EDF-WZI-APPENDIX I

WZI INC.

Resume for

Mary Jane Wilson

WZI Inc.

MARY JANE WILSON, R.E.A
President

EDUCATION/CERTIFICATION

B.S., Petroleum Engineering, Stanford University, 1972

State of California Registered Environmental Assessor No. 00050

State of California Accredited Lead Verifier of Greenhouse Gas Emissions Data, Executive Order H-09-63

Special Government Employee, Department of Energy Ultra-Deepwater Advisory Committee

Member, National Petroleum Council

Director – Mission Bank, Audit Committee

Director – Greater Bakersfield Chamber of Commerce

Patent Nos. US 6,659,178 B2 Apparatus and Method For Sealing Well Bores and Bore Holes, US 6,860,997 B1 Apparatus and method for processing Organic Materials

Past Director - California Independent Petroleum Association

Past Director - Kern Economic Development Corporation and Chairman

1994 Journal of Petroleum Technology Editor, January Issue and 1994 Review Chairman

Society of Petroleum Engineers - Member since 1972, Environment Health and Safety Committee Member, 1993 Distinguished Lecturer, Co-chairman SPE/EPA Exploration & Production Environmental Conference, 1997, Chairman SPE Monograph Committee, Editor Monograph Volume 18 Henry L. Doherty Series, *Environmental Engineering for Exploration and Production Activities*

1993-94 Advisory Board - San Joaquin Valley Chapter, American Petroleum Institute

Stanford School of Earth Sciences, Stanford University - Advisory Board and former National Fundraising Chairman

Member - Air and Waste Management Association, American Petroleum Institute, Association of Groundwater Scientists and Engineers, Central California Association of Power Producers, California Groundwater Association, California Independent Petroleum Association, California Living Museum, National Water Well Association and the Water Association of Kern County, Central California Association of Power Producers

Member at Large - Conservation Committee of California Oil and Gas Producers

Member - West Coast Advisory Group of the Petroleum Technology Transfer Council

Member - PTTC National Labs Partnership Work Group

The Council of One Hundred - California State University, Bakersfield

Future Bakersfield - Mayor's Action Team, Strategic Vision Plan

Women's Advisory Council - Girl Scouts, Joshua Tree Council

Graduate, Hill & Knowlton Media Training Seminar

Soroptimist Achievement Award, 1976 Outstanding Professional Woman, L. A. Area

SPECIAL AREAS OF EXPERTISE:

Regulatory Compliance:

Participates on an ongoing basis in regulatory reform programs both nationally and locally.

- Management of contracts where WZI acts as the client's representative in the coordination of business goals and permit conditions in large projects requiring interagency cooperation. This includes preparation of permit documents, technical support documents, public hearing representation and community relations.
- Provides strategic planning for compliance with regulations, the formulation of operations tracking protocols which improve agency/industry communication where permit conditions require a good understanding of a project.
- Working with regulatory agencies in the interpretation of "intent" of environmental regulations when applied to projects especially where Federal, State and local regulations are not clearly presented or have overlapping jurisdiction.
- Provides management direction on protocol design and implementation of environmental audits (site assessments, compliance audits, risk appraisals).
- Expert testimony in litigation involving groundwater contamination.
- Expert testimony and advise in litigation involving air emissions, health risk.

Petroleum:

Serves on the National Petroleum Council. Council advises, informs and makes recommendations to the Secretary of Energy with respect to matters submitted to the Council by the Secretary of Energy representing the views of the energy industry.

- Expert Witness Moss v. Venoco, Chevron et al. for Air Emissions, Due Diligence, Standard of Care
- Appointed by Congress to advise on the operation of the Naval Petroleum Reserve No.1 (Specific Expertise in Environmental Compliance)
- Over thirty years of oil and gas operations and reservoir engineering experience.
- Prepared numerous U. S. Securities Exchange Commission Reserves Appraisals and fair market valuations on oil and gas producing properties.

- Prepared numerous enhanced oil recovery development plans.
- Economic Analysis of business alternatives in oil/gas exploration and operations both domestically and internationally.
- Negotiated settlements regarding wastewater issues of independent refineries.
- Presentation to the National Electrical Generation Association regarding California Electrical Restructuring.

Power Generation:

- Kern County Electrical Advisory Committee member.
- California Independent Petroleum Association Oil Producers Electrical Project member.

PROFESSIONAL EXPERIENCE:

1986 - Present — President, Chief Executive Officer: WZI Inc.

Defines and directs the overall management objectives of WZI Inc. Ms Wilson provides technical standards for all projects on an as-needed basis, to assure client satisfaction, monitors all projects for contract compliance and technical content.

WZI Inc. headquartered in Bakersfield, California. WZI Inc. is an environmental and consulting engineering company, which has achieved a reputation for high quality, successful project management. WZI is a State of California Verification Body for AB32 Greenhouse Gas Mandatory Reporting, Executive Order Number H-10-173. WZI offers professional and technical services in regulatory compliance (air, water, waste), geoscience, hydrology, site characterization, hazardous waste management, and environmental impact assessment. WZI offers its clients a uniquely high level of expertise, an innovative, technical approach and disciplined project management.

1982 - 1987 — Partner: Evans, Carey & Crozier

Represented numerous clients in environmental matters related to regulatory compliance and reservoir engineering. Supervised geological and groundwater studies, performed subsurface engineering and design, and made alternative recommendations, all related to hazardous and non-hazardous waste injection facilities. Expertise has been utilized in obtaining the necessary permits required by EPA, DOHS, RWQCB and various county agencies. Conducted detailed environmental assessments of hazardous waste site selections, all of which meet the demands of CEQA, and were utilized in EIR preparation.

1979 - 1982 Consultant: Evans, Carey & Crozier

Represent Evans, Carey & Crozier with clients. Designed and implemented enhanced recovery and waste disposal programs including all permitting activities. Prepared property appraisals and evaluations.

1972 - 1979 Engineer: Texaco, Inc.

Initially, assisted in the evaluation of secondary recovery projects and pilot flood performance. Performed reservoir analysis, log interpretations and
economic analyses. Based on this knowledge, was given the task of supervising all drilling and production activities for a major secondary recovery project in which she devised a new water entry survey technique. Studied the drilling potential in California, Nevada, and Alaska, and the development of several steam flood recovery projects. Asked to represent Texaco in unit negotiations, testify before government agencies and obtain all necessary permits. Also assisted in developing the Division's investment budget.

PUBLICATIONS:

Englehardt, John, M.J. Wilson, et al., 2001, New Abandonment Technology New Materials and Placement Techniques, S.P.E. Paper No. 66496.

Wilson, M.J. and J.D. Frederick, 1999, Editors, SPE Monograph Volume 18 Henry L. Doherty Series, Environmental Engineering for Exploration and Production Activities.

Wilson, M. J. and S. C. Kiser, 1994, Transactional Environmental Assessments: Use in the Identification of Viable Enhanced Oil Recovery Projects, S.P.E./DOE Paper No. 27782.

Wilson, M. J. and S. C. Kiser, 1993, Site Assessment Methods in Determination of Liability in Oil and Gas Property Acquisition and Divestiture, S.P.E. Paper No. 25834.

Wilson, M. J. and J. D. Frederick, 1993, Particulate Emission Testing Methodologies as Applied to Natural Gas Fired Turbines, S.P.E. Paper No. 25945.

Wilson, M. J. and S. G. Muir, 1992, A Critique of Selected Case Studies in Environmental Geophysics, S.P.E. Paper No. 23998.

Kiser, S. C., M. J. Wilson and L. M. Bazeley, 1990, Oil Field Disposal Management Practices in Western Kern County, California in proceedings from First International Symposium on Oil and Gas Exploration and Production Waste Management Practices, New Orleans, Louisiana, p.677-688.

Wilson, M. J., Kiser, S. C., E. J. Greenwood, R. N. Crozier, R. A. Crewdson, 1987, Oil Field Disposal Practices in the Hydrogeologic Setting of the Midway-Sunset and Buena Vista Oil Fields: A Review of Past Effects, Current Activities and Future Scenarios, American Association of Petroleum Geologists, Bull. V. 72, No. 3, p.394 Abs.

Wilson, M. J. and S. C. Kiser, 1987, Proceedings of Hazmacon 1986 Conference April 29 - March 1, 1986, Anaheim, California, Synergistic Approach for Siting and Design for Injection of Hazardous Liquid Wastes: Case Study in Western San Joaquin Valley, Kern County, California, S.P.E. Paper No. 16327

Wilson, M. J., 1979, The Santos: A Case History of Fractured Shale Development, S.P.E. Paper No. 7978.

Wilson, M. J., 1974, A Young Engineer's Personal Look at the "Guidelines", S.P.E. Paper No. 4913.

WZI INC.

Curriculum Vitae
Of
Mary Jane Wilson

Client	Case or Variance #	Type	Dates
Clark Trevick	St James v Crimson Resources	Expert Witness	2013
Manatt Phelps	Panoche v PG&E	Expert Witness	2013
Young Wooldridge	Water Bank v Grayson	Expert Witness	2012-Current
Klein, DeNatale, et al	Palla v Amalia	Expert Witness	2012-2013
Duggan, Smith & Heath	Wells Fargo Bank, N.A. v. Anadarko Petroleum Corp. et al	Expert Witness	2012-2013
Martin, Disere, Jefferson & Wisdom	Assoc. Electric & Gas Insurance Services v. Kinder Morgan	Expert Witness	2012
Steptoe & Johnson	Murray v Chevron et al	Expert Witness	2008-2010
Steptoe & Johnson	Borsch v Chevron et al	Expert Witness	2008-2009
Steptoe & Johnson	Mydland-Jensen	Expert Witness	2008
Garrison & McInnis	Chesser v. Alea	Energy Price Forecast Insurance Claim	2009
Gallagher & Gallagher	OCWD v. Moore Wallace	Litigation Support	2007-2012
Gallagher & Gallagher Sheppard Mullin Haight Brown & Bonesteel Latham & Watkins	Moss v. Venoco, Inc., et al	Expert Witness	2004-Current
California Dairies-Fresno	C-05-10E	Emergency Variance	2005
Griffin Industries	CEQA	Hearing	2005
H. Lima Mine	CEQA	Hearing	2005
Petrissans Dairy	CEQA	Hearing	2005
Schweitzer Construction	CEQA	Hearing	2005
Klein, DeNatale et al	ChevronTexaco Cymric	Expert Opinion, settled	2005
Noriega	Lundsford vs. Key Energy	Consultant	2005
Cooper & Hoppe	Kophamer vs. Western Skye Dairy	Expert Opinion, settled	2005
California Dairies-Turlock		Short Variance	2004
Castle & Cooke	Planning Commission	Vesting Tentative Tract Map 6281	2004
Castle & Cooke	Planning Commission	Vesting Tentative Tract Map 6250	2004
Castle & Cooke	Planning Commission	Panama & Ashe GPA/ZC	2004
Castle & Cooke	Planning Commission	Stockdale & Allen GPA/ZC	2004
Castle & Cooke	Planning Commission	Vesting Tentative Tract Map 11035	2004
Martin Feed	CEQA	Hearing	2004
Hageman LP	CEQA	Hearing	2004

Klein DeNatale et al	CEQA	Expert Opinion	2003
Sierra Power	Emergency Variance	CEM Breakdown	2003
Lucas Development	City Council	Vesting Tentative Tract Map 6182	2003
Sage Community Development	Planning Commission	Vesting Tentative Tract Map 6148	2003
Sage Community Development	City Council	Vesting Tentative Tract Map 6149	2003
White & H Partners	City Council	Vesting Tentative Tract Map 6137	2003

Client	**Case or Variance #**	**Type**	**Dates**
Vanderham Dairy	Board of Supervisors Planning Commission	EIR Appeal EIR	2003 2002
Borba Dairies	Board of Supervisors Planning Commission	EIR Appeal EIR	2002 2002
Klein DeNatale et al	Hazardous Waste Truck Accident	Consultant	2002
El Paso Merchant Energy	CEC Docket 00-AFC-5	Expert Testimony	2001
Midway Sunset Cogeneration Company	CEC Docket 99-AFC-9	Expert Testimony	2000-2001
McClintock Weston	Confidential	Expert emission reduction credit, Deposition	2000
Latham and Watkins	World Oil v. City of Bakersfield	Expert condemnation activity	1998
Stradling Yocca Carlson & Rauth	Nations Title Insurance Co. v. Kellogg Properties	Expert for mining feasibility/value arbitration	1998
Golden Bear	S-98-15R	Regular Variance	1998
Babst, Calland, Clements and Zomir	U.S. EPA v. Quaker State Congo	Expert deposition review for the Quaker State Refinery	1997
Land-Aide Incorporated	McAllister Ranch	Land Use	1997
Noreiga & Alexander	Tannehill vs. Baker Chemicals	Expert Opinion, settled	1997
Borton, Petrini & Conron	Pre-litigation	CEQA Analysis regarding oilfield Development	1997
Elk Corporation	95-55R	Regular Variance	1996
Frito-Lay	95-55X	Short Variance	1996
Kern Oil & Refining Company	89-218	Cease and Desist Order	1995
Dairyman's Cooperative Creamery Association	93-51	Interim Variance Regular Variance	1994 1994
Double "C" Limited	94-14	Interim Variance Emergency Variance	1994 1994
Gibson Environmental Inc.	94-15151-B-11K	Interim Variance	1994

		Regular Variance	1994
Guy E. Taylor & Associates	CIV-94-1529T	Expert opinion groundwater contamination source delineation oilfield operation	1994
Harper Lake Company	93-015-I-1 93-015-R-2	Interim Variance Regular Variance	1994 1994
HLC IX	93-014-I-1 93-014-R-2	Interim Variance Regular Variance	1994 1994

Client	**Case or Variance #**	**Type**	**Dates**
Kern Front Limited	94-12	Interim Variance Regular Variance	1994 1994
M. Baker vs Biedermann International		Deposition	1993
Klein DeNatale et al	208568	Deposition Mojave River Lake Basin City of Barstow vs City of Adelanto	1993
Badger Creek Limited	S-93-15	Interim Variance Regular Variance	1993 1993
Chalk Cliff Limited	93-20	Interim Variance Variance	1993 1993
Dairyman's Cooperative Creamery Association	93-13	Interim Variance Regular Variance	1993 1993
	93-42	Interim Variance Regular Variance	1993 1993
Double "C" Limited	93-18	Interim Variance Regular Variance	1993 1993
High Sierra Limited	S93-16	Interim Variance Regular Variance	1993 1993
Kern Front Limited	93-17	Interim Variance Regular Variance	1993 1993
	93-30	Interim Variance Regular Variance	1993 1993
	93-25	Interim Variance Emergency Variance	1993 1993
Live Oak Limited	93-19	Regular Variance	1993
McKittrick Limited	93-21	Interim Variance Regular Variance	1993 1993
	93-26	Interim Variance Regular Variance	1993 1993
Mount Poso Cogeneration Company		Emergency Variance	1993
Twin Oil Company	Appeal of Division of	Testimony	1993

	Oil and Gas Order		
PF Corporation	93-23	Interim Variance	1993
		forming/curing oven	
		Regular Variance	1993
		Vested Rights Hearing	
Berry Petroleum Company		Appeal of ATC Denial	1992
Chalk Cliff Limited	92-52	Interim Variance	1992
		Regular Variance	1992

Client	**Case or Variance #**	**Type**	**Dates**
Live Oak Limited	92-29	Interim Variance	1992
		Regular Variance	1992
	92-37	Interim Variance	1992
		Regular Variance	1992
San Joaquin Cogen Limited	92-05	Interim Variance	1992
		Regular Variance	1992
	92-06	Interim Variance	1992
		Regular Variance	1992
UPF Corporation	92-22	Interim Variance	1992
		Modification Variance	1992
Wellhead Electric Company	91-14	Interim Variance	1992
		Modification	
		Regular Variance	1992
Badger Creek Limited	91-34	Interim Variance	1991
		Regular Variance	1991
		Lube Oil Demister Exceedance	
Cactus Gold	91-46	Interim Variance	1991
		Regular Variance	1991
San Joaquin Cogen Limited		Interim Variance	1991
		Regular Variance	1991
UPF Corporation	91-35	Interim Variance	1991
		Regular Variance	1991
Wellhead Electric Company	92-31	Interim Variance	1991
		Regular Variance	1991
Sheinfeld, Maley & Kay	Stanley Bostich vs Snyder General	Deposition	1990
LeBeau, Thelen, Lampe, McIntosh & Crear	Superior Court Case 183100 People vs Sabre Refining Corp.	Sump closure Judgement, Pretrial settlement hearings, expert testimony in court	1989

Resume for

Jesse D. Frederick

WZI Inc.

JESSE D. FREDERICK
Vice President

EDUCATION/CERTIFICATION:

USN, Surface Nuclear Mechanical Operator, 1974
B.S., Chemical Engineering, Rose-Hulman Institute of Technology, 1981
State of Texas Registered Professional Engineer
Accredited Lead Verifier of Greenhouse Gas Emissions Data, Executive Order H-10-047
Member of Texas NO_X RACT Advisory Group, 1993
Member - Society of Petroleum Engineers, Energy Engineers Institute
Guest Lecturer, Rose-Hulman Institute of Technology (1993), USC (2001)
Panelist – Valuing NO_X Offsets, Panel Discussion, Sponsored by Air Quality Week, 1993
Patent for: Steam Blow Silencer, Well Abandonment Technology, Anaerobic Digester
Dow Chemical, USA Environmental Management Course

SPECIAL CONTRIBUTIONS and RECOGNITIONS:

Recipient: Chevron Presidents Award for development of a new venture Business Plan
CoEditor: SPE EnvironmentalMonograph Environmental Engineering for Exploration and Production Activities
Guest Lecturer: Rose-Hulman Institute of Technology (1993) Advanced Coal Gasification Technology, USC (2001) Electrical Deregulation, SPE (2002) Electrical Deregulation, EUEC (2010)-Strategic Analysis of GHG Programs, Impacts on Reliability
Panelist – Valuing NOX Offsets, Panel Discussion, Sponsored by Air QualityWeek, 1993
Patent for: Steam Blow Silencer, Well Abandonment Technology, Anaerobic Digester
IOGCC, Oil and Gas Exploration and Production Environmental Reporting Requirements
DOE, Title V Guidance Manual for E&P industry
National Petroleum Council, Peer Review for Studies on Natural Gas Pipeline Infrastructure, 1999
API, Toxic Release Inventory Report on Exploration and Production
Member of Texas NOX RACT Advisory Group, 1993Board Member: Kern Environmental Education Program
Board Member: Society of Petroleum Engineers (San Joaquin Valley Chapter)
Member: Kern Economic Development Corporation, 1997-2011
Member: Kern County Electrical Restructuring Advisory Committee
Member: Kern County Chamber of Commerce Regulatory Advisory Committee

SPECIAL AREAS OF EXPERTISE:

- CARB Accredited Verifier of Greenhouse Gas Emissions Data for Refineries and Electric Transactions
- Contract assessment and negotiations
- Renewable Energy Siting and Permit Assistance
- Business Planning including financial pro forma and risk analysis
- Gas and Electricity Price Forecasting and Direct Access, Wholesale and Retail
- Sale and acquisition of large energy assets
- Audit procedures for cogeneration facilities and oil and gas producing properties for Fortune 500 Companies.
- Environmental development through initiation to various stages of development including financial closing.
- Federal, state and local regulations, including FERC, NEPA, SEQRA, CEQA, PSD,

NSPS, and NPDES.

- Dutch environmental law including MER and provincial permits.
- Expert testimony in both legal and Public Utility Proceedings regarding: valuation of environmental externalities, environmental dispatch, impact of standard offer contracts on property values, refinery wastewater, waste discharge and property values.
- Pre-commissioning including cleaning, flushing, and testing.
- Power project design and budgeting coordination for engineering, economic and engineering evaluations of various options.
- Forensic analysis of facility failures and on/offsite consequences

PROFESSIONAL EXPERIENCE:

1994 - Present Vice President - WZI Inc.

Responsible for the technical scoping of large projects which require multidisciplinary integration. Responsible for technical peer review of on-going projects. Mr. Frederick acting on behalf of major clients has performed internal energy studies for long-term purchase and production plans as well as negotiated major energy contracts. In overseeing client regulatory compliance, Mr. Frederick advises clients regarding approaches to permitting and regulatory guidelines, including facilitating the Department of Energy's sale of the Elk Hills Naval Petroleum Reserve. Directs the planning, development and implementation of policies, programs and procedures in support of contract management. Mr. Frederick provides assistance in WZI's National Petroleum Council activities. Mr. Frederick is responsible for identifying business opportunities, expert advice on energy forecasts, valuations, business planning and provides business development services to numerous clients.

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1995 - 1998 President - CONSUMERS Utility Advisors, Inc.

Provided staff leadership in strategic planning and technical negotiations for the electrical power market. Directed corporate activities including business development, goal setting and quality assurance. Mr. Frederick was responsible for business planning and economic models for various clients.

1990 - 1994 Manager of Environmental Affairs, Destec Energy, Inc.

Promoted to Project Development, Mr. Frederick provided analytical support for multi-million dollar projects. The increased need for firm project management in the area of environmentally related issues led to a promotion to the position of Sr. Environmental Engineer. Mr. Frederick established the Environmental Affairs department and managed the day-to-day activities of the Environmental Affairs staff and oversaw all environmentally related issues including: property sales and acquisitions, permitting, compliance, and facility/property audits for all Destec facilities including 740,000 acres of oil and gas properties, including water treatment, waste water disposal, and superfund sites. Mr. Frederick was a team member for all business acquisitions and financial projects.

1982 - 1990 Staff Engineer, Power Systems Engineering

Provided start-up support for facilities and interface engineering for chemical refining plants for integration of cogeneration. Specialized in water treatment design, procurement and operation.

1982 Mission Industrial Supply, Field Supervisor

Provided start-up and pre-commissioning supervision for chemical processes.

1981 - 1982 Associate (Machinery) Engineer M.W. Kellogg

Served in the Mechanical Division (Special Equipment Group) designing and procuring equipment related to refining and water treatment.

PUBLICATIONS:

Frederick, J. D., 1990, "Gas Turbine Emissions," Industrial Energy Technology Conference.

Frederick, J. D. and B. Tulloh, 1991, "Title III of the Clean Air Act and BACT," Society of Petroleum Engineers Forum.

Frederick, J. D., 1992, "Clean Air Act Title III and the Oil Industry," Society of Petroleum Engineers.

Frederick, J. D., 1993, "Air Emissions Trading," SPE/EPA Exploration & Production Environmental Conference, San Antonio, TX, 7-10 March 1993.

Frederick, J. D., 1993, "Effective Environmental Management," SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, TX, 29-30 March 1993.

Frederick, J. D. and S. Jenkins, 1993, "Cogeneration and Meeting California Environmental Requirements," 8th Cogeneration & Independent Power Congress, Boston, MA, 15-16 June 1993.

Frederick, J. D. and W. Lessig, 1993, "Environmental Considerations of Coal Gasification Technology and the Wabash River Repowering Project," American Power Conference, Boston, MA, 1993.

Frederick, J.D. and Wilson, M.J., 1993, Particulate Emission Testing Methodologies as Applied to Natural Gas Fired Turbines, S.P.E. Paper No. 25945.

Frederick, J. D. and M.S. Weaver, 1997, "Title V and the Exploration and Production Industry," S.P.E. Paper No. 37883.

Frederick, J. D. and Mary Jane Wilson, 1999, Editors, SPE Environmental Monograph Environmental Engineering for Exploration and Production Activities.

WZI INC.

Curriculum Vitae
Of
Jesse D. Frederick

WZI Inc.

1717 28th Street Bakersfield, California 93301 (661) 326-1112 FAX: (661) 326-0191

ADJUDICATORY, JURY, SEMI-ADJUDICATORY PROCEEDINGS

Client	Case or Variance #	Type	Dates
Wood, Smith, Henning & Berman	LASC-NC 044396- Refinery Accident	Expert	Current
Gray Duffy	Holly Refinery v. Mullen Crane	Expert	2008 -2012
California Public Utility Commission	General Rate Case A10-03-014	Expert Witness	2010
Garrison & McInnis	Chesser v. Alea	Litigation Support	2009
CA Dept. of Transportation	Cal Trans v 927 Indio Muerto	Expert	2008
Klein DeNatale Goldner, et al.	Geisert v. Patterson, et al.	Expert	2007
Gallagher and Gallagher	Moss v. Venoco	Litigation Support	2004
Cooper & Hoppe	Kophamer v. Western Sky	Expert Testimony	2004
El Paso Merchant Energy	CEC Docket 00-AFC-5	Expert, Power Plant Siting	2001
Midway Sunset Cogeneration Company	CEC Docket 99-AFC-9	Expert, Power Plant Siting	2000-2001
Southern California Gas Co.	The Gas Company v. Midsun Partners	Expert opinion (CPUC) Property Valuation	1998-1999
Noriega & Alexander	Tannehill v. Baker	Expert opinion Well Contamination	1997
Klein, DeNatale, Goldner, Cooper, Rosenlieb and Kimball, LLP	World Oil	Litigation Support: Refinery Accident	1997-1998
Guy E. Taylor & Associates	CIV-94-1529T	Expert opinion groundwater contamination source delineation oilfield operation.	1997
Babst, Calland Clements and Zomir	U.S. DOJ/EPA v. Quaker State Congo Refinery	Groundwater Contamination Litigation	1996
Klein, DeNatale, Goldner, Cooper, Rosenlieb and Kimball, LLP	Tuytens et al	Expert Facility Energy-Based Evaluation	1996
Destec Energy, Inc.	CCN Docket 11000	Expert Testimony, Externalities Valuation	1993

DEPOSITIONS

Client	Case or Variance #	Type	Dates
Gray Duffy	Holly Refinery v. Mullen Crane	Refinery Damages Evaluation	2012
Garrison & McInnis	Chesser v. Alea	Energy Price Forecast Insurance Claim	2008
CA Dept. of Transportation	Cal Trans v. 927 Indio Muerto	Condemnation of Chemical Facilities	2008
Klein, DeNatale, Goldner, Cooper Rosenlieb and Kimball, LLP	Tuytens et al. v. DifWind Farms VI	DifWind Farms VI Deposition Energy Contract Value	1997
Babst, Calland Clements and Zomir	U.S. DOJ/EPA v. Quaker State Congo Refinery	Groundwater Contamination Litigation	1996

TESTIMONY – ADMINISTRATIVE HEARINGS

Client	Case or Variance #	Type	Dates
Castle & Cooke	Planning Commission	Vesting Tentative Tract Map 6281	2004
Castle & Cooke	Planning Commission	Vesting Tentative Tract Map 6250	2004
Castle & Cooke	Planning Commission	Panama & Ashe GPA/ZC	2004
Castle & Cooke	Planning Commission	Stockdale & Allen GPA/ZC	2004
Castle & Cooke	Planning Commission	Vesting Tentative Tract Map 11035	2004
Lucas Development	City Council	Vesting Tentative Tract Map 6182	2003
Sage Community Development	Planning Commission	Vesting Tentative Tract Map 6148	2003
Sage Community Development	City Council	Vesting Tentative Tract Map 6149	2003
White & H Partners	City Council	Vesting Tentative Tract Map 6137	2003
Vanderham Dairy	Board of Supervisors Planning Commission	EIR Appeal EIR	2003 2002
Borba Dairies	Board of Supervisors Planning Commission	EIR Appeal EIR	2002 2002
Badger Creek Limited	S-93-15	Interim Variance Regular Variance	1993 1993
Chalk Cliff Limited	93-20	Interim Variance Variance	1993 1993
Live Oak Limited	93-19	Regular Variance	1993
Chalk Cliff Limited	92-52	Interim Variance Regular Variance	1992 1992
Live Oak Limited	92-29	Interim Variance Regular Variance	1992 1992
	92-37	Interim Variance Regular Variance	1992 1992
San Joaquin Cogen Limited	92-05	Interim Variance Regular Variance	1992 1992
	92-06	Interim Variance Regular Variance	1992 1992
Badger Creek Limited	91-34	Interim Variance Regular Variance Lube Oil Demister Exceedance	1991 1991

EDF-WZI-APPENDIX II

naa	Basin	fips	type	pol	2011vocTPYCntrldR	RP	ef	2011VOCtpy
-1	DJ	08001	O&G Condenste Tanks	VOC	1,507.0	0.925582	13.7	3,189.87
-1	DJ	08005	O&G Condenste Tanks	VOC	205.7	0.925582	13.7	435.33
-1	DJ	08013	O&G Condenste Tanks	VOC	750.1	0.925582	13.7	1,587.83
-1	DJ	08014	O&G Condenste Tanks	VOC	522.5	0.925582	13.7	1,105.94
-1	DJ	08031	O&G Condenste Tanks	VOC	48.6	0.925582	13.7	102.85
-1	DJ	08059	O&G Condenste Tanks	VOC	1.6	0.925582	13.7	3.49
-1	DJ	08069	O&G Condenste Tanks	VOC	505.1	0.925582	13.7	1,069.20
-1	DJ	08123	O&G Condenste Tanks	VOC	85,060.4	0.925582	13.7	180,053.30
0	DJ	08039	O&G Condenste Tanks	VOC	149.9	0.545831	13.7	217.56
0	DJ	08043	O&G Condenste Tanks	VOC	860.5	0.545831	13.7	1,249.08
0	DJ	08063	O&G Condenste Tanks	VOC	13.5	0.214115	3	15.32
0	DJ	08073	O&G Condenste Tanks	VOC	463.6	0.214115	3	528.09
0	DJ	08075	O&G Condenste Tanks	VOC	1,074.3	0.545831	13.7	1,559.57
0	DJ	08087	O&G Condenste Tanks	VOC	518.6	0.545831	13.7	752.83
0	DJ	08095	O&G Condenste Tanks	VOC	0.0	0.545831	13.7	0.00
0	DJ	08115	O&G Condenste Tanks	VOC	0.0	0.545831	13.7	0.00
0	DJ	08121	O&G Condenste Tanks	VOC	2,414.8	0.545831	13.7	3,505.36
0	DJ	08125	O&G Condenste Tanks	VOC	19.3	0.545831	13.7	27.97
0	NSJ	08007	O&G Condenste Tanks	VOC	9.5	0.497035	11.8	13.25
0	NSJ	08067	O&G Condenste Tanks	VOC	152.6	0.497035	11.8	212.93
0	PIC	08029	O&G Condenste Tanks	VOC	0.0	0.442467	10	0.07
0	PIC	08045	O&G Condenste Tanks	VOC	9,284.2	0.442467	10	12,415.50
0	PIC	08051	O&G Condenste Tanks	VOC	4.4	0.442467	10	5.90
0	PIC	08077	O&G Condenste Tanks	VOC	330.4	0.442467	10	441.82
0	PIC	08081	O&G Condenste Tanks	VOC	1,262.0	0.442467	10	1,687.67
0	PIC	08103	O&G Condenste Tanks	VOC	18,325.9	0.442467	10	24,506.58
0	PIC	08107	O&G Condenste Tanks	VOC	240.3	0.442467	10	321.35
0	rest	08009	O&G Condenste Tanks	VOC	199.5	0.497035	11.8	278.33
0	rest	08011	O&G Condenste Tanks	VOC	1.8	0.497035	11.8	2.50
0	rest	08033	O&G Condenste Tanks	VOC	112.5	0.497035	11.8	157.03
0	rest	08055	O&G Condenste Tanks	VOC	0.0	0.497035	11.8	0.00
0	rest	08057	O&G Condenste Tanks	VOC	693.2	0.497035	11.8	967.26
0	rest	08061	O&G Condenste Tanks	VOC	288.8	0.214115	3	328.97
0	rest	08071	O&G Condenste Tanks	VOC	3.6	0.497035	11.8	5.06
0	rest	08083	O&G Condenste Tanks	VOC	644.4	0.497035	11.8	899.20
0	rest	08099	O&G Condenste Tanks	VOC	46.1	0.497035	11.8	64.35
0	rest	08113	O&G Condenste Tanks	VOC	85.4	0.497035	11.8	119.15
					125,800.2			237,830.48

StateAndC	Short Name	CO	NOX	PM10-PRI	SO2	VOC
08001	Natural Gas Liquids / Gas Well Water Tank Losses					0.02
08005	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08009	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08011	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08013	Natural Gas Liquids / Gas Well Water Tank Losses					0.01
08014	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08031	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08033	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08039	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08043	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08057	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08059	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08061	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08063	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08069	Natural Gas Liquids / Gas Well Water Tank Losses					0.01
08071	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08073	Natural Gas Liquids / Gas Well Water Tank Losses					0.01
08075	Natural Gas Liquids / Gas Well Water Tank Losses					0.01
08083	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08087	Natural Gas Liquids / Gas Well Water Tank Losses					0.01
08099	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08113	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08115	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08121	Natural Gas Liquids / Gas Well Water Tank Losses					0.03
08123	Natural Gas Liquids / Gas Well Water Tank Losses					0.95
08125	Natural Gas Liquids / Gas Well Water Tank Losses					0.00
08007	Oil & Gas Expl & Prod /All Processes /Artificial Lift	0.06	0.27	0.00		0.01
08067	Oil & Gas Expl & Prod /All Processes /Artificial Lift	1.34	5.60	0.02		0.14
08001	Oil & Gas Expl & Prod /All Processes /Drill Rigs	4.81	16.31	2.55	0.44	0.69
08005	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.37	1.25	0.20	0.03	0.05
08007	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.79	6.89	1.12	1.08	0.34
08009	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.12	0.39	0.06	0.01	0.02
08011	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.03	0.11	0.02	0.00	0.00
08013	Oil & Gas Expl & Prod /All Processes /Drill Rigs	9.24	31.37	4.90	0.85	1.33
08014	Oil & Gas Expl & Prod /All Processes /Drill Rigs	3.70	12.55	1.96	0.34	0.53
08031	Oil & Gas Expl & Prod /All Processes /Drill Rigs	1.85	6.27	0.98	0.17	0.27

08033	Oil & Gas Expl & Prod /All Processes /Drill Rigs	4.30	14.61	2.28	0.39	0.62
08043	Oil & Gas Expl & Prod /All Processes /Drill Rigs	1.85	6.27	0.98	0.17	0.27
08045	Oil & Gas Expl & Prod /All Processes /Drill Rigs	275.02	1,410.19	493.24	149.90	39.17
08051	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.16	0.84	0.30	0.09	0.02
08055	Oil & Gas Expl & Prod /All Processes /Drill Rigs	1.56	5.31	0.83	0.14	0.23
08057	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.08	0.27	0.04	0.01	0.01
08061	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.04	0.15	0.02	0.00	0.01
08063	Oil & Gas Expl & Prod /All Processes /Drill Rigs	4.81	16.31	2.55	0.44	0.69
08067	Oil & Gas Expl & Prod /All Processes /Drill Rigs	5.90	51.47	8.33	8.04	2.54
08069	Oil & Gas Expl & Prod /All Processes /Drill Rigs	2.96	10.04	1.57	0.27	0.43
08071	Oil & Gas Expl & Prod /All Processes /Drill Rigs	12.40	42.10	6.57	1.14	1.79
08073	Oil & Gas Expl & Prod /All Processes /Drill Rigs	5.54	18.82	2.94	0.51	0.80
08075	Oil & Gas Expl & Prod /All Processes /Drill Rigs	1.48	5.02	0.78	0.14	0.21
08077	Oil & Gas Expl & Prod /All Processes /Drill Rigs	38.02	194.95	68.19	20.72	5.41
08081	Oil & Gas Expl & Prod /All Processes /Drill Rigs	3.62	18.57	6.49	1.97	0.52
08083	Oil & Gas Expl & Prod /All Processes /Drill Rigs	46.64	158.35	24.72	4.27	6.72
08087	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.37	1.25	0.20	0.03	0.05
08095	Oil & Gas Expl & Prod /All Processes /Drill Rigs	6.65	22.59	3.53	0.61	0.96
08099	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.08	0.26	0.04	0.01	0.01
08103	Oil & Gas Expl & Prod /All Processes /Drill Rigs	32.26	165.41	57.85	17.58	4.59
08113	Oil & Gas Expl & Prod /All Processes /Drill Rigs	0.79	2.67	0.42	0.07	0.11
08121	Oil & Gas Expl & Prod /All Processes /Drill Rigs	3.70	12.55	1.96	0.34	0.53
08123	Oil & Gas Expl & Prod /All Processes /Drill Rigs	485.31	1,647.69	257.23	44.47	69.97
08125	Oil & Gas Expl & Prod /All Processes /Drill Rigs	124.19	421.65	65.83	11.38	17.90
08001	Oil & Gas Expl & Prod /All Processes /Workover Rigs	4.09	18.40	4.09	0.64	1.11
08005	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.48	2.17	0.48	0.08	0.13
08009	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.02	0.08	0.02	0.00	0.00
08011	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.00	0.02	0.00	0.00	0.00
08013	Oil & Gas Expl & Prod /All Processes /Workover Rigs	1.25	5.63	1.25	0.20	0.34
08014	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.28	1.26	0.28	0.04	0.08
08029	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.01	0.03	0.01	0.00	0.00
08031	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.20	0.89	0.20	0.03	0.05
08033	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.65	2.92	0.65	0.10	0.18
08039	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.31	1.38	0.31	0.05	0.08
08043	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.20	0.89	0.20	0.03	0.05
08045	Oil & Gas Expl & Prod /All Processes /Workover Rigs	19.84	90.60	16.96	5.74	5.27
08051	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.03	0.14	0.03	0.01	0.01

08055	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.24	1.06	0.24	0.04	0.06
08057	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.01	0.05	0.01	0.00	0.00
08059	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.00	0.02	0.00	0.00	0.00
08061	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.01	0.03	0.01	0.00	0.00
08063	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.05	0.23	0.05	0.01	0.01
08069	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.67	3.01	0.67	0.10	0.18
08071	Oil & Gas Expl & Prod /All Processes /Workover Rigs	1.87	8.42	1.87	0.29	0.51
08073	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.07	0.31	0.07	0.01	0.02
08075	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.53	2.39	0.53	0.08	0.14
08077	Oil & Gas Expl & Prod /All Processes /Workover Rigs	2.28	10.41	1.95	0.66	0.61
08081	Oil & Gas Expl & Prod /All Processes /Workover Rigs	1.40	6.38	1.19	0.40	0.37
08083	Oil & Gas Expl & Prod /All Processes /Workover Rigs	7.04	31.67	7.04	1.10	1.91
08087	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.27	1.20	0.27	0.04	0.07
08095	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.31	1.38	0.31	0.05	0.08
08099	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.01	0.05	0.01	0.00	0.00
08103	Oil & Gas Expl & Prod /All Processes /Workover Rigs	5.80	26.50	4.96	1.68	1.54
08107	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.09	0.39	0.07	0.02	0.02
08113	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.12	0.53	0.12	0.02	0.03
08115	Oil & Gas Expl & Prod /All Processes /Workover Rigs	0.03	0.14	0.03	0.01	0.01
08121	Oil & Gas Expl & Prod /All Processes /Workover Rigs	1.93	8.69	1.93	0.30	0.52
08123	Oil & Gas Expl & Prod /All Processes /Workover Rigs	65.63	295.18	65.61	10.25	17.82
08125	Oil & Gas Expl & Prod /All Processes /Workover Rigs	15.69	70.58	15.69	2.45	4.26
08001	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					573.00
08005	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					67.45
08007	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					0.03
08009	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					2.44
08011	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					0.67
08013	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					175.37
08014	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					39.19
08029	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					0.88
08031	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					27.62
08033	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					90.94
08039	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					43.04
08043	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					27.62
08045	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					2,752.88
08051	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					4.39
08055	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					33.04

08057	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					1.70
08059	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					0.64
08061	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					0.94
08063	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					7.07
08067	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					0.57
08069	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					93.79
08071	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					262.11
08073	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					9.64
08075	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					74.52
08077	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					315.94
08081	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					180.55
08083	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					985.96
08087	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					37.26
08095	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					43.04
08099	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					1.59
08103	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					711.37
08107	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					7.81
08113	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					16.60
08115	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					4.50
08121	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					270.44
08123	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					9,190.56
08125	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives					2,197.59
08001	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	35.95	42.80	3.25	0.26	
08005	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	4.23	5.04	0.38	0.03	
08007	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	6.60	14.69	0.80		
08009	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.15	0.18	0.01	0.00	
08011	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.04	0.05	0.00	0.00	
08013	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	11.00	13.10	1.00	0.08	
08014	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	2.46	2.93	0.22	0.02	
08029	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.43	0.52	0.04	0.00	
08031	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	1.73	2.06	0.16	0.01	
08033	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	5.71	6.79	0.52	0.04	
08039	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	2.70	3.21	0.24	0.02	
08043	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	1.73	2.06	0.16	0.01	
08045	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	1,356.77	1,615.20	122.76	9.69	
08051	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	2.16	2.58	0.20	0.02	
08055	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	2.07	2.47	0.19	0.01	

08057	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.11	0.13	0.01	0.00	
08059	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.04	0.05	0.00	0.00	
08061	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.06	0.07	0.01	0.00	
08063	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.44	0.53	0.04	0.00	
08067	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	326.33	726.17	39.66		
08069	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	5.88	7.01	0.53	0.04	
08071	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	16.44	19.58	1.49	0.12	
08073	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.60	0.72	0.05	0.00	
08075	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	4.68	5.57	0.42	0.03	
08077	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	155.88	185.57	14.10	1.11	
08081	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	95.47	113.66	8.64	0.68	
08083	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	61.86	73.64	5.60	0.44	
08087	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	2.34	2.78	0.21	0.02	
08095	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	2.70	3.21	0.24	0.02	
08099	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.10	0.12	0.01	0.00	
08103	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	396.83	472.42	35.90	2.83	
08107	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	5.85	6.96	0.53	0.04	
08113	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	1.04	1.24	0.09	0.01	
08115	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	0.28	0.34	0.03	0.00	
08121	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	16.97	20.20	1.54	0.12	
08123	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	576.62	686.45	52.17	4.12	
08125	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	137.88	164.14	12.47	0.98	
08001	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					45.60
08005	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					5.23
08007	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					0.02
08009	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					3.72
08011	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					1.02
08013	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					12.80
08014	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					3.20
08029	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					0.96
08031	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					1.73
08033	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					138.81
08039	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					58.41
08043	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					36.02
08045	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					5,183.15
08051	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					6.59
08055	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices					50.43

08057	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				2.59
08059	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				0.98
08061	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				1.44
08063	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				11.68
08067	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				0.43
08069	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				6.86
08071	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				400.08
08073	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				11.68
08075	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				109.04
08077	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				613.43
08081	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				353.61
08083	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				1,504.94
08087	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				64.25
08095	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				18.50
08099	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				2.43
08103	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				1,524.85
08107	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				30.90
08113	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				25.34
08115	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				2.92
08121	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				444.91
08123	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				606.70
08125	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices				2,613.01
08007	Oil & Gas Expl & Prod /Natural Gas /Compressor Engines	23.62	31.71	0.07	8.50
08067	Oil & Gas Expl & Prod /Natural Gas /Compressor Engines	1,311.30	1,760.51	4.14	471.71
08001	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				36.33
08005	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				5.01
08009	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				1.52
08011	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.01
08013	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				20.53
08014	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				4.04
08029	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.00
08031	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				2.09
08033	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.86
08039	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				3.30
08043	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				3.01
08045	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				173.61
08051	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.19

08057	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				5.30
08059	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.07
08061	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				7.09
08063	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				1.22
08069	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				10.18
08071	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.03
08073	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				10.89
08075	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				17.35
08077	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				11.83
08081	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				10.49
08083	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				4.93
08087	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				8.72
08099	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.35
08103	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				29.88
08107	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.08
08113	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.65
08115	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.08
08121	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				51.67
08123	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				1,516.80
08125	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading				0.09
08007	On-Shore Gas Production / Condensate Tank Flaring	0.71	0.13	0.00	0.27
08029	On-Shore Gas Production / Condensate Tank Flaring	0.25	0.05		
08045	On-Shore Gas Production / Condensate Tank Flaring	1,126.54	207.04		
08051	On-Shore Gas Production / Condensate Tank Flaring	13.40	2.46		
08067	On-Shore Gas Production / Condensate Tank Flaring	13.63	2.51	0.00	5.16
08077	On-Shore Gas Production / Condensate Tank Flaring	311.31	57.21		
08081	On-Shore Gas Production / Condensate Tank Flaring	40.84	7.51		
08103	On-Shore Gas Production / Condensate Tank Flaring	81.23	14.93		0.64
08107	On-Shore Gas Production / Condensate Tank Flaring	5.27	0.97		
08001	On-Shore Gas Production / Gas Well Pneumatic Pumps				50.04
08005	On-Shore Gas Production / Gas Well Pneumatic Pumps				5.89
08009	On-Shore Gas Production / Gas Well Pneumatic Pumps				4.37
08011	On-Shore Gas Production / Gas Well Pneumatic Pumps				1.20
08013	On-Shore Gas Production / Gas Well Pneumatic Pumps				15.31
08014	On-Shore Gas Production / Gas Well Pneumatic Pumps				3.42
08029	On-Shore Gas Production / Gas Well Pneumatic Pumps				0.29
08031	On-Shore Gas Production / Gas Well Pneumatic Pumps				2.41

08033	On-Shore Gas Production / Gas Well Pneumatic Pumps	163.17
08039	On-Shore Gas Production / Gas Well Pneumatic Pumps	3.76
08043	On-Shore Gas Production / Gas Well Pneumatic Pumps	2.41
08045	On-Shore Gas Production / Gas Well Pneumatic Pumps	908.31
08051	On-Shore Gas Production / Gas Well Pneumatic Pumps	1.45
08055	On-Shore Gas Production / Gas Well Pneumatic Pumps	59.28
08057	On-Shore Gas Production / Gas Well Pneumatic Pumps	3.05
08059	On-Shore Gas Production / Gas Well Pneumatic Pumps	0.06
08061	On-Shore Gas Production / Gas Well Pneumatic Pumps	1.69
08063	On-Shore Gas Production / Gas Well Pneumatic Pumps	0.62
08069	On-Shore Gas Production / Gas Well Pneumatic Pumps	8.19
08071	On-Shore Gas Production / Gas Well Pneumatic Pumps	470.26
08073	On-Shore Gas Production / Gas Well Pneumatic Pumps	0.84
08075	On-Shore Gas Production / Gas Well Pneumatic Pumps	6.51
08077	On-Shore Gas Production / Gas Well Pneumatic Pumps	104.06
08081	On-Shore Gas Production / Gas Well Pneumatic Pumps	52.22
08083	On-Shore Gas Production / Gas Well Pneumatic Pumps	1,768.96
08087	On-Shore Gas Production / Gas Well Pneumatic Pumps	3.25
08095	On-Shore Gas Production / Gas Well Pneumatic Pumps	3.76
08099	On-Shore Gas Production / Gas Well Pneumatic Pumps	2.85
08103	On-Shore Gas Production / Gas Well Pneumatic Pumps	182.33
08107	On-Shore Gas Production / Gas Well Pneumatic Pumps	0.31
08113	On-Shore Gas Production / Gas Well Pneumatic Pumps	29.78
08115	On-Shore Gas Production / Gas Well Pneumatic Pumps	0.39
08121	On-Shore Gas Production / Gas Well Pneumatic Pumps	23.62
08123	On-Shore Gas Production / Gas Well Pneumatic Pumps	802.60
08125	On-Shore Gas Production / Gas Well Pneumatic Pumps	191.91
08001	On-Shore Gas Production / Gas Well Venting - Blowdowns	60.80
08005	On-Shore Gas Production / Gas Well Venting - Blowdowns	2.98
08007	On-Shore Gas Production / Gas Well Venting - Blowdowns	0.26
08009	On-Shore Gas Production / Gas Well Venting - Blowdowns	8.68
08011	On-Shore Gas Production / Gas Well Venting - Blowdowns	2.38
08013	On-Shore Gas Production / Gas Well Venting - Blowdowns	30.66
08014	On-Shore Gas Production / Gas Well Venting - Blowdowns	6.81
08029	On-Shore Gas Production / Gas Well Venting - Blowdowns	0.13
08031	On-Shore Gas Production / Gas Well Venting - Blowdowns	4.56
08033	On-Shore Gas Production / Gas Well Venting - Blowdowns	323.93

08039	On-Shore Gas Production / Gas Well Venting - Blowdowns	1.75
08045	On-Shore Gas Production / Gas Well Venting - Blowdowns	3,606.38
08051	On-Shore Gas Production / Gas Well Venting - Blowdowns	8.93
08055	On-Shore Gas Production / Gas Well Venting - Blowdowns	117.68
08057	On-Shore Gas Production / Gas Well Venting - Blowdowns	6.05
08061	On-Shore Gas Production / Gas Well Venting - Blowdowns	3.35
08063	On-Shore Gas Production / Gas Well Venting - Blowdowns	1.38
08067	On-Shore Gas Production / Gas Well Venting - Blowdowns	1.02
08069	On-Shore Gas Production / Gas Well Venting - Blowdowns	3.02
08071	On-Shore Gas Production / Gas Well Venting - Blowdowns	933.60
08073	On-Shore Gas Production / Gas Well Venting - Blowdowns	0.19
08075	On-Shore Gas Production / Gas Well Venting - Blowdowns	2.34
08077	On-Shore Gas Production / Gas Well Venting - Blowdowns	261.28
08081	On-Shore Gas Production / Gas Well Venting - Blowdowns	130.91
08083	On-Shore Gas Production / Gas Well Venting - Blowdowns	3,511.85
08087	On-Shore Gas Production / Gas Well Venting - Blowdowns	1.48
08095	On-Shore Gas Production / Gas Well Venting - Blowdowns	14.65
08099	On-Shore Gas Production / Gas Well Venting - Blowdowns	5.66
08103	On-Shore Gas Production / Gas Well Venting - Blowdowns	308.41
08107	On-Shore Gas Production / Gas Well Venting - Blowdowns	0.57
08113	On-Shore Gas Production / Gas Well Venting - Blowdowns	59.12
08115	On-Shore Gas Production / Gas Well Venting - Blowdowns	0.49
08121	On-Shore Gas Production / Gas Well Venting - Blowdowns	12.12
08123	On-Shore Gas Production / Gas Well Venting - Blowdowns	1,697.42
08125	On-Shore Gas Production / Gas Well Venting - Blowdowns	392.77
08001	On-Shore Gas Production / Gas Well Venting - Initial Completions	3.61
08005	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.28
08009	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.09
08011	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.02
08013	On-Shore Gas Production / Gas Well Venting - Initial Completions	6.94
08014	On-Shore Gas Production / Gas Well Venting - Initial Completions	2.78
08031	On-Shore Gas Production / Gas Well Venting - Initial Completions	1.39
08033	On-Shore Gas Production / Gas Well Venting - Initial Completions	3.23
08043	On-Shore Gas Production / Gas Well Venting - Initial Completions	1.39
08045	On-Shore Gas Production / Gas Well Venting - Initial Completions	6,473.98
08051	On-Shore Gas Production / Gas Well Venting - Initial Completions	3.87
08055	On-Shore Gas Production / Gas Well Venting - Initial Completions	1.17

08057	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.06
08061	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.03
08063	On-Shore Gas Production / Gas Well Venting - Initial Completions	3.61
08069	On-Shore Gas Production / Gas Well Venting - Initial Completions	2.22
08071	On-Shore Gas Production / Gas Well Venting - Initial Completions	9.31
08073	On-Shore Gas Production / Gas Well Venting - Initial Completions	4.16
08075	On-Shore Gas Production / Gas Well Venting - Initial Completions	1.11
08077	On-Shore Gas Production / Gas Well Venting - Initial Completions	894.97
08081	On-Shore Gas Production / Gas Well Venting - Initial Completions	85.23
08083	On-Shore Gas Production / Gas Well Venting - Initial Completions	35.02
08087	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.28
08095	On-Shore Gas Production / Gas Well Venting - Initial Completions	5.00
08099	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.06
08103	On-Shore Gas Production / Gas Well Venting - Initial Completions	759.37
08113	On-Shore Gas Production / Gas Well Venting - Initial Completions	0.59
08121	On-Shore Gas Production / Gas Well Venting - Initial Completions	2.78
08123	On-Shore Gas Production / Gas Well Venting - Initial Completions	364.42
08125	On-Shore Gas Production / Gas Well Venting - Initial Completions	93.26
08001	On-Shore Gas Production / Gas Well Venting - Recompletions	4.86
08005	On-Shore Gas Production / Gas Well Venting - Recompletions	0.37
08009	On-Shore Gas Production / Gas Well Venting - Recompletions	0.12
08011	On-Shore Gas Production / Gas Well Venting - Recompletions	0.03
08013	On-Shore Gas Production / Gas Well Venting - Recompletions	9.34
08014	On-Shore Gas Production / Gas Well Venting - Recompletions	3.74
08031	On-Shore Gas Production / Gas Well Venting - Recompletions	1.87
08033	On-Shore Gas Production / Gas Well Venting - Recompletions	4.35
08043	On-Shore Gas Production / Gas Well Venting - Recompletions	1.87
08045	On-Shore Gas Production / Gas Well Venting - Recompletions	855.82
08051	On-Shore Gas Production / Gas Well Venting - Recompletions	0.51
08055	On-Shore Gas Production / Gas Well Venting - Recompletions	1.58
08057	On-Shore Gas Production / Gas Well Venting - Recompletions	0.08
08061	On-Shore Gas Production / Gas Well Venting - Recompletions	0.04
08063	On-Shore Gas Production / Gas Well Venting - Recompletions	4.86
08069	On-Shore Gas Production / Gas Well Venting - Recompletions	2.99
08071	On-Shore Gas Production / Gas Well Venting - Recompletions	12.54
08073	On-Shore Gas Production / Gas Well Venting - Recompletions	5.61
08075	On-Shore Gas Production / Gas Well Venting - Recompletions	1.49

08077	On-Shore Gas Production / Gas Well Venting - Recompletions					118.31
08081	On-Shore Gas Production / Gas Well Venting - Recompletions					11.27
08083	On-Shore Gas Production / Gas Well Venting - Recompletions					47.16
08087	On-Shore Gas Production / Gas Well Venting - Recompletions					0.37
08095	On-Shore Gas Production / Gas Well Venting - Recompletions					6.73
08099	On-Shore Gas Production / Gas Well Venting - Recompletions					0.08
08103	On-Shore Gas Production / Gas Well Venting - Recompletions					100.38
08113	On-Shore Gas Production / Gas Well Venting - Recompletions					0.79
08121	On-Shore Gas Production / Gas Well Venting - Recompletions					3.74
08123	On-Shore Gas Production / Gas Well Venting - Recompletions					490.72
08125	On-Shore Gas Production / Gas Well Venting - Recompletions					125.58
08001	On-Shore Gas Production / Miscellaneous Engines	103.74	185.85	0.74	0.05	12.17
08005	On-Shore Gas Production / Miscellaneous Engines	12.21	21.88	0.09	0.01	1.43
08007	On-Shore Gas Production / Miscellaneous Engines	0.54	1.32	0.01		0.14
08009	On-Shore Gas Production / Miscellaneous Engines	0.44	0.79	0.00	0.00	0.05
08011	On-Shore Gas Production / Miscellaneous Engines	0.12	0.22	0.00	0.00	0.01
08013	On-Shore Gas Production / Miscellaneous Engines	31.75	56.88	0.23	0.02	3.72
08014	On-Shore Gas Production / Miscellaneous Engines	7.09	12.71	0.05	0.00	0.83
08029	On-Shore Gas Production / Miscellaneous Engines	0.09	0.11	0.00		0.03
08031	On-Shore Gas Production / Miscellaneous Engines	5.00	8.96	0.04	0.00	0.59
08033	On-Shore Gas Production / Miscellaneous Engines	16.46	29.50	0.12	0.01	1.93
08039	On-Shore Gas Production / Miscellaneous Engines	7.79	13.96	0.06	0.00	0.91
08043	On-Shore Gas Production / Miscellaneous Engines	5.00	8.96	0.04	0.00	0.59
08045	On-Shore Gas Production / Miscellaneous Engines	296.57	334.50	0.18		81.51
08051	On-Shore Gas Production / Miscellaneous Engines	0.47	0.53	0.00		0.13
08055	On-Shore Gas Production / Miscellaneous Engines	5.98	10.72	0.04	0.00	0.70
08057	On-Shore Gas Production / Miscellaneous Engines	0.31	0.55	0.00	0.00	0.04
08059	On-Shore Gas Production / Miscellaneous Engines	0.12	0.21	0.00	0.00	0.01
08061	On-Shore Gas Production / Miscellaneous Engines	0.17	0.31	0.00	0.00	0.02
08063	On-Shore Gas Production / Miscellaneous Engines	1.28	2.29	0.01	0.00	0.15
08067	On-Shore Gas Production / Miscellaneous Engines	26.65	65.44	0.52		6.88
08069	On-Shore Gas Production / Miscellaneous Engines	16.98	30.42	0.12	0.01	1.99
08071	On-Shore Gas Production / Miscellaneous Engines	47.45	85.01	0.34	0.02	5.57
08073	On-Shore Gas Production / Miscellaneous Engines	1.74	3.13	0.01	0.00	0.20
08075	On-Shore Gas Production / Miscellaneous Engines	13.49	24.17	0.10	0.01	1.58
08077	On-Shore Gas Production / Miscellaneous Engines	33.98	38.32	0.02		9.34
08081	On-Shore Gas Production / Miscellaneous Engines	17.05	19.23	0.01		4.69

08083	On-Shore Gas Production / Miscellaneous Engines	178.50	319.79	1.28	0.09	20.93
08087	On-Shore Gas Production / Miscellaneous Engines	6.75	12.08	0.05	0.00	0.79
08095	On-Shore Gas Production / Miscellaneous Engines	7.79	13.96	0.06	0.00	0.91
08099	On-Shore Gas Production / Miscellaneous Engines	0.29	0.52	0.00	0.00	0.03
08103	On-Shore Gas Production / Miscellaneous Engines	59.53	67.15	0.04		16.36
08107	On-Shore Gas Production / Miscellaneous Engines	0.10	0.12	0.00		0.03
08113	On-Shore Gas Production / Miscellaneous Engines	3.01	5.38	0.02	0.00	0.35
08115	On-Shore Gas Production / Miscellaneous Engines	0.81	1.46	0.01	0.00	0.10
08121	On-Shore Gas Production / Miscellaneous Engines	48.96	87.72	0.35	0.02	5.74
08123	On-Shore Gas Production / Miscellaneous Engines	1,663.90	2,980.91	11.94	0.83	195.14
08125	On-Shore Gas Production / Miscellaneous Engines	397.86	712.78	2.86	0.20	46.66
08009	On-Shore Gas Production /Fugitives: Other					0.16
08011	On-Shore Gas Production /Fugitives: Other					0.00
08033	On-Shore Gas Production /Fugitives: Other					0.09
08057	On-Shore Gas Production /Fugitives: Other					0.55
08061	On-Shore Gas Production /Fugitives: Other					0.73
08071	On-Shore Gas Production /Fugitives: Other					0.00
08075	On-Shore Gas Production /Fugitives: Other					1.90
08083	On-Shore Gas Production /Fugitives: Other					0.51
08087	On-Shore Gas Production /Fugitives: Other					0.96
08099	On-Shore Gas Production /Fugitives: Other					0.04
08113	On-Shore Gas Production /Fugitives: Other					0.07
08121	On-Shore Gas Production /Fugitives: Other					5.67
08123	On-Shore Gas Production /Fugitives: Other					166.51
08125	On-Shore Gas Production /Fugitives: Other					0.01
08007	On-Shore Gas Production /Gas Well Dehydrators	0.05	0.06	0.00		0.22
08067	On-Shore Gas Production /Gas Well Dehydrators	2.98	3.55	0.13		13.40
						62,361.74

NAA	county_fips	type	Expr1005	SCC Level Two
0	085	O&G	External Combustion Boilers	Electric Generation
0	061	O&G	External Combustion Boilers	Industrial
-1	123	O&G	Industrial Processes	Petroleum Industry
0	081	O&G	Industrial Processes	Petroleum Industry
0	103	O&G	Industrial Processes	Petroleum Industry
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	017	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	077	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	103	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	045	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	103	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	005	O&G	Industrial Processes	Oil and Gas Production
-1	069	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	083	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Internal Combustion Engines	Industrial
0	045	O&G	Internal Combustion Engines	Industrial
0	061	O&G	Internal Combustion Engines	Industrial
0	077	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Petroleum and Solvent Evaporation	Organic Chemical Storage
-1	123	O&G	Petroleum and Solvent Evaporation	Organic Chemical Storage
-1	123	O&G	Petroleum and Solvent Evaporation	Organic Chemical Storage
0	077	O&G	Petroleum and Solvent Evaporation	Petroleum Product Storage at Refineries
0	077	O&G	Petroleum and Solvent Evaporation	Petroleum Product Storage at Refineries
0	077	O&G	Petroleum and Solvent Evaporation	Petroleum Product Storage at Refineries
0	077	O&G	Industrial Processes	Petroleum Industry
0	103	O&G	Industrial Processes	Petroleum Industry
0	077	O&G	Petroleum and Solvent Evaporation	Petroleum Product Storage at Refineries
0	045	O&G	Industrial Processes	Fabricated Metal Products
0	077	O&G	Petroleum and Solvent Evaporation	Organic Solvent Evaporation
-1	001	O&G	Industrial Processes	Oil and Gas Production
-1	005	O&G	Industrial Processes	Oil and Gas Production

-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Petroleum Industry
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Petroleum Industry
0	083	O&G	Industrial Processes	Oil and Gas Production
0	083	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Petroleum Industry
0	103	O&G	Industrial Processes	Petroleum Industry
0	107	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
-1	123	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
0	045	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
-1	123	O&G	Waste Disposal	Site Remediation
-1	123	O&G	Waste Disposal	Solid Waste Disposal - Industrial
0	045	O&G	Waste Disposal	Solid Waste Disposal - Commercial/Institutional
0	087	O&G	Waste Disposal	Solid Waste Disposal - Industrial
0	077	O&G	Internal Combustion Engines	Industrial
0	083	O&G	Internal Combustion Engines	Industrial
-1	005	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	041	O&G	Internal Combustion Engines	Industrial
-1	001	O&G	Industrial Processes	Miscellaneous Manufacturing Industries
-1	001	O&G	Internal Combustion Engines	Industrial
-1	001	O&G	Internal Combustion Engines	Industrial
-1	001	O&G	Internal Combustion Engines	Industrial
-1	001	O&G	Internal Combustion Engines	Industrial
-1	001	O&G	Internal Combustion Engines	Industrial
-1	005	O&G	Internal Combustion Engines	Industrial
-1	005	O&G	Internal Combustion Engines	Industrial
-1	013	O&G	Internal Combustion Engines	Industrial
-1	013	O&G	Internal Combustion Engines	Industrial

-1	059	O&G	Internal Combustion Engines	Industrial
-1	069	O&G	Internal Combustion Engines	Industrial
-1	069	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	External Combustion Boilers	Industrial
-1	123	O&G	External Combustion Boilers	Industrial
-1	123	O&G	Internal Combustion Engines	Commercial/Institutional
-1	123	O&G	Internal Combustion Engines	Electric Generation
-1	123	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Internal Combustion Engines	Industrial
-1	123	O&G	Internal Combustion Engines	Industrial
0	007	O&G	Internal Combustion Engines	Industrial
0	017	O&G	Internal Combustion Engines	Industrial
0	017	O&G	Internal Combustion Engines	Industrial
0	017	O&G	Internal Combustion Engines	Industrial
0	025	O&G	Internal Combustion Engines	Industrial
0	025	O&G	Internal Combustion Engines	Industrial
0	029	O&G	Internal Combustion Engines	Industrial
0	033	O&G	Internal Combustion Engines	Industrial
0	033	O&G	Internal Combustion Engines	Industrial
0	033	O&G	Internal Combustion Engines	Industrial
0	033	O&G	Internal Combustion Engines	Industrial
0	045	O&G	External Combustion Boilers	Industrial
0	045	O&G	Internal Combustion Engines	Industrial
0	045	O&G	Internal Combustion Engines	Industrial
0	045	O&G	Internal Combustion Engines	Industrial
0	045	O&G	Internal Combustion Engines	Industrial
0	045	O&G	Internal Combustion Engines	Industrial
0	049	O&G	Internal Combustion Engines	Industrial
0	061	O&G	Internal Combustion Engines	Industrial
0	061	O&G	Internal Combustion Engines	Industrial
0	071	O&G	Internal Combustion Engines	Industrial
0	071	O&G	Internal Combustion Engines	Industrial
0	075	O&G	Internal Combustion Engines	Industrial
0	075	O&G	Internal Combustion Engines	Industrial
0	075	O&G	Internal Combustion Engines	Industrial

0	077	O&G	External Combustion Boilers	Industrial
0	077	O&G	Internal Combustion Engines	Electric Generation
0	077	O&G	Internal Combustion Engines	Industrial
0	077	O&G	Internal Combustion Engines	Industrial
0	077	O&G	Internal Combustion Engines	Industrial
0	077	O&G	Internal Combustion Engines	Industrial
0	077	O&G	Internal Combustion Engines	Industrial
0	077	O&G	Internal Combustion Engines	Industrial
0	081	O&G	Internal Combustion Engines	Electric Generation
0	081	O&G	Internal Combustion Engines	Electric Generation
0	081	O&G	Internal Combustion Engines	Industrial
0	081	O&G	Internal Combustion Engines	Industrial
0	081	O&G	Internal Combustion Engines	Industrial
0	081	O&G	Internal Combustion Engines	Industrial
0	081	O&G	Internal Combustion Engines	Industrial
0	083	O&G	Internal Combustion Engines	Electric Generation
0	083	O&G	Internal Combustion Engines	Industrial
0	083	O&G	Internal Combustion Engines	Industrial
0	083	O&G	Internal Combustion Engines	Industrial
0	083	O&G	Internal Combustion Engines	Industrial
0	083	O&G	Internal Combustion Engines	Industrial
0	083	O&G	Internal Combustion Engines	Industrial
0	085	O&G	Internal Combustion Engines	Industrial
0	087	O&G	Internal Combustion Engines	Industrial
0	087	O&G	Internal Combustion Engines	Industrial
0	087	O&G	Internal Combustion Engines	Industrial
0	087	O&G	Internal Combustion Engines	Industrial
0	087	O&G	Internal Combustion Engines	Industrial
0	099	O&G	Internal Combustion Engines	Industrial
0	099	O&G	Internal Combustion Engines	Industrial
0	099	O&G	Internal Combustion Engines	Industrial
0	103	O&G	Internal Combustion Engines	Industrial
0	103	O&G	Internal Combustion Engines	Industrial
0	103	O&G	Internal Combustion Engines	Industrial
0	103	O&G	Internal Combustion Engines	Industrial
0	103	O&G	Internal Combustion Engines	Industrial
0	103	O&G	Internal Combustion Engines	Industrial
0	105	O&G	Internal Combustion Engines	Industrial
0	107	O&G	Internal Combustion Engines	Industrial
0	113	O&G	Internal Combustion Engines	Industrial

0	113	O&G	Internal Combustion Engines	Industrial
0	125	O&G	Internal Combustion Engines	Industrial
0	125	O&G	Internal Combustion Engines	Industrial
0	125	O&G	Internal Combustion Engines	Industrial
0	125	O&G	Internal Combustion Engines	Industrial
0	125	O&G	Internal Combustion Engines	Industrial
-1	001	O&G	Industrial Processes	Oil and Gas Production
-1	001	O&G	Industrial Processes	Oil and Gas Production
-1	005	O&G	Industrial Processes	Oil and Gas Production
-1	005	O&G	Industrial Processes	Oil and Gas Production
-1	005	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
0	017	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	071	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	083	O&G	Industrial Processes	Oil and Gas Production
0	083	O&G	Industrial Processes	Oil and Gas Production
0	083	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	113	O&G	Industrial Processes	Oil and Gas Production
0	125	O&G	Industrial Processes	Oil and Gas Production
0	125	O&G	Industrial Processes	Oil and Gas Production

-1	001	O&G	Industrial Processes	Oil and Gas Production
-1	001	O&G	Industrial Processes	Oil and Gas Production
-1	001	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	045	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	081	O&G	Industrial Processes	Oil and Gas Production
0	083	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	087	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
0	125	O&G	Industrial Processes	Oil and Gas Production

-1	001	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	013	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	014	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	017	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	045	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	045	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	045	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	057	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	061	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	077	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	081	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	081	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	083	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	087	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	099	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	103	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	103	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	045	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
0	113	O&G	Petroleum and Solvent Evaporation	Petroleum Liquids Storage (non-Refinery)
-1	123	O&G	Internal Combustion Engines	Industrial
-1	001	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Industrial Processes	Oil and Gas Production
0	077	O&G	Industrial Processes	Oil and Gas Production
0	103	O&G	Industrial Processes	Oil and Gas Production
-1	123	O&G	Petroleum and Solvent Evaporation	Organic Chemical Transportation
-1	001	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
-1	013	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
-1	069	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
-1	123	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
-1	123	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
-1	123	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
0	045	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
0	045	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
0	045	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
0	081	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ
0	081	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ

0	103	O&G	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Produ

SCC Level One	SCC Level Three	SCC Level Four	CO	NOX	VOC
External Combustion Boilers	Anthracite Coal, Pulverized	Boiler	0.07	1.20	0.10
External Combustion Boilers	Bituminous Coal	Pulverized Coal: Wet Bottom	0.80	3.80	0.30
Industrial Processes	Blowdown Systems	Blowdown System w/o Contrc			0.94
Industrial Processes	Blowdown Systems	Blowdown System w/o Contrc			6.60
Industrial Processes	Blowdown Systems	Blowdown System w/o Contrc			9.40
Petroleum and Solvent Evaporation	Bulk Plants	Loading Racks			14.40
Petroleum and Solvent Evaporation	Bulk Plants	Gasoline RVP 10: Working Lc			12.86
Petroleum and Solvent Evaporation	Bulk Plants	Loading Racks			7.32
Petroleum and Solvent Evaporation	Bulk Plants	Loading Racks			16.61
Petroleum and Solvent Evaporation	Bulk Terminals	Gasoline RVP 10: Standing L			10.13
Petroleum and Solvent Evaporation	Bulk Terminals	Gasoline RVP 13/10/7: Withd			1.40
Petroleum and Solvent Evaporation	Bulk Terminals	Vapor Collection Losses			18.90
Petroleum and Solvent Evaporation	Bulk Terminals	Gasoline RVP 10: Standing L			3.45
Petroleum and Solvent Evaporation	Bulk Terminals	Miscellaneous Losses/Leaks:			19.31
Industrial Processes	Crude Oil Production	Processing Operations: Not C			5.00
Industrial Processes	Crude Oil Production	Evaporation from Liquid Leak	0.10	0.11	5.92
Industrial Processes	Crude Oil Production	Flanges and Connections			2.68
Industrial Processes	Crude Oil Production	Processing Operations: Not C			8.75
Industrial Processes	Crude Oil Production	Processing Operations: Not C			74.35
Industrial Processes	Crude Oil Production	Processing Operations: Not C			34.28
Industrial Processes	Crude Oil Production	Processing Operations: Not C			0.45
Industrial Processes	Crude Oil Production	Processing Operations: Not C			13.55
Internal Combustion Engines	Distillate Oil (Diesel)	Reciprocating	46.80	41.70	3.60
Internal Combustion Engines	Distillate Oil (Diesel)	Turbine: Cogeneration	93.30	83.46	7.20
Internal Combustion Engines	Distillate Oil (Diesel)	Reciprocating	2.40	11.40	0.90
Internal Combustion Engines	Distillate Oil (Diesel)	Reciprocating	4.59	21.30	1.12
Petroleum and Solvent Evaporation	Fixed Roof Tanks - Alcohols	Methyl Alcohol: Breathing Los			0.07
Petroleum and Solvent Evaporation	Fixed Roof Tanks - Alcohols	Methyl Alcohol: Working Loss			0.07
Petroleum and Solvent Evaporation	Fixed Roof Tanks - Miscellaneous	Specify In Comments: Workir			11.50
Petroleum and Solvent Evaporation	Fixed Roof Tanks (Varying Sizes)	Gasoline RVP 10: Working Lc			0.08
Petroleum and Solvent Evaporation	Fixed Roof Tanks (Varying Sizes)	Gasoline RVP 13: Working Lc			1.20
Petroleum and Solvent Evaporation	Fixed Roof Tanks (Varying Sizes)	Specify Liquid: Working Loss			0.16
Industrial Processes	Flares	Process Gas	0.40	0.20	
Industrial Processes	Flares	Not Classified **	1.77	0.50	0.27
Petroleum and Solvent Evaporation	Floating Roof Tanks (Varying Sizes)	Gasoline RVP 13: Standing L			3.28
Industrial Processes	Fuel Fired Equipment	Natural Gas: Flares	48.64	8.94	
Petroleum and Solvent Evaporation	Fuel Fired Equipment	Natural Gas: Flares	1.29	0.65	
Industrial Processes	Fugitive Emissions	Specify in Comments Field			3.25
Industrial Processes	Fugitive Emissions	Specify in Comments Field			6.40

Industrial Processes	Fugitive Emissions	Fugitive Emissions			33.25
Industrial Processes	Fugitive Emissions	Specify in Comments Field			67.64
Petroleum and Solvent Evaporation	Fugitive Emissions	Specify in Comments Field			1.37
Industrial Processes	Fugitive Emissions	Fugitive Emissions			20.04
Industrial Processes	Fugitive Emissions	Specify in Comments Field			46.59
Industrial Processes	Fugitive Emissions	Fugitive Emissions			17.20
Industrial Processes	Fugitive Emissions	Flanges: All Streams			70.30
Industrial Processes	Fugitive Emissions	Specify in Comments Field			92.67
Industrial Processes	Fugitive Emissions	Pipeline Valves and Flanges			1.00
Industrial Processes	Fugitive Emissions	Fugitive Emissions			1.99
Industrial Processes	Fugitive Emissions	Specify in Comments Field			24.77
Industrial Processes	Fugitive Emissions	Specify in Comments Field			4.20
Industrial Processes	Fugitive Emissions	Fugitive Emissions			12.28
Industrial Processes	Fugitive Emissions	Specify in Comments Field			63.04
Industrial Processes	Fugitive Emissions	Pipeline Valves and Flanges			2.36
Industrial Processes	Fugitive Emissions	Pipeline Valves: Gas Streams			18.72
Industrial Processes	Fugitive Emissions	Specify in Comments Field			4.16
Petroleum and Solvent Evaporation	Gasoline Retail Operations - Stage I	Balanced Submerged Filling			1.22
Petroleum and Solvent Evaporation	Gasoline Retail Operations - Stage I	Submerged Filling w/o Contro			20.77
Petroleum and Solvent Evaporation	Gasoline Retail Operations - Stage I	Submerged Filling w/o Contro			10.28
Waste Disposal	In Situ Venting/Venting of Soils	Active Aeration, Vacuum: Vap			4.00
Waste Disposal	Incineration	Sludge	0.01	0.00	0.01
Waste Disposal	Incineration	Single Chamber	0.00	0.01	0.05
Waste Disposal	Incineration	Fuel Not Classified	0.00		0.00
Internal Combustion Engines	Large Bore Engine	Diesel	10.62	5.31	3.72
Internal Combustion Engines	Large Bore Engine	Diesel	3.08	16.95	2.24
Industrial Processes	Liquid Waste Treatment	Liquid - Liquid Separator			65.10
Industrial Processes	Liquid Waste Treatment	Oil-Sludge-Waste Water Pit			1,042.92
Industrial Processes	Liquid Waste Treatment	Oil-Water Separator			47.74
Internal Combustion Engines	Liquified Petroleum Gas (LPG)	Propane: Reciprocating	81.50	49.80	0.70
Industrial Processes	Miscellaneous Industrial Processes	Other Not Classified			8.12
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	20.58	48.21	8.77
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	6.30	5.70	0.12
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	131.03	101.58	63.77
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	12.45	12.45	0.62
Internal Combustion Engines	Natural Gas	Reciprocating	51.25	46.34	14.87
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	83.20	87.20	
Internal Combustion Engines	Natural Gas	Reciprocating	65.90	326.10	9.29
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	3.82	2.27	0.12
Internal Combustion Engines	Natural Gas	Reciprocating	15.49	15.49	1.79

Internal Combustion Engines	Natural Gas	Reciprocating	10.90	5.50	3.80
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	0.07	7.20	
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	2.11	2.47	0.23
External Combustion Boilers	Natural Gas	< 10 Million BTU/hr	1.68	1.00	0.11
External Combustion Boilers	Natural Gas	10-100 Million BTU/hr	18.86	11.22	1.23
Internal Combustion Engines	Natural Gas	Reciprocating	1.30	0.43	1.30
Internal Combustion Engines	Natural Gas	Reciprocating	17.83	7.22	3.61
Internal Combustion Engines	Natural Gas	2-cycle Clean Burn	39.00	39.50	30.00
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	142.22	161.54	69.34
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	1,058.38	374.32	94.78
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	71.32	135.21	83.77
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	297.53	266.87	113.79
Internal Combustion Engines	Natural Gas	Reciprocating	544.62	######	440.52
Internal Combustion Engines	Natural Gas	Turbine	18.10	17.20	1.35
Internal Combustion Engines	Natural Gas	Turbine: Cogeneration	97.90	83.30	33.90
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	0.10	0.10	0.03
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	41.07	24.47	4.29
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	11.31	6.90	0.09
Internal Combustion Engines	Natural Gas	Reciprocating	56.32	56.32	4.14
Internal Combustion Engines	Natural Gas	Reciprocating	40.48	24.70	0.32
Internal Combustion Engines	Natural Gas	Turbine	1.70	12.80	0.04
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	1.66	0.84	0.59
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	20.90	25.80	0.86
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	72.18	3.25	
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	2.65	2.58	3.06
Internal Combustion Engines	Natural Gas	Reciprocating	8.06	14.91	14.52
External Combustion Boilers	Natural Gas	< 10 Million BTU/hr	4.78	5.70	0.31
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	4.91	47.63	7.78
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	134.30	92.21	29.51
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	366.64	956.99	449.80
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	29.90	38.98	16.70
Internal Combustion Engines	Natural Gas	Reciprocating	121.29	127.11	24.43
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	0.75	12.40	0.40
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	10.79	6.41	0.04
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	2.60	1.55	
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	22.52	51.63	0.90
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	16.17	139.81	5.03
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	19.72	12.03	0.85
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn		0.18	
Internal Combustion Engines	Natural Gas	Turbine	30.88	39.51	9.35

External Combustion Boilers	Natural Gas	10-100 Million BTU/hr	11.40	22.40	1.30
Internal Combustion Engines	Natural Gas	Reciprocating	11.40	20.50	0.20
Internal Combustion Engines	Natural Gas	2-cycle Clean Burn	2.61	63.96	3.94
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	2.48	9.36	3.88
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	43.69	31.87	7.86
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	17.81	17.50	5.47
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	35.31	23.27	3.33
Internal Combustion Engines	Natural Gas	Reciprocating	61.62	80.86	11.38
Internal Combustion Engines	Natural Gas	Reciprocating	11.00	13.40	1.82
Internal Combustion Engines	Natural Gas	Turbine	77.43	64.97	7.58
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	117.83	51.44	8.84
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	41.66	53.65	17.56
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	4.03	15.70	1.83
Internal Combustion Engines	Natural Gas	Reciprocating	31.78	73.69	10.37
Internal Combustion Engines	Natural Gas	Turbine	6.21	6.20	2.99
Internal Combustion Engines	Natural Gas	Reciprocating	29.20	17.40	0.16
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	38.30	31.46	2.20
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	13.80	8.42	0.20
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	122.20	118.42	20.54
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	35.39	31.41	0.51
Internal Combustion Engines	Natural Gas	Reciprocating	2.04	6.05	1.85
Internal Combustion Engines	Natural Gas	Turbine	38.29	120.00	2.71
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	12.30	11.17	0.41
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	5.40	6.70	2.70
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	8.96	7.45	2.65
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	114.40	59.20	28.00
Internal Combustion Engines	Natural Gas	Reciprocating	91.27	194.03	9.91
Internal Combustion Engines	Natural Gas	Turbine	6.81	35.80	3.11
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	43.10	353.80	13.40
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	1.23	12.70	0.26
Internal Combustion Engines	Natural Gas	Reciprocating	75.50	46.10	0.60
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	55.70	47.00	14.95
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	104.42	54.59	9.55
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	164.48	420.65	105.48
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	157.67	141.10	25.95
Internal Combustion Engines	Natural Gas	Reciprocating	144.82	492.39	49.23
Internal Combustion Engines	Natural Gas	Turbine	29.81	58.00	3.82
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	6.30	6.30	1.90
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn		6.53	0.03
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	2.00	9.00	3.00

Internal Combustion Engines	Natural Gas	Reciprocating	7.20	3.60	0.90
Internal Combustion Engines	Natural Gas	2-cycle Lean Burn	43.20	35.55	14.30
Internal Combustion Engines	Natural Gas	4-cycle Clean Burn	33.10	36.45	7.00
Internal Combustion Engines	Natural Gas	4-cycle Lean Burn	31.60	22.10	9.20
Internal Combustion Engines	Natural Gas	4-cycle Rich Burn	120.57	61.93	22.89
Internal Combustion Engines	Natural Gas	Reciprocating	84.32	257.76	25.45
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			4.73
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			6.10
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Ethylene			4.90
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			18.42
Industrial Processes	Natural Gas Processing Facilities	Process Valves			12.00
Industrial Processes	Natural Gas Processing Facilities	Gas Sweeting: Amine Proces	1.92	0.35	14.96
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler	9.30	0.09	14.67
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			17.82
Industrial Processes	Natural Gas Processing Facilities	Flanges and Connections			10.00
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Ethylene			51.26
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			80.33
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler	0.18	0.22	0.02
Industrial Processes	Natural Gas Processing Facilities	Gas Sweeting: Amine Proces			10.00
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			31.17
Industrial Processes	Natural Gas Processing Facilities	Process Valves			4.80
Industrial Processes	Natural Gas Processing Facilities	Compressor Seals			4.60
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Ethylene			36.68
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			16.87
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler	0.14	0.16	70.14
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Ethylene			13.60
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			7.45
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler	0.78	0.42	13.02
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Ethylene			3.56
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler	4.60	2.80	0.16
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			5.34
Industrial Processes	Natural Gas Processing Facilities	Process Valves			6.80
Industrial Processes	Natural Gas Processing Facilities	Gas Sweeting: Amine Proces	3.88	4.61	44.12
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Ethylene	0.10	0.12	26.12
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Phase Se	0.90	1.07	7.83
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler	10.45	12.44	30.32
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler	0.28	14.54	137.69
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			13.32
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			2.20
Industrial Processes	Natural Gas Processing Facilities	Glycol Dehydrators: Reboiler			28.49

Industrial Processes	Natural Gas Production	All Equipt Leak Fugitives (Val			3.44
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler St	4.73	1.80	7.47
Industrial Processes	Natural Gas Production	Other Not Classified			10.41
Industrial Processes	Natural Gas Production	All Equipt Leak Fugitives (Val			6.45
Industrial Processes	Natural Gas Production	Flares	51.71	9.50	252.56
Industrial Processes	Natural Gas Production	Flares Combusting Gases <1	43.38	8.13	5.80
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler Bu	5.26	2.60	2.31
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler St	6.60	3.30	44.67
Industrial Processes	Natural Gas Production	Other Not Classified	0.38	0.42	0.34
Industrial Processes	Natural Gas Production	Pipeline Pigging (releases du			2.96
Industrial Processes	Natural Gas Production	Valves: Fugitive Emissions			4.37
Industrial Processes	Natural Gas Production	All Equipt Leak Fugitives (Val			18.19
Industrial Processes	Natural Gas Production	Compressors			10.00
Industrial Processes	Natural Gas Production	Flares Combusting Gases <1	6.41	1.19	2.43
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler St			181.88
Industrial Processes	Natural Gas Production	Other Not Classified			28.67
Industrial Processes	Natural Gas Production	Valves: Fugitive Emissions			5.94
Industrial Processes	Natural Gas Production	Gas Sweetening: Amine Proc			9.00
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler St	0.40	0.40	3.10
Industrial Processes	Natural Gas Production	All Equipt Leak Fugitives (Val			8.47
Industrial Processes	Natural Gas Production	Compressors	4.80	19.40	2.90
Industrial Processes	Natural Gas Production	Flares	0.65	0.12	3.25
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler Bu	0.12	0.61	23.28
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler St			18.76
Industrial Processes	Natural Gas Production	Other Not Classified			44.55
Industrial Processes	Natural Gas Production	Pump Seals			29.00
Industrial Processes	Natural Gas Production	Relief Valves	1.30	0.24	153.54
Industrial Processes	Natural Gas Production	Valves: Fugitive Emissions			17.20
Industrial Processes	Natural Gas Production	Valves: Fugitive Emissions			23.40
Industrial Processes	Natural Gas Production	Flares	16.67	3.07	28.42
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler Bu	25.70	4.73	40.90
Industrial Processes	Natural Gas Production	Other Not Classified			1.40
Industrial Processes	Natural Gas Production	All Equipt Leak Fugitives (Val			37.39
Industrial Processes	Natural Gas Production	Flares	3.35	0.61	
Industrial Processes	Natural Gas Production	Flares Combusting Gases :10	8.90	1.64	
Industrial Processes	Natural Gas Production	Gas Stripping Operations			20.80
Industrial Processes	Natural Gas Production	Gas Sweetening: Amine Proc	3.30	3.90	9.05
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler St			58.99
Industrial Processes	Natural Gas Production	Valves: Fugitive Emissions			2.98
Industrial Processes	Natural Gas Production	Glycol Dehydrator Reboiler St			26.98

Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			24.43
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			3.45
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			1.70
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Crude Oil, v			60.90
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			141.56
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank: Breathing L	0.20	0.04	1.15
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Internal Floating Roof Tank: V			2.64
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Crude Oil, v			34.22
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			26.79
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank: Breathing L			3.11
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank: Working Lo			26.80
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			0.43
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Crude Oil, v			5.99
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			7.82
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			2.94
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Internal Floating Roof Tank, C			4.15
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			35.00
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			10.50
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	External Floating Roof Tank, (			1.50
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Crude Oil, v			4.89
Petroleum and Solvent Evaporation	Oil and Gas Field Storage and Working Ta	Fixed Roof Tank, Produced W			805.04
Petroleum and Solvent Evaporation	Petroleum Products - Underground Tanks	Distillate Fuel #2: Working Lo			11.32
Petroleum and Solvent Evaporation	Petroleum Products - Underground Tanks	Distillate Fuel #2: Working Lo			10.03
Internal Combustion Engines	Process Gas	Reciprocating Engine	0.56	2.54	
Industrial Processes	Process Heaters	Natural Gas	2.42	2.39	
Industrial Processes	Process Heaters	Natural Gas	18.85	22.85	6.58
Industrial Processes	Process Heaters	Process Gas	4.85	5.74	0.32
Industrial Processes	Process Heaters	Natural Gas	14.96	17.72	0.94
Petroleum and Solvent Evaporation	Specific Liquid	Loading Rack			2.45
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			11.72
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			3.74
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			1.95
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			21.90
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			1,303.95
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Not Classified **			1.07
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			159.16
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Not Classified **			58.97
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Transit Losses - LPG: Return			1.10
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			74.98
Petroleum and Solvent Evaporation	Tank Cars and Trucks	Not Classified **			4.61

Petroleum and Solvent Evaporation	Tank Cars and Trucks	Crude Oil: Submerged Loadir			29.67
					8,825.79

NAA	county_fips	proc_emis_estim_units	CO	NOX
-1	001	TY	228.8	218.5
-1	005	TY	149.1	413.3
-1	013	TY	19.3	17.8
-1	059	TY	10.9	5.5
-1	069	TY	2.3	9.8
-1	123	TY	2,446.9	2,329.4
0	007	TY	0.1	0.1
0	017	TY	108.7	87.7
0	025	TY	42.2	37.5
0	029	TY	1.7	0.8
0	033	TY	103.8	46.5
0	041	TY	81.5	49.8
0	045	TY	857.0	1,403.9
0	049	TY	0.8	12.4
0	061	TY	16.6	23.2
0	071	TY	38.9	191.7
0	075	TY	50.6	51.7
0	077	TY	208.5	303.3
0	081	TY	297.0	299.6
0	083	TY	283.1	350.5
0	085	TY	12.4	12.4
0	087	TY	273.8	313.8
0	099	TY	119.8	412.6
0	103	TY	704.8	1,270.9
0	105	TY	6.3	6.3
0	107	TY		6.5
0	113	TY	9.2	12.6
0	125	TY	312.8	413.8
0	777	TY	6.5	22.0

EDF-WZI-APPENDIX III

Appendix III
Well and Facility Component Count and Emissions Factor Review

Fugitive emissions, by definition, are those historic emissions associated with the numerous components surrounding a production well including the associated facilities. Generally, in the E&P industry, fugitive emissions come from Valves, Flanges, Connectors, Open-ended lines, Pump Seals, Valve Bonnets, Compressor Seals, Pressure Relief Valves, Well Cellars, and Pits. Emissions factors for these sources have been established on a per-component-basis, discussed below, speciation and mass fraction is discussed in **Appendix VI**, Speciation Analysis.

Emissions Factors

Well and Facility Component Emission Factors

Exhibit 1 below is a copy of the Table 4-2 from the 1995 EPA Protocol for Equipment Leak Emission Estimates. These commonly accepted factors are used to estimate fugitives associated with potentially leaking components.

TABLE 2-4. OIL AND GAS PRODUCTION OPERATIONS AVERAGE EMISSION FACTORS (kg/hr/source)

Equipment Type	Service[a]	Emission Factor (kg/hr/source)[b]
Valves	Gas	4.5E-03
	Heavy Oil	8.4E-06
	Light Oil	2.5E-03
	Water/Oil	9.8E-05
Pump seals	Gas	2.4E-03
	Heavy Oil	NA
	Light Oil	1.3E-02
	Water/Oil	2.4E-05
Others[c]	Gas	8.8E-03
	Heavy Oil	3.2E-05
	Light Oil	7.5E-03
	Water/Oil	1.4E-02
Connectors	Gas	2.0E-04
	Heavy Oil	7.5E-06
	Light Oil	2.1E-04
	Water/Oil	1.1E-04
Flanges	Gas	3.9E-04
	Heavy Oil	3.9E-07
	Light Oil	1.1E-04
	Water/Oil	2.9E-06
Open-ended lines	Gas	2.0E-03
	Heavy Oil	1.4E-04
	Light Oil	1.4E-03
	Water/Oil	2.5E-04

[a]Water/Oil emission factors apply to water streams in oil service with a water content greater than 50%, from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.
[b]These factors are for total organic compound emission rates (including non-VOC's such as methane and ethane) and apply to light crude, heavy crude, gas plant, gas production, and off shore facilities. "NA" indicates that not enough data were available to develop the indicated emission factor.
[c]The "other" equipment type was derived from compressors, diaphrams, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Exhibit 1

These common factors are the accepted by CDPHE for use in Colorado. See Exhibit 2, below

☐ Quarterly monitoring. Control: 70% gas valve, 61% lt. liq. valve, 45% lt. liq. pump

Section 08 – Emission Factor Information

Identify the emission factor used to estimate emissions under "E.F.", along with the units relating to the emission factor (e.g. lb/hr/component).

☒ **Check this box if you used Table 2-4 of U.S. EPA's *1995 Protocol for Equipment Leak Emission Estimates* to estimate emissions. You do not need to enter the emission factors below if checked.**

Equipment Type	Service											
	Gas			Heavy Oil (or Heavy Liquid)			Light Oil (or Light Liquid)			Water/Oil		
	Count[1]	E.F.	Units	Count[1]	E.F.	Units	Count[1]	E.F.	Units	Count[1]	E.F.	Units
Connectors	1396			0			431			104		
Flanges	15			0			0			0		
Open-Ended Lines	0			0			0			0		
Pump Seals	0			0			0			0		
Valves	124			0			79			16		
Other	3			0			0			0		

[1]Count shall be the actual or estimated number of components in each type of service used to calculate the "Actual Calendar Year Emissions" below. ☐ Estimated Count ☒ Actual Count conducted on the following date: 2/24/2012

Section 09 – Emissions Inventory Information & Emission Control Information

Exhibit 2

Storage Tank Emissions Factors

The storage tank emissions factor of 13.7 lb/bbl of condensate for condensate storage tanks is derived from work performed by Lesair Environmental Inc.[1, 2, 3]

Summary of Tank Emissions Factors	
Basin	Condensate Tank Emissions Factor, lb VOC/bbl
DJ Basin	13.7
Piceance	10.0
No. San Juan	11.8
Remainder	11.8

Independently, the Texas Environmental Research Consortium (TERC) commissioned a study of oil and gas related tank emissions in Texas. An average emissions factor was reported as 33 lbVOC/bbl ± 53 lb VOC/bbl.[4]

$$mass\ fraction\ in\ flash = \frac{33lbVOC}{bbl_{crude}} \times \frac{bbl_{crude}}{42\ gal\ crude} \times \frac{gal\ crude}{7.48lb\ crude} = 0.42\frac{lbVOC}{lbCrude}$$

This emissions factor indicates a large vapor component of VOC in tankage. I conducted a rigorous analysis of this empirical data and found that the TERC data when averaged without some of the outliers approaches 15 lb VOC/ bbl ± 12.5 lb VOC/bbl; consistent with CDPHE's emission factors related to Colorado's regional production. I found that the high standard deviation in the unadjusted average (33 lbVOC/bbl) is attributed to outliers whose measurement are suspect, the average is largely skewed by tanks that reported VOCs as less than 3.5 lb VOC/bbl (likely controlled) and tanks that reported in excess of 60 lbVOC/bbl (likely emitting more VOC [as speciated] into vapor, than physically provided for by K-factors for in the normal petroleum liquid at the specified tank pressure and temperature [8 gallons out of 42 gallons in a

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[1] Environ, FINAL EMISSIONS TECHNICAL MEMORANDUM No. 4a, 2012

[2] ENVIRON, "Development of Baseline 2006 Emissions from Oil and Gas Activity In The Denver-Julesburg Basin", Prepared for CDPHE and Independent Petroleum Association of Mountain States (IPAMS), April, 2008

[3] A conversion of the 13.7 lb/bbl VOC emissions factor results in a mass fraction of 4.4% as opposed to the post flashed value of approximately 0.1%.

[4] URS Corporation, FINAL REPORT: VOC Emissions from Oil and Condensate Storage Tanks, Prepared for Texas Environmental Research Consortium (TERC), April, 2009

barrel, 20%); only one value was dropped in the study(tank battery 26), exceeding 1200 lb VOC/bbl (using 7.48 lb/gallon this is 162 gallons in a given 42 gallon barrel). The three low measured emissions measurements were treated as possible artifacts of emissions control. On the larger tanks (and smaller tanks as well) tank vapor composition must be in balance with the liquids sent to the tank in accordance to speciations in vapor and liquid phases defined by Equations of State and K-factors, and unless adjunct vapors are injected into the vapor space the samples of vapor pulled should reflect this balance. Additionally (by virtue of conservation of mass) the mass emitted by tank as the VOC component cannot exceed the mass fraction (defined by the K-factor) possible from the liquids prior to the flash in the tank, and certainly cannot exceed the total mass of VOC components available in the Crude Oil or Condensate, as if fully weathered. While it is possible to have high tank emissions (if the tank is the direct recipient of production liquids with no interposing separator), the commensurate vapors would have high Methane content along the lines of the production separation and GOR and the subsequent sampled Vapor speciation would show low VOC and high Methane.

If one simply eliminates the high and low outliers, the TERC average approaches 15 lb VOC/bbl ± 12.5 lbVOC/bbl and is consistent with CDPHE's emission factors related to Colorado's regional production.

Glycol Dehydrator Emissions Factors

EPA and GRI jointly developed a set of Methane emissions factors for Glycol Dehydrators, based on the location of the dehydrator in the O&G process stream.

TABLE 5-3. SUMMARY OF GLYCOL DEHYDRATOR AND AGR EMISSION FACTORS

Segment	Emission Factor (scf CH_4/MMscf)
Production	275.6 ± 154%
Gas Processing	121.6 ± 202%
Transmission	93.72 ± 208%
Storage	117.2 ± 160%
AGRs	6083 scfd/AGR ± 105%

Exhibit 3

TABLE 5-2. EFFECTS OF PROCESS PARAMETERS ON METHANE EMISSIONS FROM GLYCOL REGENERATORS

Parameter	Very Low Value	Low Value	Medium Low Value	Base Value	Medium High Value	High Value	Very High Value	Supple-mental Condition
Methane Composition (vol%) Methane Emissions (tons/yr)		85 0.0701	87.5 0.0767	90 0.0837	92.5 0.0911	95 0.0999		
Glycol Circulation Rate (gph) Methane Emissions (tons/yr)		4.75 0.0419[a]	7.14 0.0626	9.48 0.0837	11.88 0.104	14.28 0.125		
Lean Glycol (% water) Methane Emissions (tons/yr)		0.5 0.0841		1 0.0837		1.5 0.0832		
Flash Tank Pressure (psig) Methane Emissions (tons/yr)	15 0.0261	30 0.0442	45 0.0635	60 0.0837	75 0.104	90 0.125	120 0.168	No tank 1.12
Flash Tank Temperature (°F) Methane Emissions (tons/yr)		70 0.092		110 0.0837		150 0.0753		
Gas Flow Rate (MMscfd) Methane Emissions (tons/yr)		0.9 0.0837		1 0.0837		1.1 0.0837		10[b] 0.837
Gas Temperature (°F) Methane Emissions (tons/yr)		90 0.0832		95 0.0837		100 0.0841		
Gas Pressure (psig) Methane Emissions (tons/yr)		600 0.0837		800 0.0837		1000 0.0837		

[a] Results not valid since the dry gas water content is greater than 7 lb H_2O/MMscf.
[b] Glycol circulation rate is also increased by a factor of ten.
Number of absorber trays is fixed at 1.48.

Exhibit 4

Table 5-2 (Exhibit 4, above) shows the various sensitivities of Methane emissions factors to certain process parameters related to glycol dehydrators. It generally shows a range from 0.062 to .104 tons of Methane per year per unit.

VOC is largely defined by the BTEX content in the pre-processed Natural gas and the recirculation rate of the glycol unit. Assuming Tri-ethylene glycol (TEG) recirculating at 300 gallons TEG/MMscf one gets 1 to 3 tons/year of VOC (as BTEX) per unit, see Exhibit 5, below. However, this value presumes the recirculation rate.

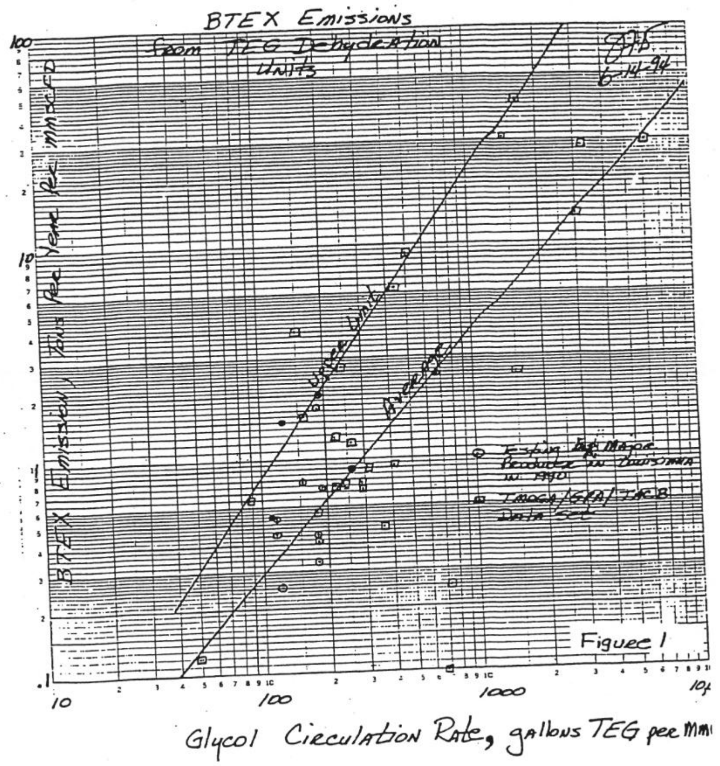

Exhibit 5

Assuming, the lowest VOC and the lowest methane (VOC/Methane =1/0.062=16.1) and the highest VOC/BTEX value to the Highest methane VOC/Methane =3/.104= 28.8). Assuming that BTEX is 50% of the VOC the VOC/Methane values would range from 8 to 14 as compared to the process gas having a VOC/Methane ratio of 0.28.[5]

Therefore the range of VOC emissions factors would be roughly 8 to 28 times that of for Methane.

Component Counts

Component counts are known to vary by extent of facility definition; a single well head may have as few as 50 components whereas a larger more encompassing facility may have as many as 500 components per facility well. [6]

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[5] Davis,JF, Triethylene Glycol Parameters for estimating BTEX Emissions, 1996

[6] Historic Studies such as those performed by WOGA , CARB and API Study have focused on field counts of components in targeted study facilities. The historic studies performed by WOGA indicated that typical fitting counts for the general population of 27,101 oil and gas wells were:

Table 1: Average Component Count-Liquid Service				
GOR	0-100	100-400	400-900	>900[6]
Count	241	197	145	63

In this particular regulatory scheme, the CDPHE has selected a facility definition that encompasses all facilities including the on-lease tankage and metering. Using the EPA/GRI study, Table 4-7 data for facilities in Onshore Production in the Western US- (Exhibit 6) one derives that a facility-well based count using Western U.S. data would be approximately 342 components associated with any given facility well (excluding tankage system piping and metering).[7] If one includes 50 components for the tankage piping system and 50 components for the metering system piping, the approximate component count approaches 442 components per facility well. Allowing ±30% design margin for differing facility layouts one gets a range of 309 to 574 components per facility well. Based on their APEN review, CDPHE estimated 1,238 components per defined facility which translates to 532 components per **facility-well** for an average facility having 2.3 facility related wells.[8]

TABLE 4-7. AVERAGE COMPONENT COUNTS FOR ONSHORE PRODUCTION IN THE WESTERN U.S.

Equipment	No. of Sites	No. of Equipment	Average Component Count[a] Valves	Connections	Open-Ended Lines	PRVs[b]	Compressor Seals
Gas Wellheads	17	184	11 (30%)	36 (20%)	1 (28%)	0	0
Separators	16	183	34 (44%)	106 (38%)	6 (94%)	2 (68%)	0
Meters/Piping	12	73	14 (31%)	51 (47%)	1 (113%)	1 (150%)	0
Gathering Compressors	13	61	73 (102%)	179 (51%)	3 (50%)	4 (84%)	4 (69%)
Heaters	11	77	14 (49%)	65 (70%)	2 (66%)	1 (89%)	0
Dehydrators	10	52	24 (31%)	90 (37%)	2 (69%)	2 (53%)	0

[a] Values in parentheses represent the 90% confidence interval.
[b] Pressure relief valves.

Exhibit 6

While fewer in number than wells and tanks, compressor stations have a larger component count (approximately 2,000 to 6,000) depending on the size and service of the facility, see Exhibit 7. A review of various facility APENS reports for 2012 for shows a similar pattern of component counts, and the CDPHE selection of components appear to be consistent with this overall trend.

Average Component Count -Gas Service				
GOR	0-100	100-400	400-900	>900
Count	5	98	108	73

[7] GRI/EPA, Methane Emissions from Natural Gas Industry-Volume 8: Equipment Leaks, 600/R96-080h
[8] CDPHE Spreadsheet, [LDAR Cost Analysis Statewide Well Production Facilities-14NOV2013.xlxs]

TABLE 4-14. AVERAGE FACILITY EMISSIONS FOR GAS PROCESSING PLANTS

Equipment Type	Component Type	Component Emission Factor,[a] Mscf/component-yr	Average Component Count	Average Equipment Emissions, MMscf/yr	90% Confidence Interval, %
Gas Plant (non-compressor related components)	Valve	1.305	1392	2.89	48
	Connection	0.117	4392		
	Open-Ended Line	0.346	134		
	Pressure Relief Valve	0.859	29		
	Site Blowdown Open-Ended Line	230	2		
Reciprocating Compressor	Compressor Blowdown Open-Ended Line	2035[c,d]	1	4.09	74
	Pressure Relief Valve	349[c,d]	1		
	Miscellaneous[b]	189[d]	1[e]		
	Starter Open-Ended Line	1341	0.25[f]		
	Compressor Seal	450[d]	2.5		
Centrifugal Compressor	Compressor Blowdown Open-Ended Line	6447[c,g]	1	7.75	39
	Miscellaneous[b]	31[g]	1[e]		
	Starter Open-Ended Line	1341	1		
	Compressor Seal	228[g]	1.5		

[a] Annual methane emission rate adjusted for average 87.0 vol. % methane in gas processing.[17]
[b] Includes cylinder valve covers and fuel valves.
[c] Adjusted for 11.1% of compressors which have sources routed to flare.
[d] Adjusted for 89.7% of time reciprocating compressors in processing are pressurized.
[e] Other components counted/measured in aggregate per compressor.
[f] Only 25% of starters for reciprocating compressors in processing use natural gas.g Adjusted for 43.6% of time centrifugal compressors in processing are pressurized.
[g] Adjusted for 43.6% of time centrifugal compressors in processing are pressurized.

Exhibit 7

EDF-WZI-APPENDIX IV

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EDF-WZI-APPENDIX V

Appendix V:

1 Speciation Analysis

The chemical characteristics of emissions from oil and gas activities vary depending in part on the source of the emissions. For example, vapors that escape from a condensate tank will generally have more volatile organic compounds (VOCs) emissions and less methane relative to vapor emissions that occur from a wellhead, which would typically contain more methane and less VOCs. This Appendix explains how various process streams at oil and gas production operations are speciated into different chemical constituents.

1.1 Speciation for source emissions of concern

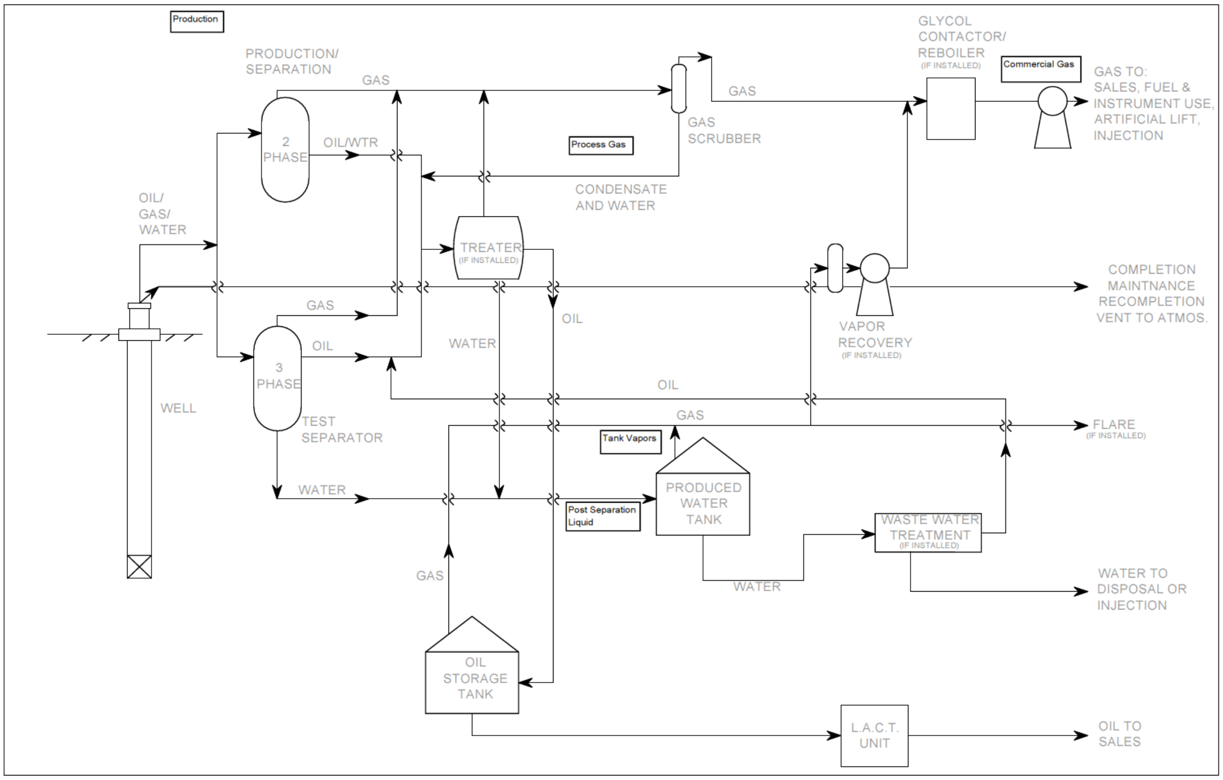
Natural Gas is produced either directly from gas reservoirs, in combination with oil production or from coal bed deposits. While all hydrocarbons (both light and heavy) are completely in solution in the reservoir at production depth, they separate into Natural Gas (lighter hydrocarbons) and Condensate or Crude as well as a water phase. The Natural Gas primarily consists of Methane, Ethane, CO2 and those various Hydrocarbon isomers in the range of Propane (C3) to Decane (C10), commonly referred to as VOCs.[1] Heavier VOC components such as heavier hazardous air pollutants (HAPS) may exist in trace amounts. Condensate or Crude contains all other heavier hydrocarbons as a liquid which have little or no residual vapors. The empirical VOC and Methane data can be summarized by sources using Form 203 data which were summarized and checked against predicted Vapor/ Liquid Speciations by flashing equivalent process stream-related-leaks using accepted Equations of State, in this instance Suave-Redlich-Kwong method.

[1] California Air Resources Board, Definitions of VOC and ROG, Planning and Technical Support Division, Emission Inventory Analysis Section, August 2000

Item	Short Name	2011 VOC, TPY	2011 Methane, TPY	Ratio VOC : Methane	Emission Source Type
1	Condensate Tanks	125,800	27,588	4.56	Post Flashed Liquid, API˚>40
2	Fugitives-Oil Well	18,253	65,656	0.28	Process Liquid and Process Gas
3	Pneumatic Devices-Oil Well	13,898	36,342	0.38	Process Gas
4	Blowdowns-Gas Well Venting	11,524	78,985	0.15	Casing Gas
5	Initial Completions-Gas Well Venting	8,760	60,044	0.15	Casing Gas
6	Pneumatic Pumps-Gas Well	4,879	17,549	0.28	Process Gas
7	Point Sources: Others (Produced Water Portion)	2,083	7,492	0.28	General Process Gas
8	Point Sources: Internal and Turbine Combustion (non coal)	2,041	7,342	0.28	NG Fuel
9	Gas Well Truck Loading-NG	1,938	422	4.59	Post Flashed Liquids, API˚<40
10	Recompletions-Gas Well Venting	1,817	12,115	0.15	Production Gas/Liquid Flash to amb.
11	Point Sources Crude Oil: Submerged Loading (Normal Service)	1,304	286	4.56	Post Flashed Liquids, API˚<45
12	Point Sources: Glycol Dehydrator Process Emissions	1,051	3,806	0.28	Process Gas
13	Point Sources: Oil-Sludge-Waste Water Pit	1,042	680	1.53	Post Flashed Liquids/Water
14	Point Sources: Fugitive Emissions	1,012	3,640	0.28	Process Liquid and Process Gas
15	Compressor Engines-NG	480	1,727	0.28	NG Fuel
16	Miscellaneous Engines	422	1,517	0.28	NG Fuel
17	Point Sources: Flares	293	1,046	0.28	Casing Gas
18	Fugitives: Other	177	637	0.28	Process Liquid and Process Gas
19	Drill Rigs	157	564	0.28	Production Gas/Liquid Flash to amb.
20	Workover Rigs	36	128	0.28	NG Fuel
21	Dehydrators-Gas Well	14	49	0.28	Process Gas
22	Tank Flaring-Condensate	6	1	4.56	Post Flashed Liquid, API˚>40
23	NG Liq./Gas Well Wtr Tnk-NG	1	4	0.28	Post Flash Production Mixed Liquids
24	Artificial Lift	0	1	0.25	NG Fuel
25	Heaters-Oil Well	-	-	0.28	NG Fuel
	Total	196,988	327,623		

Table 3.1-1 Proposed Program Summary Table-Tanks

The generalized Process Flow Diagram below shows the major streams associated with various speciation of Hydrocarbon streams, in general there are Production Streams, Post- Separation Liquids, Process Gas, Commercial Gas and Tankage Vapors. Speciation components of interest are Methane, Ethane, VOC, GHG and HAPS(a subset of VOC).



1.1.1 Methane

Methane is a known Green House Gas (GHG). It is the largest vapor component in a typical production stream. Its mass quantity is defined in the Gas Oil Ratio which measures the number of standard cubic feet of natural gas (mainly Methane) to the number of barrels of liquids (Crude Oil or Condensate). Once the oil and gas are separated, the Natural Gas vapors (which contain nearly 95% of the Methane along with other non-condensable gas, as well as lighter VOC components) are routed by dedicated piping to additional treatment/separation to a gas compressor or to a dehydrator. The Natural Gas is then shipped off the lease by way a Lease Automated Custody Transfer meter, commonly referred to as a LACT unit. Natural Gas may then be delivered to a gathering station for further treatment and compression or directly to larger compressor station.

1.1.2 Ethane

Ethane, a light molecule, which typically comprises several percent of the Oil and Gas related vapors by weight, is not considered a GHG, nor is it considered part of the more reactive VOC (sometimes called Reactive Organic Compounds, ROG).

1.1.3 Green House Gases

GHG is a composite value representing those compounds contributing to climate change (i.e., carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), other fluorinated compounds, and other chemicals).

1.1.4 VOC

VOCs are those organic compounds that are considered ozone precursors.

VOCs are in solution with Methane in the vapor and liquid phases. The composition changes as the production fluid is brought to the surface and separated from the liquids, flashed at lower pressures in a separator and each stream has a new basis for the vapor/liquid equilibrium. Gas Vapors are very rich in Methane and are driven by the Gas/Oil Ratio of the well. Dry gas and Coal Bed Methane may have little VOC. Once separated from the Hydrocarbon liquid the gas may be cleaned up by eliminating the liquids that are condensing in the pipe (a drip boot) or may be routed to a chiller to remove condensibles (VOC). Commercial gas will have the highest Methane concentration and a very low VOC content.

According to Raoult's Law and vapor pressures, the vapors in the Hydrocarbon liquid streams typically have more VOC that is released. These liquids may be routed to a treater or to subsequent separation prior to being sent to tankage at which point the VOC content is very high relative to methane but the TOC emissions rate is low.

Produced water has very little hydrocarbon in it. The Water/Hydrocarbon system is largely driven by Henry's Law for near infinite dilution conditions. Certain more soluble hydrocarbons may be present and a certain amount of methane may be dissolved in the water, depending on the pressure and temperature of the water when fed to the tank, methane may be released in the produced water tank, Soluble hydrocarbons will also be released at a rate dependent on the water diffusivity and vapor pressure but may also form azeotropes.

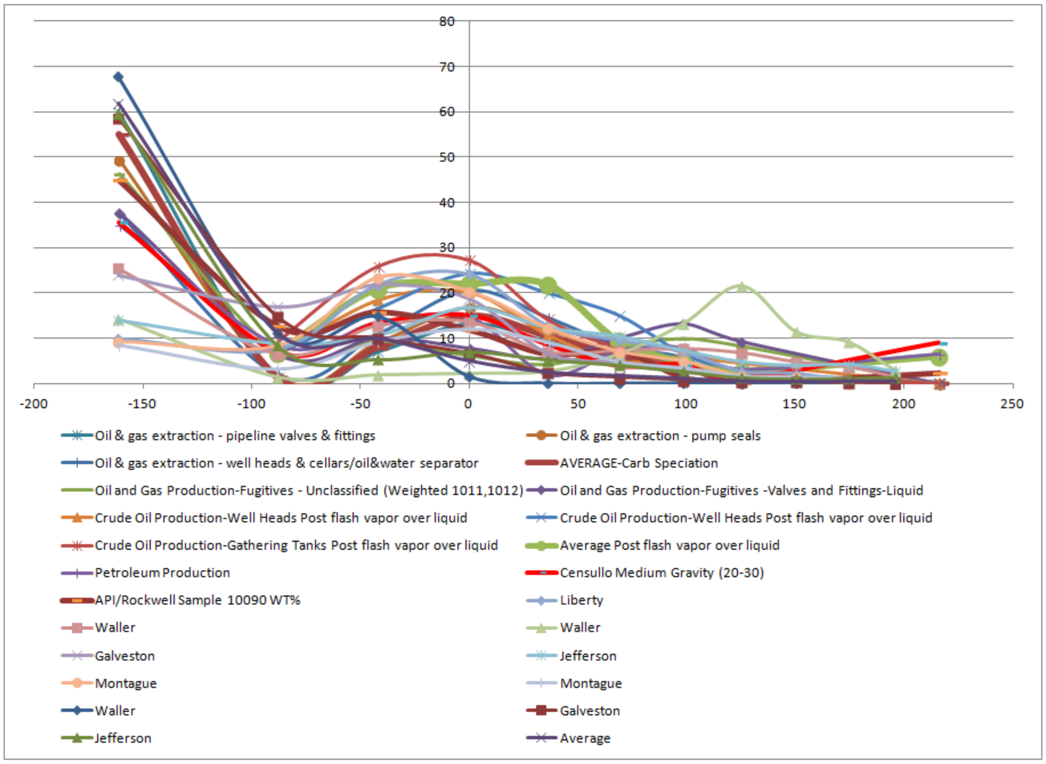
1.1.5 Hazardous Air Pollutants

HAPS are those more complex isomers of VOCs including isomers with oxygen, nitrogen, chlorine (ketones, aldehydes, etc.), certain metals, and complex organic salts whose trace quantities are known to be toxic or has a potential to cause cancer. The list of HAPS is maintained by EPA under Clean Air Act, Section 112.

2 Production stream split

The graph below shows the general speciation profiles for various empirically derived sampled streams.[2] The higher Methane content streams were either gas samples or more likely closer to production conditions with higher GOR. These data provide a foundational understanding of how Methane and VOC interrelate and should be considered in the context of mass fraction of the vapors for a given flash.

[2] This graph is a compilation of rigourous speciation data from previous studies; it has been developed by WZI for modeling purposes to validate models against empirical data. Included studies are from : API, CARB, TERC, OrgProf and EPA Speciate.



The following model shows the expected HC speciation for vapors split off at saturation and at production conditions (leaking natural gas prior to any clean-up). These vapors do not alter composition as they leak. The VOC to Methane ratio is 0.28.[3]

Production gas leaks						
MixProps: TP Flash						EOS: SRK
Initial Conditions						
Temperature:	150	°F				
Pressure:	14.696	psia				
Units:	Mass Fraction					
Component	MW	BP, C	Feed	Vapor	Liquid	K-Value
METHANE	16.0428	-161.6	0.369737	0.700173	4.49E-03	18.15086
ETHANE	30.0696	-88.6	5.55E-02	0.103222	2.67E-03	4.506184
PROPANE	44.0965	-42.5	3.72E-02	6.65E-02	4.86E-03	1.593722
BUTANE	58.1234	-0.5	2.67E-02	4.28E-02	8.83E-03	0.564377
PENTANE	72.1503	36	2.16E-02	2.73E-02	1.53E-02	0.207753
HEXANE	86.1772	68.7	3.75E-02	3.00E-02	4.57E-02	7.66E-02
HEPTANE	100.204	98.4	5.35E-02	2.22E-02	8.82E-02	2.93E-02
OCTANE	114.231	125	3.71E-02	6.92E-03	7.04E-02	1.15E-02
NONANE	128.258	150	7.57E-03	5.82E-04	1.53E-02	4.43E-03
DECANE	142.285	174.1	5.48E-03	1.65E-04	1.14E-02	1.70E-03
UNDECANE	156.312	195.6	5.21E-03	6.15E-05	1.09E-02	6.57E-04
DODECANE	170.338	216	6.97E-03	3.25E-05	1.46E-02	2.59E-04
PENTADECANE	212.419	270.5	0.051578	1.51E-05	0.108573	1.63E-05
NONADECANE	268.527	330	2.40E-02	2.88E-07	0.050439	6.65E-07
ICOSANE	282.553	343	0.260474	1.07E-06	0.548384	2.27E-07
	Flash Results		Feed	Vapor	Liquid	
	Phase Fraction:		1	34%	66%	Mass Fraction
	Molecular Weight:		50.2669	21.4864	158.4392	lbm/lbmol
	VOC to Methane ratio			0.28		

[3] This table is a summary of calculation results from MixProps using Soave Redlich Kwong method.

3 Post-Separation Liquid Flash Speciation

The first process piping check on the issues of proper speciaton for leaks should occur at the point where a saturated hydrocarbon solution (having split at production with a gas oil ratio (GOR) sufficiently high to ensure vapor saturation) can be flashed at line pressure and subsequently flashed from liquid as a liquid leak to atmospheric conditions. This was achieved by creating a surrogate solution combining vapors from EPA Speciate with a generalized hydrocarbon liquid with sufficient molecular weight to reflect the general performance of Crude Oil (both at equal weights).[4]

The results below show the production stream being flashed directly to ambient. The vapor phase shows that the VOC to Methane weight ratio is 0.48.[5] This particular model result which tends to agree with accepted speciations values such as those cited by GRI/EPA in their study.[6]

EPA Leak Flash						
MixProps: TP Flash						EOS: SRK
Initial Conditions						
Temperature:	150	°F				
Pressure:	14.696	psia				
Units:	Mass Fraction					
Component	MW	BP, C	Feed	Vapor	Liquid	K-Value
METHANE	16.0428	-161.6	21%	61%	0%	18.17921
ETHANE	30.0696	-88.6	3%	9%	0%	4.521121
PROPANE	44.0965	-42.5	5%	12%	1%	1.602346
BUTANE	58.1234	-0.5	4%	7%	2%	0.568642
PENTANE	72.1503	36	3%	4%	2%	0.2098179
HEXANE	86.1772	68.7	5%	3%	6%	7.75E-02
HEPTANE	100.204	98.4	7%	2%	10%	2.97E-02
OCTANE	114.231	125	5%	1%	7%	1.17E-02
NONANE	128.258	150	1%	0%	1%	4.52E-03
DECANE	142.285	174.1	1%	0%	1%	1.74E-03
UNDECANE	156.312	195.6	1%	0%	1%	6.74E-04
DODECANE	170.338	216	1%	0%	1%	2.66E-04
PENTADECANE	212.419	270.5	7%	0%	10%	1.69E-05
NONADECANE	268.527	330	3%	0%	5%	7.05E-07
ICOSANE	282.553	343	34%	0%	52%	2.42E-07
	Flash Results		Feed	Vapor	Liquid	
	Phase Fraction:		1	34%	66%	Mass Fraction
	Molecular Weight:		50.2669	21.4864	158.4392	lbm/lbmol
	VOC to Methane ratio			0.48		

However, the complex nature of each well precludes operators from calculating the specific stream composition and conditions for these dynamic conditions.

4 Tankage Emissions Speciations

[4] GOR typically ensures that a distinct vapor exists at the well head itself. This production split is realized in gas piping separate of the liquid sent to the separator. The resultant flash mass fraction of vapors was greater than the liquid indicating that the vapor composition loaded into the model dominated the partitioning and that the liquid surrogate did not.

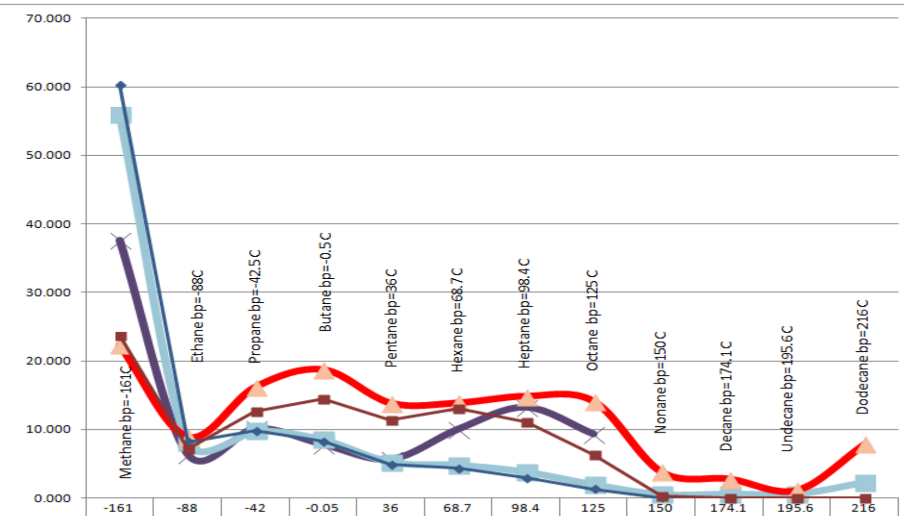
[5] This table is a summary of calculation results from MixProps using Soave Redlich Kwong method.

[6] GRI/EPA, Methane Emissions from the Natural Gas Industry, Vol. 8, Equipment Leaks, also EPA Gas Star

The Tankage Emissions are largely rich in VOC due to the separation of the vapor and liquid components prior to tankage. More VOC is expected to exist in vapors over condensate and over tanks with weathered crude having less vapor mass fractions. Using EPA Speciate vapors (the regulatory default) as the basis for modeling the Crude/Natural Gas split in a secondary flash at atmospheric (tank conditions), one sees that the ratio of VOC to Methane is approximately 4.5 by weight.

Vapors off Leaked Liquid												
Alkane C.N.	Alkane Group	MW	Approximate K-Factor	BP	AVERAGE-CARB Speciation	EPA Average Pre flash vapor over liquid	KVB Petroleum Production	Censullo Medium Gravity (20-30)	API/Rockwell Sample 10090 WT%	Houston Study Oil	Houston Study Condensate Pre Flash	Average
1	METHANE	16.0428	189.9926	-161.6	19.665%	16.887%	11.165%	10.328%	13.936%	10.805%	4.294%	11.559%
2	ETHANE	30.0696	48.88881	-88.6	1.138%	6.567%	7.440%	5.802%	10.128%	7.299%	6.526%	7.667%
3	PROPANE	44.0965	17.57595	-42.5	10.132%	14.592%	19.371%	18.158%	20.007%	17.235%	17.382%	18.693%
4	n-BUTANE	58.1234	6.356389	-0.5	25.148%	13.647%	28.203%	28.000%	20.270%	23.160%	26.084%	24.908%
5	n-PENTANE	72.1503	2.393135	36	22.088%	12.081%	5.597%	19.450%	14.445%	17.422%	20.161%	14.228%
6	n-HEXANE	86.1772	0.906252	68.7	12.343%	17.029%	14.067%	8.076%	14.672%	11.748%	16.193%	12.141%
7	n-HEPTANE	100.204	0.357101	98.4	8.017%	14.080%	10.397%	6.799%	4.596%	8.039%	7.406%	7.458%
8	n-OCTANE	114.231	0.143923	125	0.691%	4.540%	1.914%	0.985%	0.581%	2.851%	1.295%	1.583%
9	n-NONANE	128.258	5.78E-02	150	0.521%	0.387%	1.659%	2.209%	1.107%	1.015%	0.468%	1.498%
10	DECANE	142.285	2.31E-02	174.1	0.152%	0.112%	0.110%	0.113%	0.153%	0.315%	0.119%	0.173%
11	UNDECANE	156.312	9.30E-03	195.6	0.058%	0.042%	0.042%	0.043%	0.058%	0.077%	0.040%	0.055%
12	DODECANE	170.338	3.81E-03	216	0.031%	0.023%	0.023%	0.023%	0.031%	0.021%	0.020%	0.025%
15	PENTADECANE	212.419	2.75E-04	270.5	0.015%	0.011%	0.011%	0.012%	0.016%	0.011%	0.010%	0.012%
19	NONADECANE	268.527	1.34E-05	330	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
20	ICOSANE	282.553	4.92E-06	343	0.001%	0.001%	0.001%	0.001%	0.001%	0.001%	0.001%	0.001%
			Vapor Wt fract		0.122%	0.157%	0.243%	0.266%	0.167%	0.256%	0.669%	0.233%
			Vapor MW		40.5311	41.9064	44.5758	45.6927	40.9893	45.4678	53.0455	44.18
			Liquid Wt fract		99.878%	99.843%	99.757%	99.734%	99.833%	99.744%	99.331%	99.767%
			Liquid MW		209.5989	184.7707	189.87	194.4232	212.2106	187.9987	188.5648	196.1256
		VOC to Methane ratio			4.0264062	$\boxed{4.5322526}$	7.2892801	8.1191283	5.4478302	7.5780425	20.764242	6.987104

General modeling results for post separation vapors that are likely sent to tanks, then allowed to weather, as tankage vapors were compared to both crude and condensate speciations from the Texas Environmental Resource Center (TERC) tanks emissions study. The results are shown below.



	-161	-88	-42	-0.05	36	68.7	98.4	125	150	174.1	195.6	216
O & G Production-Fugitives - Valves and Fittings-Liquid	37.600	6.400	10.100	7.800	5.600	10.000	13.200	9.300				
Average Flash, C1>42%	55.914	8.068	9.814	8.493	5.214	4.798	3.787	1.934	0.500	0.587	0.597	2.270
Average Post Flash, C1<42%	22.251	8.872	16.119	18.683	13.784	13.829	14.801	14.021	3.726	2.730	1.071	7.795
Model Flash Vapor 70F	60.23	8.20	9.82	8.24	4.92	4.34	2.88	1.30	0.04	0.01	0.00	0.00
Model Post Flash Vapor 150F	23.67	7.13	12.66	14.47	11.32	13.00	11.04	6.34	0.25	0.07	0.03	0.01

The TERC study indicates a broad range of results for speciations depending on the manner tanks are managed, as well as the type of process stream being sent to tanks.[7] These results when statistically interpreted and outliers eliminated showed patterns consistent with EOS-based expectations and indicate that the VOC to Methane ratio may be much higher; more study should be conducted of future reporting results to better define the appropriate speciations. [8]

[7] Texas Environmental Research Consortium, FINAL REPORT: VOC EMISSIONS FROM OIL AND CONDENSATE STORAGE TANKS, rev. 2009

[8] This table is a summary of calculation results from MixProps using Soave Redlich Kwong method.

High Temp Separation								
MixProps: TP Flash							EOS: SRK	
Initial Conditions								
Temperatu	130	°F		130	°F			
Pressure:	147	psia		147	psia			
Units:	Mole Fraction			Mass Fraction				
Componen	Feed	Vapor	Liquid	Feed	Vapor	Liquid	K-Value	
METHANE	66%	82%	5%	21%	61%	0%	18.17921	
ETHANE	6%	7%	1%	3%	9%	0%	4.521121	1.58
PROPANE	6%	6%	4%	5%	12%	1%	1.602346	61%
BUTANE	3%	3%	5%	4%	7%	2%	0.568642	29%
PENTANE	2%	1%	5%	3%	4%	2%	0.209818	0.478098
HEXANE	3%	1%	11%	5%	3%	6%	7.75E-02	
HEPTANE	4%	0%	15%	7%	2%	10%	2.97E-02	
OCTANE	2%	0%	10%	5%	1%	7%	1.17E-02	
NONANE	0%	0%	2%	1%	0%	1%	4.52E-03	
DECANE	0%	0%	1%	1%	0%	1%	1.74E-03	
UNDECAN	0%	0%	1%	1%	0%	1%	6.74E-04	
DODECAN	0%	0%	1%	1%	0%	1%	2.66E-04	
PENTADE	2%	0%	8%	7%	0%	10%	1.69E-05	
NONADEC	1%	0%	3%	3%	0%	5%	7.05E-07	
ICOSANE	6%	0%	29%	34%	0%	52%	2.42E-07	
	100%	100%	100%	100%	100%	100%		
Flash Resu	Feed	Vapor	Liquid	Feed	Vapor	Liquid		
Phase Fra	1	0.78985	0.21015	1	0.33762	0.66238	Mass Fraction	

While many separate conditions may exist in between the well head (including first process separation) and the tankage, one expects that in those streams where the Natural Gas phase of the production is unseparated, there should be more VOC.

In summary, it is commonly accepted that the ration of VOC to Methane drops as gas moves further into downstream environements.

> "To estimate VOC and HAP, weight ratios were developed based on methane emissions per device. The specific ratios used were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment."[9]

Conversely, the EOS model demonstrates that for liquids going to tankage, when there is low pressure separation prior to the condensate tankage, the volume of VOCs is approximately than 0.1% by mass fraction. The assumption in the inventory is that condensate tanks are not necessarily preceded by low pressure separation an estimate that may not reflect the actual surface equipment.[10]

[9] EPA NSPS, 5.0 PNEUMATIC CONTROLLERS

[10] A conversion of the 13.7 lb/bbl VOC emissions factor results in a mass fraction of 4.4% as opposed to the post flashed value of approximately 0.1%.

5 Glycol Dehydrator Process Emissions

An important element of speciation is the effect of Glycol Dehydration regeneration. This is a process related stream and is a reflection of the dehydration process and selection of type of glycol and recycle rate. The glycol dehydrator uses the solubility of several different forms of glycol to strip the natural gas of certain undesirable components, water being the largest concern. Along with water some methane is removed, acids may be removed and some soluble VOCs, largely along the lines of Henry's Law.[11] The resultant regeneration-related emissions will have a certain amount of methane and water/glycol soluble aromatic VOC isomers, however the relationship between the exhaust and the processed natural gas will not be directly associated with the pre or post processed gasses by flash calculations using partial pressure, due to the solubility effect. Methane emissions can be estimated using general programs such as GlyCalc, ProSim, etc. VOV emissions have been largely focused on the aromatics with Benzene being of particular concern.[12]

[11] Wilson, MJ and Frederick JD ed., SPE Monograph: Environmental Engineering for Exploration and Production Activities, Henry L. Dougherty Series, Volume 18

[12] EPA/GRI, Methane Emissions from the Natural Gas Industry 14: Glycol Dehydrators, 600/R-96-080n, 1996

EDF-WZI-APPENDIX VI

INITIAL
ECONOMIC IMPACT ANALYSIS
PER § 25-7-110.5(4), C.R.S.

For proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

The Colorado Air Pollution Control Division (Division) submits the following Initial Economic Impact Analysis in conjunction with its proposed revisions to Colorado Air Quality Control Commission (AQCC) Regulation Number 7 (5 CCR 1001-9). The Regulation Number 7 rulemaking package proposes revisions that expand existing oil and gas control requirements and establish additional monitoring, recordkeeping and reporting requirements. Among other things, the Division proposes to: increase control requirements and improve capture efficiency requirements for oil and gas storage tanks; minimize fugitive emissions of hydrocarbons (including volatile organic compounds, methane and ethane) from leaking components at compressor stations and well production facilities; expand control requirements for pneumatic devices; increase control requirements for glycol dehydrators; and minimize venting at oil and gas production facilities.

In this Initial Economic Impact Analysis, the Division has assessed the costs and benefits associated with each of the proposed strategies based on the reasonably available data. In collecting this data, the Division has sought input from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in this analysis. To the extent that additional data regarding the costs and benefits of the proposed strategies is made available, the Division will assess this data and, where appropriate, incorporate it into the Final Economic Impact Analysis required under AQCC Procedural Rules, Section V.E.7.

II. REQUIREMENTS FOR AN INITIAL ECONOMIC IMPACT ANALYSIS

Section 25-7-110.5(4), C.R.S. sets forth the requirements governing the preparation and submittal of economic impact analyses for air quality rules. This section provides that:

> Before any permanent rule is proposed pursuant to this section, an initial economic impact analysis shall be conducted in compliance with this subsection (4) of the proposed rule or alternative proposed rules. Such economic impact analysis shall be in writing, developed by the proponent, or the division in cooperation with the proponent and made available to the public at the time any request for hearing on a proposed rule is heard by the commission.

Section 25-7-110.5(4)(a), C.R.S. The statute further provides that:

> The proponent and the division shall select one or more of the following economic impact analyses. The commission may ask affected industry to submit information with regard to the cost of compliance with the proposed rule, and, if it is not provided, it shall not be considered reasonably available. The economic impact analysis required by this subsection (4) shall be based upon reasonably available data ….

Section 25-7-110.5(4)(c), C.R.S.. For the purposes of this Initial Economic Impact Analysis, the Division has chosen to utilize the methodology set forth in § 25-7-110.5(4)(c)(I), C.R.S., which requires the following:

(I) Cost-effectiveness analyses for air pollution control that identify:

(A) The cumulative cost including but not limited to the total capital, operation, and maintenance costs of any proposed controls for affected business entity or industry to comply with the provisions of the proposal;

(B) Any direct costs to be incurred by the general public to comply with the provisions of the proposal;

(C) Air pollution reductions caused by the proposal;

(D) The cost per unit of air pollution reductions caused by the proposal;

(E) The cost for the division to implement the provisions of the proposal.

III. OVERVIEW OF PROPOSED REGULATORY CHANGES

The Division is proposing revisions to AQCC Regulation Number 7 in an effort to enhance the effectiveness of Colorado's air quality requirements for the oil and gas exploration and production sector. These proposed revisions consist of the following:

1) Enhancing the existing control program for petroleum storage tanks by:
   a. Lowering the existing control requirement threshold for condensate storage tanks from twenty to six tons per year of uncontrolled actual volatile organic compound (VOC) emissions;
   b. Requiring controls for crude oil and produced water storage tanks with uncontrolled actual VOC emissions that are equal to or greater than six tons per year; and
   c. Expanding non-attainment area requirements for tank controls during the first 90 days of production to the rest of the state;
2) Establishing requirements to ensure that emissions from controlled storage tanks are captured and routed to the control device;

3) Establishing leak detection and repair requirements for compressor stations and well production facilities;
4) Expanding the existing non-attainment area requirements for auto-igniters on flare devices to the rest of the state;
5) Expanding the existing non-attainment area requirements for low bleed pneumatic devices to the rest of the state and where feasible requiring no-bleed pneumatic devices;
6) Requiring that the gas stream at newly constructed well production facilities either be connected to a pipeline or routed to a control device from the date of first production;
7) Lowering the existing control requirement threshold for existing glycol dehydrators to six tons per year of uncontrolled actual VOC emissions and two tons per year of uncontrolled actual VOC emissions for dehydrators located within 1,320 feet of a building, and establishing a two ton per year control threshold for all new glycol dehydrators; and
8) Establishing requirements for the use of best management practices both to minimize the need for downhole well maintenance and liquids unloading and to minimize emissions during well maintenance and liquids unloading events.

IV. COST/BENEFIT ANALYSIS:

The Division's assessment of the costs and benefits for the proposed strategies is set forth below. For each strategy, these assessments identify the cumulative costs for the affected industry, the estimated air pollution reduction, and the projected cost per unit of air pollution reduced. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements. Finally, the Division considered whether there would be any additional costs for the Division to implement the proposed requirements beyond current expenditures, and concluded that there would be no additional implementation costs associated with these proposed strategies.

A. Control Requirements for Petroleum Storage Tanks

Commencing in 2004 the Air Quality Control Commission has adopted a series of requirements aimed at reducing emissions from petroleum storage tanks at well production facilities, compressor stations and gas processing plants. Currently, condensate tanks with uncontrolled actual emissions of 20 tons per year or greater of VOC must be equipped with a control device that has a control efficiency of at least 95%. Additionally, with certain exceptions, operators in non-attainment areas must achieve a 90% system-wide reduction of VOC emissions from condensate tanks during the period from May 1 through September 30, and 70% during the period from October 1 through April 30. These current requirements only apply to tanks that store condensate, which is defined in the AQCC's Common Provisions regulation as "hydrocarbon liquids . . . with an API gravity of 40 degrees or greater." While most of the petroleum liquid produced in Colorado qualifies as condensate, there are heavier hydrocarbon liquids, typically referred to as crude oil, with an API gravity below 40 degrees that are not subject to the current control requirements. Additionally, there are a number of high volume produced water tanks that have VOC emissions above six tons per year that are not currently regulated under the existing requirements.

While Colorado has achieved considerable success in controlling emissions from condensate tanks since 2004, petroleum storage tanks at oil and gas production and midstream facilities continue to be the most significant source of VOC emissions from this sector. To address this emission source the Division is proposing the following strategies: 1) reducing the control threshold from twenty tons per year VOC to six tons per year; 2) eliminating the distinction between condensate and other liquids and requiring controls strictly based on emission levels; and 3) extending the current requirement that all condensate tanks in the non-attainment area be controlled during the first 90 days of production to storage tanks throughout the state. In order to meet each of these three strategies, the Division assumes that owners and operators will equip tanks with enclosed flares, as is the typical practice under the existing tank control requirements. The estimated costs associated with installing and maintaining an enclosed flare are set forth in subsection 1 below. Utilizing the calculated flare costs, the estimated costs and benefits for each of the three tank control strategies are discussed in subsections 2-4 below.

1. General Cost Estimates for Flares

The estimated cost for a flare control device is based on identified costs from a 2008 oil and gas cost study[1] adjusted for inflation. Based on this data, the estimated annualized cost of a flare control device with auto-igniter[2] is about $6,287.

Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Flare	$18,169			
Freight/Engineering		$1,648		
Flare Installation		$6,980		
Auto Igniter	$1,648			
Pilot Fuel**			$768	
Maintenance			$2,197	
Subtotal Costs	$19,817	$8,628	$2,965	
Annualized Costs***	$2,747	$575	$2,965	$6,287

[1] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the AQCC as part of the 2008 Ozone Action Plan process.

[2] Currently only flares in the non-attainment area are required to have auto-igniters. Under the current proposal, the auto-igniter requirement would be extended statewide. For the purposes of this cost analysis, it is assumed that auto-igniters will be required statewide. The cost and benefits associated with equipping existing flares outside the non-attainment with auto-igniters are discussed below in Section D.

**Control cost evaluation based on 2008 Ozone Rulemaking cost survey and producer data. Control device costs were developed based on an oil and gas cost study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.*
*** Pilot fuel costs $3.41/MMBtu (Henry Hub Spot Price - Aug. 2013)*
**** Annualized over 15 years at 5% ROR*

2. Lowering Statewide Condensate Tank Control Threshold (from 20 tpy to 6 tpy)

The Division is proposing to lower the uncontrolled VOC emission control threshold from 20 tpy down to 6 tpy on condensate storage tanks statewide. Based on an analysis of the Air Pollution Emissions Notice (APEN) database, the Division estimates that statewide there are 588 uncontrolled condensate tank batteries with VOC emissions over six tons per year. Of these 588 tanks, 396 are outside the non-attainment area and the remaining 192 are within the current non-attainment area.

Table 2: Condensate Tank Battery Analysis

Tank Battery Type	Ozone NAA [count]	Outside NAA [count]	Cancelled Tanks [count]	Total Statewide Tanks [count]
Controlled Tanks	4,971	490		5,461
Uncontrolled Tanks	1,451	1,132	36	2,619
All Tanks	6,422	1,622	36	8,080
Uncontrolled Tanks (≥ 6 tpy)	192	396		588

Based on the reported uncontrolled actual VOC emissions for these 588 tanks, and assuming both that 75% of the VOC emissions are captured and sent to the flare,[3] and that the flare has a 95% destruction efficiency, the total VOC emission reduction associated with lowering the condensate tank threshold statewide is 5,162 tons per year.

Table 3: Condensate Tank Battery Emissions Analysis for Lowering Statewide Threshold

Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
NAA Uncontrolled Tanks (≥6 tpy)	2,355	677*	1,678
Outside NAA Uncontrolled Tanks (≥6 tpy)	4,890	1,406*	3,484
Totals:	7,245	2,083	5,162

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

[3] The costs and benefits associated with improving the capture percentage for controlled storage tanks are discussed below in Section B.

The annualized cost of installing 588 flare control devices is about $3.7 million dollars with an average cost effectiveness of about $716 per ton of VOC reduced. For the smallest individual tank battery subject to controls (six tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 4: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices

Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
588	$6,286.8	$3,696,638	5,162	$716

3. Requiring Controls for Produced Water and Crude Oil Tanks

As discussed above, the Division is proposing to eliminate the distinction between condensate tanks and other storage tanks. If the AQCC adopts this proposal, crude oil tanks and produced water tanks with uncontrolled actual VOC emissions of six tons per year or greater will require controls. Because produced water and crude oil tanks are identified separately in the Division's APEN data base, the costs and benefits for these two types of storage tanks are broken out separately.

The Division is proposing that all statewide produced water tanks with uncontrolled VOC emissions over six tons/year be required to install emission controls. Some uncontrolled produced water tanks could be co-located at sites with condensate or crude oil tanks that have flare controls, but pressure and flow differences may require the installation of a separate flare control device for the water tank. Consequently, the control costs are based on the assumption that each water tank battery will install a new flare control device. Based on an analysis of the APEN database, the Division estimates that statewide there are 52 uncontrolled produced water tank batteries with VOC emissions over six tons/year.

Table 5: Produced Water Tank Battery Analysis

Tank Battery Type	Total Statewide Water Tanks
Controlled Water Tanks:	338
Uncontrolled Water Tanks:	530
Total:	868
Uncontrolled Tanks (≥6 tpy)	52

Based on the reported uncontrolled actual emissions, the Division estimates that the total VOC emission reduction associated with controlling these produced water tanks statewide is 457 tons per year.

Table 6: Produced Water Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥6tpy)	641.4	184.4*	457

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing 52 flare control devices is about $327,000, with an average cost effectiveness of about $715 per ton of VOC reduced. For the smallest individual tank battery (six tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 7: Produced Water Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
≥ 6tpy	52	$6,286.8	$326,914	457	$715

The Division is proposing that all statewide hydrocarbon liquid storage tanks with VOC emissions over six tons/year must install emission controls. Based on a recent analysis of 2013 APEN data, there are 67 reported crude oil tanks batteries statewide. Thirty seven of the tank batteries are already equipped with controls. Of the remaining thirty, eight are over the proposed six tons/year threshold. Given that approximately 5% of the total wells in the state report crude oil production to the Colorado Oil and Gas Conservation Commission (COGCC),[4] it appears likely that the Division's APEN database may be undercounting crude oil tanks, either because these tanks have not been reported or because they are being reported as condensate tanks.[5]

Table 8: Crude Oil Tank Battery Analysis	
Tank Battery Type	Total Statewide Crude Oil Tanks
Controlled Crude Oil Tanks	37
Uncontrolled Crude Oil Tanks	30
Total:	67
Uncontrolled Tanks (≥6 tpy)	8

[4] Based on an analysis of 2010 COGCC data.
[5] Prior to 2008 crude oil storage tanks were exempt from APEN reporting requirements, which may explain in part the small numbers of tanks identified in the system.

The total VOC emission reduction associated with controlling these eight crude oil tanks statewide is 118 tons per year.

Table 9: Crude Oil Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥6tpy)	165.2	47.5*	117.7

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing eight flare control devices is about $50,294 dollars with an average cost effectiveness of about $427 per ton of VOC reduced. For the smallest individual tank battery (six tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 10: Crude Oil Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
≥ 6tpy	8	$6,286.8	$50,294.4	117.7	$427

4. *Requiring Controls During the First 90 Days of Production Statewide*

Under current requirements owners and operators of new and modified storage tanks outside the non-attainment area have 90 days after the date of first production to determine if emissions from the tank trigger the requirement to install a control. Because production is typically at its highest during this initial period, significant emissions can occur before controls are installed. To address this issue in the non-attainment area, the AQCC mandated in the 2008 Ozone Action Plan that all condensate tanks be controlled during the first 90 days. The Division is now proposing to expand this requirement to storage tanks throughout the state.

To calculate the cost effectiveness of this strategy, the Division first determined the number of new and modified storage tanks outside the non-attainment area based on reported APEN data for the period of 2010-2012. Based on this APEN data, there are on average 141 new and modified tanks each year, with yearly reported uncontrolled actual emissions of 7,370 tons VOC. Assuming that emissions during the first 90 days equal 1/4th of the annual reported emissions,[6] total uncontrolled actual VOC emissions from these tanks during the first 90 days is 1,842.5 tons.

[6] Because reported emissions typically are based on a calculation assuming a standard rate of production decline after the first 90 days, actual emissions during the first 90 days could be much higher.

Assuming enhanced capture efficiency for these new tanks (See Section B) the flare control efficiency is 95%, thus the calculated benefit from expanding the first 90 day control requirement to tanks outside the non-attainment area will be 1,750.4 tons per year.

While the Division estimates that there are 141 new and modified storage tanks outside the non-attainment area each year, the majority of these, 84, will require control devices regardless of this strategy since their uncontrolled actual emissions are over six tpy. For these 84 tanks, the cost of operating a flare during the first 90 days will be approximately 25% of the total annualized cost, or $1,571.70 per tank. For the remaining 57 tanks with emissions less than six tons/year, because controls for these tanks will only need to be in place for 90 days, the Division assumes that each flare can control three tanks per year, which means that 19 new flares are required to comply with this proposed strategy. For other applications, the annualized cost of a flare is estimated to be $6,287. Since flares required for this application will be relocated three times a year, the Division assumes an additional $3,000 in annual relocation costs, for a total annualized cost of about $9,287 per flare. Based on the emission reductions calculated above, the total cost effectiveness of this requirement is $176/ton of VOC reduction.

Table 11: Control Cost Estimates for Flare Control Devices Required During the First 90 Days of Production

Storage Tank Threshold [tpy]	Number of New Storage Tanks	Number of New Flares	Annualized Cost Each Flare	Total Flare Cost	Total VOC Reduction [tons/year]	VOC Control Cost [$/ton]
<6	57	19	$9,286.8	$176,449.2	44.7	$3,947
≥6	84	84	$1,571.7	$132,022.8	1,705.7	$77
	141			$308,472	1,750.4	$176

B. Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order for storage tank control requirements to be effective, emissions from the tank must be routed to the control device. Historically the Division has assumed that 100% of a tank's emissions will be captured and routed to the control device, typically a flare, resulting in a 95% reduction of emissions. Field observations using infra-red (IR) cameras and other methodologies indicate that in actuality emissions from controlled storage tanks often escape through the thief hatches and pressure relief valves (PRV) and therefore are not being combusted in the flare. This occurs when the tank cannot adequately contain the flashing emissions that occur when pressurized liquids from the separator are dumped into the atmospheric tank. To address this issue, the Division is proposing new regulatory language clarifying that all emissions from controlled storage tanks must be routed to the control device and that these tanks must be operated without venting emissions from thief hatches, PRVs and other openings, except when venting is reasonably necessary for maintenance, gauging, or safety of personnel and equipment.

To assure compliance with these capture standards, the Division's proposal requires that owners and operators of controlled storage tanks implement a Storage Tank Emission Management (STEM) plan. Pursuant to the STEM plan, owners and operators must evaluate and employ appropriate control technologies and/or operational practices designed to meet the proposed capture requirements, and certify that these technologies and/or operational practices are designed to minimize emissions from the tank. The Division's STEM proposal also requires implementation of a two-pronged monitoring strategy involving a weekly[7] auditory, visual, and olfactory (AVO) inspection for all controlled tanks, and a periodic instrument based monitoring for tanks using Method 21, an IR camera or other Division approved monitoring device or method. As proposed, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 12: Proposed Tiering for Instrument Based Tank Inspections	
Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
≥ 6 tpy to ≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

In assessing the cost effectiveness of the proposed requirements, the Division first calculated the costs associated with implementing technological and/or operational changes at controlled tanks. For the purposes of this analysis the Division assumed that all tanks with uncontrolled actual emissions greater than or equal to six tons per year would need to be controlled consistent with the Division's proposal discussed in Section A above. Based on reported data, there are currently 5,270 storage tanks statewide with emissions greater than or equal to six tons per day. While the Division's proposal does not specify the type of technology or operational practices that operators will use, for the purposes of this analysis the Division assumed that buffer bottle technology would be installed on each of the subject tanks.[8] The buffer bottle technology utilizes a small tank that is installed after the separator which allows for a secondary flash of pressurized liquids prior to dumping into the storage tank. The second-stage flash reduces the pressure of the liquids going to the tank and thereby helps to ensure that the tank can adequately handle the flashing emissions that occur when the liquids are brought to atmospheric pressure. Based on industry provided information, the estimated annual cost of a buffer bottle is set forth in Table 13.

[7] There is an exception for the weekly inspection requirement where the operator loads out liquids from the storage tank on less than a weekly basis. In these circumstances the operator must conduct the inspection whenever liquids are loaded out, but no less often than every 30 days. Typically liquids are loaded out multiple times in a given week, meaning that for the majority of the tanks AVO inspections will be required weekly.

[8] Based on discussions with industry representatives during the stakeholder process there may be other less costly technologies and operational practices that could be used to ensure good emission capture from tanks such as replacing seals, more frequent maintenance, changing the size of piping going to the storage tank, and timing well dumps to avoid overloading the separator. There may also be other options for new facilities that allow for the capture and sale of additional gas such as the installation of high-low pressure separators or utilizing a liquids gathering system that eliminates atmospheric storage tanks at well sites.

Table 13: Annualized Cost Analysis for Buffer Bottle				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Buffer Bottle	$6,000			
Freight/Engr		$600		
Installation		$2,280		
Maintenance			$2,000	
Subtotal Costs	$6,000	$2,880	$2,000	
Annualized Costs*	$832	$192	$2,000	$3,024

** Annualized over 15 years at 5% ROR*

The Division also calculated the costs associated with conducting enhanced inspections. Based on the proposed tiering, operators will need to conduct 24,622 tank inspections per year[9].

Assuming that each inspection takes two hours and utilizing a $99/hour inspection cost,[10] the total annual cost associated with conducting enhanced inspections under the proposed rule is $4,875,156, which equates to $925 per year for each tank that will be subject to STEM.

Table 14: Instrument Based Tank Inspections Based on Proposed Tiering				
Tank Uncontrolled Actual VOC Emissions	Number of Tanks	Inspection Frequency	Number of Inspections	STEM Inspection Costs
≥ 6 tpy to ≤ 12 tpy	1,390	Annually	1,390	$275,220
>12 tpy to ≤ 50 tpy	2,916	Quarterly	11,664	$2,309,472
> 50 tpy	964	Monthly	11,568	$2,290,464
	5,270		24,622	$4,875,156

The Division also considered whether additional costs should be included for conducting periodic AVO inspections. Because these activities are already required for controlled storage tanks under existing regulation, the Division did not include these costs in determining the total cost of the proposed capture requirements. The Division also did not include costs associated with certifying that selected technologies and/or operational practices are designed to minimize emissions, since costs for certifying capture efficiency are already included in the annualized cost of required flares.[11] Accordingly, the total projected annual cost of the proposed capture

[9] In practice, many operators are already conducting IR camera inspections at storage tanks, however, the Division does not have information regarding how many inspections are currently occurring.
[10] The hourly inspection cost is discussed below in Table 20.
[11] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008, at pg. 8.

requirements based on the use of a buffer bottle and enhanced monitoring requirements is $3,949 per tank.

To calculate the projected emissions reduction from the proposed capture requirements, the Division assumed a current capture rate of 75% for controlled tanks based on analytical work that the Division, EPA and others have performed. Based on this capture rate, the Division calculated the emissions reduction that would occur if the capture rate were increased to 100% using the following equation:

Emission reduction = [uncontrolled VOC*(1-(0.75*0.95))] – [uncontrolled VOC *(1-0.95)],

Using this equation as applied to the reported uncontrolled actual emissions from the 5,270 storage tanks statewide with emissions greater than or equal to six tons per day, the projected emission reduction from the proposed capture requirements is 52,624 tons per year.

Table 15: STEM Emission Control Analysis (Statewide)

Number of Tanks ≥6 tpy	Uncontrolled VOC [tons/year]	Controlled VOC (@ 71.25% Control) [tons/year]	Controlled VOC (@ 95% Control) [tons/year]	VOC Reduction [tons/year]
5,270	221,575	63,703	11,079	52,624

Applying this reduction to the costs calculated above, the cost effectiveness of these proposed requirements is $396/ton of VOC.

Table 16: STEM Control Cost Estimates (Statewide)

Type of Technology	Number of Tanks	Each Device Annualized Costs [$/year]	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
Buffer Bottle	5,270	$3,949	$20,811,230	52,624	$395

During the stakeholder process certain parties have raised questions about the Division's assumption that currently controlled tanks have a 75% capture efficiency. In light of this the Division has also calculated cost effectiveness based on the assumption that current capture efficiency is 50% and 95%. For the 50% case, current controlled emissions would be 116,327 tpy VOC. Accordingly, the emission reduction benefit from increasing capture to 100% would be 105,248 tons per year (116,327-11,079) and the cost effectiveness would be $198/ton VOC[12]. For the 95% capture scenario, current controlled emissions would be 21,604 tons per year VOC

[12] This may overestimate the cost effectiveness given that if the current capture rate were only 50% additional costs could be required to increase the capture rate to 100%.

and the emission reduction would be 10,525 tons per year (21,604-11,079). Under this scenario, the cost effectiveness would be $1,977/ton VOC[13].

While the buffer bottle technology offers a good alternative in a retrofit situation for reducing pressures to the tank and increasing emission capture, for new facilities, installation of a high-low pressure (HLP) separator to satisfy STEM may prove to be a better performing option. This equipment allows for two stages of separation of the gas and the liquids instead of the single stage separation accomplished in traditional separators. By adding a second stage of separation, the pressure of the liquids sent to the tank is significantly reduced, thereby helping to ensure complete capture of flashing emissions instead of venting a portion of the emission stream through the thief hatch or PRV. Additionally, rather than being routed to the flare, as in the case of the buffer bottle technology, gas from the second stage of separation can be sent to a vapor recovery unit (VRU), recompressed and sent to the sales line, resulting in increased product recovery. Based on information provided from industry, the Division has calculated that the annual cost of a HLP separator w/VRU is about $19,341.

Table 17: Annualized Cost Analysis for HLP Separator

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
HLP/VRU	$90,000			
Freight/Engr		$1,648		
HLP/VRU Installation		$11,154		
Maintenance			$9,396	
VRU Recovered NG *			$(3,382)	
Subtotal Costs	$90,000	$12,802	$6,014	
Annualized Costs**	$12,474	$853	$6,014	$19,341

** Recovered NG fuel costs $3.5/MCF (Henry Hub Spot Price - Aug. 2013) and average tank battery size of 63.2 tpy – based on 3-yr average of APEN data on storage tanks ≥6 tpy (uncontrolled VOC).*

*** Annualized over 15 years at 5% ROR*

Unlike the retrofit situation analyzed above where the emission controls are already in place, it is appropriate in new installations to aggregate the cost of the HLP separator w/VRU with the costs of the control unit (flare) to determine the overall cost of controlling emissions from the tank. Based on the $6,286.8 annual cost of a flare, the total annual control costs for a new tank will be $25,628 per year. Including instrument based monitoring costs of $925 per tank each year, the total annual cost for each new tank will be $26,553.

Based on an analysis of reported data for new tanks during the past three years, the average uncontrolled actual emissions of a new tank is 63.2 tpy. Assuming a 95% overall control

[13] This is a conservative calculation given that if the current capture rate were 95% it is likely that the control costs to increase the capture rate to 100% would be significantly less.

efficiency, equipping a tank with an HLP separator and a flare will reduce the emissions from an average new tank by 60 tpy. This yields a cost effectiveness of $443 per ton VOC reduced. If instead, the highest cost scenario (using a six tpy tank) is assumed, the cost effectiveness is $4,658 per ton VOC.

C. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

AQCC Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement leak detection and repair programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct periodic inspections using EPA Reference Method 21[14] and repair leaks within a prescribed time frame.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include leak detection and repair requirements for these facilities.[15] To address these emissions, the Division is proposing regulatory changes that would establish leak detection and repair requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The proposed regulation establishes a tiered system to determine inspection frequency. For compressor stations the tiering is based on the uncontrolled actual leak emissions at the facility as follows:

Table 18: Proposed Tiering for Leak Inspections at Compressor Stations

Component Leak Uncontrolled Actual VOC Emissions	Inspection Frequency
≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

[14] While Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

[15] Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

For well production facilities the proposed tiering is based on uncontrolled actual emissions from the largest emitting storage tank at the facility as set forth in Table 19. The tiering is based on tank emissions rather than uncontrolled actual leak emissions in order to create a Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of the STEM emission capture requirements discussed in Section B above.[16]

Table 19: Proposed Tiering for Leak Inspections at Well Production Facilities

Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
< 6 tpy	One Time (and Monthly AVO)
≥ 6 tpy to ≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.[17] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in Table 20 below, the total annual cost for each inspector will be $186,129, which equates to an hourly inspection rate of $99.

Table 20: Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis

Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$122,000		
Photo Ionization Detector	$5,000		
Vehicle (4x4 Truck)	$22,000		
Inspection Staff		$75,000	
Supervision (@ 20%)		$15,000	
Overhead (@10%)		$7,500	
Travel (@15%)		$11,250	
Recordkeeping (@10%)		$7,500	
Reporting (@10%)		$7,500	
Fringe (@30%)		$22,500	
Subtotal Costs	$149,000	$146,250	
Annualized Costs*	$39,879	$146,250	$186,129

[16] Because there may be a limited number of instances where well production facilities don't have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's potential to emit VOC.
[17] This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

**over 5 years at 6% ROR*		Annualized Hourly Rate	$99

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.

For compressor stations, the Division used reported component counts for compressor stations within each of the tiers identified in Table 18 above. Based on these counts, and the inspection times per component discussed above, the Division calculated that the total inspection time per compressor station facility tier are as follows:

Table 21: Calculated Inspection Time Compressor Station Leak Inspections

Component Leak Uncontrolled Actual VOC Emissions	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	21.2 hours	10.6 hours
>12 tpy to ≤ 50 tpy	56.2 hours	28.1 hours
> 50 tpy*		

* *there are currently no compressor stations in Colorado with calculated leaks at this level*

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on this overall average component count each Method 21 inspection will take 9.5 hours and each IR camera based inspection will take 4.75 hours.

Next, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. The calculated inspection costs for compressor stations and well production facilities do not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective. Conversely, the calculated costs also do not account for the cost savings from capturing additional product as a result of repairs. For the purposes of this initial cost analysis the Division assumes that the cost savings from additional product capture will be equal to or greater than the cost of repair and re-inspection. However, the Division welcomes additional input from stakeholders on the costs and benefits associated with repairing leaking components.

Based on this methodology, the calculated costs for compressor stations are set forth in Table 22.

Table 22: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Annual Inspection Frequency	Time per IR Camera Inspection [hours]	Total Annual Inspection Time [hours]	Total Annual Inspection Cost
≤ 12 tpy	147	1	10.6	1,558.2	$154,262
>12 to ≤ 50 tpy	53	4	28.1	5,957.2	$589,763
≥ 50 tpy	0	12			
Total:	200			7,515.4	$744,025

Estimated annual inspection costs for well production facilities are set forth in Table 23.

Table 23: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Uncontrolled VOC at Storage Tank Battery Tier [tpy]	Number of Facilities	Annual Inspection Frequency	Inspection Time Per Inspection [hours]	Total Inspection Time [hours]	Total Annual Inspection Cost
≥ 6 to ≤12	1,390	1	4.75	6,602.5	$653,648
> 12 to ≤ 50	2,916	4	4.75	55,404.0	$5,484,996
> 50	964	12	4.75	54,498.0	$5,439,852
Total:	5,270			116,954.5	$11,578,496

Additionally, there are 2,810 well production facilities with uncontrolled actual storage tank emissions below six tons per year that will be subject to a one-time instrument based inspection. The one-time cost for inspecting these facilities is estimated to be $1,321,403.[18]

[18] The Division's proposal also requires monthly AVO inspections at these facilities. Based on information provided during the stakeholder process, the Division understands that AVO inspections are part of current standard operational practice. Accordingly, the regulatory provisions should not result in additional costs. The Division requests, however, additional information from interested parties during the pre-hearing process regarding this issue.

Finally, the Division calculated the cost effectiveness of the proposed leak detection and repair requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections.

Using this information the Division calculated that the total emission reductions from leaks at compressor stations will be 1,115 tpy VOC and 2,320 tons per year methane/ethane.

Table 24: Compressor Station Leak Inspection Emission Reductions

Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	LDAR Program Reduction %	Fugitive VOC Emissions for each CS tier [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each CS tier [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	147	40%	10.1	593.9	15.5	911.4
> 12 to ≤ 50	53	60%	16.4	521.5	44.3	1,408.7
> 50		80%				
	200			1,115.4		2,320.1

Based on these reductions, the cost effectiveness of conducting leak inspections at compressor stations is estimated to be $667/ton VOC and $321/ton methane/ethane.

Table 25: Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21

Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane -Ethane Control Cost [$/ton]
≤ 12	147	$154,262	40%	593.9	$260	911.4	$169
> 12 to ≤ 50	53	$589,763	60%	521.5	$1,131	1,408.7	$419
> 50			80%				
	200	$744,025		1,115.4	$667	2,320.1	$321

For well production facilities the total emission reductions is estimated to be 14,153 tpy VOC and 22,461 tpy methane/ethane.

Table 26: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
≥ 6 to ≤ 12	1,390	40%	4.6	2,557.6	7.3	4,058.8
> 12 to ≤ 50	2,916	60%	4.6	8,048.2	7.3	12,772.1
> 50	964	80%	4.6	3,547.5	7.3	5,629.8
Total:	5,270			14,153.3		22,460.7

Based on these reductions, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be $818/ton VOC and $516/ton methane/ethane.

Table 27: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21							
Uncont. VOC at Tank Battery Tier [tpy]	Number of Tanks	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [$/ton]
≥ 6 to ≤ 12	1,390	$653,648	40%	2,557.6	$256	4,058.8	$161
> 12 to ≤ 50	2,919	$5,484,996	60%	8,048.2	$682	12,772.1	$429
> 50	964	$5,439,852	80%	3,547.5	$1533	5,629.8	$966
Total:	5,270	$11,578,496		14,153.3	$818	22,460.7	$516

Additionally, for the 2,810 well production facilities with uncontrolled actual storage tank emissions below six tons per year that will be subject to a one-time instrument based inspection, the calculated one-time benefit is 5,170 tons VOC and 8,205 tons methane/ethane, assuming a 40% reduction and a current leak rate of 4.6 tpy VOC and 7.3 tpy methane/ethane. Based on these reductions, for the one-time inspections of well production facilities with tanks that are less than six tons per year the cost effectiveness of the proposed rule is calculated to be $256/ton VOC and $161/ton methane/ethane.

In addition to conducting its own cost effectiveness analysis for the proposed leak detection requirements, the Division has considered cost information provided by industry[19] and

[19] See "Analysis of Industry Survey LDAR Responses" Lisa McDonald, PhD and Holly Bender PhD, September 11, 2013.

environmental groups[20] as part of the stakeholder process leading up to the Division's request for a hearing on its proposed changes. While none of this information specifically analyzed the Division's proposed leak detection program, the information provides additional perspectives on the likely costs and benefits of the Division's proposal.

To assess potential costs of a Colorado leak detection program for well production facilities, McDonald and Bender analyzed industry survey responses on leak detection to determine total costs for annual, quarterly and monthly inspections at 8,702 well production facilities[21] in Colorado. Since the inspection numbers in this analysis is different than the number of inspections that will be required under the Division's proposal, the overall cost that McDonald and Bender calculated is less relevant to this analysis. Based on the data they present, however, it is possible to calculate a per inspection cost that can be used to analyze the cost effectiveness of the Division's proposal. Specifically, McDonald and Bender's analysis shows that on average an annual leak detection inspection costs $2,468, a quarterly inspection costs $1,067, and a monthly inspection costs $765. Using these inspection cost numbers applied to the expected number of inspections required under the Division's proposal (<u>See</u> Table 23 above) yields a total annual cost of $24,725,528. This equates to $1,747/ton of VOC reduced, and $1,101/ton of methane/ethane reduced based on the Division's emission reduction calculations (<u>See</u> Table 26 above).

In their analysis, McCabe *et.al.*, looked at cost and benefit data from actual IR camera inspections at gas plants, compressor stations and well-sites conducted pursuant to Canada's oil and gas leak detection program. The information they provided includes a range of cost assumptions. At the high end the cost per ton of VOC reduced at well facilities is approximately $300 per ton. For compressor stations the high end shows a net cost benefit from conducting IR camera inspections.

Environmental Defense Fund's analysis looked at a number of different scenarios and concluded that the cost effectiveness of quarterly leak detection and repair ranged from between approximately $1,000/ton and $7,000/ton for VOCs and between approximately $400/ton and $2,300/ton for methane. For monthly leak detection they estimated that the cost per ton for VOCs ranged between approximately $2,000 per ton and $13,000/ton. For methane, monthly leak detection costs ranged between approximately $600/ton and $4,100/ton.

<u>D. Auto Igniter Requirements on Existing Flare Control Devices Outside the Non-Attainment Area</u>

Unlike the non-attainment area, flares used to control emissions at condensate tank batteries and glycol dehydration units outside the NAA are not required to have auto-igniters. The Division is

[20] <u>See</u> "An Examination of the Cost-Effectiveness of Leak Detection and Repair Programs Using Infrared Cameras" David McCabe, Ellen Baum, Stephanie Saunier, September 11, 2013; "Analysis of Leak Detection and Repair Program for O&G Emissions in Colorado" Environmental Defense Fund, September 20, 2013.

[21] The analysis did not look at leak detection costs for compressor stations.

proposing that all flares used to control emissions at condensate tank batteries and glycol dehydration units statewide should have auto igniters. Based on an analysis of the APEN database, the Division estimates the statewide number of existing flare control devices without auto-igniters on condensate tank batteries and glycol dehydration is 652. The reported uncontrolled actual emissions from these units are 47,675 tons per year VOC.

The estimated annualized cost for an auto-igniter is $475 based on information that the industry provided to the Division in 2008, adjusted for inflation.[22]

Table 28: Auto Igniter Control Device – Retrofit Cost Analysis				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Auto Igniter	$1,648			
Freight/Engineering		$200		
Flare Installation		$500		
Maintenance			$200	
Subtotal Costs	$1,648	$700	$200	
Annualized Costs*	$228.4	$46.7	$200	$475

** Annualized over 15 years at 5% ROR*

The Division estimates that a flare without an auto-igniter could experience about 3% pilot light downtime (262.8 hours) over a one year period. During the downtime period, any VOC emissions routed to the flare control device are uncontrolled. Based on the total uncontrolled actual emissions of 47,675 tons per year VOC from units equipped with flares without auto-igniters, the emissions during this downtime period will be 1,430.2 tons of VOC. Of this total, 495.1 tons of the emissions are from dehydrators and 935.1 tons are from storage tanks. The Division assumes that as a result of the installation of an auto-igniter, the amount of downtime can be eliminated, for a total emission reduction of 1,137 tons/year. Given that the annualized cost of installing 652 auto-igniters is about $309,700, the estimated cost effectiveness of this strategy is about $272 per ton of VOC reduced.

Table 29: Auto Igniter Control Cost Estimates (Outside NAA)				
Number	Each Auto-Igniter Annualized Costs	Total Annualized Costs	VOC Reduction* [tons/year]	Control Costs [$/ton]
652	$475	$309,700	1,136.6	$272

** Dehydrator flares assumed to have 95% control (1.0*0.95)-thus VOC reduction is 495.1*0.95 = 470.3 tpy; Tank flares assumed to have 71.25% control (0.75*0.95)-thus VOC reduction is 935.1*0.75*0.95=666.3 tpy. Total VOC reduction = 470.3 + 666.3 = 1,136.6 tpy.*

[22] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

E. Expanding Low Bleed Pneumatics Requirements Statewide

As part of the 2008 Ozone Action Plan the AQCC adopted regulatory requirements mandating the use of low bleed pneumatic controllers in the non-attainment area. The current proposal would expand this requirement statewide.

To estimate the costs and benefits of this proposed strategy, the Division estimated the number of high-bleed pneumatic devices based on Independent Petroleum Association of the Mountain States (IPAMS) survey data from 2006, which identified the average number of such devices per well. The Division then scaled this number up based on 2012 Colorado Oil and Gas Conservation Commission (COGCC) well count data. Based on this methodology, there are 9,877 high-bleed pneumatic devices outside the nonattainment area. Assuming a 95% replacement rate, the proposed rule will result in the replacement of 9,384 high bleed devices with low bleed devices. Based on this count, and the average emission reductions per device replaced identified in the IPAMS survey, the projected benefit from the proposed expansion of the current non-attainment area low bleed pneumatic rule will be approximately 14,921 tons per year VOC (40.9 tons per day).

The average retrofit cost of a high-bleed pneumatic device is based on costs from the 2008 cost study[23] adjusted for inflation. Utilizing this methodology, the annualized cost for each replaced device is $169. However, because the reduced bleed rate results in more natural gas being sold, operators will receive additional revenue as a result of the installation of a low bleed device. Based on the emission reduction data from the IPAMS survey and August 2013 spot prices for natural gas, the estimated average value of the recovered gas will be $1,268 for each device replaced. As a result, the net annual gain is $1,084 per replaced device. Based on this projected net gain, this strategy will pay for itself in approximately one year and four months.

Table 30: Replace High-Bleed Pneumatics with Low-Bleed Pneumatics – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Low/No Bleed Device*	$1,033			
Labor		$387		
Value of NG Saved**			$(1,268)	
Maintenance			$16	
Subtotal Costs	$1,033	$387	$(1,253)	
Annualized Costs***	$143	$26	$(1,253)	$(1,084)

[23] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

** Control device costs were developed based on an Oil and Gas Cost Study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.*
*** Recovered NG fuel costs $3.5/MCF (Henry Hub Spot Price - Aug. 2013)*
**** Annualized over 15 years at 5% ROR*

Assuming 9,384 total devices replaced, adoption of this strategy will result in $10,172,256 in annual cost savings.

Table 31: Low Bleed Pneumatic Control Cost Estimates (Outside NAA)				
Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
9,384	$(1,084)	$(10,172,256)	14,921	NA

The proposed rule also requires the use of no-bleed pneumatic devices if it is technically and economically feasible and where on-site electrical grid power is being used. Since the Division does not have information indicating the number of no-bleed pneumatic devices that could be required, it is not possible to calculate the cost effectiveness of this particular provision. The Division requests that interested parties provide additional information regarding this issue.

F. Require Newly Constructed Gas Wells be Connected to a Pipeline or Route Emissions to A Control Device

Currently in Colorado, natural gas produced at oil and gas sites is typically routed to a transmission pipeline. With the advent of new drilling technologies, additional areas of the state without established pipeline infrastructure may experience oil and gas exploration and production. This can lead to instances where produced gas is vented or flared instead of being put into a transmission line. To date the Division has identified 61 instances in Colorado where this is occurring. To address this, the proposed regulation provides that for newly constructed, hydraulically fractured, or recompleted wells, the gas stream must either be connected to a pipeline or routed to a control device achieving 95% control efficiency. Currently all of the sites that are not routed to a pipeline are flaring their gas. Additionally, because venting the gas at such sites would create a safety issue, the Division assumes that in the limited future instances where the gas stream is not routed to a pipeline, operators will route the emissions to a flare or other control device. Accordingly, adoption of this portion of the proposed regulation will not result in any additional costs.

G. Control Requirements for Glycol Dehydrators

The Division is proposing to revise the control requirements applicable to glycol natural gas dehydrators statewide. Currently any glycol natural gas dehydrator with uncontrolled actual VOC emissions of two tons per year or greater that is located at a facility where the sum of uncontrolled actual emissions from all of the dehydrators at the facility is greater than fifteen tons per year, must be equipped with a control device that reduces emissions by at least 90%. Under the Division's proposal, all existing dehydrators with uncontrolled actual emissions of six tons per year or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. The proposal also provides that existing dehydrators with uncontrolled actual emissions of two tons per year or greater VOC must be controlled if they are located within 1,320 feet of a building unit or designated outside activity area. Finally, the proposal requires that all new dehydrators with uncontrolled actual emissions of two tons per year or greater VOC be controlled. The Division assumes that newly subject glycol dehydrators will be controlled using flares that achieve a 95% destruction efficiency. The annual cost for these units is $6,286.80 per unit. See Section IV.A.1. above.

Based on industry reported APEN data, there are currently 433 uncontrolled dehydrators at sites with total dehydrator uncontrolled actual VOC emissions below 15 tpy. Of these, 217 have uncontrolled actual emissions greater than or equal to two tons per year. The total uncontrolled actual emissions for these 217 dehydrators are 1,827.5 tpy VOC. There are 148 dehydrators with uncontrolled actual VOC emissions greater than or equal to six tons per year. The total uncontrolled actual emissions for these 148 dehydrators are 1,549.7 tpy VOC. Currently, the Division does not have information regarding the location of these uncontrolled dehydrators relative to a building unit or designated outside activity area. Given this, the Division conducted two cost calculations for dehydrators. The first cost calculation assumed that all of the two to six ton dehydrators are located within 1,320 feet of a building unit or designated outside activity area and thus will require a control. Based on this assumption the proposed requirement will reduce 1,736 tpy of VOC at a cost effectiveness of $786/ton VOC.

Table 32: Dehydrator Control Cost Estimates (2 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
217	$6,286.8	$1,364,236	1,736	$786

The second calculation assumed that assumed that none of the two to six ton existing dehydrators will require controls. Based on this assumption the proposed requirement will reduce 1,472 tpy of VOC at a cost effectiveness of $632/ton VOC.

Table 33: Dehydrator Control Cost Estimates (6 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
148	$6,286.8	$930,446	1,472	$632

H. Control Requirements for Downhole Well Maintenance and Liquids Unloading Events

Historically, Colorado has not regulated air emissions from temporary activities such as well completions and well maintenance at well production sites. Recently, however, EPA, Colorado and other jurisdictions have identified these activities as potentially large sources of emissions from the oil and gas sector. In recognition of this, the Colorado Oil and Gas Conservation Commission and more recently EPA have adopted requirements for green completions to reduce hydrocarbon emissions during well completion activities. The Division is now proposing additional regulatory requirements designed to reduce emissions during well maintenance.

Well maintenance is required when, over time, liquids build up inside the well and reduce gas and oil flow out of the well. To remove these liquids and improve flow, the liquids are blown out of the well under pressure. This process is typically referred to as "liquids load-out" or "well blow-down." Historically emissions from well blow-downs are vented to the atmosphere. EPA has established emission factors for liquid unloading based on fluid equilibrium calculations to calculate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blow-down. Based on its calculations, EPA estimated that, in the United States, the combined methane emissions for liquid unloading and well completions in 2009 was 217 billion cubic feet, and that liquid unloading may account for 33% of the uncontrolled methane emissions from the natural gas industry.[24] For Colorado, the Division has calculated that emissions from well blow-downs in 2008 were approximately 9,306 tons of VOC per year.

To address these emissions, the Division is proposing a two-pronged requirement aimed at reducing the number of required liquids unloading events and reducing the amount of emissions vented to the atmosphere during these events. Under the Division's proposal operators shall use best management practices to minimize the need for venting associated with downhole maintenance and liquids unloading. For example, EPA's Gas Star program advocates the use of a plunger lift system to reduce the need for liquids unloading. According to EPA, use of a plunger lift will on average pay for itself in less than one year through the capture of additional product. The Division's proposal also provides that emissions during well maintenance and liquids unloading shall be captured or controlled using best management practices to limit venting during well blow-downs to the maximum extent practicable. Given the wide variety of practices that this could entail, the Division currently does not have information about the potential cost-effectiveness of this provision, but requests additional information from interested parties during the pre-hearing process regarding this issue.

[24] See EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2009,* April, 2011.

V. CONCLUSION

The Division projects that the entire proposal will reduce VOC emissions in Colorado by approximately 92,000 tons per year at a cost of approximately $29 million per year. The leak detection component of the package is estimated to reduce methane/ethane emissions by approximately 25,000 tons per year. The calculated cost per ton of VOC reduced ranges from $176 to $818 per ton. The overall cost effectiveness for the entire package is approximately $300 per ton of VOC reduced.

The Division prepared this Initial Economic Impact Analysis in accordance with the requirements of Section 25-7-110.5(4), C.R.S. Specifically, the Division utilized the methodology identified in § 25-7-110.5(4)(c)(I), C.R.S. In completing this analysis, the Division assessed the costs and benefits associated with each of the proposed strategies based on the reasonably available data. In collecting this data, the Division sought input from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in the analysis. To the extent that additional data regarding the costs and benefits of the proposed strategies is made available, the Division will assess this data and where appropriate incorporate it into the Final Economic Impact Analysis required under AQCC Procedural Rules, Section V.E.7.

EDF-WZI-APPENDIX VII

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

Executive Summary

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Methane emissions from pneumatic devices, which have been estimated at 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector and <1 Bcf per year in the processing sector, are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable.

Natural Gas STAR Partners have achieved significant savings and methane emission reductions through replacement, retrofit, and maintenance of high-bleed pneumatics. Partners have found that most retrofit investments pay for themselves in little over a year, and replacements in as little as 6 months. To date, Natural Gas STAR Partners have saved 36.4 Bcf by retrofitting or replacing high-bleed with low-bleed pneumatic devices, representing a savings of $254.8 million worth of gas. Individual savings will vary depending on the design, condition and specific operating conditions of the controller.

Technology Background

The natural gas industry uses a variety of control devices to automatically operate valves and control pressure, flow, temperature or liquid levels. Control devices can be powered by electricity or compressed air, when available and economic. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas.

Natural gas powered pneumatic devices perform a variety of functions in all three sectors of the natural gas industry. In the production sector, an estimated 400,000 pneumatic devices are used to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector, about 13,000 gas pneumatic devices are used for compressor and glycol dehydration control in gas gathering/booster stations and isolation valves in processing plants (process control in gas processing plants is predominantly instrument air).

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/year)	Value of Natural Gas Savings ($/year)			Implementation Cost ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Replacement								
Change to low-bleed device at end of life.	50 to 200	$150 to $600	$250 to $1,000	$350 to $1,400	$210 to $340[a]	4 to 27	3 to 17	2 to 12
Early-replacement of high-bleed unit.	260	$780	$1,300	$1,820	$1,850	29	17	13
Retrofit	230	$690	$1,150	$1,610 per year	$675	12	7	5
Maintenance	45 to 260	$135 to $780	$225 to $1,300	$315 to $1,820	Negligible to $500	Immediate to 8	Immediate to 5	Immediate to 4

General Assumptions:
[a] Incremental cost of low-bleed over high-bleed equipment.

Definition of High-Bleed Pneumatic

Any pneumatic device that bleeds in excess of 6 scfh (over 50 Mcf per year) is considered a high-bleed device by the Natural Gas STAR Program.

In the transmission sector, an estimated 85,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at distribution company gate stations for regulating flow, pressure, and temperature.

As part of normal operation, pneumatic devices release or bleed natural gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The actual bleed rate or emissions level largely depends on the design of the device.

Exhibit 1 shows a schematic of a gas pneumatic control system. Clean, dry, pressurized natural gas is regulated to a constant pressure, usually around 20 psig. This gas supply is used both as a signal and a power supply. A small stream is sent to a device that measures a process condition (liquid level, gas pressure, flow, temperature). This device regulates the pressure of this small gas stream (from 3 to 15 psig) in proportion to the process condition. The stream flows to the pneumatic valve controller, where its variable pressure is used to regulate a valve actuator.

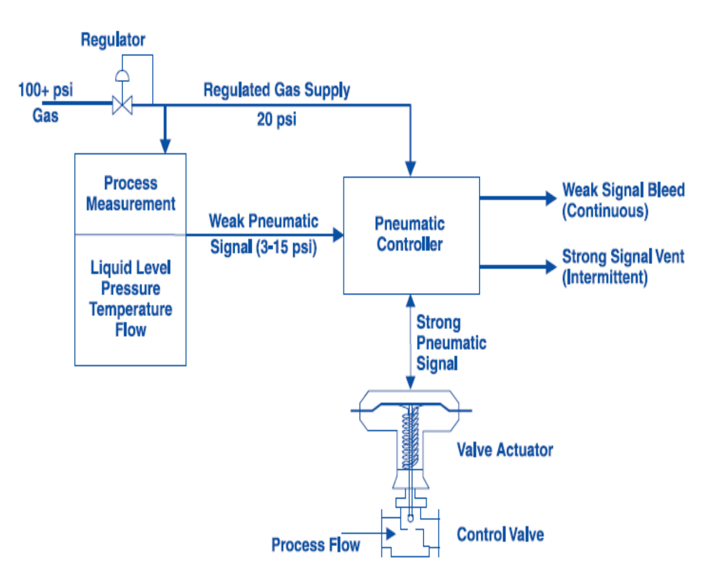
To close the valve pictured in Exhibit 1, 20-psig pneumatic gas is directed to the actuator, pushing the diaphragm down against the spring, which, through the valve stem, pushes the valve plug closed. When gas is vented off the actuator, the spring pushes the valve back open. The weak signal continuously vents (bleeds) to the atmosphere. Electro-pneumatic devices use weak electric current instead of the weak gas stream to signal pneumatic valve actuation.

In general, controllers of similar design usually have similar steady-state bleed rates regardless of brand name. Pneumatic devices come in three basic designs:

★ **Continuous** bleed devices are used to modulate flow, liquid level, or pressure and will generally vent gas at a steady rate;

★ **Actuating or intermittent** bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed or as they throttle gas flows; and

Exhibit 1: Pneumatic Device Schematic



★ **Self-contained** devices release gas into the downstream pipeline, not to the atmosphere.

To reduce emissions from pneumatic devices the following options can be pursued, either alone or in combination:

1. Replacement of high-bleed devices with low-bleed devices having similar performance capabilities.

2. Installation of low-bleed retrofit kits on operating devices.

3. Enhanced maintenance, cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings, and seals.

Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. Exhibit 2 lists the generic options applicable for different controller requirements.

In general, the bleed rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years.

Exhibit 2: Options for Reducing Gas-Bleed Emissions by Controller Type

Action	Pneumatic Types		
	Level Controllers	Pressure Controllers	Positioners/ Transducers
Replacements			
High-bleed with low-bleed	X	X	X (electro-pneumatic)
Retrofits			
Install retrofit kits	X	X	X
Maintenance			
Lower gas supply pressure/replace springs/re-bench	X	X	X
Repair leaks, clean and tune	X	X	X
Change gain setting	X	X	
Remove unnecessary positioners			X

Economic and Environmental Benefits

Reducing methane emissions from high-bleed pneumatic devices through the options presented above will yield significant benefits, including:

- ★ **Financial return from reducing gas-bleed losses.** Using a natural gas price of $7.00 per thousand cubic feet (Mcf), savings from reduced emissions can range from $315 to $1,820 or more per year per device. In many cases, the cost of implementation is recovered in less than a year.

- ★ **Increased operational efficiency.** The retrofit or complete replacement of worn units can provide better system-wide performance and reliability and improve monitoring of parameters such as gas flow, pressure, or liquid level.

- ★ **Lower methane emissions.** Reductions in methane emissions can range from 45 to 260 Mcf per device per year, depending on the device and the specific application.

Decision Process

Operators can determine the gas-bleed reduction option that is best suited to their situation, by following the decision process laid out below. Depending on the types of devices that are being considered, one or more options for reducing pneumatic gas bleed may be appropriate.

Step 1: Locate and describe the high-bleed devices.

Partners should first identify the high-bleed devices that are candidates for replacement, retrofit, or repair. The identification and description process can occur during normal maintenance or during a system-wide or facility-specific pneumatics survey. For each pneumatic device, record the location, function, make and model, condition, age, estimated remaining useful life, and bleed rate characteristics (volume and whether intermittent or continuous).

The pneumatic device's bleed rate can be determined through direct measurement or from data provided by the manufacturer. Direct measurement might include bagging studies at selected instruments, high-volume sampler measurements (see "Directed Inspection and Maintenance at Compressor Stations" Lessons Learned) or the operator's standard leak measurement approach. Operators will find it unnecessary to measure bleed rates at each device. In most cases, sample measurements of a few devices are sufficient. Experience suggests that manufacturers' bleed rates are understated, so measurement data should be used when it can be acquired.

Appendix A lists brand, model, and gas bleed information—as provided by manufacturers—for various pneumatic devices. This is not an exhaustive list, but it covers the most commonly used devices. Where available, actual field data on bleed rates are included.

Step 2: Establish the technical feasibility and costs of alternatives.

Nearly all high-bleed pneumatic devices can be replaced or retrofitted with lower-bleed equipment. Consult your pneumatic device vendor or an instrumentation specialist for availability, specifications and costs of suitable devices. Low-bleed devices can be requested by specifying bleed rates less than 6 standard cubic feet per hour (scfh). It is important to note that not all manufacturers report bleed rates in the same manner, and companies should exercise

Five Steps for Reducing Methane Emissions from Pneumatic Devices:
1. Locate and describe the high-bleed devices;
2. Establish the technical feasibility and costs of alternatives;
3. Estimate the savings;
4. Evaluate the economics; and
5. Develop an implementation plan.

caution when making purchases of low-bleed devices.

Appendix B lists cost data for many low-bleed pneumatic devices and summarizes the compatibility of retrofit kits with various controllers. This is not an exhaustive list, but it covers the most commonly used devices.

Maintenance of pneumatics is a cost-effective method for reducing emissions. All companies should consider maintenance as an important part of their implementation plan. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device.

Some high-bleed devices, however, should not be replaced with low-bleed devices. Control of very large valves that require fast and/or precise response to process changes often require high-bleed controllers. These are found most frequently on large compressor discharge and bypass pressure controllers. EPA recommends contacting vendors for new fast-acting devices with lower bleed rates.

Step 3: Estimate the savings.

Determine the quantity of gas that can be saved with a low-bleed controller, using field measurement of the high-bleed controller and a similar low-bleed device in service. If these actual bleed rates are not available, use bleed specifications provided by manufacturers.

Gas savings can be monetized to annual savings using \$7.00 per Mcf and multiplying bleed reduction, typically specified in scfh, by 8,670 hours per year.

Gas Savings = (High-bleed, scfh) — (Low-bleed, scfh)

Annual Gas Savings = Gas Savings (scfh) * 8,760 hrs/yr * 1 Mcf/1000scf * \$7.00/Mcf

Step 4: Evaluate the economics.

The cost-effectiveness of replacement, retrofit, or maintenance of high-bleed pneumatic devices can be evaluated using straightforward economic analysis. A cost-benefit analysis for replacement or retrofit is appropriate unless high-bleed characteristics are required for operational reasons.

Exhibit 3 illustrates a cost-benefit analysis for replacement of a high-bleed liquid level controller. Cash flow over a five-year period is analyzed by showing the magnitude and timing of costs (shown in parenthesis) and benefits. In this example, a \$513 initial investment buys a level controller that saves 19 scfh of gas. At \$7.00 per Mcf, the low-bleed device saves \$1,165 per year. Annual maintenance costs for the new and old controllers are shown. The maintenance cost for the older high-bleed controller is shown as a benefit because it is an avoided cost. Net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. Internal rate of return (IRR) is the discount rate at which the NPV generated by the investment equals zero.

Exhibit 3: Cost-Effectiveness Calculation for Replacement

Type of Costs	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Implementation Costs, \$ (Capital Costs)[a]	(513)					
Annual Savings, \$ (New vs. Old)[b]		1,165	1,165	1,165	1,165	1,165
Maintenance Costs, \$ (New Controller)[c]		(34)	(34)	(34)	(34)	(34)
Avoided Maintenance, \$ (Replaced Controller)[c]		70	70	70	70	70
Net Benefit	(513)	1,202	1,202	1,202	1,202	1,202

NPV[d] = \$4,042
IRR = 234%

Notes:
[a] Quoted cost of a Fisher 2680 device. Adjusted to 2006 equipment costs. See Appendix B.
[b] Annual savings per device calculated as the change in bleed rate of 19 scfh x 8,760 hrs/hr = 167 Mcf/yr at \$7/Mcf.
[c] Maintenance costs are estimated.
[d] Net Present Value (NPV) based on 10% discount rate for 5 years.

Exhibit 4 illustrates the range of savings offered by proven methods for reducing gas bleed emissions. For simplicity, it is assumed that the cost of maintenance of the pneumatic device will be the same before and after the replacement, retrofit, or enhanced maintenance activity.

As seen in Exhibit 4, sometimes more than one option to reduce gas bleed may be appropriate and cost-effective for a given application. For the listed options, please note that the payback period with respect to implementation cost can range from less than one month to two years.

Exhibit 4: Economic Benefits of Reducing Pneumatic Device Emissions

Action	Cost[a] ($)	Bleed Rate Reductions[b] (Mcf/yr/device)	Annual Savings[c] ($/year)	Payback Period (months)	IRR[d] (%)
Replacement					
Level Controllers					
High-bleed to low-bleed	513	166	1,165	6	226
Pressure Controllers					
High-bleed to low-bleed	1,809	228	1,596	14	84
Airset metal to soft-seal	104	219	1,533	<1	>1,400
Retrofit					
Level Controllers					
Mizer	675	219	1,533	6	226
Large orifice to small	41	184	1,288	<1	>3,100
Large nozzle to small	189	131	917	3	>450
Pressure Controllers					
Large orifice to small	41	184	1,288	<1	>3,100
Maintenance					
All types					
Reduce supply pressure	207	175	1,225	3	>500
Repair leaks, retune	31	44	308	2	>900
Level Controllers					
Change gain setting	0	88	616	Immediate	—-
Positioners					
Remove unnecessary	0	158	1,106	Immediate	—-

[a] Implementation costs represent average costs for Fisher brand pneumatic instruments installed.
[b] Bleed rate reduction = change in bleed rate scf/hr x 8,760 hr/yr.
[c] Savings based on $7.00/Mcf cost of gas.
[d] Internal rate of return (IRR) calculated over 5 years.

The case studies in Exhibit 5 on the next page present analyses performed and savings achieved by two Natural Gas STAR Partners who installed retrofit kits at gas production facilities.

Step 5: Develop an implementation plan.

After identifying the pneumatic devices that can be profitably replaced, retrofitted or maintained, devise a systematic plan for implementing the required changes. This can include modifying the current inspection and maintenance schedule and prioritizing replacement or retrofits. It may be most cost-effective to replace all those devices that meet the technical and economic criteria of your analysis at one time to minimize labor costs and disruption of operation.

Where a pneumatic device is at the end of its useful life and is scheduled for replacement, it should be replaced with a low-bleed model instead of a new high-bleed device whenever possible.

When assessing options for replacement of high-bleed pneumatic devices, natural gas price may influence the decision making process. Exhibit 6 shows an economic analysis of early replacement of a high bleed pneumatic device with a lower bleed device at different natural gas prices.

Exhibit 5: Case Studies on Retrofit To Reduce Gas Leaks at Natural Gas STAR Partner Sites

Study	Implementation Costs ($)	Emissions Reductions (Mcf/yr)	Annual Savings ($/year)	Payback (months)	IRR (%)
Company 1:					
Platform 1	8,988	2,286	16,002	7	177
Platform 2	13,892	3,592	25,144	7	180
Retrofit Liquid-level controllers	5,452	1,717	12,019	6	220
Company 2:					
Per device	702	219	1,533	6	218

Exhibit 6: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$780	$1,300	$1,820	$2,080	$2,600
Payback Period (months)	29	18	13	11	9
Internal Rate of Return (IRR)	31%	64%	95%	110%	139%
Net Present Value (i=10%)	$1,107	$3,078	$5,049	$6,035	$8,006

Other Technologies

Instrument air, nitrogen gas, electric valve controllers, and mechanical control systems are some of the alternatives to gas powered pneumatics implemented by Partners.

★ **Instrument Air.** These systems substitute compressed, dried air in place of natural gas in pneumatic devices, and thus eliminate methane emissions entirely. Instrument air systems are typically installed at facilities where there is a high concentration of pneumatic control valves and fulltime operator presence (for example, most gas processing plants use instrument air for pneumatic devices). The major costs associated with instrument air systems are capital and energy. Instrument air systems are powered by electric compressors, and require the installation of dehydrators and volume tanks to filter, dry and store the air for instrumentation use. Generally, Partners have found that cost-effective implementation of instrument air systems is limited to field sites with available utility or self-generated electrical power. The Lessons Learned study, "Covert Gas Pneumatic Controls to Instrument Air," provides a detailed description of the technical and economic decision process required to evaluate conversion from gas pneumatic devices to instrument air.

★ **Nitrogen Gas.** Unlike instrument air systems that require capital expenditures and electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, that is replaced periodically, and a liquid nitrogen vaporizer. The system uses a pressure regulator to control the expansion of the nitrogen gas (i.e., the gas pressure) as it enters the control system. The primary disadvantage of these systems stems from the cost of liquid nitrogen and the potential safety hazard associated with using cryogenic liquids.

★ **Electric Valve Controllers.** Due to advances in technology, the use of electronic control instrumentation is increasing. These systems use small electrical motors to operate valves and therefore do not bleed natural gas into the atmosphere. While they are reliant on a constant

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

supply of electricity, and have high associated operating costs, they have the advantage of not requiring the utilization of natural gas or a compressor to operate.

★ **Mechanical Control Systems.** These devices have been widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. While they are simple in design and require no natural gas or power supply to operate, their application is limited due to the need for the control valve to be in close proximity to the process measurement. Also, these systems are unable to handle large flow fluctuations and lack the sensitivity of pneumatic systems.

Each of these options has specific advantages and disadvantages. Where Natural Gas STAR Partners do install these systems as replacements to gas powered pneumatic devices, they should report the resulting emissions reductions and recognize the savings.

One Partner's Experience

Union Pacific Resources replaced 70 high-bleed pneumatic devices with low-bleed pneumatic devices and retrofitted 330 high-bleed pneumatic devices. As a result, this Partner has estimated a total reduction of methane emissions of 49,600 Mcf per year. Assuming a gas price of $7 per Mcf, the savings corresponds to $347,200. The costs of replacing and retrofitting all the devices, including materials and labor, is $166,300 at 2006 costs, resulting in a payback period of less than one year.

One Partner's Experience

Marathon Oil Company surveyed 158 pneumatic control devices at 50 production sites using the Hi-Flow Sampler to measure emissions. Half of these controllers were identified as non-bleed devices (e.g., weighted dump valves, spring operated regulators, enclosed capillary temperature controllers, non-bleed pressure switches). High-bleed devices accounted for 35 of 67 level controllers, 5 of 76 pressure controllers, and 1 of 15 temperature controllers. Measured gas emissions were 583 scfh total; 86 percent of emissions came from level controllers, with leaks up to 48 scfh, and averaging 7.6 scfh. Marathon concluded that "control devices with higher emissions can be identified qualitatively by sound prior to leak measurement, making it unnecessary to quantitatively measure methane emissions using technologically advanced equipment."

Lessons Learned

Natural Gas STAR Partners offer the following Lessons Learned:

★ Hear it; feel it; replace it. Where emissions can be heard or felt, this is a sign that emissions are significant enough to warrant corrective action.

★ Control valve cycle frequency is another indicator of excessive emissions. When devices cycle more than once per minute, they can be replaced or retrofitted profitably.

★ Manufacturer bleed rate specifications are not necessarily what users will experience. Actual bleed rates will generally exceed manufacturer's specifications because of operating conditions different from manufacturer's assumptions, installation settings and maintenance.

★ Combine equipment retrofits or replacements with improved maintenance activities. Do not overlook simple solutions such as replacing tubes and fittings or rearranging controllers.

★ The smaller orifices in low-bleed devices and retrofit kits can be subject to clogging from debris in corroded pipes. Therefore, pneumatic supply gas piping and tubing should be flushed out before retrofitting with smaller orifice devices, and gas filters should be well maintained.

- ★ When replacing pneumatic control systems powered by pressurized natural gas with instrument air or other systems, do not forget to account for the savings from the resulting methane emission reductions.

- ★ Include methane emission reductions from pneumatics in annual reports submitted as part of the Natural Gas STAR Program.

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Appendix A

The following chart contains manufacturer-reported bleed rates. Actual bleed rates have been included whenever possible. Discrepancies occur due to a variety of reasons, including:

- ★ Maintenance.
- ★ Operating conditions.
- ★ Manufacturer vs. operating assumptions.

It is important to note that manufacturer information has not been verified by any third party and there may be large differences between manufacturer-reported bleed rates and those found during operations. Until a full set of information is available, companies should be careful to compare bleed rates in standard units (CFH) when comparing manufacturers and models. During this study we found that manufacturers reported information in a wide range of different units and operating assumptions.

Gas Bleed Rate for Various Pneumatic Devices

Controller Model	Type	Consumption Rate (CFH)	
		Manufacturer Data	Field Data (where available)
High-Bleed Pneumatic Devices			
**Fisher 4100 Series	Pressure controller (large orifice)	35	
**Fisher 2500 Series	Liquid-level controllers (P.B. in mid range)	10-34	44-72
*Invalco AE-155	Liquid-level controller		44-63
*Moore Products—Model 750P	Positioner	42	
*Invalco CT Series	Liquid-level controllers	40	34-87
**Fisher 4150/4160K	Pressure controller (P.B. 0 or 10)	2.5-29	
**Fisher 546	Transducer	21	
**Fisher 3620J	Electro-pneumatic positioner	18.2	
Foxboro 43AP	Pressure controller	18	
**Fisher 3582i	Electro-pneumatic positioner	17.2	
**Fisher 4100 Series	Pressure controller (small orifice)	15	
**Fisher DVC 6000	Electro-pneumatic positioner	14	
**Fisher 846	Transducer	12	
**Fisher 4160	Pressure controller (P.B. 0.5)	10-34	
**Fisher 2506	Receiver controller (P.B. 0.5)	10	
**Fisher DVC 5000	Electro-pneumatic positioner	10	
**Masoneilan 4700E	Positioners	9	
**Fisher 3661	Electro-pneumatic positioner	8.8	
**Fisher 646	Transducer	7.8	
**Fisher 3660	Pneumatic positioner	6	
**ITT Barton 335P	Pressure controller	6	
*Ametek Series 40	Pressure controllers	6	
Low- or No-Bleed Pneumatic Devices			
**Masoneilan SV	Positioners	4	
**Fisher 4195 Series	Pressure controllers	3.5	
**ITT Barton 273A	Pressure transmitter	3	
**ITT Barton 274A	Pressure transmitter	3	
**ITT Barton 284B	Pressure transmitter	3	
**ITT Barton 285B	Pressure transmitter	3	
**Bristol Babcock Series 5457-70F	Transmitter	3	
**Bristol Babcock Series 5453-Model 624 -II	Liquid-level controllers	3	
**Bristol Babcock Series 5453-Model 10F	Pressure controllers	3	
**Bristol Babcock Series 5455 Model 624 -III	Pressure controllers	3	
**ITT Barton 358	Pressure controller	1.8	

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry
(Cont'd)

**ITT Barton 359	Pressure controller	1.8	
**Fisher 3610J	Pneumatic positioner	16	
**Bristol Babcock Series 502 A/D	Recording pneumatic controllers	<6	
**Fisher 4660	High-low pressure pilot	<5	
**Bristol Babcock Series 9110-00A	Transducers	0.42	
Fisher 2100 Series	Liquid-level controllers	1	
**Fisher 2680	Liquid-level controllers	<1	
*Norriseal 1001 (A) (snap)	Liquid-level controller	0.2	0.2
*Norriseal 1001 (A) ('Envirosave')	Liquid-level controller	0	0
*Norriseal 1001 (A) (throttle)	Liquid-level controller	0.007	0.007
**Becker VRP-B -CH	Double-acting pilot pressure control system (replaces controllers and positioners)	0-10	
**Becker HPP-5	Pneumatic positioner (Double-acting)	0-10	
**Becker EFP-2.0	Electro-pneumatic positioner	0	
**Becker VRP-SB	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker VRP-SB GAP Controller	Replaces pneumatic "gap" type controllers	0	
**Becker VRP-SB-PID Controller	Single-acting pilot pressure control system specifically designed for power plant type feeds (replaces controllers and positioners)	0	
**Becker VRP-SB-CH	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker HPP-SB	Pneumatic positioner (Single-acting)	0	

Actuator Model	Size	Manufacturer Data	Field Data
*Shafer RV-Series Rotary Vane Valve Actuators	33" x 32"	1,084	
	36" x 26"	768	
	26" x 22"	469	
	25" x 16"	323	
	20" x 16"	201	
	16.5" x 16"	128	
	14.5" x 14"	86	
	12.5" x 12"	49	
	12" x 9"	22	
	11" x 10"	32	
	9" x 7"	12	
	8" x 6.5"	8	
	6.5" x 3.5"	6	
	5" x 3"	6	
Actuator Model	**Size**	**Number of Snap-acting Strokes per CF**	**Number of Throttling Strokes per CF**
**Fisher Valve Actuators	20	21	39
**Fisher Valve Actuators	30	12	22
**Fisher Valve Actuators	34/40	6	10
**Fisher Valve Actuators	45/50	3	5
**Fisher Valve Actuators	46/50	2	3

* Last updated in 1996.
** Last updated in 2001.

Appendix B

Controllers Compatible with MIZER Retrofits	
Type	**Brand/Model Number**
Liquid-level controllers	C.E. Invalco — 215, 402, AE-155
	Norriseal — 1001, 1001A
Pressure controllers	Norriseal — 4300
Suggested Retail Prices for Various Brand Low-Bleed Pneumatic Devices (Estimates Based on Best Information Available at Time of Publication)	
Brand/Model	**Price per Device**
**ITT Barton 335P (pressure controller)	$920
**ITT Barton 273A (pressure transmitter)	$1,010
**ITT Barton 274A (pressure transmitter)	$1,385
**ITT Barton 284B (pressure transmitter)	$1,605
**ITT Barton 285B (pressure transmitter)	$1,990
**ITT Barton 340E (recording pressure controller)	$1,400
**ITT Barton 338E (recorder controller)	$2,800
**Ametek Series 40 (pressure controllers)	$1,100 (average cost)
**Becker VRP-B-CH	$1,575.00
**Becker HPP-5	$1,675.00
**Becker VRP-SB	$1,575.00-$2,000.00
**Becker VRP-SB-CH-PID	$2,075.00
**Becker VRP-SB-CH	$1,575.00
**Becker HPP-SB	$1,675.00
**Mizer Retrofit Kits	$400-$600
**Fisher 67AFR (airset regulators)	$80
**Fisher 2680 (liquid-level controllers)	$380
**Fisher 4195 (pressure controllers)	$1,340
**Bristol Babcock Series 9110-00A (transducers)	$1,535-$1,550
**Bristol Babcock Series 5453 (controllers)	$1,540
**Bristol Babcock 5453 40 G (temperature controllers)	$3,500
**Bristol Babcock Series 5457-624 II (controllers)	$3,140
**Bristol Babcock Series 502 A/D (recording controllers)	$3,000
**Bristol Babcock Series 5455-624 III (pressure controllers)	$1,135
**Bristol Babcock Series 5453-624 II (liquid level controllers)	$2,345
**Bristol Babcock Series 5453-10F (pressure controllers)	$1,440

* Last updated in 1996.
** Last updated in 2001.

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

October 2006

EDF-WZI-APPENDIX VIII

Methane Emissions Analysis

For Statewide Change-out to Low Bleed Pneumatic Devices

IPAMS High Bleed Rate Average:	16.8	cfh	See below TSD		
IPAMS Low Bleed Rate Average:	1.93	cfh	See below TSD		
			130 check		
Per Device Change in total gas:	14.87	cfh	33198 TOC		
Per Device Change in total gas:	130.3	Mcf/year	25936 Methane		
			7262 VOC		
Number of Pnuematic Devices:	9,384				
Total Amount of Gas Saved:	1,222,371	Mcf/year			
% of Methane in NG*	80.00%		*http://www.naturalgas.org/overview/background.asp		
Total Methane Gas Saved	977,897	Mcf/year	other sources general agree on this percentage, but it varies by region between 70-90%		
Molecular Weight of Natural Gas:	19.5	g/mol			
Molecular Weight of Methane:	16.043	g/mol	from engineering tool box- gas densities sheet		
Mcf to 1000 liter conversion:	28.317	1000L/Mcf			
Volume of Methane Gas emissions:	27,691,106	1000L/year		using NTP 20 C, 0.84 atm	
Methane Molar Emission:	1,235,399,963	moles/year	used STP= 1 atm, 0 degrees C	966,936,995	
Methane Mass Emissions:	19,819,522	kg/year		15,512,570	
Methane Mass Emissions:	21,847	tons/year		17,099	
Methane Emissions (@STP):	**21,847**	**tons/year**		**17,099**	**tpy**
			90,455.46146 mcfrVOC/yr		
	14921		13606113.98		
Methane Control Costs	0.68		6803.05699		
Cost of each pneumatic device:	-$1,083.7				
Number of pneumatic devices:	9,384				
total cost:	**-$10,169,444**				
Methane Control Costs: $	**(465.49)**	**per ton**			

Determining How Bleed Rate Relates to Emissions

Parameter	Eq.	Value	Units
Surveyed Producer Total Gas Emissions	A	989848	MCF
Annual Hours of Operation	B	8760	hrs
Well Count - surveyed producers	C	8247	wells
Well Count - basinwide	D	16894	wells
Basinwide VOC Fraction (molar)	E	7.47%	
Basinwide VOC molecular weight	F	54.7	g/mol
R	G	0.08206	L atm / K-mol
standard temp	H	273.15	K
standard press	I	1	atm
MCF to 1000 liter conversion	J	28.317	1000L/MCF
Basin-wide Emissions			
Basin-wide VOC volume emissions	K	151,567	MCF/year
Basin-wide VOC volume emissions	L	4,291,903	1000L/year
Basin-wide VOC mass emissions	M	10,473,301	kg/year
Basin-wide VOC mass emissions	N	11,545	tons/year

	IPAMS Calc	High Bleed (by definition)	High Bleed (highest IPAM)	High Bleed (avg., IPAM)	High Bleed (EPA Gas STAR)	Bleed Rate that gives 1 tpy	Avg Low/No Bleed	
		6	35	16.8	42.0	20.1	1.93	cfh total gas
IPAMS calc (use as example, modified)		52.56	306.6	147.4	367.9	176.1	16.94	MCF natural gas/year
K = A x D / C x E	151,567	3.9	22.9	11.0	27.5	13.2	1.3	MCF VOC/year
L = K x J	4,291,903	111	649	312	779	373	36	1000L VOC/year
M = I x L x 1000 / (G x H) x F / 1000	10,473,301	271	1,584	761	1,900	909	88	kg VOC/year
N = M / 907.185	11,545	0.30	1.75	0.84	2.09	1.00	0.10	tpy VOC

MCF = thousand cubic feet

Replace High Bleed Pneumatics with Low Bleed Pneumatics Outside NAA

Item	*Capital Costs (one time)*	*Non Recurring (one time)*	*O&M (recurring)*	*Annualized Total Cost (15 yrs)*
Materials	$1,033.4			
Labor		$387.2		
Value Gas Saved			-$1,268.3	
Maintenance:			$15.6	
Subtotal Costs:	$1,033	$387	-$1,253	
Annualized Costs:	$143.2	$25.8	-$1,252.7	**-$1,083.7**

8/1/2013 USDOL Data on CPI-U

	year	Annual Avg % change
	2008	3.70%
	2009	-0.50%
	2010	1.40%
	2011	3.10%
	2012	1.80%
$169.04	2013	0.35%
	increase since 2008	9.85%

Statewide Devices (outside NAA)		**9,384.0**
Statewide Initial Cost	**$**	**13,331,497.72**
Statewide Annual Cost	**$**	**(10,169,443.77)**
Statewide Emissions reduction (tpy)		**14,921.0**
Cost per ton VOC reduction		**-$681.6**
Payback Period:		**14 months at 2013 gas price**

2008 Costs

Pneumatic Device:	$	940.78
Labor:	$	352.50

Cost Amortization Calculations:

Life/YRS	*Equipment Costs (one-time)*	*Non Recurring (one time)*	*O&M (recurring)*	*Annualized Total Cost (15 yrs)*
0	$1,033	$387	-$1,253	
1	$1,085			
2	$1,139			
3	$1,196			
4	$1,256			
5	$1,319			
6	$1,385			
7	$1,454			
8	$1,527			
9	$1,603			

10	$1,683			
11	$1,768			
12	$1,856			
13	$1,949			
14	$2,046			
15	$2,148			
Annualized (15 yr):	$143.2	$25.8	-$1,252.7	-$1,083.7

Assumptions: Equipment Life = 15 yrs; Interest Rate* = 5%

*If the equipment was not purchased, the money could earn 5% per year

EDF-WZI-APPENDIX IX

AIR POLLUTANT EMISSION NOTICE (APEN) & Application for Construction Permit – Fugitive Component Leak Emissions

Permit Number: 00AD0041 [Leave blank unless APCD has already assigned a permit # & AIRS ID] **Emission Source AIRS ID:** 001 / 0229 / 006

Facility Equipment ID: **Facility Fugitives** [Provide Facility Equipment ID to identify how this equipment is referenced within your organization.]

Section 01 – Administrative Information

Company Name: **Kerr-McGee Gathering LLC**

Source Name: **Radar Compressor Station**

Source Location: **SE/4 NW/4 S 34 T2S R64W**

NAICS, or SIC Code: **1311**

County: **Adams**

Elevation: **5,390** Feet

Mailing Address: **P.O. Box 173779**
Denver, CO

ZIP Code: **80217**

Person To Contact: **Micah Carter**

Phone Number: **(720) 929-6788**

E-mail Address: **micah.carter@anadarko.com**

Fax Number: **(720) 929-7788**

Section 02 – Requested Action (Check applicable request boxes)

REC'D
12.18.2012

☐ **Request for NEW permit or newly reported emission source**

☐ **Request MODIFICATION to existing permit (check each box below that applies)**

☐ Change process or equipment ☐ Change company name

☐ Change permit limit ☐ Transfer of ownership ☐ Other

☐ **Request to limit HAPs with a Federally enforceable limit on PTE**

☒ **Request APEN update only (check the box below that applies)**

☒ Revision to actual calendar year emissions for emission inventory

☐ Update 5-Year APEN term without change to permit limits or previously reported emissions

Additional Info. & Notes: **5-yr APEN update only. Emissions calculations use factor of 1.2 on component count, per Note 3) in Construction Permit (see attached).**

Section 03 – General Information

For existing sources, operation began on: ____ / ____ / ____

For new or reconstructed sources, the projected startup date is: ____ / ____ / ____

Normal Hours of Source Operation: **24** hours/day **7** days/week **52** weeks/year

Brief description of equipment associated with these components: **Natural gas compressor station with two engines, dehy including Jatco system and 1 x 300 bbl tank**

Will this equipment be operated in any NAAQS nonattainment area? (http://www.cdphe.state.co.us/ap/attainmaintain.html) ☒ Yes ☐ No ☐ Don't know

Section 04 – Regulatory Information

Is this equipment subject to NSPS 40 CFR Part 60, Subpart KKK? ☐ Yes ☒ No ☐ Don't know

Is this equipment subject to NESHAP 40 CFR Part 63, Subpart HH? ☐ Yes ☒ No ☐ Don't know

List any other NSPS or NESHAP Subpart that applies to this equipment: ____________

Section 05 – Stream Constituents

Identify the VOC & HAP content of each applicable stream.

Stream	VOC (wt. %)	Benzene (wt. %)	Toluene (wt. %)	Ethylbenzene (wt. %)	Xylene (wt. %)	n-Hexane (wt. %)
Gas						
Heavy Oil (or Heavy Liquid)						
Light Oil (or Light Liquid)						
Water/Oil						

☒ Submit a representative gas and liquid extended analysis (including BTEX) to support emission calculations

Colorado Department of Public Health and Environment
Air Pollution Control Division (APCD)

This notice is valid for five (5) years. Submit a revised APEN prior to expiration of five-year term, or when a significant change is made (increase production, new equipment, change in fuel type, etc).

Mail this form along with a check for $152.90 to:
Colorado Department of Public Health & Environment
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, CO 80246-1530

For guidance on how to complete this APEN form:

Air Pollution Control Division: (303) 692-3150
Small Business Assistance Program (SBAP): (303) 692-3148 or (303) 692-3175

APEN forms: http://www.cdphe.state.co.us/ap/downloadforms.html

Application status: http://www.cdphe.state.co.us/ap/ss/sspcpt.html

☐ Check box to request copy of draft permit prior to issuance.

☐ Check box to request copy of draft permit prior to public notice.

FORM APCD-203

2012-12-13 RAD - APEN 5-yr Update Fugitives.doc

AIR POLLUTANT EMISSION NOTICE (APEN) & Application for Construction Permit – Fugitive Component Leak Emissions

Permit Number: 00AD0041 **Emission Source AIRS ID:** 001 / 0229 / 006

Section 06 – Location Information (Provide Datum and either Lat/Long or UTM)

Horizontal Datum (NAD27, NAD83, WGS84)	UTM Zone (12 or 13)	UTM Easting or Longitude (meters or degrees)	UTM Northing or Latitude (meters or degrees)	Method of Collection for Location Data (e.g. map, GPS, GoogleEarth)
WGS84		**-104.53645579°**	**39.83405953°**	**Google Earth**

Section 07 – Leak Detection & Repair (LDAR) & Control Information

Check appropriate boxes to identify LDAR program conducted at this site:

☐ LDAR per NSPS KKK ☐ No LDAR program

☐ Other: ______

If LDAR per NSPS KKK with 10,000 ppmv leak definition:

☐ Monthly monitoring. Control: 88% gas valve, 76% lt. liq. valve, 68% lt. liq. pump

☐ Quarterly monitoring. Control: 70% gas valve, 61% lt. liq. valve, 45% lt. liq. pump

Section 08 – Emission Factor Information

Identify the emission factor used to estimate emissions under "E.F.", along with the units relating to the emission factor (e.g. lb/hr/component).

☒ **Check this box if you used Table 2-4 of U.S. EPA's *1995 Protocol for Equipment Leak Emission Estimates* to estimate emissions. You do not need to enter the emission factors below if checked.**

Equipment Type	Service											
	Gas			Heavy Oil (or Heavy Liquid)			Light Oil (or Light Liquid)			Water/Oil		
	Count[1]	E.F.	Units	Count[1]	E.F.	Units	Count[1]	E.F.	Units	Count[1]	E.F.	Units
Connectors	1040.4			439.2			474					
Flanges	193.2			3.6			4.8					
Open-Ended Lines	70.8			22.8			19.2					
Pump Seals	0			0			1.2					
Valves	402			109.2			136.8					
Other	26.4			1.2			1.2					

[1]Count shall be the actual or estimated number of components in each type of service used to calculate the "Actual Calendar Year Emissions" below. ☒ Estimated Count ☐ Actual Count conducted on the following date: ______

Section 09 – Emissions Inventory Information & Emission Control Information

☐ **Emission Factor Documentation attached** **Data year for actual calendar year emissions below (e.g. 2007):** 2011

Pollutant	Control Device Description		Control Efficiency (% Reduction)	Emission Factor		Actual Calendar Year Emissions[2]		Requested Permitted Emissions[3]		Estimation Method or Emission Factor Source
	Primary	Secondary		Uncontrolled Basis	Units	Uncontrolled (Tons/Year)	Controlled (Tons/Year)	Uncontrolled (Tons/Year)	Controlled (Tons/Year)	
VOC	**Identify in Section 07**			**Identify in Section 08**		**8.41**				Permit 00AD0041
Benzene										
Toluene										
Ethylbenzene										
Xylene										
n-Hexane										

Please use the APCD Non-Criteria Reportable Air Pollutant Addendum form to report pollutants not listed above.

[2] Annual emission fees will be based on actual emissions reported here. If left blank, annual emission fees will be based on requested emissions.

[3] You may request permitted emissions in excess of actual emissions to account for component count and gas composition variability. If Requested Permitted Emissions is left blank, emissions will be based on info. in Sec. 03 - 09.

Section 10 – Applicant Certification - I hereby certify that all information contained herein and information submitted with this application is complete, true and correct.

Micah Carter (signature)	12/13/12	**Micah Carter**	**EHS Representative**
Signature of Person Legally Authorized to Supply Data	Date	Name of Legally Authorized Person (Please print)	Title

RADAR COMPRESSOR STATION
Facility Fugitives

Source ID Number	S006	
Equipment ID	FUG	
Source Description	Facility Fugitives	
Source Usage	N/A	
Potential Hours of Operation	8760	hr/yr

Calculation Methodology

Equipment Type	Emission Factor[1] (lb/hr/source)	Actual Source Count[2]	Source Count Factor[3]	PERMITTED EMISSIONS Based on Permit 00AD0041 % VOC	PERMITTED EMISSIONS Based on Permit 00AD0041 VOC Emissions (tpy)	ACTUAL 2011 EMISSIONS Based on 12/28/11 Gas Analysis % VOC	ACTUAL 2011 EMISSIONS Based on 12/28/11 Gas Analysis VOC Emissions (tpy)
Valves-Gas/Vapor	0.00992	335	402	38%	6.69	15%	2.62
Valves-Light Liquids	0.0055	114	136.8	100%	3.30	100%	3.30
Valves-Heavy Liquids	0.000019	91	109.2	100%	0.01	100%	0.01
Others-Gas	0.0194	22	26.4	38%	0.86	15%	0.34
Others-Heavy Oil	0.0000705	1	1.2	100%	0.00	100%	0.00
Others-Light Liquids	0.0165	1	1.2	100%	0.09	100%	0.09
Compressor Seals	0.0194	0	0	38%	0.00	15%	0.00
Pump Seals-Water/Oil	0.00529	0	0	100%	0.00	100%	0.00
Pump Seals-Light Liquids	0.02866	1	1.2	100%	0.15	100%	0.15
Pump Seals-Heavy Liquids	0.00113	0	0	100%	0.00	100%	0.00
Sample Connections	0.000243	0	0	38%	0.00	15%	0.00
Open-Ended Lines - Gas	0.00441	59	70.8	38%	0.52	15%	0.21
Open-Ended Lines - Lgt Liq	0.00309	16	19.2	100%	0.26	100%	0.26
Open-Ended Lines - Hvy Liq	0.00031	19	22.8	100%	0.03	100%	0.03
Connectors - Gas	0.00044	867	1040.4	38%	0.77	15%	0.30
Connectors - Light Liq.	0.000463	395	474	100%	0.96	100%	0.96
Connectors - Heavy Liq.	0.00002	366	439.2	100%	0.04	100%	0.04
Flanges-Gas/Vapor	0.00086	161	193.2	38%	0.28	15%	0.11
Flanges-Light Liquids	0.000243	4	4.8	100%	0.01	100%	0.01
Flanges-Heavy Liquids	0.00000086	3	3.6	100%	0.00	100%	0.00
Totals		2455	2946		13.96		8.41

[1] Oil and Gas Production Operations equipment leak emission factors (from OAQPS TTN BBS) EPA 453/R-95-017 Table 2-4, November 1995.

[2] Source Count submitted for, and used in Facility Fugitives Permit (Permit 00AD0041)

[3] Source Count multiplied by factor of 1.2 per 'Note 3)' in Facility Fugitives Permit (Permit 00AD0041)

EMPACT ANALYTICAL SYSTEMS INC.
365 S. MAIN ST.
BRIGHTON, CO
80601

303-637-0150

EXTENDED NATURAL GAS ANALYSIS (*DHA)

MAIN PAGE

PROJECT NO. :	201112177	ANALYSIS NO. :	04
COMPANY NAME :	ANADARKO	ANALYSIS DATE:	JANUARY 12, 2012
ACCOUNT NO. :		SAMPLE DATE :	DECEMBER 28, 2011
PRODUCER :		CYLINDER NO. :	476
LEASE NO. :	88124318	SAMPLED BY :	JOHN MOSER - EMPACT
NAME/DESCRIP :	RADAR COMPRESSOR RADAR DEHY INLET		
FIELD DATA		SAMPLE TEMP. :	65
SAMPLE PRES. :	225	AMBIENT TEMP.:	
VAPOR PRES. :		GRAVITY :	
COMMENTS :	SPOT; NO PROBE		

COMPONENT	MOLE %	MASS %	GPM @ 14.650	GPM @ 14.730
ALCOHOLS	0.0015	0.0036		
HELIUM	0 02	0.00	---	---
OXYGEN/ARGON	0.01	0.01	---	---
NITROGEN	1.36	1.57	---	---
CARBON DIOXIDE	2.53	4.59	---	---
METHANE	66.70650	44.11490	---	---
ETHANE	14.2732	17.6924	3.8125	3.8334
PROPANE	9.2720	16.8544	2.5517	2.5656
I-BUTANE	1.0530	2.5230	0.3445	0.3464
N-BUTANE	2.9841	7.1499	0.9394	0.9445
I-PENTANE	0.7728	2.2944	0.2794	0.2809
N-PENTANE	0.7173	2.1334	0.2594	0.2608
HEXANES PLUS	0.2996	1.0640	0.1180	0.1186
TOTALS	100.00000	100.00000	8.3049	8.3502

BTEX COMPONENTS	MOLE%	WT%
BENZENE	0.0186	0.0599
TOLUENE	0.0017	0.0065
ETHYLBENZENE	0.0000	0.0000
XYLENES	0.0001	0.0005
TOTAL BTEX	0.0204	0.0669

BTU @	14.650	14.730
LOW NET DRY REAL :	1243.7 /scf	1250.5 /scf
NET WET REAL :	1222.0 /scf	1228.8 /scf
HIGH GROSS DRY REAL :	1366.9 /scf	1374.4 /scf
GROSS WET REAL :	1343.0 /scf	1350.5 /scf
NET DRY REAL :	19457.3 /lb	19563.6 /lb
GROSS DRY REAL :	21383.3 /lb	21500.1 /lb

RELATIVE DENSITY (AIR=1).	0.8376
COMPRESSIBILITY FACTOR :	0.99542

(CALC· GPA STD 2145 & TP-17 @14 696 & 60 F)

**(DETAILED HYDROCARBON ANALYSIS NJ 1993) ; ASTM D6730*

THIS DATA HAS BEEN ACQUIRED THROUGH APPLICATION OF CURRENT STATE-OF-THE-ART ANALYTICAL TECHNIQUES THE USE OF THIS INFORMATION IS THE RESPONSIBLITY OF THE USER. EMPACT ANALYTICAL SYSTEMS, ASSUMES NO RESPONSIBLITY FOR ACCURACY OF THE REPORTED INFORMATION NOR ANY CONSEQUENCES OF IT'S APPLICATION

EMPACT ANALYTICAL SYSTEMS INC.
365 S. MAIN ST.
BRIGHTON, CO
80601

303-637-0150

EXTENDED NATURAL GAS ANALYSIS (*DHA)

GLYCALC INFORMATION

PROJECT NO. :	201112177	ANALYSIS NO. :	04
COMPANY NAME :	ANADARKO	ANALYSIS DATE:	JANUARY 12, 2012
ACCOUNT NO. :		SAMPLE DATE :	DECEMBER 28, 2011
PRODUCER :		CYLINDER NO. :	476
LEASE NO. :	88124318	SAMPLED BY :	JOHN MOSER - EMPACT
NAME/DESCRIP :	RADAR COMPRESSOR RADAR DEHY INLET		
FIELD DATA		SAMPLE TEMP. :	65
SAMPLE PRES. :	225	AMBIENT TEMP.:	
VAPOR PRES. :		GRAVITY :	
COMMENTS :	SPOT; NO PROBE		

Componet	Mole %	Wt %
Helium	0.02	0.00
Carbon Dioxide	2.53	4.59
Nitrogen	1.36	1.57
Methane	66.70650	44.11490
Ethane	14.2732	17.6924
Propane	9.2720	16.8544
Isobutane	1.0530	2.5230
n-Butane	2.9841	7.1499
Isopentane	0.7232	2.1510
n-Pentane	0.7173	2.1334
Cyclopentane	0.0496	0.1434
n-Hexane	0.0664	0.2359
Cyclohexane	0.0192	0.0666
Other Hexanes	0.1762	0.6228
Heptanes	0.0128	0.0524
Methycyclohexane	0.0038	0.0154
2,2,4 Trimethylpentane	0 0000	0.0000
Benzene	0.0186	0.0599
Toluene	0.0017	0.0065
Ethylbenzene	0 0000	0.0000
Xylenes	0.0001	0.0005
C8+ Heavies	0.0008	0.0040
Subtotal	99.98850	99.98640
Oxygen/Argon	0.01	0.01
Alcohols	0.0015	0.0036
Total	100.00000	100.00000

THE DATA PRESENTED HEREIN HAS BEEN ACQUIRED THROUGH JUDICIOUS APPLICATION OF CURRENT STATE-OF-THE ART ANALYTICAL TECHNIQUES THE APPLICATIONS OF THIS INFORMATION IS THE RESPONSIBILITY OF THE USER. EMPACT ANALYTICAL SYSTEMS, INC ASSUMES NO RESPONSIBILITY FOR ACCURACY OF THE REPORTED INFORMATION NOR ANY CONSEQUENCES OF IT'S APPLICATION.

EMPACT

EXTENDED NATURAL GAS ANALYSIS (*DHA)

DHA COMPONENT LIST

PROJECT NO. :	201112177	ANALYSIS NO :	04
COMPANY NAME :	ANADARKO	ANALYSIS DATE:	JANUARY 12, 2012
ACCOUNT NO. :		SAMPLE DATE .	DECEMBER 28, 2011
PRODUCER :		CYLINDER NO. .	476
LEASE NO. :	88124318	SAMPLED BY :	JOHN MOSER - EMPACT
NAME/DESCRIP :	RADAR COMPRESSOR RADAR DEHY INLET		
FIELD DATA		SAMPLE TEMP. :	65
SAMPLE PRES. :	225	AMBIENT TEMP.:	
VAPOR PRES. :		GRAVITY :	
COMMENTS :	SPOT; NO PROBE		

COMPONENT	PIANO #	MOLE %	MASS %	GPM @ 14.650	GPM @ 14.730
Helium	---	0.02	0.00	---	---
Oxygen/Argon	---	0.01	0.01	---	---
Nitrogen	---	1.36	1.57	---	---
Carbon Dioxide	---	2.53	4.59	---	---
Methane	P1	66.70650	44.11490	---	---
Ethane	P2	14.2732	17.6924	3.813	3.833
Propane	P3	9.2720	16.8544	2.552	2.566
i-Butane	I4	1.0530	2.5230	0.345	0.346
n-Butane	P4	2.9841	7.1499	0.939	0 945
2,2-Dimethylpropane	I5	0.0049	0.0146	0.002	0.002
Ethanol	X2	0.0002	0.0004	0.000	0.000
i-Pentane	I5	0.7183	2.1364	0.262	0.264
Acetone	X3	0.0012	0.0029	0 000	0.000
n-Pentane	P5	0.7173	2.1334	0.259	0.261
t-Butanol	X4	0.0001	0.0003	0 000	0.000
2,2-Dimethylbutane	I6	0.0054	0.0192	0.002	0.002
Cyclopentane	N5	0 0496	0.1434	0.015	0.015
2,3-Dimethylbutane	I6	0.0156	0.0554	0.006	0.006
2-Methylpentane	I6	0.0797	0.2831	0.033	0.033
3-Methylpentane	I6	0.0381	0.1353	0.016	0.016
n-Hexane	P6	0.0664	0.2359	0.027	0.027
2,2-Dimethylpentane	I7	0.0005	0 0021	0.000	0.000
Methylcyclopentane	N6	0.0374	0.1298	0.013	0 013
2,4-Dimethylpentane	I7	0.0012	0.0050	0.001	0.001
2,2,3-Trimethylbutane	I7	0.0001	0.0004	0.000	0 000
Benzene	A6	0.0186	0.0599	0.005	0.005
3,3-Dimethylpentane	I7	0.0002	0.0008	0.000	0.000
Cyclohexane	N6	0.0192	0.0666	0.007	0.007
2-Methylhexane	I7	0 0019	0.0078	0.001	0.001
2,3-Dimethylpentane	I7	0.0007	0.0029	0.000	0.000
1,1-Dimethylcyclopentane	N7	0 0010	0.0040	0.000	0.000
3-Methylhexane	I7	0.0017	0 0070	0.001	0.001
1c,3-Dimethylcyclopentane	N7	0.0011	0 0045	0.001	0.001
1t,3-Dimethylcyclopentane	N7	0.0009	0.0036	0.000	0.000
3-Ethylpentane	I7	0.0001	0.0004	0.000	0.000
1t,2-Dimethylcyclopentane	N7	0.0013	0.0053	0.001	0.001

EMPACT Analytical Systems, Inc 365 S Main Street, Brighton, CO 80601 303-637-0150

n-Heptane	P7	0.0019	0.0078	0.001	0 001
1c,2-Dimethylcyclopentane	N7	0.0001	0.0004	0.000	0.000
Methylcyclohexane	N7	0.0038	0.0154	0.002	0 002
2,2-Dimethylhexane	I8	0.0001	0 0005	0.000	0.000
Ethylcyclopentane	N7	0.0001	0.0004	0.000	0.000
2,4-Dimethylhexane	I8	0.0001	0.0005	0.000	0.000
1c,2t,4-Trimethylcyclopentane	N8	0.0001	0.0005	0.000	0.000
1t,2c,4-Trimethylcyclopentane	N8	0.0001	0.0005	0.000	0.000
Toluene	A7	0.0017	0.0065	0.001	0.001
2-Methylheptane	I8	0.0001	0.0005	0.000	0.000
1c,2t,3-Trimethylcyclopentane	N8	0.0001	0.0005	0.000	0.000
1t,4-Dimethylcyclohexane	N8	0.0001	0.0005	0.000	0.000
n-Octane	P8	0 0001	0.0005	0 000	0.000
1,3-Dimethylbenzene (m-Xylene)	A8	0 0001	0.0005	0.000	0.000
TOTAL		100 00000	100 00000	8.3049	8.3502

BTEX COMPONENTS	MOLE%	WT%
BENZENE	0.0186	0.0599
TOLUENE	0.0017	0.0065
ETHYLBENZENE	0.0000	0.0000
XYLENES	0.0001	0.0005
TOTAL BTEX	0.0204	0.0669

	BTU @	14.650	14.730
LOW	NET DRY REAL :	1243.7 /scf	1250.5 /scf
	NET WET REAL :	1222.0 /scf	1228.8 /scf
HIGH	GROSS DRY REAL :	1366.9 /scf	1374.4 /scf
	GROSS WET REAL :	1343.0 /scf	1350.5 /scf
	NET DRY REAL :	19457.3 /lb	19563.6 /lb
	GROSS DRY REAL :	21383.3 /lb	21500.1 /lb

RELATIVE DENSITY (AIR=1): 0.8376
COMPRESSIBILITY FACTOR : 0.99542

(CALC· GPA STD 2145 & TP-17 @14 696 & 60 F)
•(DETAILED HYDROCARBON ANALYSIS NJ 1993) , ASTM D6730
THIS DATA HAS BEEN ACQUIRED THROUGH APPLICATION OF CURRENT STATE-OF-THE-ART ANALYTICAL TECHNIQUES
THE USE OF THIS INFORMATION IS THE RESPONSIBLITY OF THE USER EMPACT ANALYTICAL SYSTEMS, ASSUMES NO RESPONSIBLITY FOR ACCURACY OF THE REPORTED INFORMATION NOR ANY CONSEQUENCES OF IT'S APPLICATION.

EDF-WZI-APPENDIX X

Available Upon Request

EDF-WZI-APPENDIX XI

Leak Detection and Repair Cost Analysis

Assuming 200 Statewide Compressor Stations (CS)

				Method 21 Inspections					FLIR camera- 50% time savings over Method 21								VOC Emissions			Methane-Ethane Emissions		
CS Tiers based on Fugitive VOCs from Components	CS Number in each Tier	Annual Inspection Frequency	Hourly Inspection Rate	Inspection Hours for each CS	Total Inspection Hours for each CS Tier	Total Inspection Costs for each CS Tier	VOC Control Costs [$/ton]	Methane-Ethane Control Costs [$/ton]	Inspection Hours for each CS	Total Inspection Hours for each CS Tier	Total Inspection Costs for each CS Tier	VOC Control Costs [$/ton]	Number of Inspection Hours per Composite Model Compressor Stations	Total Number of Inspection Hours for listed Compressor Stations	Methane-Ethane Control Costs [$/ton]	LDAR Program Effective-ness	Fugitive VOC Emissions for each CS [tpy]	LDAR Program VOC Emission Reduction for each CS [tpy]	Total VOC Emission Reduction for each CS Tier [tpy]	Fugitive Methane-Ethane Emissions for each CS [tpy]	LDAR Program Methane-Ethane Emission Reduction for each CS [tpy]	Total Methane-Ethane Emission Reduction for each CS Tier [tpy]
<= 12 tpy VOC	147.0	1	$ 99.0	21.20	3,116.4	$ 308,524	$ 610	$ 309	10.60	1,558.2	$ 154,262	$ 305	4.2	623	$ 154	40%	8.60	3.44	505.7	17.0	6.8	999.6
>12 to <=50 tpy VOC	53.0	4	$ 99.0	56.20	11,914.4	$ 1,179,526	$ 2,262	$ 837	28.10	5,957.2	$ 589,763	$ 1,131	11.2	1,191	$ 419	60%	16.40	9.84	521.5	44.3	26.6	1,408.7
over 50 tpy VOC	-	12	$ 99.0	-	-	$ -	$ -	$ -	-	-	$ -	$ -	-	-	$ -	80%	-	-	-	-	-	-
	200.0				**15,030.8**	**$ 1,488,049.2**	**$ 1,449**	**$ 618**		**7,515.4**	**$ 744,024.6**	**$ 724**		**1,815**	**$ 309**				**1,027.2**			**2,408.3**

Number of Staff: 1

Leak Detection And Repair (LDAR) Cost Analysis				
Item	Capital Costs (one time)	Non Recurring (one time)	Annual Costs (recurring)	Annualized Total Cost (5 yrs)
FLIR Camera:	$122,000			
Photo Ionization Detector	$5,000			
Vehicle	$22,000			
Inspection Staff:			$ 75,000	
Supervision (@20%):			$ 15,000	
Overhead (@10%):			$ 7,500	
Travel(@15%):			$ 11,250	
Recordkeeping (@10%):			$ 7,500	
Reporting (@10%):			$ 7,500	
Fringe (@30%):			$ 22,500.0	
Subtotal Costs:	$149,000	$0	$146,250	
Annualized Costs:	$39,879.1	$0.0	$146,250	**$186,129**

Hourly Total Cost

Assumptions
52 weeks/yr
10 holidays
2 weeks vacation
1 week sick
40 hour work week

Total annual working hours: 1880

Total Hourly Rate: $99.00

Cost Amortization Calculations: Annual LDAR				
Life/YRS	Equipment Costs (one-time)	Non Recurring (one time)	O&M (recurring)	Annualized Total Cost (15 yrs)
0	$149,000	$0	$146,250	
1	$157,940			
2	$167,416			
3	$177,461			
4	$188,109			
5	$199,396			
Annualized (5 yr):	$39,879	$0	$146,250	$186,129

Assumptions: Equipment Life = 5 yrs; Interest Rate* = 6%
*If the equipment was not purchased, the money could earn 6% per year

Compressor Station - Fugitive Emissions from Component Leaks

Based on: 30 APCD Form 203 APENs

#	Company	Source	AIRS ID	Uncont. Fugitive VOCs	Total CS Horsepower	Gas Service Count: VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	Light Oil Service Count: VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	TOTAL
1	Kerr-McGee Gathering LLC	Taylor CS	001-1733-002	2.5	180	39.07%	305	141	2	-	75	-	99.79%	101	14	-	-	24	-	
2	Bargath LLC	Greasewood CS	103-0248-006	2.9	5,865	5.80%	870	198	-	-	254	42	100.00%	138	34	-	4	46	-	
3	Encana Oil & Gas	East Dragon Trail CS	103-0016-006	3.0	5,354	24.11%	-	548	-	12	199	20								
4	Bargath LLC	Cottonwood Point CS	045-0689-006	3.1	9,185	7.20%	870	198	-	24	254	18	100.00%	138	34	-	4	46	-	
5	Axia Energy	Taylor CS	077-0546-008	4.2	766	5.89%	1,320	214	47	-	284	28	100.00%	214	88	8	2	71	4	
6	Kerr-McGee Gathering LLC	Third Creek CS	029-0087-003	5.2	552	33.99%	125	255	293	-	-	14	99.46%	35	68	34	6	-	-	
7	Kerr-McGee Gathering LLC	Aristocrat CS	123-0127-013	5.3	2,143	29.43%	896	306	8	-	172	-	99.74%	265	25	-	-	89	-	
8	DCP Midstream, LP	West Arapahoe CS	017-0215-004	5.3	761	33.61%	599	97	22	-	129	13	100.00%	123	51	4	2	41	2	
10	Encana Oil & Gas	Deer Creek CS	045-2235-004	5.9	675	10.43%	699	135	20	-	132	21	100.00%	328	37	7	4	65	1	
11	Kerr-McGee Gathering LLC	Ione CS	123-1351-006	6.6	2,102	25.56%	795	357	8	-	229	-	99.58%	275	33	-	-	123	-	
12	Bargath LLC	Starky Gulch CS	045-0229-006	8.0	8,191	9.44%	1,634	929	-	29	616	32	100.00%	679	74	-	-	121	-	
13	DCP Midstream, LP	Wells Ranch CS (new)	123-9950-006	8.0	6,720	24.74%	1,422	213	51	-	306	31	100.00%	217	89	8	2	72	4	
14	DCP Midstream, LP	Godfrey Bottom CS	123-9010-006	8.0	5,040	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4	
15	DCP Midstream, LP	Sullivan CS	123-9009-006	8.0	6,720	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4	
16	DCP Midstream, LP	Libsak CS	123-9008-006	8.0	6,720	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4	
17	Kerr-McGee Gathering LLC	Radar CS	001-0229-006	8.4	730	15.00%	1,040	193	71	-	402	26	100.00%	474	5	19	1	137	1	
18	Kerr-McGee Gathering LLC	Dragoon CS	005-0051-008	8.9	694		1,377	182	94	6	212	100								
19	Antero Resources Pipeline Co.	Hunter Mesa CS	045-1647-014	10.3	11,760	11.96%	1,042	364	-	32	684	50	100.00%	219	6	-	8	162	-	
20	OXY USA WTP LP	Mesa CS (permit app ca	045-2148-023	11.0	21,904	3.50%	2,106	539	-	-	696	58	29.20%	3,112	481	-	14	941	21	
21	Antero Resources Pipeline Co.	Dry Hollow CS (new)	045-2201-012	11.5	11,760	14.12%	2,224	438	-	-	555	87	100.00%	464	142	-	15	136	-	
22	OXY USA Inc.	East Plateau CS	077-0414-017	11.6	5,360	15.00%	2,744	234	-	-	503	74	100.00%	489	-	-	3	123	12	
23	Kerr-McGee Gathering LLC	Mitchell CS	005-1113-007	12.0	1,447		2,673	367	4	6	294	24								
						11%														
			<=12 VOC Average:	***7.2***	***5,210***	***19.2%***	***1,228***	***300***	***35***	***5***	***314***	***33***	***96.2%***	***417***	***76***	***5***	***4***	***127***	***3***	***2,548***
			Each Component Category - Annual VOC Emissions [tons/year]:				***0.45***	***0.22***	***0.13***	***0.02***	***2.62***	***0.54***		***0.81***	***0.08***	***0.07***	***0.45***	***2.95***	***0.21***	***8.6***
			Each Component Category - Inspection Time [Hours]:				***10.2***	***2.5***	***0.3***	***0.0***	***2.6***	***0.3***		***3.5***	***0.6***	***0.0***	***0.0***	***1.1***	***0.0***	***21.2***
			Each Component Category - Annual C1-C2 Emissions [tons/year]:				***1.92***	***0.91***	***0.55***	***0.09***	***11.04***	***2.28***		***0.03***	***0.00***	***0.00***	***0.02***	***0.12***	***0.01***	***17.0***
24	Bargath LLC	Wheeler Gulch CS	045-1030-009	13.8	5,865	13.80%	1,924	514	-	-	468	64	100.00%	1,901	123	-	-	203	8	
25	OXY USA Inc.	Alkali Creek CS	077-0447-013	15.0	5,079	15.00%	2,199	210	-	-	364	41	100.00%	810	72	-	6	262	14	
26	Hunter Ridge Energy	Story Gulch CS	045-1997-009	15.2	26,172	6.28%	2,240	444	58	-	410	69	100.00%	1,086	81	24	8	207	4	
27	ETC Canyon Pipeline, LLC	Holmes Mesa CS	045-1675-006	19.0	14,064	8.06%	3,107	780	-	-	843	61	100.00%	1,773	218	-	6	392	12	
28	Grand River Gathering LLC	Orchard CS	045-0895-003	20.3	3,945	6.68%	2,366	456	63	-	490	67	100.00%	1,244	97	27	10	258	10	
29	Encana Oil & Gas	Middle Fork CS (permits	045-0790-004	23.2	7,385	6.82%	3,137	582	81	-	605	99	100.00%	1,549	161	28	22	311	8	
30	Piceance Energy LLC	MVS CS	077-0452-004	29.3	18,027	11.48%	5,448	1,428	43	-	1,096	481	99.66%	264	65	3	-	56	17	
9	Bill Barret Corp	Bailey CS	045-1477-007	30.8	23,035	20.00%	7,073	1,232	-	-	1,200	71	100.00%	2,311	85	5	5	397	-	
			>12 to ≤ 50 tpy VOC Average:	***20.8***	***12,947***	***11.0%***	***3,437***	***706***	***31***	***-***	***685***	***119***	***100.0%***	***1,367***	***113***	***11***	***7***	***261***	***9***	***6,745***
			Each Component Category - Annual VOC Emissions [tons/year]:				***0.73***	***0.29***	***0.07***	***-***	***3.28***	***1.12***		***2.77***	***0.12***	***0.15***	***0.89***	***6.29***	***0.66***	***16.4***
			Each Component Category - Inspection Time [Hours]:				***28.6***	***5.9***	***0.3***	***-***	***5.7***	***1.0***		***11.4***	***0.9***	***0.1***	***0.1***	***2.2***	***0.1***	***56.2***
			Each Component Category - Annual C1-C2 Emissions [tons/year]:				***5.91***	***2.37***	***0.53***	***-***	***26.47***	***9.01***		***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***44.3***

Compressor Station - Component Fugitive Leak EPA Emission Factors

	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
Each Component TOC Emission Factor [1] [kg/hr]:	***2.00E-04***	***3.90E-04***	***2.00E-03***	***2.40E-03***	***4.50E-03***	***8.80E-03***	***2.10E-04***	***1.10E-04***	***1.40E-03***	***1.30E-02***	***2.50E-03***	***7.50E-03***
100% VOC factors [lb/hr/comp]:	0.000032	0.000062	0.000318	0.000381	0.000714	0.001397						

[1] See Table 2-4 "Oil and Gas Production Operations Average Emission Factors" EPA Protocol for Equipment Leak Emission Estimates, November 1996, EPA-453/R-95-017

Compressor Station - LDAR Inspection Time

Assume EPA Method 21 LDAR

Average Time-On-Leak per component [seconds]: 30

Compressor Station - Fugitive Component Leak Emissions

Composite Model based on - 30 APCD Form 203 APENs

	Company	Source	AIRS ID	Uncontrolled Fugitive VOCs	Total CS Horsepower	Gas Service Count							Light Oil Service Count						
						VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
1	Kerr-McGee Gathering LLC	Taylor CS	001-1733-002	2.5	180	39.07%	305	141	2	-	75	-	99.79%	101	14	-	-	24	-
2	Bargath LLC	Greasewood CS	103-0248-006	2.9	5,865	5.80%	870	198	-	-	254	42	100.00%	138	34	-	4	46	-
3	Encana Oil & Gas	East Dragon Trail CS	103-0016-006	3.0	5,354	24.11%	-	548	-	12	199	20							
4	Bargath LLC	Cottonwood Point CS	045-0689-006	3.1	9,185	7.20%	870	198	-	24	254	18	100.00%	138	34	-	4	46	-
5	Axia Energy	Taylor CS	077-0546-008	4.2	766	5.89%	1,320	214	47	-	284	28	100.00%	214	88	8	2	71	4
6	Kerr-McGee Gathering LLC	Third Creek CS	029-0087-003	5.2	552	33.99%	125	255	293	-	-	14	99.46%	35	68	34	6	-	-
7	Kerr-McGee Gathering LLC	Aristocrat CS	123-0127-013	5.3	2,143	29.43%	896	306	8	-	172	-	99.74%	265	25	-	-	89	-
8	DCP Midstream, LP	West Arapahoe CS	017-0215-004	5.3	761	33.61%	599	97	22	-	129	13	100.00%	123	51	4	2	41	2
9	Encana Oil & Gas	Deer Creek CS	045-2235-004	5.9	675	10.43%	699	135	20	-	132	21	100.00%	328	37	7	4	65	1
10	Kerr-McGee Gathering LLC	Ione CS	123-1351-006	6.6	2,102	25.56%	795	357	8	-	229	-	99.58%	275	33	-	-	123	-
11	Bargath LLC	Starky Gulch CS	045-0229-006	8.0	8,191	9.44%	1,634	929	-	29	616	32	100.00%	679	74	-	-	121	-
12	DCP Midstream, LP	Wells Ranch CS (new)	123-9950-006	8.0	6,720	24.74%	1,422	213	51	-	306	31	100.00%	217	89	8	2	72	4
13	DCP Midstream, LP	Godfrey Bottom CS	123-9010-006	8.0	5,040	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4
14	DCP Midstream, LP	Sullivan CS	123-9009-006	8.0	6,720	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4
15	DCP Midstream, LP	Libsak CS	123-9008-006	8.0	6,720	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4
16	Kerr-McGee Gathering LLC	Radar CS	001-0229-006	8.4	730	15.00%	1,040	193	71	-	402	26	100.00%	474	5	19	1	137	1
17	Kerr-McGee Gathering LLC	Dragoon CS	005-0051-008	8.9	694	100.00%	1,377	182	94	6	212	100							
18	Antero Resources Pipeline Co.	Hunter Mesa CS	045-1647-014	10.3	11,760	11.96%	1,042	364	-	32	684	50	100.00%	219	6	-	8	162	-
19	OXY USA WTP LP	Mesa CS (permit app ca	045-2148-023	11.0	21,904	3.50%	2,106	539	-	-	696	58	29.20%	3,112	481	-	14	941	21
20	Antero Resources Pipeline Co.	Dry Hollow CS (new)	045-2201-012	11.5	11,760	14.12%	2,224	438	-	-	555	87	100.00%	464	142	-	15	136	-
21	OXY USA Inc.	East Plateau CS	077-0414-017	11.6	5,360	15.00%	2,744	234	-	-	503	74	100.00%	489	-	-	3	123	12
22	Kerr-McGee Gathering LLC	Mitchell CS	005-1113-007	12.0	1,447	100.00%	2,673	367	4	6	294	24							
23	Bargath LLC	Wheeler Gulch CS	045-1030-009	13.8	5,865	13.80%	1,924	514	-	-	468	64	100.00%	1,901	123	-	-	203	8
24	OXY USA Inc.	Alkali Creek CS	077-0447-013	15.0	5,079	15.00%	2,199	210	-	-	364	41	100.00%	810	72	-	6	262	14
25	Hunter Ridge Energy	Story Gulch CS	045-1997-009	15.2	26,172	6.28%	2,240	444	58	-	410	69	100.00%	1,086	81	24	8	207	4
26	ETC Canyon Pipeline, LLC	Holmes Mesa CS	045-1675-006	19.0	14,064	8.06%	3,107	780	-	-	843	61	100.00%	1,773	218	-	6	392	12
27	Grand River Gathering LLC	Orchard CS	045-0895-003	20.3	3,945	6.68%	2,366	456	63	-	490	67	100.00%	1,244	97	27	10	258	10
28	Encana Oil & Gas	Middle Fork CS (permits	045-0790-004	23.2	7,385	6.82%	3,137	582	81	-	605	99	100.00%	1,549	161	28	22	311	8
29	Piceance Energy LLC	MVS CS	077-0452-004	29.3	18,027	11.48%	5,448	1,428	43	-	1,096	481	99.66%	264	65	3	-	56	17
30	Bill Barret Corp	Bailey CS	045-1477-007	30.8	23,035	20.00%	7,073	1,232	-	-	1,200	71	100.00%	2,311	85	5	5	397	-
			CS Average:	*10.8*	*7,273*														
	Composite Model Compressor Station - Average Components [number]:						*1,817*	*408*	*34*	*4*	*413*	*56*		*699*	*87*	*7*	*5*	*167*	*5*
				Average Gas Service VOC percent:		*22.4%*					*Average Light Oil Service VOC percent:*		*97.3%*						

Composite Model Compressor Station - VOC Emissions

	Gas: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	Light Oil: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
Each Component TOC Emission Factor [1] [kg/hr]:	*2.00E-04*	*3.90E-04*	*2.00E-03*	*2.40E-03*	*4.50E-03*	*8.80E-03*	*2.10E-04*	*1.10E-04*	*1.40E-03*	*1.30E-02*	*2.50E-03*	*7.50E-03*
100% VOC factors [lb/hr/comp]:	0.000032	0.000062	0.000318	0.000381	0.000714	0.001397						
Each Component VOC Emission Factor [kg/hr]:	*4.47E-05*	*8.73E-05*	*4.47E-04*	*5.37E-04*	*1.01E-03*	*1.97E-03*	*2.04E-04*	*1.07E-04*	*1.36E-03*	*1.27E-02*	*2.43E-03*	*7.30E-03*
Component Annual VOC Emissions [tons/year]:	*0.79*	*0.34*	*0.15*	*0.02*	*4.02*	*1.07*	*1.38*	*0.09*	*0.09*	*0.58*	*3.91*	*0.34*
Composite Model Compressor Station - Total Annual VOC Emissions [tpy]:	***12.8***											

[1] See Table 2-4 "Oil and Gas Production Operations Average Emission Factors" EPA Protocol for Equipment Leak Emission Estimates, November 1996, EPA-453/R-95-017

Composite Model Compressor Station - Methane/Ethane Emissions

	Gas: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	Light Oil: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
Each Component C1-C2 Emission Factor [kg/hr]:	*1.55E-04*	*3.03E-04*	*1.55E-03*	*1.86E-03*	*3.49E-03*	*6.83E-03*	*5.64E-06*	*2.96E-06*	*3.76E-05*	*3.49E-04*	*6.72E-05*	*2.02E-04*
Component Annual VOC Emissions [tons/year]:	*2.72*	*1.19*	*0.51*	*0.07*	*13.93*	*3.70*	*0.04*	*0.00*	*0.00*	*0.02*	*0.11*	*0.01*
Composite Model Compressor Station - Total Annual Methane/Ethane Emissions [tpy]:	***22.3***											

Composite Model Compressor Station - LDAR Inspection Time

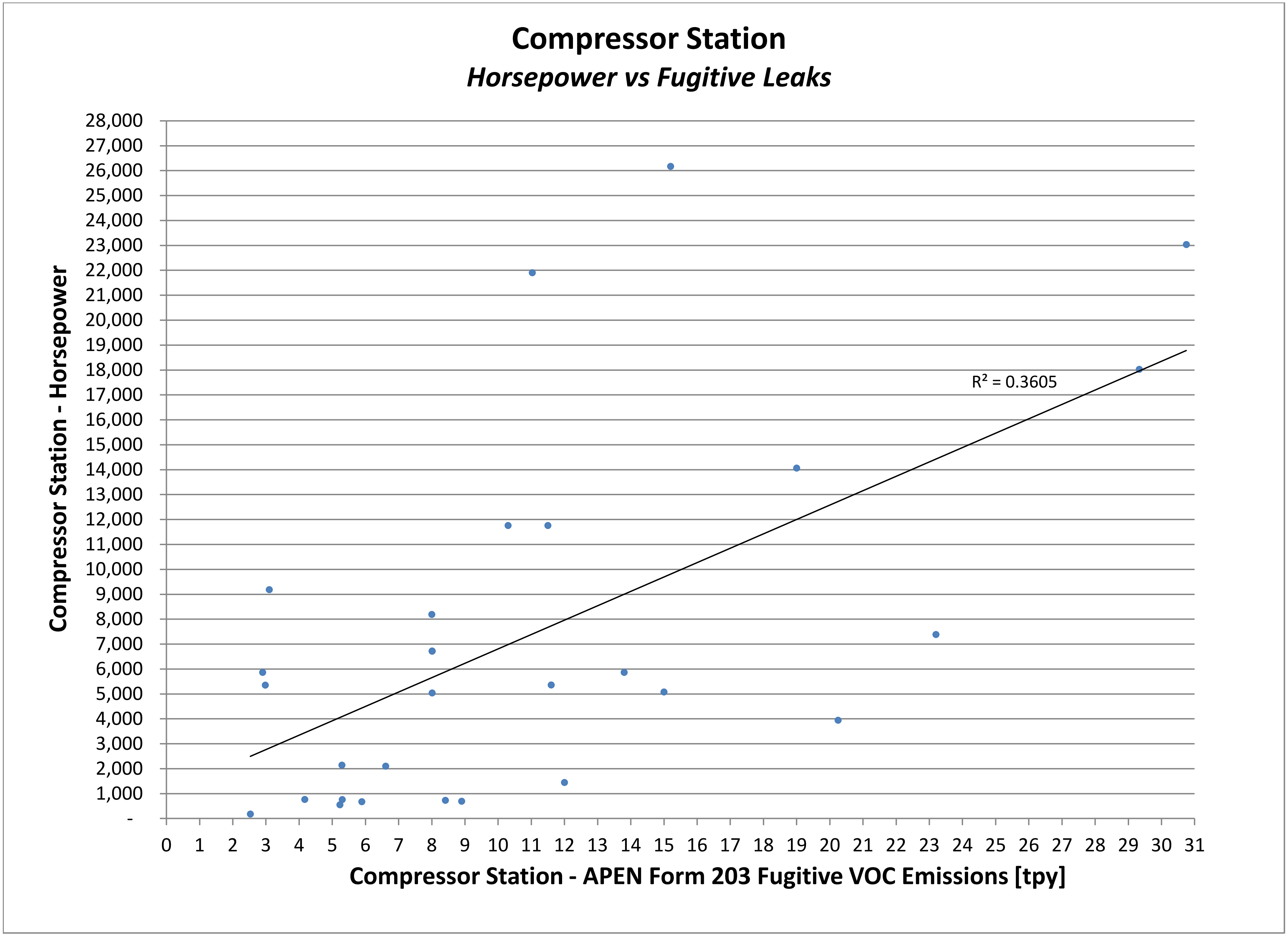
Assume EPA Method 21 LDAR — *Average Time-On-Leak per component [seconds]:* 30

LDAR with FLIR — *Average Inspection Time Reduction Incurred from FLIR [%]:* 50% | 80% | 90%

	Gas: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	Light Oil: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
Each component category - Total Time [minutes]:	908	204	17	2	207	28	349	44	4	2	83	2
Compressor Station - Total Inspection Time [minutes]:	1,848											

Composite Model Compressor Station - Total Inspection Time [hours]: **30.8**

Total Inspection Time with FLIR [hours]: **15.4** (50%) | **6.2** (80%) | **3.1** (90%)



Compressor Station
Horsepower vs Fugitive Leaks
28,000
27,000
26,000
25,000
24,000
23,000
22,000
21,000
20,000
19,000
18,000
17,000
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0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
$R^2 = 0.3605$
Compressor Station - Horsepower
Compressor Station - APEN Form 203 Fugitive VOC Emissions [tpy]

EDF-WZI-APPENDIX XII

Lessons Learned
from Natural Gas STAR Partners

Installing Plunger Lift Systems In Gas Wells

Executive Summary

In mature gas wells, the accumulation of fluids in the well can impede and sometimes halt gas production. Gas flow is maintained by removing accumulated fluids through the use of a beam pump or remedial treatments, such as swabbing, soaping, or venting the well to atmospheric pressure (referred to as "blowing down" the well). Fluid removal operations, particularly well blowdowns, may result in substantial methane emissions to the atmosphere.

Installing a plunger lift system is a cost-effective alternative for removing liquids. Plunger lift systems have the additional benefit of increasing production, as well as significantly reducing methane emissions associated with blowdown operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Natural Gas STAR Partners report significant economic benefits and methane emission reductions from installing plunger lift systems in gas wells. Companies have reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well by avoiding blowdowns. In addition, increased gas production following plunger lift installation has yielded total gas benefits of up to 18,250 Mcf per well, worth an estimated $127,750. Benefits from both increased gas production and emissions savings are well- and reservoir-specific and will vary considerably.

Technology Background

Liquid loading of the wellbore is often a serious problem in aging production wells. Operators commonly use beam lift pumps or remedial techniques, such as venting or "blowing down" the well to atmospheric pressure, to remove liquid buildup and restore well productivity. These techniques, however, result in gas losses. In the case of blowing down a well, the process must be repeated over time as fluids reaccumulate, resulting in additional methane emissions.

Plunger lift systems are a cost-effective alternative to both beam lifts and well blowdowns and can significantly reduce gas losses, eliminate or reduce the frequency of future well treatments, and improve well productivity. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface. The plunger serves as a piston between the liquid and the gas, which minimizes liquid fallback, and as a scale and paraffin scraper. Exhibit 1 depicts a typical plunger lift system.

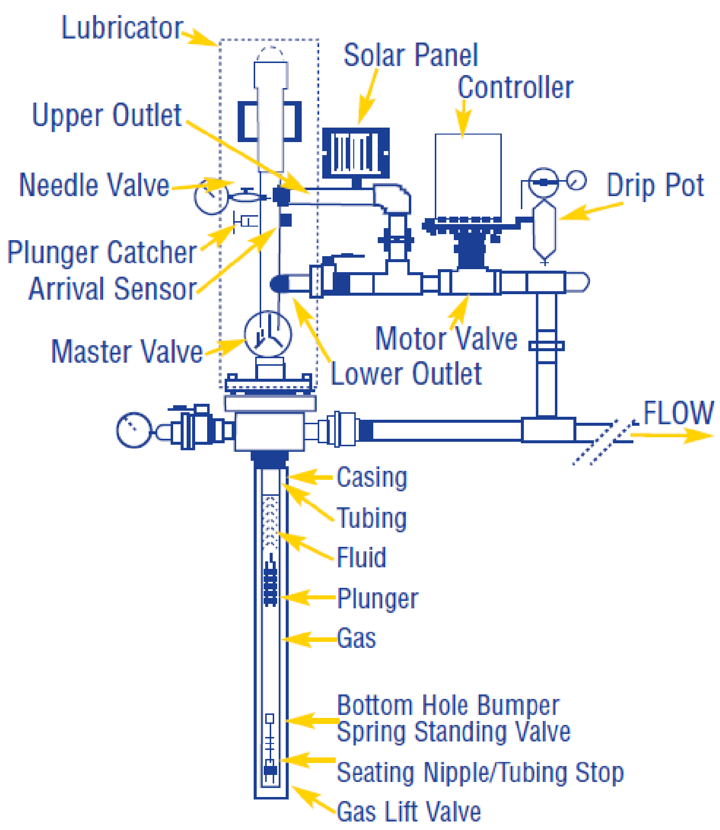
The operation of a plunger lift system relies on the natural buildup of pressure in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must be sufficiently higher than the sales-line pressure to lift the plunger and liquid load to the surface. A valve mechanism, controlled by a microprocessor, regulates gas input to the casing and automates the process. The controller is normally powered by a solar recharged battery and can be a simple timer-cycle or have solid state

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Potential Gas Savings from Increased Gas Production and Avoided Emissions (Mcf)	Value of Natural Gas Production and Savings ($)			Implementation Cost ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Install a Plunger Lift System	4,700 - 18,250[a] per year per well	$14,100 - $54,750 per year	$23,500 - $91,250 per year	$32,900 - $127,750 per year	$2,591 - $10,363 per year per well	1 - 9	1 - 6	1 - 4

General Assumptions:
[a] Based on results reported by Natural Gas STAR Partners.

Exhibit 1: Plunger Lifts



memory and programmable functions based on process sensors.

Operation of a typical plunger lift system involves the following steps:

1. The plunger rests on the bottom hole bumper spring located at the base of the well. As gas is produced to the sales line, liquids accumulate in the well-bore, creating a gradual increase in backpressure that slows gas production.

2. To reverse the decline in gas production, the well is shut-in at the surface by an automatic controller. This causes well pressure to increase as a large volume of high pressure gas accumulates in the annulus between the casing and tubing. Once a sufficient volume of gas and pressure is obtained, the plunger and liquid load are pushed to the surface.

3. As the plunger is lifted to the surface, gas and accumulated liquids above the plunger flow through the upper and lower outlets.

4. The plunger arrives and is captured in the lubricator, situated across the upper lubricator outlet.

5. The gas that has lifted the plunger flows through the lower outlet to the sales line.

6. Once gas flow is stabilized, the automatic controller releases the plunger, dropping it back down the tubing.

7. The cycle repeats.

New information technology systems have streamlined plunger lift monitoring and control. For example, technologies such as smart automation, online data management and satellite communications allow operators to control plunger lift systems remotely, without regular field visits. Operators visit only the wells that need attention, which increases efficiency and reduces cost. For more information regarding this technology and other artificial lift systems, see the Lessons Learned document titled "Options for Removing Accumulated Fluid and Improving Flow in Gas Wells".

Economic and Environmental Benefits

The installation of a plunger lift system serves as a cost-effective alternative to beam lifts and well blowdown and yields significant economic and environmental benefits. The extent and nature of these benefits depend on the liquid removal system that the plunger lift is replacing.

★ **Lower capital cost versus installing beam lift equipment.** The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain beam lift equipment.

★ **Lower well maintenance and fewer remedial treatments.** Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blowdowns are reduced or no longer needed with plunger lift systems.

★ **Continuous production improves gas production rates and increases efficiency.** Plunger lift systems can conserve the well's lifting energy and increase gas production. Regular fluid removal allows the well to produce gas continuously and prevent fluid loading that periodically halts gas production or "kills" the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

- ★ **Reduced paraffin and scale buildup.** In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with "wobble-washers" to improve their "scraping" performance.

- ★ **Lower methane emissions.** Eliminating repetitive remedial treatments and well workovers also reduces methane emissions. Natural Gas STAR Partners have reported annual gas savings averaging 600 Mcf per well by avoiding blowdown and an average of 30 Mcf per year by eliminating workovers.

- ★ **Other economic benefits.** In calculating the economic benefits of plunger lifts, the savings from avoided emissions are only one of many factors to consider in the analysis. Additional savings may result from the salvage value of surplus production equipment and the associated reduction in electricity and work over costs. Moreover, wells that move water continuously out of the well bore have the potential to produce more condensate and oil.

Decision Process

Operators should evaluate plunger lifts as an alternative to well blowdown and beam lift equipment. The decision to install a plunger lift system must be made on a case-by-case basis. Partners can use the following decision process as a guide to evaluate the applicability and cost-effectiveness of plunger lift systems for their gas production wells.

Four Steps for Evaluating Plunger Lift Systems:

1. Determine the technical feasibility of a plunger lift installation;
2. Determine the cost of a plunger lift system;
3. Estimate the savings of a plunger lift; and
4. Evaluate the plunger lift's economics.

Step 1: Determine the technical feasibility of a plunger lift installation.

Plunger lifts are applicable in gas wells that experience liquid loading and have sufficient gas volume and excess shut-in pressure to lift the liquids from the reservoir to the surface. Exhibit 2 lists four common well characteristics that are good indicators of plunger lift applicability. Vendors often will supply written materials designed to help operators ascertain whether a particular well would benefit from the installation of a plunger lift system. As an example, a well that is 3,000 feet deep, producing to a sales line at 100 psig, has a shut-in pressure of 150 psig and must be vented to the atmosphere daily to expel and average of three barrels per day of water accumulation. This well has sufficient excess shut-in pressure and would have to produce 3,600 scf per day (400 scf/bbl/1000 feet of depth times 3000 feet of depth, times 3 barrels of water per day) to justify use of a plunger lift.

Exhibit 2: Common Requirements for Plunger Lift Applications

- ★ Well blowdowns and other fluid removal techniques are necessary to maintain production.
- ★ Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.
- ★ Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.
- ★ Wells with scale or paraffin buildup.

Step 2: Determine the cost of a plunger lift system.

Costs associated with plunger lifts include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the system. These costs include:

- ★ **Capital, installation, and start-up costs.** The basic plunger lift installation costs approximately \$1,900 to \$7,800. In contrast, installation of surface pumping equipment, such as a beam lift, costs between \$26,000 and \$52,000. Plunger lift installation costs include installing the piping, valves, controller and power supply on the wellhead and setting the down-hole plunger bumper assembly assuming the well tubing is open and clear. The largest variable in the installation cost is running a wire-line to gauge the tubing (check for internal blockages) and test run a plunger from top to bottom (broaching) to assure that the plunger will move freely up and down the tubing string. Other start-up costs can include a well depth survey, swabbing to

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

remove well bore fluids, acidizing to remove mineral scale and clean out perforations, fishing-out debris in the well, and other miscellaneous well clean out operations. These additional start-up costs can range from $700 to more than $2,600.

Operators considering a plunger lift installation should note that the system requires continuous tubing string with a constant internal diameter in good condition. The replacement of the tubing string, if required, can add several thousands of dollars more to the cost of installation, depending upon the depth of the well.

★ **Operating costs.** Plunger lift maintenance requires routine inspection of the lubricator and plunger. Typically, these items need to be replaced every 6 to 12 months, at an approximate cost of $700 to $1,300 per year. Other system components are inspected annually.

Step 3: Estimate the savings of a plunger lift.

The savings associated with a plunger lift include:

★ Revenue from increased production;

★ Revenue from avoided emissions;

★ Additional avoided costs—well treatment costs, reduced electricity costs, workover costs; and

★ Salvage value.

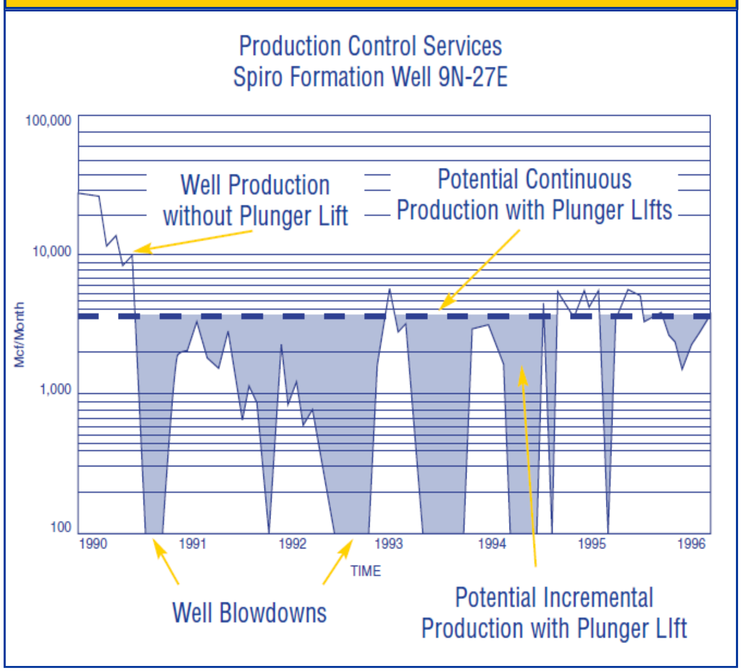
Revenue from Increased Production

The most significant benefit of plunger lift installations is the resulting increase in gas production. During the decision process, the increase in production cannot be measured directly and must be estimated. The methodology for estimating this expected incremental production varies depending on the state of the well. The methodology for continuous or non-declining wells is relatively straightforward. In contrast, the methodology for estimating the incremental production for wells in decline is more complex.

★ **Estimating incremental gas production for non-declining wells.** The incremental gas production from a plunger lift installation may be estimated by assuming that the average peak production rate achieved after blowdown is near the potential peak production rate for the well with fluid removed. A well log, like that illustrated in Exhibit 3, can be used to estimate the potential production increase.

In this exhibit, the solid line shows well production rate gradually, then steeply declining as liquids accumulate in the tubing. Production is restored by venting the well to the atmosphere, but then declines again with reaccumulation of liquids. Note that the production rate scale, in thousands of cubic feet per month, is a log scale. The dashed line shows the

Exhibit 3: Incremental Production for Non-Declining Wells



average peak production rate after liquids unloading. This is assumed to be equal to the potential peak production rate that could be achieved with a plunger lift system, typically at least 80 percent of the peak production rate after blowdown. The shaded area between the potential production (dashed-line) and the actual well production (solid-line) represents the estimate of incremental increase in gas production that can be achieved with a plunger lift system.

★ **Estimating incremental production for declining wells or for situations in which the maximum production level after blowdown is not known.** Wells that are in decline or operated without periodic blowdowns require more detailed methods for estimating incremental production under plunger lift systems. Plunger lift installations on declining wells, for example, will require generating an improved declining curve resulting from decreased pressure at perforations. Operators should seek the assistance of a reservoir engineer to aid in these determinations (see Appendix).

Once incremental production from a plunger lift installation is estimated, operators can calculate the value of incremental gas and estimate the economics of the plunger lift installation. Exhibit 4 presents an example of potential financial returns at different levels of increase in gas production. It is important to recognize that local costs and conditions may vary. Note also that the example in Exhibit 4 does not take into account other financial benefits of a plunger lift installation project, such as avoided emissions and decreased electricity and chemical treatment costs, which are described later in this Lessons Learned. Consideration of these additional benefits may improve the already excellent financial returns of a plunger lift installation.

Exhibit 4: Example of Estimated Financial Returns for Various Levels of Incremental Gas Production from a Plunger Installation

Incremental Gas Production (Mcfd)	Payout Time (months)	Internal Rate of Return (%)
3	14	71
5	8	141
10	4	309
15	3	475
20	2	640
25	2	804
30	2	969

Assumptions:
Value of gas = $7.00/Mcf.
Plunger system cost of $7,772 including start-up cost.
Lease operating expense of $790/year.
Production decline of 6%/year.

Source: Production Control Services, Inc.

Revenue from Avoided Emissions

The amount of natural gas emissions reduced following plunger lift installation will vary greatly from well to well, based on the individual well and reservoir characteristics such as sales line pressure, well shut-in pressure, liquids accumulation rate, and well dimensions (depth, casing diameter, tubing diameter). The most important variable, however, is the normal operating practice of venting wells. Some operators put wells on automatic vent timers, while others manually vent the wells with the operator standing by monitoring the vent, and still others open the well vent and leave, returning in hours or up to days, depending on how long it typically takes the well to clear liquids. Thus, the economic benefits from avoided emissions will also vary considerably. Such wide variability means that some projects will have much shorter payback periods than others. While most plunger lift installations will be justified by increased gas production rates alone, methane emissions reductions can provide an additional revenue stream.

★ **Avoided emissions when replacing blowdowns.** In wells where plunger lift systems are installed, emissions from blowing down the well can be reduced. Blowdown emissions vary widely in both their frequency and flow rates and are entirely well and reservoir specific. Emissions attributable to blowdown activities have been reported from 1 Mcf per year to thousands of Mcf per year per well. Therefore, the savings attributable to avoided emissions will vary greatly based on the data for the particular well being rehauled.

Revenue from avoided emissions can be calculated by multiplying the market value of the gas by the volume of avoided emissions. If the emissions per well per blowdown have not been measured, they must be estimated. In the example below, the amount of gas that is vented from a low pressure gas well at each blowdown is estimated as 0.5625 times the sustained flow gas rate. This emission factor assumes that the integrated average flow over the blowdown period is 56.25 percent of full well flow. Using this assumption, Exhibit 5 demonstrates that for an unloaded well producing 100 Mcf per day, the gas vented to the atmosphere can be estimated at 2 Mcf per hour of blowdown.

Exhibit 5: Example—Estimate Avoided Emissions from Blowdowns

Avoided Emissions per Hour of Blowdown[a]	= (0.56251 x Sustained Daily Flow Rate) / 24 hrs/day
Avoided Emissions[b]	= (0.5625 x 100 Mcfd) / 24 = 2 Mcf per hour of blowdown
Annual Value of Avoided Emissions[c]	= 2 Mcf x 12 x $7.00/Mcf = $168 per year

[a] Recommended methane emission factor reported in the joint GRI/EPA study, Methane Emissions From the Natural Gas Industry, Volume 7: Blow and Purge Activities (June 1995). The study estimated that at the beginning of a blowdown event, gas flow is restricted by fluids in the well to 25 percent of full flow. By the end of the blowdown event, gas flow is returned to 100 percent. The integrated average flow over the blowdown period is 56.25 percent of full well flow.
[b] Assuming a sustained daily production rate of 100 Mcfd.
[c] Assuming 1 blowdown per month lasting 1 hour.

This method is simple to use, but anecdotal evidence suggests that it produces estimates of methane emissions avoided that are unrealistically low. For an alternate method for estimating avoided emissions from blowdowns, see the Appendix.

Given the high degree of variability in emissions based on well and reservoir specific characteristics, measurement is the preferred method for determining avoided emissions. Field measurements can provide the data necessary to accurately determine the savings attributable to avoided emissions.

★ **Avoided emissions when replacing beam lifts.** In cases where plunger lifts replace beam lifts rather than blowdowns, emissions will be avoided due to reduced workovers for mechanical repairs, to remove debris and cleanout perforations, to remove mineral scale and paraffin deposits from the sucker rods. The average emissions associated with workovers have been reported as approximately 2 Mcf per workover; the frequency of workovers has been reported to range from 1 to 15 per year. Due to well-specific characteristics such as flow during workover, duration of workover, and frequency of workover, avoided emissions can vary greatly.

Avoided Costs and Additional Benefits

Avoided costs depend on the type of liquid removal systems currently in place, but can include avoided well treatment, reduced electricity costs, and reduced workover costs. Avoided well treatment costs are applicable when plunger lifts replace beam lifts or other remedial techniques such as blowdown, swabbing, or soaping. Reduced electricity costs, reduced workovers, and recovered salvage value are only applicable if plunger lifts replace beam lifts.

★ **Avoided well treatment costs.** Well treatment costs include chemical treatments, microbial cleanups, and removal of rods and scraping the borehole. Information from shallow 1,500-foot wells show well remediation costs including rod removal and tubing rehabilitation at more than $14,500 per well. Chemical treatment costs (inhibitors, solvents, dispersants, hot fluids, crystal modifiers, and surfactants) are reported in the literature at a minimum of $13,200 per well per year. Microbial costs to reduce paraffin have been shown to be $6,600 per well per year (note that microbial treatments do not address the fluids influx problem). Each of these treatment costs increases as the severity of the scale or paraffin increases, and as the depth of the well increases.

★ **Reduced electricity costs compared to beam lifts.** Reduced electric operating costs further increase the economic return of plunger lifts. No electrical costs are associated with plunger lifts, because most controllers are solar-powered with battery backup. Exhibit 6 presents a range of avoided electricity costs reported by operators who have installed plunger lifts. Assuming 365 days of operation, avoided electricity costs range from $1,000 to $7,300 per year.

★ **Reduced workover costs compared to beam lifts.** Workover costs associated with beam lifts have been reported as $1,300 per day. While typical

Exhibit 6: Electricity Costs[a] Avoided by Using a Plunger Lift in Place of a Beam Lift

Motor Size (BHP)	Operation Cost ($/day)
10	3
20	7
30	10
40	13
50	17
60	20

[a] Electricity cost assumes 50 percent of full load, running 50 percent of the time, with cost of 7.5 cents/kWh.

workovers may take one day, wells more than 8,000 feet deep will require more than one day of workover time. Depending on the well, from 1 to 15 workovers can be required per year. These costs are avoided by using a plunger lift.

★ **Recovered salvage value when replacing a beam lift.** If the plunger being installed is replacing a beam lift, extra income and a better economic return are realized from the salvage value of the old production hardware. Exhibit 7 shows the salvage value that may be obtained by selling the surplus pumping units. In some cases, salvage sales alone may pay for the installation of plunger lifts.

Exhibit 7: Salvage Value[a] of Legacy Equipment When Converting from Beam Lift to Plunger Lift Operations

Capital Savings from Salvaging Equipment	
Size of Pumping Unit (inch-lbs torque)	**Equipment Salvage Value ($)**
114,000	12,300
160,000	16,800
228,000	21,300
320,000	27,200
456,000	34,300
640,000	41,500

[a] Salvage costs include low estimate sale value of pumping unit, electric motor, and rod string.

Step 4: Evaluate the plunger lift's economics.

A basic cash flow analysis can be used to compare the costs and benefits of a plunger lift with other liquid removal options. Exhibit 8 shows a summary of the costs associated with each option.

★ **Economics of Replacing a Beam Lift with a Plunger Lift.** In Exhibit 9 the data from Exhibit 8 is used to model a hypothetical 100 Mcfd well and to evaluate the economics of plunger lift installation. The increase in production is 20 Mcf per day, yielding an annual increase in production of 7,300 Mcf. Assuming one workover per year prior to installation, the switch to a plunger lift also provides 2 Mcf of avoided emissions per year. The project profits greatly from the salvage value of the surplus beam lift equipment, yielding an immediate payback. Even if the salvage value is not recovered, the project may yield payback after only a few months depending on the well's productivity.

★ **Economics of Avoiding Blowdown with a Plunger Lift.** Exhibit 10 uses data from Exhibit 8 to evaluate the economics of a hypothetical 100 Mcfd well at which a plunger lift is installed to replace blowdown as the method for removing liquid from the well. Assuming the increased production is 20 Mcf per day, the annual increase in production is 7,300 Mcf. In addition, there will be savings from avoided emissions during blowdown. Assuming 12 one-hour blowdowns per year, the avoided emissions are 24 Mcf per year.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

Exhibit 8: Cost Comparison of Plunger Lift vs. Other Options

Cost Category	Plunger Lift	Traditional Beam Lift	Remedial Treatment[a]
Capital and Startup Costs	$1,943 - $7,772	$25,907 - $51,813	$0
Implementation Costs:			
Maintenance[b]	$1,300/yr	$1,300 - $19,500/yr	$0
Well Treatment[c]	$0	$13,200+	$13,200+
Electrical[d]	$0	$1,000 - $7,300/yr	$0
Salvage	$0	($12,000 - $41,500)	$0

[a] Includes soaping, swabbing, and blowing down.
[b] For traditional beam lift, maintenance costs include workovers and assume 1 to 15 workovers per year at $1,300 per workover.
[c] Costs may vary depending on the nature of the liquid.
[d] Electricity costs for plunger lift: assume the lift is solar and well powered.

Exhibit 9: Economic Analysis of Plunger Lift Replacing a Beam Lift

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions[a]		$51,114	$51,114	$51,114	$51,114	$51,114
Plunger Lift Equipment and Setup Cost	($7,772)					
Plunger Lift Maintenance		($1,300)	($1,300)	($1,300)	($1,300)	($1,300)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Salvage Value Beam Lift Equipment	$21,300					
Avoided Beam Lift Maintenance (1 workover/yr)		$1,300	$1,300	$1,300	$1,300	$1,300
Avoided Beam Lift Electricity Costs (10HP motor)		$1,000	$1,000	$1,000	$1,000	$1,000
Avoided Chemical Treatments		$13,200	$13,200	$13,200	$13,200	$13,200
Net Cash Inflow	$13,528	$65,314	$65,314	$65,314	$65,314	$65,314

NPV (Net Present Value)[b] = $261,119

Payback Period = Immediate

[a] Gas valued at $7.00 per Mcf for 7,300 Mcf due to increased production and 2 Mcf from avoided emissions per event (based on 1 workover per year).
[b] Net present value based on 10 percent discount rate over 5 years.

Exhibit 10: Economic Analysis of Plunger Lift Replacing Blowdown

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions[a]		$51,268	$51,268	$51,268	$51,268	$51,268
Plunger Lift Equipment and Setup Cost	$(7,772)					
Plunger Lift Maintenance		($1,300)	($1,300)	($1,300)	($1,300)	($1,300)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Avoided Chemical Treatments		$13,200	$13,200	$13,200	$13,200	$13,200
Net Cash Inflow	($7,772)	$63,168	$63,168	$63,168	$63,168	$63,168

NPV (Net Present Value)[b] = $231,684

Payback Period = 2 months

[a] Gas valued at $7.00 per Mcf for 7,300 Mcf due to increased production and 24 Mcf from avoided emissions per event (based on 12 blowdowns per year and 2 Mcf per blowdown).
[b] Net present value based on 10 percent discount rate over 5 years.

When assessing options for installing plunger lift systems on gas wells, natural gas price may influence the decision making process. Exhibit 11 shows an economic analysis of installing a plunger lift system rather than blowing down a well to the atmosphere to lift accumulated fluid at different natural gas prices.

Exhibit 11: Gas Price Impact on Economic Analysis

	$3 / Mcf	$5 / Mcf	$7 / Mcf	$8 / Mcf	$10 / Mcf
Value of Gas Saved	$21,972	$36,620	$51,268	$58,592	$73,240
Payback Period (months)	3	2	2	2	2
Internal Rate of Return (IRR)	436%	624%	813%	907%	1095%
Net Present Value (i=10%)	$120,630	$176,157	$231,684	$259,448	$314,976

Case Studies

BP (formerly Amoco) Midland Farm Field

Amoco Corporation, a Natural Gas STAR charter Partner (now merged with BP), documented its success in replacing beam lift, rod pump well production equipment with plunger lifts at its Midland Farm field. Prior to installing plunger lift systems, Amoco used beam lift installations with fiberglass rod strings. The lift equipment was primarily 640 inch-lb pumping units powered by 60 HP motors. Operations personnel noted that wells at the field were having problems with paraffin plating the well bore and sucker rods, which blocked fluid flow and interfered with fiberglass sucker rod movement. Plunger lifts were seen as a possible solution to inhibit the accumulation of paraffin downhole.

Amoco began its plunger lift replacement program with a single-well pilot project. Based on the success of this initial effort, Amoco then expanded the replacement process to the entire field. As a result of the success in the Midland Farm field, Amoco installed 190 plunger lift units at its Denver City and Sundown, Texas locations, replacing other beam lift applications.

Costs and Benefits

Amoco estimated that plunger lift system installation costs -including plunger equipment and tubing conversion costs- averaged $13,000 per well (initial pilot costs were higher than average during the learning phase, and the cost of tubing conversion is included).

Amoco then calculated savings resulting from avoided costs in three areas—electricity, workover, and chemical treatment. Overall, Amoco estimated that the avoided costs of electricity, workover, and paraffin control averaged $24,000 per well per year.

★ **Electricity.** Cost savings were estimated based on 50 percent run times. Using the costs from Exhibit 6, the estimated electrical cost savings were estimated to be $20 per day.

★ **Workover.** On average, Amoco had one workover per year per well to fix rod parts. With the old beam lift systems, the cost of this operation was $4,000, averaging about $11 per day.

★ **Chemical treatment.** The biggest savings were realized from avoided chemical treatment. Amoco was able to save the approximately $13,000 per well per year for paraffin control because the plunger operation removed paraffin accumulation in the tubing.

Increased Gas Production and Revenue

For the initial plunger lift installation, Amoco realized an increase in gas production of more than 400 Mcf per day. Upon expansion of the plunger lift installation to the entire field, the company realized notable success in many wells—although some showed little or no production increase during the 30 day evaluation period. Total production increase (including both incremental production and non-emitted gas) across all wells where plunger lifts were installed was 1,348 Mcf per day. The average annual gas savings, which assumes a 6 percent production decline, was 11,274 Mcf per well or approximately $78,918 per well at 2006 prices. Exhibit 12 and Exhibit 13 summarize the initial results and first year economics of Amoco's Midland Farm plunger lift installation. In addition to the gas savings and cost savings from the plunger lift installations, Amoco realized a one-time gain from the sale of surplus pumping units

Exhibit 12: Change in Production Rates due to Plunger Lift Installation in Midland Farm Field, Texas

[a]Well #	Production Before Plunger Lift			Production 30 Days After Installation		
	Gas (Mcfd)	Oil (Bpd)	Water (Bpd)	Gas (Mcfd)	Oil (Bpd)	Water (Bpd)
1	233	6	1	676	5	1
2	280	15	1	345	15	1
3	240	13	2	531	33	11
4	180	12	2	180	16	3
5	250	5	2	500	5	2
6	95	8	2	75	12	0
7	125	13	1	125	14	0
8	55	6	1	55	13	2
9	120	45	6	175	40	0
10	160	16	3	334	17	3
11	180	7	12	80	6	6
12	215	15	4	388	21	2
13	122	8	8	124	12	7
14	88	5	10	23	9	1
Avg.	167	12	4	258	16	3

[a] All wells approximately 11,400 feet deep.

Source: World Oil, November, 1995.

Exhibit 13: BP Economics of Plunger Lifts Replacing Beam LIfts

Average Annual Gas Savings[a] (Mcf/year)	Value of Gas Saved per Year[b]	Plunger Lift Installation Cost per Well	Avoided Rod Workover Cost per Well per Year	Avoided Chemical Treatment per Well per Year	Avoided Electrical Costs per Well per Day	Average Savings per Well[c]	Additional Salvage Value of Beam Lift per Well
11,274	$78,918	$13,000	$4,000	$13,000	$20	$90,200	$41,500

[a] Average initial gas production = 1,348 Mcfd. Assumes 6 percent annual production decline.
[b] Gas valued at $7.00 per Mcf.
[c] Value saved is averaged over 14 wells.

and motors, resulting in additional revenue of $41,500 per installation.

Analysis

A summary of the costs and benefits associated with Amoco's plunger lift installation program is provided below in Exhibit 13. For the first year of operation, the company realized an average annual savings of approximately $90,200 per well at 2006 prices. In addition the company realized approximately $41,500 per well from salvage of the beam lift equipment at 2006 costs.

ExxonMobil Big Piney Field

At Big Piney Field in Wyoming, Natural Gas STAR charter Partner Mobil Oil Corporation (now merged with Exxon) has installed plunger lift systems at 19 wells. The first two plunger lifts were installed in 1995, and the remaining wells were equipped in 1997. As a result of these installations, Mobil reduced overall blowdown gas emissions by 12,164 Mcf per year. In addition to the methane emission reduction, the plunger lift system reduced the venting of ethane (6 percent by volume), C3 hydrocarbons + VOCs (5 percent), and inerts (2 percent). Exhibit 14 shows the emission reductions for each well after plunger lift installation.

Installation Tips

The following suggestions can help ensure trouble-free installation of a plunger lift system:

★ **Do not use a completion packer, because it limits the amount of gas production per plunger trip.** Without a completion packer, the entire annular void space is available to create a large compressed gas supply. The greater the volume of gas, the larger the volume of water that can be lifted.

★ **Check for tubing obstructions with a gauge ring before installation.** Tubing obstructions hinder plunger movement and may require replacement of production tubing.

★ **Capture the plunger after the first trip.** Inspection of the plunger for the presence of any damage, sand, or scale will help prevent any subsequent plunger lift operational difficulties, permitting immediate operational repair while the crew and installation equipment are mobilized.

Lessons Learned

Plunger lift systems offer several advantages over other remedial treatments for removing reservoir fluids from wells: increased gas sales, increased well life, decreased well maintenance, and decreased methane emissions. The following should be considered when installing a plunger lift system:

★ Plunger lift installations can offer quick paybacks and high return on investments whether replacing a beam lift or blowdowns.

★ Plunger lift installations can greatly reduce the amount of remedial work needed throughout the

Exhibit 14: Plunger Lift Program at Big Piney, Wyoming

Well #	Pre-Plunger Emission Volume (Mcf/yr/well)	Post-Plunger Emission Volume (Mcf/yr/well)	Annualized Reduction (Mcf/yr/well)
1	1,456	0	1,456
2	581	0	581
3	1,959	318	1,641
4	924	0	924
5	105	24	81
6	263	95	168
7	713	80	633
8	753	0	753
9	333	0	333
10	765	217	548
11	1,442	129	1,313
12	1,175	991	184
13	694	215	479
14	1,416	1,259	157
15	1,132	708	424
16	1,940	561	1,379
17	731	461	270
18	246	0	246
19	594	0	594
Totals	**17,222**	**5,058**	**12,164**

lifetime of the well and the amount of methane vented to the atmosphere.

- ★ An economic analysis of plunger lift installation should include the incremental boost in productivity as well as the associated extension in well life.
- ★ Even when the well pressure declines below that necessary to lift the plunger and liquids against sales line back pressure, a plunger is more efficient in removing liquids with the well vented to the atmosphere than simply blowing the well without a plunger lift.
- ★ Include methane emission reductions from installing plunger lift systems in annual reports submitted as part of the Natural Gas STAR Program.

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Appendix

Estimating incremental production for declining wells.

From Dake's *Fundamentals of Reservoir Engineering* (1982) we can use the following equation to calculate the increase in downhole flow for reduced pressure that may be seen when using a plunger lift. A semi-steady state inflow equation can be expressed as:

$$m(p_{avg}) - m(p_{wf}) = [(1422 \times Q \times T)/(k \times h)] \times [\ln(r_e/r_w)-3/4+S)] \times (8.15)$$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

After the reservoir parameters are gathered, this equation can be solved for Q for the retarded flow with fluids in the hole (current conditions and current decline curve), and Q for no fluids in the hole (plunger lift active and improved decline curve). This is a guideline, and operators are reminded to use a reservoir engineer to aid in this determination.

Alternate technique for calculating avoided emissions when replacing blowdowns.

A conservative estimate of well venting volumes can be made using the following equation:

> Annual Vent Volume, Mscf/yr = (0.37×10^{-6}) × (Casing Diameter)^2 × Well Depth × Shut-in Pressure × Annual Vents

Where casing diameter is in inches, well depth is in feet and shut-in pressure is in psig. Exhibit A1 shows an example calculation.

Exhibit A1: Example—Estimate Avoided Emissions from Blowdowns

Casing Diameter	8 inches
Well Depth	10,000 feet
Shut-in Pressure	214.7 psig
Annual Vents	52 (weekly venting)
Annual Vent Volume = $(0.37 \times 10^{-6}) \times 8^2 \times 10{,}000 \times 214.7 \times 52 = 2{,}644$ Mscf/yr	

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure. If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation in Exhibit 2, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to zero psig. Partners can estimate the minimum time to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If the Partner's practice and experience is to vent the wells a longer time than calculated by these methods, the conservative Annual Vent Volume can be increased by a simple ratio of the actual vent times and the minimum vent time calculated using the Weymouth equation.

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

October 2006

EDF-WZI-APPENDIX XIII

PRO Fact Sheet No. 701

Partner Reported Opportunities (PROs) for Reducing Methane Emissions

Connect Casing to Vapor Recovery Unit

Technology/Practice Overview

Description

Crude oil and natural gas wells that produce through tubing may collect methane and other gases in the annular space between the casing and tubing. This gas, referred to as casinghead gas, is often vented directly to the atmosphere. One way to reduce methane emissions is to connect the casinghead vent to an existing vapor recovery unit (VRU).

VRUs are finding wider application at production sites with multiple oil or condensate storage tanks that have significant vapor emissions. This practice takes advantage of the similarities in gas pressure, composition, and rates between tank emissions and casinghead gas.

Operating Requirements

Pressure regulators would be necessary if low pressure casinghead gas is combined with higher pressure sources (e.g., dehydrator flash tank separator) at a VRU suction. Only small diameter piping is required to join a casinghead vent to the VRU suction.

Applicability

This option is applicable at wells producing through tubing with packerless completions.

Methane Emissions

Casinghead gas vents vary widely in quantity and methane content. One Partner reported an annual average casinghead gas methane recovery of 7,300 Mcf per year over a five-year period.

- [ ] Compressors/Engines
- [ ] Dehydrators
- [ ] Directed Inspection & Maintenance
- [ ] Pipelines
- [ ] Pneumatics/Controls
- [ ] Tanks
- [ ] Valves
- [x] Wells
- [ ] Other

Applicable Sector(s)

- [x] Production
- [ ] Processing
- [ ] Transmission
- [ ] Distribution

Other Related PROs:

Installing Vapor Recovery Units on Storage Tanks, Lessons Learned

Install Compressors to Capture Casinghead Gas, PRO No. 702

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*7,300 Mcf per well*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	7,300 Mcf	$54,400	$4,300	$3,400	2 Months
$5.00/Mcf	7,300 Mcf	$38,800	$4,300	$3,400	3 Months
$3.00/Mcf	7,300 Mcf	$23,300	$4,300	$3,400	4 Months

* *Whole gas savings are calculated using a conversion factor of 94% methane in pipeline quality natural gas.*

Additional Benefits

- Recovery of valuable product
- Fewer hydrocarbon emissions

Connect Casing to Vapor Recovery Unit (Cont'd)

Economic Analysis

Basis for Costs and Emissions Savings

Methane emission reductions of 7,300 Mcf per year are the Partner savings from connecting one well to an existing VRU.

The costs (operating and implementation) are based on Partner experiences. At 7.5¢ per kWh, the Partner reported gas recovery would increase electricity costs by $3,400 per year. Another Partner reported implementation costs of $4,300.

Discussion

This technology can pay back quickly. Revenue from gas recovery will pay back the piping cost and the incremental electrical power required by the VRU to inject the gas into a 100 psig system.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

EDF-WZI-APPENDIX XIV

Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells

Executive Summary

In recent years, the natural gas industry has developed more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involve hydraulic fracturing of the reservoir to increase well productivity. Industry reports that hydraulic fracturing is beginning to be performed in some conventional gas reservoirs as well. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and therefore methane emissions to the atmosphere. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990 - 2009* estimates that 68 billion cubic feet (Bcf) of methane are vented or flared annually from unconventional completions and workovers.

Reduced emissions completions (RECs) – also known as reduced flaring completions or green completions – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the sales pipeline. RECs help to reduce methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of thirteen different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2009 emissions reductions from RECs (as reported to Natural Gas STAR) have increased from 200 MMcf (million cubic feet) to over 218,000 MMcf. Capturing an additional 218,000 MMcf represents additional revenue from natural gas sales of over $1.5 billion from 2000 to 2009 (assuming $7/Mcf gas prices).

Technology Background

High demand and higher prices for natural gas in the U.S. have resulted in increased drilling of new wells in more expensive and more technologically challenging unconventional gas reservoirs, including those in low porosity (tight) formations. These same high demands and

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf)	Value of Natural Gas Savings ($)			Additional Savings ($)	Implementation Cost ($)	Other Costs ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf				$3 per Mcf	$5 per Mcf	$7 per Mcf
Purchased REC Equipment Annual Program	270,000 per year	$810,000 per year	$1,350,000 per year	$1,890,000 per year	$175,000 per year	$500,000	$121,250 per year	6	4	3
Incremental REC Contracted Service	10,800 per completion	$32,400 per completion	$54,000 per completion	$75,600 per completion	$6,930 per completion	$32,400	$600 per completion	Imme-diate	Imme-diate	Imme-diate

General Assumptions:
[a] Assuming 9 days per completion, 1,200 Mcf gas savings per day per well, 11 barrels of condensate recovered per day per well, and cost of $3,600 per well per day for contracted services.
[b] Assuming $70 per barrel of condensate.
[c] Based on an annual REC program of 25 completions per year.

prices also justify extra efforts to stimulate production from existing wells in tight reservoirs where the down-hole pressure and gas production rates have declined, a process known as well workovers or well-reworking. In both cases, completions of new wells in tight formations and workovers of existing wells, one technique for improving gas production is to fracture the reservoir rock with very high pressure water containing a proppant (generally sand) that keeps the fractures "propped open" after water pressure is reduced. Depending on the depth of the well, this process is carried out in several stages, usually completing one 200- to 250-foot zone per stage.

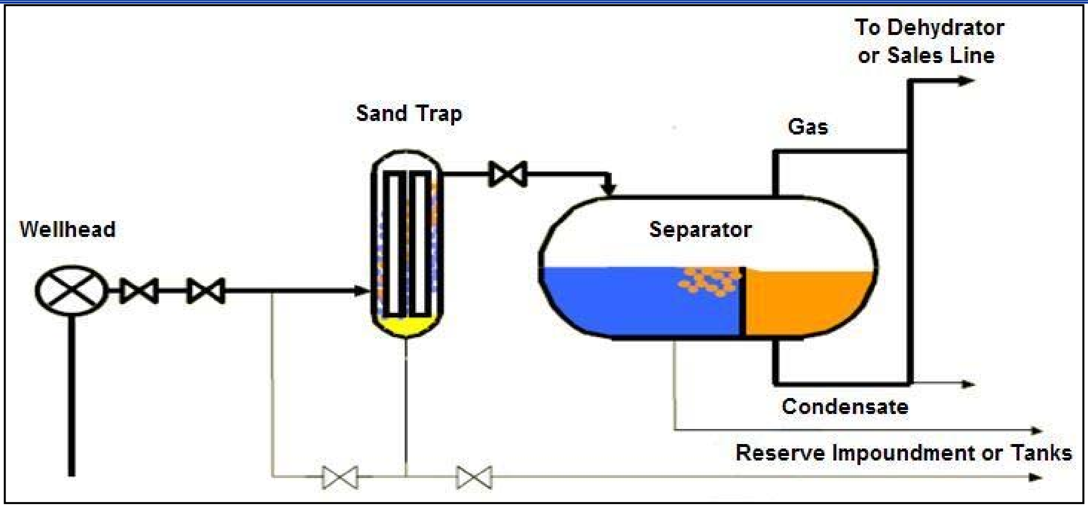
These new and "workover" wells are completed by producing the fluids at a high rate to lift the excess sand to the surface and clear the well bore and formation to increase gas flow. Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids and sand are captured and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from one day to several weeks during which time a substantial amount of gas may be released to the atmosphere or flared. Testing of production levels occurs during the well completion process, and it may be necessary to repeat the fracture process to achieve desired production levels from a particular well.

Natural gas lost during well completion and testing can be as much as 25 million cubic feet (MMcf) per well depending on well production rates, the number of zones completed, and the amount of time it takes to complete each zone. This gas is generally unprocessed and may contain volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) along with methane. Flaring gas may eliminate most methane, VOC and HAP emissions, but open flaring is not always a preferred option when the well is located near residential areas or where there is a high risk of grass or forest fires. Moreover, flaring may release additional carbon dioxide and other criteria pollutants (SOx, NOx, PM and CO) to the atmosphere.

Natural Gas STAR partners have reported performing RECs that recover much of the gas that is normally vented or flared during the completion process. This involves installing portable equipment that is specially designed and sized for the initial high rate of water, sand, and gas flowback during well completion. The objective is to capture and deliver gas to the sales line rather than venting or flaring this gas.

Sand traps are used to remove the finer solids present in the production stream. Plug catchers are used to remove any large solids such as drill cuttings that could damage the other separation equipment. The piping configuration to the sand traps is critical as the abrasion from high velocity water and sand can erode a hole in steel pipe elbows, creating a "washout" with water, sand,

Exhibit 1: Reduced Emissions Completion Equipment Layout



Adapted from BP.

hydrocarbon liquids and gas in an uncontrolled flow to the pad. Depending on the gas gathering system, it may be necessary to dehydrate (remove water from) the produced gas before it enters the sales pipeline. The gas may be routed to the permanent glycol unit for dehydration or a portable desiccant/glycol dehydrator used for dehydration during the completion process.

Free water and condensate are removed from the gas in a three phase separator. Condensate (liquid hydrocarbons) collected during the completion process may be sold for additional revenue. Temporary piping may be used to connect the well to the REC skid and gathering system if the permanent piping is not yet in place. Exhibit 1 shows a typical layout of temporary REC portable equipment, and Exhibit 2 explains some alternate, emerging, and/or experimental procedures for a well completion and REC.

Exhibit 2: Alternate Completion Procedures

Energized Fracturing

Based on Natural Gas STAR partner experiences, RECs can also be performed in combination with energized fracturing, wherein inert gas such as CO_2 or nitrogen is mixed with the frac water under high pressure to aid in the process of fracturing the formation. The process is generally the same with the additional consideration of the composition of the flowback gas. The percent of inert gases in the flowback gas is, at first, unsuitable for delivery into the sales line. As the fraction of inerts decreases, the gas can be recovered economically. A portable membrane acid gas separation unit can further increase the amount of methane recovered for sales after a CO_2 energized fracture.

Compression

Two compressor applications during an REC have been identified or explored by Natural Gas STAR partners.

1) Gas Lift. In low pressure (i.e. low energy) reservoirs RECs are often carried out with the aid of compressors for gas lift. Gas lift is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the frac fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during an REC.

2) Boost to Sales Line. When the gas recovered in the REC separator is lower pressure than the sales line, some companies are experimenting with a compressor to boost flowback gas into the sales line. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate. Coal bed methane well completion is an example where additional compression might be required.

The equipment used during RECs is only necessary for the time it takes to complete the well; therefore, it is essential that all the equipment can be readily transported from site to site to be used in a number of well completions. A truck mounted skid, as shown in Exhibit 3, is ideal for transporting the equipment between sites. In a large basin that has a high level of drilling activity it may be economic for a gas producer to build its own REC skid. Most producers may prefer contracting a third party service to perform completions.

When using a third party to perform RECs, it is most cost effective to integrate the scheduling of completions with the annual drilling program. Well completion time is another factor to consider for scheduling a contractor for RECs. Some well completions, such as coal bed methane, may take less than a day. On the other hand, completing wells which fracture various zones, such as shale gas wells, may take several weeks to complete. For most wells, it takes about 3 to 10 days to perform a well completion following a hydraulic fracture, based on partner experiences.

Exhibit 3: Truck Mounted Reduced Emissions Completion Equipment

Source: Weatherford

Economic and Environmental Benefits

- ★ Gas recovered for sales
- ★ Condensate recovered for sales
- ★ Reduced methane emissions

- ★ Reduced loss of a valuable hydrocarbon resource
- ★ Reduced emissions of criteria and hazardous air pollutants

Emissions from well completions can contribute to a number of environmental problems. Direct venting of VOCs can contribute to local air pollution, HAPs are deemed harmful to human health, and methane is a powerful greenhouse gas that contributes to climate change. Where it is safe, flaring is preferred to direct venting because methane, VOCs, and HAPs are combusted, lowering pollution levels and reducing global warming potential (GWP) of the emissions as CO_2 from combustion has a lower GWP than methane. RECs allow for recovery of gas rather than venting or flaring and therefore reduce the environmental impact of well completion and workover activities.

RECs bring economic benefits as well as environmental benefits. The incremental costs associated with the rental of third party equipment for performing RECs can be offset by the additional revenue from the sale of gas and condensate. As this technology is being perfected and equipment becomes commonplace, the revenues in gas and condensate sales often exceed the incremental costs.

Decision Process

Step 1: Evaluate candidate wells for Reduced Emissions Completions.

When setting up an annual RECs program it is important to examine the characteristics of the wells that are going to be brought online in the coming year. Wells in conventional reservoirs that do not require a reservoir fracture (frac job) and will produce readily without stimulation can be cleared of drilling fluids and connected to a production line in a relatively short period of time with minimal gas venting or flaring, and therefore usually do not economically justify REC equipment. Wells that undergo energized fracture using inert gases require special considerations because the initial produced gas captured by the REC equipment would not meet pipeline specifications due to the inert gas content. However, as the amount of inerts decreases, the quality of the gas will likely meet pipeline specifications. In the case of CO_2 energized fracks, the use of portable acid gas removal membrane separators will improve gas quality and make it possible to direct gas to the pipeline (see Partner Experiences section for more information).

Decision Process
Step 1: Evaluate candidate wells
Step 2: Determine costs
Step 3: Estimate savings
Step 4: Evaluate economics

State and Local Regulations
The States of Wyoming and Colorado have regulations requiring the implementation of "flareless completions". Operators of new wells in this region are required to complete wells without flaring or venting. These completions have reduced flaring by 70 to 90 percent.

For more information, visit:
http://deq.state.wy.us
http://www.cdphe.state.co.us

Exploratory and delineation wells in areas that do not yet have sales pipelines in close proximity to the wells are not candidates for RECs as the infrastructure is not in place to receive the recovered gas. In depleted or low pressure fields with low energy reservoirs, implementing a RECs program would most likely require the addition of compression to overcome the sales line pressures–an approach that is still under development and may add significant cost to implementation.

Wells that require hydraulic fracturing to stimulate or enhance gas production may need a lengthy completion, and therefore are good candidates for RECs. Lengthy completions mean that a significant amount of gas may be vented or flared that could potentially be recovered and sold for additional revenue to justify the additional cost of a REC. If newly drilled wells are in close proximity, they could share the REC equipment to minimize transport, set-up, and equipment rental costs.

Selecting a Basis for Costs and Savings

- ★ Estimate the number of producing gas wells that will be drilled in the next year
- ★ Evaluate well depth and reservoir characteristics
- ★ Determine whether additional equipment is necessary to bring recovered gas up to pipeline specifications
- ★ Estimate time needed for each completion

Step 2: Determine the costs of a REC program.

Most Natural Gas STAR partners report using third party contractors to perform RECs on wells within their producing fields. It should be noted that third party contractors are also often used to perform traditional well completions. Therefore, the economics presented deal with incremental costs to carry out RECs versus traditional completions.

Generally, the third party contractor will charge a commissioning fee for transporting and setting up the equipment for each well completion within the operator's producing field. Some RECs vendors have their equipment mounted on a single trailer while others lay down individual skids that must be connected with temporary piping at each site. The incremental cost associated with transportation between well sites in the operator's field and connection of the REC equipment within the normal flowback piping from the wellhead to an impoundment or tank is generally around $600/completion.

In addition to the commissioning fee, there is a daily cost for equipment rental and labor to perform each REC. As mentioned above, when evaluating the costs of well completions, it is important to consider the incremental cost of a REC over a traditional completion rather than focusing on the total cost. REC vendors and Natural Gas STAR partners have reported the incremental cost of equipment rental and labor to recover natural gas during completion ranging from $700 to $6,500/day over a traditional completion. Equipment costs associated with RECs will vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment such as a glycol dehydrator is already installed at the well site, REC costs may be reduced as this equipment can be used rather than bringing a portable dehydrator on-site, assuming the flow-back rate does not exceed the capacity of the equipment. Some operators report installing permanent equipment that can be used in the RECs as part of normal well completion operations, such as oversized three-phase separators, further reducing incremental REC costs. Well completions usually take between 1 to 30 days to clean out the well bore, complete well testing, and tie into the permanent sales line. Wells requiring multiple fractures of a tight formation to stimulate gas flow may require additional completion time. Exhibit 4 shows the typical costs associated with undertaking a REC at a single well.

Exhibit 4: Typical Costs for RECs

One-time Transportation and Incremental Set-up Costs	Incremental REC Equipment Rental and Labor Costs	Well Clean-up Time
$600 per well	$700 to $6,500 per day	3 to 10 days

For low energy reservoirs, gas from the sales line may be routed down the well casing to create artificial gas lift, as mentioned in Exhibit 2. Depending on the depth of the well, a different quantity of gas will be required to lift the fluids and clean out the well. Using average reservoir depths for major U.S. basins and engineering calculations, Exhibit 5 shows various estimates of the volume of gas required to lift fluids for different well depths.

A REC annual program may consist of completing 25 wells/year within a producer's operating region. Exhibit 6 shows a hypothetical example of REC program costs based on information provided by partner companies.

Exhibit 5: Sizing and Fuel Consumption for Booster Compressor

Well Depth (ft)	Pressure Required to Lift Fluids (psig)	Gas Required to Lift Fluids (Mcf)[a]	Compressor Size (horsepower)[a]	Compressor Fuel Consumption (Mcf/hr)[a]
3,000	1,319 + Sales line pressure	195 to 310	195 to 780	2 to 7
5,000	2,323 + Sales line pressure	315 to 430	400 to 1,500	3 to 13
8,000	3,716 + Sales line pressure	495 to 610	765 to 2,800	7 to 24
10,000	4,645 + Sales line pressure	615 to 730	1,040 to 3,900	9 to 33

[a] Based on sales line pressures between 100 to 1,000 psig.

Exhibit 6: Hypothetical Example Cost Calculation of a 25 Well Annual REC Program

Given

W = Number of completions per year
D = Well depth in feet (ft)
P_s = Sales line pressure in pounds per square inch gauge (psig)
T_s = Time required for transportation and set-up (days/well)
T_c = Time required for well clean-up (days/well)
O = Operating time for compressor to lift fluids (hr/well)
F = Compressor fuel consumption rate (Mcf/hr)
G = Gas from pipeline routed to casing to lift fluids (Mcf/well), typically used on low energy reservoirs
C_s = Transportation and set-up cost ($/well)
C_e = Equipment and labor cost ($/day)
P_g = Sales line gas price ($/Mcf)

W = 25 wells/yr
D = 8000 ft
P_s = 100 psig
T_s = 1 day/well
T_c = 9 days/well
O = 24 hr/well
F = 10 Mcf/hr
G = 500 Mcf/well (See Exhibit 5)
C_s = $600/well
C_e = $2,000/day
P_g = $7/Mcf

Calculate Total Transportation and Set-up Cost, C_{TS}

$C_{TS} = W * C_s$

C_{TS} = 25 wells/yr * $600/well
C_{TS} = $15,000/yr

Calculate Total Equipment Rental and Labor Cost, C_{EL}

$C_{EL} = W * (T_s + T_c) * C_e$

C_{EL} = 25 wells/yr * (1 day/well + 9 days/well) * $2,000/day
C_{EL} = $500,000/yr

Calculate Other Costs, C_O

$C_O = W * [(O * F) + G] * P_g$

C_O = 25 wells/yr * [(24 hr/well * 10 Mcf/hr) + 500 Mcf/well] * $7/Mcf
C_O = $129,500/yr

Total Annual REC Program Cost, C_T

$C_T = C_{TS} + C_{EL} + C_O$
C_T = $15,000/yr + $500,000/yr + $129,500/yr
C_T = $644,500/yr

Step 3: Estimate Savings from RECs.

Gas recovered from RECs can vary widely because the amount of gas recovered depends on a number of variables such as reservoir pressure, production rate, amount of fluids lifted, and total completion time. Exhibit 7 shows the range of recovered gas and condensate reported by Natural Gas STAR partners. Partners also have reported that not all the gas that is produced during well completions may be captured for sales. Fluids from high pressure wells are often routed directly to the frac tank in the initial stages of completion as the fluids are often being produced at a rate that is too high for the REC equipment. Where inert gas is used to energize the frac, the initial gas production may have to be flared until the gas meets pipeline specifications. Alternatively, a portable acid gas membrane separator may be used to recover methane rich gas from CO_2. As the flow rate of fluids drops and gas is encountered, backflow is then switched over to the REC equipment so that the gas may be captured. Gas compressed from the sales line to lift fluids (by artificial gas lift) will also be recovered in addition to the gas produced from the reservoir. The volume of gas needed to lift fluids can be estimated based on the well depth and sales line pressure. Gas saved during RECs can be translated directly into methane emissions reductions based on the methane content of the produced gas.

In addition to gas savings, valuable condensate may also be recovered from the REC three-phase separator. The amount of condensate that can be recovered during a REC is dependent on the reservoir conditions and fluid compositions. Condensate may also be lost if fluids are produced directly to the frac tank before switching to the REC equipment.

Exhibit 7: Ranges of Gas and Condensate Savings

Produced Gas Savings (Mcf/day/well)	Gas-Lift Savings (Mcf/well)	Condensate Savings (bbl/day/well)
500 to 2,000	See Exhibit 5	Zero to several hundred

Exhibit 8 shows typical values of gas and condensate savings during the REC process.

Step 4: Evaluate REC economics.

The example application of an REC program to 25 wells within a producing field can yield a total theoretical revenue of $2,152,500 based on the assumptions listed above from the sale of natural gas and condensate. Equipment rental, labor, and other costs associated with implementing this program are estimated to be $644,500 (see Exhibit 6) resulting in an annual theoretical profit of $1,508,000. To maintain a profitable REC program, it is important to move efficiently from well to well within a producing field so that there is little down time when paying for equipment rental and labor. Other factors that affect the profitability of an REC program include the amount of condensate recovery and sales price, the need for additional compressors, the amount of gas recovered, and gas sales price.

Exhibit 9 shows a five year cash flow projection for carrying out a 25 well per year REC program. In this example, the equipment necessary to perform RECs has been purchased by the operator rather than using a third party contractor to perform the service. The capital cost of a simple REC set-up without a portable compressor has been reported by British Petroleum (BP) to be $500,000.

Producers with high levels of localized drilling and workover activity may benefit from constructing and operating their own REC equipment. As illustrated above, even though large capital outlay is required to construct a REC skid, a high rate of return can be achieved if the equipment is in continuous use. If the operator is unable to keep the equipment busy on their own wells, they may

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Exhibit 8: Savings of a 25 Well Annual REC Program

Given

W = Number of completions per year
D = Well depth in feet (ft)
P_s = Sales line pressure in pounds per square inch gage (psig)
S_p = Produced gas savings (Mcf/day)
T_c = Time recovered gas flows to sales line in days (days/well)
S_c = Condensate savings (bbl/well)
G = Gas used to lift fluids (Mcf/well), typically used on low energy reservoirs
P_g = Sales line gas price ($/Mcf)
P_l = Natural gas liquids price ($/bbl)

W =	25 wells/yr
D =	8000 ft
P_s =	100 psig
S_p =	1,200 Mcf/day
T_c =	9 days/well
S_c =	100 bbl/well
G =	500 Mcf/well (See Exhibit 5)
P_g =	$7/Mcf
P_l =	$70/bbl

Calculate Produced Gas Savings

$S_{PG} = W * (S_p * T_c) * P_g$

S_{PG} = 25 wells/yr * (1,200 Mcf/day * 9 days/well) * $7/Mcf
S_{PG} = $1,890,000/yr

Calculate Other Savings

$S_O = W * [(G * P_g) + (S_c * P_l)]$

S_O = 25 wells/yr * [(500 Mcf/well * $7/Mcf) + (100 bbl/well * $70/bbl)]
S_O = $262,500/yr

Total Savings, S_T

$S_T = S_{PG} + S_O$
S_T = $1,890,000/yr + $262,500/yr
S_T = $2,152,500/yr

contract it out to other operators to maximize usage of the equipment.

When assessing REC economics, the gas price may influence the decision making process; therefore, it is important to examine the economics of undertaking a REC program as natural gas prices change. Exhibit 10 shows an economic analysis of performing the 25 well per year REC program in Exhibit 8 at different gas prices.

Exhibit 9: Economics for Hypothetical 25 Well Annual REC Program with Purchased Equipment

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Volume of Natural Gas Savings (Mcf/yr)[a]		270,000	270,000	270,000	270,000	270,000
Value of Natural Gas Savings ($/year)[a]		1,890,000	1,890,000	1,890,000	1,890,000	1,890,000
Additional Savings ($/yr)[a]		175,000	175,000	175,000	175,000	175,000
Set-up Costs ($/yr)[b]		(15,000)	(15,000)	(15,000)	(15,000)	(15,000)
Equipment Costs ($)[b]	(500,000)					
Labor Costs ($/yr)[c]		(106,250)	(106,250)	(106,250)	(106,250)	(106,250)
Net Annual Cash Flow ($)	**(500,000)**	**1,943,750**	**1,943,750**	**1,943,750**	**1,943,750**	**1,943,750**

Internal Rate of Return = 389%
NPV (Net Present Value)[d] = $6,243,947
Payback Period = 3 months

[a] See Exhibit 8.
[b] See Exhibit 6.
[c] Labor costs for purchased REC equipment estimated as 50% of Equipment Rental and Labor costs in Exhibit 3.
[d] Net present value based on 10% discount rate over five years.

Exhibit 10: Gas Price Impact on Economic Analysis of Hypothetical 25 Well Annual REC Program with Purchased Equipment

	Gas Price				
	$3/Mcf	**$5/Mcf**	**$7/Mcf**	**$8/Mcf**	**$10/Mcf**
Total Savings	$985,000	$1,525,000	$2,065,000	$2,335,000	$2,875,000
Payback (months)	7	5	4	3	3
IRR	172%	280%	389%	443%	551%
NPV (i = 10%)	$2,522,084	$4,383,015	$6,243,947	$7,174,413	$9,035,345

Partner Experience

This section highlights specific experiences reported by Natural Gas STAR partners.

BP Experience in Green River Basin

- ★ Implemented RECs in the Green River Basin of Wyoming
- ★ RECs performed on 106 wells, which consisted of high and low pressure wells
- ★ Average 3,300 Mcf of natural gas sold versus vented per well
  - – Well pressure will vary from reservoir to reservoir
  - – Reductions will vary for each particular region
  - – Conservative net value of gas saved is $20,000 per well
- ★ Natural gas emission reductions of 350,000 Mcf in 2002
- ★ Total of 6,700 barrels of condensate recovered per year total for 106 wells
- ★ Through the end of 2005, this partner reports a total of 4.17 Bcf of gas and more than 53,000 barrels of condensate recovered and sold rather than flared. This is a combination of activities in the Wamsutter and Jonah/Pinedale fields.

Noble Experience in Ellis County, Oklahoma

- ★ Implemented RECs on 10 wells using energized fracturing.
- ★ Employed membrane separation in which the permeate was a CO_2 rich stream that was vented and the residue was primarily hydrocarbons which were recovered.
- ★ Total cost of $325,000.
- ★ Total gas savings of approximately 175 MMcf.
- ★ Estimated net profits to be $340,000
- ★ For more information, see the Partner Profile Article in the Spring 2011 Natural Gas STAR Partner Update available at: http://epa.gov/gasstar/newsroom/partnerupdatespring2011.html

Partner Company A

- ★ Implemented RECs in the Fort Worth Basin of Texas
- ★ RECs performed on 30 wells, with an incremental cost of $8,700 per well
- ★ Average 11,900 Mcf of natural gas sold versus vented per well
  - – Natural gas flow and sales occur 9 days out of 2 to 3 weeks of well completion
  - – Low pressure gas sent to gas plant
  - – Conservative net value of gas saved is $50,000 per well
- ★ Expects total emission reduction of 1.5 to 2 Bcf in 2005 for 30 wells

Lessons Learned

- ★ Incremental costs of recovering natural gas and condensate during well completions following hydraulic fracturing result from the use of additional equipment such as sand traps, separators, portable compressors, membrane acid gas removal units and desiccant dehydrators that are designed for high rate flowback.
- ★ During the hydraulic fracture completion process, sands, liquids, and gases produced from the well are separated and collected individually. Natural gas and gas liquids captured during the completion may be sold for additional revenue.
- ★ Implementing a REC program will reduce flaring which may be a particular advantage where open flaring is undesirable (populated areas) or unsafe (risk of fire).
- ★ Wells that do not require hydraulic fracturing are not good candidates for reduced emissions completions. Methane emissions reductions achieved through performing RECs may be reported to the Natural Gas STAR Program unless RECs are required by law (as in the Jonah-Pinedale area in WY).

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2011

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

EDF-WZI-APPENDIX XV

Appendix XV

Control Efficiencies (CE) of the Proposed Regulation 7 Program

The Colorado Department of Public Health and Environment (CDPHE) uses the following control effectiveness thresholds for instrument based leak detection and repair (LDAR) inspections: 40% for one-time and annual inspections, 60% for quarterly inspections and 80% for monthly inspections. This Appendix evaluates whether the CE applied by CDPHE are appropriate and consistent with available data. WZI reviewed the historic studies establishing control effectiveness for various related programs and incorporated our own experiences and those of others to assess the control efficiencies used for the Regulation 7 based strategies against certain monitoring cycles (i.e., the time between surveys).[1] Applying the EPA four factor analysis yields CE values consistent with (and in fact slightly higher than) the CE established for LDAR for similar control schemes and results. This analysis in fact suggests that the CE values applied by CDPHE are conservative (e.g. understate the anticipated CE).

By definition the Control Effectiveness (CE) measures the performance of a proposed regulatory scheme in the context of the uncontrolled condition. In this case, the reduction in the air inventory relative to the uncontrolled inventory of emissions (from the proposed regulated body of equipment operating prior to implementation) extrapolated to account for the current population of regulated equipment.

1 More frequent inspections result in greater reductions in emissions.

Industry and EPA reviews of maintenance programs such as those related to Planned Maintenance, LDAR and Directed have consistently shown what one would expect: from an engineering perspective, the shorter the interval between events for monitoring for failure, scheduled maintenance or repair, the better the Control Efficiency. As one would expect, the shorter the time between surveys the better the overall Control Efficiency. As one moves to frequencies more frequent than monthly (such as weekly or daily surveys), one approaches a point of diminishing returns (such as weekly surveys which can only increase benefit from 80% to something less than 100%).

Studies of fugitive emissions show that “leakage was more prevalent in gas line components [due to the fact that crude leaks were always more noticeable and self-sealing]…and only 4% of the valves and

[1] These field studies have been performed since the late 1970’s:
API/Rockwell: Eaton, W, et al., “Fugitive Hydrocarbon Emissions from Petroleum Production Operations”, American Petroleum Institute, March 1980
Taback, H, et al, “Emissions Characteristics of Crude Oil Production Operations in California”, KVB, Jan 1983,
Censullo, A.C., “Final Report on Development of Species for Selected Organic Emissions Sources, Volume 1: Oil Field Fugitive Emissions”. California Air Resources Board, Apr 1991.

fittings tested leaked. [Of these leaks] [o]nly one in ten of those were found to be large leakers. However, the large leakers accounted for 80% of the emissions from these sources."[3]

Separately, the lowering of thresholds to determine pass/fail for a leak may capture some additional components whose leakage is less. Additional studies have shown that the differential due to lowering the threshold results by roughly 10 to 20% for a 20 fold lowering of the threshold.[4] For simplicity, programs typically do not differentiate between the severity of the leak (based on the leak threshold) except in some instances (such as South Coast Air Quality Management District) which uses a sliding scale where the time allowed from time of detection to repair is greater for components having low leak levels but the emissions factor remains the same.

2 Examples of Related Control Effectiveness Values

A generalized engineering review of available and accepted data for Control Effectiveness shows current typical results such as those shown in the Hazardous Organic NESHAP (HON) related analysis: EPA, Leak Detection and Repair, "A Best Practices Guide", (Exhibit 1, below).

[3] Sonnichsen, T. et al, "Hydrocarbon Emissions from Petroleum Operations in California's South Coast Air Basin", p 4, 1978.

[4] EPA, Leak Detection and Repair: A Best Practices Guide, No date given

Table 4.1 – Control effectiveness for an LDAR program at a chemical process unit and a refinery.

Equipment Type and Service	Control Effectiveness (% Reduction)		
	Monthly Monitoring 10,000 ppmv Leak Definition	Quarterly Monitoring 10,000 ppmv Leak Definition	500 ppm Leak Definition[a]
Chemical Process Unit			
Valves – Gas Service[b]	87	67	92
Valves – Light Liquid Service[c]	84	61	88
Pumps – Light Liquid Service[c]	69	45	75
Connectors – All Services			93
Refinery			
Valves – Gas Service[b]	88	70	96
Valves – Light Liquid Service[c]	76	61	95
Pumps – Light Liquid Service[c]	68	45	88
Connectors – All Services			81

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

[a] Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.

[b] Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.

[c] Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

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Exhibit 1

TABLE 5-2. CONTROL EFFECTIVENESS FOR AN LDAR PROGRAM AT A SOCMI PROCESS UNIT

Equipment type and service	Control effectiveness (%)		
	Monthly monitoring 10,000 ppmv leak definition	Quarterly monitoring 10,000 ppmv leak definition	HON reg neg[a]
Valves - gas	87	67	92
Valves - light liquid	84	61	88
Pumps - light liquid	69	45	75
Connectors - all	b	b	93

[a] Control effectiveness attributable to the requirements of the proposed hazardous organic NESHAP equipment leak negotiated regulation are estimated based on equipment-specific leak definitions and performance levels.

[b] Data are not available to estimate control effectiveness.

5-9

Exhibit 2

These values above in Table 5-2 (Exhibit 2, above) are for hydrocarbon emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) facilities and refineries, but it is reasonable to expect the same in exploration and production allowing for some physical design and process differences (these are similar pieces of equipment and component parts). These values reflect the degree to which leaking components can be identified as leaking, repaired to a non-leaking condition and the degree to which the leaking component does not return to a leaking condition.

The values derived from the SOCMI/Refinery as well as the original sector EIR results show general component weighted averages of the component-specific Control Effectiveness for the two programs using the 10,000 ppm leak definition for monthly and quarterly testing shows approximately 80% reduction for monthly monitoring and 60% for quarterly, as shown in Table 4-1 (Exhibit 1, above).

In the HON study flanges/connectors were treated by EPA as having no affected emissions at thresholds above 1,000 ppm. It is reasonable to expect hydrocarbon emissions, therefore, the relationships established in this HON study were used to extend the four factor formula to allow the connectors to have a Control Effectiveness for Connectors-All Services. WZI used the relationships established in the EPA HON study to adjust the factor assignment for flanges/connectors for monthly and quarterly by first using the HON proposed 500 ppm value for monthly surveys to create a 10,000 ppm monthly value of 62% for connectors and then using the pump-based curve data from to extrapolate flanges and connector Control Effectiveness from monthly (62%) to quarterly (39%). This approach more accurately represents the expected performance of LDAR for these subject components.

Table 1: EPA Refinery Control Effectiveness Data from Proposed HON

	Monthly- 10,000ppm	HON (as proposed) Monthly- 500 ppm
Threshold	10,000 ppm	500 ppm
Valves-Gas Service	88%	96%
Valves-Light Liq. Service	84%	95%
Pumps-Light Liquid Service	69%	88%
Connectors-All Services	62%*	81%

*Adjusted based on pump line to intercept connectors, see graph below

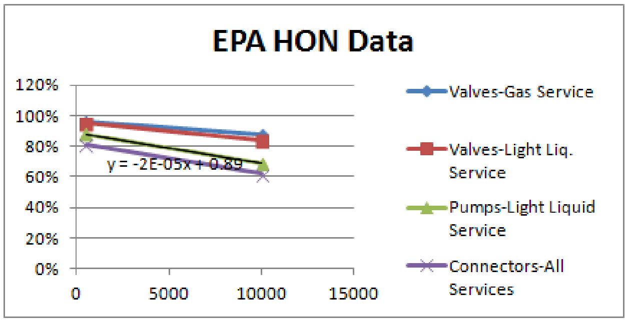

Exhibit 3

Source: EPA NESHAP except for connectors at 10,000 ppm.

2.1 EPA Four Factor Formula

To evaluate the CE for the Colorado LDAR program, WZI used the EPA four factor formula to develop a single adjustment factor to be applied to the uncontrolled emissions. The four EPA factors were based on statistical treatment of field observations, WZI extended the application to Connectors-All Services as discussed above.

The four factor criteria used for EPA defined factors to calculate Reduction Efficiency:

$$Reduction\ Efficiency = A \times B \times C \times D$$

Where:

(A) Theoretical Maximum Control Efficiency-Fraction of the total mass emissions from sources with VOC emissions Greater than the VOC limit.

(B) Leak Occurrence and Reoccurrence Correction Factor-Correction factor to account for source which start to leak between inspections (occurrences), for sources which are found to be leaking, are repaired and start to leak again before the next inspection (reoccurrence), and for known leaks that cannot be repaired.

(C) Non-Instantaneous Repair Correction Factor-Correction factor to account for emissions which occur between detection of a leak and a subsequent repair since the repair is not instantaneous.

(D) Imperfect Repair Correction Factor-Correction factor to account for the fact that some sources which are repaired are not reduced to zero. For computational purposes this factor assumes that all repairs are made to reduce the emission level equivalent to a concentration of 1,000 ppm.

As part of this study the impact of the findings by EPA Enforcement Division were included to reflect the higher population of leakers found when a rigorous adherence to protocol was employed. Table 4-3 below shows the factors used by EPA in their EIR for the VOC Fugitive Emissions in Petroleum Refining Industry, 450/3-81-015a. WZI used these basic factors to derive Control Effectiveness values to compare to CDPHE values used in the state of Colorado.

Table 4-3. EMISSION CORRECTION FACTORS FOR VARIOUS INSPECTION INTERVALS, ALLOWABLE REPAIR TIMES, AND LEAK DEFINITIONS[a] (Reference 14)

	Leak Occurrence and Recurrence Correction Factor[b]			Non-Instantaneous Repair Correction Factor[c]			Imperfect Repair Correction Factor[d]			
	Inspection Interval			Allowable Repair Time (Days)			Leak Definition (ppmv)			
Source	Yearly	Quarterly	Monthly	15	5	1	100,000	50,000	10,000	1,000
Pump Seals										
Light Liquid[e]	0.800	0.900	0.950	0.979	0.993	0.999	0.974	0.972	0.941	0.886
Valves										
Gas[f]	0.800	0.900	0.950	0.979	0.993	0.999	0.998	0.998	0.996	0.992
Light Liquid[e]	0.800	0.900	0.950	0.979	0.993	0.999	0.988	0.980	0.958	0.916
Safety/Relief Valves[g]	0.800	0.900	0.950	0.979	0.993	0.999	0.995	0.993	0.985	0.968
Compressor Seals	0.800	0.900	0.950	0.979	0.993	0.999	0.994	0.992	0.984	0.972

[a]Note that these correction factors taken individually do not correspond exactly to the overall emission reduction obtainable by a monitoring and maintenance program. The overall effectiveness of the program is determined by the product of all correction factors.

[b]Values are assumed and account for sources that start to leak between inspections (occurrence), for sources that are found to be leaking, are repaired, and start to leak again before the next inspection (recurrence), and for leaking sources that could not be repaired.

[c]Accounts for emissions that occur between detection of a leak and subsequent repair.

[d]Accounts for the fact that some sources that are repaired are not reduced to zero. The average repair factors at 1,000 ppmv are assumed.

[e]Light liquid is defined as a petroleum liquid with a vapor pressure greater than that of kerosene.

[f]Valves in gas service carry process fluids in the gaseous state.

[g]Gas service only.

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Exhibit 4

2.2 Theoretical Maximum Control Efficiency

These factors were presented in Table 4-2 (Exhibit 5, below)and not shown in the Table 4-3 (Exhibit 4, above). This value is simply based on the percentage of emissions that are possibly controllable. Some equipment cannot achieve 100% non-leakage.

Table 4-2. PERCENT OF TOTAL MASS EMISSIONS AFFECTED AT VARIOUS LEAK DEFINITIONS[1]

Source Type	Percent of Mass Emissions Affected at This Leak Definition[a]			
	100,000 ppmv	50,000 ppmv	10,000 ppmv	1,000 ppmv
Pump Seals				
Light Liquid[b]	62	73	92	98
Heavy Liquid[c]	0	0	37	85
Valves				
Gas[d]	89	95	98	99
Light Liquid[b]	53	65	86	98
Heavy Liquid[c]	0	0	0	35
Safety/Relief Valves (Gas)[d]	30	47	74	95
Compressor Seals	48	66	91	98
Flanges	0	0	0	57

[a] These figures relate the leak definition to the percentage of total mass emissions that can be expected from sources with concentrations at the source greater than the leak definition. If these sources were instantaneously repaired to a zero leak rate and no new leaks occurred, then emissions could be expected to be reduced by this maximum theoretical efficiency.

[b] Light liquid is defined as a petroleum liquid with a vapor pressure greater than the vapor pressure of kerosene.

[c] Heavy liquid is defined as a petroleum liquid with a vapor pressure equal to or less than that of kerosene.

[d] Equipment in gas service contain process fluid in the gaseous state.

Exhibit 5

2.3 Leak Occurrence and Reoccurrence Correction Factor

One of the aspects that adversely affects the expected or desired outcome (CE) is the problem of recidivism, often defined in the context of time between component failures. Components that are prone to frequently fail (i.e., hold a leak-proof seal) will be caught by more frequent inspections and it will be returned to a condition where the leak does not exceed the set threshold. EPA addressed this concept in their guidance for fugitive leak estimates. Exhibit 6, below, is from the EPA guidance and graphically represents the pattern of leak frequency and inspection intervals and the impact of the surveys on a final percentage of leakage.[6] This trend follows the common premise of requiring operators to check for leaks on a regular schedule and planned maintenance schedules that call for regularly planned inspections.

The annual value is considered similar for all components, and due to the duration of the annual interval is also similar to the affect of a one-time inspection where the leaking components that are big leakers may be found by attentive operators adopting safety related practices and seeking to capture lost product.

[6] EPA, “Protocol for Equipment Leak Emission Estimates”, EPA-453/R-95-017, 1995

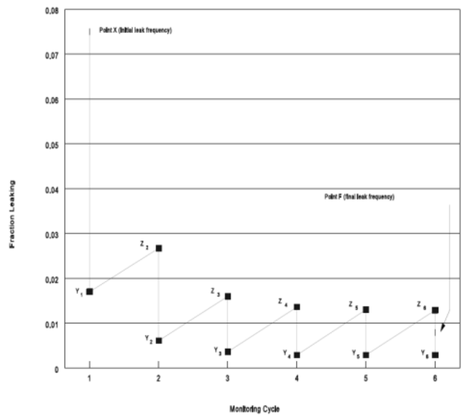

Figure 5-35. Simplified Graphical Presentation of Changes in Leak Frequency After Implementation of an LDAR Program

5-55

Exhibit 6

2.4 Non-Instantaneous Repair Correction Factor

These values were derived by statistical analysis. The reader is directed to the EPA treatment in the guidance document.[7]

This factor is correlated to interval to repair, not to survey interval.

2.5 Imperfect Repair Correction Factor

2.5.1 General Discussion of Factor

These values were derived by statistical analysis. The reader is directed to the EPA treatment in the guidance document.[8]

This factor is correlated to threshold and indicates, as one would expect, that lower thresholds will result in lower area-wide emissions. While pump seals show a greater improvement from 100,000 ppm to 1000 ppm (0.974 to 0.886), the general population of components shows a diminishing return as the threshold is lowered (I.E., Valves in Gas Service go from 0.998 to 0.992).

[7] EPA, "EIS : VOC Fugitive Emissions in Petroleum Refining Industry", 450/3-81-015a, Appendix C.

[8] Ibid.

2.5.2 EPA Enforcement Alert Factor

More importantly EPA enforcement staff visited several refineries to test the overall compliance with the LDAR program in place.[9] They found a higher percentage of leaking components than had been reported in the population studied by the reporting facilities. EPA staff took a more targeted approach to identifying potential leakers and studied a smaller population than the original refinery staff.

EPA's interpretation of the statistics relied only on their targeted body of data and did not consider all otherwise random data gathered at these locations. When one includes all data one can also include a human factor to account for poor implementation of the method itself. The purpose of this factor is to account for the problem associated with maintaining the skill to consistently apply the correct methodology for the survey. The monthly frequency would create a need for dedicated persons who would consistently survey sites on a full time basis. The quarterly frequency would have survey personnel only partially assigned to surveys or infrequent visits by contractors. While they may retain some familiarity, the data show that they cannot maintain a consistent application, selecting the correct probe position, maintain the correct probe distance, adequate time on station for the detector, etc. Annual monitoring is assumed to be largely ad hoc. The annual pre-survey equipment checkout and training program is adequate but does not provide the same degree of consistency. Our analysis used both sets of data which WZI reduced to a factor to incorporate a correction accounting for the human factor of not necessarily adhering to a rigorous protocol for the summary table, "Adjusted Emissions Factors for Various Inspection Intervals for EPA Four factor Formula and Enforcement Adjuster." While FLIR technology will help alleviate some of this inconsistence, the factor should still be included until further test data shows no need for a human adjustment factor.

[9] EPA, Office of Enforcement and Compliance Enforcement Alert Volume 2, Number 9, October 1999, Ref: 300-N-99-014

Table 2: Calculation of Enforcement Alert Results: Human Factor Adjuster for Four Factor Formula				
	Surveys	Percentage of Leakers Found during routine or enforcement survey		
Industry	170,717	1.30%	2219.321	
EPA Enforcement	47,526	5.00%	2376.3	
Total	218,243		4595.621	2.11%
Leakage Adjustment Ratio (To adjust for human factor) (2.11-1.3/1.3=0.619797)				
Leakage Adjustment Factor (To account for the increment in leakage) (1+0.619797=1.619797)				
Effectiveness is Inversely Proportional to Leakage (1/1.619=0.62)				
62%	Adjustment to A' Factor for Four Factor (Annual)			
100%	Assumed to be Monthly Adjuster to EPA Enforcement Findings (assuming leakage was found due to small count of annual intervals from EPA see 1995 Fugitive Guidelines. P5-50 to 5-61 , figure on p 5-55			
80%	Estimated Quarterly Adjuster Between Annual and Monthly values			

2.6 Adjusted Interval Control Effectiveness

The table below summarizes the outcome of the application of the EPA four factor analysis and the adjustment related to the enforcement finding. The net result of the control effectiveness is: 49% Annual, 69% quarterly, 84% monthly.

Table 3: Adjusted Emissions Factors for Various Inspection Intervals for EPA Four factor Formula and Enforcement Adjuster									
Ref EPA Table 7-1									
		Period	**Uncontrolled EF**	**Enforcement Adjust**	A	B	C	D	Control Effectiveness
			kg/day/comp						
Valves	Gas/Vapor	*Ann*	0.64	*0.7*	*0.98*	*0.8*	*0.98*	*1*	54%
	Gas/Vapor	Qrtly	0.64	0.85	0.98	0.9	0.98	1	73%
	Gas/Vapor	Mo	0.64	1	0.98	0.95	0.98	1	91%
	Lt Liq.	Ann	0.26	0.7	0.86	0.8	0.98	0.96	45%
	Lt Liq.	Qrtly	0.26	0.85	0.86	0.9	0.98	0.96	62%
	Lt Liq.	Mo	0.26	1	0.86	0.95	0.98	0.96	77%
Pump Seals	Lt Liq.	Ann	2.7	0.7	0.92	0.8	0.98	0.94	47%
	Lt Liq.	*Qrtly*	*2.7*	*0.85*	0.92	0.9	0.98	0.94	65%
	Lt Liq.	Mo	2.7	1	0.92	0.95	0.98	0.94	81%
PSV	Gas/Vapor	Ann	3.9	0.7	0.74	0.9	0.98	0.98	45%
	Gas/Vapor	Qrtly	3.9	*0.85*	0.74	0.9	0.98	0.98	54%
	Gas/Vapor	Mo	3.9	1	0.74	0.9	0.98	0.98	64%
Comp. Seal		Ann	15	0.7	0.91	0.9	0.98	0.98	55%
		Qrtly	15	*0.85*	0.91	0.9	0.98	0.98	67%
		Mo	15	1	0.91	0.9	0.98	0.98	79%
Connectors and OEL	Average From Table 2-4	Ann	1.70E-02	0.7	0.57	0.9	1	1	36%
		Qrtly	1.70E-02	*0.85*	0.57	0.9	1	1	44%
		Mo	1.70E-02	1	0.57	0.95	1	1	54%
General Weighted Average Effectiveness		Ann							49%
		Qrtly							68%
		Mo							84%

The CEs calculated for the LDAR programs have been used for numerous years to report inventory impacts.[10] In fact, CDPHE Form 203 reflects these values for facilities currently performing LDAR in Colorado pursuant to Subpart KKK, Exhibit 7 below.

[10] South Coast Air Quality Management District, Santa Barbara County Air Pollution Control District, San Joaquin Valley Air Pollution Control District, Ventura County Air Pollution Control District and Colorado Air Pollution Control Division use similar values.

AIR POLLUTANT EMISSION NOTICE (APEN) & Application for Construction Permit – Fugitive Component Leak Emissions

Permit Number: ________________ **Emission Source AIRS ID:** ______ / _______ / ______

Section 06 – Location Information (Provide Datum and **either** Lat/Long **or** UTM)

Horizontal Datum (NAD27, NAD83, WGS84)	UTM Zone (12 or 13)	UTM Easting or Longitude (meters or degrees)	UTM Northing or Latitude (meters or degrees)	Method of Collection for Location Data (e.g. map, GPS, GoogleEarth)

Section 07 –Leak Detection & Repair (LDAR) & Control Information

Check appropriate boxes to identify LDAR program conducted at this site:

☐ LDAR per NSPS KKK ☐ No LDAR program

☐ Other: ________________________________

If LDAR per NSPS KKK with 10,000 ppmv leak definition:

☐ Monthly monitoring. Control: 88% gas valve, 76% lt. liq. valve, 68% lt. liq. pump

☐ Quarterly monitoring. Control: 70% gas valve, 61% lt. liq. valve, 45% lt. liq. pump

Section 08 – Emission Factor Information

Exhibit 7