phases, ion exchange reactions, and consequent alteration of hydraulic properties over time in the wellbore or within the receiving formation. There may be a potential for scaling in the pipeline or wellbore as temperature, pH, and carbon dioxide pressure change during injection. Seneca asked Tetra Tech to conduct a compatibility evaluation to assess potential for the above adverse conditions. Also part of the scope is performing settling testing to help assess settling and filtration design parameters. Compatibility analyses was performed on chemical analysis results from eight samples of potential disposal solutions, including representative samples of Marcellus, Utica, and Upper Devonian Formation-produced water, and of one sample of Elk Sandstone-produced water as a representative of the receiving formation water. Findings from this assessment are intended to identify the nature of the scale so that the selection of scale inhibitors or corrosion inhibitors can be optimized by suppliers in order to prevent loss of throughput in the borehole or permeability in the receiving formation, and will be utilized as part of the design basis for the injection well facility.

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2.0 METHODS

In accordance with standard procedures, Tetra Tech collected groundwater samples from the producing zone of nine wells in western Pennsylvania. Produced water samples were collected from production facilities for well fields producing from the Marcellus Shale (four wells), Utica Shale (one well), and Upper Devonian Formation (three wells). Additionally, one well was sampled that produced from the Elk Sandstone and is assumed to represent the composition of the receiving formation.

Protocols for sampling require that some measurements be conducted in the field at the well site. Tetra Tech measured the following parameters in the field: pH, specific conductance, groundwater temperature, turbidity, dissolved oxygen, and oxidation reduction potential (ORP) at the time of sampling. Table 1 provides sample locations as well as the sample formation. Tetra Tech filtered, preserved, and shipped the samples according to professionally-accepted methods and recommended procedures, to TestAmerica where the laboratory analyses were performed. Analytical reports from TestAmerica (Attachment 1) indicate the samples as being received in good condition, properly preserved, on ice, and in the appropriate sample bottles. The analyses were performed according to standard procedures, and the methods used are approved and recommended by EPA and are included in the laboratory report in Attachment 1.

Tetra Tech used the results from the water quality analysis to create input files for a computer simulation of scaling potential. A geochemical model, SOLMINEQ, was employed to compute the saturation conditions of minerals or amorphous phases that could potentially precipitate from the solution with respect to the known or estimated oxidation/reduction state, pH, and temperature conditions, both at the land surface or at the temperature of the reservoir.

Tetra Tech used SOLMINEQ to examine the saturation state of the samples. SOLMINEQ is a non-proprietary reaction path chemical equilibrium model supplied and supported by the U.S. Geological Survey (USGS); the original model was published by the USGS in hardcopy (1988). SOLMINEQ is a widely utilized and professionally-accepted model for interpreting the solubility of minerals and gases in water; computing the change in solution chemical composition as conditions of pH, temperature, and oxidation/reduction state are altered; and computing simultaneous chemical reactions of dissolved constituents with mineral surfaces. The model is both an equilibrium code able to process the redistribution of dissolved species, mixing of water sources, solubility and sorption reactions, and a dynamic model for predicting the final concentrations of chemical constituents in a specified aqueous solution with migration or changing conditions. In addition to a computer code, geochemical modeling requires a qualified database of necessary equilibrium constants for all reactions and other thermodynamic data, as well as the required constants governing the kinetic processes. The database is a separate file to allow for additions, deletions, and updates to the information without impacting the model code. The solutions modeled have high concentrations of dissolved constituents and computations require unique equations, which are the most appropriate ones for solutions of this type, and which are included in the SOLMINEQ database.

3.0 RESULTS

The analytical results of the groundwater samples, including inorganic parameters, dissolved organic carbon, settleable solids, and sulfate-reducing bacteria as provided by TestAmerica are summarized in Table 1. Also provided in Table 1 are field parameter data, total alkalinity calculated as bicarbonate, and cation/anion balance calculation of the inorganic parameters. All analytical results as received from TestAmerica are provided in Attachment 1.

Table 1. Analytical Results of Produced Water Samples

		Trap Run 38539		Tionesta 10H		Fagley Lease		James Pond 50083		James Pond 38735		Wilson Run 39171		Boon Mountain Pad A		Tract 100 Pad M		4384 James City Prospect	
		Upper Devonian		Utica		Marcellus		Marcellus		Upper Devoian		Upper Devonian		Marcellus		Marcellus		Elk Sandstone	
Parameter	**Units**	**8/12/2013**		**8/12/2013**		**8/12/2013**		**8/12/2013**		**8/12/2013**		**8/12/2013**		**8/12/2013**		**8/13/2013**		**8/16/2013**	
pH (Field)	std units	6.08		5.69		5.88		5.29		5.97		4.28		5.06		NM		6.77	
PH (Lab)	std units	5.58	HF	5.48	HF	4.99	HF	5.06	HF	5.96	HF	3.62	HF	5.28	HF	7.26	HF	5.53	HF
SPECIFIC CONDUCTIVITY (Field)	mS/cm	76.3		100		93.9		100		100		100		100		NM		100	
SPECIFIC CONDUCTIVITY (Lab)	mhos/cm	161	E	196	E	92.6	E	204	E	142	E	203	E	209	E	191	E	134	E
Temperature (Field)	deg C	20.21		20.64		25.38		20.98		20.64		23.57		21.53		Nm		22.1	
Temp (Lab)	deg C	21.2	HF	21.2	HF	21.2	HF	21.2	HF	21.2	HF	21.2	HF	21.2	HF	21.2	HF	22.2	HF
Turbidity	NTU	6.5		123		125		42.1		57.1		45.4		251		NM		144	
Dissolved Oxygen	mg/L	1.4		1.57		1.27		1.08		2.71		1.49		1.05		NM		8.88	
ORP	mV	48		44		-128		80		-17		263		-39		NM		-22	
CHLORIDE	mg/L	80900		124000		46200		157000		118000		153000		154000		108000		71300	
FLUORIDE	mg/L	7.09		3.45		37.2		2.00	U	13		3.47		2.00	U	2.00	U	1.00	U
SULFATE	mg/L	134		23.4		36.0		24.2		41.2		16.2	J	29.1		20.0	U	3.2	
BARIUM (M6010)	mg/L	14.3		3580		46.5		115		11.2		606		6220		12900		19.7	
BARIUM (M6020)	mg/L	13.8		3180		43.8		108		11.2		494		5390		14900		27.0	
SILICON AS SiO2	mg/L	6.46	JB	20.1	JB	9.35	JB	14.8	JB	6.42	JB	5.48	JB	13.0	JB	15.6	JB	7.25	B
CALCIUM	mg/L	16300		22900		6000		37400		13900		34100		35100		19700		11100	
IRON (M6010)	mg/L	28.1		101		60.0		85.7	J	32.8		190		161		104		45.8	
IRON (M6020)	mg/L	32.5		86.9		56.5		81.8		33.7		155		122		109		46.4	
MAGNESIUM	mg/L	2070		2010		1040		3090		1740		3250		2400		1160		1620	
POTASSIUM	mg/L	135	B	1380	B	86.5	JB	885	JB	108	B	248	JB	1130	B	189	JB	103	B
SODIUM	mg/L	40500		61700		21200		55800		32400		67800		62200		42800		29900	B
STRONTIUM	mg/L	136		4360		122		6530		304		3850		9900		6390		297	
SULFUR	mg/L	87.5	B	31.9	JB	16.5	JB	36.2	JB	24.1	JB	41.6	JB	250	U	36.6	JB	2.58	J
CARBONATE AS $CaCO_3$	mg/L	10	U	10	U	10	U	10	U	10	U	10.0	U	10.0	U	10.0	U	10.0	U
BICARBONATE AS $CaCO_3$	mg/L	40.8		42.5		151		4.90	J	98.0		10.0	U	38.5		106		9.17	J
TOTAL ALKALINITY AS $CaCO_3$	mg/L	40.8		42.5		151		4.90	J	98.0		10.0	U	38.5		106		9.17	J
TOTAL ALKALINITY AS HCO_3	mg/L	49.8		51.8		184.1		6.0		119.5		12.2		47.0		129.3		11.2	
TOTAL DISSOLVED SOLIDS	mg/L	163000		190000	E	82800		263000	E	141000		272000	E	315000	E	235000	E	95600	
Cation/anion balance	%	9.2		7.0		0.1		1.6		-19.4		6.6		3.7		-1.7			
Sulfate Reducing Bacteria	MPN/100 ml	<3		<3		>870		<3		240		<3		<3		<3		24	
Settleable solids	ml/L	0.500	U	0.500	U	0.500	U	0.500	U	0.500	U	0.500	U	0.500	U	0.500	U	0.500	U
Dissolved Organic Carbon	mg/L	221		148		303		8.19		169		109		214		26.3		16.8	

B = Compound was found in the blank and sample. Blank results was less than 0.7% of sample result in all samples
E = Result exceed calibration range
HF = Field parameter with holding time great then 15 minutes
J = Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.
U = Result below RL, RL value reported

4.0 DISCUSSION

The practical value in using the geochemical code SOLMINEQ for this application is the ability to predict which phases are potentially capable of forming scale in the injection well or precipitating within the formation and lowering permeability. Geochemical computations can predict which phases have the potential to precipitate, but actual precipitation may not occur due to a variety of factors such as flow rate, scale inhibitors, changing pH, or other kinetic- or rate-related issues in which insufficient time is available for precipitation to be initiated. Some of the most common scale-forming phases are listed in Table 2. To compute the results for this application, several minimal criteria must be met: 1) a total chemical analysis of the major dissolved species in the water is needed to compute some of the needed baseline solution parameters; 2) the dissolved concentration of all the elements in each phase considered in scaling potential must have been analyzed; and 3) the master variables of pH, temperature, and oxidation conditions must be known. The following discussion considers first the Elk Sandstone Formation water, then the water to be injected, and finally the mixing of the two endmembers.

4.1 Disposal Solution

4.1.1 Scaling and Formation Reactions

These aforementioned minimal criteria are satisfied with the analyses from each of the eight samples of produced water and the Elk Sandstone Formation water. For the purposes of calculating potential scale issues, Tetra Tech assumes that the measured field temperatures represent the temperature of the water during future injection, and that the maximum formation temperature is 75 °C. The field measured pH and oxidation and reduction potential (redox) represented as ORP in Table 1, is also assumed to be representative of typical conditions for each water source expected for future injection. The exception to this is the pH for the Tract 100 Pad M sample, which was not measured successfully in the field, thus only the laboratory pH measurement is available and is not sufficiently representative for the scaling calculations to be reliable. For the other samples the difference between the field and laboratory pH is significant (Table 1).

Using the field data and analytical results, the reaction state of the solution is computed using the model SOLMINEQ; output from the model is a “saturation index” which predicts whether a scaling phase selected for consideration has the potential to precipitate, or if it is undersaturated with respect to that mineral, and would dissolve if the mineral is present. The results are given in Table 2. The index is positive if the solution has the potential to precipitate the indicated phase and negative if the phase would dissolve; the absolute number is a log unit, so a value of +1 would indicate the solution is 10 times supersaturated, or 10 times the value of the thermodynamic equilibrium constant at that temperature, pressure, and solution composition. Note that at both ambient and elevated formation temperature all of the carbonate scaling minerals ($BaCO_3$, $CaCO_3$, $FeCO_3$, and $SrCO_3$), which are among the most important phases in terms of scale mass, are undersaturated or essentially at equilibrium in all but one sample. The exception is Tract 100 Pan M solution; this is the result of having to use of the lab pH in the calculation rather than the field measured pH. This is important to note because the increase in pH from the time field collection to the time pH was measured in the lab, pH increased as the result of carbon dioxide loss. It further indicates that even though the sampled solutions have a low potential to precipitate carbonate scale, long surface storage and loss of carbon dioxide, which elevates pH, appears to increase the carbonate scaling potential. A scale inhibitor for these cations associated with the carbonate phases are indicated as important considerations.

The other scale-forming phases that should be noted are silica, iron hydroxide, and barite. Silica, as an amorphous phase, is generally the first to precipitate; however in these samples it is undersaturated and would not precipitate in all sampled solutions. The silica mineral chalcedony is the more stable phase that forms over extended time frames, and these samples all compute to be close to equilibrium with chalcedony. This result indicates that these produced waters were probably at equilibrium with chalcedony in the original formation and because the silica concentration is so low, these waters will not be a significant risk for forming an amorphous silica scale. Iron hydroxide is undersaturated at the measured pH and redox potential in all samples, and appears to be at equilibrium in the Elk Sandstone. It is important to note, however, that if the pH elevates and these produced water solutions are exposed to atmospheric oxygen for enough time that iron begins to oxidize from ferrous (Fe^{+2}) to ferric (Fe^{+3}), the probability is high that iron hydroxide will precipitate due to the elevated iron concentration. This is not likely to be a large mass of precipitation, but because iron forms an amorphous flocculent it can impact formation permeability when injected. A scale inhibitor for iron would be indicated as useful in those circumstances.

Finally, the $BaSO_4$ is slightly-to-significantly supersaturated in all samples except the Elk Sandstone. The three Upper Devonian samples and two of the four Marcellus samples (Tables 1, 2) are essentially at equilibrium with $BaSO_4$ at the temperature of the formation, but become supersaturated as the temperature cools to surface conditions. Two of the Marcellus wells and the Utica Formation sample (Tables 1, 2) are significantly supersaturated with respect to $BaSO_4$. Barium is known to be elevated in the produced water of the Marcellus in this region, and scaling potential is expected to be high. The fact that it is computed to be significantly supersaturated is suspected to be related to the difficulty in measuring sulfate concentration in brines because of interferences during analysis. Barium should be a dissolved constituent that needs to sequestered with a scale inhibitor.

4.1.2 Organic Content

The sum of all organic content in water whether dissolved, colloidal, bacterial, or present as a separate phase is included in the measurement of total organic carbon (TOC); the TOC is regulated by the EPA, and the permit governing this injection well states that exceedances of 250 milligrams per liter (mg/L) TOC require that the EPA be notified. Similarly, the organic content that remains in solution as dissolved material after a sample is filtered prior to analysis is defined as dissolved organic carbon (DOC). Both TOC and DOC have specific applications. In this project the focus was on scaling potential, and there are dissolved organic constituents such as aliphatic acids that are often present in oilfield-derived water; these acids can interfere with the determination of carbonate alkalinity and consequently impact the assessment of the potential for carbonate phases such as calcium carbonate or iron carbonate to precipitate. The DOC values ranged from 8 to 303 mg/L (Table 1), indicating a significant amount of organic material. Had the computed scaling potential of these samples indicated that calcite was supersaturated and problematic for precipitation, then the elevated DOC would have suggested that the aliphatic acids as a component of the DOC might also be high, which would require further examination. Except for Tract 100 Pad M as discussed above, all samples computed to be undersaturated with all phases that contain carbonate (e.g. witherite [$BaCO_3$], calcite [$CaCO_3$] siderite [$FeCO_3$] and strontianite [$SrCO_3$]). Consequently, since scaling potential for carbonate phases is low, then the organic acid content is not of concern.

It should be noted, however, that the TOC, which would be expected to be higher than DOC, should be monitored in the future for potential permit exceedance because the DOC values are elevated in some samples. The DOC for the Flagley Lease is 303 mg/L, which exceeds the permit limit of 250 mg/L for notification; and the Trap Run 38539 sample and the Boon Mountain Pad A sample have a DOC concentration of 221 and 214 mg/L, respectively. All would likely be close to or would exceed 250 mg/L TOC limit had they been measured.

4.1.3 Sulfate Reducing Bacteria

Tests were conducted for the presence of sulfate reducing bacteria (SRB) in all eight produced water samples and the injection well. The results indicate that SRB were detected in significant concentrations in two produced water samples (Fagley Lease at > 870 MPN/100 ml, and James Pond 38735 at 240 MPN/100 ml) and in relatively low levels in the injection well (Table 1). The fact that the injection well tested positive for SRB means that even clean produced water has the potential to develop an SRB population after injection and thus increase the risk for well corrosion. The two produced waters with detected SRB are definitely in need of biocide treatment prior to injection; injection of these waters without treatment would increase the risk of corrosion in the injection well. No SRB were positively detected in the other six produced water samples.

To be conservative it is recommended that several more tests for SRB be conducted on the injection well to confirm the presence in the Elk Sandstone. SRB can live on the hardware or valves and may not actually yet be present in the reservoir. If confirmed to be present, then injected water will need to be treated with a product that kills the SRB such as a biocide or similar product to lower the risk. Secondly, the presence of the SRB in the two produced water samples is indicating that the wells from which this water was produced are probably developing a corrosion problem from the presence of SRB and should be tested and treated if found.

The fact that the sulfate concentration is low in all samples is to some extent a self-limiting factor because SRB do not use other dissolved ions as electron acceptors, only sulfate and dissolved oxygen.

Finally, the use of biocide may be problematic if the compounds are hazardous and will need to be registered and approved by EPA. An alternative SRB well treatment is available that uses biological processes and is non-toxic and non-hazardous rather than use typical biocide which may contain hazardous compounds. Companies such as Micro-tes Inc. in San Antonio, Texas, distribute this worldwide for this application (http://www.micro-tes.com/). (contact person is Bill Botto, 210.558.4757). If produced water from the well field is testing positive for SRB, then a program of well treatment may be needed to mitigate corrosion.

Parameters		Trap Run 38539		Tionesta 10H		Fagley Lease		James Pond 50083		James Pond 38735		Wilson Run 39171		Boon Mountain Pad A		Tract 100 Pad M		4384 James City Prospect	
		MODEL INPUTS																	
Field Temp (°C)		20.21	20.21	20.64	20.64	25.38	25.38	20.98	20.98	20.64	20.64	23.57	23.57	21.53	21.53	21.2	21.2	22.1	22.1
Model Temp (°C)		20.21	75	20.64	75	25.39	75	20.98	75	20.64	75	23.57	75	21.53	75	21.2	75	22.1	75
pH		6.08	5.94	5.69	5.51	5.88	5.78	5.29	5.14	5.97	5.87	4.28	4.18	5.06	4.86	7.26 (lab)	6.69	6.77	6.38
Model Pressure (bar)		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Eh (mV)		0.048	0.048	0.044	0.044	-0.128	-0.128	0.08	0.08	-0.017	-0.017	0.263	0.263	-0.039	-0.039	-0.1	-0.1	-0.022	-0.022
		MODEL OUTPUTS																	
pCO_2 (bar)		0.02	0.04	0.04	0.08	0.12	0.25	0.01	0.02	0.06	0.12	0.22	0.38	0.13	0.24	0.0022	0.01	0.001	0.003
		SATURATION INDEX																	
Carbonate Phases	Calcite ($CaCO_3$)	-0.70	-0.54	-1.03	-1.04	-0.53	-0.31	-2.23	-2.22	-0.52	-0.35	-2.94	-2.86	-1.60	-1.71	0.84	0.35	-0.76	-0.87
	Siderite ($FeCO_3$)	-1.26	-0.79	-1.22	-0.95	-0.43	0.05	-2.61	-2.34	-0.91	-0.46	-2.98	-2.67	-1.77	-1.63	0.79	0.58	-1.00	-0.81
	Strontianite ($SrCO_3$)	-2.13	-1.90	-1.01	-0.91	-1.66	-1.39	-2.19	-2.05	-1.44	-1.15	-3.09	-2.89	-1.35	-1.34	1.06	0.68	-1.70	-1.74
Silica Phases	Chalcedony (SiO_2)	0.16	-0.64	0.81	-0.02	0.08	-0.58	0.75	-0.09	0.18	-0.61	0.28	-0.51	0.71	-0.13	0.61	-0.18	0.11	-0.63
	Silica, amorphous (SiO_2)	-0.92	-1.37	-0.26	-0.75	-0.95	-1.31	-0.31	-0.82	-0.89	-1.34	-0.76	-1.24	-0.36	-0.86	-0.45	-0.91	-0.95	-1.36
Other Phases	Anhydrite ($CaSO_4$)	-1.51	-1.37	-2.30	-2.21	-2.22	-2.03	-2.10	-2.02	-2.10	-1.99	-2.35	-2.28	-2.06	-1.99	-2.32	-2.20	-3.20	-3.03
	Barite ($BaSO_4$)	0.82	0.07	2.34	1.57	0.90	0.23	0.91	0.16	0.31	-0.44	1.30	0.59	2.66	1.91	3.01	2.28	-0.45	-1.16
	Celestite ($SrSO_4$)	-1.60	-1.61	-0.93	-0.97	-2.01	-1.99	-0.71	-0.74	-1.67	-1.68	-1.17	-1.20	-0.47	-0.50	-0.76	-0.77	-2.79	-2.79
	Iron Hydroxide ($Fe(OH)_3$)	-3.11	-0.49	-3.94	-1.52	-5.98	-3.15	-4.54	-2.17	-4.54	-1.72	-4.02	-2.14	-7.06	-4.58	-1.53	0.09	-1.92	0.02
	Gypsum ($CaSO_4 \cdot 2H_2O$)	-1.25	-1.52	-2.08	-2.40	-1.97	-2.15	-1.90	-2.23	-1.85	-2.16	-2.18	-2.49	-1.87	-2.20	-2.09	-2.37	-2.94	-3.18
	Witherite ($BaCO_3$)	-3.95	-3.63	-1.97	-1.78	-2.91	-2.57	-4.79	-4.65	-3.69	-3.32	-4.81	-4.52	-2.44	-2.34	0.60	0.31	-3.57	-3.51

5.0 CONCLUSIONS

- Tetra Tech assumes that the new analytical results obtained in August 2013 for the chemical composition of the potential disposal water is representative of water that can be used for the purpose of the scale calculations Tetra Tech performed.

- The common scale forming phases such as carbonates, sulfates, silica, and metal oxyhydroxides were examined for saturation state using the geochemical code SOLMINEQ. The pH of these samples was measured in the field at the time of sample collection and is assumed to be representative of the water that will be injected. This is an important assumption because the precipitation of carbonate phases such as $BaCO_3$, $CaCO_3$, $FeCO_3$, and $SrCO_3$, is strongly dependent on the pH of the solution. If the water is stored for periods of time that allow the pH to become more alkaline, these four phases will become closer to saturation and have higher potential to precipitate as scale. As an example, the lab pH values are generally higher than the field values, indicating loss of carbon dioxide from the sample over time, which may be an indication of how the pH might change if the produced water is allowed to remain in storage on the surface for extended time periods. Because of mechanical difficulties with the field instrument, the Tract 100 Pad M sample has only a lab pH, and using this pH, the resulting calculations indicate all four carbonate minerals are supersaturated and could precipitate if the water were injected at this pH.

- Barium sulfate precipitation is a known scale problem in the region, and saturation is indicated in all wells. Some wells indicate significant supersaturation (such as Tract 100 Pad M), but that can be attributed to the uncertainty in the sulfate concentration which is below the reporting limit. Barium should be considered problematic, and a scale inhibitor that treats for barium should be considered.

- Dissolved iron concentrations are elevated, and precipitation of iron carbonate and iron oxyhydroxides are possible. Changes in pH to higher values or entrainment of oxygen during storage will both increase the probability that iron phases will precipitate. Scale inhibitor that chelates iron should be considered for these water sources.

- The Elk Sandstone is at equilibrium or undersaturated with respect to key scale forming phases; mixing of injected water that has been treated with scale inhibitor to prevent precipitation of iron carbonate, barium sulfate, and other carbonate phases should not become a greater issue with mixing. Precipitation as scale is limited to these few phases and is not made more probable with mixing of formation water.

- The increase in temperature as injected water moves from the surface to the depth of the receiving sub-surface formation slightly increases the potential of carbonate phases to form scale. Under the current pH circumstances most carbonate phases are undersaturated. If pH elevates with storage of water to the saturation point of these phases at the land surface then scaling during injection as the temperature increases is possible without scale inhibitors.

- The DOC was measured for the produced water investigated in this study, and the concentration is high for two of the samples from the Marcellus Formation and one from the Upper Devonian. This suggests that the TOC which is generally an even higher concentration than DOC, should be measured in the future to monitor compliance with the permit which requires that EPA be notified if TOC exceeds 250 mg/L.

- Sulfate reducing bacteria (SRB) was detected to two of the produced water samples at significant levels, and SRB were detected in the injection well. Injection of affected produced water, even as a mixture will potentially initiate SRB growth in the injection well and increase the risk of corrosion. Treatment is recommended to mitigate this potential corrosion as the consequence of the SRB presence. The samples containing SRB are from wells that may have a corrosion problem and these originating wells may also be in need of treatment. Non-hazardous SRB treatment methods are available.

- Long-term injection of disposal solutions will effect a change in the composition of the formation water in the vicinity of the injection well. To optimize the prevention of this it is likely that a scale inhibitor will need to be added to the disposal water, especially since both the disposal and formation water are already close to equilibrium with some problematic phases. Metal content is such that a scale inhibitor should be employed that specifically complexes Si, Ba, Al, Fe, Ca, and Sr preventing them from precipitating under more extreme circumstances of pH, increased redox potential, and variable solution composition.

6.0 REFERENCES

Kharaka YJ, Gunter WD, Aggarwal PK, Perkins EH, and Dedrale JD. 1988. SOLMINEQ.88 – A computer program for geochemical modeling of water – rock interactions. USGS Water Resources Investigation Report, 88-4227.

Please do not hesitate to contact me should you have any questions.

Sincerely,
Tetra Tech

R.L. Bassett, Ph.D.
Principal Geochemist

cc: Dale Skoff, PG – Tetra Tech

Attachment 1 – TestAmerica Chemical Analysis

ATTACHMENT 1
TESTAMERICA CHEMICAL ANALYSIS

Client Sample Results

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33254-1
SDG: UIC Compatibility Evaluation

Client Sample ID: 4384 James City Prospect
Date Collected: 08/16/13 09:00
Date Received: 08/16/13 11:47

Lab Sample ID: 490-33254-1
Matrix: Water

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	**71300**		1000	500	mg/L			08/27/13 14:19	1000
Fluoride	<1.00		1.00	0.800	mg/L			08/26/13 14:35	10
Sulfate	**3.16**		2.00	1.20	mg/L			08/27/13 13:59	2

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	**19.7**		1.00	0.0500	mg/L		08/26/13 09:52	08/27/13 10:18	100
Silicon Dioxide, SiO2	**7250**	**B**	5350	144	ug/L		08/21/13 09:47	08/27/13 07:04	5
Calcium	**11100**		100	15.0	mg/L		08/26/13 09:52	08/27/13 10:18	100
Iron	**45.8**		10.0	0.560	mg/L		08/26/13 09:52	08/27/13 10:18	100
Magnesium	**1620**		100	5.30	mg/L		08/26/13 09:52	08/27/13 10:18	100
Potassium	**103**	**B**	100	8.80	mg/L		08/26/13 09:52	08/27/13 10:18	100
Sodium	**29900**	**B**	100	2.10	mg/L		08/26/13 09:52	08/27/13 10:18	100
Strontium	**297**		5.00	0.0400	mg/L		08/26/13 09:52	08/27/13 10:18	100
Sulfur	**2.58**	**J**	25.0	1.90	mg/L		08/26/13 09:52	08/27/13 10:18	100

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/28/13 19:44	1
Bicarbonate Alkalinity as CaCO3	**9.17**	**J**	10.0	3.50	mg/L			08/28/13 19:44	1
Alkalinity	**9.17**	**J**	10.0	3.50	mg/L			08/28/13 19:44	1
Specific Conductance	**134000**	**E**	10.0	10.0	umhos/cm			08/27/13 14:19	1
Total Dissolved Solids	**95600**		1000	1000	mg/L			08/23/13 11:54	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/16/13 13:40	1
pH	**5.53**	**HF**	0.100	0.100	SU			08/29/13 13:00	1
Temperature	**22.2**	**HF**	0.100	0.100	Degrees C			08/29/13 13:00	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	**16.8**		1.00	0.500	mg/L			08/28/13 08:42	1

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-33023-1
TestAmerica SDG: UIC Compatibility Evaluation
Client Project/Site: Seneca TO4

For:
Tetra Tech, Inc
Foster Plaza VII
661 Anderson Drive
Pittsburgh, Pennsylvania 15220-2745

Attn: Dale Skoff

Jennifer Gambill

Authorized for release by:
8/30/2013 5:39:21 PM

Jennifer Gambill, Project Manager I
jennifer.gambill@testamericainc.com

The test results in this report meet all 2003 NELAC and 2009 TNI requirements for accredited parameters, exceptions are noted in this report. This report may not be reproduced except in full, and with written approval from the laboratory. For questions please contact the Project Manager at the e-mail address or telephone number listed on this page.

This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.

Results relate only to the items tested and the sample(s) as received by the laboratory.

1 2 3 4 5 6 7 8 9 10 11 12 13

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Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-33023-1	Trap Run 38539	Water	08/12/13 09:10	08/13/13 15:43
490-33023-2	Tionesta 10H	Water	08/12/13 11:30	08/13/13 15:43
490-33023-3	Fagley Lease	Water	08/12/13 13:00	08/13/13 15:43
490-33023-4	James City Pad 50083	Water	08/12/13 14:20	08/13/13 15:43
490-33023-5	James City Well 38735	Water	08/12/13 15:00	08/13/13 15:43
490-33023-6	Wilson Run 39171	Water	08/12/13 16:30	08/13/13 15:43
490-33023-7	Boone Mountain Pad A	Water	08/12/13 17:00	08/13/13 15:43
490-33023-8	Tract 100 Pad M	Water	08/13/13 10:00	08/13/13 15:43

1 2 3 4 5 6 7 8 9 10 11 12 13

Job ID: 490-33023-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-33023-1

Partial Final
Waiting on subcontracted analysis.

Comments
No additional comments.

Receipt
The samples were received on 8/13/2013 4:45 PM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperatures of the coolers at receipt time were 1.7º C, 5.4º C, 3.7º C, 5.6º C, 2.6º C, 4.2º C, 3.6º C, 0.0º C and 1.1º C.

HPLC
Method(s) 300.0: The following samples were diluted due to the nature of the sample matrix: James City Pad 50083 (490-33023-4), Boone Mountain Pad A (490-33023-7), and Tract 100 Pad M (490-33023-8). Elevated reporting limits (RLs) are provided.

No other analytical or quality issues were noted.

Metals
Method(s) 6010C: Due to sample matrix effect on the internal standard (ISTD), a dilution was required for the following samples: (490-33023-1 MS), (490-33023-1 MSD), (490-33023-1 PDS), (490-33023-1 SD), Trap Run 38539 (490-33023-1), Tionesta 10H (490-33023-2), Fagley Lease (490-33023-3), James City Pad 50083 (490-33023-4), James City Well 38735 (490-33023-5), Wilson Run 39171 (490-33023-6), Boone Mountain Pad A (490-33023-7), and Tract 100 Pad M (490-33023-8).

Method(s) 6010C: Matrix spikes for batch 100400 could not be recovered due to sample matrix interferences which required sample dilution. The associated laboratory control sample (LCS) met acceptance criteria.

Method(s) 6010C: The method blank for batch 100400 contained Potassium, Sodium, and Sulfur above the method detection limit. This target analyte concentration was less than the reporting limit (RL); therefore, re-extraction and/or re-analysis of samples was not performed.

Method(s) 6010C: The method blank for batch 80892 contained Silicon Dioxide, SiO_2 above the method detection limit. This target analyte concentration was less than the reporting limit (RL); therefore, re-extraction and/or re-analysis of samples was not performed.

No other analytical or quality issues were noted.

General Chemistry
Method(s) SM 2320B: The following sample had an initial pH below endpoint for total alkalinity analysis: Wilson Run 39171 (490-33023-6).

Method(s) SM 2510B: Conductivity concentration estimated for the following samples: Trap Run 38539 (490-33023-1), Tionesta 10H (490-33023-2), Fagley Lease (490-33023-3), James City Pad 50083 (490-33023-4), James City Well 38735 (490-33023-5), Wilson Run 39171 (490-33023-6), Boone Mountain Pad A (490-33023-7), and Tract 100 Pad M (490-33023-8).
Result over calibration reading of 100,000 umhos/cm standard.

Method(s) SM 2540C: The minimum analysis volume of 1 mL was used for the following samples which produced a base result greater than 200mg before calculation of the final result:
Tionesta 10H (490-33023-2), James City Pad 50083 (490-33023-4), Wilson Run 39171 (490-33023-6), Boone Mountain Pad A (490-33023-7), and Tract 100 Pad M (490-33023-8). The reference method specifies that no more than 200mg of weight be recovered for a chosen sample analysis volume in order to produce the best data precision. As such, these data have been qualified.

1 2 3 4 5 6 7 8 9 10 11 12 13

Job ID: 490-33023-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

Method(s) SM 5310B: Due to the high concentration of Dissolved Organic Carbon, the matrix spike / matrix spike duplicate (MS/MSD) for batch 101394 could not be evaluated for accuracy and precision. The associated laboratory control sample (LCS) met acceptance criteria.

No other analytical or quality issues were noted.

1 2 3 4 5 6 7 8 9 10 11 12 13

Qualifiers

HPLC/IC

Qualifier	Qualifier Description
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

Metals

Qualifier	Qualifier Description
B	Compound was found in the blank and sample.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.
4	MS, MSD: The analyte present in the original sample is 4 times greater than the matrix spike concentration; therefore, control limits are not applicable.
E	Result exceeded calibration range.

General Chemistry

Qualifier	Qualifier Description
HF	Field parameter with a holding time of 15 minutes
E	Result exceeded calibration range.
4	MS, MSD: The analyte present in the original sample is 4 times greater than the matrix spike concentration; therefore, control limits are not applicable.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CNF	Contains no Free Liquid
DER	Duplicate error ratio (normalized absolute difference)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision level concentration
MDA	Minimum detectable activity
EDL	Estimated Detection Limit
MDC	Minimum detectable concentration
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative error ratio
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample ID: Trap Run 38539

Lab Sample ID: 490-33023-1

Date Collected: 08/12/13 09:10
Date Received: 08/13/13 15:43
Matrix: Water

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	80900		2500	1250	mg/L			08/20/13 12:56	2500
Fluoride	7.09		2.00	1.60	mg/L			08/20/13 15:30	20
Sulfate	134		20.0	12.0	mg/L			08/20/13 15:30	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	14.3		1.00	0.0500	mg/L		08/15/13 15:21	08/19/13 17:25	100
Silicon Dioxide, SiO2	6460	J B	26800	718	ug/L		08/18/13 12:51	08/21/13 11:51	25
Calcium	16300		100	15.0	mg/L		08/15/13 15:21	08/19/13 17:25	100
Iron	28.1		10.0	0.560	mg/L		08/15/13 15:21	08/19/13 17:25	100
Magnesium	2070		100	5.30	mg/L		08/15/13 15:21	08/19/13 17:25	100
Potassium	135	B	100	8.80	mg/L		08/15/13 15:21	08/19/13 17:25	100
Sodium	40500		100	2.10	mg/L		08/15/13 15:21	08/19/13 17:25	100
Strontium	136		5.00	0.0400	mg/L		08/15/13 15:21	08/19/13 17:25	100
Sulfur	87.5	B	25.0	1.90	mg/L		08/15/13 15:21	08/19/13 17:25	100

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 16:56	1
Bicarbonate Alkalinity as CaCO3	40.8		10.0	3.50	mg/L			08/15/13 16:56	1
Alkalinity	40.8		10.0	3.50	mg/L			08/15/13 16:56	1
Specific Conductance	161000	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	163000		1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 06:00	1
pH	5.58	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	221		5.00	2.50	mg/L			08/15/13 16:04	5

Client Sample ID: Tionesta 10H

Lab Sample ID: 490-33023-2

Date Collected: 08/12/13 11:30
Date Received: 08/13/13 15:43

Matrix: Water

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	124000		2500	1250	mg/L			08/20/13 13:17	2500
Fluoride	3.45		2.00	1.60	mg/L			08/20/13 15:50	20
Sulfate	23.4		20.0	12.0	mg/L			08/20/13 15:50	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	3580		10.0	0.500	mg/L		08/15/13 15:27	08/19/13 17:36	1000
Silicon Dioxide, SiO2	20100	J B	26800	718	ug/L		08/18/13 12:51	08/21/13 11:03	25
Calcium	22900		1000	150	mg/L		08/15/13 15:27	08/19/13 17:36	1000
Iron	101		100	5.60	mg/L		08/15/13 15:27	08/19/13 17:36	1000
Magnesium	2010		1000	53.0	mg/L		08/15/13 15:27	08/19/13 17:36	1000
Potassium	1380	B	1000	88.0	mg/L		08/15/13 15:27	08/19/13 17:36	1000
Sodium	61700		1000	21.0	mg/L		08/15/13 15:27	08/19/13 17:36	1000
Strontium	4360		50.0	0.400	mg/L		08/15/13 15:27	08/19/13 17:36	1000
Sulfur	31.9	J B	250	19.0	mg/L		08/15/13 15:27	08/19/13 17:36	1000

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:10	1
Bicarbonate Alkalinity as CaCO3	42.5		10.0	3.50	mg/L			08/15/13 17:10	1
Alkalinity	42.5		10.0	3.50	mg/L			08/15/13 17:10	1
Specific Conductance	196000	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	241000	E	1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 06:00	1
pH	5.43	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	148		4.00	2.00	mg/L			08/15/13 16:04	4

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	46200		500	250	mg/L			08/20/13 12:50	500
Fluoride	37.2		2.00	1.60	mg/L			08/20/13 16:11	20
Sulfate	36.0		20.0	12.0	mg/L			08/20/13 16:11	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	46.5		1.00	0.0500	mg/L		08/15/13 15:27	08/19/13 17:40	100
Silicon Dioxide, SiO2	9350	J B	26800	718	ug/L		08/18/13 12:51	08/21/13 11:08	25
Calcium	6000		100	15.0	mg/L		08/15/13 15:27	08/19/13 17:40	100
Iron	60.0		10.0	0.560	mg/L		08/15/13 15:27	08/19/13 17:40	100
Magnesium	1040		100	5.30	mg/L		08/15/13 15:27	08/19/13 17:40	100
Potassium	86.5	J B	100	8.80	mg/L		08/15/13 15:27	08/19/13 17:40	100
Sodium	21200		100	2.10	mg/L		08/15/13 15:27	08/19/13 17:40	100
Strontium	122		5.00	0.0400	mg/L		08/15/13 15:27	08/19/13 17:40	100
Sulfur	16.5	J B	25.0	1.90	mg/L		08/15/13 15:27	08/19/13 17:40	100

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:16	1
Bicarbonate Alkalinity as CaCO3	151		10.0	3.50	mg/L			08/15/13 17:16	1
Alkalinity	151		10.0	3.50	mg/L			08/15/13 17:16	1
Specific Conductance	96200	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	82800		1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 06:00	1
pH	4.99	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	303		7.00	3.50	mg/L			08/15/13 16:04	7

Client Sample Results

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Client Sample ID: James City Pad 50083

Lab Sample ID: 490-33023-4

Date Collected: 08/12/13 14:20
Matrix: Water
Date Received: 08/13/13 15:43

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	157000		2500	1250	mg/L			08/20/13 13:59	2500
Fluoride	<2.00		2.00	1.60	mg/L			08/20/13 16:31	20
Sulfate	24.2		20.0	12.0	mg/L			08/20/13 16:31	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	115		10.0	0.500	mg/L		08/15/13 15:27	08/19/13 17:51	1000
Silicon Dioxide, SiO2	14800	J B	53500	1440	ug/L		08/18/13 12:51	08/21/13 12:01	50
Calcium	37400		1000	150	mg/L		08/15/13 15:27	08/19/13 17:51	1000
Iron	85.7	J	100	5.60	mg/L		08/15/13 15:27	08/19/13 17:51	1000
Magnesium	3090		1000	53.0	mg/L		08/15/13 15:27	08/19/13 17:51	1000
Potassium	885	J B	1000	88.0	mg/L		08/15/13 15:27	08/19/13 17:51	1000
Sodium	55800		1000	21.0	mg/L		08/15/13 15:27	08/19/13 17:51	1000
Strontium	6530		500	4.00	mg/L		08/15/13 15:27	08/20/13 12:37	10000
Sulfur	36.2	J B	250	19.0	mg/L		08/15/13 15:27	08/19/13 17:51	1000

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:20	1
Bicarbonate Alkalinity as CaCO3	4.90	J	10.0	3.50	mg/L			08/15/13 17:20	1
Alkalinity	4.90	J	10.0	3.50	mg/L			08/15/13 17:20	1
Specific Conductance	204000	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	263000	E	1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 06:00	1
pH	5.06	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	8.19		1.00	0.500	mg/L			08/15/13 16:04	1

Client Sample Results

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Client Sample ID: James City Well 38735

Lab Sample ID: 490-33023-5

Date Collected: 08/12/13 15:00
Date Received: 08/13/13 15:43

Matrix: Water

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	118000		2500	1250	mg/L			08/20/13 14:20	2500
Fluoride	13.0		2.00	1.60	mg/L			08/20/13 16:51	20
Sulfate	41.2		20.0	12.0	mg/L			08/20/13 16:51	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	11.2		1.00	0.0500	mg/L		08/15/13 15:27	08/19/13 18:07	100
Silicon Dioxide, SiO2	6420	J B	26800	718	ug/L		08/18/13 12:51	08/21/13 11:29	25
Calcium	13900		100	15.0	mg/L		08/15/13 15:27	08/19/13 18:07	100
Iron	32.8		10.0	0.560	mg/L		08/15/13 15:27	08/19/13 18:07	100
Magnesium	1740		100	5.30	mg/L		08/15/13 15:27	08/19/13 18:07	100
Potassium	108	B	100	8.80	mg/L		08/15/13 15:27	08/19/13 18:07	100
Sodium	32400		100	2.10	mg/L		08/15/13 15:27	08/19/13 18:07	100
Strontium	304		5.00	0.0400	mg/L		08/15/13 15:27	08/19/13 18:07	100
Sulfur	24.1	J B	25.0	1.90	mg/L		08/15/13 15:27	08/19/13 18:07	100

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:37	1
Bicarbonate Alkalinity as CaCO3	98.0		10.0	3.50	mg/L			08/15/13 17:37	1
Alkalinity	98.0		10.0	3.50	mg/L			08/15/13 17:37	1
Specific Conductance	142000	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	141000		1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 06:00	1
pH	5.96	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	169		5.00	2.50	mg/L			08/15/13 16:04	5

Client Sample Results

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Client Sample ID: Wilson Run 39171

Lab Sample ID: 490-33023-6

Date Collected: 08/12/13 16:30
Date Received: 08/13/13 15:43

Matrix: Water

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	153000		2500	1250	mg/L			08/20/13 14:41	2500
Fluoride	3.47		2.00	1.60	mg/L			08/20/13 17:11	20
Sulfate	16.2	J	20.0	12.0	mg/L			08/20/13 17:11	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	606		10.0	0.500	mg/L		08/15/13 15:27	08/19/13 18:18	1000
Silicon Dioxide, SiO2	5480	J B	26800	718	ug/L		08/18/13 12:51	08/21/13 11:34	25
Calcium	34100		1000	150	mg/L		08/15/13 15:27	08/19/13 18:18	1000
Iron	190		100	5.60	mg/L		08/15/13 15:27	08/19/13 18:18	1000
Magnesium	3250		1000	53.0	mg/L		08/15/13 15:27	08/19/13 18:18	1000
Potassium	248	J B	1000	88.0	mg/L		08/15/13 15:27	08/19/13 18:18	1000
Sodium	67800		1000	21.0	mg/L		08/15/13 15:27	08/19/13 18:18	1000
Strontium	3850		50.0	0.400	mg/L		08/15/13 15:27	08/19/13 18:18	1000
Sulfur	41.6	J B	250	19.0	mg/L		08/15/13 15:27	08/19/13 18:18	1000

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:40	1
Bicarbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:40	1
Alkalinity	<10.0		10.0	3.50	mg/L			08/15/13 17:40	1
Specific Conductance	203000	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	272000	E	1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 06:00	1
pH	3.62	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	109		3.00	1.50	mg/L			08/15/13 16:04	3

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Client Sample ID: Boone Mountain Pad A

Lab Sample ID: 490-33023-7

Date Collected: 08/12/13 17:00
Matrix: Water
Date Received: 08/13/13 15:43

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	154000		5000	2500	mg/L			08/20/13 15:02	5000
Fluoride	<2.00		2.00	1.60	mg/L			08/20/13 17:31	20
Sulfate	29.1		20.0	12.0	mg/L			08/20/13 17:31	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	6220		10.0	0.500	mg/L		08/15/13 15:27	08/19/13 18:25	1000
Silicon Dioxide, SiO2	13000	J B	26800	718	ug/L		08/18/13 12:51	08/21/13 11:40	25
Calcium	35100		1000	150	mg/L		08/15/13 15:27	08/19/13 18:25	1000
Iron	161		100	5.60	mg/L		08/15/13 15:27	08/19/13 18:25	1000
Magnesium	2400		1000	53.0	mg/L		08/15/13 15:27	08/19/13 18:25	1000
Potassium	1130	B	1000	88.0	mg/L		08/15/13 15:27	08/19/13 18:25	1000
Sodium	62200		1000	21.0	mg/L		08/15/13 15:27	08/19/13 18:25	1000
Strontium	9900		500	4.00	mg/L		08/15/13 15:27	08/20/13 12:42	10000
Sulfur	<250		250	19.0	mg/L		08/15/13 15:27	08/19/13 18:25	1000

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:45	1
Bicarbonate Alkalinity as CaCO3	38.5		10.0	3.50	mg/L			08/15/13 17:45	1
Alkalinity	38.5		10.0	3.50	mg/L			08/15/13 17:45	1
Specific Conductance	209000	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	315000	E	1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 08:00	1
pH	5.28	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	214		5.00	2.50	mg/L			08/15/13 16:04	5

Client Sample ID: Tract 100 Pad M — **Lab Sample ID: 490-33023-8**
Date Collected: 08/13/13 10:00 — **Matrix: Water**
Date Received: 08/13/13 15:43

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	108000		5000	2500	mg/L			08/20/13 15:23	5000
Fluoride	<2.00		2.00	1.60	mg/L			08/20/13 17:51	20
Sulfate	<20.0		20.0	12.0	mg/L			08/20/13 17:51	20

Method: 6010C - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	12900		100	5.00	mg/L		08/22/13 13:45	08/23/13 12:30	10000
Silicon Dioxide, SiO2	15600	J B	26800	718	ug/L		08/18/13 12:51	08/21/13 11:45	25
Calcium	19700		1000	150	mg/L		08/22/13 13:45	08/23/13 12:23	1000
Iron	104		100	5.60	mg/L		08/22/13 13:45	08/23/13 12:23	1000
Magnesium	1160		1000	53.0	mg/L		08/22/13 13:45	08/23/13 12:23	1000
Potassium	189	J	1000	88.0	mg/L		08/22/13 13:45	08/23/13 12:23	1000
Sodium	42800		1000	21.0	mg/L		08/22/13 13:45	08/23/13 12:23	1000
Strontium	6390		500	4.00	mg/L		08/22/13 13:45	08/23/13 12:30	10000
Sulfur	36.6	J	250	19.0	mg/L		08/22/13 13:45	08/23/13 12:23	1000

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 17:49	1
Bicarbonate Alkalinity as CaCO3	106		10.0	3.50	mg/L			08/15/13 17:49	1
Alkalinity	106		10.0	3.50	mg/L			08/15/13 17:49	1
Specific Conductance	191000	E	10.0	10.0	umhos/cm			08/16/13 13:58	1
Total Dissolved Solids	235000	E	1000	310	mg/L			08/15/13 18:13	1
Settleable Solids	<0.500		0.500	0.500	mL/L			08/14/13 08:00	1
pH	7.26	HF	0.100	0.100	SU			08/16/13 10:51	1
Temperature	21.2	HF	0.100	0.100	Degrees C			08/16/13 10:51	1

General Chemistry - Dissolved

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	26.3		1.00	0.500	mg/L			08/15/13 16:04	1

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-101335/3
Matrix: Water
Analysis Batch: 101335

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	<1.00		1.00	0.500	mg/L			08/20/13 11:09	1
Fluoride	<0.100		0.100	0.0800	mg/L			08/20/13 11:09	1
Sulfate	<1.00		1.00	0.600	mg/L			08/20/13 11:09	1

Lab Sample ID: LCS 490-101335/4
Matrix: Water
Analysis Batch: 101335

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Chloride	50.0	50.22		mg/L		100	90 - 110
Fluoride	5.00	5.493		mg/L		110	90 - 110
Sulfate	50.0	50.36		mg/L		101	90 - 110

Lab Sample ID: LCSD 490-101335/5
Matrix: Water
Analysis Batch: 101335

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Chloride	50.0	50.17		mg/L		100	90 - 110	0	20
Fluoride	5.00	5.460		mg/L		109	90 - 110	1	20
Sulfate	50.0	50.32		mg/L		101	90 - 110	0	20

Lab Sample ID: MB 490-101340/3
Matrix: Water
Analysis Batch: 101340

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	<1.00		1.00	0.500	mg/L			08/20/13 11:53	1
Sulfate	<1.00		1.00	0.600	mg/L			08/20/13 11:53	1

Lab Sample ID: LCS 490-101340/4
Matrix: Water
Analysis Batch: 101340

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Chloride	50.0	46.16		mg/L		92	90 - 110
Sulfate	50.0	48.58		mg/L		97	90 - 110

Lab Sample ID: LCSD 490-101340/5
Matrix: Water
Analysis Batch: 101340

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Chloride	50.0	46.13		mg/L		92	90 - 110	0	20
Sulfate	50.0	48.24		mg/L		96	90 - 110	1	20

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Method: 6010C - Metals (ICP)

Lab Sample ID: MB 490-100400/1-A
Matrix: Water
Analysis Batch: 101173

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 100400

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	<0.0100		0.0100	0.000500	mg/L		08/15/13 15:21	08/19/13 16:01	1
Calcium	<1.00		1.00	0.150	mg/L		08/15/13 15:21	08/19/13 16:01	1
Iron	<0.100		0.100	0.00560	mg/L		08/15/13 15:21	08/19/13 16:01	1
Magnesium	<1.00		1.00	0.0530	mg/L		08/15/13 15:21	08/19/13 16:01	1
Potassium	0.2025	J	1.00	0.0880	mg/L		08/15/13 15:21	08/19/13 16:01	1
Strontium	<0.0500		0.0500	0.000400	mg/L		08/15/13 15:21	08/19/13 16:01	1
Sulfur	0.1120	J	0.250	0.0190	mg/L		08/15/13 15:21	08/19/13 16:01	1

Lab Sample ID: MB 490-100400/1-A
Matrix: Water
Analysis Batch: 101366

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 100400

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Sodium	0.09210	J	1.00	0.0210	mg/L		08/15/13 15:21	08/20/13 11:57	1

Lab Sample ID: LCS 490-100400/2-A
Matrix: Water
Analysis Batch: 101173

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 100400

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Barium	2.00	2.163		mg/L		108	80 - 120
Calcium	5.00	5.055		mg/L		101	80 - 120
Iron	1.00	1.081		mg/L		108	80 - 120
Magnesium	5.00	5.181		mg/L		104	80 - 120
Potassium	5.00	5.083		mg/L		102	80 - 120
Strontium	1.00	1.037		mg/L		104	80 - 120

Lab Sample ID: LCS 490-100400/2-A
Matrix: Water
Analysis Batch: 101366

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 100400

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Sodium	5.00	5.220		mg/L		104	80 - 120

Lab Sample ID: LCSD 490-100400/3-A
Matrix: Water
Analysis Batch: 101173

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 100400

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Barium	2.00	2.108		mg/L		105	80 - 120	3	20
Calcium	5.00	4.858		mg/L		97	80 - 120	4	20
Iron	1.00	1.029		mg/L		103	80 - 120	5	20
Magnesium	5.00	5.018		mg/L		100	80 - 120	3	20
Potassium	5.00	4.903		mg/L		98	80 - 120	4	20
Sodium	5.00	5.691		mg/L		114	80 - 120	11	20
Strontium	1.00	1.006		mg/L		101	80 - 120	3	20
Sulfur	1.00	1.030		mg/L		103	80 - 120	16	20

QC Sample Results

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Method: 6010C - Metals (ICP) (Continued)

Lab Sample ID: 490-33068-G-21-B MS
Matrix: Water
Analysis Batch: 101173

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 100400

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Barium	0.0228		2.00	2.014		mg/L		100	75 - 125
Calcium	568		5.00	561.2	E 4	mg/L		-140	75 - 125
Iron	6.01		1.00	6.867	4	mg/L		86	75 - 125
Magnesium	133		5.00	135.8	4	mg/L		60	75 - 125
Potassium	11.6		5.00	17.08		mg/L		110	75 - 125
Sodium	1420		5.00	1429	E 4	mg/L		240	75 - 125
Strontium	5.31		1.00	6.213	E 4	mg/L		91	75 - 125
Sulfur	948		1.00	933.9	E 4	mg/L		-1440	75 - 125

Lab Sample ID: 490-33068-G-21-C MSD
Matrix: Water
Analysis Batch: 101173

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA
Prep Batch: 100400

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Barium	0.0228		2.00	2.006		mg/L		99	75 - 125	0	20
Calcium	568		5.00	554.5	E 4	mg/L		-274	75 - 125	1	20
Iron	6.01		1.00	6.751	4	mg/L		74	75 - 125	2	20
Magnesium	133		5.00	134.3	4	mg/L		30	75 - 125	1	20
Potassium	11.6		5.00	17.05		mg/L		109	75 - 125	0	20
Sodium	1420		5.00	1392	E 4	mg/L		-500	75 - 125	3	20
Strontium	5.31		1.00	6.148	E 4	mg/L		84	75 - 125	1	20
Sulfur	948		1.00	925.7	E 4	mg/L		-2260	75 - 125	1	20

Lab Sample ID: MB 490-101969/1-A
Matrix: Water
Analysis Batch: 102247

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 101969

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	<0.0100		0.0100	0.000500	mg/L		08/22/13 13:45	08/23/13 11:47	1
Calcium	<1.00		1.00	0.150	mg/L		08/22/13 13:45	08/23/13 11:47	1
Iron	<0.100		0.100	0.00560	mg/L		08/22/13 13:45	08/23/13 11:47	1
Magnesium	<1.00		1.00	0.0530	mg/L		08/22/13 13:45	08/23/13 11:47	1
Potassium	<1.00		1.00	0.0880	mg/L		08/22/13 13:45	08/23/13 11:47	1
Sodium	<1.00		1.00	0.0210	mg/L		08/22/13 13:45	08/23/13 11:47	1
Strontium	<0.0500		0.0500	0.000400	mg/L		08/22/13 13:45	08/23/13 11:47	1
Sulfur	<0.250		0.250	0.0190	mg/L		08/22/13 13:45	08/23/13 11:47	1

Lab Sample ID: LCS 490-101969/2-A
Matrix: Water
Analysis Batch: 102247

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 101969

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Barium	2.00	1.946		mg/L		97	80 - 120
Calcium	5.00	4.775		mg/L		96	80 - 120
Iron	1.00	0.9750		mg/L		98	80 - 120
Magnesium	5.00	4.818		mg/L		96	80 - 120
Potassium	5.00	4.798		mg/L		96	80 - 120
Sodium	5.00	4.979		mg/L		100	80 - 120
Strontium	1.00	0.9764		mg/L		98	80 - 120

Method: 6010C - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-101969/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 102247 — **Prep Batch: 101969**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Sulfur	1.00	0.9996		mg/L		100	80 - 120

Lab Sample ID: 490-33498-C-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 102247 — **Prep Batch: 101969**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Barium	0.00380		2.00	1.913		mg/L		95	75 - 125
Calcium	145		5.00	153.4	4	mg/L		172	75 - 125
Iron	0.163		1.00	1.140		mg/L		98	75 - 125
Magnesium	226		5.00	237.5	4	mg/L		226	75 - 125
Potassium	26.6		5.00	32.29	4	mg/L		114	75 - 125
Sodium	160		5.00	166.3	4	mg/L		120	75 - 125
Strontium	0.215		1.00	1.206		mg/L		99	75 - 125
Sulfur	437		1.00	450.3	4	mg/L		1370	75 - 125

Lab Sample ID: 490-33498-C-1-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 102247 — **Prep Batch: 101969**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Barium	0.00380		2.00	1.902		mg/L		95	75 - 125	1	20
Calcium	145		5.00	153.5	4	mg/L		174	75 - 125	0	20
Iron	0.163		1.00	1.125		mg/L		96	75 - 125	1	20
Magnesium	226		5.00	237.3	4	mg/L		222	75 - 125	0	20
Potassium	26.6		5.00	32.25	4	mg/L		113	75 - 125	0	20
Sodium	160		5.00	168.0	4	mg/L		154	75 - 125	1	20
Strontium	0.215		1.00	1.202		mg/L		99	75 - 125	0	20
Sulfur	437		1.00	450.6	4	mg/L		1400	75 - 125	0	20

Lab Sample ID: MB 180-80892/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 81232 — **Prep Batch: 80892**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Silicon Dioxide, SiO2	37.79	J	1070	28.7	ug/L		08/18/13 12:51	08/21/13 10:18	1

Lab Sample ID: LCS 180-80892/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 81232 — **Prep Batch: 80892**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Silicon Dioxide, SiO2	21400	21360		ug/L		100	80 - 120

Method: 6010C - Metals (ICP) (Continued)

Lab Sample ID: 490-33023-1 MS
Matrix: Water
Analysis Batch: 81232

Client Sample ID: Trap Run 38539
Prep Type: Total/NA
Prep Batch: 80892

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Silicon Dioxide, SiO2	6460	J B	21400	28020		ug/L		101	75 - 125

Lab Sample ID: 490-33023-1 MSD
Matrix: Water
Analysis Batch: 81232

Client Sample ID: Trap Run 38539
Prep Type: Total/NA
Prep Batch: 80892

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Silicon Dioxide, SiO2	6460	J B	21400	27890		ug/L		100	75 - 125	0	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-100485/3
Matrix: Water
Analysis Batch: 100485

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Carbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 16:16	1
Bicarbonate Alkalinity as CaCO3	<10.0		10.0	3.50	mg/L			08/15/13 16:16	1
Alkalinity	<10.0		10.0	3.50	mg/L			08/15/13 16:16	1

Lab Sample ID: LCS 490-100485/4
Matrix: Water
Analysis Batch: 100485

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	100	91.23		mg/L		91	90 - 110

Lab Sample ID: 490-33023-1 MS
Matrix: Water
Analysis Batch: 100485

Client Sample ID: Trap Run 38539
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	40.8		100	128.0		mg/L		87	80 - 120

Lab Sample ID: 490-33023-1 DU
Matrix: Water
Analysis Batch: 100485

Client Sample ID: Trap Run 38539
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Carbonate Alkalinity as CaCO3	<10.0		<10.0		mg/L		NC	20
Bicarbonate Alkalinity as CaCO3	40.8		40.66		mg/L		0.2	20
Alkalinity	40.8		40.66		mg/L		0.2	20

Lab Sample ID: 490-33149-H-3 DU
Matrix: Water
Analysis Batch: 100485

Client Sample ID: Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Carbonate Alkalinity as CaCO3	<10.0		<10.0		mg/L		NC	20

1 2 3 4 5 6 7 8 9 10 11 12 13

Method: SM 2320B - Alkalinity (Continued)

Lab Sample ID: 490-33149-H-3 DU
Matrix: Water
Analysis Batch: 100485

Client Sample ID: Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	55.4		55.33		mg/L		0.2	20
Alkalinity	55.4		55.33		mg/L		0.2	20

Method: SM 2510B - Conductivity, Specific Conductance

Lab Sample ID: MB 490-100662/2
Matrix: Water
Analysis Batch: 100662

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Specific Conductance	<10.0		10.0	10.0	umhos/cm			08/16/13 13:58	1

Lab Sample ID: LCS 490-100662/4
Matrix: Water
Analysis Batch: 100662

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Specific Conductance	1410	1378		umhos/cm		98	90 - 110

Lab Sample ID: LCSD 490-100662/5
Matrix: Water
Analysis Batch: 100662

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Specific Conductance	1410	1378		umhos/cm		98	90 - 110	0	10

Lab Sample ID: 490-33045-I-1 DU
Matrix: Water
Analysis Batch: 100662

Client Sample ID: Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Specific Conductance	404		408.0		umhos/cm		1	10

Lab Sample ID: 490-33149-H-3 DU
Matrix: Water
Analysis Batch: 100662

Client Sample ID: Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Specific Conductance	147		147.0		umhos/cm		0.1	10

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-98002/1
Matrix: Water
Analysis Batch: 98002

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	<10.0		10.0	3.10	mg/L			08/15/13 18:13	1

Method: SM 2540C - Solids, Total Dissolved (TDS) (Continued)

Lab Sample ID: LCS 490-98002/2
Matrix: Water
Analysis Batch: 98002

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Dissolved Solids	99.4	108.0		mg/L		109	90 - 110

Lab Sample ID: 490-33040-O-1 DU
Matrix: Water
Analysis Batch: 98002

Client Sample ID: Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Total Dissolved Solids	135		138.0		mg/L		2	20

Lab Sample ID: 490-33123-D-1 DU
Matrix: Water
Analysis Batch: 98002

Client Sample ID: Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Total Dissolved Solids	1090		1094		mg/L		0.3	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-33023-3 DU
Matrix: Water
Analysis Batch: 100580

Client Sample ID: Fagley Lease
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
pH	4.99	HF	4.930		SU		1	20
Temperature	21.2	HF	21.20		Degrees C		0	20

Method: SM 5310B - Organic Carbon, Dissolved (DOC)

Lab Sample ID: MB 490-100430/1-A
Matrix: Water
Analysis Batch: 101394

Client Sample ID: Method Blank
Prep Type: Dissolved

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Dissolved Organic Carbon	<1.00		1.00	0.500	mg/L			08/15/13 16:04	1

Lab Sample ID: LCS 490-100430/2-A
Matrix: Water
Analysis Batch: 101394

Client Sample ID: Lab Control Sample
Prep Type: Dissolved

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Dissolved Organic Carbon	10.0	<10.0		mg/L		95	90 - 110

Lab Sample ID: 490-33023-1 MS
Matrix: Water
Analysis Batch: 101394

Client Sample ID: Trap Run 38539
Prep Type: Dissolved

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Dissolved Organic Carbon	221		50.0	237.0	4	mg/L		32	74 - 134

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QC Association Summary

HPLC/IC

Analysis Batch: 101335

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	300.0	
490-33023-2	Tionesta 10H	Total/NA	Water	300.0	
490-33023-3	Fagley Lease	Total/NA	Water	300.0	
490-33023-3	Fagley Lease	Total/NA	Water	300.0	
490-33023-4	James City Pad 50083	Total/NA	Water	300.0	
490-33023-5	James City Well 38735	Total/NA	Water	300.0	
490-33023-6	Wilson Run 39171	Total/NA	Water	300.0	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	300.0	
490-33023-8	Tract 100 Pad M	Total/NA	Water	300.0	
LCS 490-101335/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-101335/5	Lab Control Sample Dup	Total/NA	Water	300.0	
MB 490-101335/3	Method Blank	Total/NA	Water	300.0	

Analysis Batch: 101340

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	300.0	
490-33023-2	Tionesta 10H	Total/NA	Water	300.0	
490-33023-4	James City Pad 50083	Total/NA	Water	300.0	
490-33023-5	James City Well 38735	Total/NA	Water	300.0	
490-33023-6	Wilson Run 39171	Total/NA	Water	300.0	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	300.0	
490-33023-8	Tract 100 Pad M	Total/NA	Water	300.0	
LCS 490-101340/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-101340/5	Lab Control Sample Dup	Total/NA	Water	300.0	
MB 490-101340/3	Method Blank	Total/NA	Water	300.0	

Metals

Prep Batch: 80892

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	3010A	
490-33023-1 MS	Trap Run 38539	Total/NA	Water	3010A	
490-33023-1 MSD	Trap Run 38539	Total/NA	Water	3010A	
490-33023-2	Tionesta 10H	Total/NA	Water	3010A	
490-33023-3	Fagley Lease	Total/NA	Water	3010A	
490-33023-4	James City Pad 50083	Total/NA	Water	3010A	
490-33023-5	James City Well 38735	Total/NA	Water	3010A	
490-33023-6	Wilson Run 39171	Total/NA	Water	3010A	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	3010A	
490-33023-8	Tract 100 Pad M	Total/NA	Water	3010A	
LCS 180-80892/2-A	Lab Control Sample	Total/NA	Water	3010A	
MB 180-80892/1-A	Method Blank	Total/NA	Water	3010A	

Analysis Batch: 81232

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	6010C	80892
490-33023-1 MS	Trap Run 38539	Total/NA	Water	6010C	80892
490-33023-1 MSD	Trap Run 38539	Total/NA	Water	6010C	80892
490-33023-2	Tionesta 10H	Total/NA	Water	6010C	80892
490-33023-3	Fagley Lease	Total/NA	Water	6010C	80892

Metals (Continued)

Analysis Batch: 81232 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-4	James City Pad 50083	Total/NA	Water	6010C	80892
490-33023-5	James City Well 38735	Total/NA	Water	6010C	80892
490-33023-6	Wilson Run 39171	Total/NA	Water	6010C	80892
490-33023-7	Boone Mountain Pad A	Total/NA	Water	6010C	80892
490-33023-8	Tract 100 Pad M	Total/NA	Water	6010C	80892
LCS 180-80892/2-A	Lab Control Sample	Total/NA	Water	6010C	80892
MB 180-80892/1-A	Method Blank	Total/NA	Water	6010C	80892

Prep Batch: 100400

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	3010A	
490-33023-2	Tionesta 10H	Total/NA	Water	3010A	
490-33023-3	Fagley Lease	Total/NA	Water	3010A	
490-33023-4	James City Pad 50083	Total/NA	Water	3010A	
490-33023-5	James City Well 38735	Total/NA	Water	3010A	
490-33023-6	Wilson Run 39171	Total/NA	Water	3010A	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	3010A	
490-33068-G-21-B MS	Matrix Spike	Total/NA	Water	3010A	
490-33068-G-21-C MSD	Matrix Spike Duplicate	Total/NA	Water	3010A	
LCS 490-100400/2-A	Lab Control Sample	Total/NA	Water	3010A	
LCSD 490-100400/3-A	Lab Control Sample Dup	Total/NA	Water	3010A	
MB 490-100400/1-A	Method Blank	Total/NA	Water	3010A	

Analysis Batch: 101173

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	6010C	100400
490-33023-2	Tionesta 10H	Total/NA	Water	6010C	100400
490-33023-3	Fagley Lease	Total/NA	Water	6010C	100400
490-33023-4	James City Pad 50083	Total/NA	Water	6010C	100400
490-33023-5	James City Well 38735	Total/NA	Water	6010C	100400
490-33023-6	Wilson Run 39171	Total/NA	Water	6010C	100400
490-33023-7	Boone Mountain Pad A	Total/NA	Water	6010C	100400
490-33068-G-21-B MS	Matrix Spike	Total/NA	Water	6010C	100400
490-33068-G-21-C MSD	Matrix Spike Duplicate	Total/NA	Water	6010C	100400
LCS 490-100400/2-A	Lab Control Sample	Total/NA	Water	6010C	100400
LCSD 490-100400/3-A	Lab Control Sample Dup	Total/NA	Water	6010C	100400
MB 490-100400/1-A	Method Blank	Total/NA	Water	6010C	100400

Analysis Batch: 101366

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-4	James City Pad 50083	Total/NA	Water	6010C	100400
490-33023-7	Boone Mountain Pad A	Total/NA	Water	6010C	100400
LCS 490-100400/2-A	Lab Control Sample	Total/NA	Water	6010C	100400
MB 490-100400/1-A	Method Blank	Total/NA	Water	6010C	100400

Prep Batch: 101969

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-8	Tract 100 Pad M	Total/NA	Water	3010A	
490-33498-C-1-B MS	Matrix Spike	Total/NA	Water	3010A	
490-33498-C-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	3010A	
LCS 490-101969/2-A	Lab Control Sample	Total/NA	Water	3010A	

Metals (Continued)

Prep Batch: 101969 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-101969/1-A	Method Blank	Total/NA	Water	3010A	

Analysis Batch: 102247

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-8	Tract 100 Pad M	Total/NA	Water	6010C	101969
490-33023-8	Tract 100 Pad M	Total/NA	Water	6010C	101969
490-33498-C-1-B MS	Matrix Spike	Total/NA	Water	6010C	101969
490-33498-C-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	6010C	101969
LCS 490-101969/2-A	Lab Control Sample	Total/NA	Water	6010C	101969
MB 490-101969/1-A	Method Blank	Total/NA	Water	6010C	101969

General Chemistry

Analysis Batch: 80499

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	SM 2540F	
490-33023-2	Tionesta 10H	Total/NA	Water	SM 2540F	
490-33023-3	Fagley Lease	Total/NA	Water	SM 2540F	
490-33023-4	James City Pad 50083	Total/NA	Water	SM 2540F	
490-33023-5	James City Well 38735	Total/NA	Water	SM 2540F	
490-33023-6	Wilson Run 39171	Total/NA	Water	SM 2540F	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	SM 2540F	
490-33023-8	Tract 100 Pad M	Total/NA	Water	SM 2540F	

Analysis Batch: 98002

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	SM 2540C	
490-33023-2	Tionesta 10H	Total/NA	Water	SM 2540C	
490-33023-3	Fagley Lease	Total/NA	Water	SM 2540C	
490-33023-4	James City Pad 50083	Total/NA	Water	SM 2540C	
490-33023-5	James City Well 38735	Total/NA	Water	SM 2540C	
490-33023-6	Wilson Run 39171	Total/NA	Water	SM 2540C	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	SM 2540C	
490-33023-8	Tract 100 Pad M	Total/NA	Water	SM 2540C	
490-33040-O-1 DU	Duplicate	Total/NA	Water	SM 2540C	
490-33123-D-1 DU	Duplicate	Total/NA	Water	SM 2540C	
LCS 490-98002/2	Lab Control Sample	Total/NA	Water	SM 2540C	
MB 490-98002/1	Method Blank	Total/NA	Water	SM 2540C	

Filtration Batch: 100430

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Dissolved	Water	Filtration	
490-33023-1 MS	Trap Run 38539	Dissolved	Water	Filtration	
490-33023-1 MSD	Trap Run 38539	Dissolved	Water	Filtration	
490-33023-2	Tionesta 10H	Dissolved	Water	Filtration	
490-33023-3	Fagley Lease	Dissolved	Water	Filtration	
490-33023-4	James City Pad 50083	Dissolved	Water	Filtration	
490-33023-5	James City Well 38735	Dissolved	Water	Filtration	
490-33023-6	Wilson Run 39171	Dissolved	Water	Filtration	
490-33023-7	Boone Mountain Pad A	Dissolved	Water	Filtration	

General Chemistry (Continued)

Filtration Batch: 100430 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-8	Tract 100 Pad M	Dissolved	Water	Filtration	
LCS 490-100430/2-A	Lab Control Sample	Dissolved	Water	Filtration	
MB 490-100430/1-A	Method Blank	Dissolved	Water	Filtration	

Analysis Batch: 100485

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	SM 2320B	
490-33023-1 DU	Trap Run 38539	Total/NA	Water	SM 2320B	
490-33023-1 MS	Trap Run 38539	Total/NA	Water	SM 2320B	
490-33023-2	Tionesta 10H	Total/NA	Water	SM 2320B	
490-33023-3	Fagley Lease	Total/NA	Water	SM 2320B	
490-33023-4	James City Pad 50083	Total/NA	Water	SM 2320B	
490-33023-5	James City Well 38735	Total/NA	Water	SM 2320B	
490-33023-6	Wilson Run 39171	Total/NA	Water	SM 2320B	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	SM 2320B	
490-33023-8	Tract 100 Pad M	Total/NA	Water	SM 2320B	
490-33149-H-3 DU	Duplicate	Total/NA	Water	SM 2320B	
LCS 490-100485/4	Lab Control Sample	Total/NA	Water	SM 2320B	
MB 490-100485/3	Method Blank	Total/NA	Water	SM 2320B	

Analysis Batch: 100580

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	SM 4500 H+ B	
490-33023-2	Tionesta 10H	Total/NA	Water	SM 4500 H+ B	
490-33023-3	Fagley Lease	Total/NA	Water	SM 4500 H+ B	
490-33023-3 DU	Fagley Lease	Total/NA	Water	SM 4500 H+ B	
490-33023-4	James City Pad 50083	Total/NA	Water	SM 4500 H+ B	
490-33023-5	James City Well 38735	Total/NA	Water	SM 4500 H+ B	
490-33023-6	Wilson Run 39171	Total/NA	Water	SM 4500 H+ B	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	SM 4500 H+ B	
490-33023-8	Tract 100 Pad M	Total/NA	Water	SM 4500 H+ B	
LCS 490-100580/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	

Analysis Batch: 100662

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	SM 2510B	
490-33023-2	Tionesta 10H	Total/NA	Water	SM 2510B	
490-33023-3	Fagley Lease	Total/NA	Water	SM 2510B	
490-33023-4	James City Pad 50083	Total/NA	Water	SM 2510B	
490-33023-5	James City Well 38735	Total/NA	Water	SM 2510B	
490-33023-6	Wilson Run 39171	Total/NA	Water	SM 2510B	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	SM 2510B	
490-33023-8	Tract 100 Pad M	Total/NA	Water	SM 2510B	
490-33045-I-1 DU	Duplicate	Total/NA	Water	SM 2510B	
490-33149-H-3 DU	Duplicate	Total/NA	Water	SM 2510B	
LCS 490-100662/4	Lab Control Sample	Total/NA	Water	SM 2510B	
LCSD 490-100662/5	Lab Control Sample Dup	Total/NA	Water	SM 2510B	
MB 490-100662/2	Method Blank	Total/NA	Water	SM 2510B	

QC Association Summary

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

General Chemistry (Continued)

Analysis Batch: 101394

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Dissolved	Water	SM 5310B	100430
490-33023-1 MS	Trap Run 38539	Dissolved	Water	SM 5310B	100430
490-33023-1 MSD	Trap Run 38539	Dissolved	Water	SM 5310B	100430
490-33023-2	Tionesta 10H	Dissolved	Water	SM 5310B	100430
490-33023-3	Fagley Lease	Dissolved	Water	SM 5310B	100430
490-33023-4	James City Pad 50083	Dissolved	Water	SM 5310B	100430
490-33023-5	James City Well 38735	Dissolved	Water	SM 5310B	100430
490-33023-6	Wilson Run 39171	Dissolved	Water	SM 5310B	100430
490-33023-7	Boone Mountain Pad A	Dissolved	Water	SM 5310B	100430
490-33023-8	Tract 100 Pad M	Dissolved	Water	SM 5310B	100430
LCS 490-100430/2-A	Lab Control Sample	Dissolved	Water	SM 5310B	100430
MB 490-100430/1-A	Method Blank	Dissolved	Water	SM 5310B	100430

Client Sample ID: Trap Run 38539

Lab Sample ID: 490-33023-1

Date Collected: 08/12/13 09:10

Matrix: Water

Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 15:30	JHS	TAL NSH
Total/NA	Analysis	300.0		2500	101340	08/20/13 12:56	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT
Total/NA	Analysis	6010C		25	81232	08/21/13 11:51	RJR	TAL PIT
Total/NA	Prep	3010A			100400	08/15/13 15:21	DBK	TAL NSH
Total/NA	Analysis	6010C		100	101173	08/19/13 17:25	DEB	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 06:00	CLL	TAL PIT
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 16:56	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Dissolved	Analysis	SM 5310B		5	101394	08/15/13 16:04	JKF	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Client Sample ID: Tionesta 10H

Lab Sample ID: 490-33023-2

Date Collected: 08/12/13 11:30

Matrix: Water

Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 15:50	JHS	TAL NSH
Total/NA	Analysis	300.0		2500	101340	08/20/13 13:17	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT
Total/NA	Analysis	6010C		25	81232	08/21/13 11:03	RJR	TAL PIT
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH
Total/NA	Analysis	6010C		1000	101173	08/19/13 17:36	DEB	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 06:00	CLL	TAL PIT
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 17:10	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Dissolved	Analysis	SM 5310B		4	101394	08/15/13 16:04	JKF	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Client Sample ID: Fagley Lease

Lab Sample ID: 490-33023-3

Date Collected: 08/12/13 13:00

Matrix: Water

Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 16:11	JHS	TAL NSH
Total/NA	Analysis	300.0		500	101335	08/20/13 12:50	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT

Client Sample ID: Fagley Lease
Lab Sample ID: 490-33023-3
Date Collected: 08/12/13 13:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	6010C		25	81232	08/21/13 11:08	RJR	TAL PIT
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH
Total/NA	Analysis	6010C		100	101173	08/19/13 17:40	DEB	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 06:00	CLL	TAL PIT
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 17:16	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Dissolved	Analysis	SM 5310B		7	101394	08/15/13 16:04	JKF	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Client Sample ID: James City Pad 50083
Lab Sample ID: 490-33023-4
Date Collected: 08/12/13 14:20
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 16:31	JHS	TAL NSH
Total/NA	Analysis	300.0		2500	101340	08/20/13 13:59	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT
Total/NA	Analysis	6010C		50	81232	08/21/13 12:01	RJR	TAL PIT
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH
Total/NA	Analysis	6010C		1000	101173	08/19/13 17:51	DEB	TAL NSH
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH
Total/NA	Analysis	6010C		10000	101366	08/20/13 12:37	KDJ	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 06:00	CLL	TAL PIT
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 17:20	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Analysis	SM 5310B		1	101394	08/15/13 16:04	JKF	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Client Sample ID: James City Well 38735
Lab Sample ID: 490-33023-5
Date Collected: 08/12/13 15:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 16:51	JHS	TAL NSH
Total/NA	Analysis	300.0		2500	101340	08/20/13 14:20	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT
Total/NA	Analysis	6010C		25	81232	08/21/13 11:29	RJR	TAL PIT
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH

Lab Chronicle

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Client Sample ID: James City Well 38735

Lab Sample ID: 490-33023-5

Date Collected: 08/12/13 15:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	6010C		100	101173	08/19/13 18:07	DEB	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 06:00	CLL	TAL PIT
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 17:37	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Analysis	SM 5310B		5	101394	08/15/13 16:04	JKF	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Client Sample ID: Wilson Run 39171

Lab Sample ID: 490-33023-6

Date Collected: 08/12/13 16:30
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 17:11	JHS	TAL NSH
Total/NA	Analysis	300.0		2500	101340	08/20/13 14:41	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT
Total/NA	Analysis	6010C		25	81232	08/21/13 11:34	RJR	TAL PIT
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH
Total/NA	Analysis	6010C		1000	101173	08/19/13 18:18	DEB	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 06:00	CLL	TAL PIT
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 17:40	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Dissolved	Analysis	SM 5310B		3	101394	08/15/13 16:04	JKF	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Client Sample ID: Boone Mountain Pad A

Lab Sample ID: 490-33023-7

Date Collected: 08/12/13 17:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 17:31	JHS	TAL NSH
Total/NA	Analysis	300.0		5000	101340	08/20/13 15:02	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT
Total/NA	Analysis	6010C		25	81232	08/21/13 11:40	RJR	TAL PIT
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH
Total/NA	Analysis	6010C		1000	101173	08/19/13 18:25	DEB	TAL NSH
Total/NA	Prep	3010A			100400	08/15/13 15:27	DBK	TAL NSH
Total/NA	Analysis	6010C		10000	101366	08/20/13 12:42	KDJ	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 08:00	CLL	TAL PIT

Lab Chronicle

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Client Sample ID: Boone Mountain Pad A
Date Collected: 08/12/13 17:00
Date Received: 08/13/13 15:43

Lab Sample ID: 490-33023-7
Matrix: Water

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 17:45	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Dissolved	Analysis	SM 5310B		5	101394	08/15/13 16:04	JKF	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Client Sample ID: Tract 100 Pad M
Date Collected: 08/13/13 10:00
Date Received: 08/13/13 15:43

Lab Sample ID: 490-33023-8
Matrix: Water

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	300.0		20	101335	08/20/13 17:51	JHS	TAL NSH
Total/NA	Analysis	300.0		5000	101340	08/20/13 15:23	JHS	TAL NSH
Total/NA	Prep	3010A			80892	08/18/13 12:51	CEH	TAL PIT
Total/NA	Analysis	6010C		25	81232	08/21/13 11:45	RJR	TAL PIT
Total/NA	Prep	3010A			101969	08/22/13 13:45	JBD	TAL NSH
Total/NA	Analysis	6010C		1000	102247	08/23/13 12:23	KDJ	TAL NSH
Total/NA	Analysis	6010C		10000	102247	08/23/13 12:30	KDJ	TAL NSH
Total/NA	Analysis	SM 2540F		1	80499	08/14/13 08:00	CLL	TAL PIT
Total/NA	Analysis	SM 2320B		1	100485	08/15/13 17:49	DMT	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1	100580	08/16/13 10:51	BLG	TAL NSH
Total/NA	Analysis	SM 2510B		1	100662	08/16/13 13:58	RKG	TAL NSH
Dissolved	Filtration	Filtration			100430	08/15/13 16:04	CLJ	TAL NSH
Dissolved	Analysis	SM 5310B		1	101394	08/15/13 16:04	JKF	TAL NSH
Total/NA	Analysis	SM 2540C		1	98002	08/15/13 18:13	JMR	TAL NSH

Laboratory References:

EMLab P&K = EMLab P&K - South San Francisco, 1150 Bayhill Drive #100, San Bruno, CA 94066, TEL (866)888-6653
TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177
TAL PIT = TestAmerica Pittsburgh, 301 Alpha Drive, RIDC Park, Pittsburgh, PA 15238, TEL (412)963-7058

Method Summary

Method	Method Description	Protocol	Laboratory
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
6010C	Metals (ICP)	SW846	TAL NSH
6010C	Metals (ICP)	SW846	TAL PIT
SM 2320B	Alkalinity	SM	TAL NSH
SM 2510B	Conductivity, Specific Conductance	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 2540F	Solids, Settleable	SM	TAL PIT
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Dissolved (DOC)	SM	TAL NSH
Sulfate Reducing Bacteria	General Sub Contract Method	NONE	EMLab P&K

Protocol References:

MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.

NONE = NONE

SM = "Standard Methods For The Examination Of Water And Wastewater",

SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

EMLab P&K = EMLab P&K - South San Francisco, 1150 Bayhill Drive #100, San Bruno, CA 94066, TEL (866)888-6653

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

TAL PIT = TestAmerica Pittsburgh, 301 Alpha Drive, RIDC Park, Pittsburgh, PA 15238, TEL (412)963-7058

Certification Summary

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Laboratory: TestAmerica Nashville

All certifications held by this laboratory are listed. Not all certifications are applicable to this report.

Authority	Program	EPA Region	Certification ID	Expiration Date
	ACIL		393	10-30-13
A2LA	ISO/IEC 17025		0453.07	12-31-13
Alaska (UST)	State Program	10	UST-087	07-24-14
Arizona	State Program	9	AZ0473	05-05-14
Arkansas DEQ	State Program	6	88-0737	04-25-14
California	NELAP	9	1168CA	10-31-13
Connecticut	State Program	1	PH-0220	12-31-13
Florida	NELAP	4	E87358	06-30-14
Illinois	NELAP	5	200010	12-09-13
Iowa	State Program	7	131	05-01-14
Kansas	NELAP	7	E-10229	10-31-13
Kentucky (UST)	State Program	4	19	06-30-14
Louisiana	NELAP	6	30613	06-30-14
Maryland	State Program	3	316	03-31-14
Massachusetts	State Program	1	M-TN032	06-30-14
Minnesota	NELAP	5	047-999-345	12-31-13
Mississippi	State Program	4	N/A	06-30-14
Montana (UST)	State Program	8	NA	01-01-15
Nevada	State Program	9	TN00032	07-31-13 *
New Hampshire	NELAP	1	2963	10-10-13
New Jersey	NELAP	2	TN965	06-30-14
New York	NELAP	2	11342	04-01-14
North Carolina DENR	State Program	4	387	12-31-13
North Dakota	State Program	8	R-146	06-30-14
Ohio VAP	State Program	5	CL0033	01-19-14
Oklahoma	State Program	6	9412	08-31-14
Oregon	NELAP	10	TN200001	04-29-14
Pennsylvania	NELAP	3	68-00585	06-30-14
Rhode Island	State Program	1	LAO00268	12-30-13
South Carolina	State Program	4	84009 (001)	02-28-14
South Carolina	State Program	4	84009 (002)	02-23-14
Tennessee	State Program	4	2008	02-23-14
Texas	NELAP	6	T104704077-09-TX	08-31-14
USDA	Federal		S-48469	11-02-13
Utah	NELAP	8	TN00032	07-31-14
Virginia	NELAP	3	460152	06-14-14
Washington	State Program	10	C789	07-19-14
West Virginia DEP	State Program	3	219	02-28-14
Wisconsin	State Program	5	998020430	08-31-14
Wyoming (UST)	A2LA	8	453.07	12-31-13

Laboratory: TestAmerica Pittsburgh

All certifications held by this laboratory are listed. Not all certifications are applicable to this report.

Authority	Program	EPA Region	Certification ID	Expiration Date
Arkansas DEQ	State Program	6	88-0690	06-27-14
California	NELAP	9	4224CA	03-31-14
Connecticut	State Program	1	PH-0688	09-30-14
Florida	NELAP	4	E871008	06-30-14
Illinois	NELAP	5	002602	06-30-14

* Expired certification is currently pending renewal and is considered valid.

Certification Summary

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-1
SDG: UIC Compatibility Evaluation

Laboratory: TestAmerica Pittsburgh (Continued)

All certifications held by this laboratory are listed. Not all certifications are applicable to this report.

Authority	Program	EPA Region	Certification ID	Expiration Date
Kansas	NELAP	7	E-10350	01-31-14
L-A-B	DoD ELAP		L2314	07-16-16
Louisiana	NELAP	6	04041	06-30-13 *
New Hampshire	NELAP	1	203011	04-05-14
New Jersey	NELAP	2	PA005	06-30-14
New York	NELAP	2	11182	04-01-14
North Carolina DENR	State Program	4	434	12-31-13
Pennsylvania	NELAP	3	02-00416	04-30-14
South Carolina	State Program	4	89014	04-30-13 *
US Fish & Wildlife	Federal		LE94312A-1	11-30-14
USDA	Federal		P-Soil-01	04-16-15
USDA	Federal		P330-10-00139	05-23-16
Utah	NELAP	8	STLP	04-30-14
Virginia	NELAP	3	460189	09-14-13 *
West Virginia DEP	State Program	3	142	01-31-14
Wisconsin	State Program	5	998027800	08-31-13 *

* Expired certification is currently pending renewal and is considered valid.

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

Nashville, TN

490-33023 Chain of Custody

COOLER RECEIPT FORM

Cooler Received/Opened On 8/15/2013@ 0815

1. Tracking # 3047 (last 4 digits, FedEx)

Courier: FedEx IR Gun ID 96210146

2. Temperature of rep. sample or temp blank when opened: 1.1 Degrees Celsius
3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO..NA
4. Were custody seals on outside of cooler? YES..NO..NA

   If yes, how many and where: ________
5. Were the seals intact, signed, and dated correctly? YES...NO..NA
6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) DA

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA
8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None
9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None
10. Did all containers arrive in good condition (unbroken)? YES..NO...NA
11. Were all container labels complete (#, date, signed, pres., etc)? YES..NO...NA
12. Did all container labels and tags agree with custody papers? YES..NO...NA

13a. Were VOA vials received? YES..NO..NA

b. Was there any observable headspace present in any VOA vial? YES...NO...NA

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence # ________

I certify that I unloaded the cooler and answered questions 7-14 (intial) mdm

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES..NO..NA

b. Did the bottle labels indicate that the correct preservatives were used YES..NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) mdm

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA
18. Did you sign the custody papers in the appropriate place? YES...NO...NA
19. Were correct containers used for the analysis requested? YES...NO...NA
20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) mdm

I certify that I attached a label with the unique LIMS number to each container (intial) mdm

21. Were there Non-Conformance issues at login? YES..NO Was a NCM generated? YES..NO..# ________

BIS = Broken in shipment

Cooler Receipt Form.doc

LF-1

End of Form

Revised 11/28/12

 490-33023

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

Cooler Received/Opened On 8/15/2013 @ 0815

1. Tracking # 3036 (last 4 digits, FedEx)

Courier: FedEx IR Gun ID 94660220

2. Temperature of rep. sample or temp blank when opened: 0.0 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO..NA

4. Were custody seals on outside of cooler? YES...NO...NA

If yes, how many and where: (1) Top

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) MDM

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

b. Was there any observable headspace present in any VOA vial? YES...NO...NA

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #______

I certify that I unloaded the cooler and answered questions 7-14 (intial) MDM

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES..NO..NA

b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) MDM

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) MDM

I certify that I attached a label with the unique LIMS number to each container (intial) MDM

21. Were there Non-Conformance issues at login? YES..NO Was a NCM generated? YES..NO..#______

BIS = Broken in shipment
Cooler Receipt Form.doc

LF-1
End of Form

Revised 11/28/12

TestAmerica Pittsburgh
301 Alpha Drive
RIDC Park
Pittsburgh, PA 15238
Phone: 412.963.7058 Fax:

For assistance in accessing this document contact R3_UIC_Mailbox@epa.gov

Chain of Custody Record

Loc: 490
33023

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
TestAmerica Laboratories, Inc.
TAL-C-WI-002, Rev. 4.2, dated 04/02/2013

Regulatory Program: ☐ DW ☐ NPDES ☐ RCRA ☒ Other:

Client Contact	Project Manager: Kelly Carper	Site Contact:	COC No:
Company Name: TetraTech, Inc.	Tel/Fax: " "	Lab Contact:	Carrier:	1 of 1 COCs
Address: 661 Andersen Drive	Analysis Turnaround Time		Sampler:
City/State/Zip: Pittsburgh, PA 15220	☐ CALENDAR DAYS ☐ WORKING DAYS		For Lab Use Only:
Phone: (412) 920-7015	TAT if different from Below ____		Walk-in Client:
Fax: (412) 921-4040	☐ 2 weeks		Lab Sampling:
Project Name: Seneca TO4	☐ 1 week		
Site: UIC Compatibility Evaluation	☐ 2 days		Job / SDG No.:
PO# 112C05696	☐ 1 day		

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.	Filtered Sample (Y/N)	Perform MS / MSD (Y/N)	DOC	Settleable Solids	(MOD) Custom Metals List	2540C_Calcd, 2320B	SM4500_H+	300_ORGFM_28D	SM4500_SiO2_C	Sample Specific Notes:
Trap Run 38537	8/12/13	0910	G	NP	9	Y	N	X	X	X	X	X	X	X	
Tionesta 10H	8/12/13	1130	G	NP	9			X	X	X	X	X	X	X	
Fagley Lease	8/12/13	1300	G	NP	9			X	X	X	X	X	X	X	
James City Pad 50083	8/12/13	1420	G	NP	9			X	X	X	X	X	X	X	
James City Well 38735	8/12/13	1500	G	NP	9			X	X	X	X	X	X	X	
Wilson Run 39171	8/12/13	1630	G	NP	9			X	X	X	X	X	X	X	
Boone Mountain Pad A	8/12/13	1700	G	NP	9			X	X	X	X	X	X	X	
Tract 100 Pad M	8/13/13	1000	G	NP	9			X	X	X	X	X	X	X	

Preservation Used: 1= Ice, 2= HCl; 3= H2SO4; 4=HNO3; 5=NaOH; 6= Other 1, 4

Possible Hazard Identification:
Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.
☒ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return to Client ☐ Disposal by Lab ☐ Archive for______ Months

Special Instructions/QC Requirements & Comments:

Custody Seals Intact: ☐ Yes ☐ No | Custody Seal No.: | Cooler Temp. (°C): Obs'd:______ Corr'd:______ Therm ID No.:______

Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
[signature]	Tetra Tech, Inc.	8/13/13/1543	[signature]	TestAmerica	8/13/13 1543
Jon Watson	TA Pitt	8/14/13 1700	[signature]	TAW	8-15-13 @ 0815 6.0/1.1°C
Relinquished by:	Company:	Date/Time:	Received in Laboratory by:	Company:	Date/Time:

8/30/2013

490-33023

Bottle Order Information

Bottle Order: *Seneca Resources Corporation*
Bottle Order #: *6093*
Date Order Posted: *8/5/2013 2:25:22PM*
Order Status: *Ready To Process*
Prepared By: *Jennifer Gambill*
Deliver By Date: ***8/7/2013 11:59:00PM***
Lab Project Number: *49005204*

Job - All match

Order Completion Information

Filled by:
Sent Date:
Sent Via:
Tracking #:

Sets	Bottles/Set	Qty	Bottle Type Description	Preservative	Method	Matrix	Sample Type	Comments	Lot #
11	3	33	Plastic 250ml - unpreserved	None	SM4500_H+ - pH & Temperature	Water	Normal	pH/SC/Method 300/Silicon Dioxide	
					300_ORGFM_28D - (MOD) Custom Anions List	Water	Normal		
					SM4500_SiO2_C - Silicon dioxide	Water	Normal		
					2510B - Specific Conductance	Water	Normal		
11	1	11	Plastic 500ml - unpreserved	None	2540C_Calcd - Total Dissolved Solids	Water	Normal	TDS/Alkalinity	
					2320B - (MOD) Alkalinity as CaCO3 (Total, Carbon	Water	Normal		
11	2	22	Plastic 250ml - with Nitric Acid	Nitric Acid	6010C - (MOD) Custom Metals List	Water	Normal	Metals/Silicon	
11	1	11	Bacti Bottle Sterile	None	SUBCONTRACT - Sulfate Reducing Bacteria	Water	Normal	SRB	
11	2	22	Plastic 1 liter - unpreserved	None	SM2540F - Settleable Solids (mL/L)	Water	Normal	Settleable Solids	
11	1	11	Plastic 250ml – unpreserved - dis	None	SM5310_DOC_B - Dissolved Organic Carbon (DOC)	Water	Normal	DOC	

Page 38 of 55

Notes to Field Staff:

Health and Safety Notes:

Preservative	Comment
Nitric Acid	CAUTION! STRONG OXIDIZER! CONTAINS 1:1 NITRIC ACID. Avoid skin and eye contact. If contact is made, FLUSH IMMEDIATELY with water.

Relinquished By	Company	Date	Time	Received By	Company	Seal #:
						Seal #:
						Seal #:
Relinquished By	Company	Date	Time	Received By	Company	Seal #:
						Seal #:
						Seal #:

Please notify us immediately if an error is found in shipment

Shipping Order ID: 14060

Printed on 8/6/2013 7:12:38AM

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

490-33254 Chain of Custody

COOLER RECEIPT FORM

Cooler Received/Opened On 8/24/2013 @ 8:15

1. Tracking #_3768________(last 4 digits, FedEx)

Courier: _____FedEx_________ IR Gun ID___17610176___

2. Temperature of rep. sample or temp blank when opened:_3.0_Degrees Celsius
3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO..NA
4. Were custody seals on outside of cooler? YES..NO..NA

   If yes, how many and where:____
5. Were the seals intact, signed, and dated correctly? YES...NO...NA
6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) ___AJH___

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA
8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None
9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None
10. Did all containers arrive in good condition (unbroken)? YES...NO...NA
11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA
12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

b. Was there any observable headspace present in any VOA vial? YES...NO...NA

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #________

I certify that I unloaded the cooler and answered questions 7-14 (intial) ___MDM___

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES..NO..NA

b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) ___MDM___

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA
18. Did you sign the custody papers in the appropriate place? YES...NO...NA
19. Were correct containers used for the analysis requested? YES...NO...NA
20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) ___MDM___

I certify that I attached a label with the unique LIMS number to each container (intial) ___MDM___

21. Were there Non-Conformance issues at login? YES..NO Was a NCM generated? YES..NO..#_______

BIS = Broken in shipment
Cooler Receipt Form.doc

TestAmerica Pittsburgh
301 Alpha Drive
RIDC Park
Pittsburgh, PA 15238
Phone: 412.963.7058 Fax:

Chain of Custody Record

Loc: 490
33254

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
TestAmerica Laboratories, Inc.

Form No. CA-C-WI-002, Rev. 4.2, dated 04/02/2013

Regulatory Program: ☐ DW ☐ NPDES ☐ RCRA ☐ Other:

Client Contact	Project Manager:	Site Contact:	Date:	COC No:
Company Name: TetraTech	Tel/Fax:	Lab Contact:	Carrier:	____ of ____ COCs
Address:	Analysis Turnaround Time			Sampler:
City/State/Zip:	☐ CALENDAR DAYS ☐ WORKING DAYS			For Lab Use Only:
Phone:	TAT if different from Below ____			Walk-in Client:
Fax:	☐ 2 weeks			Lab Sampling:
Project Name:	☐ 1 week			
Site:	☐ 2 days			Job / SDG No.:
P O #	☐ 1 day			

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.	Filtered Sample (Y / N)	Perform MS / MSD (Y / N)	P 250 un	P 250 nitric	P 1 Liter	Sample Specific Notes:
490-33254-1								4	1	1	

Preservation Used: 1= Ice, 2= HCl; 3= H2SO4; 4=HNO3; 5=NaOH; 6= Other

Possible Hazard Identification:
Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return to Client ☐ Disposal by Lab ☐ Archive for ____ Months

Special Instructions/QC Requirements & Comments:

Custody Seals Intact: ☐ Yes ☐ No | Custody Seal No.: | Cooler Temp. (°C): Obs'd: ____ Corr'd: ____ | Therm ID No.: ____

Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
[signature]	TAP	8/23/13	[signature]	TAN	8-24-13 @ 0815 3.°
Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
Relinquished by:	Company:	Date/Time:	Received in Laboratory by:	Company:	Date/Time:

TestAmerica Pittsburgh
301 Alpha Drive
RIDC Park
Pittsburgh, PA 15238
Phone: 412.963.7058 Fax:

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
TestAmerica Laboratories, Inc.

Form No. CA-C-WI-002, Rev. 4.2, dated 04/02/2013

Regulatory Program: ☐ DW ☐ NPDES ☐ RCRA ☒ Other:

Client Contact	
Company Name:	Tetra Tech Inc.
Address:	661 Andersen Drive
City/State/Zip:	Pittsburgh, PA 15220
Phone:	(412) 920-7015
Fax:	(412) 921-4040
Project Name:	Seneca T04
Site:	UIC Compatibility Evaluation
PO#	112C05096

Project Manager: Kelly Casper
Tel/Fax: "

Site Contact:
Lab Contact:
Date:
Carrier:

COC No:
1 of 1 COCs
Sampler:
For Lab Use Only:
Walk-in Client:
Lab Sampling:
Job / SDG No.:

Analysis Turnaround Time
☐ CALENDAR DAYS ☐ WORKING DAYS
TAT if different from Below
☐ 2 weeks
☐ 1 week
☐ 2 days
☐ 1 day

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.	Filtered Sample (Y/N)	Perform MS / MSD (Y/N)	DOC	Settleable Solids	(HOD) Custom Metals List	2540C - Calc'd 2340B	SM4500 H+	300_ORGFM_28D	SM4500 SiO2 - C	Sample Specific Notes:
4384 James City Prospect	8/16/13	0900	G	NP	9	Y	N	X	X	X	X	X	X	X	

Preservation Used: 1= Ice, 2= HCl; 3= H2SO4; 4=HNO3; 5=NaOH; 6= Other

Possible Hazard Identification:
Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.
☒ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return to Client ☐ Disposal by Lab ☐ Archive for ______ Months

Special Instructions/QC Requirements & Comments:

Custody Seals Intact: ☑ Yes ☐ No
Custody Seal No.:
Cooler Temp. (°C): Obs'd: Corr'd: Therm ID No.:

Relinquished by: [signature]	Company: Tetra Tech, Inc.	Date/Time: 8/16/13/1147	Received by: [signature]	Company: TAPGH	Date/Time: 8/16/13 1147
Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
Relinquished by:	Company:	Date/Time:	Received in Laboratory by:	Company:	Date/Time:

8/20/2013

TETRA TECH ISG
TtNUS, Information Systems Group

Streamlined Laboratory EDD Checker

The data was successfully transmitted.
Your Tickey Key Number is: 20130830_5766659846_SLEDD_TestAmerica.
Use this key in correspondence when referring to this data upload.
File Uploaded: SLEDD_UIC Compatibility Evaluation.xls
Comment Added: Seneca Resources Corporation / Seneca TO4

1
2
3
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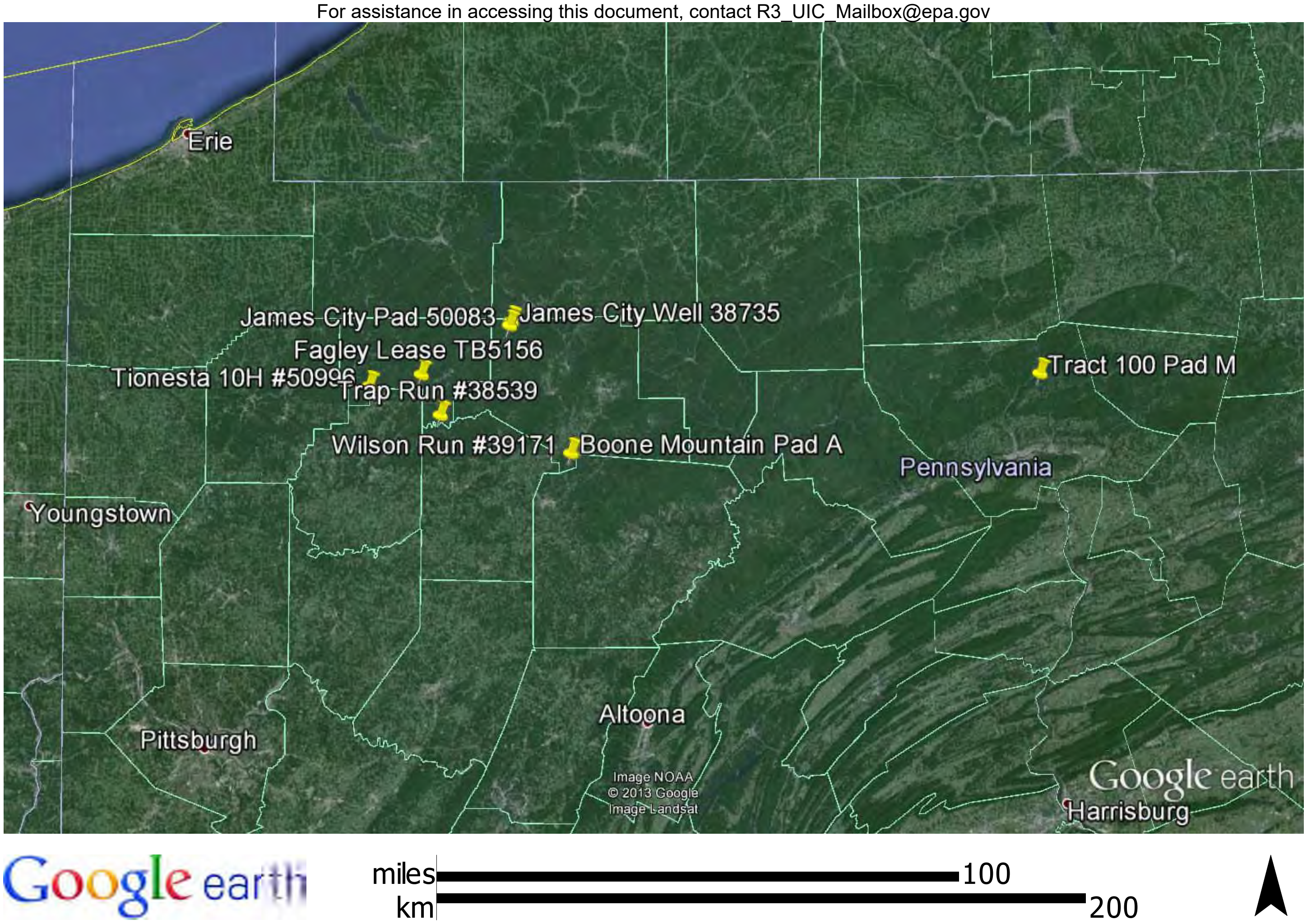
11
12
13


Erie
James City Pad 50083
James City Well 38735
Fagley Lease TB5156
Tionesta 10H #50996
Trap Run #38539
Tract 100 Pad M
Wilson Run #39171
Boone Mountain Pad A
Pennsylvania
Youngstown
Altoona
Pittsburgh
Image NOAA
© 2013 Google
Image Landsat
Google earth
Harrisburg
miles
100
km
200

41° 19' 33" N * Upper Devonian
79° 9' 21" W

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696
WELL ID.: Trap Run 38539
DATE: 8/12/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
0905	—	—	6.08	76.3	6.5	1.40	20.21	48		

SIGNATURE(S): [signature]

PAGE 1 OF 8

41°24'17"N *UTICA WELL
79°24'58"W

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696

WELL ID.: Tionesta 10H 50996
DATE: 8/12/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
1130	—	—	5.69	100	123	1.57	20.64	44		

SIGNATURE(S):

PAGE 2 OF 8

41°26'12"N
79°13'32"W

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696

WELL ID.: Fogley Lease TB5156
DATE: 8/12/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
1300	—	—	5.88	93.9	125	1.27	25.38	-128		

SIGNATURE(S): [signature]

PAGE 3 OF 8

*Marcellus

41°34'15"N
78°54'12"W

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696

WELL ID.: James City Pad 50083
DATE: 8/12/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
1420	—	—	5.29	100	42.1	1.08	20.98	80		

SIGNATURE(S): [signature]

PAGE 4 OF 8

*Upper Devonian

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696

WELL ID.: James City Well 38735
DATE: 8/12/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
—	—	—	5.97	100	57.1	2.71	20.64	-17		

SIGNATURE(S):

PAGE 5 **OF** 8

*Upper Devonian
41°13'16.64" N
78°40'53.60" W

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696
WELL ID.: Wilson Run 39171
DATE: 8/12/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
1630	—	—	4.28	100	45.4	1.49	23.57	263		

SIGNATURE(S):

PAGE 6 OF 8

* Marcellus Well

LOW FLOW PURGE DATA SHEET

41°13'22.76"N
78°40'37.03"W

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696
WELL ID.: Boone Mountain Pad A
DATE: 8/12/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
	—	—	5.06	100	251	1.05	21.53	-39		

SIGNATURE(S): [signature]

PAGE 7 **OF** 8

* No field readings due to Horiba Malfunction

* Marcellus Well
41°25'23"N
76°58'6"W

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696

WELL ID.: Tract 100 Pad M
DATE: 8/13/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
										*Could not obtain
										field readings due
										to Horiba malfunction

SIGNATURE(S):

PAGE 8 OF 8

41° 36' 55" N
78° 49' 13" W

* Upper Devonian

LOW FLOW PURGE DATA SHEET

PROJECT SITE NAME: Seneca Resources TO4
PROJECT NUMBER: 112C05696

WELL ID.: 4384 Jones City Prospect
DATE: 8/16/13

Time (Hrs.)	Water Level (Ft. below TOC)	Flow (mL/Min.)	pH (S.U.)	S. Cond. (mS/cm)	Turb. (NTU)	DO (mg/L)	Temp. (Celcius)	ORP +/- mV		Comments
0900	—	—	6.77	100	144	8.88	22.10	-22		

SIGNATURE(S):

PAGE 1 OF 1

Gambill, Jennifer

Sent:
To:
Subject:

38539 is confirmed by the client. Thanks!

Sent from my iPhone

On Aug 14, 2013, at 12:13 PM, "Gambill, Jennifer" <Jennifer.Gambill@testamericainc.com> wrote:

> You're welcome. And if we need to change it, we can.
> Thanks - Jennifer
>
> JENNIFER GAMBILL
> Project Manager
>
>
>
> -----Original Message-----
> From: Shirey, Kyle [mailto:Kyle.Shirey@tetratech.com]
> Sent: Wednesday, August 14, 2013 11:11 AM
> To: Gambill, Jennifer
> Subject: RE: Seneca Samples / Sample Receipt Confirmation
>
> Yes, I believe it is 38539. I will email our client to confirm. Thanks.
>
> -----Original Message-----
> From: Gambill, Jennifer [mailto:Jennifer.Gambill@testamericainc.com]
> Sent: Wednesday, August 14, 2013 12:06 PM
> To: Shirey, Kyle
> Subject: RE: Seneca Samples / Sample Receipt Confirmation
>
> Hello Kyle,
>
> Just one more quick question. For the first sample ID, the chain of
> custody has Trap Run 38537 and the field sheets have Trap Run 38539.
> Should we use the 38539 for the number?
>
> Thanks - Jennifer
>
>
> JENNIFER GAMBILL
> Project Manager
>
> TestAmerica
> THE LEADER IN ENVIRONMENTAL TESTING
>
> 2960 Foster Creighton Drive
> Nashville, TN 37204
> Tel 615-301-5044
> www.testamericainc.com
>
>
> -----Original Message-----
> From: Shirey, Kyle [mailto:Kyle.Shirey@tetratech.com]
> Sent: Tuesday, August 13, 2013 5:38 PM
> To: Gambill, Jennifer
> Cc: Skoff, Dale; Carper, Kelly
> Subject: Re: Seneca Samples / Sample Receipt Confirmation

Login Sample Receipt Checklist

Client: Tetra Tech, Inc

Job Number: 490-33023-1
SDG Number: UIC Compatibility Evaluation

Login Number: 33023
List Number: 1
Creator: Gambill, Jennifer

List Source: TestAmerica Nashville

Question	Answer	Comment
Radioactivity wasn't checked or is </= background as measured by a survey meter.	True	
The cooler's custody seal, if present, is intact.	True	
Sample custody seals, if present, are intact.	True	
The cooler or samples do not appear to have been compromised or tampered with.	True	
Samples were received on ice.	True	
Cooler Temperature is acceptable.	True	
Cooler Temperature is recorded.	True	
COC is present.	True	
COC is filled out in ink and legible.	True	
COC is filled out with all pertinent information.	True	
Is the Field Sampler's name present on COC?	True	
There are no discrepancies between the containers received and the COC.	True	
Samples are received within Holding Time.	True	
Sample containers have legible labels.	True	
Containers are not broken or leaking.	True	
Sample collection date/times are provided.	True	
Appropriate sample containers are used.	True	
Sample bottles are completely filled.	True	
Sample Preservation Verified.	True	
There is sufficient vol. for all requested analyses, incl. any requested MS/MSDs	True	
Containers requiring zero headspace have no headspace or bubble is <6mm (1/4").	True	
Multiphasic samples are not present.	True	
Samples do not require splitting or compositing.	True	
Residual Chlorine Checked.	N/A	

Login Sample Receipt Checklist

Client: Tetra Tech, Inc

Job Number: 490-33023-1
SDG Number: UIC Compatibility Evaluation

Login Number: 33023
List Number: 1
Creator: Kovitch, Christina M

List Source: TestAmerica Pittsburgh
List Creation: 08/14/13 09:01 AM

Question	Answer	Comment
Radioactivity wasn't checked or is </= background as measured by a survey meter.	True	
The cooler's custody seal, if present, is intact.	True	
Sample custody seals, if present, are intact.	True	
The cooler or samples do not appear to have been compromised or tampered with.	True	
Samples were received on ice.	True	
Cooler Temperature is acceptable.	True	
Cooler Temperature is recorded.	True	
COC is present.	True	
COC is filled out in ink and legible.	True	
COC is filled out with all pertinent information.	True	
Is the Field Sampler's name present on COC?	True	
There are no discrepancies between the containers received and the COC.	True	
Samples are received within Holding Time.	True	
Sample containers have legible labels.	True	
Containers are not broken or leaking.	True	
Sample collection date/times are provided.	True	
Appropriate sample containers are used.	True	
Sample bottles are completely filled.	True	
Sample Preservation Verified.	True	
There is sufficient vol. for all requested analyses, incl. any requested MS/MSDs	True	
Containers requiring zero headspace have no headspace or bubble is <6mm (1/4").	True	
Multiphasic samples are not present.	True	
Samples do not require splitting or compositing.	True	
Residual Chlorine Checked.	N/A	

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-33023-2
TestAmerica SDG: UIC Compatibility Evaluation
Client Project/Site: Seneca TO4

For:
Tetra Tech, Inc
Foster Plaza VII
661 Anderson Drive
Pittsburgh, Pennsylvania 15220-2745

Attn: Dale Skoff

Jennifer Gambill

Authorized for release by:
9/30/2013 10:06:56 AM

Jennifer Gambill, Project Manager I
(615)726-0177
jennifer.gambill@testamericainc.com

The test results in this report meet all 2003 NELAC and 2009 TNI requirements for accredited parameters, exceptions are noted in this report. This report may not be reproduced except in full, and with written approval from the laboratory. For questions please contact the Project Manager at the e-mail address or telephone number listed on this page.

This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.

Results relate only to the items tested and the sample(s) as received by the laboratory.

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Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-33023-1	Trap Run 38539	Water	08/12/13 09:10	08/13/13 15:43
490-33023-2	Tionesta 10H	Water	08/12/13 11:30	08/13/13 15:43
490-33023-3	Fagley Lease	Water	08/12/13 13:00	08/13/13 15:43
490-33023-4	James City Pad 50083	Water	08/12/13 14:20	08/13/13 15:43
490-33023-5	James City Well 38735	Water	08/12/13 15:00	08/13/13 15:43
490-33023-6	Wilson Run 39171	Water	08/12/13 16:30	08/13/13 15:43
490-33023-7	Boone Mountain Pad A	Water	08/12/13 17:00	08/13/13 15:43
490-33023-8	Tract 100 Pad M	Water	08/13/13 10:00	08/13/13 15:43
490-33254-1	4384 James City Prospect	Water	08/16/13 09:00	08/16/13 11:47

Job Narrative
490-33023-2

Comments
No additional comments.

Receipt
The samples were received on 8/13/2013 3:43 PM and 8/16/2013 11:47 AM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperatures of the coolers at receipt time were 0.0º C, 1.1º C, and 3.0º C.

Metals
Method(s) 3010A: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with batch 109708.

Method(s) 6020: The following samples were diluted to bring the concentration of Barium within the calibration range: Boone Mountain Pad A (490-33023-7), Tionesta 10H (490-33023-2), and Tract 100 Pad M (490-33023-8). Elevated reporting limits (RLs) are provided.

No other analytical or quality issues were noted.

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CNF	Contains no Free Liquid
DER	Duplicate error ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision level concentration
MDA	Minimum detectable activity
EDL	Estimated Detection Limit
MDC	Minimum detectable concentration
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative error ratio
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample ID: Trap Run 38539

Lab Sample ID: 490-33023-1

Date Collected: 08/12/13 09:10
Date Received: 08/13/13 15:43

Matrix: Water

Method: 6020 - Metals (ICP/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	13.8		2.00	0.500	mg/L		09/25/13 11:40	09/27/13 03:01	1000
Iron	32.5		25.0	10.0	mg/L		09/25/13 11:40	09/27/13 03:01	1000

Client Sample ID: Tionesta 10H

Lab Sample ID: 490-33023-2

Date Collected: 08/12/13 11:30
Date Received: 08/13/13 15:43
Matrix: Water

Method: 6020 - Metals (ICP/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	3180		10.0	2.50	mg/L		09/25/13 11:40	09/27/13 13:37	5000
Iron	86.9		25.0	10.0	mg/L		09/25/13 11:40	09/27/13 03:06	1000

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Client Sample ID: James City Well 38735

Lab Sample ID: 490-33023-5

Date Collected: 08/12/13 15:00
Matrix: Water
Date Received: 08/13/13 15:43

Method: 6020 - Metals (ICP/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	11.2		2.00	0.500	mg/L		09/25/13 11:40	09/27/13 03:20	1000
Iron	33.7		25.0	10.0	mg/L		09/25/13 11:40	09/27/13 03:20	1000

Client Sample ID: Wilson Run 39171 | **Lab Sample ID: 490-33023-6**

Date Collected: 08/12/13 16:30 | **Matrix: Water**

Date Received: 08/13/13 15:43

Method: 6020 - Metals (ICP/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	494		2.00	0.500	mg/L		09/25/13 11:40	09/27/13 03:25	1000
Iron	155		25.0	10.0	mg/L		09/25/13 11:40	09/27/13 03:25	1000

Client Sample ID: Boone Mountain Pad A

Lab Sample ID: 490-33023-7

Date Collected: 08/12/13 17:00
Matrix: Water
Date Received: 08/13/13 15:43

Method: 6020 - Metals (ICP/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	5390		20.0	5.00	mg/L		09/25/13 11:40	09/27/13 13:42	10000
Iron	122		25.0	10.0	mg/L		09/25/13 11:40	09/27/13 03:30	1000

Client Sample ID: Tract 100 Pad M
Lab Sample ID: 490-33023-8
Date Collected: 08/13/13 10:00
Matrix: Water
Date Received: 08/13/13 15:43

Method: 6020 - Metals (ICP/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	14900		40.0	10.0	mg/L		09/25/13 11:40	09/27/13 13:46	20000
Iron	109		25.0	10.0	mg/L		09/25/13 11:40	09/27/13 03:44	1000

Client Sample Results

Client: Tetra Tech, Inc
Project/Site: Seneca TO4

TestAmerica Job ID: 490-33023-2
SDG: UIC Compatibility Evaluation

Client Sample ID: 4384 James City Prospect
Lab Sample ID: 490-33254-1
Date Collected: 08/16/13 09:00
Matrix: Water
Date Received: 08/16/13 11:47

Method: 6020 - Metals (ICP/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	27.0		2.00	0.500	mg/L		09/25/13 11:40	09/27/13 03:49	1000
Iron	46.4		25.0	10.0	mg/L		09/25/13 11:40	09/27/13 03:49	1000

1 2 3 4 5 6 7 8 9 10 11 12

Method: 6020 - Metals (ICP/MS)

Lab Sample ID: MB 490-109708/1-A
Matrix: Water
Analysis Batch: 110229

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 109708

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Barium	<0.00200		0.00200	0.000500	mg/L		09/25/13 11:40	09/27/13 02:47	1
Iron	<0.0250		0.0250	0.0100	mg/L		09/25/13 11:40	09/27/13 02:47	1

Lab Sample ID: LCS 490-109708/2-A
Matrix: Water
Analysis Batch: 110229

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 109708

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Barium	0.100	0.1025		mg/L		103	80 - 120
Iron	1.00	1.049		mg/L		105	80 - 120

Lab Sample ID: LCSD 490-109708/3-A
Matrix: Water
Analysis Batch: 110229

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 109708

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Barium	0.100	0.1023		mg/L		102	80 - 120	0	20
Iron	1.00	1.037		mg/L		104	80 - 120	1	20

Metals

Prep Batch: 109708

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	3010A	
490-33023-2	Tionesta 10H	Total/NA	Water	3010A	
490-33023-3	Fagley Lease	Total/NA	Water	3010A	
490-33023-4	James City Pad 50083	Total/NA	Water	3010A	
490-33023-5	James City Well 38735	Total/NA	Water	3010A	
490-33023-6	Wilson Run 39171	Total/NA	Water	3010A	
490-33023-7	Boone Mountain Pad A	Total/NA	Water	3010A	
490-33023-8	Tract 100 Pad M	Total/NA	Water	3010A	
490-33254-1	4384 James City Prospect	Total/NA	Water	3010A	
LCS 490-109708/2-A	Lab Control Sample	Total/NA	Water	3010A	
LCSD 490-109708/3-A	Lab Control Sample Dup	Total/NA	Water	3010A	
MB 490-109708/1-A	Method Blank	Total/NA	Water	3010A	

Analysis Batch: 110229

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-1	Trap Run 38539	Total/NA	Water	6020	109708
490-33023-2	Tionesta 10H	Total/NA	Water	6020	109708
490-33023-3	Fagley Lease	Total/NA	Water	6020	109708
490-33023-4	James City Pad 50083	Total/NA	Water	6020	109708
490-33023-5	James City Well 38735	Total/NA	Water	6020	109708
490-33023-6	Wilson Run 39171	Total/NA	Water	6020	109708
490-33023-7	Boone Mountain Pad A	Total/NA	Water	6020	109708
490-33023-8	Tract 100 Pad M	Total/NA	Water	6020	109708
490-33254-1	4384 James City Prospect	Total/NA	Water	6020	109708
LCS 490-109708/2-A	Lab Control Sample	Total/NA	Water	6020	109708
LCSD 490-109708/3-A	Lab Control Sample Dup	Total/NA	Water	6020	109708
MB 490-109708/1-A	Method Blank	Total/NA	Water	6020	109708

Analysis Batch: 110421

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-33023-2	Tionesta 10H	Total/NA	Water	6020	109708
490-33023-7	Boone Mountain Pad A	Total/NA	Water	6020	109708
490-33023-8	Tract 100 Pad M	Total/NA	Water	6020	109708

1 2 3 4 5 6 7 8 9 10 11 12

Client Sample ID: Trap Run 38539
Lab Sample ID: 490-33023-1
Date Collected: 08/12/13 09:10
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		1000	110229	09/27/13 03:01	BWW	TAL NSH

Client Sample ID: Tionesta 10H
Lab Sample ID: 490-33023-2
Date Collected: 08/12/13 11:30
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	6020		1000	110229	09/27/13 03:06	BWW	TAL NSH
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		5000	110421	09/27/13 13:37	BWW	TAL NSH

Client Sample ID: Fagley Lease
Lab Sample ID: 490-33023-3
Date Collected: 08/12/13 13:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		1000	110229	09/27/13 03:11	BWW	TAL NSH

Client Sample ID: James City Pad 50083
Lab Sample ID: 490-33023-4
Date Collected: 08/12/13 14:20
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		1000	110229	09/27/13 03:15	BWW	TAL NSH

Client Sample ID: James City Well 38735
Lab Sample ID: 490-33023-5
Date Collected: 08/12/13 15:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		1000	110229	09/27/13 03:20	BWW	TAL NSH

Client Sample ID: Wilson Run 39171
Lab Sample ID: 490-33023-6
Date Collected: 08/12/13 16:30
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH

Lab Chronicle

Client Sample ID: Wilson Run 39171

Lab Sample ID: 490-33023-6
Date Collected: 08/12/13 16:30
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	6020		1000	110229	09/27/13 03:25	BWW	TAL NSH

Client Sample ID: Boone Mountain Pad A

Lab Sample ID: 490-33023-7
Date Collected: 08/12/13 17:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		1000	110229	09/27/13 03:30	BWW	TAL NSH
Total/NA	Analysis	6020		10000	110421	09/27/13 13:42	BWW	TAL NSH

Client Sample ID: Tract 100 Pad M

Lab Sample ID: 490-33023-8
Date Collected: 08/13/13 10:00
Matrix: Water
Date Received: 08/13/13 15:43

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		1000	110229	09/27/13 03:44	BWW	TAL NSH
Total/NA	Analysis	6020		20000	110421	09/27/13 13:46	BWW	TAL NSH

Client Sample ID: 4384 James City Prospect

Lab Sample ID: 490-33254-1
Date Collected: 08/16/13 09:00
Matrix: Water
Date Received: 08/16/13 11:47

Prep Type	Batch Type	Batch Method	Run	Dilution Factor	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Prep	3010A			109708	09/25/13 11:40	NLI	TAL NSH
Total/NA	Analysis	6020		1000	110229	09/27/13 03:49	BWW	TAL NSH

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Method	Method Description	Protocol	Laboratory
6020	Metals (ICP/MS)	SW846	TAL NSH

Protocol References:

SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Laboratory: TestAmerica Nashville

All certifications held by this laboratory are listed. Not all certifications are applicable to this report.

Authority	Program	EPA Region	Certification ID	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-13
Alaska (UST)	State Program	10	UST-087	07-24-14
Arizona	State Program	9	AZ0473	05-05-14
Arizona	State Program	9	AZ0473	05-05-14 *
Arkansas DEQ	State Program	6	88-0737	04-25-14
California	NELAP	9	1168CA	10-31-13
Canadian Assoc Lab Accred (CALA)	Canada		3744	03-08-14
Connecticut	State Program	1	PH-0220	12-31-13
Florida	NELAP	4	E87358	06-30-14
Illinois	NELAP	5	200010	12-09-13
Iowa	State Program	7	131	05-01-14
Kansas	NELAP	7	E-10229	10-31-13
Kentucky (UST)	State Program	4	19	06-30-14
Louisiana	NELAP	6	30613	06-30-14
Maryland	State Program	3	316	03-31-14
Massachusetts	State Program	1	M-TN032	06-30-14
Minnesota	NELAP	5	047-999-345	12-31-13
Mississippi	State Program	4	N/A	06-30-14
Montana (UST)	State Program	8	NA	01-01-20
Nevada	State Program	9	TN00032	07-31-14
New Hampshire	NELAP	1	2963	10-10-13
New Jersey	NELAP	2	TN965	06-30-14
New York	NELAP	2	11342	04-01-14
North Carolina DENR	State Program	4	387	12-31-13
North Dakota	State Program	8	R-146	06-30-14
Ohio VAP	State Program	5	CL0033	01-19-14
Oklahoma	State Program	6	9412	08-31-14
Oregon	NELAP	10	TN200001	04-29-14
Pennsylvania	NELAP	3	68-00585	06-30-14
Rhode Island	State Program	1	LAO00268	12-30-13
South Carolina	State Program	4	84009 (001)	02-28-14
Tennessee	State Program	4	2008	02-23-14
Texas	NELAP	6	T104704077-09-TX	08-31-14
USDA	Federal		S-48469	11-02-13
Utah	NELAP	8	TN00032	07-31-14
Virginia	NELAP	3	460152	06-14-14
Washington	State Program	10	C789	07-19-14
West Virginia DEP	State Program	3	219	02-28-14
Wisconsin	State Program	5	998020430	08-31-14
Wyoming (UST)	A2LA	8	453.07	12-31-13

* Expired certification is currently pending renewal and is considered valid.

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

Nashville, TN

490-33023 Chain of Custody

COOLER RECEIPT FORM

Cooler Received/Opened On 8/15/2013@ 0815

1. Tracking # 3047 (last 4 digits, FedEx)

Courier: FedEx IR Gun ID 96210146

2. Temperature of rep. sample or temp blank when opened: 1.1 *Degrees Celsius*
3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO..NA
4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where:
5. Were the seals intact, signed, and dated correctly? YES...NO...NA
6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) DA

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA
8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None
9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None
10. Did all containers arrive in good condition (unbroken)? YES...NO...NA
11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA
12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

b. Was there any observable headspace present in any VOA vial? YES...NO...NA

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #

I certify that I unloaded the cooler and answered questions 7-14 (intial) MDM

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES..NO..NA

b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) MDM

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA
18. Did you sign the custody papers in the appropriate place? YES...NO...NA
19. Were correct containers used for the analysis requested? YES...NO...NA
20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) MDM

I certify that I attached a label with the unique LIMS number to each container (intial) MDM

21. Were there Non-Conformance issues at login? YES..NO Was a NCM generated? YES..NO..#

BIS = Broken in shipment

Cooler Receipt Form.doc

LF-1

End of Form

Revised 11/28/12

490-33023

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

Cooler Received/Opened On 8/15/2013 @ 0815

1. Tracking # 3036 (last 4 digits, FedEx)

Courier: FedEx IR Gun ID 94660220

2. Temperature of rep. sample or temp blank when opened: 0.0 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

If yes, how many and where: (1) Top

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) MDM

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

b. Was there any observable headspace present in any VOA vial? YES...NO...NA

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #______

I certify that I unloaded the cooler and answered questions 7-14 (intial) MDM

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES..NO..NA

b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) MDM

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) MDM

I certify that I attached a label with the unique LIMS number to each container (intial) MDM

21. Were there Non-Conformance issues at login? YES..NO Was a NCM generated? YES..NO..#______

TestAmerica Pittsburgh
301 Alpha Drive
RIDC Park
Pittsburgh, PA 15238
Phone: 412.963.7058 Fax:

Chain of Custody Record

Loc: 490
33023

TestAmerica
LEADER IN ENVIRONMENTAL TESTING
TestAmerica Laboratories, Inc.
TAL-C-WI-002, Rev. 4.2, dated 04/02/2013

Regulatory Program: ☐ DW ☐ NPDES ☐ RCRA ☒ Other:

Client Contact		Project Manager: Kelly Carper	Site Contact:
Company Name:	TetraTech, Inc.	Tel/Fax: " "	Lab Contact:
Address:	661 Andersen Drive		Carrier:
City/State/Zip:	Pittsburgh, PA 15220		
Phone:	(412) 920-7015		
Fax:	(412) 921-4040		
Project Name:	Seneca TO4		
Site:	UIC Compatibility Evaluation		
P O #	112C05696		

COC No.: 1 of 1 COCs

Sampler:

For Lab Use Only:
Walk-in Client:
Lab Sampling:

Job / SDG No.:

Analysis Turnaround Time
☐ CALENDAR DAYS ☐ WORKING DAYS
TAT if different from Below ______
☐ 2 weeks
☐ 1 week
☐ 2 days
☐ 1 day

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.	Filtered Sample (Y / N)	Perform MS / MSD (Y / N)	DOC	Settleable Solids	(MOD) Custom Metals List	2540C_Calcd, 2320B	SM4500_H+	300_ORGFM_28D	SM4500_SiO2_C	Sample Specific Notes:
Trap Run 38537	8/12/13	0910	G	NP	9	Y	N	X	X	X	X	X	X	X	
Tionesta 10H	8/12/13	1130	G	NP	9	|	|	X	X	X	X	X	X	X	
Fazley Lease	8/12/13	1300	G	NP	9	|	|	X	X	X	X	X	X	X	
James City Pad 50083	8/12/13	1420	G	NP	9	|	|	X	X	X	X	X	X	X	
James City Well 38735	8/12/13	1500	G	NP	9	|	|	X	X	X	X	X	X	X	
Wilson Run 39171	8/12/13	1630	G	NP	9	|	|	X	X	X	X	X	X	X	
Boone Mountain Pad A	8/12/13	1700	G	NP	9	|	|	X	X	X	X	X	X	X	
Tract 100 Pad M	8/13/13	1000	G	NP	9	↓	↓	X	X	X	X	X	X	X	

Preservation Used: 1= Ice, 2= HCl; 3= H2SO4; 4=HNO3; 5=NaOH; 6= Other 1, 4

Possible Hazard Identification:
Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.
☒ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return to Client ☐ Disposal by Lab ☐ Archive for________ Months

Special Instructions/QC Requirements & Comments:

Custody Seals Intact: ☐ Yes ☐ No | Custody Seal No.: | Cooler Temp. (°C): Obs'd:________ Corr'd:________ Therm ID No.:________

Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
[signature]	Tetra Tech, Inc.	8/13/13/1543	[signature]	TestAmerica	8/13/13 1543
Relinquished by: Jon Watson	Company: TA Pitt	Date/Time: 8/14/13 1700	Received by: [signature]	Company: TAW	Date/Time: 8-15-13 @ 0815 0.0/1.1°C
Relinquished by:	Company:	Date/Time:	Received in Laboratory by:	Company:	Date/Time:

9/30/2013

490.33023

Bottle Order Information

Bottle Order: *Seneca Resources Corporation*
Bottle Order #: *6093*
Date Order Posted: *8/5/2013 2:25:22PM*
Order Status: *Ready To Process*
Prepared By: *Jennifer Gambill*
Deliver By Date: ***8/7/2013 11:59:00PM***
Lab Project Number: *49005204*

Job - All match

Order Completion Information

Filled by:
Sent Date:
Sent Via:
Tracking #:

Sets	Bottles/Set	Qty	Bottle Type Description	Preservative	Method	Matrix	Sample Type	Comments	Lot #
11	3	33	Plastic 250ml - unpreserved	None	SM4500_H+ - pH & Temperature	Water	Normal	pH/SC/Method 300/Silicon Dioxide	
					300_ORGFM_28D - (MOD) Custom Anions List	Water	Normal		
					SM4500_SiO2_C - Silicon dioxide	Water	Normal		
					2510B - Specific Conductance	Water	Normal		
11	1	11	Plastic 500ml - unpreserved	None	2540C_Calcd - Total Dissolved Solids	Water	Normal	TDS/Alkalinity	
					2320B - (MOD) Alkalinity as CaCO3 (Total, Carbon	Water	Normal		
11	2	22	Plastic 250ml - with Nitric Acid	Nitric Acid	6010C - (MOD) Custom Metals List	Water	Normal	Metals/Silicon	
11	1	11	Bacti Bottle Sterile	None	SUBCONTRACT - Sulfate Reducing Bacteria	Water	Normal	SRB	
11	2	22	Plastic 1 liter - unpreserved	None	SM2540F - Settleable Solids (mL/L)	Water	Normal	Settleable Solids	
11	1	11	Plastic 250ml – unpreserved - dis	None	SM5310_DOC_B - Dissolved Organic Carbon (DOC)	Water	Normal	DOC	

Notes to Field Staff:

Health and Safety Notes:

Preservative	Comment
Nitric Acid	CAUTION! STRONG OXIDIZER! CONTAINS 1:1 NITRIC ACID. Avoid skin and eye contact. If contact is made, FLUSH IMMEDIATELY with water.

Relinquished By	Company	Date	Time	Received By	Company	Seal #:
						Seal #:
						Seal #:
Relinquished By	Company	Date	Time	Received By	Company	Seal #:
						Seal #:
						Seal #:

Please notify us immediately if an error is found in shipment

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

490-33254 Chain of Custody

COOLER RECEIPT FORM

Cooler Received/Opened On 8/24/2013 @ 8:15

1. Tracking #_3768_______(last 4 digits, FedEx)

Courier: _____FedEx_________ IR Gun ID___17610176___

2. Temperature of rep. sample or temp blank when opened:_3.0_Degrees Celsius

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO..NA

4. Were custody seals on outside of cooler? YES..NO..NA

   If yes, how many and where:_______________

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) AJH

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #________

I certify that I unloaded the cooler and answered questions 7-14 (intial) MDM

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES..NO..NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) MDM

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) MDM

I certify that I attached a label with the unique LIMS number to each container (intial) MDM

21. Were there Non-Conformance issues at login? YES..NO Was a NCM generated? YES..NO..#________

BIS = Broken in shipment
Cooler Receipt Form.doc

1 2 3 4 5 6 7 8 9 10 11 12

TestAmerica Pittsburgh
301 Alpha Drive
RIDC Park
Pittsburgh, PA 15238
Phone: 412.963.7058 Fax:

Chain of Custody Record

Loc: 490
33254

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
TestAmerica Laboratories, Inc.
Form No. CA-C-WI-002, Rev. 4.2, dated 04/02/2013

Regulatory Program: ☐ DW ☐ NPDES ☐ RCRA ☐ Other:

Client Contact	Project Manager:	Site Contact:	Date:	COC No:
Company Name: TetraTech	Tel/Fax:	Lab Contact:	Carrier:	____ of ____ COCs
Address:	**Analysis Turnaround Time**			Sampler:
City/State/Zip:	☐ CALENDAR DAYS ☐ WORKING DAYS			**For Lab Use Only:**
Phone:	TAT if different from Below ____			Walk-in Client:
Fax:	☐ 2 weeks			Lab Sampling:
Project Name:	☐ 1 week			
Site:	☐ 2 days			Job / SDG No.:
P O #	☐ 1 day			

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.	Filtered Sample (Y / N)	Perform MS / MSD (Y / N)	P 250 un	P 250 nitric	P 1 Liter	Sample Specific Notes:
490-33254-1								4	1	1	

Preservation Used: 1= Ice, 2= HCl; 3= H2SO4; 4=HNO3; 5=NaOH; 6= Other ____

Possible Hazard Identification:
Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return to Client ☐ Disposal by Lab ☐ Archive for ____ Months

Special Instructions/QC Requirements & Comments:

Custody Seals Intact: ☐ Yes ☐ No | Custody Seal No.: | Cooler Temp. (°C): Obs'd: ____ Corr'd: ____ | Therm ID No.: ____

Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
[signature]	TAP	8/23/13 1420	[signature]	TAN	8-24-13 @ 0815 3.°c
Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
Relinquished by:	Company:	Date/Time:	Received in Laboratory by:	Company:	Date/Time:

TestAmerica Pittsburgh
301 Alpha Drive
RIDC Park
Pittsburgh, PA 15238
Phone: 412.963.7058 Fax:

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
TestAmerica Laboratories, Inc.

Regulatory Program: ☐ DW ☐ NPDES ☐ RCRA ☒ Other:

Form No. CA-C-WI-002, Rev. 4.2, dated 04/02/2013

Client Contact			
Company Name:	Tetra Tech, Inc.	Project Manager:	Kelly Casper
Address:	661 Andersen Drive	Tel/Fax:	"
City/State/Zip:	Pittsburgh, PA 15220	Site Contact:	
Phone:	(412) 920-7015	Lab Contact:	
Fax:	(412) 921-4040	Date:	
Project Name:	Seneca T04	Carrier:	
Site:	UIC Compatibility Evaluation	COC No:	1 of 1 COCs
PO#	112C05696	Sampler:	

Analysis Turnaround Time
☐ CALENDAR DAYS ☐ WORKING DAYS
TAT if different from Below ______
☐ 2 weeks
☐ 1 week
☐ 2 days
☐ 1 day

For Lab Use Only:
Walk-in Client:
Lab Sampling:
Job / SDG No.:

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=Grab)	Matrix	# of Cont.	Filtered Sample (Y/N)	Perform MS/MSD (Y/N)	DOC	Settleable Solids	(HOD) Custom Metals List	2540C - Calc'd 2340B	SM4500-H+	300_ORGFM_28D	SM4500-SiO2-C	Sample Specific Notes:
4384 James City Prospect	8/16/13	0900	G	NP	9	Y	N	X	X	X	X	X	X	X	

Preservation Used: 1= Ice, 2= HCl; 3= H2SO4; 4=HNO3; 5=NaOH; 6= Other

Possible Hazard Identification:
Are any samples from a listed EPA Hazardous Waste? Please List any EPA Waste Codes for the sample in the Comments Section if the lab is to dispose of the sample.
☒ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return to Client ☐ Disposal by Lab ☐ Archive for ______ Months

Special Instructions/QC Requirements & Comments:

Custody Seals Intact: ☒ Yes ☐ No
Custody Seal No.:
Cooler Temp. (°C): Obs'd: ______ Corr'd: ______ Therm ID No.: ______

Relinquished by: [signature]	Company: Tetra Tech, Inc.	Date/Time: 8/16/13/1147	Received by: [signature]	Company: TAPGH	Date/Time: 8/16/13 1147
Relinquished by:	Company:	Date/Time:	Received by:	Company:	Date/Time:
Relinquished by:	Company:	Date/Time:	Received in Laboratory by:	Company:	Date/Time:

APPENDIX J

Existing Permits

Well #38268 EPA Permit

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

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

JUN 17 2014

Mr. Doug Kepler, Vice President
Seneca Resources Corporation
5800 Corporate Blvd, Suite 300
Pittsburgh, PA 15237

Re: Underground Injection Control Permit PAS2D025BELK;
Well # 38268 in Highland Township, Elk County, PA
Underground Injection Control Appeal No. 14-01, 14-02 & 14-03
Notice of Final Permit Decision

Dear Mr. Kepler:

Pursuant to 40 C.F.R. § 124.19(l)(2)(i), this is a notice of the U. S. Environmental Protection Agency (EPA) Region III's final permit decision regarding UIC Permit No. PAS2D025BELK, which EPA issued to Seneca Resources Corporation on January 28, 2014.

Following the issuance of the permit, several petitioners filed for review of the permit with the EPA Environmental Appeals Board. The effect of these petitions was to stay the issued permit pending a decision by the Board and final agency action. See 40 C.F.R. § 124.16(a)(1). On May 29, 2014, the Board denied the three petitions. *In re Seneca Resources Corp.,* UIC Appeal Nos. 14-01, 14-02 and 14-03 (EAB, May 29, 2014)(Order Denying Review).

Under 40 C.F.R. § 124.19(l)(2)(i), the Region must issue a final permit decision when the Board issues notice denying a petition for review, and the allowed period for a motion for reconsideration has expired. Hence, EPA is hereby issuing the final permit decision regarding Permit No. PAS2D025BELK. This permit will become effective on the date of this letter.

If you have any questions, please contact Roger Reinhart of my staff by telephone at (215) 814-5462 or by email to reinhart.roger@epa.gov.

Sincerely,

Jon M. Capacasa, Director
Water Protection Division

cc: Judith Hudson
Susan Swanson
Kevin Moran, Chairman, Highland Township Municipal Authority

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

UNDERGROUND INJECTION CONTROL PERMIT NUMBER PAS2D025BELK
AUTHORIZATION TO OPERATE A CLASS IID INJECTION WELL

In compliance with provisions of the Safe Drinking Water Act, as amended, (42 U.S.C. §§ 300f-300j-11, commonly known as the SDWA), the Resource Conservation and Recovery Act (42 U.S.C. §§ 6901-6991i, commonly known as RCRA) and attendant regulations promulgated by the U. S. Environmental Protection Agency under Title 40 of the Code of Federal Regulations,

Seneca Resources Corporation
5800 Corporate Blvd, Suite 300
Pittsburgh, PA 15237

is authorized by this permit to inject fluids produced solely in association with oil and gas production from Seneca Resources oil and gas production activities through a Class II-D injection well (#38268), located in the SRC Kane Field, located in Highland Township, Elk County, PA, into the Upper Devonian of the Elk 3 Sand Formation in accordance with the conditions set forth herein. The coordinates for this injection well are:
Latitude 41° 37' 08.1" and Longitude -78° 49' 17.5".

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit becomes effective.

This permit shall become effective on June 17, 2014.

This permit and its authorization to inject shall remain in effect until midnight

June 17, 2024.

Signed this 17 day of June, 2014.

Jon M. Capacasa
Jon M. Capacasa, Director
Water Protection Division

PART I

A. Effect of Permit

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The underground injection activity, otherwise authorized by this permit, shall not allow the movement of fluid containing any contaminant into underground sources of drinking water (USDW), if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized in this permit or otherwise authorized by rule is prohibited. Issuance of this permit does not convey property rights or mineral rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with terms of this permit does not constitute a defense to any action brought under Part C and the imminent and substantial endangerment provisions in Part D of the Safe Drinking Water Act (SDWA) or any other common or statutory law for any breach of any other applicable legal duty.

B. Permit Actions

This permit can be modified, revoked and reissued or terminated for cause as specified in 40 CFR §§ 144.12, 144.39 and 144.40. Also, the permit is subject to minor modifications as specified in 40 CFR § 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee shall not stay the applicability or enforceability of any permit condition.

C. Severability

The provisions of this permit are severable, and if any provision of this permit or the permittee's application, dated June 25, 2012, is held invalid, the remainder of this permit shall not be affected thereby.

D. General Requirements

1. <u>Duty to Comply.</u> The permittee shall comply with all applicable UIC Program regulations and conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued under 40 C.F.R. 144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement

action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. Need to Halt or Reduce Activity Not a Defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

3. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

4. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, adequate security at the facility to prevent unauthorized access and operation of the well, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facility or similar systems only when necessary to achieve compliance with the conditions of this permit.

5. Duty to Provide Information. The permittee shall furnish to the Director of the Water Protection Division ("Director"), within a time specified by the Director, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit. If the permittee becomes aware of any incomplete or incorrect information in the Permit Application or subsequent reports, the permittee shall promptly submit information addressing these deficiencies.

6. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law to:

a. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

d. Sample or monitor any substances or parameters at any location, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by SDWA.

7. Penalties. Any person who violates a permit requirement is subject to civil penalties, fines and other enforcement actions under the SDWA and may be subject to the same such actions pursuant to RCRA. Any person who willfully violates permit conditions is subject to criminal prosecution.

8. Transfer of Permits. This permit is not transferable to any person except after notice is sent on EPA Form 7520 and approval is given by the Director and the requirements of 40 CFR § 144.38 are satisfied. The Director may require modification or revocation of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

9. Signatory Requirements.

a. All reports required by this permit and other information requested by the Director shall be signed as follows:

(1) for a corporation, by a responsible corporate officer of at least the level of vice-president;

(2) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively; or

(3) for a Municipality, State, Federal, or other public agency by either a principal executive or a ranking elected official.

b. A duly authorized representative of the official designated in paragraph a. above may also sign only if:

(1) the authorization is made in writing by a person described in paragraph a. above;

(2) the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or a position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and

(3) the written authorization is submitted to the Director.

c. If an authorization under paragraph b. of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph b. of this section must be submitted to the Director prior to or together with any reports, information or applications to be signed by an authorized representative.

d. Any person signing a document under paragraph a. or b. of this section shall make the following certification:

> "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person(s) who manage the system, or those persons directly responsible for gathering the information, the information submitted is to the best of my knowledge and belief, true accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

10. Confidentiality of Information.

a. In accordance with 40 CFR Parts 2 (Public Information) and § 144.5, any information submitted to the Director pursuant to these permits may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 CFR Part 2.

b. Claims of confidentiality for the following information will be denied:

(1) The name and address of any permit applicant or permittee.

(2) Information which deals with the existence, absence, or level of contaminants in drinking water.

11. Reapplication. If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must submit a complete application for a new permit at least 100 days before this permit expires.

12. State Laws. Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation.

PART II

A. General

Copies of all reports and notifications required by this permit shall be signed and certified in accordance with the requirements of Section D(9) of Part I of this permit and shall be submitted to the Director at the following address:

Ground Water & Enforcement Branch (3WP22)
Office of Drinking Water & Source Water Protection
U. S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, Pennsylvania 19103

B. Record Retention

1. The permittee shall retain records of all monitoring and other information required by this permit, including the following (if applicable), for a period of at least five years from the date of the sample, measurement, report or application, unless such records are required to be retained for a longer period of time under paragraph B.2, below. This period may be extended by request of the Director at any time.

a. All data required to complete the Permit Application form for this permit and any supplemental information submitted under 40 CFR § 144.31.

b. Calibrations and maintenance records and all original strip chart recordings for continuous monitoring instrumentation.

c. Copies of all reports required by this permit.

2. The permittee shall retain records concerning the nature and composition of all injected fluids, as listed in Part II, paragraphs C.3. and C.4. of this permit, until three years after the completion of any plugging and abandonment procedures. After three years from the completion of plugging and abandonment, the permittee shall continue to retain these records unless he or she delivers the records to the Director or obtains written approval from the Director to discard the records.

3. Records of monitoring information shall include:

a. The date, exact place, and the time of sampling or measurements;

b. The individual(s) who performed the sampling or measurements;

c. A precise description of both sampling methodology and the handling (custody) of samples;

d. The date(s) analyses were performed;

e. The individual(s) who performed the analyses;

f. The analytical techniques or methods used; and

g. The results of such analyses.

4. Monitoring the nature of injected fluids shall comply with applicable analytical methods cited in Part II, paragraph C.1., below.

5. All environmental measurements required by the permit, including, but not limited to; measurements of pressure, temperature, mechanical integrity (as applicable) and chemical analyses shall be done in accordance with EPA guidance on quality assurance.

C. Monitoring Requirements

1. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. The method used to obtain a representative sample of the fluid to be analyzed and the procedure for analysis of the sample shall be in accordance with test procedures approved under 40 CFR § 136.3 unless otherwise approved by the Director. The permittee shall identify the types of tests and methods used to generate the monitoring data.

2. Injection pressure, annular pressure, flow rate and cumulative volume shall be observed and recorded continuously beginning on the date on which the well commences operation and concluding when the well is plugged and abandoned. The well shall be equipped with an automatic shut-off device which would be activated in the event of a mechanical integrity failure. The permittee shall monitor and record, quarterly, the fluid level from monitoring wells #38281 and #01144 located within the SRC Kane Field. Each of these monitoring wells shall completely isolate the Elk 3 Sand formation from the rest of the wellbore by placement of a monitoring string on a packer set immediately above the Elk 3 Sand formation.

3. The permittee shall sample, analyze and record the nature of the injected fluid for the parameters listed below at the initiation of the injection operation and every two years thereafter, or whenever the operator observes or anticipates a change in the injection fluid (see condition C.4. below).

- pH
- Specific Gravity
- Specific Conductance
- Sodium
- Iron
- Magnesium
- Chloride
- Total Organic Carbon (TOC)
- Manganese
- Total Dissolved Solids
- Barium
- Hydrogen Sulfide
- Dissolved Oxygen
- Alkalinity
- Hardness

4. Any analysis of specific gravity greater than 1.16 and any analysis of TOC greater than 250 mg/l shall be reported to the Director within twenty-four hours of the results.

5. A demonstration of mechanical integrity in accordance with 40 CFR § 146.8 shall, after the initial demonstration, be made at least once every five years. Subsequent five year demonstrations shall be conducted within five years of the date that the previous demonstration was made. In addition to the above requirement, a mechanical integrity test demonstration shall be conducted whenever protective casing or tubing is removed from the well, the packer is reseated, or a well failure is evident. The permittee may continue operation only if he or she has successfully demonstrated to the Director the mechanical integrity of the permitted well. The permittee shall cease injection operations if a loss of mechanical integrity becomes evident or if mechanical integrity cannot be demonstrated. Any such test shall be conducted in keeping with the notification requirements of Permit Condition D.11. of Part II of this permit.

D. Reporting and Notification Requirements.

1. Report on Permit Review. Within 30 days of receipt of this permit, the permittee shall report to the Director that he or she has read and is personally familiar with all terms and conditions of this permit.

2. Commencing Injection. The operator of an injection well may not commence injection until construction or well rework is complete and all of the following conditions have been satisfied:

a. The permittee has demonstrated to EPA that the injection well has mechanical integrity in accordance with 40 CFR § 146.8 and the permittee has received written notice from the Director that such demonstration is satisfactory;

b. The permittee has submitted notice of completion of construction (EPA Form 7520-10) to the Director; and

c.(1) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the permit; or

c.(2) The permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in paragraph (a) of this permit condition, in which case, prior inspection or review is waived and the permittee may commence injection.

3. <u>Twenty-four Hour Reporting.</u>

a. The permittee shall report to the Director any noncompliance which may endanger human health or the environment. Such report shall be provided orally (phone numbers: (215)814-5464 or (215)814-5445 within 24 hours from the time the permittee becomes aware of the circumstances. The following shall be included as information which must be reported orally within 24 hours:

(1) Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water.

(2) Any noncompliance with a permit condition, or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water, or failure of mechanical integrity test demonstrations.

b. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

4. <u>Anticipated Noncompliance.</u> The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

5. <u>Other Noncompliance.</u> The permittee shall report all other instances of noncompliance in writing within ten (10) days of the time the permittee becomes aware of the circumstances. The reports shall contain the information listed in Permit Condition D.3., of Part II of this permit.

6. Planned Changes. The permittee shall give notice to the Director as soon as possible of any planned physical alterations or additions to the permitted facility.

7. Conversion. The permittee shall notify the Director thirty days prior to the conversion of the well to an operating status other than an injection well.

8. Annual Report. The permittee shall submit an Annual Report to the Director summarizing the results of the monitoring required by Permit Condition C within Part II of this permit. This report shall include monthly monitoring records of injected fluids, the results of any mechanical integrity test(s), and any major changes in characteristics or sources of injected fluids. The permittee shall complete and submit this information with its Annual Report EPA Form 7520-11 (Annual Disposal/Injection Well Monitoring Report). The Annual Report shall be submitted not later than January 31st of each year, summarizing the activity of the calendar year ending the previous December 31st.

9. Plugging and Abandonment Reports and Notifications.

a. The permittee shall notify the Director 45 days before the plugging and abandonment of the well. The Director may allow a shorter notice period upon written request.

b. Revisions to the Plugging and Abandonment Plan must be submitted to the Director no less than 45 days prior to plugging and abandonment on EPA Plugging and Abandonment Form 7520-14. The Director must approve the revisions prior to the start of plugging operations.

c. Within 60 days after plugging the well, the permittee shall submit a report to the Director which shall consist of either:

(1) A statement that the well was plugged in accordance with the plan previously submitted to and approved by the Director; or

(2) Where actual plugging differed from the plan previously submitted, an updated version of the plan, on the form supplied by the Director, specifying the different procedures used.

The report shall be certified as accurate by the person who performed the plugging operation.

10. Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 30 days following each schedule date.

11. Mechanical Integrity Tests. The permittee shall notify the Director of his or her intent to conduct a mechanical integrity test at least 30 days prior to such a demonstration.

12. Cessation of Injection Activity. After a cessation of injection for two years the owner or operator shall plug and abandon the well in accordance with the Plugging and Abandonment Plan in Attachment 1, unless he:

a. Provides notice to the Director; and

b. Describes actions or procedures, satisfactory to the Director, which the permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. These actions and procedures shall include compliance with the technical requirements applicable to an active injection well unless waived in writing by the Director.

E. Mechanical Integrity Standards

1. Standards. The permittee shall have and maintain the mechanical integrity of the permitted injection well pursuant to 40 CFR § 146.8.

2. Request from Director. The Director may, by written notice, require the permittee to demonstrate mechanical integrity at any time.

PART III

A. Construction Requirements

1. Notwithstanding any other provision of this permit, the injection well shall inject only into formations which are separated from any underground source of drinking water by a confining zone that is free of known open faults or fractures within the Area of Review.

2. Casing and Cementing. The permittee is required to case and cement the well to prevent the movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of the well was designed for the life expectancy of the well. Surface casing has been installed from the surface to a depth of approximately 553 feet, and cemented back to the surface. This exceeds the requirement for surface casing to be cemented to at least 50 feet beneath the lowermost underground source of drinking water, which in this case is 450 feet. The injection zone shall be isolated by the placement of long string casing to approximately 2354 feet, and cemented back at least 100 feet above the injection zone. Injection shall occur through a tubing string and packer installed inside the long string casing and set above the injection zone.

3. Logs and Tests. The logs and tests listed below shall be conducted during the drilling and construction of the well or, in the event that the well is being converted to an injection well, obtain and submit the logs and tests from the well's original construction. A descriptive report interpreting the results (which specifically relate to (1) the lowermost underground source of drinking water and the confining zone adjacent to it and (2) the injection zone and adjacent formations) shall be prepared by a knowledgeable log analyst and submitted to the Director. At a minimum, such logs and or tests shall include the following:

- A cement bond log and variable density log which document the cemented portion of the long string casing.

- A log which documents the location of the surface casing.

- Records documenting the cementing of the surface casing.

- Gamma Ray logs which document the geologic formations in the wellbore.

4. Mechanical Integrity. Injection operations are prohibited until the permittee demonstrates that the well covered by this permit has mechanical integrity in accordance with 40 CFR § 146.8 and the permittee has received notice from the Director that such a demonstration is satisfactory in accordance with the provisions of Condition D.2. located in Part II of this permit.

5. Corrective Action. If necessary, corrective action, in the form of plugging and abandoning wells within the one-quarter mile area of review, which could provide conduits for fluid migration into USDWs, will be completed prior to the authorization of injection. If an abandoned well is discovered within the one-quarter mile area of review after injection commences, the permittee shall notify the Director upon discovery, and within five (5) days, submit to the Director for approval a plan for corrective action and implement the approved plan.

B. Operating Requirements

1. Injection Formation. Injection shall be limited to the Upper Devonian Elk 3 Sand formation in the subsurface interval between approximately 2354 feet and 2403 feet.

2. Injection Fluid. The permittee shall not inject any hazardous substances, as defined by 40 CFR 261, or any other fluid, other than the fluids produced solely in association with Seneca Resources oil and gas production activity.

3. Injection Volume Limitation. Injection volume shall not exceed 45,000 barrels per month.

4. Injection Pressure Limitation. Injection pressure shall not exceed a surface injection pressure maximum of 1416 psi. This pressure calculation is based on the specific

gravity of the injection fluid not exceeding 1.16. If the specific gravity of the injection fluid is greater than 1.16, the surface injection pressure will need to be reduced accordingly. Injection at a pressure which initiates new fractures or propagates existing fractures in the confining zone adjacent to underground sources of drinking water or causes the movement of injection or formation fluids into an underground source of drinking water is prohibited.

5. Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited, as is injection into any USDW.

C. Plugging and Abandonment

1. The permittee shall plug and abandon the well in accordance with the approved plugging and abandonment plan in Attachment 1.

2. Plugging and Abandonment shall be conducted in such a manner that movement of fluids will not be allowed into or between underground sources of drinking water.

D. Financial Responsibility

The permittee shall maintain financial responsibility and resources to close, plug and abandon the underground injection well in accordance with 40 CFR Section 144.52(a)(7) in the amount of at least $24,650. If the circumstances regarding the acceptability of the Financial Statement, submitted to EPA to demonstrate financial responsibility should change, the permittee shall provide advance notification to the Director, and the Director may seek an alternative financial demonstration from the permittee. The financial statement demonstration must be submitted to the EPA Director on an annual basis for evaluation and approval.

The permittee shall not substitute an alternative demonstration of financial responsibility for that which the Director has approved, unless he or she has previously submitted evidence of that alternative demonstration to the Director and the Director notifies him or her that the alternative demonstration of financial responsibility is acceptable. The Director may require the permittee to submit a revised demonstration of Financial Responsibility if the Director has reason to believe that the original demonstration is no longer adequate to cover the costs of plugging and abandonment.

Well #38268 EPA Permit Modification

A R M G r o u p L L C

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

UNDERGROUND INJECTION CONTROL PERMIT NUMBER PAS2D025BELK
AUTHORIZATION TO OPERATE A CLASS IID INJECTION WELL

In compliance with provisions of the Safe Drinking Water Act, as amended, (42 U.S.C. §§ 300f-300j-11, commonly known as the SDWA), the Resource Conservation and Recovery Act (42 U.S.C. §§ 6901-6991i, commonly known as RCRA) and attendant regulations promulgated by the U.S. Environmental Protection Agency under Title 40 of the Code of Federal Regulations,

Seneca Resources Company, LLC
2000 Westinghouse Drive, Suite 400
Cranberry Township, PA 16066

is authorized by this permit to inject fluids produced solely in association with oil and gas production from Seneca Resources oil and gas production activities through a Class II-D injection well (#38268), located in the SRC Kane Field, located in Highland Township, Elk County, PA, into the Upper Devonian of the Elk 3 Sand Formation in accordance with the conditions set forth herein. The coordinates for this injection well are:
Latitude 41º37’08.1” and Longitude -78º 49’ 17.5”.

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit becomes effective.

This permit shall become effective as of the date of signature.

This permit and its authorization to inject shall remain in effect until midnight January 28, 2024.

____
Catherine A. Libertz, Director
Water Protection Division

PART I

A. Effect of Permit

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The underground injection activity, otherwise authorized by this permit, shall not allow the movement of fluid containing any contaminant into underground sources of drinking water (USDW), if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized in this permit or otherwise authorized by rule is prohibited. Issuance of this permit does not convey property rights or mineral rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with terms of this permit does not constitute a defense to any action brought under Part C and the imminent and substantial endangerment provisions in Part D of the Safe Drinking Water Act (SDWA) or any other common or statutory law for any breach of any other applicable legal duty.

B. Permit Actions

This permit can be modified, revoked and reissued or terminated for cause as specified in 40 CFR §§ 144.12, 144.39 and 144.40. Also, the permit is subject to minor modifications as specified in 40 CFR § 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee shall not stay the applicability or enforceability of any permit condition.

C. Severability

The provisions of this permit are severable, and if any provision of this permit or the permittee's application, dated June 25, 2012, is held invalid, the remainder of this permit shall not by affected thereby.

D. General Requirements

1. Duty to Comply. The permittee shall comply with all applicable UIC Program regulations and conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued under 40 C.F.R. 144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. Need to Halt or Reduce Activity Not a Defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to half or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

3. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

4. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, adequate security at the facility to prevent unauthorized access and operation of the well, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facility or similar systems only when necessary to achieve compliance with the conditions of this permit.

5. Duty to Provide Information. The permittee shall furnish to the Director of the Water Protection Division "(Director"), within a time specified by the Director, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit. If the permittee becomes aware of any incomplete or incorrect information in the Permit Application or subsequent reports, the permittee shall promptly submit information addressing these deficiencies.

6. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law to:

a. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

d. Sample or monitor any substances or parameters at any location, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by SDWA.

7. Penalties. Any person who violates a permit requirement is subject to civil penalties, fines and other enforcement actions under the SDWA and may be subject to the same such actions pursuant to RCRA. Any person who willfully violates permit conditions is subject to criminal prosecution.

8. Transfer of Permits. This permit is not transferable to any person except after notice is sent on EPA Form 7520-7 (Application to Transfer Permit/Ownership) and approval is given by the Director and the requirements of 40 CFR § 144.38 are satisfied. The Director may require modification or revocation of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

9. Signatory Requirements.

a. All reports required by this permit and other information requested by the Director shall be signed as follows:

(1) for a corporation, by a responsible corporate officer of at least the level of vice-president;

(2) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively; or

(3) for a Municipality, State, Federal, or other public agency by either a principal executive or a ranking elected official.

b. A duly authorized representative of the official designated in paragraph a. above may also sign only if:

(1) the authorization is made in writing by a person described in paragraph a. above;

(2) the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or a position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and

(3) the written authorization is submitted to the Director.

c. If an authorization under paragraph b. of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph b. of this section must be submitted to the Director prior to or together with any reports, information or applications to be signed by an authorized representative.

d. Any person signing a document under paragraph a. or b. of this section shall make the following certification:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person(s) who manage the system, or those persons directly responsible for gathering the information, the information submitted is to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

10. Confidentiality of Information.

a. In accordance with 40 CFR Parts 2 (Public Information) and § 144.5, any information submitted to the Director pursuant to these permits may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may take the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 CFR Part 2.

b. Claims of confidentiality for the following information will be denied:

(1) The name and address of any permit applicant or permittee.

(2) Information which deals with the existence, absence, or level of contaminants in drinking water.

11. Reapplication. If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must submit a complete application for a new permit at least 100 days before this permit expires.

12. State Laws. Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation.

PART II

A. General

Copies of all reports and notifications required by this permit shall be signed and certified in accordance with the requirements of Section D(9) of Part I of this permit and shall be submitted to the Director in hard copy, by mail, and in portable document format (*i.e.,* as a ".pdf" file), via e-mail, at the following mailing and/or e-mail addresses:

Source Water & UIC Section (3WD22)
Drinking Water & Source Water Protection Branch
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, Pennsylvania 19103
rowsey.kevin@epa.gov

B. Record Retention

1. The permittee shall retain records of all monitoring and other information required by this permit, including the following (if applicable), for a period of at least five years from the date of the sample, measurement, report or application, unless such records are required to be retained for a longer period of time under paragraph B.2, below. This period may be extended by request of the Director at any time.

a. All data required to complete the Permit Application form for this permit and any supplemental information submitted under 40 CFR § 144.31.

b. Calibrations and maintenance records and all original strip chart recordings for continuous monitoring instrumentation.

c. Copies of all reports required by this permit.

2. The permittee shall retain records concerning the nature and composition of all injected fluids, as listed in Part II, paragraphs C.3. and C.4. of this permit, until three years after the completion of any plugging and abandonment procedures. After three years from the completion of plugging and abandonment, the permittee shall continue to retain these records unless he or she delivers the records to the Director or obtains written approval from the Director to discard the records.

3. Records of monitoring information shall include:

a. The date, exact place, and the time of sampling or measurements;

b. The individual(s) who performed the sampling or measurements;

c. A precise description of both sampling methodology and the handling (custody) of samples;

d. The date(s) analyses were performed;

e. The individual(s) who performed the analyses;

f. The analytical techniques or methods used; and

g. The results of such analyses.

4. Monitoring the nature of injected fluids shall comply with applicable analytical methods cited in Part II, paragraph C.1., below.

5. All environmental measurements required by the permit, including, but not limited to; measurements of pressure, temperature, mechanical integrity (as applicable) and chemical analyses shall be done in accordance with EPA guidance on quality assurance.

C. Monitoring Requirements

1. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. The method used to obtain a representative sample of the fluid to be analyzed and the procedure for analysis of the sample shall be in accordance with test procedures approved under 40 CFR § 136.3 unless otherwise approved by the Director. The permittee shall identify the types of tests and methods used to generate the monitoring data.

2. Injection pressure, annular pressure, flow rate and cumulative volume shall be observed and recorded continuously beginning on the date on which the well commences operation and concluding when the well is plugged and abandoned. The well shall be equipped with an automatic shut-off device which would be activated in the event of a mechanical integrity failure. The permittee shall monitor and record, quarterly, the fluid level from monitoring wells #38281 and #01144 located within the SRC Kane Field. Each of these monitoring wells shall completely isolate the Elk 3 Sand formation from the rest of the wellbore by placement of a monitoring string on a packer set immediately above the Elk 3 Sand formation.

3. The permittee shall sample, analyze and record the nature of the injected fluid for the parameters listed below at the initiation of the injection operation and every two years thereafter, or whenever the operator observes for anticipates a change in the injection fluid (see condition C.4. below).

- pH
- Specific Gravity
- Specific Conductance
- Sodium
- Iron
- Magnesium
- Chloride
- Total Organic Carbon (TOC)
- Manganese
- Total Dissolved Solids
- Barium
- Hydrogen Sulfide
- Dissolved Oxygen
- Alkalinity
- Hardness

4. Any analysis of specific gravity greater than 1.16 and any analysis of TOC greater than 250 mg/l shall be reported to the Director within twenty-four hours of the results.

5. A demonstration of mechanical integrity in accordance with 40 CFR § 146.8 shall, after the initial demonstration, be made at least once every five years. Subsequent five year demonstrations shall be conducted within five years of the date that the previous demonstration was made. In addition to the above requirement, a mechanical integrity test demonstration shall be conducted whenever protective casing or tubing is removed from the well, the packer is reseated, or a well failure is evident. The permittee may continue operation only if he or she has successfully demonstrated to the Director the mechanical integrity of the permitted well. The permittee shall cease injection operations if a loss of mechanical integrity becomes evident or if mechanical integrity cannot be demonstrated. Any such test shall be conducted in keeping with the notification requirements of Permit Condition D.11. of Part II of this permit.

D. Reporting and Notification Requirements

1. Report on Permit Review. Within 30 days of receipt of this permit, the permittee shall report to the Director that he or she has read and is personally familiar with all terms and conditions of this permit.

2. Commencing Injection. The operator of an injection well may not commence injection until construction or well rework is complete and all of the following conditions have been satisfied:

a. The permittee has demonstrated to EPA that the injection well has mechanical integrity in accordance with 40 CFR § 146.8 and the permittee has received written notice from the Director that such demonstration is satisfactory;

b. The permittee has submitted notice of completion of construction (EPA Form 7520-18: Completion Report for Injection Wells) to the Director; and

c.(1) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the permit; or

c.(2) The permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in paragraph (a) of this permit condition, in which case, prior inspection or review is waived and the permittee may commence injection.

3. Twenty-four Hour Reporting.

a. The permittee shall report to the Director any noncompliance which may endanger human health or the environment. The Permittee shall provide such report orally to the Senior Permit Specialist for the Source Water & UIC Section (currently, Kevin Rowsey, 215-814-5463) or to the Senior Field Inspector for the Source Water & UIC Section (currently, David Rectenwald, 814-827-1952) within 24 hours from the time the permittee becomes aware of the circumstances. The following shall be included as information which must be reported orally within 24 hours:

(1) Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water.

(2) Any noncompliance with a permit condition, or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water, or failure of mechanical integrity test demonstrations.

b. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

4. Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

5. Other Noncompliance. The permittee shall report all other instances of noncompliance in writing within ten (10) days of the time the permittee becomes aware of the circumstances. The reports shall contain the information listed in Permit Condition D.3., of Part II of this permit.

6. Planned Changes. The permittee shall give notice to the Director as soon as possible of any planned physical altercations or additions to the permitted facility.

7. Conversion. The permittee shall notify the Director thirty days prior to the conversion of the well to an operating status other than an injection well.

8. Annual Report. The permittee shall submit an Annual Report to the Director summarizing the results of the monitoring required by Permit Condition C within Part II of this permit. This report shall include monthly monitoring records of injected fluids, the results of any mechanical integrity test(s), and any major changes in characteristics or sources of injected fluids. The permittee shall complete and submit this information with its Annual Report EPA Form 7520-11 (Annual Class II Disposal/Injection Well Monitoring Report). The Annual Report shall be submitted not later than January 31st of each year, summarizing the activity of the calendar year ending the previous December 31st.

9. Plugging and Abandonment Reports and Notifications.

a. The permittee shall notify the Director 45 days before the plugging and abandonment of the well. The Director may allow a shorter notice period upon written request.

b. Revisions to the Plugging and Abandonment Plan must be submitted to the Director no less than 45 days prior to plugging and abandonment on EPA Well Rework, Plugging & Abandonment Plan, or Plugging & Abandonment Affidavit Form 7520-19. The Director must approve the revisions prior to the start of plugging operations.

c. Within 60 days after plugging the well, the permittee shall submit a report to the Director which shall consist of either:

(1) A statement that the well was plugged in accordance with the plan previously submitted to and approved by the Director; or

(2) Where actual plugging differed from the plan previously submitted, an updated version of the plan, on the form supplied by the Director, specifying the different procedures used.

The report shall be certified as accurate by the person who performed the plugging operation.

10. Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 30 days following each schedule date.

11. Mechanical Integrity Tests. The permittee shall notify the Director of his or her intent to conduct a mechanical integrity test at least 30 days prior to such a demonstration.

12. Cessation of Injection Activity. After a cessation of injection for two years the owner or operator shall plug and abandon the well in accordance with the Plugging and Abandonment Plan in Attachment 1, unless he:

a. Provides notice to the Director; and

b. Describes actions or procedures, satisfactory to the Director, which the permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. These actions and procedures shall include compliance with the technical requirements applicable to an active injection well unless waived in writing by the Director.

E. Mechanical Integrity Standards

1. Standards. The permittee shall have and maintain the mechanical integrity of the permitted injection well pursuant to 40 CFR § 146.8.

2. Request from Director. The Director may, by written notice, require the permittee to demonstrate mechanical integrity at any time.

PART III

A. Construction Requirements

1. Notwithstanding any other provision of this permit, the injection well shall inject only into formations which are separated from any underground source of drinking water by a confining zone that is free of known open faults or fractures within the Area of Review.

2. Casing and Cementing. The permittee is required to case and cement the well to prevent the movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of the well was designed for the life expectancy of the well. Surface casing has been installed from the surface to a depth of approximately 553 feet, and cemented back to the surface. This exceeds the requirement for surface casing to be cemented to at least 50 feet beneath the lowermost underground source of drinking water, which in this case is 450 feet. The injection zone shall be isolated by the placement of long string casing to approximately 2354 feet, and cemented back at least 100 feet above the injection zone. Injection shall occur through a tubing string and packer installed inside the long string casing and set above the injection zone.

3. Logs and Tests. The logs and tests listed below shall be conducted during the drilling and construction of the well or, in the event that the well is being converted to an injection well, obtain and submit the logs and tests from the well's original construction. A descriptive report interpreting the results (which specifically relate to (1) the lowermost underground source of drinking water and the confining zone adjacent to it and (2) the injection zone and adjacent formations) shall be prepared by a knowledgeable log analyst and submitted to the Director. At a minimum, such logs and or tests shall include the following:

- A cement bond log and variable density log which document the cemented portion of the long string casing.

- A log which documents the location of the surface casing.

- Records documenting the cementing of the surface casing.

- Gamma Ray logs which document the geologic formations in the wellbore.

4. Mechanical Integrity. Injection operations are prohibited until the permittee demonstrates that the well covered by this permit has mechanical integrity in accordance with 40 CFR § 146.8 and the permittee has received notice from the Director that such a demonstration is satisfactory in accordance with the provisions of Condition D.2. located in Part II of this permit.

5. Corrective Action. If necessary, corrective action, in the form of plugging and abandoning wells within the one-quarter mile area of review, which could provide conduits for fluid migration into USDWs, will be completed prior to the authorization of injection. If an abandoned well is discovered within the one-quarter mile area of review after injection commences, the permittee shall notify the Director upon discovery, and within five (5) days, submit to the Director for approval a plan for corrective action and implement the approved plan.

B. Operating Requirements

1. Injection Formation. Injection shall be limited to the Upper Devonian Elk 3 Sand formation in the subsurface interval between approximately 2354 feet and 2403 feet.

2. Injection Fluid. The permittee shall not injection any hazardous substances, as defined by 40 CFR 261, or any other fluid, other than the fluids produced solely in association with Seneca Resources oil and gas production activity.

3. Injection Volume Limitation. Injection volume shall not exceed 75,000 barrels per month.

4. Injection Pressure Limitation. Injection pressure shall not exceed a surface injection pressure maximum of 1416 psi. This pressure calculation is based on the specific gravity of the injection fluid not exceeding 1.16. If the specific gravity of the injection fluid is greater than 1.16, the surface injection pressure will need to be reduced accordingly. Injection at a pressure which initiates new fractures or propagates existing fractures in the confining zone adjacent to underground sources of drinking water or causes the movement of injection or formation fluids into an underground source of drinking water is prohibited.

5. Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited, as is injection into any USDW.

C. Plugging and Abandonment

1. The permittee shall plug and abandon the well in accordance with the approved plugging and abandonment plan in Attachment 1.
2. Plugging and Abandonment shall be conducted in such a manner that movement of fluids will not be allowed into or between underground sources of drinking water.

D. Financial Responsibility

The permittee shall maintain financial responsibility and resources to close, plug and abandon the underground injection well in accordance with 40 CFR § 144.52(a)(7) in the amount of at least $24,650. If the circumstances regarding the acceptability of the Financial Statement, submitted to EPA to demonstrate financial responsibility should change, the permittee shall provide advance notification to the Director, and the Director may seek an alternative financial demonstration from the permittee. The financial statement demonstration must be submitted to the EPA Director on an annual basis for evaluation and approval.

The permittee shall not substitute an alternative demonstration of financial responsibility for that which the Director has approved, unless he or she has previously submitted evidence of that alternative demonstration to the Director and the Director notifies him or her that the alternative demonstration of financial responsibility is acceptable. The Director may require the permittee to submit a revised demonstration of Financial Responsibility if the Director has reason to believe that the original demonstration is no longer adequate to cover the costs of plugging and abandonment.

ATTACHMENT 1

PADEP Well #38268 Record of Decision

A R M G r o u p L L C

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

MEMO

TO Craig Lobins, PG SCL
District Manager
Northwest District Oil and Gas Office
District Oil and Gas Operations

FROM Brian Babb, PG
Professional Geologist Manager
Northwest District Oil and Gas Office
District Oil and Gas Operations

DATE March 20, 2017

RE Seneca Resources Corporation Well Permit No. 047-23835
Class II Disposal Well application to inject waste into an underground formation for disposal
Fee-SRC WT 3771 No. 38628 Highland Township, Elk County

Background

Seneca Resources Corporation ("Seneca") submitted an application to alter the use of the Fee-SRC WT 3771 No. 38628 conventional well, Well Permit No. 047-23835, on November 12, 2014 ("Application"). The location of Fee-SRC WT 3771 No. 38628 well ("Well") is in Highland Township ("Township"), Elk County, off of Lamont Road. The surface landowner at the location is Seneca. The Application proposes to alter the use of the Well from the production of gas in the Elk formation to disposal of waste in the same formation, to a maximum depth of 2530 feet. On January 8, 2015, the Department received a letter from the Township notifying the Department that Highland Township had a local ordinance that prohibited the presence of the proposed underground injection disposal well. On April 6, 2015, Seneca filed a complaint in Federal Court challenging the validity of the Highland Township Ordinance. On August 12, 2015, the Department suspended its review of the Application pending the outcome of the litigation over the Highland Township Ordinance. On August 11, 2016, Seneca notified the department of the rescission of the Highland Township Ordinance and requested the Department take action on the Application. On August 17, 2016, Seneca filed a Petition for Review in the nature of a complaint in mandamus, seeking an order directing the Department to either grant or deny the Application. The matter is pending at docket No. 455 MD 2016. On November 8, 2016, the citizens of the Township voted to adopt a home rule charter that changed the form of government in the Township from a Second Class Township to a Home Rule Municipality. The newly enacted Home Rule Charter prohibits injection wells within the township through Article IV (§ 401) and Article IX. Seneca has commenced an action challenging the legality of the Home Rule Charter.

Application Review

The Department's authority to deny a well permit application is set forth in Section 3211(e) of the 2012 Oil and Gas Act, 58 Pa. C.S. §3211(e). This section provides that "the department shall issue a permit within 45 days of submission of a permit application unless the department denies the permit application for one or more of the reasons set forth in subsection (e.1), except that the department shall have the right to extend the period for 15 days for cause shown upon notification to the applicant of the reasons for the extension." Pursuant to Section 3211(e.1) of the 2012 Oil and Gas Act, the Department may only deny a well permit application for the following six reasons:

§3211 (e.1) Denial of permit. -- The Department may deny a permit for any of the following:

(1) The well site for which a permit is requested is in violation of any of this chapter or issuance of the permit would result in a violation of this chapter or other applicable law.
(2) The permit application is incomplete.
(3) Unresolved objections to the well location by the coal mine owner or operator remain.
(4) The requirements of section 3225 (relating to bonding) have not been met.
(5) The Department finds that the applicant, or any parent or subsidiary corporation of the applicant, is in continuing violation of this chapter, any other statute administered by the Department, any regulation promulgated under this chapter or a statute administered by the Department or any plan approval, permit or order of the Department, unless the violation is being corrected to the satisfaction of the Department. The right of the Department to deny a permit under this paragraph shall not take effect until the Department has taken a final action on the violations and:

(i) The applicant has not appealed the final action in accordance with the act of July 13, 1988 (P.L.530, No.94), known as the Environmental Hearing Board Act; or
(ii) If an appeal has been filed, no supersedeas has been issued.

(6) The applicant failed to pay the fee or file a report under section 2303(c) (relating to administration), unless an appeal is pending. The commission shall notify the Department of any applicant who has failed to pay the fee or file a report and who does not have an appeal pending.

§3211e1(1) *DEP may deny a permit if the well site for which a permit is requested is in violation of any of this chapter or issuance of the permit would result in a violation of this chapter or other applicable law.*

The Department has reviewed the application and has determined that the well site is not currently in violation of Chapter 32, or any other applicable law. The Application meets all applicable distance requirements of 58 C.S. 3215(a) of the 2012 Oil and Gas Act.

Additionally, the Department reviewed the Application in connection with 25 Pa.Code §91.51(Potential Pollution Resulting from Underground Disposal).

Pursuant to 25 Pa.Code §91.51(b), the disposal of wastes into underground horizons is prohibited unless the proposed underground disposal is for an abatement of pollution and it is improbable that the underground diposal would be prejudicial to the public interest and is acceptable to the Department.

The proposed fluid has been recycled for hydraulic fracturing activities to a point where it is not feasible for hydraulic fracturing activities any longer and disposal is necessary. The disposal of this fluid through the proposed injection at the Well is an alternative to the other forms of disposal available. If not disposed at the Well, the fluid would have to be trucked a distance to a properly permitted industrial wastewater treatment facility, publically owned treatment works or another permitted underground injection well. These identified alterantives result in a greater likelihood of pollution to the waters of the Commonwealth, as opposed to the disposal of the fluid at the Well that will result in no pollution to the fresh groundwater.

The Department considered the possible potential pollution and to ensure "the applicant can show by the log of the strata penetrated and by the stratigraphic structure of the region that it is improbable that the disposal would be prejudicial to the public interest." In making this determination, the Department conducted an analysis of the mechanical integrity of the well casing; and a review of the targeted geologic formation and its ability to accept the waste at the pressures proposed without causing a detrimental impact to the environment, the public or the geologic formation, including an analysis of the potential for inducing seismic activity. The mechical intergrity analysis was conducted by Department employee Bruce Jankura P.E., and a technical memorandum setting forth his analysis, conclusions, and recommendations is provided in Attachment A. The geologic analysis was conducted by Department employee Harry Wise P.G., and a technical memorandum setting forth his analysis, conclusions, and recommendations is provided in Attachment B.

The Department determined that the requirments of 25 Pa.Code §91.51(b) have been satisfied and the the issuance of a permit will not lead to a violation of 25 Pa.Code §91.51(b)

As stated above, the Department had previously suspended review of the application pending Seneca's lawsuit against Highland Township regarding the Highland Township Ordinance that prohibited injections wells within Highland Township. Highland Township rescinded the ordinance that sought to prohibit injection wells, resolving the pending lawsuit with Seneca Resources. Subsequently, Highland Township adopted a home rule charter, changing the form of government in Highland Township from a Second Class Township to a Home Rule Municipality. The Home Rule Charter specifically prohibits disposal wells in the municipality through Article IV (§ 401) and Article IX. The Home Rule Charter was not enacted pursuant to the Municipalities Planning Code. The Home Rule Charter is not legally enforceable and therefore would not be an applicable law. Further, the permit will include a special condition indicating that the issuance of the permit by the Department does not alleviate Seneca from otherwise complying with local laws.

<u>§3211e1(2)</u> *The Department may deny a permit if the permit application is incomplete.*

Purusant to 58 Pa. C.S. §3211(b) and 3211(b.1), an application shall include a plat and proof of notification. The Application included a complete plat as required by 58 Pa. C.S. §3211(b) and all required proof of notification as required by 58 Pa. C.S. §3211(b.1).

Additionally, because the Application was submitted as an alteration to the existing production well, to inject waste as a disposal well, additional application requirements are set forth in 25 Pa.Code §78.18(a).

Specifically, 25 Pa.Code §78.18(a) requires an applicant to:

(1) obtain a well permit pursuant to 25 Pa.Code §78.11,
(2) submit the EPA approved UIC Permit and necessary application material and documents pursuant to 40 CFR Part 146,
(3) submit a copy of the control and disposal plan for the well and related facilities pursuant to 25 Pa.Code §91.34 and
(4) submit a copy of the erosion and sedimentation plan for the well site pursuant to 25 Pa.Code §102 and 25 Pa.Code §78.53.

Seneca submitted the EPA approved UIC permit, along with the application material and other related documents under 40 CFR 146, pursuant to 25 Pa.Code §78.18(a)(2).

Seneca submitted the control and disposal plan as required by 25 Pa.Code §78.18(a)(3). Seneca's control and disposal plan must meet the requirements of 25 Pa.Code §91.34, detailing the preventative measures to be utilized to prevent the activity from directly or indirectly reaching waters of the Commonwealth through accidents, carelessness, maliciousness, hazards, weather or other causes. Also, 25 Pa.Code §91.34 indicates that the applicant should address the nature of the disposal activity. Seneca detailed numerous preventive measures to meet the requirements of 25 Pa.Code §91.34, including: training, sound detection, remote access, battery back-up, material compatibility, automatic shut-in, clay absorption material, floor sloping to sumps, emergency shut-off, fire extinguisher, facility fencing, secondary containment, totes for chemicals, pressure monitoring, emergency contacts, cameras, motion lights, access codes for entry and regular inspections. Seneca indicates treatment to protect the injection well and geologic formation, to include oil/water separation, biocide, corrosion and scale inhibitors to reduce potential problematic constituents into the well or waste stream. The fluid has been recycled to a point where it is not feasible for fracking activities any longer and disposal is necessary.

Seneca submitted a copy of the erosion and sedimentation control plan pursuant to 25 Pa.Code §78.18(a)(4). The erosion and sedimentation control plan must meet the requirements of 25 Pa Code Chapter 102 and 25 Pa Code 78.53. The erosion and sedimentation control plan describes the project and earth disturbance activity. The earth disturbance is less than 5 acres, so no Erosion and Sedimentation Control Permit is necessary. This plan indicates soil types and the geologic formations. The limit of disturbance is in an area known to contain acid-producing sulfide minerals. Since the excavation is less than 30 feet below the ground surface, the risk of producing acid drainage is minimal. Seneca indicates that there are no riparian buffers in the limit of disturbance and that thermal impacts are minimized. The area of interest is delineated for streams and wetlands; two wetlands are identified. The project is located in the Wolf Run watershed. Wolf Run is designated as a High Quality, Special Protection Watershed. Anti-degradation, best management plan technologies are proposed that meet the requirements of 25 Pa Code Chapter 102. Specific entry and road designs, along with filter material, vegetation stabilization, energy dissipation and material management plans should meet the requirements of Chapter 102 and 25 Pa.Code §78.53. Several updates were necessary for completeness, consistency and accuracy. Seneca submitted satisfactory revisions promptly and they are included with the submittal. A general review of the topographic map shows a drainage pattern to the south, which is consistent with the erosion and sedimentation plan. Any escaping material will follow this drainage pattern and pose no threat to the Highland Township Municipal Authority located to the north in a different watershed.

A new Pennsylvania National Diversity Inventory (PNDI) receipt was necessary, as the Department is requiring all PNDIs to be updated as of May 4, 2015, to ensure including the updated status for the Long-Eared bat; the bat was not present. No endangered or threatened species were noted on the receipt. Seneca completed two separate PNDI reports with different parameters. One for energy production facilities, and one for waste facilities, to ensure covering all aspects of this facility to the jurisdictional agencies.

The Department's review disclosed that there are no deep mines or gas storage fields in the area. The Departments review of other oil or gas wells within the area of review is consistent with the submittal. There are two other gas wells in the area; both are Seneca wells. One is plugged and the other will be utilized as a monitoring well for the injection activity. The Department does not see a discrepancy with the water supplies indicated in the area of review by Seneca.

The Application is complete and accurate. All portions of the necessary forms have been completed and all necessary submittals required by law and applicable regulations for review have been submitted.

<u>§3211e1(3)</u> *The department may deny a permit if unresolved objections to the well location by coal mine owner or operator remain.*

Coal owners and/or operators can object to the permit with good cause, pursuant to 58 Pa. C.S. §3211e.1(3) of the 2012 Oil and Gas Act, potentially leading to the denial of the permit after sufficient review by the the Department of the issues brought forth by the coal owner/ operator.

The Department did not receive an objection to the well location from a coal mine owner or operator.

§3211e1(4) *The department may deny a permit if the requirements of Section 3225 (relating to bonding) have not been met.*

The operator must secure sufficient bond in accordance with 58 Pa. C.S. §3225 of the 2012 Oil and Gas Act, or risk denial of the permit.

Seneca has provided sufficient bond in accordance with 58 Pa. C.S. §3225. Agreement ID No. 5133 indicates that Seneca has $25,000 Blanket Surety Bond approved on June 15, 2005 for all of their conventional wells including this proposed injection well.

§3211e1(5) *The department may deny a permit if the Department finds that the applicant, or any parent or subsidiary corporation of the applicant is in continuing violatoin of this chapter, any other statute administered by the Department, any regulation promulgated under this chapter or a statute adminstered by the Department or any plan approval, permit or order of the Department, unless the violation is being corrected to the satisfaction of the Department.*

The applicant and its parent or subsidiary corporations must be in compliance as defined by 58 Pa. C.S. §3211e.1(5) of the 2012 Oil and Gas Act. The applicant and its parent or subsidiary corporations must not be in continuing violation of this chapter, any other statute administered by the Department, any regulation promulgated under this chapter or any plan approval, permit or order of the department, unless the violation is being corrected to the department's satisfaction, or risk denial of the permit.

The Department has not taken any final action on any potential compliance issues that Seneca or its subsidiaries, as defined in 58 Pa. C.S. §3211e.1(5), might have incurred as of the date of this decision. Therefore, no baiss for denial of the Applicatoin exist under this subsection.

§3211e1(6) *The department may deny a permit if the applicant failed to pay the fee or file a report under section 2303(c) (relating to administration), unless an appeal is pending. The commission shall notify the Department of any applicant who has failed to pay the fee or file a report and who does not have an appeal pending.*

The applicant must remain in good standing regarding the proper payment of fees and/or required reports pursuant to 58 Pa. C.S. §2303(c) of the 2012 Oil and Gas Act, or risk denial of the permit.

The Department has not been notified that Seneca failed to pay proper impact fee or submit proper reports related to the impact fee pursuant to 58 Pa. C.S. §3211e.1(f) by the Public Utilities Commission ("PUC"). Seneca is in compliance with their impact fee and report requirements as of February 1, 2017, as indicated on the PUC's public website for Act 13 reporting, attached as Exhibit C. Specifically, Seneca is not listed as an operator with outstanding payments.

Summary

The Department issues a permit from a submitted application unless it is denied in accordance with the provisions outlined in Section 58 Pa. C.S. §3211.e.1 of the 2012 Oil and Gas Act. The Department has determined that there is no basis for denial of the Application pursuant to 58 Pa. C.S. §3211.e.1 of the 2012 Oil and Gas Act.

Accordingly, I recommend issuance of Well Permit No. 047-23835, Fee-SRC WT 3771, located in Highland Township, Elk County, with the following special conditions as recommended by Bruce Jankura, Harry Wise and myself, attached as Exhibit D.

Attachment A- Bruce Jankura/ Mechanical Integrity Review
Attachment B- Harry Wise/ Geologic Review
Attachment C- Public Utilities Commission/ Act 13 Compliance
Attachment D- Special Conditions

Attachment- A

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

ATTORNEY WORK PRODUCT; ATTORNEY-CLIENT COMMUNICATION; CONFIDENTIAL AND PRIVILEGED

MEMO

TO S. Craig Lobins SCL

FROM Bruce E. Jankura, P.E.

DATE February 10, 2017

RE Seneca – Elk County Well #38268
Mechanical Integrity Review
EPA UIC Application Documents

MESSAGE:

This is an assessment of the mechanical integrity, for conversion from a production well to an underground injection well, of Seneca's existing gas Well #38268 well in Highland Township, Elk County, Pennsylvania, API # 37-047-23835.

I reviewed all the documents that were submitted by Seneca in a 3-ring binder to PADEP Office of Oil and Gas Management. The cover indicated "Change of Use – Class II Injection Well Permit Application Supporting Documents, API #37-047-23835, US EPA UIC Permit PAS2D025BELK dated November 17, 2014". Various documents were identified as having information pertaining to mechanical integrity. A well is considered to have mechanical integrity when it is in compliance with the well construction and operating requirements of Pennsylvania laws and regulations.

Each document, listed in the "Table of Contents" by Sections and Appendices and Additional Documents, that was determined applicable to mechanical integrity is listed below with comments. My comments are based on 39 years of experience as a Petroleum Engineer and Environmental Regulator.

This well is a vertical, conventional, natural gas well with 9 5/8" conductor pipe set at 63' with 106 sacks of cement and one (1) additional strings of casing cemented in place; surface casing set at 553'and cemented to surface. This well meets the most recent (2011) regulatory requirements for well construction and operation. Based on the Mechanical Integrity data reported for 2014and 2015 (See Table #1) and a review of DEP'S eFACTS database (most recent inspection on 8/11/08, see Table #2), this well has no outstanding issues or violations. Additional information regarding the construction and operation of this well is set forth below.

Section 1 – Area of Review Methods/Calculations – Tetra Tech Technical Memorandum – Draft June 14, 2012 – This Document includes the statement, "...we believe the well is an excellent candidate for use as a brine disposal well."

– Under the document tab; "Notice of Deficiency and Response", Seneca provided a letter dated June 13, 2013 and titled, "Response to Request for Additional Information dated May 8, 2013". This request was made by EPA via email and telephone communication, which were not provided with the documents I reviewed. The request was for , "…information regarding reservoir pressures in the Elk 3 reservoir as well as any available production information to support our statement that the Elk 3 reservoir is depleted." Seneca provided a pressure plot for seven (7) wells titled, "Elk 3 Reservoir Pressures Over Time, Highland Township, Elk County, PA" and a table for five (5) wells titled, "Estimated Cumulative Gas Production For Selected Wells Near Seneca Well #38268". Seneca makes the statement, "The Elk 3 Sandstone is a depleted reservoir, as evidenced by the reservoir pressure decline curves and significant volumes of gas produced since 1898."

Comment – Converting depleted reservoirs to water disposal zones is a common practice throughout the oil & gas industry. Based on my review of the data presented above, it is apparent that there has been sufficient pressure depletion and gas production from the Elk 3 reservoir to consider it significantly depleted. It is reasonable to consider this formation a candidate for conversion.

Section 2 – Maps of Well Area and Area of Review

– "The only active oil and gas well located within ¼ mile of the Seneca Well #38268 is Seneca Well 38281 located approximately 0.2 miles to the southwest (drilled in 2008; notched and frac'd). A plugged gas well, Seneca Well #01328, is located approximately 1320 ft southeast of the proposed injection well (drilled in 1902, shot with nitroglycerin, plugged in 1991)."

Comment – Both of these wells penetrated the zone of injection. Well #38281 is planned to be used as a monitoring well, which is reasonable. Well #01328 was plugged under recent regulatory requirements in 1991 that should provide adequate wellbore seals and environmental protection.

Section 3 – Corrective Action Plan and Well Data

– "As discussed further in Section 8, Well #38281 will be utilized as a monitoring well and is properly constructed for that purpose."

Comment – See comment under Section 8.

– "This well (#01328) has been properly plugged and abandoned; therefore, no additional corrective action is necessary within the AOR."

Comment – The "Certificate Of Plugging Well", dated 2-6-91, indicates; the well plugging was completed on 2-12-91 and 5 cement plugs were set at various depths, ranging from 30' to 350' in length. These plugs should be adequate to provide an effective seal within the wellbore, at a distance of 1,320' away from the injection well. This distance is equal to 1/4 mile, which is the radial length for the Area of Review. Four (4) of the plugs appear to be at depths above the proposed injection zone. I concur that no additional corrective action is necessary within the AOR, at this time.

– Seneca provided the "Well Record and Completion Report" (WRAC) and other data for the wells #38268 (injection) and #38281 (monitor).

Comment – The reports and data for both wells indicate;
1.The geologic "Formation" names wherein the #38268 has an Elk 4 interval (also depicted in the notes on the electric log provided), but no Elk 3 and the #38281 has an Elk 3, but no Elk 4. In section 1, the Tetra Tech letter says, "Brine disposal via injection well would take place into the Elk 3 Sandstone." So there appears to be a discrepancy of planned injection into the Elk 3, but no Elk 3 formation described in the #38268 injection well.

2.The hole sizes drilled for each casing string are adequate or exceed regulatory requirements.

3.The size of casings installed are adequate.

4.The casing shoe set depths to protect fresh water sources are adequate.

5.The cement blends used to cement the surface casing strings were adequate.

6.The cement returns to surface during the surface casing string cement jobs (7 barrels on the #38268 and 6 barrels on the #38281) are indicators of good cement jobs.

Section 4 – Name and Depth of USDWs

– "It is noted that surface casing for the proposed injection well extends to 553 feet, which is greater than 200 feet deeper than the deepest groundwater drinking source in the Tri-Township Area."

Comment –The surface casing program is adequate and meets the regulatory requirements.

Section 5 – Geologic Data

– "Maximum Injection Pressure Calculations"

Comment – The value for the ISIP (1,580 psi) is appropriate, as shown on the "Frac Data" plot dated 4/5/07 for the #38268 well. If the frac displacement fluid had a hydrostatic gradient of fresh water (which is typical for frac work), then the fracture gradient value of 1.104 psi/ft is reasonable. Using this value and a 1.14 specific gravity (equating to a 9.2 pound per gallon weight fluid) for the proposed injection fluid, then the Maximum Injection Pressure Calculation value of 1,437 psi is reasonable. See below, the "Notice of Deficiency and Response" documents for EPA Comment 3 – Revising the Maximum Injection Pressure (MIP).

Section 6 – Operating Data

– Various parameters are listed for the proposed injection operation.

Comment – The critical parameter listed here is the Maximum Allowable Surface Injection Pressure (MASIP) of 1,437 psi. This will be the controlling factor, not the injection flow rate. As the pressure increases toward the maximum, the injection rate will have to be reduced to stay below the MASIP. Based on Chart B dated 4/5/2007 for the last pumping stage of the hydraulic fracturing treatment, Seneca's proposed injection rates appear reasonable.

Section 7 – Well Construction – Injection Well Configuration

– Well construction diagrams for #38268 and #38281 were provided.

Comment – Both documents are basic depictions of the well and casing program. Additional details are provided in Section 8.

Section 8 – Monitoring Program and Monitoring Program Addendum (dated January 23, 2013)

– From the addendum; "Wells #38281 and #1144, located 1,090 feet southwest of the subject injection well and 2,040 feet northwest of the subject injection well, respectively, will be utilized as monitor wells for injection at Well #38268."

Comment

1.These documents describe subsurface casing and cementing modifications for all three (3) wells mentioned above and pressure/liquid level monitoring procedures. The installation of cemented 4½" casing in both the #1144 and #38268 and installing 4½" casing on a packer in the #38281 are adequate to effectively isolate the Elk 3 interval in the respective wellbores for injection and monitoring.

2.Detailed pipe strength data is not provided, but the common oilfield tubulars used in northwest PA are expected to have adequate internal yield pressure ratings for the tubing and production casing that would contain the proposed maximum injection pressure of 1,437 psi. Seneca should provide the detailed tubular specifications for the injection well #38268. See Recommendations below.

3.The #38268 well is currently in regulatory compliance based on a review of the PADEP eFACTS system.

4.A routine site inspection should be conducted on the #38268 well by the PADEP Oil & Gas Inspector to confirm the well status prior to initiation of injection. See Recommendations Below.

Section 9 – Plugging and Abandonment Plan

– "At the point when the well is no longer used, the well will be abandoned in accordance with EPA and PADEP regulations."

Comment – The Plugging and Abandonment Plan, cost estimate and cement plug set depths appear adequate.

Section 11 – Plan for Well Failures

– "Pressure will be measured in the annulus between the 4½"-inch casing and tubing and continuously monitored during injection at Well #389268. Should a pressure increase occur in the monitored space, injection will cease and EPA will be verbally notified within 24 hours and notified in writing within 7 days."

Comment – This plan outline is reasonable. Note that there are three (3) levels of protection for the USDW's in the Area of Review considering the path from the perforations up through the (1)tubing/packer/wellhead system, (2)4 ½" casing proposed for installation and (3) existing surface casing. Seneca should specify the pressure setting for the annular space that will cease injection. See Clarification #4 below on page #7.

EPA Approval Notices - EPA UIC Permit & EPA Response to Summary Comments

– In Part II, D.2.b. of the UIC Permit, Seneca is required to meet the following condition; "The Permittee has demonstrated to EPA that the Injection Well has mechanical integrity in accordance with 40 CFR § 146.8 and the Permittee has received written notice from the Director that such demonstration is satisfactory; and..."

Comment – There is no reasonable need to duplicate this demonstration of mechanical integrity prior to initiating injection. I recommend that, prior to commencing injection, Seneca provide DEP with the documentation showing how they complied with this provision of the EPA UIC Permit. See Recommendations below.

Notice of Deficiency and Response

– Seneca's August 16, 2012 Response to EPA's Notice of Deficiency (Dated August 2, 1012) provided the original EPA comments and their responses. Only the EPA comments applicable to mechanical integrity with responses that prompted additional comments are addressed below.

EPA Comment 3 – Revising the Maximum Injection Pressure (MIP).

Comment – Seneca revised the MIP for the EPA requested injection fluid specific gravity value of 1.16 (versus the original 1.14 average value preciously used). The revised MIP is 1,416 psi and is a reasonable value. Seneca repeats this information in their response dated August 29, 2012.

EPA Comment 4 – Modifications to well #38281 for monitoring; EPA suggested "A preferable alternative would be to install cemented long string in order to isolate the injection zone."

Comment

1.Seneca' response indicates, "… (Seneca) is not willing to sacrifice the reserves in Well #38281 at this time to serve as a full time observation well." But would at a later time, "If, over time, this well became "flooded out" from nearby water injection, we would then be willing to isolate the Elk Sand, and monitor pressures and water levels from that point forward." Seneca repeats this information in their response dated August 29, 2012. It is not clear when Seneca modified its position on well #38281to install 4 ½" casing on a packer, set above the Elk 3, but the language to do this is included in Section 8 above, reviewed previously.

2.In Seneca's Response Dated February 4, 2013, "Addendum to Permit Application", a revised "Section 8 – Monitoring Program" is attached. The language has been revised for the second half of paragraph 1 to modify the 4 ½" casing and 2 7/8" tubing pressure monitoring scenario for Well #36268 with the addition of an automatic high pressure shut off device. This is an appropriate revision.

Mechanical Integrity Info Clarifications

1. Corrective Action Plan and Well Data. Clarify the apparent discrepancy of planned injection into the Elk 3 formation, but no Elk 3 formation described in the #38268 injection well.

   Clarification – 6/6/15 email - When the well was originally drilled, the Seneca geologist at the time interpreted the reservoir of interest as "Elk 4". Subsequent interpretation by other Seneca geologists reclassified the target reservoir as "Elk 3". Therefore, the target reservoir is called "Elk 3" in all of our application documents.

2. Seneca should provide all the detailed tubular specifications for the injection well #38268 and monitoring wells.

   Clarification – 3/7/16 emial –

   Disposal well # 38268

   Casing: We are planning to run 4.5" 10.5lb./ft. J55 casing on disposal well. Collapse pressure is 4,010 psi and Burst pressure is 4790 psi

   Tubing: We are planning to run 2 3/8" 4.70 lb./ft. J-55 Tubing on disposal well. Collapse pressure is 8100 psi and Burst pressure is 7700 psi

   Monitoring well #1144:

   Casing: We will check the integrity of existing 6 1/4" surface casing and based upon the surface casing integrity, we will run 3.5" production casing cemented to surface or pull 6 1/4" surface casing and run 6 5/8" surface casing and 4 ½" production casing cemented to the surface.
   If we decide to install 3 1/2" casing, we will run 3.5" 9.2 lb./ft. J-55 casing. Collapse pressure is 7400 psi and Burst pressure is 6980 psi.

If we decide to install 6 5/8" surface casing and 4 ½" production casing, we will run 6 5/8" 20.00 lb./ft. J55 surface casing and 4.5" 10.5lb./ft. J55 production casing. Collapse pressure and Burst pressure for 6 5/8" surface casing is 2970 psi and 4180 psi respectively. Collapse pressure and Burst pressure for 4 ½" production casing is 4,010 psi and is 4790 psi respectively.

Tubing: No tubing

Monitoring well #38281:

Casing: We are planning to run 4.5" 10.5lb./ft. J55 casing. Collapse pressure is 4,010 psi and Burst pressure is 4790 psi

Tubing: No tubing

3. Verify the ISIP of 1580 psi on the Frac Data chart for well #38268 dated 4/5/07. There appear to be 2 pressure drops near the end of pumping. Pumping appears to be ongoing at the 1580 psi level for several minutes, then drops to a pump rate of zero where the pressure drops to approximately 1100 psi. Also, confirm the type of operation that was being performed and describe the fluid in the casing, ie. frac job, injection test.

   Clarification – 3/7/16 email – The chart that we sent earlier (attached Chart A) is from stage one of the planned eleven stage frac job.

   From the chart that we sent earlier (attached Chart A) the drop in pressure at 24 mins is due to the frac breaking around to other zones in Elk 4. The next seven stages (2-8) also showed signs of communication and were completed as one stage. The next three stages (9-11) broke around as well and communicated with other stages. The attached Chart B shows the last frac job where we treated all eleven stages from up above stage one and we saw 1580 psi post frac ISIP.

4. Specify the pressure setting for the 4½" casing by tubing annular space at Well #38268 and the pressure deviation setting that will cease injection.

   Clarification – 3/7/16 email - We would maintain zero psi pressure on the casing by tubing annulus during operations, if the pressure reaches 300 psi, we will bleed it off to zero psi. Resume injection and monitor pressure. If the pressure exceeds 500 psi we will perform diagnostics to assess the integrity.

Overall Mechanical Integrity Review Assessment

Mechanical Integrity for the Seneca – Elk County Well #38268 gas well:

In my opinion, based on the data reviewed and proposed well upgrades, the mechanical integrity of the Seneca – Elk County Well #38268 is adequate for conversion from a production well to an underground injection well.

The Seneca – Elk County Well #38268 is currently in compliance with the well construction and operating requirements of Pa Code Title 25 Ch78.

Recommendations

These recommendations are additions to the proposed Seneca procedures and EPA UIC Permit requirements.

1. Any stimulation treatment plan should be reviewed by the Department prior to implementation.

2. Provide, on a monthly basis to the DEP, injection pressures, annular pressures, injection rates and cumulative volume; in both digital and graphical formats. All pressures and rates should be monitored continuously.

3. An inspection of the well site and well must be conducted by the PADEP Oil & Gas Inspector to confirm the well status and wellbore mechanical integrity including annular pressure readings, prior to initiation of injection.

4. Prior to commencing injection, Seneca should provide DEP with the documentation showing how they complied with provision Part II, D.2.b. of the EPA UIC Permit, demonstrating that the well has mechanical integrity.

5. DEP should be notified in the same fashion as EPA when conditions indicate mechanical integrity problems, which call for injection to cease and EPA to be verbally notified within 24 hours and notified in writing within 7 days.

cc: John Ryder

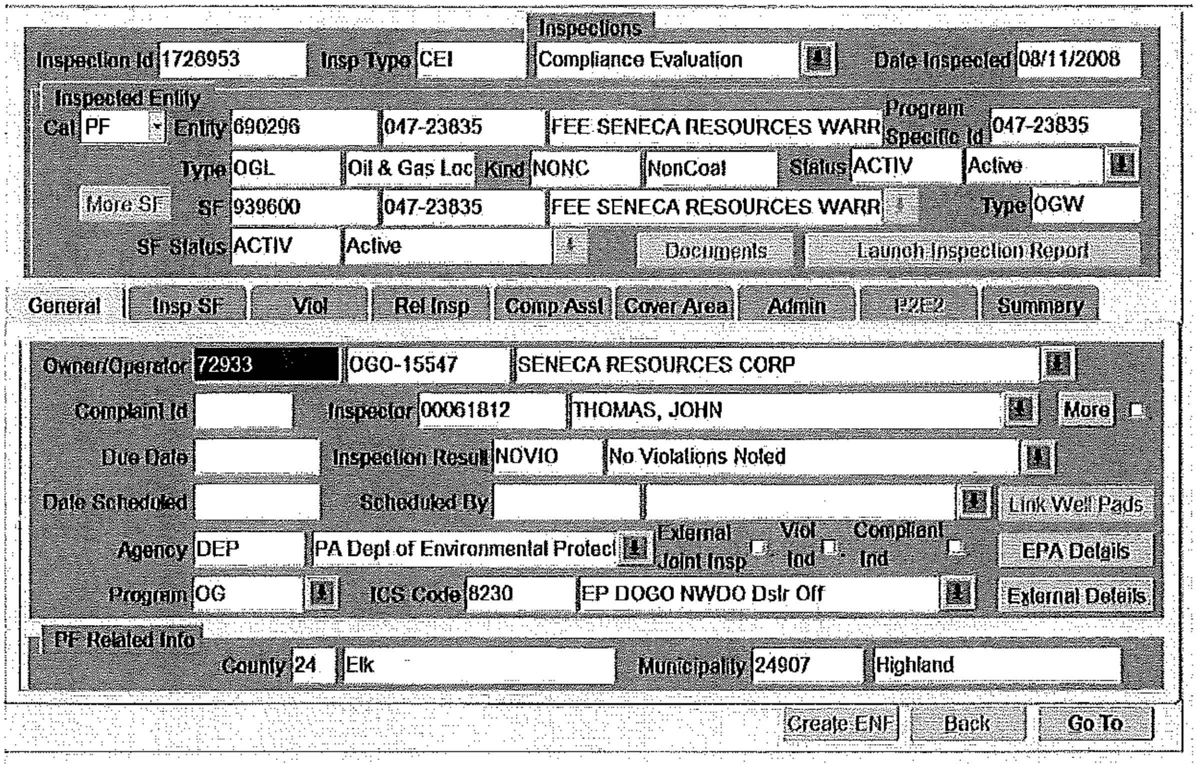
<u>Table #1</u> – Seneca #38268 Mechanical Integrity Report – 2014 and 2015

OPERATOR	OGO	PERMIT_API	INSPECTION_YEAR	INSPECTION_DATE	RECEIVED_DATE	FORM_ID	DOCUMENT_CATEGORY	PRIMARY_PRODUCTION_PRESSURE_PSIG	PRODUCTION_OPEN_VENT_FLOW	PRODUCTION_OPEN_VENT_FLOW_UNIT_CFPD	ANNULAR_PRODUCTION_PRESSURE_PSIG
SENECA RESOURCES CORP	#	047-23835	2015	12/1/15	2/12/2016	C	DEP Integrity Short Form C	14		NA	
SENECA RESOURCES CORP	#	047-23835	2014	10/1/14	2/11/2015	C	DEP Integrity Short Form C	12		NA	

MAX_ALLOWABLE_PRESSURE_EXCEEDED	WATER_LEVEL_OR_OTHER	WATER_LEVEL_OR_OTHER_UNIT_VARIOUS	PRODUCTION_ANNULUS_OPEN_FLOW OR SHUT_IN_PRESSURE	PRODUCTION_ANNULUS_OPEN_FLOW_OR_SHUT_IN_PRESSURE_UNIT_CFPD_OR_PSIG	FLUIDS_NOTED	OPEN_FLOW_OUTSIDE_FRESHWATER_CASING	OPEN_FLOW_OUTSIDE_FRESHWATER_CASING_UNIT_CFPD	OPEN_FLOW_OUTSIDE_INTERMEDIATE_CASING	OPEN_FLOW_OUTSIDE_INTERMEDIATE_CASING_UNIT_CFPD	SURFACE_WELLHEAD_EQUIPMENT_EMISSION_RATE	SURFACE_WELLHEAD_EQUIPMENT_EMISSION_RATE_UNIT_CFPD
NA			0	cfpd	N		NA		NA		NA
N			0	cfpd	N		NA		NA		NA

SURFACE_WELLHEAD_EQUIPMENT_EMISSION_RATE	SURFACE_WELLHEAD_EQUIPMENT_EMISSION_RATE_UNIT_CFPD	LIQUIDS_TO_SURFACE_OR_OUTSIDE_FRESHWATER_CASING	CORROSION_PROBLEMS	COMMENTS	STANDARD_COMMENTS_FOR_NO_INSPECTION	FILE_NAME	REGION	COUNTY	MUNICIPALITY	UN-CONVENTIONAL	WELL_TYPE
	NA	N	N			PA_DEP_In	EP DOGO NWDO Dstr Off	Elk	Highland	No	MULTIPLE WELL BORE TYPE
	NA	NA	N			PA_DEP_In	EP DOGO NWDO Dstr Off	Elk	Highland	No	MULTIPLE WELL BORE TYPE

Table #2 – DEP eFACTS Inspection Report Dated 8/11/08



Inspections

Inspection Id 1726953 | Insp Type CEI | Compliance Evaluation | Date Inspected 08/11/2008

Inspected Entity

Cat PF | Entity 690296 | 047-23835 | FEE SENECA RESOURCES WARR | Program Specific Id 047-23835

Type OGL | Oil & Gas Loc | Kind NONC | NonCoal | Status ACTIV | Active

More SF | SF 939600 | 047-23835 | FEE SENECA RESOURCES WARR | Type OGW

SF Status ACTIV | Active | Documents | Launch Inspection Report

General | Insp SF | Viol | Rel Insp | Comp Asst | Cover Area | Admin | P2E2 | Summary

Owner/Operator 72933 | OGO-15547 | SENECA RESOURCES CORP

Complaint Id | Inspector 00061812 | THOMAS, JOHN | More

Due Date | Inspection Result NOVIO | No Violations Noted

Date Scheduled | Scheduled By | Link Well Pads

Agency DEP | PA Dept of Environmental Protect | External Joint Insp | Viol Ind | Compliant Ind | EPA Details

Program OG | ICS Code 8230 | EP DOGO NWDO Dslr Off | External Details

PF Related Info

County 24 | Elk | Municipality 24907 | Highland

Create ENF | Back | Go To

Attachment- B

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

MEMO

TO S. Craig Lobins SCL

FROM Harry C. Wise, P.G. HCW

DATE February 8, 2017

RE Seneca Resources – Elk County Well #38268
Geological Review
EPA UIC Application Documents

MESSAGE:

Analysis
This technical review is in response to a request from John Ryder to assess the geologic structure and setting associated with Seneca Resources' (Seneca) gas well (Well #38368) in Highland Township, Elk County, Pennsylvania, API # 37-047-23835. The well formerly served as a production well and is a candidate for conversion to an underground injection control (UIC) well. The intent of the analysis is to determine the suitability for conversion.

I reviewed all the documents submitted by Seneca to the Pennsylvania Department of Environmental Protection's Office of Oil and Gas Management (Department) as part of the UIC permit package. The permit package is titled "Change of Use – Class II Injection Well Permit Application Supporting Documents, API #37-047-23835, United States Environment Protection Agency (EPA) UIC Permit PAS2D025BELK dated November 17, 2014". Various documents were identified as having information pertaining to local geologic structure and setting.

The discussion that follows is based on my experience as a Professional Geologist and environmental regulator.

The proposed UIC well (Well #38268) served as a former gas production well targeting the Elk 3 Sandstone. Seneca has indicated that the Upper Devonian siltstones, shales and sands between 635 feet and 2354 feet below existing site grades would effectively serve as a stratigraphic seal (confining zone). In EPA's Notice of Deficiency, further clarification regarding the confining zone for the proposed injection well was requested. Seneca noted in their response that the Elk 3 Shale, at a depth interval from 2,328 feet to 2,354 feet below existing site grades, would act as the confining zone for the proposed injection well. In addition, Seneca notes additional shales, silty shales and siltstones above the Elk 3 shale that would serve as confining zones, isolating the injection zone from the interval of the subsurface bearing fresh groundwater. Seneca Resources described the Elk 3 Shale as a silty shale zone.

The Department reviewed a petrophysical log as required by *§ 91.51. Potential pollution resulting from underground disposal* submitted via email by Seneca on June 6, 2015. The data corroborates Seneca's identification of a sandy injection zone and shows that there is a silty to shaly sequence of rocks directly above the injection zone (between 2,352 feet and 2,404 feet). The petrophysical log also identifies confining (shaly) zones that are present between 2,144 and 2,210 feet below site grades.

The Department's analysis of Alleghanian structures confirms the presence of an anticlinal trap structure – the Simpson Anticline is located within the quarter-mile and mile radius areas of review. The presence of anticlinal/synclinal pairs is commonly associated with structural deformation features throughout the Appalachian fold belt/plateau of Pennsylvania. (Figure 1).

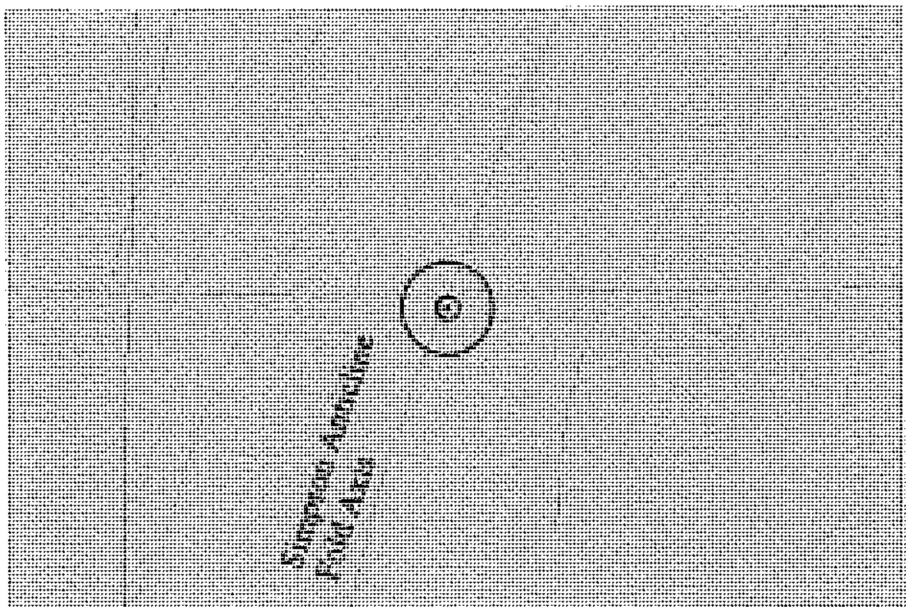


Figure 1. Alleghanian folds near well site. Well surrounded by quarter-mile and one-mile buffers.

It is my professional opinion that the injection horizon and surrounding strata result in suitable geologic structure and stratigraphy for waste disposal via underground injection. There are no concerns related to containment.

The Department's review of operating and plugged wells within a quarter-mile radial distance confirmed the information provided by Seneca in their application. The only operating well that penetrates the produced horizon is a Seneca owned well. This well is API# 047-23884, located 0.21 miles southwest of the site. This well extends to a total depth of 2,544 feet.

A plugged well, API# 047-00449/Seneca Well #01328; (the Department's eFACTS operator is listed as National Fuel Gas Supply Corporation) is located 0.21 miles east-southeast of the site. This well was plugged in February 1991 and the plugging certificate was approved by DEP in March 1991. Ninety (90) sacks of cement were used to plug the gas-bearing zone from 2,100 feet to 2,431 feet (Figure 2).

Seneca did not perform a one-mile radial review of wells in their application to EPA. EPA did not comment in their Notice of Deficiency that this was necessary. The Department's review identified 31 additional wells within a 1-mile radial search area. These wells include 14 active wells, 8 plugged wells, 4 DEP Orphan list wells and 5 wells that were reported as proposed but never drilled by the operator (Figure 2). Some wells just outside the quarter-mile radial review area are noted in Seneca's Preparedness, Prevention, and Contingency (PPC) Plan and Seneca's Response to Request for Additional Information dated May 8, 2013.

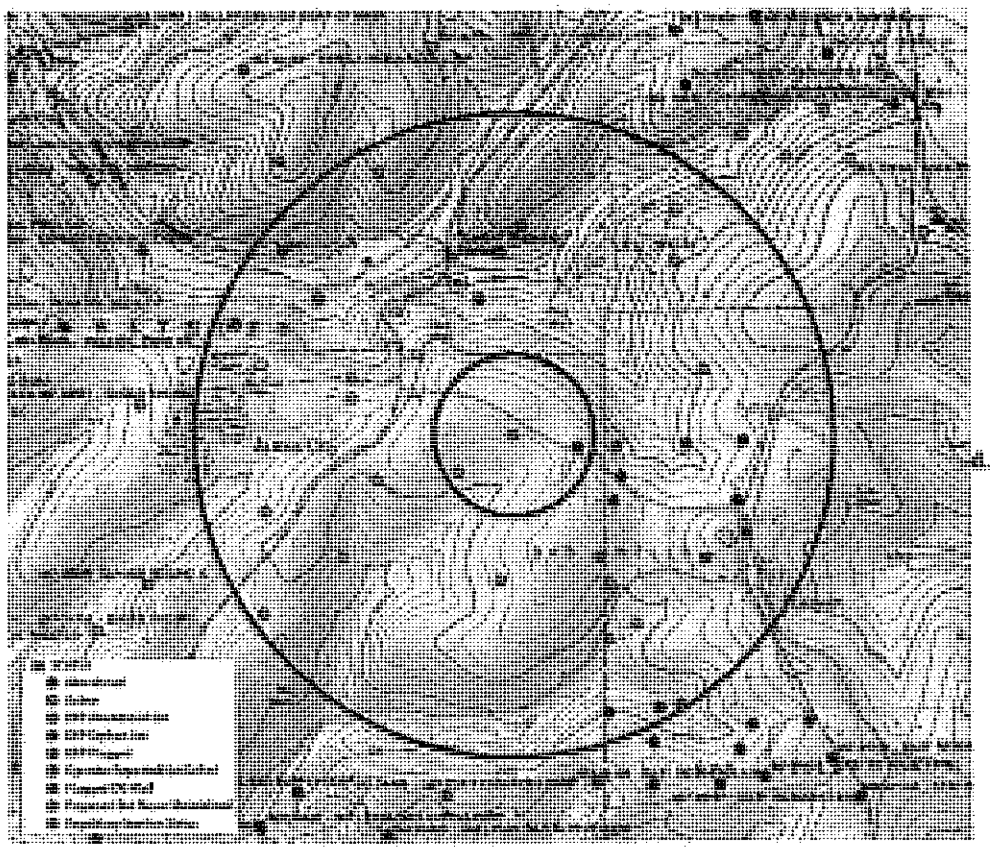


Figure 2. Surrounding conventional wells with the quarter-mile and one-mile buffers depicted.

A search was completed for historic and other well sites not in the Department's eFACTS database. No wells not already listed in eFACTS are located within the quarter mile-radial distance around the proposed injection site. There are four wells not listed in eFACTS that are within the one-mile radial distance of the proposed well site (Figure 3). Three of these wells (red symbols) are listed as plugged and abandoned (API #'s 047-21639, 047-21442 and 047-20609). The other well is listed as active (blue symbol) and the API# is 047-21054. This well is listed as belonging to Seneca.

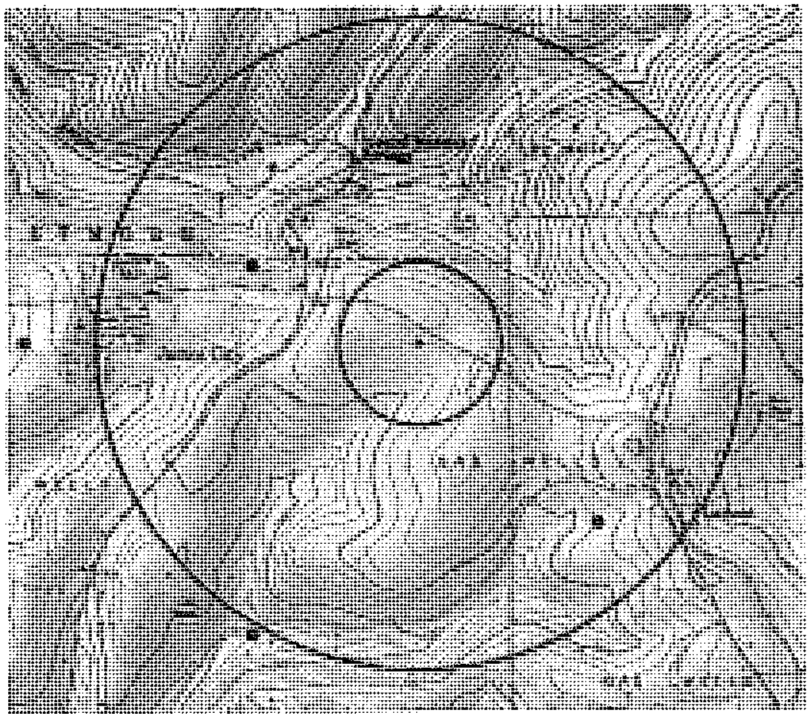


Figure 3. Historical well information with the quarter- and one-mile buffers depicted.

It is my professional opinion that there are no concerns related to the suitability of the caprock, or seal, created by ongoing and legacy oil and gas production activities in the vicinity of the proposed UIC well location.

The Department's review indicates there are no mapped faults or structural fronts in the quarter- and mile-radius areas of review (Figure 4). The Department could not find a review of the geologic structure in Seneca's application to EPA. The nearest fault is identified as an "Unnamed Structural Fault", approximately 13 miles to the southeast of the site. It appears the faulting is roughly coincidental with the folding classified as an anticlinal axis. Faulting is often noted in association with structural deformation features such as the anticline/syncline pairs common throughout the Appalachian fold belt/plateau of Pennsylvania.

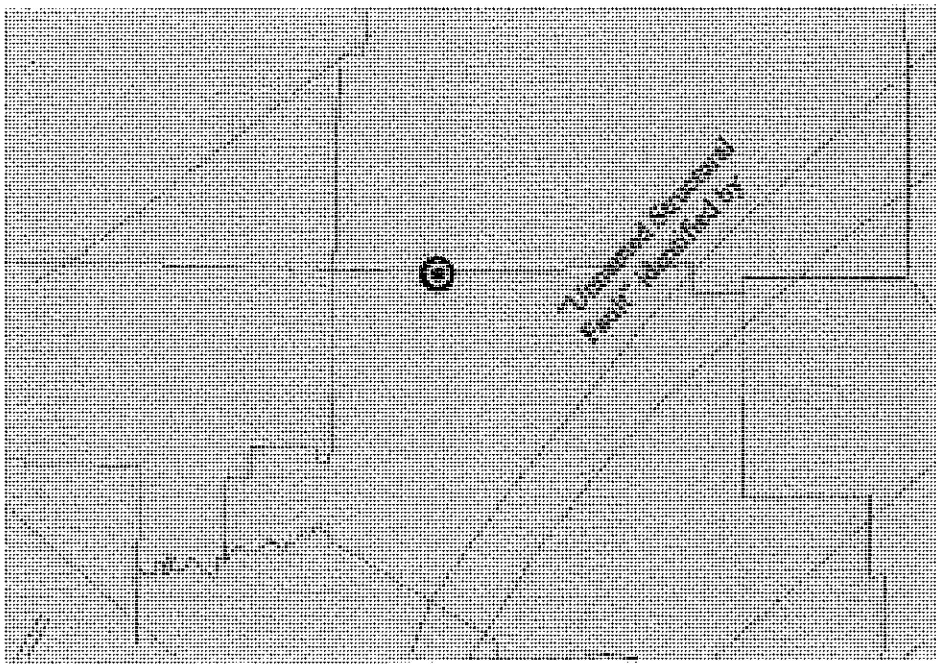


Figure 4. Faults located near the proposed well site.

The Department's review indicates there are no historical seismic events within the quarter- and one-mile radius area of review (Figure 5). There have been no recorded earthquakes of 2M or greater within Elk and McKean Counties.

It should be noted that EPA reports induced seismicity associated with injection wells in Ohio resulted from injection into Precambrian basement rock. These rocks are often cross-cut by blind faults and are crystalline in nature. Additional studies by the state of Oklahoma (http://earthquakes.ok.gov/) and within the geologic community appears to corroborate the belief that injecting fluid into brittle, crystalline basement rock can induce seismicity. The Department could not find where Seneca's application addressed any seismic concerns and the EPA did not address this in the Notice of Deficiency. As part of its review, the Department analyzed maps showing the basement rock (depth of approximately 12,000 feet to 13,000 feet) and the injection zone (depth of 2,328 feet to 2,354 feet) for this well and estimated a vertical offset distance of approximately 9,600 to 10,600 feet (Figure 6).

Induced seismicity relating to the operation of injection wells results from the interrelationship of factors such as depth to basement rock, distance to existing faults, fault plane orientation and pore pressure regimes. This geologic analysis has not revealed indicators suggestive of a heightened potential for induced seismicity. Based upon the review of all available information, it is my professional opinion that injection activities at this well pose a low risk with regard to induced seismicity. It is recommended that this risk be managed through the application of permit conditions addressing seismic monitoring and mitigation.

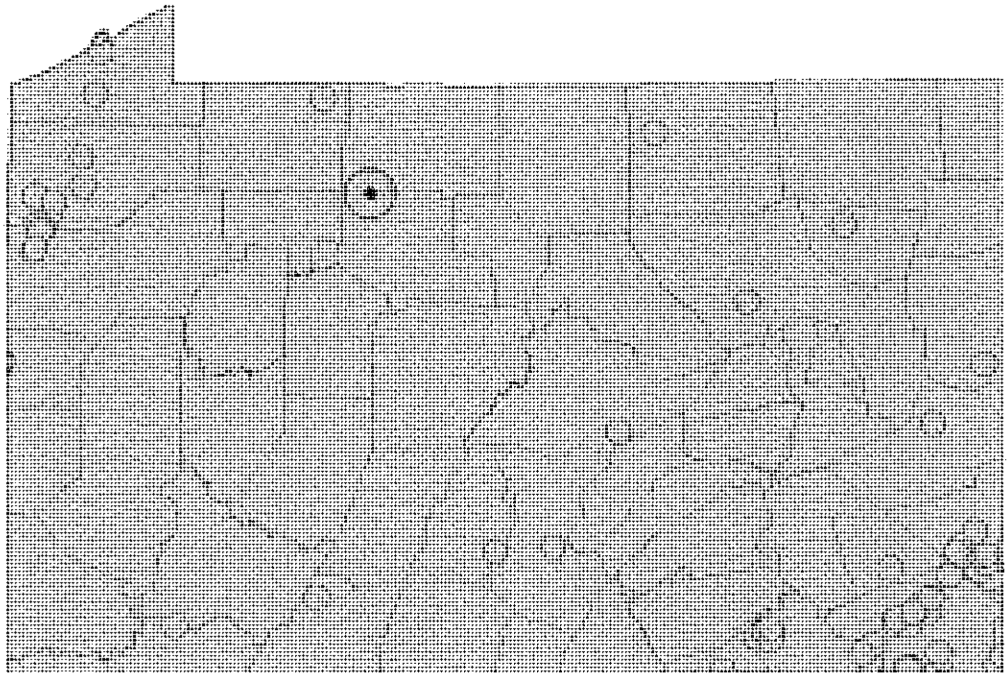


Figure 5. Seismic activity map showing 3-mile buffers around Magnitude 2 or greater earthquakes.

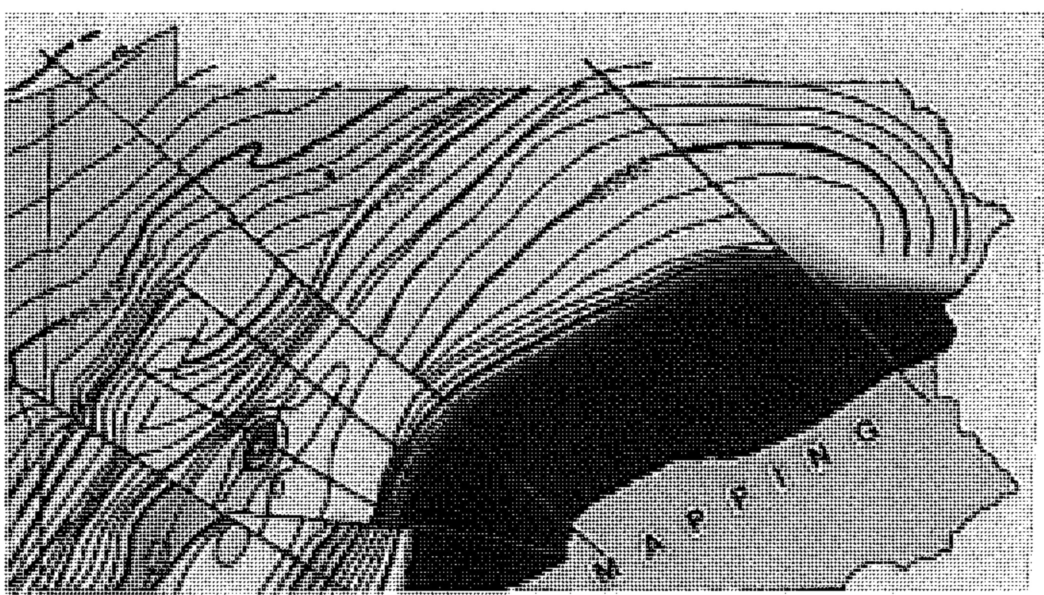


Figure 6. Depth to Precambrian crystalline basement rock. UIC well site (pink circle)

The Department's review indicates the closest storage well (API # 083-04492) is located approximately 5.7 miles northwest of the proposed injection well site. There is an active storage field (East Branch A) located approximately 6 miles northwest of the site and an abandoned storage field (McKinley) approximately 3 miles southwest of the site (Figure 7). Since the East Branch A Storage Field is approximately 6 miles northwest of the site, and outside the ¼ mile radius of review, it is not expected to be of concern. The Department's review indicated a proposed injection well within the 1-mile radius of review; however, this well is listed as proposed but was reportedly never drilled.

The Department's review indicates there is no surface or underground mining within the quarter- and one-mile radius area of review (Figure 8).

The Department's review indicates there are active municipal water wells/springs associated with Highland Township Municipal Authority within the 1-mile radius of review which were identified in Seneca's Addendum to Permit Application to EPA, dated October 2, 2012. These wells are located north to northwest of the site (Figure 9). In Seneca's application to EPA, two (2) alleged water wells were identified within the 1-mile radial area of review. The first of these was documented by Seneca as the deepest USDW well and it is completed at a depth of 130 feet below existing site grades and serves as a domestic water supply well belonging to Randy Klaiber. The second well, which is completed at a depth of 2,389 feet below existing site grades, belongs to National Fuel Gas Supply Corporation. Seneca identifies the latter well as a gas test well, and not a drinking water well. Additional private water wells were identified in Seneca's PPC Plan within the one-mile radial area of review. The Department could not find any discussion on these wells within the application or addendum. Seneca does note in the Addendum to Permit Application that they have reviewed water well depths throughout Highland and Jones Township of Elk County and Wetmore Township of McKean County and found the deepest groundwater well to be approximately 320 feet below site grades. The surface casing set depth for the proposed injection well is 553 feet below site grades. The Department concurs with Seneca's assessment that the casing set depth is adequate provided the casing and cementing requirements of 25 Pa. Code Chapter 78, Subchapter D are met.

<u>Regarding local water supplies:</u>

- It is recommended that the location, depth and use of any additional private water wells detailed in Seneca's PPC Plan be confirmed by the Department.

- It is recommended that the location and usage of the well identified by Seneca as belonging to National Fuel Gas Supply Corporation be confirmed by the Department as a test gas well and not a water well.

Once the location, depth and usage of the aforementioned wells are confirmed, the Department should ensure the casing and cementing design of the proposed injection well satisfies the requirements of 25 Pa. Code Chapter 78, Subchapter D by completing an engineering assessment of the well's construction characteristics and integrity. If no issues are noted during the review, it is my professional opinion that there is no expected risk to surrounding water supply wells provided injection well integrity is maintained per the requirements of EPA's UIC Program. This belief is due to the required construction of the well, the geology, and the distance of these features to the well and its injection horizon.

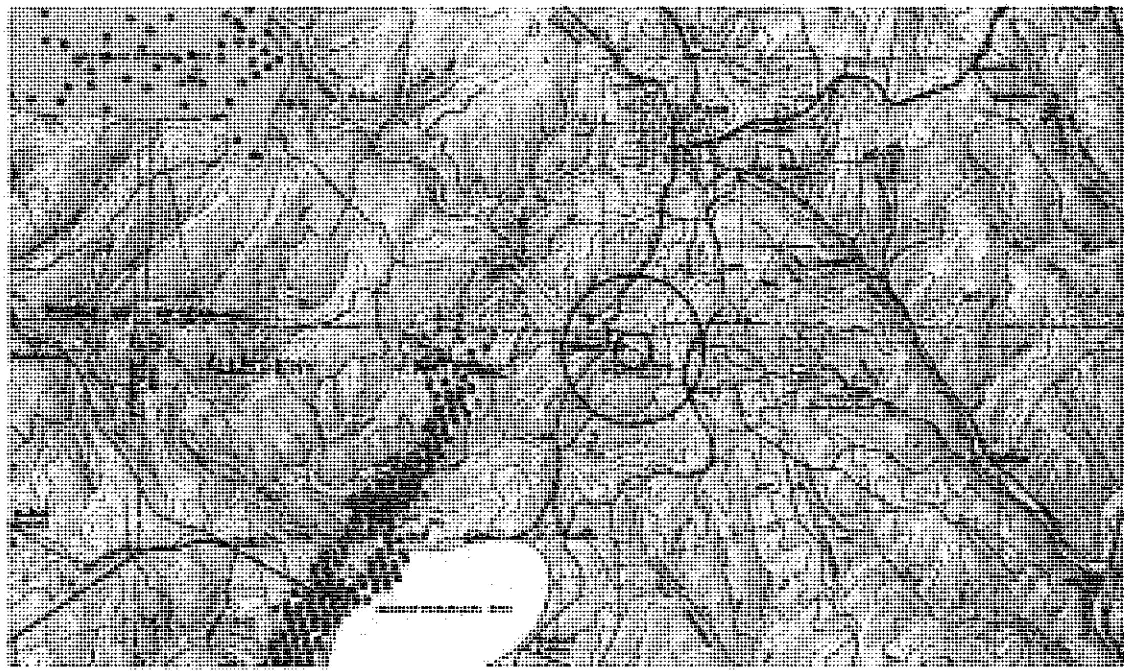


Figure 7. **Map showing storage well locations.** **Quarter-mile and one-mile buffers depicted.**

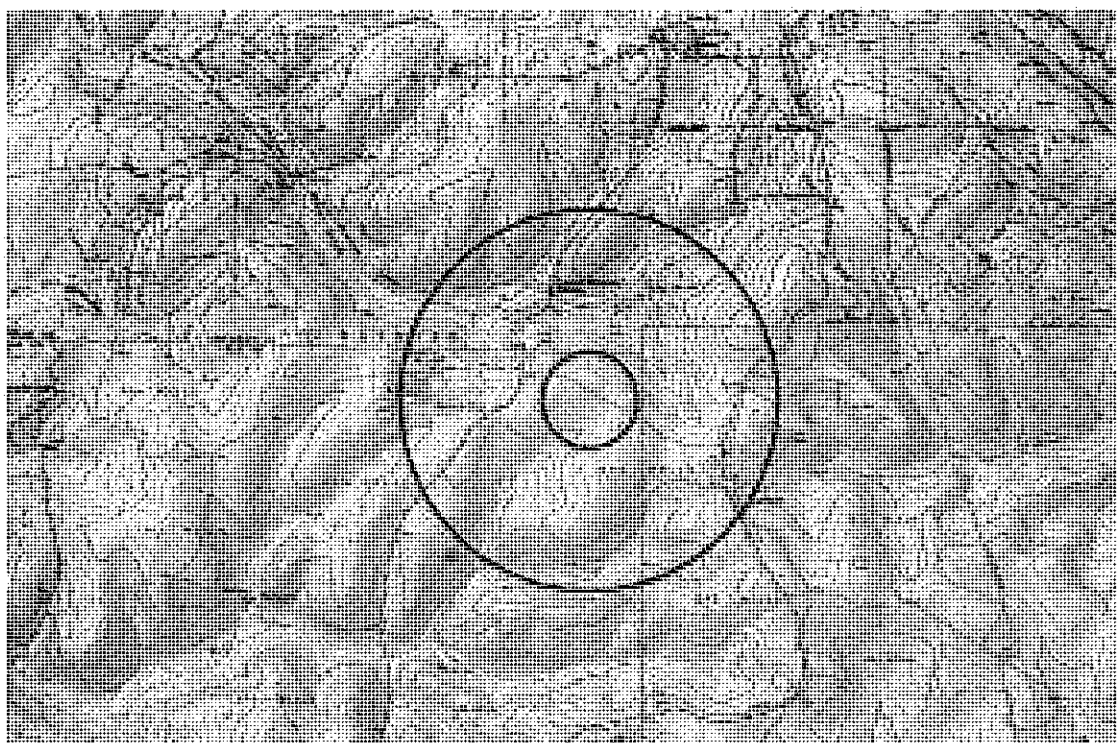


Figure 8. **Map showing surface and underground mining activities in the area.** **Quarter-mile and one-mile buffers depicted.**

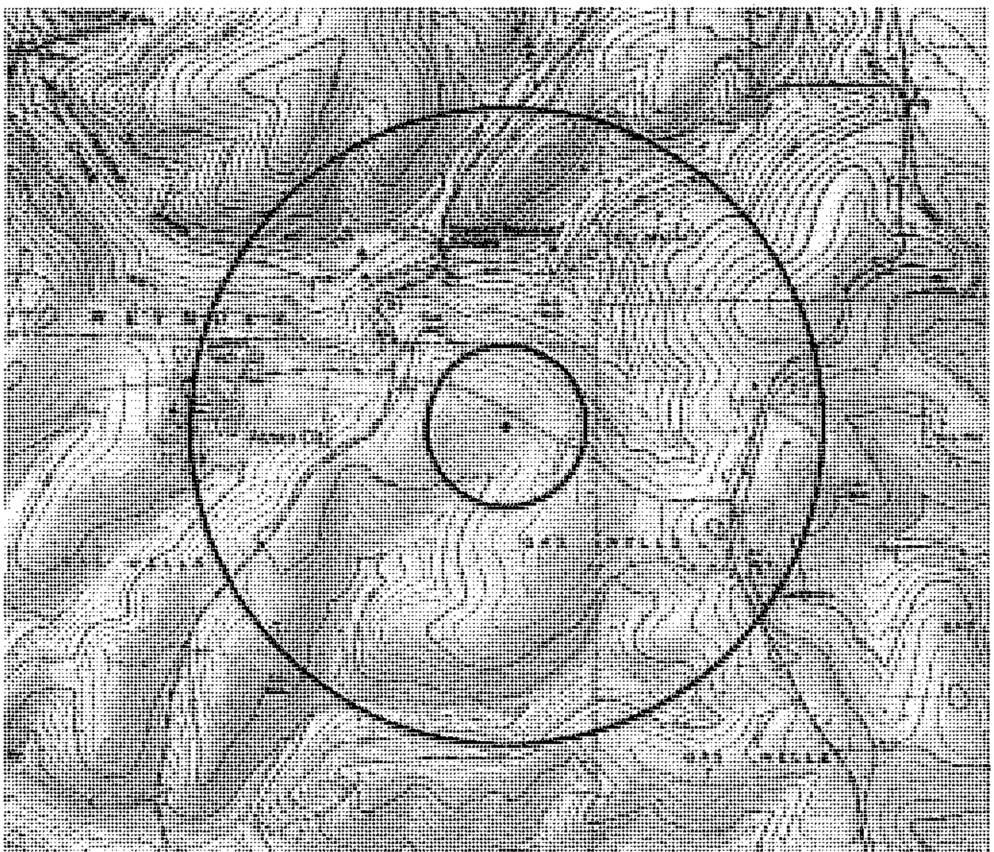


Figure 9. Map showing public water supply wells (municipal water wells shown as blue symbols and private supply wells as gold symbols). Quarter-mile and one-mile buffers depicted.

Summary of Geological Review/Assessment and Recommendations

Geological Assessment for the Seneca – Elk County Well #38268 gas well:

In my professional opinion, based on the data reviewed, the geological structure and setting associated with the Seneca – Elk County Well #38268 makes it a suitable candidate for conversion from a production well to an underground injection well.

The following recommendations are suggested:

(1) It is recommended that the location, depth and use of any additional private water wells detailed in Seneca's PPC Plan be confirmed by the Department.

(2) It is recommended that the location and usage of the well identified by Seneca as belonging to National Fuel Gas Supply Corporation be confirmed by the Department as a test gas well and not a water well.

Once the location, depth and usage of the aforementioned wells are confirmed, the Department must take steps to ensure the casing and cementing design of the proposed injection well satisfies the requirements of 25 Pa. Code Chapter 78, Subsection D. If this is the case, it is my professional opinion that there is no expected risk to these wells provided injection well integrity is maintained per the requirements of EPA's UIC Program.

cc: John Ryder
Douglas Moorhead
Keith Salador

End

Attachment- C

Filter Payments

Producer Name

Filter

Outstanding Payments

Producer Name	Client ID	Amount	Paid Amount	Owed Amount
GUARDIAN EXPLORATION LLC	237396	$50,050.00	$0.00	$50,050.00
XTREME ENERGY CO	317770	$70,600.00	$0.00	$70,600.00

Producer Reports

Statement Of Account (../Reports/ReportViewer.aspx?rptPath=/Act 13/ProducerStatementOfAccount&params=/wASbQn4xyQ=)

Attachment- D

Administrative and Compliance Monitoring and Reporting

1. Pursuant to **§ 78.125,** submit to the Department, a copy of the annual monitoring report submitted to the EPA summarizing the results of the monitoring as required by 40 CFR Part 146 (relating to underground injection control program) when these reports are submitted to the EPA. This summary, at a minimum, shall include the following:
   a. Monthly records of major changes in characteristics or sources of injected fluids.
   b. Reports of volumes and pressures of injection fluids.
   c. Reports of mechanical integrity testing.
   d. Other information or reports required to be submitted to the EPA under 40 CFR Part 146.

2. Submit, to the Department, copies of the periodic monitoring reports or reports of failures, releases, accidents or other incidents required to be submitted to the EPA under 40 CFR 146 when these reports are submitted to the EPA.

3. Prior to initiation of injection of waste into the disposal well, ensure an inspection is conducted by the Department's Oil and Gas Inspector for the well, which includes pressure readings of the annulus, to confirm compliance.

4. Prior to initiation of injection of waste into the disposal well, submit, to the Department, a copy of the EPA form 7520-10 that was submitted to the EPA, indicating completion of construction.

Seismic Monitoring and Mitigation

The permittee shall prepare and implement a seismic Monitoring and Mitigation Plan. The seismic Monitoring and Mitigation Plan shall be submitted to the Department of Environmental Protection ("Department") at least 30 days prior to the anticipated start date of disposal activities in an existing well. This plan, or the plan as modified by the Department, shall be fully implemented at the time disposal activities begin and thereafter shall include the following components:

1. Installation of a seismometer that includes the following:
   a. One 3-component velocity sensor (X, Y, and Z axes), high-frequency seismometer **or** a local network consisting of a **minimum** of four high-frequency seismometers that have 3-component velocity sensors.
   b. For purposes of this seismic Monitoring and Mitigation Plan, a "seismic event" shall mean circumstances which reflect tectonic seismic activity above the thresholds and within the distances set forth in Paragraphs (11) or (12) below.
   c. For purposes of this seismic Monitoring and Mitigation Plan, an "Injection-Induced Seismic Event" shall mean circumstances which reflect seismic activity that may be directly attributable to the permitted injection activities. Raw seismic data gathered by the seismometer(s) described in (1) a. will be processed to calculate event location (epicenter/hypocenter) and magnitude. Events attributable to surface activities (such as, but not limited to, mining or blasting) or system

noise, or events with hypocenters deeper than the top of the Salina Salts will not be considered potential Injection-Induced Seismic Events.

   d. If the one sensor option is chosen, and an Injection-Induced Seismic Event occurs at or above the thresholds specified in (11) c and d below, the operator will mobilize a local network consisting of a minimum of four (4) high-frequency seismometers that have 3-component velocity sensors within 48 hours of the event.
   e. All seismometers shall be installed in accordance with the manufacturer's instructions prior to operation of the disposal well.

2. A description of and specification sheet for the seismometer(s) installed at the disposal well site.
3. The installation of a recorder that, at a minimum, continuously records 100 samples per second using a data logger with 24-bit digitizer and Global Positioning System (GPS) timing, in accordance with the manufacturer's instructions prior to operation of the disposal well.
4. A description of and specification sheet for the seismic recorder installed at the disposal well site.
5. A description of the protocol for operating and completing calibration of the seismometer and seismic recorder installed at the disposal well site demonstrating that it conforms with the standards employed by the Pennsylvania State Seismic Network (PASEIS) and the manufacturer's instructions.
6. A description of the routine maintenance and service checks that will be implemented to monitor the operability or running condition of the seismometer and seismic recorder installed at the disposal well site. The description should detail how the checks satisfy the manufacturer's instructions.
7. Verification that Seismic Event data will be captured at the disposal well site electronically and in a manner that is suitable for Seismic Event recordation and analysis.
8. Verification that seismic data will be provided to the Incorporated Research Institutions for Seismology (IRIS) Network in real time and that the continuous, real time data conforms to the data format required by IRIS for archiving under PASEIS' network code (PE) and open distribution. If data transmission is interrupted notification will be provided to the Department verbally within 24 hours and in writing within seven (7) days.
9. A description of measures that will be taken to install the seismometer in a manner that will minimize interference from background sources and allow for optimal Seismic Event identification and location (epicenter and hypocenter). This shall include a plan view map of proposed seismometer location(s).
10. Contact information for the responsible person in charge of conducting seismic monitoring activities at the disposal well site.
11. If the one sensor option is chosen, an Injection-Induced Seismic Event contingency plan that includes monitoring, reporting and mitigation provisions consistent with the following:
    a. Immediate electronic notification to the Department and the Department of Conservation and Natural Resources' Bureau of Topographic and Geologic

Survey (BTGS) of detection of any measurable event, within six (6) miles measured radially from the disposal well.

b. Notification within 10 minute via email to the Department and within 1 hour via telephone to the Department's statewide toll free number in the case of seismic activity referenced in a. above will include filtering/processing of raw seismic data to identify and remove non-tectonic events (e.g. mine blasts or system noise) and events hypocenters deeper than the top of the Salina Salts.

c. Should an Injection-Induced Seismic Event occur (i.e., not a surface-related event, system noise or seismic events with hypocenters deeper than the top of the Salina Salts), the Operator will reduce the well's operating injection rates. Reduction of the disposal well's operating injection rates in use at the time of the Injection-Induced Seismic Event by 50% within 48 hours of the occurrence of 3 or more consecutive Injection-Induced Seismic Events greater than 1.0 and less than 2.0 on the Richter Scale over a seven (7) day period occurring within three (3) miles measured radially from the disposal well. The seven (7) day period is defined as starting with the occurrence of any Injection-Induced Seismic Event of magnitude 1.0 or greater. Reduced operating injection rates shall be maintained until the Department provides written notice addressing injection rates.

d. Termination of all injection activities within 48 hours of the occurrence of an Injection-Induced Seismic Event of magnitude 2.0 or greater within three (3) miles measured radially from the disposal well until receipt of a written notice from the Department addressing continued well usage and operating conditions. The assessment of continued usage will include, but not limited to, the following criteria:

    i. Magnitude and frequency of events detected;
    ii. Operational history prior to the event and operating conditions at the time of the event (rates, volumes, pressures);
    iii. Any mitigation/intervention attempts made prior to termination of activities;
    iv. Ability of permittee to identify another potential source for the event based on data processing and analysis of conditions.

12. If the network option is chosen, an Injection-Induced Seismic Event contingency plan that includes monitoring, reporting and mitigation provisions consistent with the following:

    a. Immediate electronic notification to the Department and the Department of Conservation and Natural Resources' BTGS of detection of any measurable event, within three (3) miles measured radially from the disposal well.
    b. Notification within 10 minute via email to the Department and within 1 hour via telephone to the Department's statewide toll free number in the case of seismic activity referenced in a. above will include filtering/processing of raw seismic data to identify and remove non-tectomic events (e.g. mine blasts or system noise) and events hypocenter deeper than the top of the Salina Salts.
    c. Should an Injection-Induced Seismic Event occur (i.e., not a surface-related event, system noise or seismic events with hypocenters deeper than the top of the Salima Salts), the Operator will reduce the well's operating injection rates. Reduction of the disposal well's operating injection rates in use at the time of the Injection-

Induced Seismic Event by 50% within 48 hours of the occurrence of 3 or more consecutive Injection-Induced Seismic Events greater than 1.0 and less than 2.0 on the Richter Scale over a seven (7) day period occurring within two (2) miles measured radially from the disposal well. The seven (7) day period is defined as starting with the occurrence of any Injection-Induced Seismic Event of magnitude 1.0 or greater. Reduced operating injection rates shall be maintained until the Department provides written notice addressing injection rates.

d. Termination of all injection activities within 48 hours of the occurrence of an Injection-Induced Seismic Event of magnitude 2.0 or greater within two (2) miles measured radially from the disposal well until receipt of a written notice from the Department addressing continued well usage and/or addressing injection rates. The assessment of continued usage will include, but not limited to, the following criteria:
    i. Magnitude and frequency of events detected;
    ii. Operational history prior to the event and operating conditions at the time of the event (rates, volumes, pressures);
    iii. Any mitigation/intervention attempts made prior to termination of activities;
    iv. Ability of permittee to identify another potential source for the event based on data processing and analysis of conditions.

13. Provisions for submitting an updated seismic Monitoring and Mitigation Plan, as needed or as may be required by the Department. Updates may be necessary in cases where the risk profile associated with injection activities changes. A signed and certified statement by a qualified professional person responsible for preparing the seismic Monitoring and Mitigation Plan that the plan is true and accurate and includes the components outlined above. The certification shall provide: "I, (insert name), hereby certify, under penalty of law as provided in 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities) that I prepared the seismic Monitoring and Mitigation Plan for (insert facility name) and the information provided is true, accurate and complete to the best of my knowledge and belief."
14. Upon commencement of disposal activities at the disposal well, the permittee shall record Injection-Induced Seismic Event data electronically in an appropriate format for analysis (event location and magnitude) and maintain daily records of Injection-Induced Seismic Event data electronically for review at the request of the Department. Injection-Induced Seismic Event records must be maintained for one (1) year.
15. The permittee shall maintain all calibration, maintenance and repair records for the seismometer for at least five (5) years.
16. The permittee shall maintain all calibration, maintenance and repair records for the seismic recorder for at least five (5) years.
17. The operator may submit a summary report and plan for modification or discontinuation of the seismic Monitoring and Mitigation Plan five (5) years after injection activities commence. The Department's review will be completed as soon as practicable after receipt of the summary report and a written response will be provided to the operator. DEP's assessment of the report will be dependent on, but not limited to, the following criteria:
    a. Magnitude and frequency of any events during the monitoring period;

b. Operational history during the monitoring period (rates, volumes, pressures);
c. Planned operational conditions moving ahead (rates, volumes, pressures);
d. Demonstration through pressure fall-off that system is at equilibrium and behaving in as a homogenous reservoir;
e. Need for any mitigation/intervention during the monitoring period.

Mechanical Integrity Special Permit Conditions

18. At least 30 days prior to any formation stimulation, the permittee shall submit a treatment plan to the Department.
19. The permittee shall provide on a monthly basis an electronic and graphical record of injection pressures, annular pressures, injection rates, and injection volumes and cumulative volumes in a format acceptable to the Department. All pressures and rates shall be monitored continuously with digital devices. The permittee shall also maintain records of this information for review at the request of the Department, for one (1) year.
20. Prior to the initial injection of fluids into the disposal well, the permittee shall coordinate and conduct an inspection of the well site, including the seismometer and recorder, with the Department's Bureau of Oil and Gas Management.
21. Prior to operation of the disposal well, the permittee shall provide the Department with documentation showing how it complied with provision Part II, D.2.b. of the EPA UIC Permit, demonstrating that the well has mechanical integrity.
22. The permittee shall notify the Department verbally within 24 hours and in writing within seven (7) days of obtaining information showing evidence of compromised mechanical integrity and immediately cease injection operations.

Other Conditions

23. This permit modification is conditioned upon the existence of the Class II-D brine disposal Injection Well dated November17, 2014, U.S. EPA permit #PAS2D025BELK ("EPA Permit")
24. A wellbore diagram of the proposed Plugging and Abandonment Plan shall be provided to the Department with a "Notice of Intention by Well Operator to Plug Well" form (8000-FM-OOGM0005) prior to plugging the well.
25. The statements in the November 12, 2014 permit application and updates for this modification are incorporated into this permit.

PADEP Well #38268 Permit

5500-FM-OG0001A Rev. 11/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Permittee's eFACTS ID: 72933	Auth ID: 1051705
Watershed Name: Wolf Run	Quality: HQ

WELL PERMIT

Permittee	OGO.#	Permit Number	Date Issued
SENECA RESOURCES CORPORATION	OGO-15547	37-047-23835-00-01	03/27/2017

Address: 51 ZENTS BLVD		Farm Name & Well Number: FEE SENECA RESOURCES WARRANT 3771 38268		Well Serial #
		Municipality: Highland Twp		County: Elk
BROOKVILLE, PA 15825-2701		7½ ' Quadrangle Name: James City		Map Section #: 2
Phone: (814) 220-1511	Project #	Latitude: 41-37-8.3700		Longitude: -78-49-16.5600
Surf Elev at Site: 2040 feet	Anticipated Maximum TVD: 2530 feet	Well Type: Disposal	Offset distances referenced to NE corner of map section. South 2189 feet	West 8093 feet

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act, the Oil and Gas Conservation Law, if the well is subject to that act, and the Clean Streams Law, and the rules and regulations promulgated thereunder, including but not limited to Sections 78.18 and 91.51 of the Department's Regulations, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling, if any, will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act, the Clean Streams Law and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

Special Permit Conditions:

Administrative and Compliance Monitoring and Reporting

1. Pursuant to §78.125, submit to the Department, a copy of the annual monitoring report submitted to the EPA summarizing the results of the monitoring as required by 40 CFR Part 146 (relating to underground injection control program) when these reports are submitted to the EPA. This summary, at a minimum, shall include the following:

a. Monthly records of major changes in characteristics or sources of injected fluids.

b. Reports of volumes and pressures of injection fluids.

c. Reports of mechanical integrity testing.

d. Other information or reports required to be submitted to the EPA under 40 CFR Part 146.

2. Submit, to the Department, copies of the periodic monitoring reports or reports of failures, releases, accidents or other incidents required to be submitted to the EPA under 40 CFR 146 when these reports are submitted to the EPA.

3. Prior to initiation of injection of waste into the disposal well, ensure an inspection is conducted by the Department's Oil and Gas Inspector for the well, which includes pressure readings of the annulus, to confirm compliance.

4. Prior to initiation of injection of waste into the disposal well, submit, to the Department, a copy of the EPA form 7520-10 that was submitted to the EPA, indicating completion of construction.

Seismic Monitoring and Mitigation

The permittee shall prepare and implement a seismic Monitoring and Mitigation Plan. The seismic Monitoring and Mitigation Plan shall be submitted to the Department of Environmental Protection ("Department") at least 30 days prior to the anticipated start date of disposal activities in an existing well. This plan, or the plan as modified by the Department, shall be fully implemented at the time disposal activities begin and thereafter shall include the following components:

1. Installation of a seismometer that includes the following:

   a. One 3-component velocity sensor (X, Y, and Z axes), high-frequency seismometer or a local network consisting of a minimum of four high-frequency seismometers that have 3-component velocity sensors.

   b. For purposes of this seismic Monitoring and Mitigation Plan, a "seismic event" shall mean circumstances which reflect tectonic seismic activity above the thresholds and within the distances set forth in Paragraphs (11) or (12) below.

   c. For purposes of this seismic Monitoring and Mitigation Plan, an "Injection-Induced Seismic Event" shall mean circumstances which reflect seismic activity that may be directly attributable to the permitted injection activities. Raw seismic data gathered by the seismometer(s) described in (1) a. will be processed to calculate event location (epicenter/hypocenter) and magnitude. Events attributable to surface activities (such as, but not limited to, mining or blasting) or system noise, or events with hypocenters deeper than the top of the Salina Salts will not be considered potential Injection-Induced Seismic Events.

   d. If the one sensor option is chosen, and an Injection-Induced Seismic Event occurs at or above the thresholds specified in (11) c and d below, the operator will mobilize a local network consisting of a minimum of four (4) high-frequency seismometers that have 3-component velocity sensors within 48 hours of the event.

   e. All seismometers shall be installed in accordance with the manufacturer's instructions prior to operation of the disposal well.

2. A description of and specification sheet for the seismometer(s) installed at the disposal well site.

3. The installation of a recorder that, at a minimum, continuously records 100 samples per second using a data logger with 24-bit digitizer and Global Positioning System (GPS) timing, in accordance with the manufacturer's instructions prior to operation of the disposal well.

4. A description of and specification sheet for the seismic recorder installed at the disposal well site.

5. A description of the protocol for operating and completing calibration of the seismometer and seismic recorder installed at the disposal well site demonstrating that it conforms with the standards employed by the Pennsylvania State Seismic Network (PASEIS) and the manufacturer's instructions.

6. A description of the routine maintenance and service checks that will be implemented to monitor the operability or running condition of the seismometer and seismic recorder installed at the disposal well site. The description should detail how the checks satisfy the manufacturer's instructions.

7. Verification that Seismic Event data will be captured at the disposal well site electronically and in a manner that is suitable for Seismic Event recordation and analysis.

8. Verification that seismic data will be provided to the Incorporated Research Institutions for Seismology (IRIS) Network in real time and that the continuous, real time data conforms to the data format required by IRIS for archiving under PASEIS' network code (PE) and open distribution. If data transmission is interrupted notification will be provided to the Department verbally within 24 hours and in writing within seven (7) days.

9. A description of measures that will be taken to install the seismometer in a manner that will minimize interference from background sources and allow for optimal Seismic Event identification and location (epicenter and hypocenter). This shall include a plan view map of proposed seismometer location(s).

10. Contact information for the responsible person in charge of conducting seismic monitoring activities at the disposal well site.

11. If the one sensor option is chosen, an Injection-Induced Seismic Event contingency plan that includes monitoring, reporting and mitigation provisions consistent with the following:

   a. Immediate electronic notification to the Department and the Department of Conservation and Natural Resources' Bureau of Topographic and Geologic Survey (BTGS) of detection of any measurable event, within six (6) miles measured radially from the disposal well.

   b. Notification within 10 minute via email to the Department and within 1 hour via telephone to the Department's statewide toll free number in the case of seismic activity referenced in a. above will include filtering/processing of raw seismic data to identify and remove non-tectonic events (e.g. mine blasts or system noise) and events hypocenters deeper than the top of the Salina Salts.

   c. Should an Injection-Induced Seismic Event occur (i.e., not a surface-related event, system noise or seismic events with hypocenters deeper than the top of the Salina Salts), the Operator will reduce the well's operating injection rates. Reduction of the disposal well's operating injection rates in use at the time of the Injection-Induced Seismic Event by 50% within 48 hours of the occurrence of 3 or more consecutive Injection-Induced Seismic Events greater than 1.0 and less than 2.0 on the Richter Scale over a seven (7) day period occurring within three (3) miles measured radially from the disposal well. The seven (7) day period is defined as starting with the occurrence of any

Injection-Induced Seismic Event of magnitude 1.0 or greater. Reduced operating injection rates shall be maintained until the Department provides written notice addressing injection rates.

d. Termination of all injection activities within 48 hours of the occurrence of an Injection-Induced Seismic Event of magnitude 2.0 or greater within three (3) miles measured radially from the disposal well until receipt of a written notice from the Department addressing continued well usage and operating conditions. The assessment of continued usage will include, but not limited to, the following criteria:

i. Magnitude and frequency of events detected;

ii. Operational history prior to the event and operating conditions at the time of the event (rates, volumes, pressures);

iii. Any mitigation/intervention attempts made prior to termination of activities;

iv. Ability of permittee to identify another potential source for the event based on data processing and analysis of conditions.

12. If the network option is chosen, an Injection-Induced Seismic Event contingency plan that includes monitoring, reporting and mitigation provisions consistent with the following:

a. Immediate electronic notification to the Department and the Department of Conservation and Natural Resources' BTGS of detection of any measurable event, within three (3) miles measured radially from the disposal well.

b. Notification within 10 minute via email to the Department and within 1 hour via telephone to the Department's statewide toll free number in the case of seismic activity referenced in a. above will include filtering/processing of raw seismic data to identify and remove non-tectonic events (e.g. mine blasts or system noise) and events hypocenter deeper than the top of the Salina Salts.

c. Should an Injection-Induced Seismic Event occur (i.e., not a surface-related event, system noise or seismic events with hypocenters deeper than the top of the Salina Salts), the Operator will reduce the well's operating injection rates. Reduction of the disposal well's operating injection rates in use at the time of the Injection-Induced Seismic Event by 50% within 48 hours of the occurrence of 3 or more consecutive Injection-Induced Seismic Events greater than 1.0 and less than 2.0 on the Richter Scale over a seven (7) day period occurring within two (2) miles measured radially from the disposal well. The seven (7) day period is defined as starting with the occurrence of any Injection-Induced Seismic Event of magnitude 1.0 or greater. Reduced operating injection rates shall be maintained until the Department provides written notice addressing injection rates.

d. Termination of all injection activities within 48 hours of the occurrence of an Injection-Induced Seismic Event of magnitude 2.0 or greater within two (2) miles measured radially from the disposal well until receipt of a written notice from the Department addressing continued well usage and/or addressing injection rates. The assessment of continued usage will include, but not limited to, the following criteria:

i. Magnitude and frequency of events detected;

ii. Operational history prior to the event and operating conditions at the time of the event (rates, volumes, pressures);

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25. The statements in the November 12, 2014 permit application and updates for this modification are incorporated into this permit.

S. Craig Lobins

Regional Oil and Gas Program Manager

Oil & Gas Inspector	Address	Phone Number
SCOTT D MOTTER	321 NORTH STATE STREET NORTH WARREN, PA 16365	814-723-3273