United States Environmental Protection Agency
Office of Water Washington, DC 20460
EPA-820-R-13-009
April 2013

Technical Development Document for the Coalbed Methane (CBM) Extraction Industry

United States Environmental Protection Agency

Technical Development Document for the Coalbed Methane (CBM) Extraction Industry

EPA-820-R-13-009

April 2013

U.S. Environmental Protection Agency
Office of Water (4303T)
Washington, DC 20460

This document was prepared by the Environmental Protection Agency. Neither the United States Government nor any of its employees, contractors, subcontractors, or their employees make any warrant, expressed or implied, or assume any legal liability or responsibility for any third party's use of or the results of such use of any information, apparatus, product, or process discussed in this report, or represents that its use by such party would not infringe on privately owned rights.

Questions regarding this document should be directed to:

U.S. EPA Engineering and Analysis Division (4303T)
1200 Pennsylvania Avenue NW
Washington, DC 20460
(202) 566-1000

TABLE OF CONTENTS

Page

List of Tables

Page

List of Tables *(Continued)*

Page

List of Figures

Page

SECTION 1
INTRODUCTION

EPA identified the CBM Extraction Industry as a candidate for a preliminary study in the Final 2006 Effluent Guidelines Program Plan (71 FR 76644). In response, EPA received comments from citizens and environmental advocacy groups on the Final 2006 Effluent Guidelines Program Plan requesting development of a regulation for the CBM Extraction Industry. In 2007, EPA began a detailed study of the CBM Extraction Industry. EPA gathered information by conducting numerous outreach meetings with stakeholders, performing site visits to observe produced water treatment technologies, and administering an industry questionnaire to gather site-specific data. Section 2 describes the CBM data collection effort in detail.

EPA published *Coalbed Methane Extraction: Detailed Study Report* (the CBM detailed study report) in December 2010 (U.S. EPA, 2010a). This report contained an initial technical and economic industry profile and EPA's preliminary review of the data collected. Based on this preliminary review, EPA announced its plan to develop effluent limitations guidelines and standards (ELGs) for the discharge of wastewater from the CBM Extraction Industry in the Final 2010 Effluent Guidelines Program Plan. EPA listed the following reasons for selecting CBM for potential rulemaking:

- CBM is not included in the current applicability of the Oil and Gas Extraction Point Source Category (40 CFR Part 435).
- The industry is discharging high concentrations of total dissolved solids (TDS) mainly sodium salts, either sodium chloride (common table salt) or sodium carbonate.
- Treatment technologies for removal of TDS are available.
- The industry expanded since EPA's previous review of this industry in 2004 and 2005 for the 2006 Effluent Guidelines Program Plan (71 FR 76644).

EPA's recent findings show that the natural gas industry has changed since EPA conducted a detailed study and selected this category for rulemaking. Declining industry economics result in the potential for measurable and significant economic impacts, including project closures. See the document *Economic Analysis for Existing and New Projects in the Coalbed Methane Industry* for additional details (U.S. EPA, 2013a).

This document provides a summary of the technical information EPA has collected to date on the CBM industry, a snapshot of the CBM operations in 2008 (when EPA collected information from the industry) and an update on the industry since EPA's data collections efforts. EPA used the information provided in this document to develop an economic analysis of the industry. The economic analysis is described in the document *Economic Analysis for Existing and New Projects in the Coalbed Methane Industry* (U.S. EPA, 2013a).

EPA's analysis of the CBM industry is based on data generated or obtained in accordance with its Quality Policy and Information Quality Guidelines. EPA's quality assurance (QA) and quality control (QC) activities include the development, approval, and implementation of Quality Assurance Project Plans for the use of environmental data generated or collected from all sampling and analyses, existing databases, and literature searches, and for the development of any models that use environmental data. Unless otherwise stated within this document, the data used and associated data analyses were evaluated as described in these QA documents to ensure they are of known and documented quality; meet EPA's requirements for objectivity, integrity, and utility; and are appropriate for the intended use.

1.1 REFERENCES

1. U.S. EPA. 2010a. Coalbed Methane Extraction: Detailed Study Report. Also available at: http://water.epa.gov/scitech/wastetech/guide/cbm_index.cfm. EPA-HQ-OW-2008-0517, DCN 09999.

2. U.S. EPA. 2013a. Economic Analysis for Existing and New Projects in the Coalbed Methane Industry. EPA-HQ-OW-2010-00824, DCN CBM00680.

SECTION 2
DATA COLLECTION ACTIVITIES

EPA collected information about the CBM Extraction Industry in three phases:

- 2007 – Site visit and stakeholder outreach.
- 2009 – Additional site visits and Screener and Detailed Questionnaires requesting information characterizing operations in 2008.
- 2012 – Supplemental data collection.

With the exception of questionnaire responses, additional documentation is included in the following dockets, accessible through http://www.regulations.gov:

- Preliminary 2008 Effluent Guidelines Program Plan (EPA-HQ-OW-2006-0771).
- Preliminary 2010 Effluent Guidelines Program Plan (EPA-HQ-OW-2008-0517).
- Final 2010 Effluent Guidelines Program Plan (EPA-HQ-OW-2010-0824).

Copies of responses to the Screener and Detailed Questionnaire are not available in the public docket due to the significant number of CBI claims in the responses. The *Summary of Coalbed Methane Information Collection Request Confidential Business Information* memorandum discusses the quantity of CBI information in these data sources (U.S. EPA, 2013).

2.1 EPA'S STAKEHOLDER OUTREACH PROGRAM

EPA conducted extensive outreach during the CBM detailed study to help identify key issues and concerns of industry and other stakeholders. The outreach goals included (1) collecting information from stakeholders, (2) explaining the purpose of EPA's planned industry survey and the process for approval and implementation of the survey, and (3) identifying and resolving issues with survey implementation as early as possible. This outreach helped EPA develop the Detailed Questionnaire. EPA incorporated comments and suggestions from industry and other stakeholders into the Detailed Questionnaire design. For more information on the stakeholder outreach program, see the CBM detailed study report (U.S. EPA, 2010).

2.2 EPA'S SITE VISIT PROGRAM

Between 2007 and 2009, EPA visited six coal basins[1] with CBM development in eight states. In total, EPA visited 33 CBM operators with a range of CBM operations that demonstrate the typical production and water management methods in the basin. During each site visit, EPA collected general site information (e.g., location, operator name, field name, produced water management practices, and well spacing); information about produced water beneficial use and disposal methods; details of produced water treatment; and economic information such as descriptions of factors affecting decisions to begin production or shut in (cease production).

[1] Coal basins are regions of coal deposits resulting from the accumulation and sedimentation of organic and inorganic debris.

Information collected during the site visits is available in the public dockets for the 2006 and 2008 Effluent Guidelines Program Plans. For more information on the site visit program, see *Coalbed Methane Detailed Study 2007 Data Collection and Outreach* (U.S. EPA, 2008).

2.3 QUESTIONNAIRES

Based on information collected during the site visit and outreach programs, EPA identified the primary unit of interest for the CBM Extraction Industry as a ***project***, defined as a well, group of wells, lease, group of leases, or recognized unit that is operated as an economic unit when making production decisions. A lease is an agreement between the operator and mineral rights owner to acquire the rights to hold the property for a period of time, whether or not the lease is developed. EPA developed a set of questionnaires (i.e., Screener and Detailed Questionnaires) to collect nationally representative data on the CBM Extraction Industry including information on basin characteristics, project size (number of wells), and discharge methods (i.e., direct or indirect discharge and zero discharge). EPA distributed the Detailed Questionnaires to operators who are in charge of day-to-day operations of the CBM projects. For more details on the questionnaires, see the CBM detailed study report (U.S. EPA, 2010). The questionnaires collected data on CBM operations in 2008.

As part of this effort, EPA developed survey sample weights to scale project data collected in the questionnaires to represent the entire CBM Extraction Industry. The survey weights account for the operators who did not receive a Detailed Questionnaire (nonsurveyed) or did not respond to the Detailed Questionnaire (nonrespondent). The memorandum *Development of Final Survey Weights for CBM Analyses* (DCN CBM00653) provides a detailed description of how survey weights were developed (U.S. EPA, 2012).

2.4 EXISTING DATA COLLECTION

EPA reviewed existing data sources, including state and federal agency databases, journal articles and technical papers, technical references, industry/vendor telephone queries, and vendor websites to supplement the Detailed Questionnaire data. EPA identified the following information specific to CBM operations in existing data sources:

- General operating conditions (e.g., produced water management, storage, and transportation).
- Produced water constituents and concentrations.
- Treatment technologies implemented at CBM operations to reduce TDS concentrations (e.g., reverse osmosis, ion exchange).
- Current state permitting practices and discharge requirements.
- Data on CBM operations as of 2010 to update 2008 Detailed Questionnaire data collection and determine any changes to the industry.[2] 2010 was the most recent year in which a complete data set was available for most states.

[2] EPA's *2010 Data Collection and Methodology Used to Update 2008 Existing Source Analysis* memorandum (U.S. EPA, 2013c) documents all of the assumptions and calculations used to update the 2008 Detailed Questionnaire data to 2010.

EPA reviewed the following existing data sources:

- ALL Consulting[3] documents on CBM, shale gas, and oil and gas produced water (2002 through 2011).
- The Colorado School of Mines (CSM) report *An Integrated Framework for Treatment and Management of Produced Water* (CSM, 2009).
- The National Academy of Sciences report *Management and Effects of Produced Water in the United States* (NAS, 2010).
- Vendor information on specific treatment technologies.
- Water treatment references on the use and limitations of general wastewater and produced water treatment technologies for produced water.
- Well data from HPDI, Inc. (a data service company) to identify existing CBM wells and coal basins.
- Information from other federal and state agencies, including:
    - U.S. Department of Energy (DOE) – National Energy Technology Laboratory (NETL) research on volume and management of produced water, downhole separation, and ion exchange (http://www.netl.doe.gov/).
    - U.S. DOE's Energy Information Administration (EIA) – information on natural gas projections, wellhead prices, and other supplemental information used to complete the 2010 analysis of the CBM Extraction Industry (http://www.eia.gov/).
    - State permitting agencies – 2008 and 2010 discharge monitoring reports (DMRs) from the Alabama Department of Environmental Management and the Wyoming Department of Environmental Quality.
    - National Pollutant Discharge Elimination System (NPDES) Permit Program – 2008 and 2010 DMRs for the state of Montana (Powder River Basin).
    - State oil and gas websites – gas and water production data from the following state oil and gas websites, used to evaluate changes in produced water volumes and gas production from 2008 to 2010:
        - Colorado (Raton Basin)
        - Wyoming (Powder River and Green River Basins)
        - Pennsylvania (Appalachian Basin)
        - West Virginia (Appalachian Basin)

[3] ALL Consulting is a professional services firm specializing in energy and water management. They have published documents about the CBM industry, CBM best management practices, and produced water management options and beneficial use alternatives.

- Alabama (Black Warrior and Cahaba Basins)
- Montana (Powder River Basin)

2.5 REFERENCES

1. CSM (Colorado School of Mines). 2009. An Integrated Framework for Treatment and Management of Produced Water: Technical Assessment of Produced Water Treatment Technologies. 1st Edition. RPSEA Project 07122-12. EPA-HQ-OW-2008-0517. DCN 10007.

2. NAS (National Academy of Science). 2010. Management and Effects of Produced Water in the United States. Available online at: http://www.nap.edu/catalog.php?record_id=12915.

3. U.S. EPA. 2008. Coalbed Methane Detailed Study 2007 Data Collection and Outreach. EPA-HQ-OW-2006-0771, DCN 05354.

   U.S. EPA. 2010. Coalbed Methane Extraction: Detailed Study Report. Also available at: http://water.epa.gov/scitech/wastetech/guide/cbm_index.cfm. EPA-HQ-OW-2008-0517, DCN 09999.

4. U.S. EPA. 2012. Development of Final Survey Weights for CBM Analyses. EPA-HQ-OW-2010-0824, DCN CBM00662.

5. U.S. EPA. 2013. Summary of Coalbed Methane Information Collection Request Confidential Business Information. EPA-HQ-OW-2010-0824, DCN CBM00661.

SECTION 3
INDUSTRY PROFILE

This section describes the CBM Extraction Industry's gas and water production and produced water volumes, characteristics, and management practices.

3.1 OVERVIEW OF COALBED METHANE INDUSTRY

Production of natural gas from coal seams is considered unconventional gas extraction. Conventional gas extraction involves extracting natural gas from permeable rock formations such as siltstones, sandstones, and carbonates. In contrast, unconventional gas extraction involves extracting natural gas from lower-permeability, harder-to-produce formations, such as shale plays, coal basins, and tight gas sands.

The natural gas contained in and removed from coal seams is called coalbed methane or CBM (U.S. DOE, 2006). CBM exists in the coal seams in three basic states: as free gas, as gas dissolved in the water in coal, and as gas adsorbed on the solid surface of the coal (ALL, 2004). CBM extraction requires drilling wells into the coal seams and removing the formation water contained in the coal seam to reduce hydrostatic pressure and allow the adsorbed CBM to be released from the coal (Wheaton et al., 2006; U.S. DOE, 2006). The water produced during CBM extraction is called ***produced water***. Produced water from CBM operations primarily consists of formation water, i.e., the water contained within the coal formation; in some cases, it may include wastewater from drilling activities. The infrastructure for CBM extraction sites typically comprises the well pad, gathering system pumps and pipelines, storage tanks, and treatment equipment (if treatment occurs).

3.2 CBM PRODUCTION AND THE LIFESPAN OF CBM WELLS

The typical lifespan of a CBM well is between five and 15 years, with maximum methane production often achieved after one to six months of water removal (Horsley & Witten, 2001). CBM wells go through the following production stages (De Bruin et al., 2001):

- An early stage, in which large volumes of formation water are pumped from the seam to reduce the underground pressure and encourage the natural gas to release from the coal seam.
- A stable stage, in which the amount of natural gas produced from the well increases as the amount of formation water pumped from the coal seam decreases.
- A late stage, in which the amount of gas produced declines and the amount of formation water pumped from the coal seam remains low.

Figure 3-1 generalizes the gas and water production curves for CBM wells.

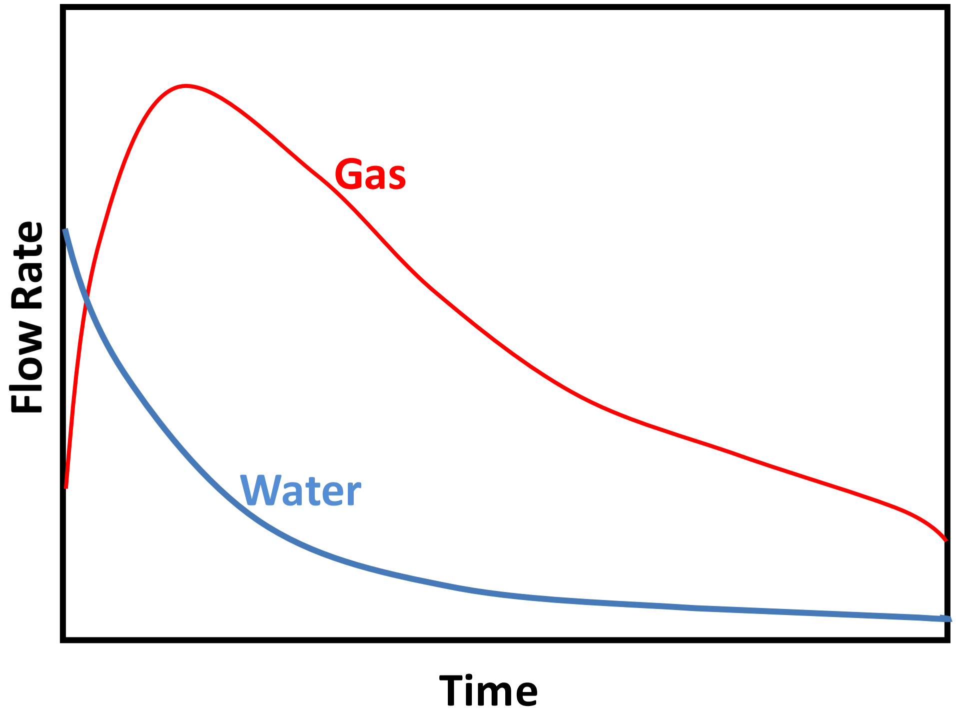


Figure 3-1. Generalized Gas and Water Production Curves for CBM Wells

This production profile is very different from conventional gas or oil production. Most conventional gas wells produce relatively little water throughout their lives, although some increase in water production might occur as the well ages. Oil wells, or those which produce both gas and water, tend to produce little water at first, with production of water rising as the well ages. A frequently used model of the production from conventional oil or oil and gas wells assumes a constant decline rate for oil with an inverse growth rate in water, achieving a constant production of total fluid over time (see, for example, Appendix C in U.S. EPA, 1996).

3.3 Identifying Coal Basins With CBM Development

CBM is produced in a limited number of coal basins located across the United States. The gas and water content in the coal vary by hardness of coal or the "rank" of the coal. Coal basins in the eastern United States tend to have lower water content and higher gas content (i.e., higher rank) than western coal formations. Mid-rank coals contain a good balance of gas and water content in the coal seams and are most economical for CBM extraction: thus, CBM development has primarily occurred in mid-rank bituminous coals (ALL, 2003).

Using information from HPDI, Inc. (see Section 2.4), EPA identified the coal basins with CBM development as of 2006. The HPDI database included information about CBM production in 15 coal basins and was used to develop the distribution list for the Screener and Detailed Questionnaires, which collected data on operations in 2008. Table 3-1 lists the 15 CBM basins and the number of CBM operators in 2008 within each coal basin based on information from the surveys. EPA determined that a total of 251 operators operated 766 projects and over 57,000

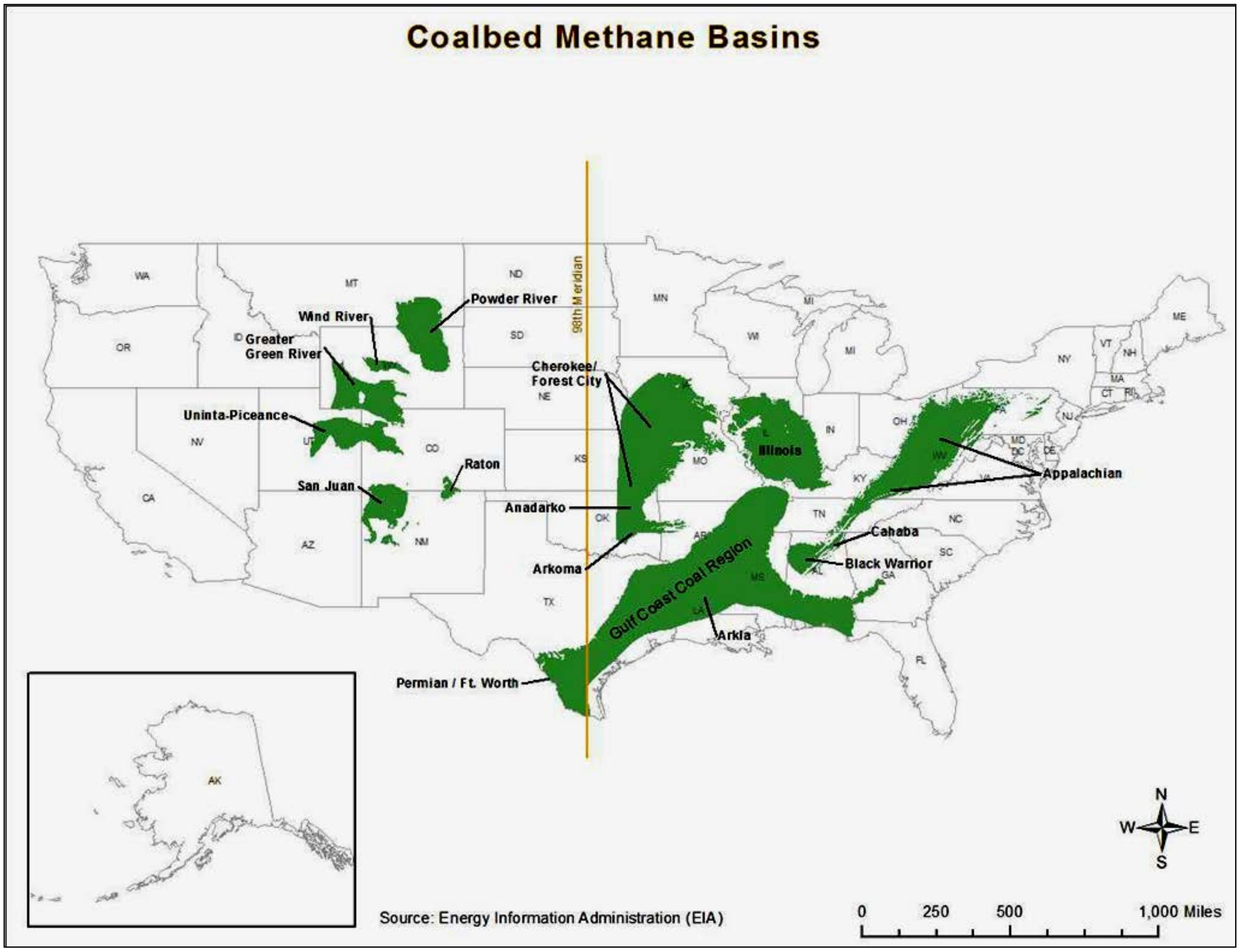
CBM wells in 2008 (U.S. EPA, 2010). Figure 3-2 illustrates the coal basins that produced CBM in 2008.

CBM development began in the early 1980s. The first area to be developed was the Black Warrior Basin in Alabama, followed in the latter part of the 1980s by the San Juan Basin in New Mexico and Colorado. For many years, CBM production was limited to these three states (Fisher, 2001). Production in the Powder River Basin, primarily located in Wyoming, began in earnest in the early 1990s, and the Powder River Basin quickly became a major source of CBM by the end of the 1990s (WOGCC, 2010). By 2000, Wyoming was producing 10 percent of all CBM; by 2008, production in the state was approaching a third of the total production (EIA, 2010; U.S. EPA, 2010). According to EIA, CBM production continues to center around these 15 coal basins in 2009 (EIA, 2013).

Table 3-1. CBM Basins and Locations, 2008

Coal Basin	States	Number of CBM Operators
Anadarko	Oklahoma	32
Appalachian	Virginia, West Virginia, Pennsylvania	13
Arkla	Louisiana	2
Arkoma	Oklahoma, Arkansas	41
Black Warrior	Alabama	8
Cahaba	Alabama	3
Cherokee/Forest City	Kansas	36
Greater Green River	Wyoming	8
Illinois	Illinois, Indiana	2
Permian/Fort Worth	Texas	1
Powder River Basin	Montana, Wyoming	68
Raton	Colorado, New Mexico	5
San Juan	New Mexico	55
Uinta-Piceance	Utah, Colorado	9
Wind River	Wyoming	1

Source: U.S. EPA, 2010.



Source: EIA, 2013.

Figure 3-2. Map of CBM Basins with Location of 98th Meridian[4]

In addition to the producing basins listed in Table 3-1, EPA also identified a number of other coal basins that have limited or no CBM production. CBM development depends on factors including projected amounts of gas and water production, availability of gas and water pipeline infrastructure, availability of land, and the difficulty associated with water and gas extraction.

EPA reviewed published information on potential CBM developments. Table 3-2 lists basins that were not producing CBM as of 2008 and provides a discussion of the CBM potential in each basin. Based on the information available to date, EPA found that a large number of the coal basins that had no development in 2008 have limited to no potential for future development.

[4] The ELGs for the Oil and Gas Extraction Point Source Category (40 CFR Part 435) allow oil and gas wells located west of the 98th meridian to be regulated under Subpart E (Agricultural and Wildlife Water Use).

Table 3-2. CBM Basins With Potential for CBM Gas Development

Coal Basin	State(s)	Potential for CBM Development
Some Potential for CBM Development		
Black Mesa	Arizona	There has been large-scale surface coal mining in the area since the 1960s, but no CBM testing has occurred. The area has easy access to market via the recently constructed Questar Southern Trails gas pipeline (ARI, 2010).
Coos Bay Field	Oregon	• EIA did not identify this field as a significant CBM resource (EIA, 2007). • Several wells were drilled in 2005 and 2006, but commercial operations have not occurred. Coalbeds are located at depths over 12,000 feet. Drilling at these depths results in high volumes of produced water, with high salt concentration (AAPG, 2005; OPB, 2011).
Kaiparowits	Utah	As at Black Mesa, large-scale surface coal mining existed in the area since the 1960s but no CBM testing has occurred. The area has easy access to market via the recently constructed Questar Southern Trails gas pipeline (ARI, 2010).
Unknown Potential for CBM Development		
Alaska	North and South Central Alaska	CBM content is unknown in most Alaska coal basins. Most of the CBM potential exists in the North Slope region; however, the area lacks gas and water pipeline infrastructure. Other prospective areas include Central Alaska–Nenana and Southern Alaska Cook Inlet. Few pilot studies have been implemented, but no commercial production has occurred in Alaska to date (NAEG, n.d.; AKCEP, 2012).
Denver	Colorado	CBM content is unknown in this area. The potential impact of the aquifers bordering the formations also hinders CBM development (Bryner, 2002).
North Central Coal	North Montana	CBM potential has not been studied extensively in this region (ARI, 2010). EIA estimates 1.2 trillion cubic feet of recoverable CBM resources in this basin (EIA, 2007).
Southwestern Coal Region	North Central Texas	Coal mining occurs in this region; however, CBM potential has not been studied extensively. EIA estimates 6.8 trillion cubic feet of recoverable CBM resources in this basin (EIA, 2007).
Limited or No Potential for CBM Development		
Big Horn	Wyoming Montana (West of Powder River Basin)	Geology limits CBM production. The basin lacks thick, persistent coal in most of the region (USGS, 1999).
Deep River	Central North Carolina	Geology limits CBM production. The fragmented basin geology makes gas production uneconomical (BLM, 2008).
Gulf Coast	Florida Panhandle to Texas Gulf Coast	• Pilot projects have occurred in Louisiana and Texas. In Louisiana, a few wells have successfully produced CBM, but there is limited knowledge on the production in this region (ARI, 2010). • Expansion in this basin will be limited because it is heavily populated and limited leasable public lands are available. Access to lands where CBM reservoirs exist could be a problem. (USGS, 2000).
Hanna Carbon	Wyoming	Production ceased in 2006 (EIA, 2007).
Henry Mountains	Utah	Geology limits CBM production. Topography of coal beds is discontinuous, which is unfavorable for trapping of CBM (Utah BLM, 2005).

Table 3-2. CBM Basins With Potential for CBM Gas Development

Coal Basin	State(s)	Potential for CBM Development
Michigan	Michigan	CBM potential has not been studied extensively in this region (ARI, 2010). EIA indicates the resources in this basin are minimal (0.01 trillion cubic feet) (EIA, 2007).
Pacific	Washington	Geology limits CBM production. The geologically complex area makes gas recovery challenging. Development may also impact existing basalt aquifers (U.S. EPA, 2004).
Park	Colorado	Basin formation favors conventional oil and gas production, which will limit CBM production in this area (Sanborn, 1981).
Southwest Colorado	Southwest Colorado	Geology limits CBM production. The topography of coal beds is discontinuous, which is unfavorable for trapping of CBM (Utah BLM, 2005).
Terlingua Field	West Texas	EIA indicates that the resources in this basin are near zero (EIA, 2007).
Williston	North Dakota Montana	• EIA indicates that this coal basin has 0.6 trillion cubic feet of potentially recoverable CBM (EIA, 2007). • CBM potential of lignite coals has not been studied extensively, but anecdotal evidence from water well drillers suggests CBM exists in North Dakota lignite. This basin is primarily a coal mining and shale oil and gas area, which will likely limit CBM production. No CBM has been identified in this area to date (NAEG, n.d.).
Wyoming Overthrust	Western Wyoming	• EIA indicates that the CBM in this basin are near zero (EIA, 2007). • The region primarily focuses on conventional oil and gas production. Most of the CBM-producing regions are in the eastern part of the Powder River coal region (in Wyodak coal zone), also known as the Powder River Basin (WYSGS, 1999).

3.4 GAS PRODUCTION

Table 3-3 summarizes the total gas production from coalbed methane and shale gas wells between 2007 and 2011, as published by EIA[5] (EIA, 2013a). Coalbed methane gas production peaked in 2008 at about 2 trillion cubic feet. The peak production year also coincides with the calendar year that EPA collected CBM Extraction Industry data (see Section 2 for a summary of EPA's data collection activities). From 2008 to 2011, CBM production saw a constant decline while shale gas production increased.

Table 3-4 shows a detailed summary of natural gas production, by basin, for 2008 and 2011 (EIA, 2013b). EIA did not report CBM production for Pennsylvania, West Virginia, and Illinois in 2008 or 2011, and did not explain why they did not report production for these states. However, EPA's 2008 Detailed Questionnaire included CBM production and produced water discharges for these three states.

Figure 3-3 presents EIA projections for the natural gas market through 2035. EIA anticipates the total U.S. gas production to increase from 22 trillion cubic feet in 2010 to 28 trillion cubic feet in 2035, mainly due to a rapid rise of shale gas production. EIA projects that

[5] 2011 gas production data were estimated values.

CBM production will decline over the next 20 years, with its contribution to total gas production falling from about 9 percent of total natural gas production in 2008 to an expected 7 percent by 2035 (EIA, 2010).

Table 3-3. Total CBM Gas Production (Million Cubic Feet), 2007–2011

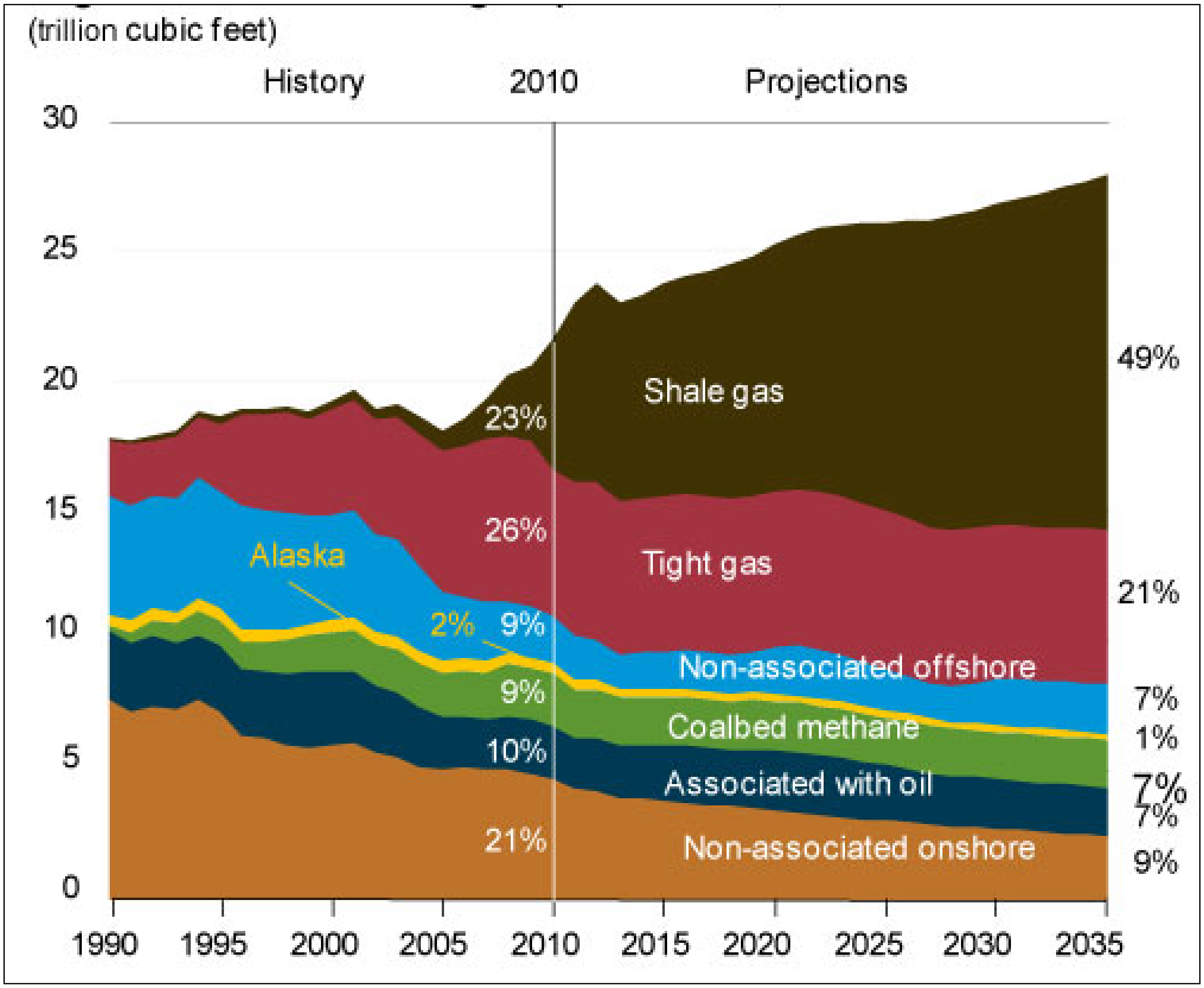
Industry	2007	2008	2009	2010	2011[a]
Coalbed Methane Wells	1,999,748	2,022,228	2,010,171	1,916,762	1,779,055
Shale Gas Wells	1,990,145	2,869,960	3,958,315	5,817,122	8,500,983

Source: EIA, 2013a.
a – Data for 2011 are estimated.

Table 3-4 Detailed Summary of CBM Gas Production, by Basin in 2008 and 2011

Basin	State	Gas Production (Million Cubic Feet) 2008	Gas Production (Million Cubic Feet) 2011 [b]	Percent Change
Anadarko, Arkoma	Oklahoma, Arkansas	76,860	53,206	-30.8%
Appalachian	Pennsylvania, Virginia, West Virginia [c]	101,567	112,219	10.5%
Arkla	Louisiana	0	0	0.0%
Black Warrior/Cahaba	Alabama	112,222	95,727	-14.7%
Cherokee/Forest City	Kansas	44,066	35,924	-18.5%
Illinois	Illinois	0	0	0.0%
Green River, Wind River, Powder River (Wyoming)	Wyoming	563,274	508,739	-9.7%
Powder River (Montana)	Montana	14,496	6,691	-53.8%
Permian/Fort Worth	Texas	0	0	0.0%
Raton, San Juan, Uinta-Piceance	Colorado, New Mexico, Utah	1,102,493	961,185	-12.8%
Other	Ohio	0	0	0.0%
Total		2,014,978	1,773,691	-12.0%

Source: EIA, 2013b.
Note: EIA provides detailed state production data. To present the gas production data by basin, EPA consolidated state data where necessary. State production data may also represent more than one basin.
b – Data for 2011 are estimated.
c – EIA indicates zero gas production for Pennsylvania and West Virginia in 2008 and 2011 (EIA, 2013b). Therefore, the gas production values for the Appalachian basin in 2008 and 2011 are for Virginia. The Detailed Questionnaire included responses for CBM projects operating in Pennsylvania and West Virginia in 2008 and included these projects in the summaries using Detailed Questionnaire data.



Source: EIA, 2010.

Figure 3-3. U.S. Natural Gas Production, 1990–2035

3.5 WATER PRODUCTION AND MANAGEMENT

As discussed in Section 2, CBM operators often group wells together into projects to manage, store, treat, and dispose of produced water, a byproduct of CBM gas production. CBM operators often combine produced water from multiple wells and occasionally multiple projects into a produced water management system (PWMS). In some cases, operators transfer water to another operator's PWMS for management and disposal.

To dispose produced water, CBM operators currently choose from surface water discharge and zero discharge alternatives. Surface water discharge includes direct discharge to waters of the United States and indirect discharge through POTWs to surface water. Zero discharge includes underground injection, evaporation/infiltration ponds, land application (for crop or non-crop production), and livestock or wildlife watering. Section 4 discusses these management approaches in detail.

Table 3-5 lists the 15 basins that had CBM production in 2008, indicates whether EPA classified the basin as discharging or zero-discharging[6], and lists the discharge practices used by each basin based on results of the screener and Detailed Questionnaire. Operators in seven of 15 basins reported surface water discharge. Projects in discharging basins may also use zero discharge method for produced water disposal. Zero discharge methods used in each basin are also noted in Table 3-5.

Table 3-5. Produced Water Discharge Practices in Use by Basin

Basin	Basin Discharge Status[a]	Zero Discharge Methods Reported
Anadarko	Zero Discharge	Underground Injection
Appalachian	Discharge[b]	Underground Injection, Land Application, Evaporation/Infiltration Pond
Arkla	Zero Discharge	CBI[d]
Arkoma	Zero Discharge	Underground Injection
Black Warrior	Discharge	None
Cahaba	Discharge	CBI[d]
Cherokee/Forest City	Zero Discharge	Underground Injection
Greater Green River	Discharge	CBI[d]
Illinois	Discharge	CBI[d]
Permian/Ft. Worth	Zero Discharge	CBI[d]
Powder River Basin (PRB)	Discharge	Underground Injection, Land Application, Livestock Watering, Evaporation/Infiltration Pond
Raton	Discharge	Underground Injection, Livestock Watering[c], Evaporation/Infiltration Pond
San Juan	Zero Discharge	Underground Injection, Livestock Watering[c], Evaporation/Infiltration Pond
Uinta-Piceance	Zero Discharge	Underground Injection, Evaporation/Infiltration Pond
Wind River	Zero Discharge	CBI[d]

Source: Screener and Detailed Questionnaire. Zero discharge methods listed have at least one project that uses this practice.
a – Some discharging basins may also use zero discharge methods as shown in the zero discharge methods column.
b – Of the discharging basins, only the Appalachian basin had both direct and indirect dischargers. Of the 78 projects that reported discharging in the Detailed Questionnaires, only four projects in the Appalachian Basin reported indirect discharge. All other discharging basins use direct discharge.
c – Zero discharge method was indicated in the screener survey response but cannot be confirmed through the Detailed Questionnaire.
d – To protect CBI, specific zero discharge methods could not be presented for basins with few operators.

Table 3-6 shows the estimated total volume of produced water generated and the estimated total volume of water discharged to surface water (directly or indirectly) in 2008 by operators in the discharging basins. Overall, operators discharged approximately 30 percent of the water produced and used zero discharge practices to manage the remaining produced water volume.

[6] If any project in a basin discharges, then EPA classified the basin as “discharge.” If no projects in a basin discharge, then EPA classified the basin as “zero discharge.”

Table 3-6. 2008 CBM Production and Produced Water Discharge Volumes for Discharging Projects

Water Production (million bbl) [a]	Discharge Volume (million bbl) [b]
1,234	371

Source: Detailed Questionnaire.
a – EPA weighted the Detailed Questionnaire results to reflect the total water produced in the discharging basins listed in Table 3-5.
b – EPA used available DMR data to estimate the total volume discharged to surface water for the Black Warrior, Cahaba, Greater Green River, Illinois, and Powder River (MT and WY) basins. DMR data were not available for the Appalachian and Raton basins; therefore, EPA used the reported discharge volumes from the Detailed Questionnaire and survey weights to estimate total discharge volumes for the basins.

3.6 PRODUCED WATER CHARACTERISTICS

As discussed in Section 1, one of the reasons EPA selected the CBM Extraction Industry for potential rulemaking is the discharge of high concentrations of TDS to surface water. Produced water from the CBM industry is characterized by elevated levels of dissolved constituents commonly measured as TDS or salinity. The main constituents of TDS in produced water are sodium salts, either sodium chloride (common table salt) or sodium carbonate. TDS may also include trace elements (e.g., barium and iron). Some produced waters are also monitored for the sodium adsorption ratio. This ratio is expressed as a ratio of the sodium concentration to the concentration of calcium and magnesium. Table 3-7 shows the average, minimum, and maximum TDS concentrations for produced water effluent for the discharging basins listed in Table 3-6.[7]

Table 3-7. Produced Water Effluent TDS Concentrations for the Discharging Basins

Basin	Minimum Concentration	Average Concentration	Maximum Concentration	Units
Appalachian	4,480	9,470	14,300	mg/L
Black Warrior / Cahaba [a]	527	11,800	34,290	mg/L
Green River / Powder River (WY) [a]	385	621	739	mg/L
Illinois	7	254	423	mg/L
Powder River (MT) [a]	603	1,260	1,880	mg/L
Raton	420	1,310	2,650	mg/L

Source: 2008 CBM Detailed Questionnaire and 2008 DMRs.
a – Estimated based on reported conductivity and the conversion: 1 μS/cm (or 1 μmho/cm) = 0.67 mg/L TDS.

[7] EPA obtained the produced water concentration information presented in this section from Discharge Monitoring Reports (DMR). Therefore, these data reflect available information on CBM discharges to surface water. The tables do not include concentration information for CBM produced water that may be handled by other disposal methods such as underground injection.

CBM produced water generally contains low levels of other constituents, such as oil and grease and dissolved organics, that are associated with conventional oil and gas produced water. As reported in Wyoming DMRs, other trace pollutants that may be present in produced water include potassium, sulfate, bicarbonate, fluoride, ammonia, arsenic, and radionuclides. Pollutant concentrations will vary by basin depending on the geology of the underlying coal. Table 3-8 presents the average, minimum, and maximum concentrations for the monitored pollutants reported in DMRs for the industry (industry-level concentrations).

Table 3-8. Pollutant Data Summary for Produced Water Discharges

Pollutant	Qualifier	Minimum	Average	Maximum	Unit
Alkalinity		75	410	698	mg/L
Ammonia, Total	<	0.05	1.43	2.54	mg/L
Arsenic, Total [a]		0	0.0011	0.0044	mg/L
Barium, Total		0.033	0.038	0.043	mg/L
Bicarbonate [a]		13	817.3	3190	mg/L
BOD, 5-day	<	1	4.93	16.5	mg/L
Boron, Total	<	0.05	0.17	0.18	mg/L
Calcium, Total		2.6	14.9	150	mg/L
Chloride, Total		8.4	4,470	18,700	mg/L
Copper, Total	<	0.01	0.008	1.2E-6	mg/L
Fluoride, Total		3.24	3.51	3.87	mg/L
Iron, Total	<	0.05	0.69	4.88	mg/L
Magnesium, Total		0.6	1.92	7.1	mg/L
Manganese, Total	<	0.05	0.10	0.51	mg/L
Nitrogen, Total		0.2	2.13	4.7	mg/L
Oil and Grease	<	1	1.88	8.5	mg/L
Phosphorus, Total	<	0.01	8.06E-2	0.14	mg/L
Potassium, Total [a]		2	10.25	19	mg/L
Radium 226 [a]		0.07	0.47	1	pCi/L
Radium 228 [a]		0.17	0.53	1.2	pCi/L
Radium 226 + 228 [a]		0.03	1.48	4.1	pCi/L
Selenium, Total	<	0.004	0.004	0.004	mg/L
Sodium, Total		97	513	842	mg/L
Sulfate, Total		15.3	68.0	118	mg/L
TDS		7	5,218	34,300	mg/L
TSS	<	4	11.4	60.0	mg/L
Zinc, Total	<	0.02	1.46E-02	2.98E-5	mg/L

a – Wyoming is the only state that reported radionuclide (radium 226 and radium 228), arsenic, bicarbonate, and potassium concentrations in DMRs. Wyoming projects only report daily maximum values for these pollutants (i.e., they do not report average values). Therefore, the minimum, maximum, and average values presented in the table are all calculated using the daily maximum values.
Source: 2008 CBM Detailed Questionnaire and 2008 DMRs.

3.7 References

1. AAPG (American Association of Petroleum Geologists). 2005. Understanding Basalts May Be the Key: Pacific Northwest Plays Present a Puzzle. The Explorer. November. Available online at: http://www.aapg.org/explorer/2005/11nov/pacific_nw.cfm. Accessed August 28, 2012.

2. AKCEP (Alaska Center for Energy and Power). 2012. Coalbed Methane. Alaska Energy Wiki. Available online at: http://energy-alaska.wikidot.com/coalbed-methane. Accessed August 28, 2012.

3. ALL (ALL Consulting). 2003. Handbook on Coal Bed Methane Produced Water: Management and Beneficial Use Alternatives. Prepared for Ground Water Protection Research. Available online at: http://www.all-llc.com/publicdownloads/CBM_BU_Screen.pdf. EPA-HQ-OW-2004-0032-2483, DCN 03451.

4. ALL. 2004. Coal Bed Methane Primer. Available online at: http://www.all-llc.com/publicdownloads/CBMPRIMERFINAL.pdf.

5. ARI. 2010. Memorandum from Michael Godec, ARI, to James Covington, U.S. EPA. April. EPA-HQ-OW-2008-0517, DCN 07346.

6. BLM (Bureau of Land Management). 2008. North Carolina: Reasonably Foreseeable Development Scenario for Fluid Minerals. Available online at: http://www.blm.gov/pgdata/etc/medialib/blm/es/jackson_field_office/planning/planning_pdf_nc_rfds.Par.49259.File.dat/N_Carolina_RFDS_R1.pdf.

7. Bryner, G. 2002. Coalbed Methane Development in the Intermountain West: Primer. University of Colorado, School of Law. Available online at: http://www.oilandgasbmps.org/docs/GEN174-CBMConferenceReportNRLC.pdf.

8. De Bruin, R.H., R.M. Lyman, R.W. Jones, and L.W. Cook. 2001. Coalbed Methane in Wyoming Information Pamphlet 7 (revised). Wyoming State Geological Survey. EPA-HQ-OW-2004-0032-1904, DCN 03070.

9. EIA (U.S. Department of Energy, Energy Information Administration). 2007. US Coalbed Methane: Past, Present, and Future. Available online at: http://www.eia.gov/oil_gas/rpd/cbmusa2.pdf.

10. EIA, 2010. Annual Energy Outlook 2012. Available online at: http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf. Accessed August 28, 2012.

11. EIA. 2013a. Natural Gas Gross Withdrawals and Production, Annual, 2007-2011. Available online at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_nus_a.htm. Accessed March 3, 2013.

12. EIA. 2013b. Natural Gas Gross Withdrawals from Coalbed Wells, 2002-2011. Available online at: http://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_fgc_mmcf_a.htm. Accessed March 3, 2013.

13. Fisher, J.B. 2001. Environmental Issues and Challenges in Coal Bed Methane Production. Exponent, Inc. Tulsa, OK. Available online at: http://ipec.utulsa.edu/Conf2001/fisher_92.pdf. EPA-HQ-OW-2008-0517, DCN 07229.

14. Horsley & Witten, Inc. 2001. Draft Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. Prepared for the U.S. Environmental Protection Agency. EPA-HQ-OW-2004-0032-2543 (DCN 03489).

15. NAEG (Native American Energy Group). n.d. Coal Bed Methane Operations. Available online at: http://www.nativeamericanenergy.com/index.php?option=com_content&view=article&id=54&Itemid=152. Accessed September 20, 2012.

16. OPB (Oregon Public Broadcasting). 2011. Oregon Gas Drilling: Different Challenges Between Sandstone and Coal Beds. Oregon Public Broadcasting. July 31. Available online at: http://earthfix.opb.org/energy/article/coal-bed-methane-creates-coos-bay-challenges/. Accessed August 28, 2012.

17. Sanborn, A.F. 1981. Potential Petroleum Reserves of Northeastern Utah and Northwestern Colorado. In: New Mexico Geological Society. New Mexico Geological Society Fall Field Conference Guidebook – 32: Western Slope (Western Colorado and Eastern Utah). Available online at: http://nmgs.nmt.edu/publications/guidebooks/downloads/32/32_p0255_p0266.pdf. Accessed September 20, 2012.

18. U.S. DOE (Department of Energy). 2006. Future Supply and Emerging Resources – Coalbed Natural Gas. EPA-HQ-OW-2004-0032 (DCN 03480).

19. U.S. EPA (Environmental Protection Agency). 1996. Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. Office of Water. EPA-821-R-96-022. Available at: http://nepis.epa.gov/.

20. U.S. EPA. 2004. Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, Attachment 11. Office of Groundwater and Drinking Water. Available online at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_coalbedmethanestudy.cfm.

21. U.S. EPA. 2010. Screener Survey Database (CBI). EPA-HQ-2008-0517 (DCN 07363).

22. USGS (U.S. Geological Survey). 1999. 1999 Resource Assessment of Selected Tertiary Coal Beds and Zones in the Northern Rocky Mountains and Great Plains Region. Professional Paper 1625-A. Available online at: http://pubs.usgs.gov/pp/p1625a/.

23. USGS. 2000. Preliminary Gulf Coast Coalbed Methane Exploration Maps: Depth to Wilcox, Apparent Wilcox Thickness and Vitrinite Reflectance. Report 2000-113. Available online at: http://pubs.usgs.gov/of/2000/ofr-00-0113/downloads/OF00-113.pdf.

24. Utah BLM (Bureau of Land Management). 2005. Chapter 4: Mineral Occurrence Potential and Likelihood of Development of Mineral Resources. In: Mineral Potential Report. Utah Department of Interior, Bureau of Land Management. Available online at: http://www.blm.gov/pgdata/etc/medialib/blm/ut/richfield_fo/planning/rmp/background_documents/mineral_potential.Par.97714.File.dat/RichfieldMineralPotentialReport_CH_4.pdf. Accessed August 28, 2012.

25. Wheaton, J., T. Donato, S. Reddish, and L. Hammer. 2006. 2005 Annual Coalbed Methane Regional Ground-Water Monitoring Report: Northern Portion of the Powder River Basin. Open-File Report 538. Montana Bureau of Mines and Geology. EPA-HQ-OW-2008-0517 (DCN 03474).

26. WOGCC (Wyoming Oil and Gas Conservation Commission). 2010. Wyoming CBM Production. Available online at: http://wogcc.state.wy.us/. EPA-HQ-OW-2008-0517 (DCN 07364).

27. WYSGS (Wyoming State Geological Survey). 1999. Wyoming Fossil Fuels for the 21st Century. Available online at: http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/44_1_ANAHEIM_03-99_0061.pdf. Accessed August, 28, 2012.

SECTION 4
PRODUCED WATER MANAGEMENT AND TREATMENT TECHNOLOGIES

This section provides information on the management and treatment technologies to reduce or eliminate pollutant discharges from CBM extraction operations. EPA identified technologies used at CBM operations in 2008 through site visits and the responses to the Detailed Questionnaire (see Section 2 for a description of EPA's data collection efforts). Through publicly available information, EPA also identified technologies that have not been implemented at CBM operations in 2008 but are potential candidates for treating produced water. Section 4.1 describes treatment technologies that can reduce pollutant discharges. Section 4.2 presents information on zero discharge practices that eliminate the discharge of produced water, and therefore the discharge of associated pollutants to surface water.

4.1 TREATMENT TECHNOLOGIES

This section describes technologies to treat produced water prior to discharge. Each section describes the technology, discusses factors impacting implementation of the technology at CBM operations at a national level, and provides information on the components required for developing cost estimates associated with their use. Before discharging produced water, CBM operators may treat produced water to reduce concentrations of suspended and dissolved solids. As discussed in Section 3.6, produced water contains dissolved cations such as sodium, calcium, and magnesium. These constituents are in equilibrium with dissolved anions such as bicarbonate, chloride, and sulfate. The concentrations and types of cations and anions present in the produced water will depend on the geology of the basin and will impact the treatment types that can be used to reduce the dissolved constituents. Ion exchange and reverse osmosis are the only treatment technologies reported to be used by CBM operators to reduce TDS concentrations in 2008. Other treatment technologies capable of TDS removal, such as nanofiltration, capacitative deionization, electrodialysis/electrodialysis reversal, and distillation/evaporation, have not yet been implemented at full-scale CBM operations and, therefore, are only briefly discussed.

4.1.1 Settling Ponds

Settling ponds are designed to remove particulates from wastewater using gravity sedimentation. They work by allowing water to stagnate or flow very slowly through the pond, thereby allowing suspended solids to settle to the bottom of the pond. Large particles settle quickly, but smaller suspended particles take longer to settle. For this reason, the suspended solids removal rates increase with residence time (i.e., the amount of time that it takes a discrete quantity of water to flow through the system) and particle size.

The size and configuration of settling ponds vary; some ponds operate in series or in parallel, while others consist of one large settling pond. Operators size ponds to provide enough residence time to reduce the total suspended solids (TSS) levels in the wastewater to a target concentration and to allow for a certain lifespan of the pond.

Some CBM operators have added aeration to settling ponds (i.e., rip-rap, fountains, aerators) to enhance gravity settling and to aid in the removal of metals. When certain dissolved metals come in contact with oxygen, the metals oxidize and become solid particles in the water. These solid particles can then be removed by filtration or flotation. For example, at a neutral pH, iron exists as soluble ferrous iron (Fe^{+2}). However, in the presence of oxygen, the soluble ferrous iron oxidizes to ferric iron (Fe^{+3}), which can hydrolyze to form insoluble ferric hydroxide ($Fe(OH)_{2(s)}$), as shown in Equation 4-1.

$$Fe(OH)_{2(s)} = Fe^{+2} + 2OH^{-}$$ **Equation 4-1**

Insoluble ferric hydroxide will precipitate from solution, thereby removing dissolved iron from the influent water. Initiating iron oxidation in produced water involves adjusting the pH to a neutral value, if needed, and routing the produced water over rip-rap to enhance the water's contact with air before discharge or by adding aerators to the pond. The use of rip-rap also helps in controlling erosion at the influent to or effluent from the pond, where scouring is a problem.

Implementing Settling Ponds at CBM Operations

The concentration of settleable solids in produced water will affect the design and operation of the pond. Higher levels of settleable solids may generate more residuals that require disposal, require a longer residence time, or require a larger pond footprint. Settling ponds do not target reductions in the concentrations of TDS.

CBM extraction generates large volumes of produced water at the beginning stages of a well and steadily decreases over the lifetime of the well (as discussed in Section 3.2). Settling ponds are designed to store the maximum initial volume of produced water generated by a given well or group of wells. Pond construction requires a large footprint to construct a pond capable of treating the maximum volume of produced water initially coming out of a well or group of wells. As the produced water volume declines over time, the settling ponds will likely be closed or used for treatment of produced water from a newly producing well or group of wells. The latter option may incur a higher cost to operators because, if the new well or group of wells is not near the pond, transportation costs will increase.

Table 4-1 lists considerations for using settling ponds at CBM operations.

Table 4-1. Considerations for Using Settling Ponds at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• Settling ponds do not target reduction of total dissolved solid concentrations. • Ponds may require increased residence time due to higher levels of settleable solids. • Ponds may require large footprint to handle maximum produced water flow. • Also, see considerations for evaporation/infiltration ponds in Table 4-17.
Available in All Basins?	Yes. However, settling ponds will not remove TDS.
Currently In Use at CBM Operations?	Yes, settling ponds were reported at CBM operations in all of the discharging basins.

Components of Costs

Table 4-2 shows operating capital and operating and maintenance (O&M) cost components for settling ponds.

Table 4-2. Capital and O&M Costs for Settling Ponds

Cost	Use
Capital Costs	• Land acquisition or leasing is required for the pond footprint if the operator does not own the land adjacent to the wells. The pond footprint is often large to achieve the appropriate residence time to meet targeted treatment efficiencies. The availability of additional land owned by the operator for a pond will be site-specific. Alternatively, ponds can be located elsewhere and transportation costs must be considered. • Operators constructing new ponds on undisturbed land will incur costs for excavation and mobilization. • Operators may also need: - Piping infrastructure to transport the water from the wellhead(s) to the pond. - Pumps to transport the water, if gravity flow is not possible. - Liners to contain the produced water or to minimize infiltration into the subsoil (e.g., all CBM constructed ponds in Alabama must use liners because the state does not allow infiltration from ponds.) (CMAA, 2012). • Settling ponds may require additional power. If the CBM project does not currently have electricity, operators will need to bring infrastructure or generators on site. • Operators also incur costs for pond closure at end of life.
O&M Cost Components	• Pumps will require electricity. • Costs will be incurred to transport produced water to the pond by pumps and pipeline or trucking. • Ponds can achieve higher removal efficiencies for TSS and other pollutants through the addition of chemicals (e.g., pH adjustments, coagulants, flocculants, scale inhibitors, biocides).
Other Cost Components	Ponds require permits to operate.
Residuals Generated	As solids settle, sludge will accumulate at the bottom of the pond and may need periodic removal, typically by dredging, and disposal off site. Otherwise, the sludge will remain in the pond until closure (ERG, 2007a).
Energy Requirements	Pond systems can be designed to use gravity flow, but most need pumps to move water from the wellhead to the pond and then from the pond to the final destination. If the operator does not already have power on-site for transporting produced water, he will need to install power lines or generators.
Personnel Requirements	Operators may need to periodically check the system (e.g., ensure that produced water flow into and out of the pond is not obstructed, ensure that water levels in the pond are appropriate) and perform monitoring required by the discharge permit.

4.1.2 Chemical Precipitation

Chemical precipitation wastewater treatment systems remove dissolved metals and suspended solids through the addition of chemicals to the wastewater to alter the physical state of targeted pollutant to help settle and remove the solids. The specific chemical(s) used depends upon the type of pollutant requiring removal. Operators can precipitate chemicals using the following methods:

- Adding Chemicals to Enhance Coagulation – The addition of chemical coagulants can enhance settling by promoting the growth of larger, heavier particles. Polymers can be added to water to bind together particles into larger particles. Additional chemicals such as alum (aluminum sulfate, $Al_2(SO_4)_3\ 18H_2O$) or iron salts may be required to change the charge of the particles such that they can aggregate and settle. However, the use of these compounds in produced water treatment may introduce additional dissolved constituents (i.e., constituents present in the chemical additives) that are being targeted for removal from the produced water (e.g., iron, sulfate).
- Adding Chemicals for Precipitation – Chemicals can also be added to convert the dissolved pollutants to insoluble forms that can then precipitate, or settle, out of solution. For example, Pollutant B (which is soluble in water) is the pollutant targeted for removal. Chemical A is added to the solution with dissolved pollutant B. A and B react to form a new chemical, AB, which is insoluble; it therefore becomes a suspended solid rather than a dissolved solid. The insoluble solids precipitate out of the solution; they either settle over time or need to be removed by filtration. Chemical precipitation cannot be used for highly soluble ions, such as sodium and chloride that are the components of TDS found in produced water. Sodium and chloride will remain in solution at all pH levels (Eckenfelder, 2000).

Table 4-3 shows how different additive chemicals remove different pollutants.

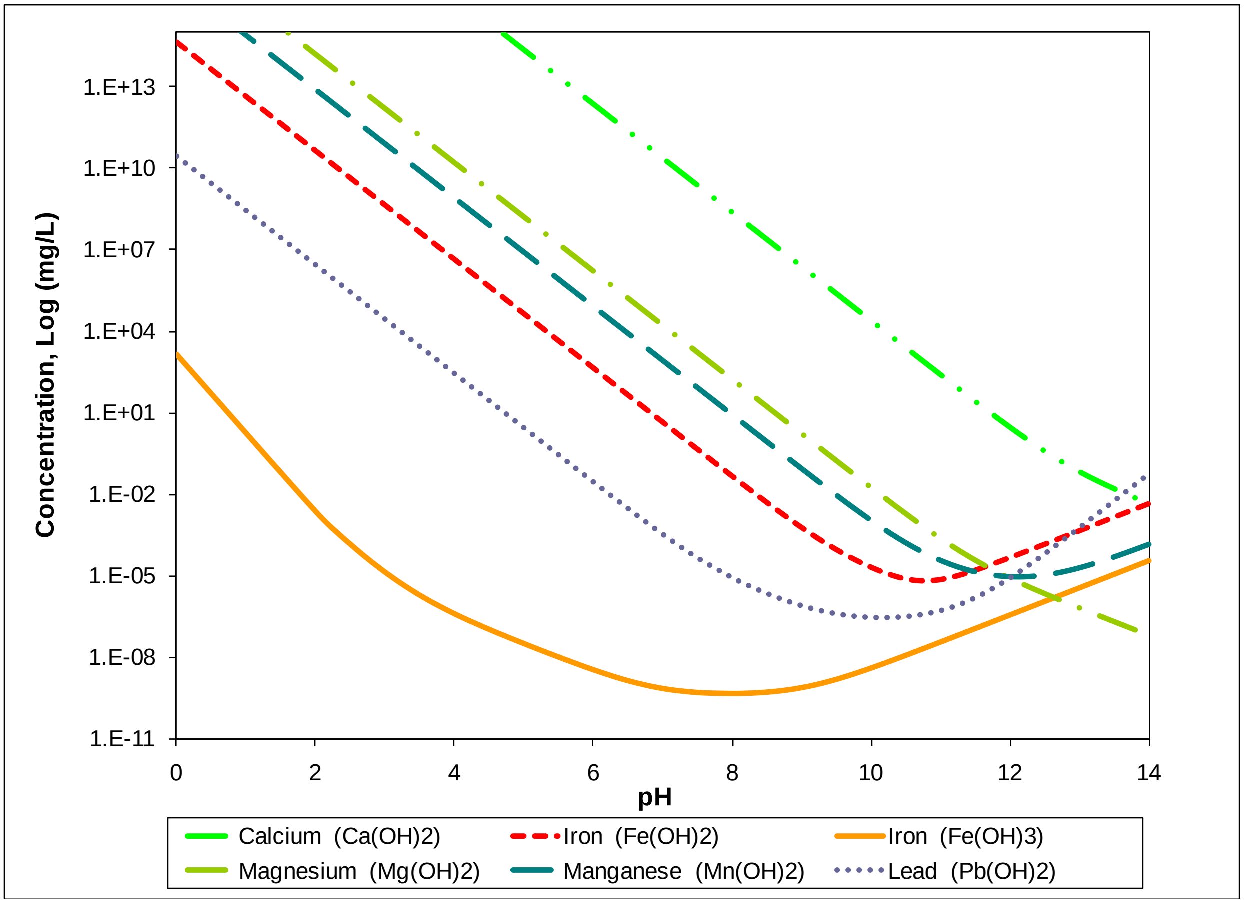
Table 4-3. Common Additive Chemicals and Targeted Pollutants

Additive Chemical	Targeted Pollutants
Alum	Calcium and Magnesium Bicarbonate, Alkalinity, Phosphate, Mercury
Sulfides	Arsenic, Cadmium, Selenium, Mercury
Lime (Calcium Hydroxide)	Hardness and Total Suspended Solids
Ferric Chloride	Alkalinity or Phosphates
Ferric Sulfate	Barium
Ferrous Sulfate	Barium, Calcium, Calcium Hydroxide
Ferric Hydroxide	Mercury, Cadmium

Sources: Metcalf and Eddy, 2003; U.S. EPA, 2000.

One of the underlying principles that dictate chemical precipitation design and operation is that a metal’s solubility is a direct result of pH. Each metal is soluble at different pH ranges (Metcalf and Eddy, 2003). As a result, chemical precipitation operation involves careful control of pH to maximize metals removal. Figure 4-1 shows how pH affects the solubility of different metals. The minimum of each curve represents the minimum solubility and optimum pH for chemical precipitation. As shown in the figure, the solubility of calcium and magnesium, two of the pollutants present in produced water, decrease with increasing pH; however, these pollutants do not have minimum solubility points within the typical pH range for this technology. Sodium, the dissolved salt commonly targeted for removal in produced water, is not typically removed by chemical precipitation.

Because CBM pollutants have different solubility points, it is not possible to achieve maximum removal of all pollutants in a one-step precipitation process. In order to remove all of the influent pollutants, multiple stages of precipitation are necessary, using different pH levels and additive chemicals (Metcalf and Eddy, 2003). Table 4-3 lists what additive chemicals remove different pollutants.



Source: Means and Hilton, 2004.

Figure 4-1. pH versus Concentration of Pollutants

Implementing Chemical Precipitation at CBM Operations

Treatment system designers and operators consider the influent water characteristics and the desired effluent quality when selecting the appropriate quantity and type of additive chemical, including influent wastewater temperature, volume feed rate, pH, and pollutant concentrations (Metcalf and Eddy, 2003). Pollutant concentrations in produced water can vary over time, requiring ongoing monitoring and operation considerations during chemical addition and treatment.

As shown in Table 4-3, the common additives used for precipitation may include pollutants that are targeted for removal in produced water (e.g., iron, calcium); therefore, adding these chemicals may add dissolved solids to the effluent water. Advanced monitoring systems may be installed to minimize the effects of chemical addition on effluent water (Metcalf and Eddy, 2003).

Table 4-4 lists considerations for using chemical precipitation at CBM operations.

Table 4-4. Considerations for Using Chemical Precipitation at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	Chemical precipitation does not reduce concentrations of the constituents of TDS found in produced water (e.g., sodium, chloride).
Available in All Basins?	Yes. However, these treatment systems require appropriate pH and temperature controls and pollutant concentrations for efficient treatment to remove soluble metals, as shown in Figure 4-1. Sodium and chloride are not removed by chemical precipitation.
Currently In Use at CBM Operations?	No; operators may add chemicals to settling ponds to enhance precipitation but CBM operators are not using chemical precipitation systems with equalization tanks, precipitation tanks, and clarifiers.

Chemical Precipitation Cost Components

Table 4-5 shows capital and O&M cost components for chemical precipitation.

Table 4-5. Capital and O&M Costs for Chemical Precipitation

Cost	Use
Capital Costs	• If the operator does not have the land available for the treatment system footprint, he will need to acquire additional land. Alternatively, system can be located elsewhere and transportation costs must be considered. • The operator may also need: - Chemical storage and mixing tanks. - Equalization tanks or basins; - A settling tank (clarifier) or filtration system. - Piping infrastructure to transport the water to and from the treatment system. - Low-pressure pumps for chemical addition. - Monitoring equipment to monitor chemical levels and ensure appropriate chemical addition.
O&M Cost Components	• The treatment system may require additive chemicals. • Costs will be incurred to transport produced water by pumps and pipeline or trucking. • The treatment system will require periodic system maintenance, including sludge disposal.
Residuals Generated	In addition to treated wastewater, chemical precipitation processes produce sludge. The quantity and composition of the sludge depends on the pollutants removed and the additive chemical used. The sludge produced from chemical precipitation may go through further treatment to recover water and concentrate the solids before ultimate disposal (e.g., landfill).
Energy Requirements	Low-pressure pumps used for chemical addition will need electricity to power them.
Personnel Requirements	The treatment system requires personnel to monitor and control the system.

4.1.3 Ion Exchange

Ion exchange removes charged ions (metals and other dissolved salts) from produced water by exchanging them with other charged ions. Ion exchange units use either cation or anion resins: cation resins exchange positive ions and anion resins exchange negative ions. Positively charged cations such as sodium, magnesium, and calcium are the primary ions in produced water targeted for removal. Therefore, cation resins are required for the treatment of produced water.

In CBM ion exchange applications, pretreatment is not a significant concern because of the low levels of suspended solids. A representative from Exterran (formerly EMIT), a Powder River Basin ion exchange vendor, noted that the Exterran/Higgins Loop™ ion exchange unit has a high tolerance for TSS and produced water does not require filtration before treatment with this system.

Implementing Ion Exchange at CBM Operations

As discussed previously, produced water contains dissolved cations such as sodium, calcium, and magnesium in equilibrium with dissolved anions such as bicarbonate, chloride, and sulfate. The concentrations and types of cations and anions present in the produced water will depend on the geology of the basin. For example, in the Powder River Basin, the dissolved solids consist mostly of sodium bicarbonate, present as sodium ions (Na^+) and bicarbonate ions (HCO_3^-). The type of ion exchange resin used will depend on both the pollutants targeted for removal and their influent and targeted effluent concentrations.

Equation 4-2 illustrates the ion exchange reaction that takes place to remove sodium from produced water with the presence of bicarbonate ions. The resin (R) first exchanges its hydrogen ions (H^+) with sodium ions (Na^+). After the initial ion exchange reaction, the hydrogen ions (H^+) are free to react with the bicarbonate (HCO_3^-) ions in solution to form CO_2 (Beagle, 2007). After ion exchange treatment, the effluent wastewater may require pH adjustment before reuse or discharge due to the depletion of bicarbonate (ALL, 2006). Many ion exchange resins use sodium as the cation on the resin rather than hydrogen. These resins would not be appropriate for removing sodium because they add sodium rather than hydrogen ions to the solution. Therefore, ion exchanges systems designed for produced water use hydrogen ions as the cation on the resin. Because the treated water will contain more hydrogen ions, the produced water will become more acidic (pH will decrease) (NETL, 2011a).

$$R\text{-}H^+ + Na^+ + HCO_3^- \rightarrow R^-Na^+H^+ + HCO_3^- \rightarrow R\text{-}Na^+ + H_2O + CO_2 \qquad \textbf{Equation 4-2}$$

In a paper discussing the application of produced water treatment technologies, Kimball (2010) noted that, outside the Powder River Basin, ion exchange has limited application due to the presence of higher concentrations of mixed salts such as sodium chloride and sodium sulfate. Removing TDS in this type of water may require a two-stage process, shown in Equation 4-3 and Equation 4-4. In the first step, sodium is removed, similar to the first step of Equation 4-2. The hydrogen ions remain in solution rather than reacting with bicarbonate. The second step removes the chloride ions using an anion resin. This additional step increases the cost of the ion exchange system because both cation and anion exchange units are required.

$$R\text{-}H^+ + Na^+ + Cl^- \rightarrow R^-Na + H^+ + Cl^- \qquad \textbf{Equation 4-3}$$

$$R^-OH + H^+ + Cl^- \rightarrow Cl^-R + H_2O \qquad \textbf{Equation 4-4}$$

As discussed previously, ion exchange resins designed for sodium ion removal replace the sodium ions in the produced water with hydrogen ions from the resin. The increase in hydrogen ions decreases the pH of the effluent water. The decrease in pH changes the concentrations of the carbonic components of the water (CO_2, HCO_3^-, H_2CO_3), which in turn affects the concentrations of calcium and magnesium in the produced water and the overall effluent quality.

As shown in Equation 4-2, the hydrogen ions on the resin used for sodium removal fill with sodium ions as the process occurs. The hydrogen ions replace the sodium ions to regenerate the resin and to continue produced water treatment. Regeneration requires a strong acid (for example, sulfuric acid) to be added over the resin bed. The sodium ions desorb from the resin and the hydrogen ions from the acid replace them. The resulting regenerate solution is a high-sodium brine solution. Operators rinse the resin with clean water to prepare it for another cycle, and collect and dispose of the regeneration solution and rinse water. Resins also require periodic disinfection in some cases to prevent biological fouling (ALL, 2006).

Operators may further treat the resulting brine stream before disposal (i.e., crystallization, thermal evaporation/distillation). Operators in the Powder River Basin currently using ion exchange typically dispose of the brine through underground injection.

In addition to considerations previously discussed, the following factors are important when implementing ion exchange at CBM operations:

- Influent Water –*An Integrated Framework for Treatment and Management of Produced Water: Technical Assessment of Produced Water Treatment Technologies* (CSM 2009) states that ion exchange is effective for produced water with TDS between 500 and 7,000 milligrams per liter (mg/L). As shown in Table 3-7, the average TDS concentration of produced water in the eastern U.S. CBM basins may be higher than recommended for use of ion exchange. In addition, 3,500 mg/L is the upper limit TDS concentration for an ion exchange system used in the Powder River Basin to remove sodium from sodium bicarbonate produced water.
- Flow Bypass and Blending – Ion exchange can reduce TDS concentrations to less than the permit-required discharge concentrations. To reduce costs, operators may treat only a portion of their produced water and blend treated and untreated water to reach the required effluent concentration.

Table 4-6 summarizes the considerations for using ion exchange at CBM operations.

Table 4-6. Considerations for Using Ion Exchange at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• The effectiveness of ion exchange treatment systems depends on the produced water TDS concentrations and the TDS constituents (e.g., sodium chloride versus sodium bicarbonate). - These systems can be operated as a batch or continuous processes (with one or multiple treatment trains), allowing for treatment of decreasing volumes of water. • Regeneration waste requires recycling or disposal.
Available in All Basins?	No, TDS concentrations may be too high to make ion exchange a viable treatment method in most basins.
Currently in Use at CBM Operations?	Yes, ion exchange is in use only in the Powder River Basin.

Table 4-7 lists known ion exchange vendors identified by EPA in the CBM Extraction Industry. As of 2008, only the Powder River Basin operated ion exchange units for produced water. The *Ion Exchange Vendors in the CBM Industry* memorandum (U.S. EPA, 2013) provides additional details for each type of ion exchange unit listed in Table 4-7. In general, the variations between each ion exchange system represent different configurations to reduce treatment residuals volumes or reduce system downtime for resin regeneration events. Systems are specifically designed and operated based on discharge requirements and influent water quality. Ion exchange systems are typically capable of removing up to 66 percent of the conductivity in influent waters (Kimball, 2010).

Table 4-7. Summary of Known Ion Exchange Vendors in the CBM Industry

Vendor	Technology Name	Resin[a]	CBM Status	Basin	References
Exterran Water Discharge Technology, LLC (Exterran) and Severn Trent Services	Higgins Loop™ continuous ion exchange	SAC	Deployed at full scale.	Powder River	• Dennis, 2005 • Johnston, 2010
Drake Water Technologies	Drake countercurrent process	SAC	Deployed at full scale.[b]	Powder River	• ERG, 2007b (site visit) • Drake, 2011 (vendor call) • Drake, 2012 (vendor email)
Eco-Tec Equipment	Recoflo™	SAC	Deployed at full scale.	Powder River	• Eco-Tec, 2008 • Eco-Tec, 2007 • Eco-Tec, 2006
Rohm and Haas	Cross-current ion exchange process	SAC and WAC	Pilot testing.	Powder River	PG Environmental, 2007a (site visit)
SET Corp (formerly RG Global)	DynIX™	WAC	Deployed at full scale.	Powder River	Jangbarwala, 2008

a – SAC – strong-acid cation; WAC – weak-acid cation.

b – The Drake Water Technologies ion exchange unit was successfully installed at two sites in the Powder River Basin. However, in the fall of 2010, the price of gas dropped and made it cost-prohibitive for operators to install and/or maintain ion exchange units for treatment of their produced water (Drake, 2012).

Components of Costs

Ion exchange technologies have lower capital and O&M costs than other TDS treatment technologies such as reverse osmosis (URS, 2011; ALL, 2011). The capital costs cover tanks, pumps, and piping. Vendors estimate that 70 to 80 percent of the operating costs are for the regeneration solution and the disposal of the regenerate; only a small portion of the operating costs is from purchasing the resin (CSM, 2009; Drake, 2011). Third-party ion exchange vendors may offer ion exchange units to CBM operators for a dollar per barrel ($/bbl) operating and maintenance cost, which includes everything needed to treat the water to a specified effluent concentration, discharge the water, and dispose of residual waste. CBM operators work with ion exchange vendors to design a system appropriate for their influent water quality flow and targeted effluent.

Table 4-8 shows operating capital and O&M cost components for ion exchange.

Table 4-8. Capital and O&M Costs for Ion Exchange

Cost	Use

Capital Costs	• If the operator does not have the land available for the treatment system footprint, he will need to acquire additional land. Alternatively, skid-mounted units with smaller footprints may be useful for produced water because of the finite length of time water treatment will be required.
	• The operator may also need:
	  - Treatment vessels for ion exchange.
	  - Chemical storage tanks for chemicals used in regeneration and for storing brine prior to disposal.
	  - Equalization tanks to ensure constant flow to the system.
	  - Piping infrastructure to transport the water to and from the treatment system.
	  - Low-pressure pumps.
	• Ion exchange will require additional power. If the CBM project does not currently have electricity, operators will need to bring infrastructure or generators on site.

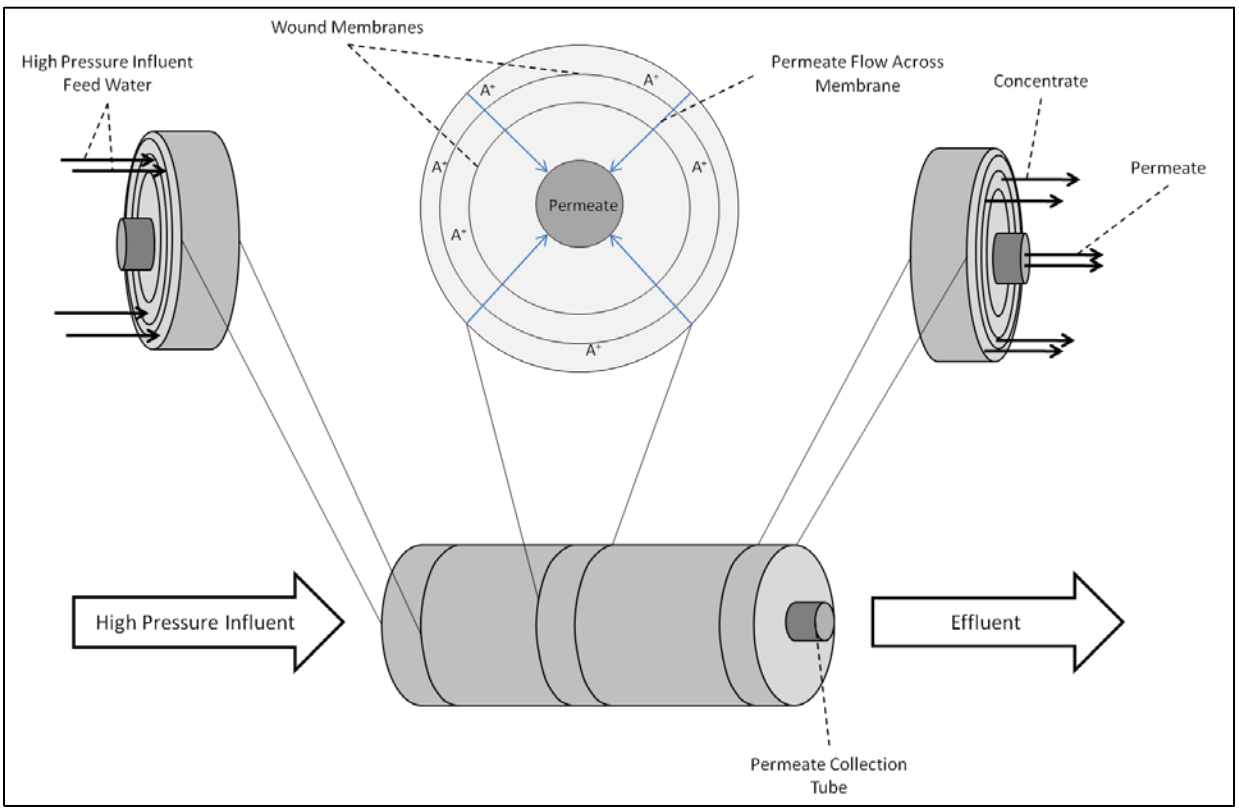
O&M Cost Components	• Operators may use biocides to prevent resin fouling. • Costs will be incurred to transport produced water by pumps and pipeline or trucking. • Resin fouling may occur and will require regeneration using chemicals such as hydrochloric or sulfuric acid. The frequency of regeneration will increase with increased TDS concentrations. • The frequency of resin replacement will depend on the amount of pollutant removed and the effectiveness of resin regeneration. The lifespan of the resin will vary across CBM operations due to the varying concentrations and volumes of produced water treated.
Residuals Generated	Operators must remove, neutralize, and dispose of residuals generated by the treatment system. Operators typically dispose of the residuals via underground injection in the CBM Extraction Industry.
Energy Requirements	Various sources indicate that ion exchange alone requires lower energy consumption per treated gallon than electrodialysis/electrodialysis reversal, reverse osmosis, or evaporation/condensation (URS, 2011; ALL, 2006). Energy requirements typically only include electricity for pumps.
Personnel Requirements	The treatment system requires personnel to monitor and control flow rates, product water quality, and resin regeneration.

4.1.4 Reverse Osmosis

Reverse osmosis (RO) is a well-established membrane treatment process used for desalination of seawater and removal of dissolved materials from industrial wastewater. This section provides a brief overview of membrane filtration and then focuses on RO, the membrane filtration technology that can be used to remove dissolved salts, such as sodium, from produced water.

Membrane filtration uses thin film membranes that are semi-permeable, meaning they allow water but not dissolved solids to flow through; they are permeable to water, but impermeable to dissolved solids. The rate that water passes through the membrane depends on the operating pressure, concentration of dissolved materials, and temperature, as well as the permeability of the membrane.

In wastewater treatment applications, membrane filtration separates the feed wastewater into two product streams: the permeate, which has passed through the membrane, and the concentrate, which has been retained ("rejected") by the membrane. The percentage of membrane system feed that emerges from the system as permeate – i.e., the volume of permeate divided by the volume of feed – is known as the water recovery. Figure 4-2 illustrates a typical RO system.



Source: Based on information from Metcalf and Eddy, 2003 and CSM, 2009.

Figure 4-2. Spiral-Wound Membrane Flow Diagram

Membrane filtration technologies include microfiltration, ultrafiltration, nanofiltration, and reverse osmosis. Table 4-9 lists general characteristics of membrane filtration technologies and the typical constituents removed. As shown in Table 4-9, the differences in the pollutants removed by these filtration technologies lie in the pore sizes. As seen in the table, both nanofiltration and RO can remove dissolved inorganics. However, the nanofiltration membrane is not a complete barrier to dissolved salts. In general, salts that have monovalent ions such as sodium chloride or sodium bicarbonate have rejections (removals) of 20 to 80 percent. Salts with divalent anions (e.g., magnesium sulfate) have rejections of 90 to 98 percent. Therefore, RO membranes are the most effective for removing the TDS found in produced water from CBM operations (Dow Chemical, 2011).

Table 4-9. Effectiveness of Membrane Filtration Technologies

Feature	Microfiltration	Ultrafiltration	Nanofiltration	Reverse Osmosis
Operating Pressure (psi)	15	75	225	400
Pore Size (nm)	>50	2–50	<2	<2
Reject/Concentrate Volume	5–15%	5–15%	10–25%	40–70%
Suspended Solids Removal	Excellent	Impractical	Impractical	Impractical
Dissolved Inorganic Removal	Not Applicable	Not Applicable	Good (Depending on Salt Species)	Very Good
Energy Requirements	Low	Medium	Medium	High

Sources: Metcalf and Eddy, 2003; CSM, 2009; Eckenfelder, 2000.

RO membranes separate constituents based on size and electrostatic charge. They will repel most ions (charged particles) and allow neutral molecules like water to pass through. RO removes both cations and anions simultaneously. Because salts, such as sodium (Na^+) and chloride (Cl^-), are ions that are repelled by RO membranes, RO is used for desalination (Metcalf and Eddy, 2003). Typical RO membranes reject more than 99 percent of the ions in the produced water (CSM, 2009). According to information from CDM, an RO vendor, because RO removes both cations and anions simultaneously, it has broader applications than ion exchange for treatment of produced water (CDM, 2007).

The typical design characteristics of membranes result in treatment rates of 8 to 12 gallons per square foot of membrane per day (Metcalf and Eddy, 2003). To reduce the space required by membrane systems, the system design generally configures the membranes as spirals, tubes, or multiple layers, as shown in Figure 4-2. With a high-pressure pump, feed water is continuously pumped at elevated pressure to the membrane system. Within the membrane system, the feed water is split into the permeate and concentrate (i.e., a highly saline, concentrated brine). Disposal options for concentrate from produced water treatment include deepwell injection and evaporation basins.

Without proper pretreatment, RO membranes are subject to fouling.[8] Constituents that cause fouling include metal hydroxides, colloidal and particulate foulants, precipitates or salts,

[8] Fouling occurs when both dissolved and suspended solids deposit onto a membrane surface and degrade its overall performance, thereby decreasing permeate quality and water recovery percentage.

organics (e.g., oil), and biologicals (e.g., microbes, bacteria). To prevent scaling and reduce membrane fouling, the addition of antiscalants or biocides or TSS removal is required.

Implementing RO at CBM Operations

Operators consider the following in the design and operation of RO units for produced water:

- Influent Water Quality – RO was optimized for desalination of sea water, which typically has a TDS concentration of 35,000 mg/L. RO units are generally only able to treat wastewater with TDS concentrations up to about 50,000 mg/L (CSM, 2009). High water recovery[9] (75 to 90 percent) is possible if influent TDS is below approximately 25,000 mg/L (ALL, 2011). As shown in Section 3.6, the maximum average basin TDS concentration is 12,512 mg/L.
- Fouling and Scaling – Compounds in produced water can foul membranes, which can reduce treatment efficiency and result in high volumes of concentrate. A larger concentrate stream can lead to higher disposal costs.
- Membrane Life – Because of potential fouling issues, membranes can last as little as one to two years in some cases (Asano, 2007).

RO systems can be manufactured and installed as portable, skid-mounted units, suitable for the generally short time required to treat produced water. Table 4-10 shows considerations for using RO in CBM operations.

Table 4-10. Considerations for Using RO at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• Design variations in RO treatment systems are dependent on the discharge requirements and influent water quality. • Constituents in produced water can foul membranes and pretreatment (e.g., filtration, pH adjustment, antiscalant addition) and/or periodic cleaning may be required to mitigate scaling. • Membranes may need frequent replacement because of the common fouling/scaling issues (Asano, 2007).
Available in All Basins?	Yes, TDS levels in produced water in the discharging basins are within the range that is treatable by RO (up to about 50,000 mg/L) (CSM, 2009).
Currently In Use?	Yes; RO was reported at CBM operations in the Powder River Basin.[a]

a – While some operators reported using RO treatment systems in their responses to the Detailed Questionnaire, many of them also noted that the systems did not prove to be economically feasible, and they were forced to shut them down.

[9] The water recovery percentage is defined as the treated wastewater volume divided by the total influent wastewater volume.

Components of Costs

RO vendors note that system costs depend on influent water quality, flow rate, and desired effluent quality (Kimball, 2010; Migliavacca, 2011; Alexander, 2011). Table 4-11 shows operating capital and O&M cost components for RO systems.

Table 4-11. Capital and O&M Costs for RO

Cost	Use
Capital Costs	• If the operator does not have the land available for the treatment system footprint, he will need to acquire additional land. Alternatively, skid-mounted units with smaller footprints may be useful for produced water because of the finite length of time water treatment will be required. • The operator may also need: - Pretreatment equipment if the influent water does not meet the requirements of the RO system. - Treatment vessels for ion exchange. - Chemical storage tanks for chemicals used for maintaining the RO system and for storing brine prior to disposal. - Equalization tanks to ensure constant flow to the system. - Piping infrastructure to transport the water to and from the treatment system. - High-pressure pumps.
O&M Cost Components	• Operators may use chemicals for pretreatment and/or to prevent membrane fouling. • Costs will be incurred to transport produced water by pumps and pipeline or trucking. • Membrane fouling may occur and will require replacement.
Residuals Generated	The amount of brine requiring disposal will depend on produced water salt concentration. According to CDM, brine disposal represents the most expensive treatment component due to the cost of trucking, limited number of disposal wells, and limited injection capacity (Kimball, 2010).
Energy Requirements	RO requires energy to run the pumps required to pressurize the influent. According to Siemens, a general rule of thumb is that for every 100 parts per million TDS in the influent, one pound of osmostic pressure is required (Siemens, 2011).
Personnel Requirements	RO systems operate with minimal onsite operator supervision.

Table 4-12 lists vendors that have developed RO systems for oil and gas wastewater as identified by EPA. EPA found only one vendor that had implemented RO at a full-scale CBM operation.

Table 4-12. Summary of Known RO Technologies Applicable in the CBM Industry

Vendors	Technology Description	Status[a]	References
Siemens Water Technologies	Siemens provides standard RO technology in mobile trailers and permanent installations that include settling ponds and media filtration for pretreatment.	Deployed at full scale (CBM).	Alexander, 2011 (vendor call)
GeoPure and Texas A&M	These vendors developed RO technology specifically for treating oilfield waters for agricultural and other beneficial use. The system has been tested with shale gas flowback water and is currently being applied in multiple feasibility studies.	Deployed at shale gas operations.	Burnett, 2006
Veolia Water Solutions[a]	Veolia markets various RO technologies (e.g., MORO, OPUS, ZDD) that are designed for different influent TDS concentrations and/or different residual generation rates.	Deployed at shale gas operations.	Migliavacca, 2011 (vendor call) Veolia Water Solutions, 2008
Triwatech, LLC	Triwatech configures site-specific treatment systems using various treatment technologies (including RO). EPA has not identified any full-scale systems to date.	Pilot testing (CBM).	Malecha, 2006
CDM	CDM reports that its RO technology can achieve greater than 98 percent recovery of produced water.	Bench testing (CBM).	Kimball, 2010

a – EPA did not find information to confirm status of the systems after the referenced date.

b – Veolia offers several different RO technologies, which target different flow rates and influent water quality.

c – Triwatech did not provide information on the operators that use its RO technology. In 2011, Triwatech LLC was consolidated under the trade name Rockwater®.

4.1.5 Other Desalination Technologies

This section provides information on additional technologies, such as distillation and electrodialysis, that are capable of removing TDS. With the exception of one distillation application, these technologies have not been implemented at CBM operations.

4.1.5.1 Distillation/Evaporation

Evaporation and distillation technologies separate dissolved salts from wastewater by evaporating the water, leaving a concentrated pollutant stream and, in some cases, condensing the purified water. These technologies are capable of handling very high influent TDS concentrations while creating small volumes of concentrated brine residuals, which require disposal. There are many variations of distillation and evaporation technologies, some of which require adding heat or mechanical energy to the wastewater to accelerate evaporation, thus using more energy. Existing data sources discuss the following types of thermal distillation processes used to treat wastewater (ALL, 2006):

- *Vapor Compression (VC):* Increases the water vapor pressure until it is greater than atmospheric pressure by increasing the temperature of the influent wastewater.
- *Multi-Stage Flash (MSF) and Multi-Effect Distillation (MED):* Decreases atmospheric pressure and increases water vapor pressure to immediately evaporate (“flash”) influent wastewater without heat addition (CSM, 2009).
- *Rapid Spray Evaporation (RSE):* Increases the rate of evaporation by increasing both the surface area of the wastewater and the air movement around the wastewater.
- *Freeze Thaw Evaporation (FTE):* Uses conventional evaporation in combination with a cycle of freezing and thawing influent wastewater. These systems are ideal for locations with drastic climate changes, where it is most efficient to operate as a conventional evaporation system during the warmer months and as a freeze-thaw evaporation system during the colder months.

All evaporation/condensation processes result in a concentrated brine stream in addition to treated wastewater. Distillation technologies typically have water recovery percentages between 60 and 95 percent (CSM, 2009; ALL, 2011). In general, as influent TDS concentrations increase, water recovery percentages decrease, resulting in a larger volume of residuals and higher disposal costs (URS, 2011). Metcalf and Eddy (2003) suggest that the disposal options for concentrated brine generated from thermal distillation units are the same as the disposal options for membrane technologies.

Typical influent TDS concentrations for wastewaters treated with this technology range from 60,000 to 80,000 mg/L and effluent concentrations can be less than 10 mg/L (ALL, 2011; CSM, 2009). Existing data sources suggest that, unlike other wastewater treatment technologies, the achievable effluent pollutant concentrations in the treated wastewater are not greatly affected by the influent concentrations.

Distillation is an energy-intensive process. The major energy requirement is for the evaporation of the influent wastewater. Produced water at CBM operations is managed at ambient temperature. Evaporation costs would vary by climate because colder climates will require more energy to evaporate the water. There are minor electricity requirements for running low-pressure pumps.

Table 4-13 summarizes the distillation and evaporation vendors in the oil and gas industry identified by EPA.

Table 4-13. Summary of Known Distillation/Evaporation Vendors in the Oil and Gas Industry

Vendor	Technology Name	Status	Source		References
			Site Visits	Shale Gas Vendor Calls	
Altela	AltelaRain[SM]	Deployed at full-scale CBM site.[a]	X		PG Environmental, 2007b
212 Resources	VACOM MVR System	Deployed at shale gas site.		X	Mertz, 2011
Fountain Quail	NOMAD Evaporator	Deployed at shale gas sites.		X	Roman, 2011
INTEVRAS	EVRAS Evaporation	Deployed at shale gas sites.		X	Adams, 2011

a – The AltelaRain[SM] treatment unit was deployed at a full-scale CBM operation, but only treated water from one CBM well.

Considerations for using distillation and evaporation technologies include the following (URS, 2011):

- Heat exchange surfaces tend to lose their ability to transfer heat through scaling. As the heat exchanger efficiencies decrease, more energy is required to run the unit, making the process less cost effective and energy efficient.
- Pretreatment processes, including media filtration, may need to be added prior to thermal distillation unit to remove solids from the influent wastewater stream.
- The concentrated brine stream generated from distillation and evaporation units requires handling and disposal.
- Distillation and evaporation treatments require a larger capital investment and physical footprint than other treatment technologies.

4.1.5.2 Electrodialysis and Electrodialysis Reversal

Electrodialysis (ED) and electrodialysis reversal (EDR) are separation processes that use electric charge and membranes to remove metals and dissolved solids from water. Electrodialysis membranes are semi-permeable, meaning they allow ions but not water to pass through. These processes are electrically driven and conducted at low pressures; however, they require more electricity to operate than most other membrane technologies, which, in comparison, make ED and EDR reversal less attractive treatment options (CSM, 2009).

ED and EDR technologies can treat wastewater with TDS concentrations as high as 15,000 mg/L and can remove between 50 and 95 percent of salts (ALL, 2011; URS, 2011). ED and EDR treatment costs vary depending on the influent wastewater and energy input. Total costs are site-specific and depend on the feed water quality. CSM (2009) reports that ED/EDR treatment costs increase with increasing influent TDS concentrations (assuming flow stays the same).

EPA did not identify any CBM operators who use ED/EDR technologies.

Advantages of using ED and EDR include the following:

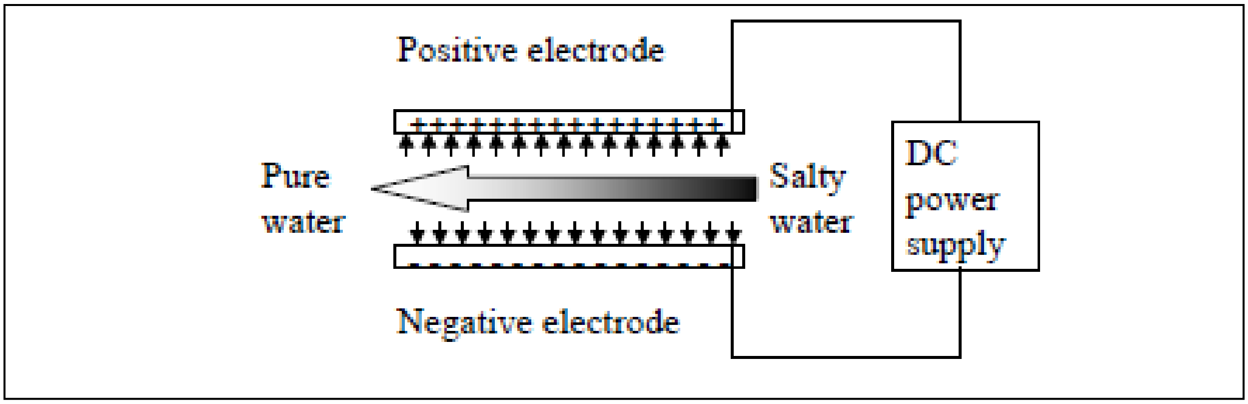
- Membrane life expectancy is longer for EDR than RO because of the continuous polarity reversal and membrane flushing (Asano, 2007). EDR membranes have an expected membrane life of eight to 10 years compared to as little as one to two years with RO membranes (Hayes, 2004);
- The reversal and flushing mechanism of EDR needs less maintenance than is required with RO (Asano, 2007).

Considerations for using ED and EDR include the following:

- Pretreatment is typically required prior to use and may include scaling control (i.e., pH adjustment, addition of an antiscalant), filtration to remove suspended solids, and disinfection to prevent biofouling (CSM, 2009).
- Calcium carbonate and magnesium hydroxide may form a scale inside the unit, which can decrease efficiency (URS, 2011).
- High influent wastewater TDS concentrations (>12,000 mg/L) may make ED and EDR treatment technologies cost prohibitive (ASIRC, 2005).

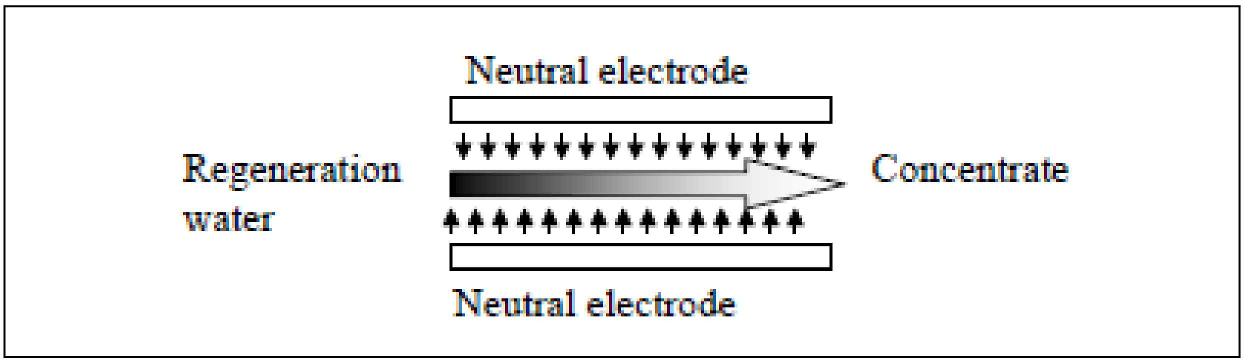
4.1.5.3 Capacitative Deionization

Capacitative deionization (CDI) is a developing desalination technology that works by adsorbing ions onto high-surface, porous electrodes with a low-voltage electric field. Water flows between the electrodes and ions in the water attract to the oppositely charged electrode (see Figure 4-3). Unlike ion exchange, where regenerating the resin requires using corrosive chemicals, electrodes can be cleaned of the ions they have acquired by simply removing the electric field (see Figure 4-4) (CSM, 2009).



Source: CSM, 2009.

Figure 4-3. Schematic of the CDI Treatment Process



Source: CSM, 2009.

Figure 4-4. Schematic of Electrode Regeneration in a CDI Treatment Unit

CDI has been shown to be cost-competitive with RO, at the pilot scale, in drinking water applications for feed water with TDS below 3,000 mg/L. However, capital costs for CDI modules become comparatively more expensive than RO at higher TDS levels (CSM, 2009).

EPA has identified one pilot test of CDI for a conventional gas reservoir and another pilot test of CDI for a CBM operation in the Green River Basin of Wyoming (CSM, 2009). In these tests, CDI was shown to be less susceptible to fouling and scaling than RO. EPA did not identify any examples of full-scale deployment of CDI for produced water treatment in the existing literature or responses to the CBM Detailed Questionnaire.

4.2 ZERO DISCHARGE MANAGEMENT METHODS

This section discusses produced water management methods capable of eliminating direct or indirect discharges to surface water by the operator (zero discharge methods).

4.2.1 Underground Injection

Underground injection involves pumping produced water into a permeable underground formation for storage or disposal. The formation must have adequate permeability and porosity to accept the wastewater.

EPA regulates underground injection wells under the Safe Drinking Water Act (SDWA), Underground Injection Control (UIC) program by setting minimum federal requirements (40 CFR 144) to protect underground sources of drinking water from contamination. States, territories, and tribes have the option of requesting primacy, or primary enforcement authority, from EPA for the injection wells located within their boundaries. To receive primacy, the requesting authority must set standards at least as stringent as the federal standards. Currently, EPA has delegated primacy to 33 states and three territories and it shares responsibility with seven states. EPA has complete control over the UIC programs in the remaining 10 states, and on Indian lands (U.S. EPA, 2011b).

EPA groups underground injection wells into six categories (U.S. EPA, 2011a):

- Class I industrial and municipal waste.
- Class II oil and gas production waste.
- Class III solution mining.
- Class IV hazardous and radioactive waste (since 1984, only used for disposal of wastes from EPA- or state-authorized ground water clean-up action).
- Class V wastes not covered in Class I through IV or Class VI (e.g., leach fields).
- Class VI geologic sequestration of carbon dioxide.

Most wells used for disposal of CBM produced water are UIC Class II wells. In some circumstances, CBM produced water has been treated first and then injected into UIC wells that have been constructed in undisturbed receiving formations, as has been seen in the Wyoming portion of the Powder River Basin. In the CBM Extraction Industry, Class I wells accept treatment residuals from ion exchange or reverse osmosis (NETL, 2006).

Table 4-14 summarizes available information on general underground injection practices for Class II wells in the major CBM basins. It presents typical depths at which CBM is produced and summary information on UIC regulations in each state. Receiving formations for produced water must have sufficient separation from production formations. Considerations for implementing underground injection for produced water disposal based on the design and cost are discussed below.

Implementing Underground Injection at CBM Operations

Drilling and completing injection wells in suitable formations requires careful planning. During site visits to the Powder River Basin, one state official noted that approximately half of the wells drilled for injection cannot accept produced water and half of the wells that initially accept produced water quickly become unusable due to limited storage capacity in the receiving formation. State officials explained that historically, in the Powder River Basin, disposal of produced water by injection has been difficult due to the lack of receptive geologic formations (PG Environmental, 2007b). EPA also spoke with officials at the Alabama Department of

Environmental Management, who expressed similar difficulties with using underground injection in Alabama basins (e.g., Black Warrior, Cahaba).

Underground injection wells constructed in undisturbed receiving formations are generally sensitive to clogging from even small quantities of suspended solids (e.g., coal fines) and biofilm resulting from bacterial growth. For this reason, operators usually treat produced water prior to reinjection, typically using low-pressure filtration followed in some cases by chlorine disinfection. During site visits, EPA observed CBM operators using filter socks, filtration canisters, and hydrocyclone separators for low-pressure filtration (ERG, 2007d; ERG, 2007e; PG Environmental, 2007c; PG Environmental, 2007a). Residual wastes from these units are expected to be generated in low volumes and comprise mainly coal fines. In contrast, produced water injected into UIC Class II disposal wells constructed in previously mined coal seams generally requires no pretreatment, because there is no risk of clogging in the receiving formation (ERG, 2007f).

Table 4-14. Summary of Underground Injection by Basin

Basin	State	Depth of Production Interval (Feet Below Ground Surface)	State Permitting Requirements Applicable to Injection[a]
Black Warrior and Cahaba	Alabama	350 – <4,100	Alabama has UIC implementation authority over Class II. UIC Class I wells are prohibited by state regulation.
Powder River	Montana and Wyoming	200 – <2,500	• Wyoming has UIC implementation authority over Class II wells. • Montana has UIC implementation authority over Class II wells. In addition to federal requirements, Montana requires detailed groundwater quality analyses for Class II wells.
Greater Green River	Wyoming	Unknown	See Powder River summary.
Central Appalachian	West Virginia and Virginia	1,500 – 2,500	• West Virginia has UIC implementation authority over Class II wells. • EPA has UIC implementation authority over all injection wells in Virginia.
Northern Appalachian	Pennsylvania	500 – 2,000	EPA has UIC implementation authority over all injection wells in Pennsylvania.
Raton	Colorado and New Mexico	<500 – <4,100	• Colorado has UIC implementation authority over Class II wells. • New Mexico has UIC implementation authority over Class II wells. In New Mexico, state permits are not required for Class II wells on federal lands, but injection wells must be approved by the Bureau of Land Management (BLM).
Illinois	Illinois, Indiana, and Kentucky	<650 – <3,000	Illinois has UIC implementation authority over all injection wells.
San Juan	Colorado and New Mexico	550 – 6,500	See Raton summary.
Uinta-Piceance	Colorado and Utah		• CO – See Raton summary. • Utah has UIC implementation authority over Class II injection wells not on Indian lands (EPA has authority for wells on Indian lands). Utah's regulations are similar to federal requirements, although Utah allows Class V wells to be permitted on an area basis rather than an individual basis.

Sources: Detailed Questionnaire responses; ALL, 2003; COGCC, 2009; ERG, 2007d; ERG, 2007e; ERG, 2007f; Illinois EPA, 2012; PG Environmental, 2007c; PG Environmental, 2007a; U.S. EPA, 2004; U.S. EPA, 2011a.
a EPA has authority for wells on Indian lands.
NA – Not applicable.

One of the most important considerations in managing produced water using underground injection is transporting the water to the injection site. Whether water is pumped through a pipeline or trucked to the injection site, it is typically transferred from the production wells into a tank battery or other water storage area prior to long-distance transportation. During site visits, operators who trucked water for disposal consistently indicated that trucking costs were the largest component of their reinjection costs. In addition to paying the drivers' fees, in some states operators must also post bonds for road maintenance and contribute to road repairs. During EPA's site visits to the Central Appalachian Basin, one operator noted that the number of available water trucks in his area was insufficient to support the operation's need, and explained that reinjection was only economically viable after the operation's water pipeline was constructed (PG Environmental, 2007a; ERG, 2007d; ERG, 2007e; ERG, 2007f).

Table 4-15 lists considerations for using underground injection at CBM operations.

Table 4-15. Considerations for Using Underground Injection at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• UIC wells require nearby receiving reservoirs with: - Sufficient permeability and porosity. - Sufficient storage capacity for the produced water volume. - Low reservoir pressure. - Separation from sources of drinking water and the CBM production formation. - Similar water quality as the produced water. • High non-water quality and cost impacts may occur if trucking is required to transport the water to the UIC well. • Produced water may require pretreatment (e.g., filtration, disinfection) to control clogging or microbial scaling in the geologic formation in which the produced water is injected.
Available in All Basins?	Although all basins have UIC wells, Alabama and Pennsylvania have limited UIC wells and would likely need to truck produced water to another state (ERG, 2012).
Currently In Use at CBM Operations?	Yes, in western U.S and West Virginia.

Underground Injection Cost Components

Table 4-16 lists the capital and O&M costs components for underground injection. Transportation may be a significant portion of the costs. Section 5 provides information on the underground injection costs used in EPA's initial engineering cost analysis.

Table 4-16. Capital and O&M Costs for Underground Injection

Cost	Use
Capital Cost Components	• The site footprint and therefore, the need for acquiring land, will depend on water storage requirements and the injection site. The injection well may not be located near the CBM operations. • Costs vary based on depth and local geology. This management method may require road and site construction if the injection site is not located near the production wells. • The operator may also need: - Pretreatment equipment (e.g., filter socks, chlorine injection). - Piping infrastructure to transport water to and from the injection site. Some sites may transport all water via truck. Sites collecting produced water via haul trucks may require more storage than sites receiving water from collection piping. - Pumps. - Monitoring equipment (e.g., pressure transducers, sampling ports). • Underground injection requires additional power. If the CBM project does not currently have electricity, operators will need to bring infrastructure or generators on site.
O&M Cost Components	• Operators may use chemicals (e.g., chlorine disinfectant) or filters prior to injection. • If operators select using a truck to haul water to the injection site, they may be subject to state law to contribute to road maintenance activities (ERG, 2007e). • Transportation is a significant component of the costs; therefore, underground injection will be expensive in areas without available UIC wells nearby. • If CBM operators use third parties to inject produced water, they will typically pay for disposal based on the produced water volume.[a]
Other Costs	• Injection wells also require permits prior to installing and operating the well. • Operators must also obtain financial assurance/bonding for road maintenance (where applicable) and injection site closure.
Residuals Generated	If filtration is required, operators will generate low quantities of coal fines.
Energy Requirements	Depending on the pressure of the receiving formation, operators may inject water with or without using high-pressure, multi-pump systems.
Personnel Requirements	• Underground injection requires personnel to monitor and control injection pressure, perform well maintenance activities and periodic inspections, and replace filter elements and disinfectant (PG Environmental, 2007a). • Regulatory agencies typically require quarterly monitoring of produced water.

a – Based on information gathered during EPA's site visits, CBM operators more commonly own and operate their own injection wells (ERG, 2007d; ERG, 2007e; ERG, 2007f; PG Environmental, 2007c; PG Environmental, 2007a).

4.2.2 Evaporation/Infiltration Ponds

Evaporation and infiltration ponds are constructed impoundments designed to collect and store produced water until it evaporates and/or infiltrates into the water table (ALL, 2003). Unlike the settling ponds discussed in Section 4.1.1, evaporation and infiltration ponds do not discharge to surface waters, and are therefore considered zero discharge practices. Evaporation and infiltration ponds are primarily found in the western U.S. CBM basins, but were also reported for projects in the Appalachian basin in the Screener (see Table 3-5). The use of evaporation and infiltration ponds in Wyoming is permitted through the Wyoming Department of Environmental Quality (WYDEQ). WYDEQ permits evaporation and infiltration ponds via WYPDES permits that allow discharge to on-channel reservoirs, which are ponds designed for full containment (i.e., evaporation/infiltration ponds) (ERG, 2012).

Seasonal variations like temperature, wind, and humidity are large factors in the efficiency of evaporation or infiltration ponds. Other factors that affect the efficiency of evaporation or infiltration ponds include:

- Landscape, topography, and local water table considerations.
- Runoff accumulation and associated pond flooding.
- Vegetation (ALL, 2003).

Implementing Evaporation/Infiltration Ponds at CBM Operations

Table 4-17 lists considerations for using evaporation/infiltration ponds at CBM operations.

Table 4-17. Considerations for Using Evaporation/Infiltration Ponds at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• Ponds may require large footprint to handle maximum produced water flow. • The ponds may potentially attract wildlife. Operators may consider covering ponds. • Pond leakage and saline seepage into the soil may cause environmental harm (e.g., contamination of shallow aquifers). • There is potential for adverse human health effects (e.g., mosquito breeding ground). • Water may infiltrate into the water table; therefore, ponds may not be suitable for more saline (i.e., high salt) produced water (CSM, 2009; ALL, 2003).
Available in All Basins?	No, the technology requires climate suitable for evaporation and soil type suitable for infiltration.
Currently In Use at CBM Operations?	Yes, in the Appalachian Basin and western United States.

Cost Components

Table 4-18 lists the capital and O&M costs components for evaporation/infiltration ponds.

Table 4-18. Capital and O&M Costs for Evaporation/ Infiltration Ponds

Cost	Use
Capital Cost Components	• Land acquisition or leasing is required for the pond footprint if the operator does not own the land adjacent to the wells. The pond footprint is often large to contain the required volume. The availability of additional land owned by the operator for a pond will be site-specific. • Operators constructing new ponds on undisturbed land will incur costs for excavation and mobilization. • Operators may also need: - Piping infrastructure to transport the water from the wellhead(s) to the pond. - Pumps to transport the water, if gravity flow is not possible. - Monitoring equipment, if needed (e.g., groundwater monitoring). - Aerators to enhance evaporation. • Evaporation/infiltration ponds may require additional power. If the CBM project does not currently have electricity, operators will need to bring infrastructure or generators on site if pumps or aerators are needed. • Operators also incur costs for pond closure at end of life.
O&M Cost Components	The solids at the bottom of the pond may have to be periodically dredged.
Other Cost Components	Ponds require permits to operate.
Residuals Generated	Settled solids – Solids may or may not need to be removed from the pond. During site visits, CBM operators indicated that ponds may require limited or no removal of solids, depending on the geometry and removal efficiency of the ponds (ERG, 2007a).
Energy Requirements	Electricity for any pumps may be required.
Personnel Requirements	Labor may be required to periodically remove solids from bottom of pond.

4.2.3 Land Application

Managing produced water by land application consists of spreading produced water directly on the land or through subsurface irrigation, with or without crop production. Optimal land application requires adding produced water at a rate equal to the soil's capacity to accept both the volume of and the constituents in produced water without destroying soil integrity, creating subsurface soil contamination problems, or causing other adverse environmental impacts, which may include water ponding and subsequent runoff. Using land application as a disposal method will depend on produced water quality, local land use, water needs, plant status, and permitting requirements. For example, in the Powder River Basin, water is a limited resource and produced water is being used for crop irrigation.

As of 2008, CBM operators used land application for the following:

- Crop production/irrigation.
- Dust suppression (benefits also include preventing air quality issues and loss of surface soils.
- Disposal without beneficial use (without crop production or dust suppression).

In some cases, CBM operators may land apply produced water without crop production. In 2007, EPA visited CDX's West Virginia operations and observed land application of produced water without crop production. CDX's land application permit specifies the allowable chloride and TDS concentrations. Operators must inject produced water underground if it does not meet these concentration levels. The produced water flows across a gravel apron to help disperse the water prior to land application. The water then flows downward through a set of logs and hay bales that act as a weir to control water flow. CDX operations are located on the top of a mountain making other management methods for produced water impractical (ERG, 2007c).

Implementing Land Application at CBM Operations

Table 4-19 lists considerations for using land application at CBM operations.

Table 4-19. Considerations for Using Land Application at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• Land application may not be feasible in areas that have low infiltration rates, which may be caused by one or more of the following: - High clay content in the soil. - Wet, supersaturated soil conditions. - Frozen soil conditions. • Produced water with high SAR or TDS concentrations can alter soil properties, reducing water infiltration, and/or limiting plant growth. • Land application may be inconsistent with permitting requirements, including water quality based effluent limits.
Available in All Basins?	No; see considerations listed above.
Currently In Use at CBM Operations?	Yes, in the Appalachian and Powder River Basins. Operators in the Powder River Basin use various irrigation systems for land application.

Land Application Cost Components

Table 4-20 lists the capital and O&M costs components for land application.

Table 4-20. Capital and O&M Costs for Land Application

Cost	Use
Capital Cost Components	Operations may potentially incur the following capital costs: • Land application equipment (e.g., sprayers). • Storage tanks to contain water prior to land application. • Pumps and piping to transport water to the land application site. • Monitoring equipment, if needed (e.g., groundwater monitoring). • Electrical installation (if pumps are used to transport water).
O&M Cost Components	• Land application may require soil amendments and sampling and analysis of the water and soil at the land application site to prevent damage and sustain the land application, depending on the type of land application and the related costs for operating land equipment (energy, labor). • Costs will be incurred to transport produced water by pumps and pipeline or by trucking to land application site.

Table 4-20. Capital and O&M Costs for Land Application

Cost	Use
Residuals Generated	No residuals are generated.
Energy Requirements	Electricity may be required for pumps or land application equipment.
Personnel Requirements	Operators require personnel for periodically monitoring the system.

4.2.4 Livestock or Wildlife Watering

In areas of livestock grazing, CBM operators can coordinate with local land owners to transfer produced water to ranching areas for livestock watering if the produced water is of good enough quality. CBM projects on ranch land have created impoundments or watering stations (e.g., tire tanks) for livestock.

Implementing Livestock Watering at CBM Operations

Table 4-21 lists considerations for using livestock watering as a method of disposing produced water.

Table 4-21. Considerations for Using Livestock Watering at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• It is applicable only in areas with nearby livestock or wildlife. • It may not have sufficient livestock for all produced water; therefore, other management methods may still be required. • Use for livestock may be inconsistent with permitting requirements, including water quality based effluent limits.
Available in All Basins?	No; see limitations listed above.
Currently In Use at CBM Operations?	Yes, livestock watering is used in the Powder River Basin.

Livestock Watering Cost Components

Table 4-22 lists the capital and O&M costs components for livestock watering.

Table 4-22. Capital and O&M Costs for Livestock Watering

Cost	Use
Capital Cost Components	• Operators may need: - Storage containers (e.g., troughs, tire tanks, impoundments) to hold water for livestock to drink from and to store excess water prior to livestock watering. - Pumps and piping to transport water to the livestock watering site. • Livestock may require additional power to pump water to the livestock watering site. If the CBM project does not currently have electricity, operators will need to bring infrastructure or generators on site.

Table 4-22. Capital and O&M Costs for Livestock Watering

Cost	Use
O&M Cost Components	• The water may require minimal pretreatment or periodic testing to ensure the water quality is suitable for livestock watering. • Costs will be incurred to transport produced water by pumps and pipeline or trucking to livestock watering site.
Residuals Generated	No residuals are generated.
Energy Requirements	Pumps will require electricity.
Personnel Requirements	Operators need personnel to periodically monitor the system.

4.2.5 Downhole Gas Water Separators

Downhole gas water separation (DGWS) technologies separate methane from formation water prior to extracting the gas to the surface. Instead of pumping the formation water to the surface, operators inject it into other porous formations either above or below the producing coal seam, thus reducing produced water volumes (NETL, 2011b).

EPA did not observe DGWS during the site visit program and operators did not indicate using DGWS in 2008 in their Detailed Questionnaire responses. EPA reviewed information on DGWS from the DOE's NETL and a vendor indicating DGWS has been implemented at wells in the Powder River Basin.

Table 4-23 shows four different types of DGWS technologies identified by U.S. DOE NETL. These technologies can be installed at the bottom of the gas well based on the produced water flowrate and the well depth. Table 4-23 also shows the applicable range of produced water flowrates and appropriate well depths for using each DGWS technology (NETL, 2011b).

Table 4-23. DGWS Technologies Design Criteria

DGWS Technology	Produced Water Flow Rate (Barrels Per Day)	Well Depth (Feet)
Bypass Tools	25 – 250	6,000 – 8,000
Modified Plunger Rod Pumps	250 – 800	2,000 – 8,000
Electric Submersible Pumps	>800	>6,000
Progressive Cavity Pumps	NA	NA

Source: NETL, 2011b.

According to a NETL fact sheet, implementing any of these separation devices requires a receiving formation with good injectivity[10]. For CBM applications, there should be good separation between the production and receiving formations to ensure that the producing formation is depressurized to allow the gas to flow (NETL, 2011b).

[10] Injectivity is a measurement of the rate and pressure at which fluids can be pumped into a receiving formation without fracturing the formation (Schlumberger, 2011).

EPA has identified only one vendor, Big Cat Energy Corp. (Big Cat), providing DGWS to the CBM Extraction Industry. Big Cat's ARID™ tool has been used only in the Wyoming portion of the Powder River Basin, although Big Cat believes their tool would work in other areas such as Montana and Alabama. Approximately 12 CBM wells in Wyoming have used the ARID system. Big Cat developed the ARID aquifer recharge injection system to reduce the volume of produced water requiring disposal. The ARID system uses the existing well bore to move the formation water from the producing coal seam to a shallower depleted aquifer with water quality similar to the coalbed formation water.

Big Cat has installed the ARID technology on new wells and retrofitted it on existing wells. New installations are easier, because the well can be planned in a way that easily incorporates the ARID technology. Big Cat estimated that this technology has allowed operators to reinject all of the produced water in at least 80 percent of the wells where the technology was installed. In one case, limitations of the receiving formation required that some of the produced water be pumped to the surface. In other cases, CBM producers have chosen to pump some of the water to the surface to meet a surface water need (e.g., livestock watering for a landowner).

Implementing DGWS at CBM Operations

According to Big Cat, the only major logistical issue has been the failure of tool seals during installation, which was apparently caused by sharp edges inside the production casing. To mitigate this issue, Big Cat instructs operators to run a "scraper" from the interval where the tool will be installed to the surface to smooth the inside of the production casing and prevent damaging the seal. Big Cat offers seals in a variety of hardness to suit the conditions of the production casing. Big Cat recommends that operators replace seals each time they remove the tool, for which the operator pays Big Cat. Operators incur additional required operating costs for wells that use the ARID tool to periodically monitor the reinjected water and remove the tool during well maintenance activities (e.g., workovers).

Clogging of the receiving formation may be an issue if solid particles from the production formation or from drilling activities enter the receiving formation. Bacteria that form scale on the receiving formation are another source of clogging. To prevent scale formation, Big Cat typically tests produced water for scale-forming bacteria prior to tool installation and uses a chlorine drip disinfection system as necessary during the initial implementation of the tool (Barritt, 2012).

The underground injection information previously presented in Section 4.2.1 is also relevant to the technical feasibility of DGWS for CBM. As noted above, the success rate of DGWS depends on "site-specific properties of the disposal zone at individual wells" (Veil, 2004). In addition, Big Cat noted that the feasibility of DGWS can only be firmly established by a successful pilot study in the basin of interest (Barritt, 2012).

Table 4-24 lists considerations for using DGWS at CBM operations.

Table 4-24. Considerations for Using DGWS at CBM Operations

Consideration	Use
Considerations for Use at Existing CBM Operations	• DGWS requires suitable geologic formation with sufficient injectivity, storage capacity, water quality, and separation from CBM production formations. Feasibility should be established by a pilot study in the basin of interest. • Water quality of produced water quality may need to be similar to the water quality in the receiving formation. • The technology requires coordination with local UIC programs. For example, one operator noted that UIC programs may require operators to monitor the water injected. However, no water is produced to the surface when using DGWS. Therefore, if water monitoring is required, operators would need to shut in the well periodically to either remove the DGWS tool or install a mechanism to bypass the tool so that water could be brought to the surface and monitored (Olson, 2012). • Landowners may want some produced water for land application or livestock watering. • The tool can be installed at the time well is drilled and could handle the changes in volume over the life of the well.
Available in All Basins?	Unknown; see limitations listed above.
Currently In Use at CBM Operations?	Yes, this technology is in use in the Powder River Basin.

DWGS Cost Components

Table 4-25 shows operating capital and O&M costs for DGWS based on information collected on the tools used in the Powder River Basin.

Table 4-25. Capital and O&M Costs for DGWS

Cost	Use
Capital Cost Components	• The operator must prepare the well casing prior to installing the ARID tool. • DGWS ARID tool
O&M Cost Components	• Big Cat recommends replacing the rubber seal on the ARID tool each time it is removed (Barritt, 2012). • The Wyoming Department of Environmental Quality initially required quarterly testing of produced water, but they have become more flexible due to the logistical issues with collecting samples.
Residuals Generated	No residuals are generated.
Energy Requirements	The tool may reduce energy requirements at the wellhead because produced water does not need to be pumped to the surface.
Personnel Requirements	• Operators require personnel to monitor the pressure of the injection formation. • In general, operators need to remove the ARID tool for any downhole well maintenance activities (e.g., workovers). Removing and replacing the ARID tool results in additional man-hour needs in the field.

4.3 REFERENCES

1. Adams, A. 2011. Telephone Communication Between Andy Adams, Intevras & Layne Water Technologies, and Brent Ruminski, Eastern Research Group, Inc. "Intevras EVRAS Evaporation Technology." November. EPA-HQ-OW-2010-0824, DCN CBM00671.

2. Alexander, J. 2011. Telephone Communication Between Jerry Alexander, Siemens and Sarah Hays, Eastern Research Group, Inc. "Siemens Reverse Osmosis Technology." September. EPA-HQ-OW-2010-0824, DCN CBM00672.

3. ALL. 2003. Handbook on Coal Bed Methane Produced Water: Management and Beneficial Use Alternatives. Prepared for Ground Water Protection Research. Available online at: http://www.all-llc.com/CBM/pdf/CBMBU/CBM%20BU%20Screen.pdf. EPA-HQ-OW-2004-0032-2483 (DCN 03451).

4. ALL. 2006. A Guide to Practical Management of Produced Water from Onshore Oil and Gas Operations in the United States. Prepared for U.S. DOE, National Petroleum Technology Office. EPA-HQ-OW-2008-0517 (DCN 10000).

5. ALL. 2011. Shale Gas Produced Water Treatment Catalog. Available online at: http://www.all-llc.com/projects/produced_water_tool/page.php?14.

6. Asano, T. 2007. Water Reuse: An Integrated Approach to Managing the World's Water Resources. McGraw-Hill.

7. ASIRC (Australian Sustainable Industry Research Centre). 2005. Overview of Treatment Processes for the Production of Fit for Purpose Water: Desalination and Membrane Technologies. Available online at: http://www.water.vic.gov.au/__data/assets/pdf_file/0003/5853/Overview_Treatment_Process_Water_Desalination.pdf.

8. Barritt, T. 2012. Telephone Communication Between Tim Barritt, Big Cat Energy Corp., and Chris Krejci, Eastern Research Group, Inc. "ARID Produced Water Reinjection Technology." January. EPA-HQ-OW-2010-0824, DCN CBM00585.

9. Beagle, D. 2007. Continuous Countercurrent Ion Exchange Applied to CBM Produced Water Treatment in the Powder River Basin of Wyoming and Montana. EPA-HQ-OW-2006-0771-0882 (DCN 05158).

10. Burnett, D. 2006. Advanced Membrane Filtration Technology for Cost Effective Recovery of Fresh Water from Oil & Gas Produced Brine. Texas A&M University. EPA-HQ-OW-2010-0824, DCN CBM00773.

11. CMAA (Coalbed Methane Association of Alabama). 2012. Comments on 2010 Effluent Guidelines Program Plan. February. EPA-HQ-OW-2008-0517-0853.

12. COGCC (Colorado Oil and Gas Conservation Commission). 2009. Staff Presentation: Coal Bed Methane Production, Raton Basin. EPA-HQ-OW-2010-0824, DCN CBM00607.

13. CDM. 2007. Innovative Produced Water Treatment Process For Coal Bed Methane Production. Prepared by Bob Kimball and Ken Klinko. November 7. EPA-HQ-OW-2006-0771-0874 (DCN 05149).

14. CSM (Colorado School of Mines). 2009. An Integrated Framework for Treatment and Management of Produced Water: Technical Assessment of Produced Water Treatment Technologies. 1st Edition. RPSEA Project 07122-12. EPA-HQ-OW-2008-0517 (DCN 10007).

15. Dennis, R. 2005. A Positive Trade-Off. Environmental Protection. July. Available online at: http://eponline.com/articles/2005/07/01/a-positive-tradeoff.aspx?admgarea=Features. EPA-HQ-OW-2004-0032-0332 (DCN 02226).

16. Dow Chemical. 2011. Basics of Reverse Osmossis. http://www.dowwaterandprocess.com/support_training/literature_manuals/lm_techinfo/basics.htm.

17. Drake, R. 2011. Telephone Communication Between Brent Ruminski, ERG, and Ron Drake, Drake Water Technologies. "Drake Water Technologies: IonFlo (Ion Exchange)." September. EPA-HQ-OW-2010-0824, DCN CBM00673.

18. Drake, V. 2012. Email Communication Between Brent Ruminski, ERG, and Vivian Drake, Drake Water Technologies. "Drake Process Unit Installation Locations". January. EPA-HQ-OW-2010-0824, DCN CBM00629.

19. Eckenfelder, W.W. 2000. Industrial Water Pollution Control. 3rd Edition. McGraw-Hill.

20. Eco-Tec. 2006. Short Bed Ion Exchange Technology Produces Ultrapure Water Without Using a Mixed Bed. EPA-HQ-OW-2006-0771-1342 (DCN 06160).

21. Eco-Tec. 2007. Size Does Matter: Evolution of Counter-Current Ion Exchange for Industrial Water Treatment. EPA-HQ-OW-2006-0771-1341 (DCN 06159).

22. Eco-Tec. 2008. Eco-Tec Awarded CBNG Produced Water Treatment System Contract. Available online at: http://www.wateronline.com/doc.mvc/Eco-Tec-Awarded-Water-Treatment-Contract-0001.

23. ERG (Eastern Research Group). 2007a. Site Visit Report for the Howard Treatment Facility, Enervest Operating, LLC, Blairsville, PA. EPA-HQ-OW-2006-0771-0996. (DCN 05198).

24. ERG. 2007b. Final Site Visit Report for the Brinkerton Treatment Facility, Great Lakes Energy Partners, LLC Mount Pleasant Township, PA. EPA-HQ-OW-2006-0771-0969. (DCN 05199).

25. ERG. 2007c. Final Site Visit Report, Drake Water Technologies, LLC, Gillette, WY (Powder River Basin). EPA-HQ-OW-2008-0517-0685. (DCN 10032).

26. ERG. 2007d. Final Site Visit Report: Penn Virginia Corporation, Central Appalachian Basin Coalbed Methane Operations. EPA-HQ-OW-2006-0771-0966. (DCN 05232).

27. ERG. 2007e. Final Site Visit Report: CNX Gas Company LLC, Upper Appalachian Basin Coalbed Methane Operations. EPA-HQ-OW-2006-0771-1047. (DCN 05235).

28. ERG. 2007f. Final Site Visit Report: CNX Gas Company, LLC, Central Appalachian Basin Coalbed Methane Operations. EPA-HQ-OW-2006-0771-0967. (DCN 05233).

29. ERG. 2012. Coalbed Methane State Phone Calls. Various Dates and Contacts. EPA-HQ-OW-2010-0824. DCN CBM00678.

30. Hayes, T. 2004. The Electrodialysis Alternative for Produced Water Management. Prepared by Gas Technology Institute. Available online at: http://www.netl.doe.gov/technologies/oil-gas/publications/GasTIPS/GasTIPS-Summer04.pdf.

31. Illinois EPA (Environmental Protection Agency). 2012. Underground Injection Control Program. Available online at: http://www.epa.state.il.us/land/regulatory-programs/underground-injection-control.html. Accessed: March 6, 2012.

32. Jangbarwala. 2008. Custom-Designed Process Treats CBM Produced Water. EPA-HQ-OW-2006-0771-1338 (DCN 06156).

33. Johnston. 2010. Summary of EMIT Water Discharge Technology (an Exterran Company) held on February 18, 2010. July 27, 2010. EPA-HQ-OW-2008-0517 (DCN 10020).

34. Kimball, B. 2010. High Recovery Reverse Osmosis for Treatment of Produced Water. Camp Dresser & McKee, Inc. Helena, Montana. 71st International Water Conference. IWC-10-54. EPA-HQ-OW-2010-0824, DCN CBM00618.

35. Malecha, S. 2006. Final Report: Coal Bed Methane Produced Water Treatment: Wallace Gulch Reverse Osmosis Test. August 4. EPA-HQ-OW-2004-0032-1452 (DCN 02840).

36. Means, B., and T. Hilton. 2004. Comparison of Three Methods to Measure Acidity of Coal-Mine Drainage. 2004. National Meeting of the American Society of Mining and Reclamation. EPA-HQ-OW-2006-0771-0142 (DCN 04358).

37. Mertz, B. 2011. Telephone Communication Between Barry Mertz, 212 Resources VACOM Technology, and Brent Ruminski, Eastern Research Group, Inc. "212 Resources VACOM Technology." November.

38. Metcalf and Eddy, Inc. 2003. Wastewater Engineering: Treatment, Disposal, and Reuse. McGraw-Hill, Inc. 4th edition.

39. Migliavacca. 2011. Telephone Communication Between Michele Migliavacca, Veolia Water, and Brent Ruminski, Eastern Research Group, Inc. "Veolia Water OPUS and MULTIFLO." November. EPA-HQ-OW-2010-0824, DCN CBM00674.

40. NETL (National Energy Technology Laboratory). 2006. A Guide to Practical Management of Produced Water from Onshore Oil and Gas Operations in the United States. Prepared by Interstate Oil and Gas Compact Commission and ALL Consulting. Prepared for U.S. DOE NETL. EPA-HQ-OW-2010-0824, DCN CBM00771.

41. NETL. 2011a. Produced Water Management Technology Descriptions: Fact Sheet – Ion Exchange. Available online at: http://www.netl.doe.gov/technologies/pwmis/techdesc/ionex/index.html.

42. NETL. 2011b. Produced Water Management Technology Descriptions: Fact Sheet – Downhole Separation. Available online at: http://www.netl.doe.gov/technologies/pwmis/techdesc/downsep/index.html.

43. Olson. 2012. Email from Joe Olson, Williams Production Company to Ahmar Siddiqui, U.S. EPA. "Downhole Separation Use with Coalbed Methane Wells." February 20.

44. PG Environmental. 2007a. Final Site Visit Report: Anadarko Petroleum Corporation Johnson County, WY (Powder River Basin), Coalbed Methane Detailed Study. EPA-HQ-OW-2006-0771-1002 (DCN 05239).

45. PG Environmental. 2007b. Final Site Visit Report: St. Mary Land & Exploration Company (Formerly Nance Petroleum Corporation) River 1 Project, Sheridan and Campbell Counties, WY (Powder River Basin), Coalbed Methane Detailed Study. EPA-HQ-OW-2006-0771-0970 (DCN 05236).

46. PG Environmental. 2007c. Final Site Visit Report: Altela, Inc. Thermal Distillation Produced Water Treatment Technology (AltelaRainSM) at the Blackshawl and Moncisco Sites Farmington, NM (San Juan Basin), Coalbed Methane Detailed Study. EPA-HQ-OW-2006-0771-1012 (DCN 05225).

47. Roman, J. 2011. Telephone Communication Between Jaime Roman, Fountain Quail, and Brent Ruminski, Eastern Research Group, Inc. "Fountain Quail NOMAD Evaporator Technology." November.

48. Schlumberger. 2011. Oilfield Glossary – Injectivity Test. Available online at: http://www.glossary.oilfield.slb.com/Display.cfm?Term=injectivity%20test.

49. URS. 2011. Water-Related Issues Associated With Gas Production in the Marcellus Shale. Prepared in Support of the Supplemental Generic Environmental Impact Statement for Natural Gas Production. Fort Washington, PA. EPA-HQ-OW-2010-0824, DCN CBM00772.

50. U.S. EPA (Environmental Protection Agency). 2000. Wastewater Technology Fact Sheet: Chemical Precipitation. EPA-832-F-00-018.

51. U.S. EPA. 2004. Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. National Study Final Report.

52. U.S. EPA. 2011a. Underground Injection Control Program. Available online at: http://water.epa.gov/type/groundwater/uic/index.cfm.

53. U.S. EPA. 2011b. Aquifer Recharge (AR) and Aquifer Storage & Recovery (ASR). Underground Injection Control Program. Available online at: http://water.epa.gov/type/groundwater/uic/aquiferrecharge.cfm.

54. U.S. EPA. 2013. Ion Exchange Vendors in CBM Industry. EPA-HQ-OW-2010-0824, DCN CBM00667.

55. Veil, J.A. 2004. Downhole Separation Technology Performance: Relationship to Geologic Conditions. Prepared by Argonne National Laboratory. Prepared for U.S. DOE NETL. Available online at: http://www.netl.doe.gov/KMD/cds/disk23/D-

Water%20Management%20Projects/Produced%20Water%5CW-31-109-ENG-38%5CW-31-109-Eng-38-DOWS-DGWS-final.pdf.

56. Veolia Water Solutions. 2008. CeraMem®Ceramic Membrane Technology. Industrial Water World Magazine. EPA-HQ-OW-2006-0771-1337 (DCN 06155).

SECTION 5
PRODUCED WATER MANAGEMENT COSTS

In establishing ELGs, EPA identifies a subset of technologies (treatment processes and operational/management practices) that are most promising as candidate regulatory options. ELGs typically establish numerical limits on the discharge of pollutants to surface waters; EPA also establishes technonoloy-based pretreatment standards for dischargers to Publicly Owned Treatment Works. These limits and standards are based on the performance of specific technologies that constitute the regulatory options. EPA does not require that dischargers use the specific technologies that form the basis for the proposed regulatory options. EPA does, however, estimate the compliance costs for the industry to meet the numerical limitations and standards, including any identified best management practices (BMPs). EPA estimates the compliance costs by calculating the costs for operators to implement the technologies that form the basis of the proposed regulatory options. For existing sources, compliance costs are incremental, meaning they represent the costs operators are expected to incur to revise existing operations to match those that form the bases of the regulatory options. For new sources, EPA estimates the costs to install such technologies rather than in the technologies that would be installed the absence of the rule.

For the CBM Extraction Industry, EPA estimated the costs of implementing certain wastewater pollution controls at existing wells. Based on the review of available treatment technologies for the industry described in Section 4, EPA included two CBM control technologies in this preliminary cost evaluation: ion exchange and underground injection. EPA evaluated ion exchange because it is the lowest-cost technology capable of removing TDS from produced water. Although ion exchange may not be applicable to all basins, EPA used ion exchange costs to provide an initial likely low cost indicator of the economic feasibility of implementing a TDS removal technology. As explained in Section 4, other technologies identified to remove TDS from produced waters would have higher costs. EPA also evaluated underground injection because it eliminates all pollutant discharges to surface water and POTWs and is currently being used for produced water disposal in all basins except for the Black Warrior and Cahaba Basins.

Only projects that discharge some portion of their produced water would possibly incur costs under any ELGs. Based on questionnaire/screener responses, EPA estimates that 149 CBM projects discharged directly to waters of the U.S. and that 7 projects discharged indirectly in 2008[11]. Because the number of indirect dischargers is small, for purposes of this analysis, EPA developed costs only for those projects that reported discharging any portion of produced water directly to surface water in 2008. EPA used the 2008 project-level data for the discharging projects along with costs for the two included CBM control technologies to evaluate the potential economic impacts associated with an ELG for the industry. The *Economic Analysis for Existing and New Projects in the Coalbed Methane Industry* document presents the results of EPA's economic analysis (U.S. EPA, 2013a). This section describes EPA's methodology for estimating compliance costs for the included technology options. Because most respondents claimed their entire response to the Detailed Questionnaire to be CBI, EPA is not providing project-level or

[11] EPA calculated the number of projects for the entire CBM industry using the Detailed Questionnaire responses and survey weights.

basin-level computed costs. The following references contain supporting information for the analysis described in this section:

- Summary of Coalbed Methane Information Collection Request Confidential Business Information (U.S. EPA, 2013b).
- Supporting Information for CBM Existing Sources Analysis (U.S. EPA, 2013d).

This section describes the development of the cost estimates using Detailed Questionnaire data, which are used in the economic analysis. EPA used the following steps for this analysis:

1. Identify CBM projects that discharged produced water in 2008 (Section 5.1).
2. Develop costs for ion exchange treatment systems to treat produced water prior to surface discharge or underground injection as an alternative disposal method to surface discharge (Section 5.2).
3. Calculate the project-level costs associated with ion exchange and underground injection (Section 5.3).
4. Combine the ion exchange and underground injection cost information with project-level economic and financial data, gas and water decline rates, and projected gas prices to develop an economic assessment of the additional controls. (See *Economic Analysis for Existing and New Projects in the Coalbed Methane Industry*).

5.1 IDENTIFY DISCHARGING PROJECTS AND DISCHARGE VOLUME

Of the 149[12] direct discharging projects in the industry, EPA estimated project specific engineering costs associated with 74 direct discharging CBM projects. EPA used data from the Screener survey responses to identify the total population of direct discharging projects and used information from the Detailed Questionnaire responses for the 74 projects to determine the final disposal method and the produced water volume disposed of through each method (Questions C3-1 and C3-2). EPA scaled the costs estimated for the 74 analyzed projects to the total industry population of 149 direct discharging projects using survey weights. The memorandum *Development of Final Survey Weights for CBM Analyses* (DCN CBM00653) provides a detailed description of how survey weights were developed (U.S. EPA, 2012).

For the 74 analyzed projects, operators reported discharging some portion of their produced water directly to surface water in 2008; but for 37 of these projects, operators reported using at least one other disposal method.

EPA excluded one of the 74 direct discharging projects from this analysis because the first (undeveloped) lease in the project was acquired in 2008 as reported in the Detailed Questionnaire (Question B3-15). This project was in the first year of production where peak water is produced but peak gas flows have not yet been reached. As shown in Figure 3-1, water must first be extracted for gas production to begin. As the figure implies, with high costs of

[12] The total number of direct dischargers reported in the TDD was calculated using the survey weighted Detailed Questionnaire responses.

water management and relatively low revenues in the first few years, a new project may not yet be generating positive earnings. An analysis using a one-year assessment of the ability of a project beginning in 2008 to generate positive operating earnings from gas production would misrepresent longer-run costs and revenues; therefore, this project was excluded from the existing source analysis.

EPA used the direct discharge volume reported in the Detailed Questionnaire (Question C3-2) to estimate costs to retrofit or replace each project's existing produced water management system (PWMS). As mentioned previously, some projects may use zero discharge methods in addition to discharging to surface water. EPA did not include the volume disposed of through zero discharge practices in this analysis.

EPA identified five CBM projects out of the 74 direct discharging projects that transfer their produced water to another CBM operator or project prior to surface water discharge. Two of the five projects transferred the produced water to another operator's CBM project and the remaining three projects transferred water between projects owned by the same operator. EPA assessed costs for new treatment or disposal methods to the operator and project receiving the produced water for the volume of water received. The operators receiving water may charge a fee to the operators transferring water to offset the cost of treating additional water. The revenues offset the overall produced water management system operating costs for the project. EPA included any revenues or fees reported in the Detailed Questionnaire in the analysis of these projects.

5.2 DETERMINE COSTS FOR NEW WATER MANAGEMENT METHOD

Typically, EPA estimates both operation and maintenance costs and capital costs, which are then used to estimate annualized costs for a wastewater management approach. O&M costs are typically the largest contributor to the annualized costs. As explained in more detail below, for this screening level analysis, EPA only developed O&M costs. As a result, the estimated costs are most likely an underestimate of the actual annualized costs. EPA developed O&M costs for ion exchange and underground injection in dollars per barrel and used the project discharge volume to compute project-level costs for these water management methods.

Ion Exchange

EPA based costs for ion exchange on the ion exchange system used by operators in the Powder River Basin, and publicly available ion exchange cost data. As explained in Section 4.1.3, this system may not be appropriate for TDS levels in CBM produced water in all basins evaluated. Nevertheless, EPA applied the ion exchange costs to projects in all basins to determine whether the projects are economically capable of implementing a technology with a similar or higher cost than ion exchange (e.g., reverse osmosis).

The cost per barrel reported to operate existing ion exchange units in the Powder River basin includes the following costs associated with operating the system: flow equalization/storage, bypass piping and pumps, chemicals, electricity, materials, material storage, brine disposal, labor, and maintenance. Therefore, the O&M costs incurred by the operator represent the full cost of operating the ion exchange system, with the exception of transporting the produced water to the system. Although there may be additional capital costs associated with the piping needed to route the water into the new ion exchange unit, EPA assumed any changes in the O&M costs associated solely with the produced water transport from the aggregation point to the ion exchange unit would be negligible and did not include these costs in the analysis. EPA used a cost of $0.50/barrel to implement ion exchange in the economic analysis.

For the purpose of its cost estimate, EPA assumed that the ion exchange system would receive the entire volume of produced water discharged by each project. Because EPA calculates costs for operators incremental to existing practices, EPA did not apply ion exchange costs to projects that were operating any type of TDS removal technology (either ion exchange or reverse osmosis) in 2008 as reported in the Detailed Questionnaire (Question C3-8, C3-10, C3-12).

Zero Discharge by Underground Injection

EPA used questionnaire responses for projects that used underground injection as the only disposal method to develop an average cost of underground injection by geographic area. To protect CBI, EPA developed average underground injection costs for eastern and western U.S. basins using costs from the Appalachian and Powder River Basins. EPA assumed that basins in similar geographic areas would have similar costs. These average costs represent a range of distances between the CBM project and the injection well. EPA used the reported produced water gathering and transportation costs and the reported underground injection O&M cost to obtain the a total O&M costs for underground injection.

EPA used the following assumptions:

- For the Appalachian, Black Warrior, Cahaba, and Illinois Basins: EPA used the average underground injection costs for the Appalachian Basin ($4.10/bbl).
- For the Green River, Powder River, and Raton Basin: EPA used the average underground injection costs for the Powder River Basin ($0.54/bbl).

5.3 COMPUTE COSTS OF OPERATING ION EXCHANGE OR USING UNDERGROUND INJECTION

EPA estimated the additional O&M costs that would be incurred from implementing ion exchange or underground injection. EPA did not estimate ion exchange costs for projects that already had a TDS removal technology in place (either ion exchange or reverse osmosis) or that currently manage their wastewater through any zero discharge alternative including underground injection.

In developing the costs for new water management methods, EPA assigned additional cost to the operator to use either ion exchange or underground injection for the portion of water discharged to surface water without subtracting any baseline produced water management O&M costs. EPA did not subtract baseline costs because for many projects, operators use multiple produced water management methods and the additional costs assigned are only for the portion of water discharged to surface water. Operators would continue to incur costs for discharge methods other than surface water discharge. In addition, regardless of the wastewater management method, operators will incur costs to aggregate and store water prior to disposal, so they will still incur these O&M costs. The produced water management system costs reported in the Detailed Questionnaire did not breakout subcosts for water aggregation, storage, or the various disposal alternatives by disposal method.[13]

For each project and each wastewater management approach (i.e. ion exchange or underground injection), EPA multiplied the produced water volume discharged (bbl/yr) by the O&M costs ($/yr) to obtain the projected additional wastewater management costs incurred at the project level:

Additional Project-Level Costs Incurred ($/yr)= Project Discharge Volume (bbl/yr) ×
Ion Exchange *or* Underground Injection O&M ($/bbl)

EPA used the project-level water management costs in the economic analysis described in *Economic Analysis for Existing and New Projects in the Coalbed Methane Industry*.

5.4 References

1. ERG. 2012. 2012 Shale Gas Water Management Conference Notes. November 27.

2. U.S. EPA. 2012. Development of Final Survey Weights for CBM Analyses. EPA-HQ-OW-2010-0824, DCN CBM00653.

3. U.S. EPA. 2013a. Economic Analysis for Existing and New Projects in the Coalbed Methane (CBM) Industry. EPA-HQ-OW-2010-0824, DCN CBM00680.

4. U.S. EPA. 2013b. Summary of Coalbed Methane Information Collection Request Confidential Business Information. EPA-HQ-OW-2010-0824, DCN CBM00661.

5. U.S. EPA. 2013c. 2010 Data Collection and Methodology Used to Update 2008 Existing Source Analysis. EPA-HQ-OW-2010-0824, DCN CBM00665.

6. U.S. EPA. 2013d. Supporting Information for CBM Existing Source Analysis. EPA-HQ-OW-2010-0824, DCN CBM00664.

[13] For the underground injection management alternative, EPA estimated additional costs for underground injection, but did not subtract the ion exchange O&M costs for the projects that had ion exchange installed as of 2008. Consequently, for these projects, our calculated undergournd injection may be overestimated. EPA considered an alternate calculation method: assuming the projects could convert to undergournd injection disposal with no change in costs. This calculation resulted in less than a 10% decrease in the total industry cost. This decrease is unlikely to change the overall conclusion described in the *Economic Analysis for Existing and New Projects in the Coalbed Methane (CBM) Industry*.