Economic Analysis of Methane Emission Reduction Opportunities in the Mexican Oil and Natural Gas Industries

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ICF received and considered data and commentary from numerous stakeholder organizations, including oil and gas producers, pipelines, equipment vendors, service providers, NGOs, and a trade organization. No information in this report should be attributed to any single organization, as all data is aggregated from multiple sources and often uses average values. Furthermore, acknowledgement of industry participation does not imply their agreement with the study conclusions, which reflect the professional judgment of ICF.

We thank all of the stakeholder organizations for providing input to this study, and specifically acknowledge PEMEX.

Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AEO	Annual Energy Outlook
AGR	Acid Gas Removal
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR	Assessment Report
BAMM	Best Available Monitoring Methods
bbl	Barrel
Bcf	Billion Cubic Feet
BCF	Billion Cubic Feet
BEA	Bureau of Economic Analysis
BTEX	Benzene, Toluene, Ethylbenzene, and Xylenes
CAC	Coalition on Climate Control
CapEx	Capital Expenditures
CBM	Coal Bed Methane
CCR	Coal Combustion Residuals
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CPI	Consumer Price Index
CSAPR	Cross-State Air Pollution Rule
DI&M	Directed Inspection and Maintenance
DUC	Drilled but Uncompleted Wells
EDF	Environmental Defense Fund
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
EUR	Estimated Ultimate Recovery
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GGFR	Global Gas Flaring Reduction
GHG	Greenhouse Gas

Acronym / Abbreviation	Stands For
GHGRP	Greenhouse Gas Reporting Program
GMM	Gas Markets Model
GRI	Gas Research Institute
GWP	Global Warming Potential
HAP	Hazardous Air Pollutant
hp	Horsepower
IEA	International Energy Agency
IMF	International Monetary Fund
INDC	Intended Nationally Determined Contribution
INECC	Instituto Nacional de Ecología y Cambio Climático
IPCC	Intergovernmental Panel on Climate Change
IR	Infrared
LDAR	Leak Detection and Repair
LDCs	Local Distribution Companies
LNG	Liquefied Natural Gas
MAC	Marginal Abatement Cost
MATS	Mercury & Air Toxics Standards Rule
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
$MMTCH_4$	Million Metric Tons Methane
$MMTCO_2e$	Million Metric Tons CO2 equivalent
MRR	Mandatory Reporting Rule
MXN	Mexican Peso ($)
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquid
NPV	Net Present Value
NSPS	New Source Performance Standards promulgated under the Federal Clean Air Act
OECD	Organization for Economic Co-operation and Development
OpEx	Operating Expenditures
OVA	Organic Vapor Analyzer
PRO	Partner Reported Opportunity
PRV	Pressure Relief Valve
psig	Pounds per Square Inch – Gauge

Acronym / Abbreviation	Stands For
RECs	Reduced Emission Completions
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
SME	Subject Matter Expert
TEG	Triethylene Glycol
TSD	Technical Support Document
UNFCCC	United Nations Framework Convention on Climate Change
USD	U.S. Dollars
VOC	Volatile Organic Compound
VRU	Vapor Recovery Unit

1. Executive Summary

Methane is an important climate change forcing greenhouse gas (GHG) with a short-term impact many times greater than carbon dioxide. According to Mexico's fifth national communication to the UNFCCC published in 2012, methane accounted for approximately 27% of Mexico's total emissions, resulting from activities in the IPCC sectors such as agriculture and waste, as well as emissions from oil and natural gas systems[1], and would comprise a substantially higher portion based on a shorter timescale measurement. A recent emissions inventory published in 2015 by Mexico's Instituto Nacional de Ecología y Cambio Climático (INECC)[2] estimates total methane emissions to be 19% of total emissions. Regardless of which estimate is used, recent research also suggests that mitigation of short-term climate forcers such as methane is a critical component of a comprehensive response to climate change[3].

Methane is the primary component of natural gas. As a result, methane emissions occur throughout the oil and gas industry, and are one of the largest anthropogenic sources of Mexican methane emissions[4]. At the same time, there are demonstrated methods to reduce emissions of fugitive and vented methane from the oil and gas industry and, because of the value of the gas that is conserved, some of these measures could potentially increase revenue (e.g. reduce lost product) or have limited net cost. The Mexican federal government has also discussed reducing these emissions as part of its commitment to international GHG reduction efforts, and pledged to cut GHG by 25% by the year 2030[5].

International nonprofit organization Environmental Defense Fund (EDF) commissioned this economic analysis of methane emission reduction opportunities from the Mexican oil and natural gas industries to identify the most cost-effective approaches to reduce these methane emissions. This study is solutions-oriented and builds off similar studies that ICF undertook for EDF on oil and gas methane reductions in Canada and the United States[6]. This study attempts to project the trajectory of methane emissions from these industries through 2020. It then identifies the largest emitting segments and estimates the magnitude and cost of potential reductions achievable through currently available and applicable technologies. The key conclusions of the study include:

- **22.7 BCF of Emissions in 2020** - Methane emissions from oil and gas activities are projected to decrease from 14.6 million metric tons of CO_2e (27.05 Bcf) in 2013 to 12.2 million metric tons of CO_2e (22.7 Bcf) in 2020.

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[1] National Inventory Report – Greenhouse Gas Sources and Sinks in Mexico derived using the 100 year GWP.. https://unfccc.int/national_reports/non-annex_i_natcom/items/2979.php

[2] INVENTARIO DE GASES Y COMPUESTOS DE EFECTO INVERNADERO 2013 http://www.inecc.gob.mx/descargas/cclimatico/2015_inv_nal_emis_gei_result.pdf

[3] Shoemaker, J. et. al., "What Role for Short-Lived Climate Pollutants in Mitigation Policy?". Science Vol 342 13 December 2013

[4] Mexican UNFCCC Submission Report section IV.4 "Panorama genera" and IV.5 "Emisiones de gases de efecto invernadero por gas"

[5] Mexican INDC submission: http://www.semarnat.gob.mx/sites/default/files/documentos/mexico_indc.pdf

[6] Available at: https://www.edf.org/energy/icf-methane-cost-curve-report

- The opening up of Mexico's oil and gas sector to foreign companies was analyzed as part of this emissions analysis but not found to significantly affect emissions in 2020 as projects will not yet be online.
- The majority of this emissions decrease is caused by the continued decline of Mexico's most prolific offshore producing field - Cantarell. Offshore fields such as Ku-Maloob-Zaap (KMZ) are also projected to decline from 2013 to 2020, contributing to an overall decrease in emissions.
- Existing 2013 emissions sources account for over 90% of emissions in 2020.

- **Concentrated Reduction Opportunities** - 21 of the over 100 emission source categories[7] account for over 80% of the 2020 emissions, primarily at existing facilities. Thus, reductions from these sources offer the opportunity for high overall reductions.
- **54% Onshore and Offshore Emissions Reduction Possible with Existing Technologies[8]** – This 54% reduction of all oil and gas methane is equal to 6.6 million metric tons CO_2e (12.2 Bcf of methane) and is achievable with existing technologies and techniques. This reduction:
  - Comes at a net total cost of $0.43 MXN[9] /Mcf reduced ($0.03 USD/Mcf reduced) or for less than $0.01 MXN /Mcf of gas produced nationwide[10], taking into account savings that accrue directly to companies implementing methane reduction measures (Figure 1-1).
  - Is equal to $0.79 MXN / metric tons CO_2e reduced. If the natural gas is valued at $62 MXN/Mcf ($4/Mcf), the methane reduction potential includes recovery of gas worth approximately $483.6 million MXN[11] ($31.4 million USD) per year.
  - Is achievable at a net cost of over $5.2 million MXN per year ($313,546 USD) if the full economic value of recovered natural gas is taken into account and not including savings that do not directly accrue to companies implementing methane reduction measures[12]. If the additional savings that do not accrue to companies are included, the 54% reduction is achievable at a net savings of $78 million MXN ($5 million USD).
  - Is in addition to regulations already in place as well as projected voluntary actions companies will take by 2020.
- Capital Cost – The initial capital cost of the measures is estimated to be approximately $1.6 billion MXN ($106 million USD).

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[7] For example, fugitive emissions from reciprocating compressors or vented emissions from liquids unloading.

[8] Converted emissions and monetary values may not exactly match due to rounding

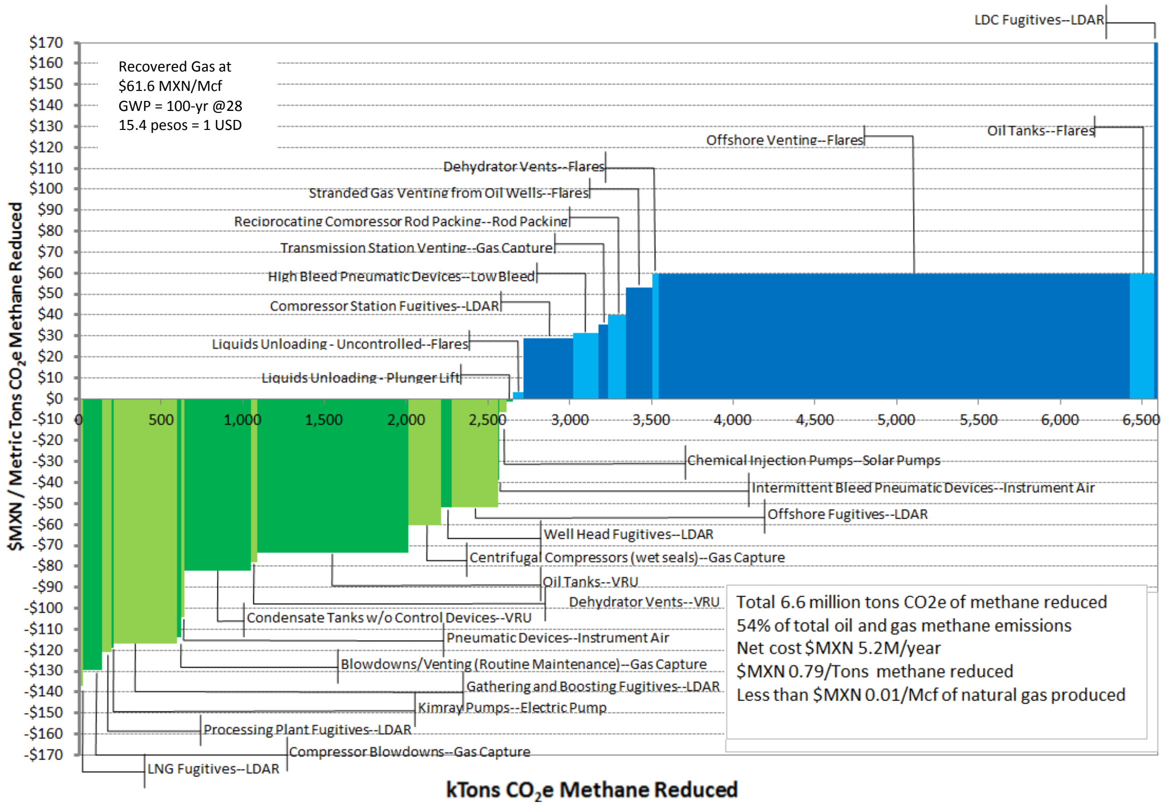
[9] All costs in this report are on a Mexican Peso basis (MXN) unless where specifically expressed as U.S. Dollars (USD). A 2015 monthly average was used to calculate an exchange rate of 15.4 MXN to 1 USD. Figures may not match due to rounding. https://research.stlouisfed.org/fred2/series/EXCAUS/downloaddata

[10] Based on average natural gas production numbers across Mexico

[11] Value is calculated based on whole gas and not just methane, excluding flaring.

[12] Does not include or take into account potential social cost of methane emissions.

Figure 1-1 - Marginal Abatement Cost Curve for Total Oil and Gas Methane Reductions by Source in CO2e



- **Largest Abatement Opportunities -** In 2020, the Offshore segment makes up 54% of total oil and gas methane emissions, follow ed by Gathering and Boosting (19%) and Oil Production (11%). By volume, the top five largest sources of on and offshore Mexican oil and gas methane emissions and reduction opportunities are:
  - Offshore Venting – opportunity to reduce emissions by 78% by installing flares.
  - Venting from Oil Tanks – opportunity to reduce emissions by 48% by installing vapor recovery units.
  - Reciprocating compressor rod packing seals - opportunity to reduce emissions by 22% by replacing rod packing at a higher frequency.
  - Stranded Gas Venting – opportunity to reduce emissions by 78% by installing flares.
  - Venting from Condensate Tanks – opportunity to reduce emissions by 48% by installing vapor recovery units.
- **Co-Benefits Exist** – Reducing methane emissions will also reduce - at no extra cost - conventional pollutants that can harm public health and the environment. The methane reductions projected here would also result in a reduction in volatile organic compounds (VOCs) and hazardous air

pollutants (HAPs) associated with methane emissions from the oil and gas industry. This was not quantified in this study due to lack of data.

There are several caveats to the results:

- This study used as much Mexican-specific data as possible and modeled emissions by resource type and by using Mexico-specific activity data, where possible. Various assumptions across each segment were utilized in conjunction with Mexican-specific data (e.g. Secretaría De Energía (SENER), Petróleos Mexicanos (PEMEX), Instituto Nacional de Ecología y Cambio Climático (INECC), etc.) in order to develop equipment and segment-specific activity estimates for the Mexican oil and gas industry. Where no Mexican data existed, supplementary data from U.S. studies was used. Assumptions about site configurations are also U.S. based. Factors specific to Mexican oil and gas operations were also considered in the estimation of emissions, specifically the presence of sour gas and nitrogen injection in select oil production wells such as the Cantarell for enhanced oil recovery.
- IPCC guidelines[13] for oil and gas methane reporting are split into three regions; U.S. and Canada, Western Europe, and other oil exporting countries. Mexico falls into the last region, which has higher emission factors, specifically for venting and flaring emissions. Mexico prepares its inventory using these IPCC emissions factors and reports it to the UNFCCC[14]. Mexican emissions inventories are higher in comparison to this ICF study, in part, because of the higher IPCC emission factors. The more recent INECC study indicates a different approach to estimating emissions and is significantly lower than the previous UNFCCC reporting. However, if IPCC emission factors used by Mexico are directionally correct, this study provides a conservative estimate for potential reductions.
- This ICF study developed a bottoms up emissions estimate using specific activity and emissions factor data where applicable. Where no Mexican emission factors were available, this study used data from the Subpart W[15] of the U.S. EPA GHG Reporting Rule (GHGRP) which was analyzed in conjunction with regional proxies (based on geology) to develop emission factors that apply to the Mexican case. Source-specific emissions factors from U.S. data are not expected to be significantly different vs. Mexican operations. For example, a pneumatic device made by the same company can reasonably be assumed to operate the same in Mexico as it would in the U.S.
- Various assumptions across each segment were utilized in conjunction with available public reports (e.g. SENER, PEMEX, INECC, etc.) in order to develop equipment and facility information for Mexican segments, which is not otherwise available.
- Emission mitigation cost and performance are highly site-specific and variable. The values used here are estimated average values.

[13] http://www.ipcc-nggip.iges.or.jp/public/gl/guidelin/ch1ref8.pdf
[14] http://www.inecc.gob.mx/descargas/cclimatico/inf_inegei_energia_2010.pdf
[15] Subpart W – Petroleum and Natural Gas Systems
http://www.epa.gov/ghgreporting/reporters/subpart/w.html

2. Introduction

Methane emissions have an enhanced effect on climate change because methane has a climate forcing effect 25 times greater on a 100 year basis than that of carbon dioxide, the primary greenhouse gas (GHG). Methane's impact is 72 greater on a 20 year basis[16], illustrating that methane reductions made today can have a real and tangible impact on reducing impacts of climate change tomorrow. Recent research also suggests that mitigation of short-term climate forcers such as methane is a critical component of a comprehensive response to climate change[17].

Methane emissions from the oil and gas industries are among the largest anthropogenic sources of Mexican methane emissions according to the most recent Mexican inventory[18]. At the same time, there are many ways to reduce emissions of fugitive and vented methane from the oil and gas industries and, because of the value of the gas that is conserved, some of these measures actually increase revenue or have limited net cost.

The oil and gas industry has also made voluntary reductions in methane emissions, which were included in this analysis, but the statistics on the specific efforts undertaken are unclear in many instances given the lack of publicly available data sources. The reductions projected here are additional to projected voluntary actions taken until 2020. Overall reductions from voluntary measures are included in the 2020 baseline, but the specific reductions are not assessed in this study by source category. Methane emissions remain a significant component of the Mexican GHG inventory and there is a sizeable potential for additional cost-effective reduction opportunities.

2.1. Goals and Approach of the Study

Environmental Defense Fund (EDF) commissioned this economic analysis of methane emission reduction opportunities from the Mexican oil and natural gas industry. This study's analysis is solutions-oriented and complements EDF's ongoing work on methane emissions in the oil and natural gas sectors. This study also references and implements a similar approach and methodology to the U.S. and Canadian marginal abatement cost curve studies recently undertaken by ICF International[19,20]. The approach of the Mexican study was to:

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[16] Based on AR-4 values for GWP. See section 2.3 of this report for further discussion of GWP and AR-5 values for 20-yr and 100-yr.

[17] Shoemaker, J. et. al., "What Role for Short-Lived Climate Pollutants in Mitigation Policy?". Science Vol 342 13 December 2013

[18] INVENTARIO DE GASES Y COMPUESTOS DE EFECTO INVERNADERO 2013 http://www.inecc.gob.mx/descargas/cclimatico/2015_inv_nal_emis_gei_result.pdf

[19] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

[20] https://www.edf.org/climate/icf-report-canadas-oil-and-gas-methane-reduction-opportunity

- Define a baseline of methane emissions from the oil and gas sectors according to segments defined further in Section 2.2 below. The baseline was established for 2013 and projected to 2020 as a conservative estimate of a point when existing mitigation technologies could be fully installed throughout the supply chain.
- Review existing literature and conduct further analysis to identify the largest reduction opportunities and validate and refine cost-benefit estimates of mitigation technologies.
- Conduct interviews with industry, oil and gas experts, and equipment vendors with a specific focus to identify additional mitigation options.
- Use this information to develop marginal abatement cost (MAC) curves for methane reductions in these industries.
- Document and present the results.

The final outputs of the study include:

- The projected 2020 emissions baseline. (Chapter 3 and Appendix B)
- Inventory of methane mitigation technologies. (Chapter 3)
- Emissions abatement cost curves across a range of scenarios (Chapter 4 and Appendix C)
- Conclusions (Chapter 5)
- Additional sensitivity cases (Appendix D)

2.2. Overview of Gas Sector Methane Emissions

There are many sources of methane emissions across the entire oil and gas supply chain. These emissions can be characterized as:

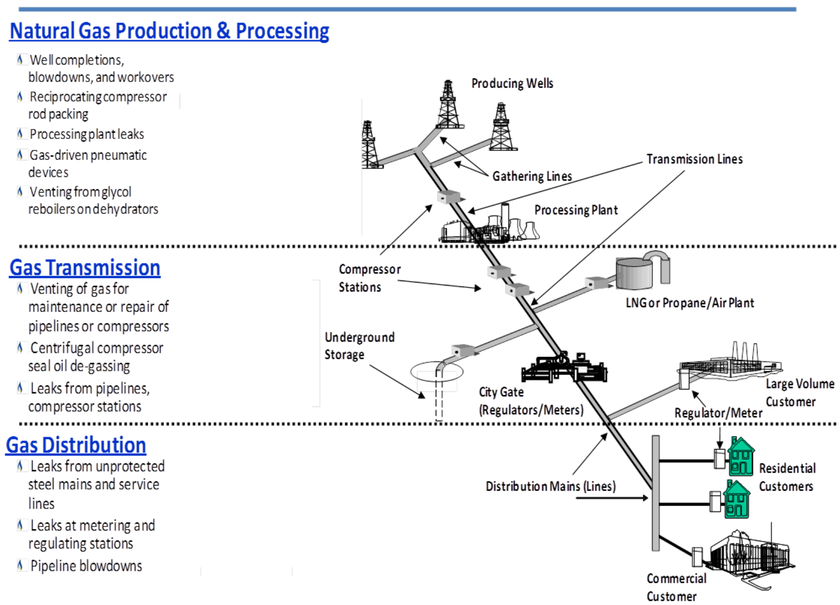
- Fugitive emissions – methane that "leaks" unintentionally from equipment such as from flanges, valves, or other equipment.
- Vented emissions – methane that is released due to equipment design or operational procedures, such as from pneumatic device bleeds, blowdowns, or equipment venting.
- Incomplete combustion – methane that passes through a combustion device, such as an engine or flare, without being combusted due to less than 100% combustion efficiency of the device.

Although 'leaks' or 'fugitives' is sometimes used to refer to all methane emissions from the oil and gas industry, we use the more narrow technical definitions in this report.

Figure 2-1 illustrates the major segments of the natural gas industry and examples of the primary sources of methane emissions as gas is produced, processed, and delivered to consumers. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas"). Up until the 2004-2005, most of the Mexican oil supply came from the

Cantarell field in the north-west offshore region. More recently, Mexico has been continuing its efforts developing the Chicontepec region in the northern onshore region, but production numbers still remain below expectations. Mexico will continue efforts to replace the significant production lost with the decline of the Cantarell field including through privatization of the oil production sector. While these reforms have begun, the results to-date suggest that they will not likely impact production before 2020, therefore these reforms are not reflected in this analysis. Further discussion can be found below.

Figure 2-1 - Natural Gas Industry Processes and Example Methane Emission Sources



Sources: American Gas Association; EPA Natural Gas STAR Program

Gas Production

Raw gas (including methane) is vented at various points during the production process. Gas can be vented when the well is "completed" at the initial phase of production. Further, because gas wells are often in remote locations without electricity, gas pressure is used to control and power a variety of control devices and on-site equipment, such as pumps. These pneumatic devices typically release or "bleed" small amounts of gas during their operation. In both oil and gas production, water and hydrocarbon liquids are separated from the product stream at the wellhead. The liquids release entrained gas, which may be vented from tanks unless it is captured. Water is removed from the gas stream by glycol dehydrators, which vent the removed moisture and some gas to the atmosphere. In some cases, the gas released by these processes and equipment may be flared rather than vented, to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO_2, a significant but less potent GHG than methane, but no flare is 100% efficient, and some methane (uncombusted) is emitted during flaring. In addition to the various sources of vented emissions, the many components and complex network of small gathering lines have the potential for fugitive emissions.

Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. The gathering system has pneumatic devices and compressors that vent gas and have potential fugitive emissions. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order for the gas to be pipeline-quality and ready to be compressed and transported. Such plants are another source of fugitive and vented emissions.

From the gas processing plant, natural gas is transported, generally over long distances by pipeline to the "city gate" hub and then to consumers. The vast majority of the compressors that pressurize the pipeline to move the gas are fueled by natural gas, although a small share is powered by electricity. Compressors emit CO_2 and methane during fuel combustion and are also a source of fugitive and vented methane through leaks in compressor seals, valves, and connections and through venting that occurs from seals and during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission.

Some power plants and large industrial facilities receive gas directly from transmission pipelines, while others as well as residential and commercial consumers have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment.

Oil Production

Many of the emission sources from domestic oil production are similar to those in gas production – completion emissions, pneumatic devices, processing equipment and engine/compressors. Crude oil contains natural gas and the gas is separated from the oil stream at the wellhead and can be captured for sale, vented, or flared. Venting or flaring is most common in regions that do not have gas gathering infrastructure ("stranded gas"). For example, Mexican offshore operations have significant flaring and venting emissions according to publicly available sources[21].

Oil is taken from the wellhead in electric-powered pipelines to refineries for processing. Petroleum products are then taken to consumers by pipeline, truck, rail, or barge. The downstream methane emissions in the petroleum sector are much smaller than in the gas sector as most of the methane has been removed from the oil by this point. The oil transportation and refining segments are not included in the emissions analysis of this report.

Mexican Oil and Gas Operations and Other Developments

[21] Discussed in more detail in Section 2.5

Domestic oil production has been primarily in the offshore region of Mexico, mainly from conventional fields such as Cantarell and KMZ. Significant offshore production started in the 1970's and peaked around 2004. Domestic non-associated gas production is primarily onshore and has also been mostly concentrated in the northern region, while gas production offshore is mainly associated gas. While shale development does not seem to be a major part of the near future of Mexico's oil and gas industry, a continued focus has been on the Chicontepec onshore region for heavy oil development. There has been much debate on the content of reserves in the Chicontepec formation, and the economic viability of such reserves. Although there has been significant investment from PEMEX to fully develop the formation, overall production of the Chicontepec has been met by not only economic and technical challenges, but also political ones[22]. While there have been debates on the future productivity of the Chicontepec region, history has shown that the region has significant challenges that have limited its production potential and thus this study assumes no significant changes in production in the Chicontepec region during the 2013 to 2020 period.

Finally, with Mexico recently announcing the opening of its oil industry to private competition, it is unarguable that this step forward will have ramifications for not only production values but also emissions. However, due to lukewarm reactions from the initial rounds of oil block auctions[23], it is unlikely that many of these changes to the oil and gas industry will have significant impact on Mexican operations before 2020. Thus, this analysis does not consider any further implications from foreign investment in oil field development during this period.

Mexican Offshore Operations

In Mexico, significant amounts of both oil and gas are produced from offshore facilities. Similar to the challenges in the onshore Chicontepec region, the Cantarell field in the north-east marine region has been in significant decline and will continue to do so through 2020. However, increased production will likely come from activity in the southwest marine offshore region. In addition to utilizing publicly available PEMEX and SENER[24] data on Mexico-specific platform counts and types, this study analyzed numerous reports to gain insight into offshore oil and gas activities in Mexico. The Bureau of Ocean Energy Management (BOEM) has extensive data on offshore platform emissions in the U.S., and the structure of that data was analyzed to better characterize Mexico's offshore emissions. The Gulfwide Offshore Activity Data System (GOADS) database contains detailed data on emissions by equipment and platform type, as well as distinguishing between shallow and deep water operations. Every effort has been made to ensure the offshore emissions estimation methodology is consistent with the rest of the

[22] The Chicontepec region is densely populated.

[23] Mexico Awards First Oil Blocks in Historic Auction
http://www.wsj.com/articles/mexico-awards-first-oil-block-in-historic-auction-1436978568

[24] SENER: Sie Database.
http://sie.energia.gob.mx/bdiController.do?action=temas&fromCuadros=true

inventory for this study. Therefore, unlike the US and Canada studies, this study focuses on *both* onshore and offshore oil and gas industry operations in Mexico.

2.3. Climate Change-Forcing Effects of Methane

Different greenhouse gases persist in the atmosphere for different lengths of time and have different warming effects, and thus have different effects on climate change. In order to compare them, the scientific community uses a factor called the global warming potential (GWP), which relates each GHG's effect to that of CO_2, which is assigned a GWP of 1. The science and policy communities have historically looked to the Intergovernmental Panel on Climate Change (IPCC) assessment reports as the authoritative basis for GWP values. The currently accepted values are from the IPCC Fifth Assessment Report[25] (AR-5).

CO_2 emissions are the primary driver for climate change over the long term, due to their long lifetime in the atmosphere. Because stabilizing climate will require deep cuts in GHG emissions, GWP values are most commonly expressed on a 100-year time horizon. On a 100-year basis, methane is assigned a GWP of 34 according to the most recent science in the AR-5. This means that one ton[26] of methane has the same effect as 34 tons of CO_2 over 100 years. The 100 year GWP is the standard value used by SEMARNAT/INECC, EPA, and international agencies to measure GHG emissions but there are different values in use. The different values come from different versions of the IPCC Assessment Reports, which have different GWPs for methane as the scientific understanding of methane's impact on the climate has improved. For example, the 5th Mexican National Communication uses a 100 year GWP of 21 which is derived from the 2nd IPCC Assessment Report. The U.S. EPA GHG inventories uses a 100 year GWP of 25 from the 4th IPCC Assessment Report, as specified by the United Nations Framework Convention on Climate Change (UNFCCC) inventory protocol. The most recent Mexican inventory and the Mexican INDC (Intended Nationally Determined Contribution) use a 100 year GWP of 28 based on the AR-5. Since both the INDC and the most recent inventory use the GWP of 28, that metric is used for CO_2e conversions in this report.

Some GHGs, including methane, have a stronger climate-forcing effect than CO_2 but a shorter lifetime in the atmosphere (12 years for methane). In order to evaluate the short-term effects, the GWP is also calculated on a 20 year basis. On a 20 year basis, the AR-5 assigns methane a GWP of 86. In summary:

- The most recent Mexican inventory and Mexico's INDC use a 100 year GWP of 28 derived from AR-5.
- Mexico's 5th National Communication released in 2012, uses a 100 year GWP of 21, derived from the 2nd IPCC Assessment report.

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[25] IPCC. Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.
https://www.ipcc.ch/report/ar5/wg1/

[26] 'Ton' is equivalent to a Metric Ton

- U.S. EPA uses the AR-4 100 year GWP of 25. The AR-4 20 year GWP is 72.
- The GWPs for AR-5 are 34 for 100 years and 86 for 20 years.
- This report uses the AR-5 100 year GWP of 28 except where otherwise noted.

2.4. Cost-Effectiveness of Emission Reductions

It is common in discussing emission reductions to describe "cost-effective" emission reductions. However, there are three different concepts of cost effectiveness that must be understood and differentiated.

The Company Perspective - The first concept is cost-effectiveness for the company implementing the measure. In this case, "cost-effective" means that the value of gas that is recovered through a methane reduction measure exceeds the incremental capital and operating cost of the measure sufficiently to create a payback or rate-of-return that meets the company's investment criteria. Measures that meet these criteria might be described as having a positive net present value (NPV), a short payback period, or an internal rate of return that exceeds a certain threshold. In order for a measure to meet this cost-effectiveness criterion, the measure must recover the methane emissions and be able to recover their monetary value. Flaring of methane emissions does not meet this criterion, for example. In addition, the company must be able to monetize the value of the recovered methane. For example, if a producer reduces methane losses, it will have more gas to sell and will receive an economic benefit.

Economy Perspective - The second concept is cost-effectiveness at the economy-wide scale. In segments in which the company owns the gas, such as oil and gas production, the company can clearly monetize the value of reduced gas losses. This is also true in some other segments. Most midstream companies (gathering, processing, and storage) are paid a fixed fee for gas lost and consumed during their operations. If they can reduce their losses then they will benefit directly from the reduced losses.

Transmission and local distribution companies typically do not own the gas they transport and they are usually required by regulators to return the value of reduced losses to their customers, so they cannot recover the benefit of reduced methane losses. Methane reductions in these segments of the industry will not have a positive return to the company or be "cost-effective" in this sense. That said, the value of reduced losses will accrue to other parts of the economy. If a pipeline or LDC reduces its losses, the benefit will eventually flow through to the customers and to the economy overall. Reduced losses will eventually flow through as lower prices for gas delivery and delivered cost of gas to consumers. Thus, even when the entity implementing a reduction cannot directly benefit from reduced losses, there is a broader benefit and that full economic benefit can be calculated and allocated against the cost of the methane reduction, the second kind of cost-effectiveness.

The Regulatory Perspective - The last concept of cost-effectiveness is in the context of pollution control programs. In conventional pollution control programs the control technology rarely results in a cost reduction to the company that is required to implement it. That is, the cost-of-control is almost always positive and the net present value is negative and there is no payback for the investment. Nevertheless, these programs incorporate the concept of cost-effectiveness, meaning that the cost is acceptable to society as a means of meeting public health and environmental goals. The cost-effectiveness varies for different pollutants and different regulatory programs. In this context, methane reductions can be considered cost-effective even if they have a net cost to the company or society overall. Where methane reductions do create a net value to the implementing company, the cost-of-control will be negative, i.e., the company is reducing emissions and saving money rather than spending money.

In this study, the value of recovered gas is included in calculating the cost-effectiveness of mitigation measures where the gas can be recovered and where it can be monetized by the company. Therefore, the same measure may have different costs for different segments, e.g., reducing compressor emissions will have a lower net cost in the production segment than in the transmission segment because the savings can be monetized in the former but not that latter. This reflects the net cost to the company to implement the measure. However, where gas can be recovered through a mitigation measure, it will have value to the broader economy, even if it is not recognized by the company that must make the investment. The cost-of-control, whether positive or negative, can be also evaluated in the regulatory sense and compared to other available emission reduction options. Finally, there are additional social and environmental benefits of methane reductions that are not captured in these calculations, including the broader economic value of reduced climate risk and co-benefit reductions of conventional pollutants such as ground-level ozone and hazardous air pollutants.

2.5. Mexican Regulatory Landscape and Emission Reporting

Recently, Mexico has issued new regulations to collect information on emissions of GHG across the country. The “Reglamento de la Ley General de Cambio Climático en Materia del Registro Nacional de Emisiones” or GHG regulation, was a new regulation issued by the Secretariat of Environment and Natural Resources (SEMARAT) in 2014 that created Mexico’s GHG registry and reporting system Registro Nacional de Emisiones (RENE), similar to the U.S. GHGRP. Similar to the U.S., the regulation is mainly reporting in nature, and does not explicitly regulate GHG emissions at this time.

Beyond the reporting regulation on GHGs, Mexico’s regulatory requirements for emissions focus heavily on flaring and venting activities, partly due to flaring and venting being the largest sources of methane emissions in the oil and gas sector. While there is a large self-regulation component to Mexico’s approach to decreasing flared and vented methane (i.e. by PEMEX), Mexico does have some other regulatory mechanisms to address methane emissions, namely CNH.06.001/09[27], or the National Hydrocarbon Commission’s set of performance criteria and application for the calculation of flaring and

[27] National Hydrocarbon Commission (CNH.06.001/09) – Performance criteria and application for the calculation of flaring and venting of natural gas.
http://www.cnh.gob.mx/_docs/QuemaVto/DT_QyV.pdf

venting of natural gas[28]. The regulation is mainly performance-based, focusing on the following principles:

- Technical provisions are set forth for PEMEX to evaluate and plan oil field operations regarding potential flaring and venting activities, so as to avoid the unnecessary wastage of gas;
- PEMEX must perform an economic analysis when seeking controlled destruction in hydrocarbon exploration and development projects and submit it to the commission for review (i.e. perform and analysis of costs incurred in the destruction of the extracted gas, including capital costs and operation of the execution of the gas destruction, verification and monitoring, and the financial burdens or insurance required to remedy any damages generated to the country);
- Venting is not considered economic and if the volume of gas can support continuous and stable combustion, it should be combusted;
- PEMEX must develop and implement a plan to detect and repair leaks that present in their facilities and must calculate and report the volume of gas that is evolving their facilities;

Although providing high level guidance on maximum values or targets to achieve, CNH.06.001/09 does not provide further specific guidance for the management of flaring and venting volumes or for penalties that would apply if limits were exceeded. Beyond the focus on flaring and venting, Mexican oil and gas regulations do not lay out prescriptive requirements for specific emissions sources across the various oil and gas segments. Rather, it is up to the self-regulation by PEMEX to identify sources that may or may not require mitigation options to reduce methane emissions. Thus, it is unclear whether all sources that emit methane are being captured and analyzed across Mexican oil and gas activities, what control measures have been implemented by oil and gas operators and the magnitude of the resulting reductions in methane emissions. Overall, this leads to uncertainty regarding existing methane reduction efforts.

Mexican Emission Reporting

According to Mexico's Fifth National Communication to the UNFCCC reporting (released in 2012), total methane emissions were estimated to be 7,938.9 Gg. 45.9% of these emissions are attributed to the natural gas and petroleum sector, totaling 3643.9 Gg of oil and gas methane emissions. This converts to 3.64 million metric tons of methane, or approximately 189.2 Bcf of methane emissions from the oil and gas sector[29]. A recent emissions inventory published by INECC/SEMARNAT (released in 2015) estimates methane emissions from oil and gas to be closer to 1.1 million metric tons or 57.4 Bcf, a significant difference from the values reported in the 5th National Communication.

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[28] There is also a second regulation CNH.07.002/10 that establishes interpretation and application criteria for the calculation of the maximum national level of venting and flaring

[29] Inventario de Gases y Compuestos de Efecto Invernadero (published in 2015 using 2013 data) http://www.inecc.gob.mx/descargas/cclimatico/2015_inv_nal_emis_gei_result.pdf

Both estimates include vented and flared emissions and when the emissions are sent to the flare then only a small portion of the natural gas typically remains as uncombusted methane. In the United States the flare efficiency is estimated at 98%. Flare combustion efficiency in Mexico has been estimated at 83.7% which would mean higher methane emissions from flares[30]. However, to be conservatively lower from an emissions perspective, this analysis used an efficiency of 98%, providing a starting point for potential emission reductions. Both the 189 Bcf estimate and the 57 Bcf estimate are higher than the 27 Bcf estimate in this study. This study used several different data sources beyond the 5th National Communication and most recent inventory to develop an emissions baseline. This includes publically available documents from PEMEX and other Mexican organizations[31]. ICF undertook the following steps to support its emission estimate, particularly the treatment of venting and flaring, which are believed to be a significant part of the inventory:

1. ICF consulted publically available information including the 5th National Communication, the most recent INECC/SEMARNART GHG Inventory, and publically available documents from PEMEX (e.g. Documents filed with the Securities and Exchange Commissions (SEC)[32] indicate the typical annual flaring volume for Pemex is approximately 125 Bcf/year).

2. ICF consulted other sources including a Global Methane Initiative presentation given by PEMEX in 2012[33] and conversations with technical experts at PEMEX. These sources also yielded a flaring estimate of about 125 Bcf/year.

These flaring estimates are similar to each other, and this study uses the data from PEMEX's SEC filing which yielded a flaring volume estimate of 129 Bcf in 2013. The annual venting volume in this report (also obtained from PEMEX) is 8 Bcf in 2013.

ICF is confident in its approach for determining flaring and venting volumes. Methodological differences between this study, the 5th National Communication, and the INECC/SEMARNAT inventory yield different results, which is not surprising. It should be noted though, that lower estimates of flaring efficiency may lead to greater emissions estimates from flaring. Additionally, this study did not have the ability to parse out the data from the inventory in a more complete fashion. More Mexico-based data is needed to fully understand the discrepancy between inventories and further investigation as to why there is a difference would be useful.

Finally, looking ahead at the regulatory landscape across Mexico, according to the Intended Nationally Determined Contributions (INDC) submitted to the UNFCCC, Mexico is continuing to develop and

[30] http://www.inecc.gob.mx/descargas/cclimatico/2012_estudio_cc_invgef3.pdf, see page 129.
[31] http://www.inecc.gob.mx/descargas/cclimatico/2012_estudio_cc_invgef3.pdf
[32] PETRÓLEOS MEXICANOS – Report of Private Issuer
http://www.ri.pemex.com/files/content/Form%206-K%20as%20filed%20June%207,%202013_RR.pdf
[33] Pemex Exploración y Producción - Air Emissions Reduction Strategy
http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/bocanegra.pdf

implement measures to reduce emissions from key greenhouse gas sources. The Mexican Government specifically included Short Lived Climate Pollutants (SLCPs), stating “The INDC that Mexico is submitting encompasses for mitigation purposes both the reduction of all GHG and SLCPs.” Mexico’s INDC also states, “For Mexico, the inclusion of SLCPs constitutes an increase of its level of ambition and commitment since it is additional to what the country has committed to previously[34].”

[34] Mexico’s INDC available at: http://www.semarnat.gob.mx/sites/default/files/documentos/mexico_indc.pdf

3. Approach and Methodology

3.1. Overview of Methodology

This section provides an overview of the methodology applied for this study. The major steps were:

- **Establish the 2013 Baseline Inventory for Mexico** – upstream and midstream operations in Mexico were divided into two categories based on the presence of hydrogen sulfide (H_2S) ("sweet" or "sour" gas). H_2S is poisonous and its presence requires systems that are less prone to leak. The determination of whether or not to classify production as sweet or sour was made based on data extracted from various reports published by CNH[35]. If the measured H_2S content was greater than 0.1%, the field and its associated production were assumed to be sour. The data structure and taxonomy of the U.S. EPA GHG Inventory was then used as a starting point to generate the list of source categories for the Mexican baseline. Emissions were not segregated by Mexican region, except that offshore operations were considered to be its own segment.

  Mexican-specific data were used wherever possible. This was particularly applicable for the activity data (the characterization of the number and type of facilities) such as well counts, miles of transmission pipeline, number of gathering stations, etc. When Mexican emissions data were less available, U.S. emission factors or data were used, such as the emission factors from the Subpart W reporting program. This was estimated to be an appropriate approach because the types of equipment and operating procedures are very similar between the U.S. and Mexico. Surrogate locations were identified in the U.S. to help generate these estimates for select emissions sources based on geological and operating criteria. The following analogs were identified specifically for oil and gas activity from production through processing segments of the industry based on SME input:

  - Northern Mexico– Gulf Coast
  - Southern Mexico – Mid-Continent

To further clarify the approach above, on a basic level, emissions in this study are estimated by the following equation:

$$Emissions = \sum_{i=1}^{n} (AF_i \times EF_i)$$

Where n is the total number of emissions sources and AF and EF stand for activity and emissions factor, respectively, for each source. Mexican-specific data were mainly used to estimate the AF portion of the equation, while some Mexican data as well as proxy data and detailed analysis of Subpart W, external reports, etc., were used to estimate the EF portion.

[35] Activo de Producción Cantarell
http://www.cnh.gob.mx/_docs/Manifiestos/Man_Cantarell_2013.pdf

The Mexican analysis was developed using publicly available reports from PEMEX for GMI, along with CNH, SIE, and SENER publications on the Mexican oil and gas industry[36]. Support from Mexican oil and gas experts and the evaluation of the most recent U.S. EPA inventory of methane emissions in the EPA Inventory of U.S. GHG Emissions published in 2014 with data for 2012[37] was also a part of the analysis. The 5th national communication and the 2015 Mexican inventory was then reviewed and revised to account for additional, more recent information such as information from the EPA GHG Reporting Program[38], recently published studies such as the University of Texas gas production measurement study[39], and other recent studies sponsored by EDF. These changes were applied to develop a 2013 Baseline, which was used as the basis for projecting onshore methane emissions to 2020. The baseline inventory includes methane emissions by source for the onshore and offshore exploration and production, gas processing, gas storage, gas transmission, LNG import / storage, and distribution segments of the industry.

Finally, routine checks were made in the development of the baseline with external sources as points of comparison in the analysis.

- **Projection of emissions to 2020**– the analysis then used the 2013 baseline inventory to project emissions to the year 2020 based on various drivers such as growth in gas production, pipeline mileage, etc. Data for projections were obtained mainly from SENER and internal analysis from ICF and is discussed in Appendix B. Potential reductions were based on regulatory analysis and input from subject matter experts. The year 2020 was chosen as a conservative date by which control technologies could be installed.
- **Identification of major sources and key mitigation options** – the next step was to identify the largest emitting sources in the projected 2020 inventory and the emissions with associated mitigation technology that would be most effective and cost-effective for these sources.
- **Characterization of emission reduction technologies** – a key part of the study was to review and update information on the cost and performance of the selected mitigation technologies. Information was gathered from equipment manufacturers, oil and gas companies, and other knowledgeable parties and then applied to the volume of associated emissions.
- **Development of Marginal Abatement Cost curves** – the technology information was applied to the emissions inventory to calculate the potential emission reduction volume and cost. The results were displayed in a series of marginal abatement cost curve to highlight which options are considered most cost-effective.

[36] An example is the 2013-2017 Prospectiva - http://sener.gob.mx/res/PE_y_DT/pub/2013/Prospectiva_Gas_Natural_y_Gas_LP_2013-2027.pdf

[37] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2012", http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

[38] http://www.epa.gov/ghgreporting/

[39] Allen, David, et. al., "Measurements of Methane Emissions at Natural Gas Production Sites in the United States". 10.1073/pnas.1304880110

The key steps are discussed further in the following sections.

3.2. Development of the 2013 Baseline Inventory

The first step in this analysis was to develop a baseline inventory of fugitive and vented methane emissions from each oil and gas segment. The inventory serves as a basis for identifying existing sources and associated quantities of emissions with potential for mitigation. The following approach was used:

- **Develop estimates for equipment-specific activity and/or drivers –** This study relied on publically available information to estimate activity data for each emission source. While detailed information and sources are described in Appendix A, some examples include:
  - PEMEX 2013 Annual Report[40]
  - PEMEX 2013 Statistical Handbook[41]

  Organizations such as the SENER, the Mexican National Institute of Ecology, U.S. EIA (Energy Information Agency), International Energy Agency (IEA), and the CNH also provide information on historic and projections of oil and gas activity in addition to other data such as transmissions/distribution mileage. This study has well level data for Mexico according to PEMEX and SENER. PEMEX has also published some specific equipment level data, and this study extracted Mexican activity data when available, mainly production volumes for the production segment, natural gas and condensate volumes for processing facilities, counts of processing plants and associated compressors, miles of transmission pipeline for transmission, LNG import/export volumes for the LNG facilities, and natural gas end use volumes for the distribution segment. Absent of the information stated above, this study used relevant U.S. specific counts and expert judgment to estimate Mexican specific equipment counts. Detailed steps for developing both activity and emissions factors can be found in Appendix A.

  Finally, data from the U.S. EPA's mandatory Greenhouse Gas Reporting Rule (GHGRP) subparts C (combustion from stationary sources) and W (methane emissions from petroleum and natural gas systems) were used to provide supplemental information to estimate Mexico's baseline inventory.

- **Develop equipment-specific activity data based on activity drivers -** Once activity drivers for 2013 and 2020 were established, the next step was to estimate activity for equipment for which specific public information was not available. For example, a well count was used to establish the number of separators, and the miles of transmission pipelines to determine the count of compressors. This study used expert judgment and data from reports and publications to determine the most

[40] PETRÓLEOS MEXICANOS Informe Anual 2013
http://www.pemex.com/acerca/informes_publicaciones/Documents/informes_art70/2013/Informe_Anual_PEMEX_2013.pdf

[41] Statistical Handbook PEMEX 2013
http://www.pemex.com/en/investors/publications/Anuario%20Estadstico%20Archivos/2013_full.pdf

appropriate drivers for existing activity. This methodology made it was possible to fill in the data gaps identified by research efforts on equipment activity. Some examples include:

- Oil and gas production volumes – this activity driver was used to estimate equipment-specific activity data for production and gathering and boosting segments that are correlated to production volumes, such as storage tanks and glycol dehydrators. This study's modeling approach allowed for the development of additional activity drivers that represent the specific Mexican oil and gas operational characteristics. Production volumes were used to estimate volume of gas processed.
- Well count – this activity driver was used to estimate equipment activity data that are correlated to well count, such as separators and pneumatic devices.
- Residential/commercial gas demand – this was used to determine the activity and capacity changes in the distribution segment, if any.
- LNG import and export volumes –this was used to determine the number of new LNG facilities that will come online by 2020.

- **Establish relevant emission factors -** After establishing Mexican-specific equipment counts, emission factors were used to determine the volume of methane being emitted by source. Methane emissions for approximately 200 sources were calculated using the developed activity factors (e.g. equipment counts) multiplied by emission factors (average emissions from each source) to estimate the total emissions. These factors were developed either from Mexican literature, the EPA Inventory, or calculated using available GHGRP data[42] and regional proxy data specific to each particular emission source.
- **Establish current control measures** - The next step was to establish current control measures in place and develop a scenario for expected penetration of control measures in the future, i.e. whether the proportion of control measures is expected to remain the same or accelerate in the future. This study primarily relied on the library of technologies and practices identified in the Natural Gas STAR and Global Methane Initiative Programs and utilized in the earlier ICF/EDF MAC[43] work as control measures for this project. There are typically two options to develop current control measure penetration estimates: 1) Research and utilize all reported country-specific control measures, or 2) Research all publicly available data on facility, segment and source specific implementation of control measures in the countries. Companies often report their reduction measures to organizations like the Global Methane Initiative, United Nations Clean Development Mechanism, and Carbon Disclosure Project. These sources provide some information on control measures. For Mexico, the information was compiled using PEMEX data and other sources

[42] Envirofacts Customized GHG Search – Subpart W Petroleum and Natural Gas Systems http://www.epa.gov/enviro/facts/ghg/customized.html

[43] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

depending on the availability of data. When there were any data gaps, this study relied on using expert judgment and U.S.-specific data combined with regional proxies. ICF worked with EDF to determine the future scenario of control measure penetration.

- **Calculate emissions from the baseline inventory model -** The baseline inventory model calculates emissions estimates by source and segment. The inventory identifies the portion of emissions by source that is controlled versus the portion that is uncontrolled and, thus provides the potential for reductions. The study also projected the baseline to 2020 based on the oil and gas activity forecast. Table 3-1 below summarizes emissions by segment from the developed baseline inventory. As a point of comparison, this study contrasted the inventory estimates against the various industry and governmental sources (e.g., UNFCCC, SENER, PEMEX, INECC, etc.) and found the estimates to be comparable with the exception of the characterization of vented and flared gas as discussed above.

Table 3-1: 2013 Baseline Inventory Emissions by Segment

Segment	Million tons CO_2e	Bcf CH_4
Natural Gas		
Gas Production	0.4	0.7
Gathering and Boosting	2.5	4.6
Gas Processing	0.6	1.1
Gas Transmission	0.5	1.0
Gas Storage	0.0	<0.1
Gas Distribution	0.1	0.1
Petroleum		
Oil Production	1.7	3.2
Offshore		
Gas Offshore Production	8.7	16.2
Total Emissions	14.6	27.0

3.3. Projection to 2020

The 2020 forecast of natural gas and petroleum systems methane emissions starts with the 2013 Baseline described in Section 3.2. Using quantities such as gas production, gas consumption, or pipeline miles as drivers, emission estimates from the baseline inventory were projected to 2020. Figure 3-1 shows the results for estimated methane emissions for both the 2013 baseline inventory and the 2020 projections. Data from SENER and ICF analysis was used to estimate future data such as production volumes, pipeline mileage, number of completions, etc., and the U.S. EIA's Annual Energy Outlook (e.g. Mexican import/exports to and from the U.S.) were utilized to supplement the projections. In addition, expected emission reductions from sources such as high bleed pneumatic devices and wet seal centrifugal compressors as a result of voluntary control efforts are included in the forecast. Other sources were assumed to have no additional control measures applied. Emissions are projected to be decline slightly over this period: 27.1 Bcf in 2013 to 22.7 Bcf in 2020. Growth is observed in the Transmission segment, mostly due to new pipeline projects, while much of the decline in emissions can be attributed to the decrease in conventional production across Mexico's offshore fields (e.g. Cantarell, KMZ), driven mainly by economics and geology. Given the decreasing emissions projection profile, more than 90% of the emissions in 2020 come from existing sources (sources in place as of 2013) as shown in Figure 3-2.

Figure 3-1 – Emission Projections to 2020 – (Including Offshore)

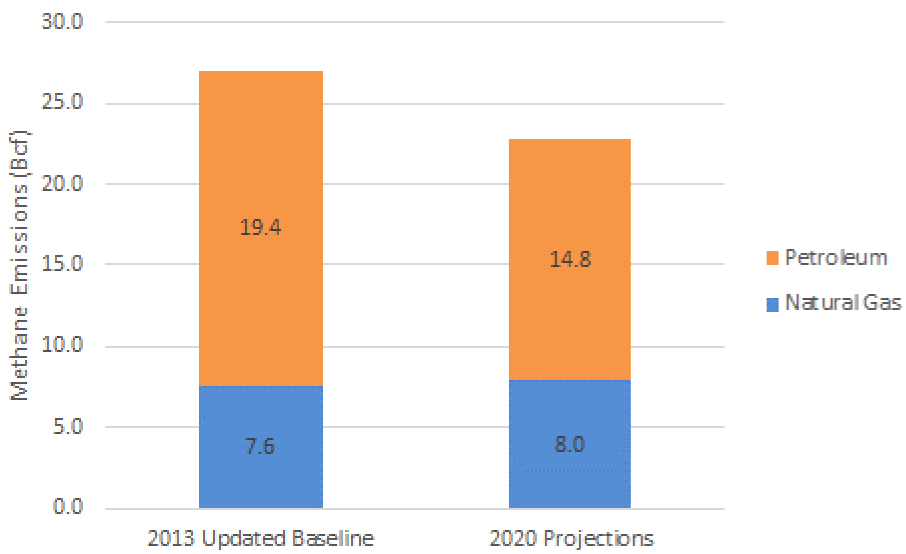
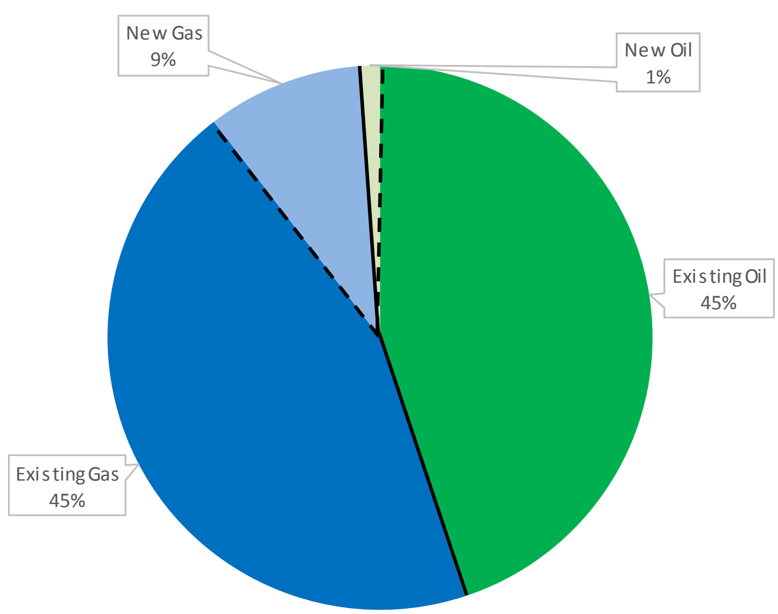


Figure 3-2 - Distribution of Onshore and Offshore Emissions in 2020



The projection also disaggregated the national level emissions estimate of the 2013 inventory across Mexico onshore and offshore. The details of the analysis are discussed in Appendix A.

3.4. Identification of Targeted Emission Sources

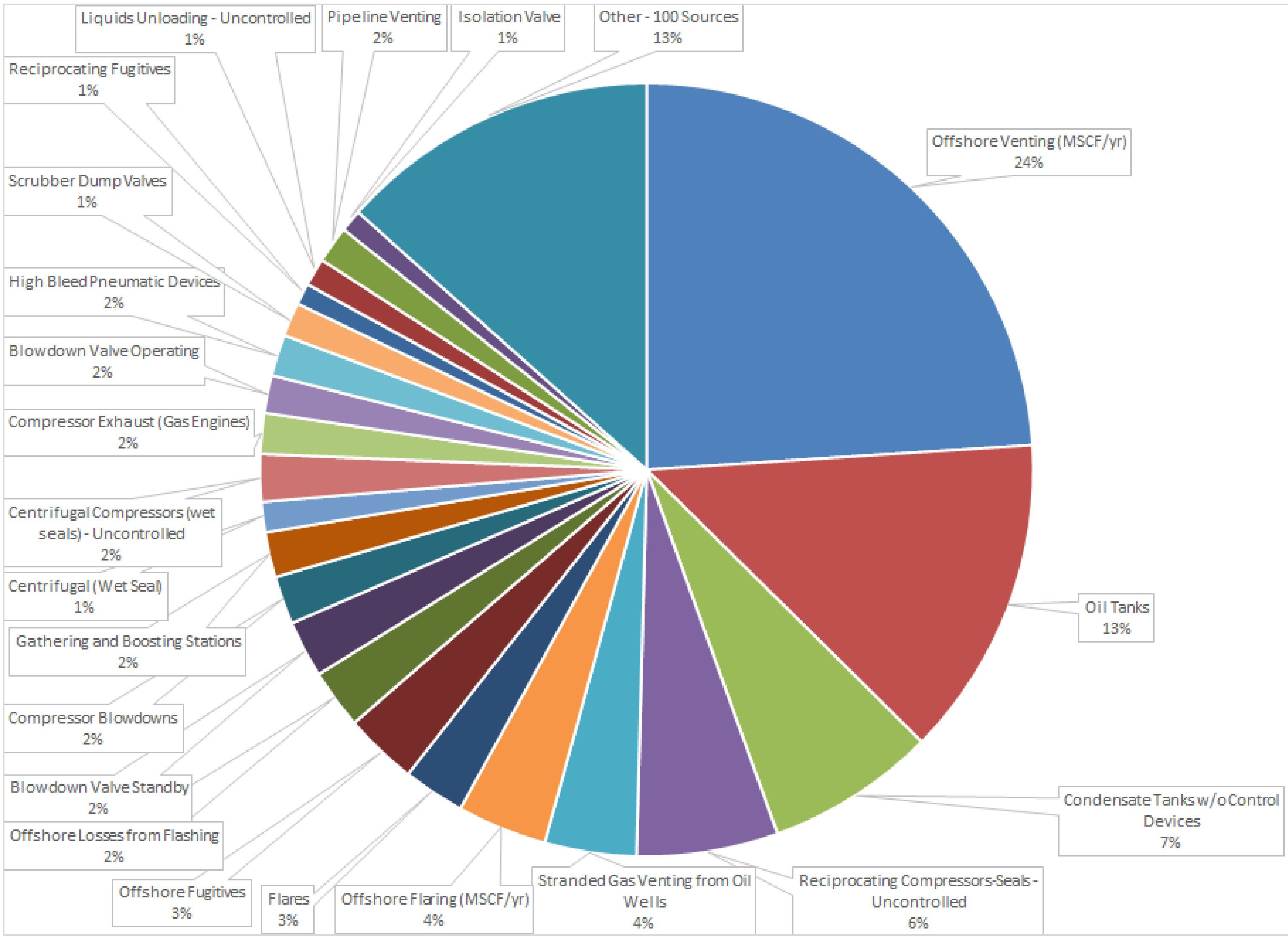
Table 3-2 summarizes the largest emitting source categories in the projected 2020 emissions for the oil and gas sectors by major source category. The top 21 source categories account for approximately 80% of the total 2020 methane emissions of 22.7 Bcf and the remaining 100+ categories each account for 1.0% or less of the total emissions. Although these smaller source categories were not included in this specific table due to their small size, there are demonstrated methane reduction technologies that can provide cost-effective reductions for many of those sources on a selective case-by-case basis. Figure 3-3 shows the distribution of sources graphically. Vented emissions are the largest emission source category overall, with stranded gas venting, reciprocating compressor seals, blowdowns, pneumatic controllers and pumps being among the significant sources. Fugitives as a collective source across segments is a significant emissions category.

Table 3-2 - Highest Emitting Onshore Methane Source Categories in 2020

Segment	Source	Emissions Type	2020 Emissions (MMcf)	Percent of Total	Cumulative MMcf	Cumulative %
Oil Production - Offshore	Venting	Vented	5,451.2	24.0%	5,451.2	24.0%
Oil Production - Offshore	Oil Tanks	Vented	2,772.5	12.2%	8,223.8	36.2%
Gathering and Boosting	Reciprocating Compressors-Seals - Uncontrolled	Vented	1,162.6	5.1%	9,386.3	41.3%
Oil Production	Stranded Gas Venting from Oil Wells	Vented	872.7	3.8%	10,259.1	45.1%
Oil Production - Offshore	Flaring (MSCF/yr)	Combusted	851.6	3.7%	11,110.7	48.9%
Gathering and Boosting	Condensate Tanks w/o Control Devices	Vented	847.5	3.7%	11,958.2	52.6%
Oil Production - Offshore	Condensate Tanks w/o Control Devices	Vented	764.5	3.4%	12,722.6	56.0%
Oil Production - Offshore	Fugitives	Fugitive	696.3	3.1%	13,419.0	59.0%
Oil Production	Flares	Combusted	587.2	2.6%	14,006.2	61.6%
Oil Production - Offshore	Losses from Flashing	Vented	562.6	2.5%	14,568.8	64.1%
Gathering and Boosting	Blowdown Valve Standby	Fugitive	534.6	2.4%	15,103.4	66.5%
Gathering and Boosting	Compressor Blowdowns	Vented	458.3	2.0%	15,561.7	68.5%
Gathering and Boosting	Gathering and Boosting Stations	Fugitive	428.1	1.9%	15,989.7	70.4%

Segment	Source	Emissions Type	2020 Emissions (MMcf)	Percent of Total	Cumulative MMcf	Cumulative %
Gas Transmission	Pipeline Venting	Vented	350.9	1.5%	16,340.7	71.9%
Gathering and Boosting	Blowdown Valve Operating	Fugitive	332.9	1.5%	16,673.6	73.4%
Oil Production	High Bleed Pneumatic Devices	Vented	306.8	1.3%	16,980.4	74.7%
Oil Production - Offshore	Centrifugal (Wet Seal)	Vented	287.8	1.3%	17,268.2	76.0%
Gathering and Boosting	Scrubber Dump Valves	Fugitive	287.4	1.3%	17,555.6	77.2%
Oil Production	Oil Tanks	Vented	279.6	1.2%	17,835.2	78.5%
Gas Production	Liquids Unloading - Uncontrolled	Vented	265.1	1.2%	18,100.2	79.6%
Gas Processing	Compressor Exhaust (Gas Engines)	Combusted	242.2	1.1%	18,342.5	80.7%

Figure 3-3 – Top 2020 Projected Methane Emission Sources



3.5. Selected Mitigation Technologies

The following sections describe the mitigation measures included in this analysis to address the high-emitting source categories. Much of the cost and performance data for the technologies is based on information provided by industry and equipment vendor sources consulted during this and earlier ICF cost-curve studies, which has been updated and augmented with Mexican-specific information as well as updates from the EPA Natural Gas STAR program[44]. The costs have also been adapted to emissions profiles estimated for Mexico, specifically for leak detection and repair practices. The discussion is organized according to the emission source and mitigation option. **All costs in this section are listed in Mexico Pesos and also use the '$' currency symbol unless otherwise stated.** If the costs are in U.S. dollars they will be stated as such. In general, costs were conservatively kept in U.S. Gulf Coast dollars for the analysis and were not adjusted downwards any further to reflect lower Mexican costs. This is discussed further in Section 4.

This analysis attempts to define reasonable estimates of average cost and performance based on the available data. The costs and performance of an actual individual project may not be directly comparable to the averages employed in this analysis because implementation costs and technology effectiveness are highly site-specific. Costs for specific actual facilities could be higher or lower than the averages used in this analysis.

Special note should be given to offshore operations in Mexico, as costs are very likely going to be much higher for mitigation of sources offshore when compared with their onshore counterparts because of transportation, logistics, and overall complexity. To account for the difference in offshore costs, this study has applied a set of escalation factors to the capital cost of mitigation technologies being considered for offshore emissions sources. Thus, for all offshore emissions sources, discussion of mitigation technology costs and MAC curves, the following set of factors have been applied to the capital costs of mitigation technologies applied offshore. These factors have been developed based on SME input and prior industry experience. For example, there is a positive correlation between capital cost escalation offshore and the size of equipment (e.g. a centrifugal compressor vs. a pneumatic device).

Table 3-3- Offshore Capital Cost Escalation Factors

Mitigation Option	Escalation Factor
Early replacement of high-bleed devices with low-bleed devices	1.5
Replacement of Reciprocating Compressor Rod Packing Systems	1.5
Install Flares-Stranded Gas Venting	3.0

[44] http://www.epa.gov/gasstar/

Mitigation Option	Escalation Factor
Install Flares-Portable	1.0
Install Plunger Lift Systems in Gas Wells	1.0
Install Vapor Recovery Units	1.75
LDAR Wells	1.0
LDAR Gathering	1.0
LDAR LDC – MRR	1.0
LDAR Processing	1.0
LDAR Transmission	1.0
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	1.0
Replace Kimray Pumps with Electric Pumps	1.25
Pipeline Pump-Down Before Maintenance	1.0
Wet Seal Degassing Recovery System for Centrifugal Compressors	1.75
Wet Seal Retrofit to Dry Seal Compressor	1.75
Blowdown Capture and Route to Fuel System (per Compressor)	1.0
Blowdown Capture and Route to Fuel System (per Plant)	1.25
Replace with Instrument Air Systems - Intermittent	1.5
Replace with Instrument Air Systems - High Bleed	1.5

Fugitive Emissions – Fugitive emissions are the unplanned loss of methane from pipes, valves, flanges, and other types of equipment. Fugitive emissions from reciprocating compressors, compressor stations (transmission, storage, and gathering), wells, and LDC metering and regulator equipment constitute one of the largest combined emission categories.

Leak Detection and Repair (LDAR) is the generic term for the process of locating and repairing these fugitive leaks. There are a variety of techniques and types of equipment that can be used to locate and quantify these fugitive emissions. Extensive work has been done by EPA and others to document and describe these techniques, both in the Gas STAR reference materials and in several regulatory analyses. In some instances and in this study, LDAR has been found to be amongst the most cost-effective options to reduce methane emissions.

The potential size and nature of these fugitive emissions can vary widely by industry segment and even by site. Currently no specific requirements exist for leak detection and repair in Mexico. In addition, no Mexican emissions factor data exists nor are the costs publicly available for LDAR in Mexico. Therefore, this study relied on data available from U.S. studies and regulations. Other than labor, the cost of equipment for locating leaks will not be different. This is because there are only two vendors who supply the primary leak detection equipment, the infrared camera capable of detecting methane emissions from the oil and gas industry.

LDAR programs have been analyzed for several recent U.S. regulatory initiatives, including for the EPA's NSPS Subpart OOOO[45] and the Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9)[46]. This study used both the Colorado regulatory analysis and the EPA Technical Support Document (TSD) [47] for NSPS Subpart OOOO and OOOOa as the basis for cost structure and reduction effectiveness calculations. This study took the average emissions per facility type from the Mexico baseline developed in this study to establish emission reductions from implementing a LDAR program.

The key factors in the analysis are how much time it takes an inspector to survey each facility (or, alternatively, how many facilities can be surveyed in a day), how many inspections are required each year, how much reduction can be achieved, and how much time is required for repairs. According to the recently published NSPS OOOOa Technical Support Document, the EPA indicates that more frequent inspections result in greater reductions[48], summarized as approximately:

- Annual inspection = 40% reduction
- Semi-Annual inspection = 60% reduction
- Quarterly inspection = 80% reduction

Although this analysis assumes quarterly emission surveys for all facilities, the reduction was assumed to be only 60%. This measure was taken to account for the fact that Mexican operators are already implementing some LDAR programs per PEMEX GMI presentations.

This study adapted the EPA and Colorado analysis, which calculates the capital and labor cost to field a full-time inspector, including allowances for travel and record-keeping (Table 3-4). This study added additional time for training. The capital cost includes an infrared camera (which is used to locate fugitive emissions) a truck and the cost of a record-keeping system. The combined hourly cost was the basis for the cost estimates.

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[45] http://www.epa.gov/airquality/oilandgas/

[46] http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820

[47] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards". http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf

[48] NSPS OOOOa Technical Support Document http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-5021

Table 3-4 - LDAR Hourly Cost Calculation ($ MXN)

Labor			Capital and Initial Costs	
Inspection Staff	$462,000		Infrared Camera	$1,881,880
Supervision (@ 20%)	$92,400		Photo Ionization Detector	$77,000
Overhead (@10%)	$46,200		Truck	$338,800
Travel (@15%)	$69,300		Record keeping system	$223,300
Recordkeeping (@10%)	$46,200		Total	$2,520,980
Reporting (@10%)	$46,200			
Fringe (@30%)	$138,600		Training Hours	80
Subtotal Costs	**$900,900**		Training Dollars	$38,331
Hours/yr	1880		Amortized Capital +Training	$675,136
Hourly Labor Rate	**$479.2**		Annual Labor	$900,900
			Annual Total Cost	$1,576,036
			Total Cost as Hourly Rate	**$838**

Many analyses have used facility component counts and historical data on the time required to inspect each component to estimate facility survey times. However, the use of the infrared camera technology allows much shorter survey times[49]. The estimates here are based on experience with the infrared camera and are shorter than the estimates that are based on the older leak detection approach using hand-held devices, such as the organic vapor analyzer (OVA).

This study then established the average fugitive emission values per facility for production, gathering and boosting, transmission, processing, and LDCs from the baseline developed in this study. For the purposes of implementing LDAR, "facility" in production is defined as the well pad with basic process equipment such as separator, heaters, and glycol dehydrators. In gathering and boosting, transmission, and processing the facility is defined as the station, without the pipelines included. And finally LDCs are defined as meter and regulator stations/ vaults. For each segment the average fugitive emissions value is the total fugitive emissions from the segment divided by the total number of facilities in that segment.

[49] Robinson, D, et. al., "Refinery Evaluation of Optical Imaging to Locate Fugitive Emissions". Journal of the Air & Waste Management Association. Volume 57 June 2007.

Table 3-5 summarizes the assumptions for the overall LDAR calculation. In addition to the surveys, the estimate includes one initial visit to each site to inventory the equipment (equivalent hours to two inspection visits for each site with cost averaged over five years) and additional visits for repairs. Assumptions were made for estimating the hours for each inspection based on SME input and review of the NSPS. A large number of the entire population of wells are expected to have only the well without any substantial equipment on site. The time required to survey the "christmas tree"/well and associated piping is minimal. When the time required to survey these wells is averaged with other sites that have process equipment it is reasonable to assume that it takes 0.33 hours per site across an 8 hour work workday, on average, or 24 wells per day. Not all wells are expected to have equipment on them, therefore 24 wells per day is a reasonable assumption. For offshore LDAR programs, it was assumed a team of technicians could feasibly survey a platform in 20 to 25 hours, and this analysis has assumed 22 hours per platform.

Some repairs can be made at the time of the survey, such as tightening valve packing or flanges but others will require additional repair time. This analysis assumes repair time equivalent to three survey visits for each facility for repairs each year. The capital cost of larger repairs is not included on the assumption that these repairs would need to be made anyway and the LDAR program is simply alerting the operator to the need. The time for repairs is consistent with the low end of the Colorado analysis that was derived based on component counts and leak rates. This lower repair estimate takes into account that:

- These are average values across facilities – not every facility will require repairs.
- These are average values over time – not every facility will need repairs every year while being monitored on a continuing basis.
- Some or all of cost of major repairs is assumed to be part of regular facility maintenance. The LDAR process allows operators to pinpoint these leaks that are fixed during regular shutdown cycles.

Table 3-5 – Cost Calculation – Quarterly LDAR ($ MXN)

	Well Pads	Gathering	Processing	Transmission	LDC
Methane Mcf/yr	80	3,638	14,105	14,910	93
% Reduction	60%	60%	60%	60%	60%
Reduction Mcf	48	2,183	8,463	8,946	56
Hours each Inspection	0.33	10.7	16.0	16.0	0.7
Frequency (per year)	4	4	4	4	5
Annual Inspection Cost	$1,124	$35,774	$53,654	$53,654	$2,787
Initial Set-Up	$108	$3,573	$5,359	$5,359	$231
Repair Labor Cost	$832	$26,827	$40,240	$40,240	$1,679

	Well Pads	Gathering	Processing	Transmission	LDC
Total Cost/yr	$2,064	$66,174	$99,253	$99,253	$4,697
Recovered Gas Value*	$3,942	$417,663	$735,935	$610,287	$3,804
Net Cost	($122)	($22,824)	($41,343)	($33,183)	$58
Cost of Reduction ($/Mcf methane reduced)					
Without Gas Credit	**$40.94**	**$12.32**	**$10.47**	**$11.09**	**$84.24**
With Gas Credit[50]	**$(37.27)**	**$(65.76)**	**$(67.61)**	**$(57.13)**	**(16.02)**

*Gas at $62 MXN /Mcf ($4 USD/Mcf)

The value of reduced gas losses is credited to the program for the upstream segments. These final reduction cost values were used for the analysis. Finally, adjustments were also made to take a conservative stance with respect to labor costs for LDAR, regardless of whether operations were offshore or onshore. According to a 2012 report released by the U.S. Bureau of Labor Statistics[51], the average yearly compensation costs for a Mexican worker in manufacturing was approximately $13,000 USD/yr. In the LDAR cost summaries above, inspection staff salary was escalated to $30,000 USD/yr as a conservative measure when considering cost variations between onshore and offshore operations. A secondary source was researched to provide a check against this calculated salary, specifically data available in PEMEX's contrato colectivo for 2013-2015[52]. According to PEMEX's documentation, salary for a maintenance specialist was estimated to be roughly $10,500 USD per year. This data supports this study's conservative approach for an LDAR salary.

Reciprocating Compressor Rod Packing – Reciprocating compressors are used in most segments of the natural gas and oil industry, though rarely in local gas distribution than in other segments. Rod packing systems are used to maintain a seal around the piston rod, minimizing the leakage of high pressure gas from the compressor cylinder, while still allowing the rod to move freely (Figure 3-4). However, some gas still escapes through the rod packing, and this volume increases as the packing wears out over time, potentially to many times the initial leak rate. There is no Mexican emission factor for these emissions, nor any standard optimum interval to replace the rod packing, but the NSPS Subpart OOOO requires rod packing in new reciprocating compressors in the production and processing sectors to be replaced every 26,000 hours of operation (approximately every three years).

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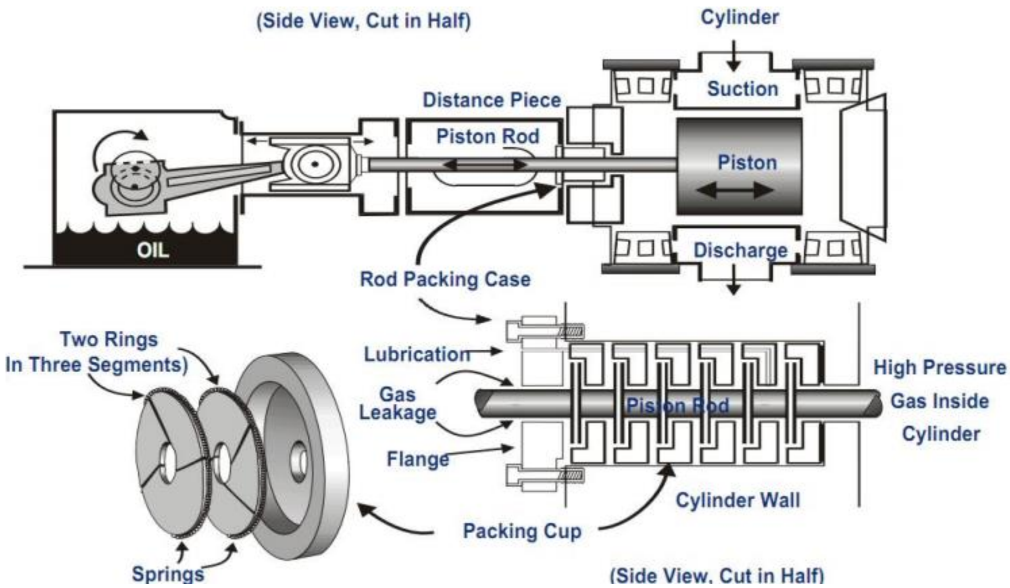
[50] With Gas Credit – Operator is able to monetize the methane recovered, thus reducing overall reduction cost.

[51] International Comparisons of Hourly Compensation Costs In Manufacturing , 2011 http://www.bls.gov/news.release/pdf/ichcc.pdf

[52] http://www.pemex.com/acerca/informes_publicaciones/Documents/contrato_colectivo/cct_2013-2015.pdf

Figure 3-4 - Reciprocating Compressor Rod Packing



Industry reports that the rod packing for compressors at gas processing plants and some transmission stations is routinely replaced at least that frequently as part of routine maintenance. However, it is believed that rod packing in the production and gathering and boosting sectors is replaced less frequently. This is due, in part, to several factors, including the remote location of these compressors, the lack of a back-up compressor for use during compressor downtime, and the fact that many of the compressors in these sectors are leased rather than owned. This analysis assumes a requirement to replace rod packing for all reciprocating compressors every 26,000 hours of operation.

Gas STAR data[53] indicates that rings (the compressor packing) cost between $ MXN 4,620 and $ MXN 9,240 per cylinder and $ MXN 15,400 to $ MXN 38,500 per compressor to install. Industry sources from the previous U.S. MAC Curve study[54] put the cost at $77,000 per cylinder, which was adopted for this analysis. Across a 15-year period, replacing a cylinder every 3 years costs approximately $ MXN 231,000, while replacing a cylinder every 5 years costs approximately $ MXN 385,000. The incremental difference between the 5-year and 3-year case is $ MXN 154,000 total or $ MXN 30,800 if annualized over the 5-year case. Assuming 3.3 cylinders per reciprocating compressor yields a total incremental cost of $ MXN 101,640 per reciprocating compressor.

The Technical Support Document (TSD) for NSPS Subpart OOOO provides a detailed analysis of rod packing replacement. The emissions from new rod packing are estimated in the TSD at 11.5 standard cubic feet per hour (scfh). Baseline emissions for rod packing are estimated at approximately 57 scfh,

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[53] "Reducing Methane Emissions From Compressor Rod Packing Systems" http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

[54] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

however the age of the packing at that time is not stated. There is little data on the emissions from rod packing over time but reductions for this mitigation option come from replacing the rod packing at a shorter interval than currently being practiced at a given facility.

For this analysis it was assumed that the facility currently replaces the rod packing every five years and that the interval is reduced to three years (26,000 hours). It was assumed that the new rod packing emits 11.5 scfh and the emissions increase linearly to 57 scfh after three years and increase linearly thereafter. Comparing the emissions under this scenario for 15 years, the three year replacement schedule would emit 31% less than the five year replacement schedule. In addition, the cost of rod packing replacement would be 67% greater for the three year replacement schedule than the five year schedule. As noted above, it was assumed that rod packing is already changed on this schedule in many processing plants and some transmission stations, so the applicability was reduced to 25% for processing and 70% for transmission, storage and LNG. The assumptions are summarized in Table 3-6.

Table 3-6 - Assumptions for Rod Packing Replacement ($ MXN)

Capital Cost per Compressor	Percent Reduction	Mcf Reduced/year	Lifetime (years)	Cost w/o Gas Credit
$101,640	31%	438	3	$93.32/Mcf

Centrifugal Compressors (wet seals) – The seals in a centrifugal compressor perform a similar function to the rod packing in a reciprocating compressor – allowing the rotating shaft to move freely without allowing excessive high pressure gas to escape. Centrifugal compressors with wet seals use circulating oil as a seal against the escape of high pressure gas, and the oil entrains some of the gas as it circulates through the compressor seal. This gas must be separated from the oil to maintain proper operation (called "degassing the seal oil"), and the gas removed from the seal oil is typically vented to the atmosphere, and in some cases captured and rerouted for beneficial use or sent to a flare. [55] These emissions can total 30,000 Mcf/year or more. There are two options to mitigating emissions from wet seal systems. The first is the replacement of the wet seals with dry seals that do not use oil and do not vent significant amounts of gas. The dry seal technology also provides additional benefits in terms of reduced operational and downtime costs. Most new centrifugal compressors are being fitted with the dry seal as a standard option.

The second option is to capture and use the entrained seal oil gas rather than venting it. Typically, this recovered gas is either injected back into the compressor suction, injected into a low pressure fuel line,

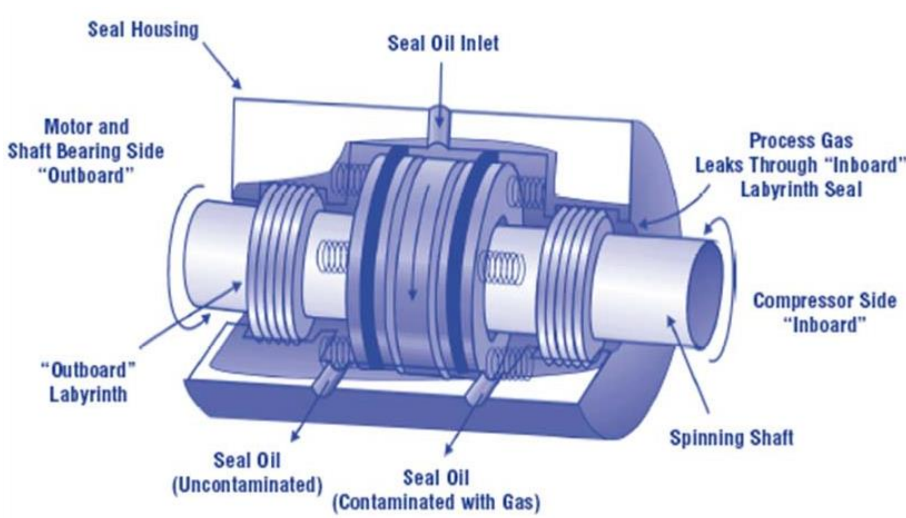
[55] Replacing Wet Seals with Dry Seals in Centrifugal Compressors http://www.epa.gov/gasstar/documents/ll_wetseals.pdf

or sent to the sales line. In some cases, the captured gas may be sent to a flare for combustion. This retrofit technology currently exists at several compressor stations that had such systems installed as original equipment, but it has not been applied commercially as a retrofit. However, the equipment needed for a retrofit is commercially available.

Both technologies are commercially available, but there are no Mexican emission factors for either. The choice on whether to use a dry seal or wet seal retrofit depends on several factors, such as size and life expectancy of the compressor, wet seal emissions rate, and whether there is a place to put the captured gas. In either case, it is quite likely that an operator will implement the option that provides the most benefit specific to the particular operators situation (e.g. operations, location, economics, safety, etc.).

Although the gas can be re-captured, it may be difficult to use it productively, as this depends on both the pressure of the captured gas and whether a need for the gas exists. The applicability is therefore discounted by 10% to 25% depending on the industry segment. The dry seal retrofit has large upfront capital cost, anywhere from \$ MXN 3,850,000 to \$ MXN 7,700,000, depending on compressor size. However, it does provide operational efficiency over the long run, because it does not require seal oil replenishment and touts lower maintenance than a wet seal. The wet seal capture system has a much lower up front capital investment of approximately \$ MXN 770,000 to \$ MXN 1,540,000 depending on the size of the compressor and the efficiency of capture. However, the maintenance cost of a retrofit do not change. For this study, it was assumed that the operator will either replace the wet seal with a dry seal at \$ MXN 6,930,000with a maintenance cost reduction of \$ MXN 770,000 or they will retrofit the wet seal with a capture system at a cost of \$70,000. Both options result in an equivalent cost-effectiveness of \$ MXN 4.93/Mcf without a gas credit and -\$ MXN 73.15/Mcf with a gas credit.

Figure 3-5 - Wet Seal Compressor Schematic



Pneumatic Devices – Pneumatic devices use the pressure of the natural gas stream to operate various control functions, such as adjusting valves to maintain proper pressure, actuating liquid level and temperature controllers, etc. Some devices require a continuous small discharge of gas as part of the controller function. These types of devices are designated as either low bleed devices (emitting < 6 scf/hr) or high bleed devices (emitting ≥6 scf/hr, but typically much more – often more than 30 scf/hr). In addition to these two categories, there are intermittent devices that are designed to discharge gas only when they are actuating. These types of pneumatic devices can have emissions anywhere between high and low bleed controllers. One common device is an intermittent level control device ("dump valve") that emits gas only when actuated and typically has emissions similar to low bleed controllers. The level of emissions from an intermittent device is highly variable and depends on the process it is located on and the function it performs.

There are no Mexican emission factor for high bleed and intermittent bleed pneumatics so this analysis used other proxy data. The EPA GHG Reporting Program Subpart W provides information on pneumatic controllers that can be used to estimate the distribution of these devices in each segment of the Mexican oil and gas industry. This analysis is discussed in Appendix A and, for example, yields a rough distribution of 10% high bleed, 60% intermittent, and 30% low bleed devices for the Production segment. Further analysis was performed to estimate the distribution of higher-emitting intermittent devices vs lower-emitting dump valves, also discussed in Appendix B. For the Production segment, it was estimated that 75% of the intermittent bleed devices are of the dump valve variety.

The two mitigation options considered in the study are:

- Replace high bleed controllers with low bleed controllers.
- Install instrument air systems where grid power is available.

Some components require high bleed controllers for operational reasons, primarily for fast-acting valves associated with compressors, so the measure was applied to only 60% of the inventory of high bleed controllers in transmission, storage, and LNG, 80% in processing and 90% of the high bleed controllers in other segments. Although there are lower cost estimates from Gas STAR and vendors, this measure assumed a cost of $ MXN 46,200 per replacement based on industry comments. Both options achieve a greater than 90% reduction. This yields a reduction cost of $ MXN 14.94/Mcf of methane for replacement of high bleed pneumatics and $ MXN 93.17/Mcf of methane for replacement of intermittent bleed pneumatics with instrument air systems, including a credit for recovered gas, where applicable.

Instrument air systems directly replace natural gas that is used by pneumatic devices as a source of power with air. This requires the installation of an air compressor, compressed air tank, and dryer. The instrument air can be compressed to the same pressure as the existing natural gas pressure used in the pneumatic devices. Therefore, there are no operational limitations on what high bleed devices can be converted to instrument air, i.e. they can achieve the same level of fast-action as natural gas. However, not all facilities have access to grid power. Hence, this study assumes that 30% of gathering, 50% of processing, and 30% of transmission high bleed devices can be converted to instrument air, resulting in a 100% reduction in methane emissions. Implementation of instrument air at facilities that only have low bleed (with possibly a few high bleed devices for operational consideration) is usually not feasible economically and has not been considered in this study.

Chemical Injection Pumps – These are small pumps used to inject various chemicals, including methanol and corrosion inhibitors. They are typically driven by gas pressure and vent gas when they operate. The suggested mitigation measure is to replace the gas-driven pumps with electric pumps driven by solar energy or grid power. (Well pads and many gathering/boosting stations typically do not have electricity.) This technology has been demonstrated by Gas STAR Partners and industry respondents indicated that it is gaining broader acceptance. Replacement results in elimination of the methane emissions, and the gas-driven pump could be left in place as a back-up. The cost of the measure was estimated at $ MXN 77,000 per pump, yielding an annual reduction of 180 Mcf/year and a cost-effectiveness of -$ MXN 3.39/Mcf of methane reduced with the recovered gas credit. Local conditions or operational considerations may limit the applicability so the measure is applied to 60% of the inventory.

Oil and Condensate Tanks without Control Devices – Crude oil and liquid condensate production at wells and gathering facilities is stored in fixed roof field tanks and dissolved gas in the liquids is released and collects in the tank space above the liquid. Ultimately, this gas is often vented to the atmosphere or occasionally sent to the flare. Vapor recovery units (VRUs) collect and compress this gas, which can then be re-directed to a sales line, used on-site for fuel, or flared.

The sizing of the VRU depends on the vapor volume, which in turn depends on the upstream separator pressure, API gravity of the oil or condensate, and the throughput of the tank., This study assumed a distribution of tanks, and thereby VRUs, by size which is representative of the industry where fewer tanks are large and located in gathering systems and most of the tanks are at the wellheads and smaller in size. Table 3-7 shows the distribution assumed for VRU sizes applicable in this study. Data was adapted from the EPA Natural Gas STAR lessons learned – Installing Vapor Recovery Units on Storage Tanks[56].

Table 3-7- Assumptions for Vapor Recovery Units ($ MXN)

Design Capacity (Mcfd)	Population Distribution Weighting	Installation & Capital Costs (thousand $)	O&M (thousand $/Year)	Value of Gas (thousand $/Yr), Payback (months), Internal Rate of Return (%)		
25	25%	$550	$113	$466	19	58
50	45%	$710	$129	$933	11	111
100	15%	$855	$155	$1,868	6	200
200	10%	$1,146	$181	$3,737	4	310
500	5%	$1,600	$259	$9,344	3	567

[56] EPA Lessons Learned: Vapor Recovery Units
http://www.epa.gov/gasstar/documents/ll_final_vap.pdf

Based on Gas STAR and industry data, the weighted average capital cost of this measure is assumed to be $ MXN 779,794 with an operating cost (electricity) of $ MXN 141,156 per year and a reduction of 9,232 Mcf per year. This yields a reduction cost of -$ MXN 49.13/Mcf if the gas is recovered for sale or $ MXN 29.11/Mcf if it is flared. Some facilities already have VRUs and they may not be effective where the liquid volume is small or the methane content is low. Also VRUs require electricity, which is not available at all sites. For these reasons, the measure is applied to 50% of the remaining oil and 25% of the remaining condensate tank emission inventory.

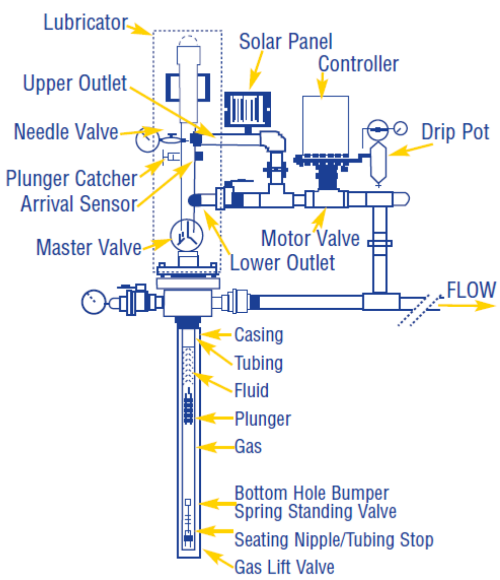
Kimray Pumps – Kimray pumps are gas-powered pumps used to circulate glycol in gas dehydrators. They are larger than the chemical injection pumps and vent larger amounts of gas. In the facilities that have electricity, these could be replaced by electric motor-driven pumps. The replacement cost is estimated at $154,000 per pump based on vendor and Gas STAR data. Unlike the solar pumps, these pumps will require grid electricity, estimated to cost $ MXN 30,800 per year. Based on a 5,000 Mcf emission reduction, the cost-effectiveness is -$ MXN 64.22/Mcf of methane with credit for gas recovered and it is applied to 50% of the inventory.

Liquids Unloading – Liquids unloading is the process of removing liquids from the bottom of gas wells when the accumulation is impeding the gas production. The liquids must be removed in order to allow effective production from the well. Historically this has been practiced on older, vertical wells whose pressure has declined.

While there are a variety of methods of removing this liquid, one method is by venting or "blowing" the well to the atmosphere, using the pressurized gas in the reservoir to lift and blow the liquids out of the well. The frequency and duration of liquids unloading depends on the well and reservoir conditions, however, venting is not a very effective method of removing the liquids. Further, since the well is vented to the atmosphere, it results in large methane emissions and losses of gas. There are multiple methods of removing liquids without venting, but in standard practice, the primary goal of liquids unloading is to improve well performance, not reduce emissions. The choice of method is normally a function of the cost versus the value of improved well performance. The previous U.S. MAC curve contains case studies on this topic[57].

[57]Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf

Figure 3-6 - Plunger Lift Schematic



Plunger lifts are devices that fit into the well bore and use the gas pressure to bring liquids to the surface more efficiently while controlling and limiting the amount of venting (Figure 3-6). If there is sufficient reservoir pressure, the gas can be directed to the sales line with no venting. If there is insufficient pressure to direct the gas to the sales line and the gas must be vented, the emissions can still be reduced by 90% compared to uncontrolled venting. Plunger lifts are a relatively low cost option and can be implemented in a relatively simple manual control method or more complex automated installations. That said, the technology does have limitations. The well must have sufficient pressure to operate the plunger and older wells may require clean-outs or work-overs to allow the plunger to operate. Further, not all well types can use a plunger lift for liquids removal.

Gas STAR estimates for plunger lift installation range from $ MXN 38,500 to $ MXN 154,000[58] but industry commenters on the U.S. study cited costs in the range of $ MXN 231,000 and pointed out that well treatments and clean-outs may be required before plunger lifts can be installed. This analysis assumes a cost of $ MXN 308,000, including the allowance that some wells may need clean-outs or other work. Gas STAR Partners report reductions of venting emissions of 90% for plunger lifts that do not go to the sales line. In addition, they report that liquids unloading can increase production by anywhere from 3 to 300 thousand cubic feet per day (Mcf/day). The increased productivity of the well is the primary goal of liquids unloading and the higher gas production can pay for the cost of plunger lifts many times over. However, the subsequent increase in well productivity is difficult to predict and is not included in this analysis. Without credit for the productivity increase, the cost-effectiveness breakeven point is at about 1,200 Mcf/year of venting, estimated here as a reduction cost of -$ MXN 0.77/Mcf reduced.

If the well does not have sufficient pressure or cannot support a plunger lift, there are a variety of mechanical pumping technologies that can be employed to remove liquids. However, these are much more expensive and while they may have a positive payback for increasing well production, they most often do not purely for the methane emission reduction. Moreover, the methane reduction value only applies if the well would otherwise be vented. As the well pressure declines, venting becomes a diminishingly effective option. In addition, it is not clear how effective venting will be at removing liquids from long horizontal wells that are now being drilled. It may be that venting for liquids removal will continue to be primarily focused on older, vertical wells.

[58] Installing Plunger Lift Systems In Gas Wells http://epa.gov/gasstar/documents/ll_plungerlift.pdf

There is no Mexican data set, so a proxy was used but with Mexican specificity included as described below. The GHG Reporting Program Subpart W provides extensive data on wells that are venting for liquids unloading with and without plunger lifts. The data for 2013 shows over 25,000 wells venting an average of 352 Mcf per year without plunger lifts and over 28,000 wells with plunger lifts venting an average of 362 Mcf per year. Wells that use plunger lifts and send the gas to the sales line do not have any venting emissions and do not report to this part of Subpart W. While it seems counterintuitive that wells with plunger lifts that vent would be emitting more than those without plunger lifts, this study interprets this information to indicate that most of the wells with the largest venting emissions have already installed plunger lifts while most of the remaining wells are venting infrequently or venting small volumes that do not justify the cost of installing plunger lifts. That said, there are a small number of wells without plunger lifts that report larger venting emissions and account for a disproportionate fraction of the venting emissions for wells without plunger lifts, approximately 36% of total venting emissions. Installing plunger lifts on these wells could be cost-effective and create significant emission reductions. Because plunger lifts are not applicable to all wells, the measure was applied to 30% of this emission segment for the analysis.

As noted above, wells with plunger lifts also report significant emissions from venting. Operation of a plunger lift is complex and its effectiveness as an emission reduction technique depends on many factors to operate the plunger at the optimum time to maximize production and minimize emissions. Approaches to plunger lift operation range from ad hoc manual operation, to fixed mechanical timers, to programmable "fuzzy logic" automated controllers. Specific data on the potential reductions from optimized plunger lift operation is not available but it is clear from industry experience that an integrated program of training, technology, and automation can improve the performance of plunger lifts for both productivity and emission reductions. Consequently, there may be an opportunity for significant emission reduction through optimization of plunger lifts, which is not included here and would be additional to the reduction estimates this analysis provides for installation of new plunger lifts.

Finally, another option to reduce methane emissions from liquids unloading is to use a portable or temporary flare system to burn vented emissions. Although this still results in the emissions of GHGs (CO_2) and other air pollutants, a portable flare would be used to flare gas from venting events, thus avoiding the release of a gas with a higher global warming potential. A temporary flare would be used to flare gas from manual unloading of the well. Estimated costs for purchasing a trailer-mounted flare system ranging from 20 – 50 ft. in height, designed to handle gas flow rates of 1 - 10 MMscfd is approximately $ MXN 462,000. Based on data for liquids unloading vented emissions, the 1-10 MMscfd capacity flare should be adequate across most oil & gas facilities and is used as such.

Stranded Gas Venting from Oil Wells and Venting of Oil Completion Gas – Oil contains some amount of natural gas, which is separated at the wellhead. Where there is a gas sales line available, the gas is sent to sales. When no nearby sales line exists, the gas is either vented or flared. This can occur during the short period after the well is completed or it can continue throughout the life of the well, depending on the access to gathering infrastructure. While flaring creates CO_2 emissions from combustion and some unburned methane, the total greenhouse gas emissions are much lower than venting the methane, with its higher global warming potential.

The measure modeled here is flaring of the gas on the assumption that the gas would be sent to sales if the infrastructure were available. There is no Mexican dataset; but Gas STAR and vendor information cite relatively low-cost flares, and U.S. industry cited more expensive flaring equipment that is being required to meet regulatory requirements. This study adopted this higher estimate, assuming a capital cost of $MXN 770,000 and a fuel cost of $ MXN 92,400 for ignition. The flare is assumed to be 98% effective. The cost-effectiveness depends on the amount of gas flared, which is lower for completion emissions than flaring of associated gas on a continuous basis. The cost-effectiveness is estimated at $ MXN 28.64/Mcf of methane for completion gas.

Stranded Gas Venting from Offshore Platforms and Floating, Production, Storage and Offloading (FPSOs) Vessels – Similar to the previous section on stranded gas venting, oil production from offshore platforms and FPSOs also contain some amount of natural gas. Due to limited availability of gas sales lines in offshore operations, the gas is either vented or flared. This can occur intermittently or continue throughout the life of the well, depending on specific offshore operations. As with onshore operations, flaring creates CO_2 emissions from combustion and some unburned methane. However, the total greenhouse gas emissions are much lower than venting the methane, with its higher global warming potential.

For offshore platforms and FPSOs, the measure modeled here is flaring of the gas on the assumption that the gas would be vented instead. Onshore flaring discussed above adopted a higher cost estimate, assuming a total capital cost of $ MXN 770,000 and a fuel cost of $ MXN 92,400 for ignition, with the flare assuming to be 98% effective. Two additional factors were implemented to properly adjust the cost of flares in offshore operation. First, the capital cost for onshore flares was escalated by a factor of 3 to a value of $ MXN 2,310,000 to account for additional complexities and aspects when installing an offshore flare. This was taken as a conservative basis since publicly available PEMEX documents[59] on offshore flaring costs put the installed cost of offshore flares between $ MXN 385,000 and $ MXN 2,310,000. Secondly, the operating and maintenance costs for onshore flares were escalated by a factor of 3.3 to an annual cost of $ MXN 308,000 from $ MXN 92,400.

The cost-effectiveness depends on the amount of offshore gas flared, which has been compensated to a higher value for average offshore flaring emissions. 2013 Subpart W emissions were analyzed and an average offshore flaring volume of 19MMscf/yr was calculated and assumed as an annual reduction basis. The resultant cost-effectiveness is estimated at $ MXN 32.19/Mcf of methane for completion gas.

[59] PROGRAMA ANUAL DE ADQUISICIONES, ARRENDAMIENTOS, OBRAS Y SERVICIOS PARA EL AÑO 2012 http://www.pep.pemex.com/Document%20Library/Informacion/DCO_ZPAR_PEP_FINAL_VER0.pdf

Pipeline Venting (Routine Maintenance/Upsets) – These emissions occur when companies take sections of pipeline out of service for maintenance and vent the gas that is in the pipeline. These emissions can be reduced for planned shutdowns (not emergency shutdowns) by first using the pipeline inline compressors located at compressor stations to pump down the gas in the affected section to a pressure that is within the compression ratio of the compressor. Often this still leaves a significant amount of gas that can further be captured using a leased mobile compressor unit. This mobile unit captures the remaining gas and injects it into the pipeline upstream or downstream of the pipe section being blowndown. In cases where the pipe section to be blowdown is not in close proximity to the inline compressor then only the portable unit may be an effective option. The analysis in this study assumed a combination of both measures applied to 10 mile sections of pipeline, based on a Gas STAR analysis[60]. This study also assumed that only 1 in 4 pipeline pumpdown activities were able to use both portable and inline compression, and the rest used only inline compression. Using the pipeline compressor requires no capital cost but only the fuel cost to pump down the line. The second option was to lease a portable compressor and pay for the delivery and fuel consumption. When considering both technologies, average total capital costs are zero while operating costs are $ MXN 6,059,654/yr, yielding a cost-effectiveness of $ MXN 21.10 with no gas recovery credit.

Transmission Station Venting –Transmission station venting is characterized as a single emissions source characterized as routine blowdowns/maintenance. Compressors may be blowndown to the atmosphere for maintenance or upset conditions multiple times a year, releasing methane to the atmosphere, or in some cases to the flare. Capture of this gas is possible and can be routed to the fuel system or other low pressure gas stream.

There is no Mexican dataset for these emissions, but Subpart W has two distinct tables with emissions data on blowdown emissions. One table contains data on physical volumes that were blown down more than once during the reporting year, while the other table has unique physical emission volumes that were blown down only once during the reporting year. Both tables were considered when characterizing emissions factors and reduction opportunities across the transmission and gas processing segments. For performing pipeline capture of gas from other routine blowdown emissions, assumptions were made based on SME input. Capital costs vary between $ MXN 308,000 and $ MXN 770,000 whether performed on a per compressor or per plant basis, respectively. The cost effectiveness is estimated at $ MXN 8.32/Mcf and $ MXN 16.63/Mcf on a per compressor or per plant basis, respectively.

Summary

Table 3-8 summarizes the mitigation measures applied in the analysis for each major emission source. Table 3-9 summarizes the characteristics of the measures modeled. The cost-effectiveness ($/Mcf of

[60] "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance". http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

methane removed) was calculated with and without credit for any recovered gas[61]. The Mexican annual cost was calculated as the annual amortized capital cost over the equipment life plus annual operating costs. This was divided by annual methane reductions to calculate the cost-effectiveness without credit for recovered gas. Where gas can be recovered and monetized by the operating company, the value of that gas was subtracted from the annual cost to calculate the cost-effectiveness with credit for recovered gas. The costs shown here are the baseline costs, which are adjusted for regional cost variation in the analysis. As noted earlier, these are average costs that may not reflect site-specific conditions at individual facilities.

Table 3-8 - Summary of Mitigation Measures Applied

Source	Mitigation Measure
Oil/Condensate Tanks w/o Control Devices	Vapor Recovery Units
Liquids Unloading - Wells w/o Plunger Lifts	Plunger lifts and Portable Flares
High Bleed Pneumatic Devices	Replace with low bleed devices or instrument air
Intermittent Bleed Pneumatic Devices	Replace with instrument air systems
Chemical Injection Pumps	Solar electric pumps
Kimray Pumps	Electric pumps
Pipeline Venting (Routine Maintenance/Upsets)	Pipeline pump-down
Centrifugal Compressors (wet seals)	Wet seal gas capture and Dry seal retrofits
Transmission Station Venting	Gas capture and route to fuel system or lower pressure gas stream
Stranded Gas Venting from Oil Wells	Flaring
Reciprocating Compressor Rod Packing	Rod packing replacement
Reciprocating Compressor Fugitives	Leak detection and repair (LDAR)
Compressor Station Fugitives	Leak detection and repair (LDAR)
Well Fugitives	Leak detection and repair (LDAR)
Gathering Station Fugitives	Leak detection and repair (LDAR)
Large LDC Facility Fugitives	Leak detection and repair (LDAR)

[61] The price of natural gas was assumed to be $4 USD/Mcf for the main portion of analysis in this report.

Source	Mitigation Measure
Offshore Venting	Flaring

Table 3-9 - Summary of Mitigation Measure Characteristics (in $MXN)

Name	Capital Cost[62]	Operating Cost	Percent Reduction	$/Mcf w/ Credit	$/Mcf w/o Credit
Early replacement of high-bleed devices with low-bleed devices	$46,200	$0	97%	$14.94	$93.17
Replacement of Reciprocating Compressor Rod Packing Systems	$101,640	$0	30.7%	$15.09	$93.32
Install Flares-Stranded Gas Venting	$770,000	$92,400	98.0%	$28.64	$28.64
Install Flares-Portable	$462,000	$0	98%	$1.69	$1.69
Install Plunger Lift Systems in Gas Wells	$308,000	$36,960	95%	-$0.77	$77.46
Install Vapor Recovery Units	$779,794	$141,156	95%	-$49.13	$29.11
LDAR Wells	$2,559,311	$900,900	60%	-$28.03	$50.20
LDAR Gathering	$2,559,311	$900,900	60%	-$62.99	$15.25
LDAR LDC - MRR	$2,559,311	$900,900	60%	$24.95	$103.18
LDAR Processing	$2,559,311	$900,900	60%	-$65.30	$12.94
LDAR Transmission	$2,559,311	$900,900	60%	-$64.53	$13.55

[62] Cost escalations for offshore capital, operating, and maintenance costs are performed on a separate basis from the standard cost table

Name	Capital Cost[62]	Operating Cost	Percent Reduction	$/Mcf w/ Credit	$/Mcf w/o Credit
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$77,000	$1,155	100%	-$3.39	$74.84
Replace Kimray Pumps with Electric Pumps	$154,000	$30,800	100%	-$64.22	$14.01
Pipeline Pump-Down Before Maintenance	$0	$6,072,405	80%	-$56.98	$21.10
Wet Seal Degassing Recovery System for Centrifugal Compressors	$1,078,000	$0	95%	-$73.15	$4.93
Wet Seal Retrofit to Dry Seal Compressor	$6,930,000	-$770,000	95%	-$73.15	$4.93
Blowdown Capture and Route to Fuel System (per Compressor)	$308,000	$0	95%	-$69.92	$8.32
Blowdown Capture and Route to Fuel System (per Plant)	$770,000	$0	95%	-$61.45	$16.63
Replace with Instrument Air Systems - Intermittent	$924,000	$273,658	100%	-$59.14	$19.10
Replace with Instrument Air Systems - High Bleed	$924,000	$273,658	100%	-$59.14	$19.10

3.6. Source Categories Not Included in MAC Analysis

Several source categories with emissions were not addressed in the analysis. The sources and the reasons for their treatment are summarized below.

- **Cast-iron gas mains** – Cast-iron mains have been identified as a significant emission source in the distribution segment in the United States. In the United States, these cast-iron mains are primarily located in congested urban areas where replacement or repair is very expensive, reported as $1 million to $3 million (US) per mile. This makes for a very expensive control option based purely on emission reduction. In addition, LDCs are making increasing efforts to replace miles of cast iron each year for safety reasons, so the emissions are gradually declining. New technologies could reduce the cost of reduction in the future. That said, research indicated that cast-iron mains are not common in Mexico and this option was not included.
- **Engine exhaust** – The exhaust from gas-burning engines and turbines contains a small amount of unburned methane from incomplete combustion of the fuel. While it is a small percentage, it is significant in aggregate. Oxidation catalyst devices are used to reduce unburned emissions of other hydrocarbons in the exhaust but they are not effective at reducing emissions of methane due to its lower reactivity. However, new catalysts are being developed, in part for natural gas vehicles, which may be applicable to these sources. This is a topic for further research and technology deployment.
- **Other sources** – There are additional cost-effective measures for methane reduction that have been identified by the EPA Gas STAR program and others. They are not included here because this report focuses only on the largest emitting sources. However, their omission should not be taken to indicate that the measures listed here are the only cost-effective methane reduction measures.

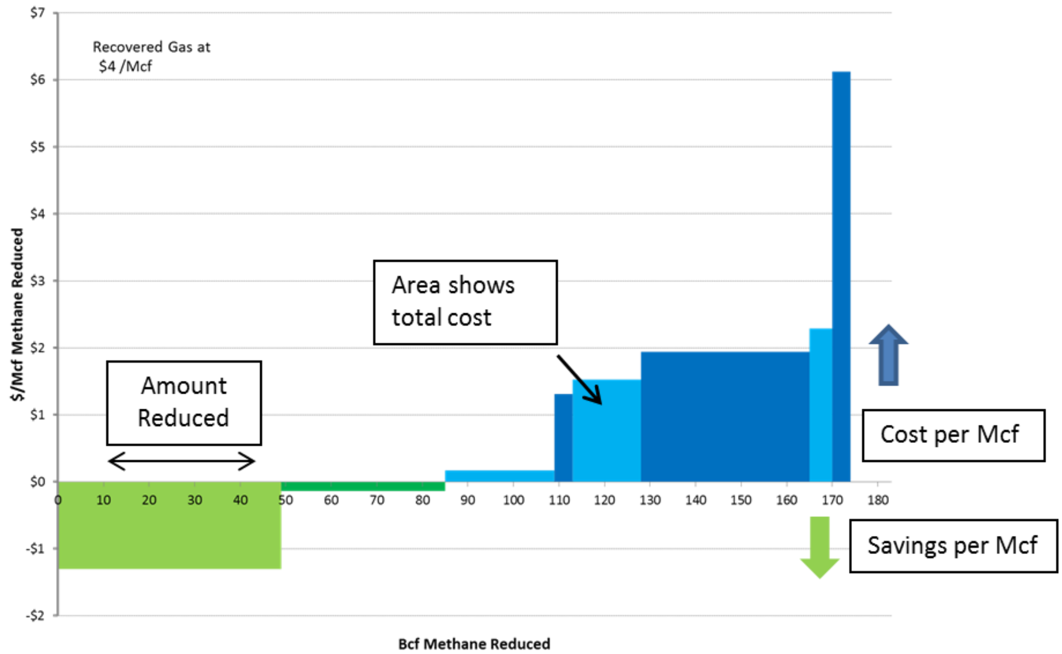
4. Analytical Results

4.1. Development of Emission Control Cost Curves

With the 2020 Projected Baseline established and mitigation technologies identified and characterized for the major emitting sectors, emission cost reduction curves were calculated for a variety of scenarios. The model developed for this task includes the individual source categories for each segment of the oil and gas industry by region. Mitigation technologies can be matched to each source by region and/or individual source applied. The model can also specify what portion of each source population the measure applies to and whether it applies to new (post-2013), existing (as of 2013), or all facilities. The model calculates the reduction achieved for each source and calculates the cost of control based on the capital and operating costs, the equipment life, and where appropriate, the value of recovered gas. Key global input assumptions include: whether a particular segment is able to monetize the value of recovered gas, the value of gas, and the discount rate/cost of capital. The Gulf Coast region in the U.S. was used as a proxy to represent base cost in Mexico on a national level. This was chosen as a conservative estimate because based on the U.S. EDF MAC curve study, Gulf Coast costs were the base costs and not adjusted downwards further, even though it is likely costs would be less in Mexico.

The results are presented primarily as a Marginal Abatement Cost Curve (MAC curve), shown in Figure 4-1. This representation shows the emission reductions sorted from lowest to highest cost-of-reduction and shows the amount of emission reduction available at each cost level. The vertical axis shows the cost per unit in $/Mcf of methane reduced. A negative cost-of-reduction indicates that the measure has a positive financial return, i.e. saves money for the operator. The horizontal width of the bars shows the amount of reduction. The area within the bars is the total cost per year. The area below the horizontal axis represents savings and the area above the axis represents cost. The net sum of the two is the total net cost per year. All costs in this section are in Mexican Pesos ($MXN) unless otherwise stated.

Figure 4-1 - Example MAC Curve



4.2. Emission Reduction Cost Curves

This section presents the results of the cost curve analysis. The curves represent different views of a potential emission control scenario in 2020 based on measures installed between 2013 and 2020. The emission reduction costs are the annual costs per Mcf of methane reduced. This should not be confused with cost per Mcf of natural gas produced, which is an entirely different metric. In the cases shown here, the total annual cost of reductions divided by total Mexican gas production is less than $ MXN 0.01/Mcf of gas produced in all cases.

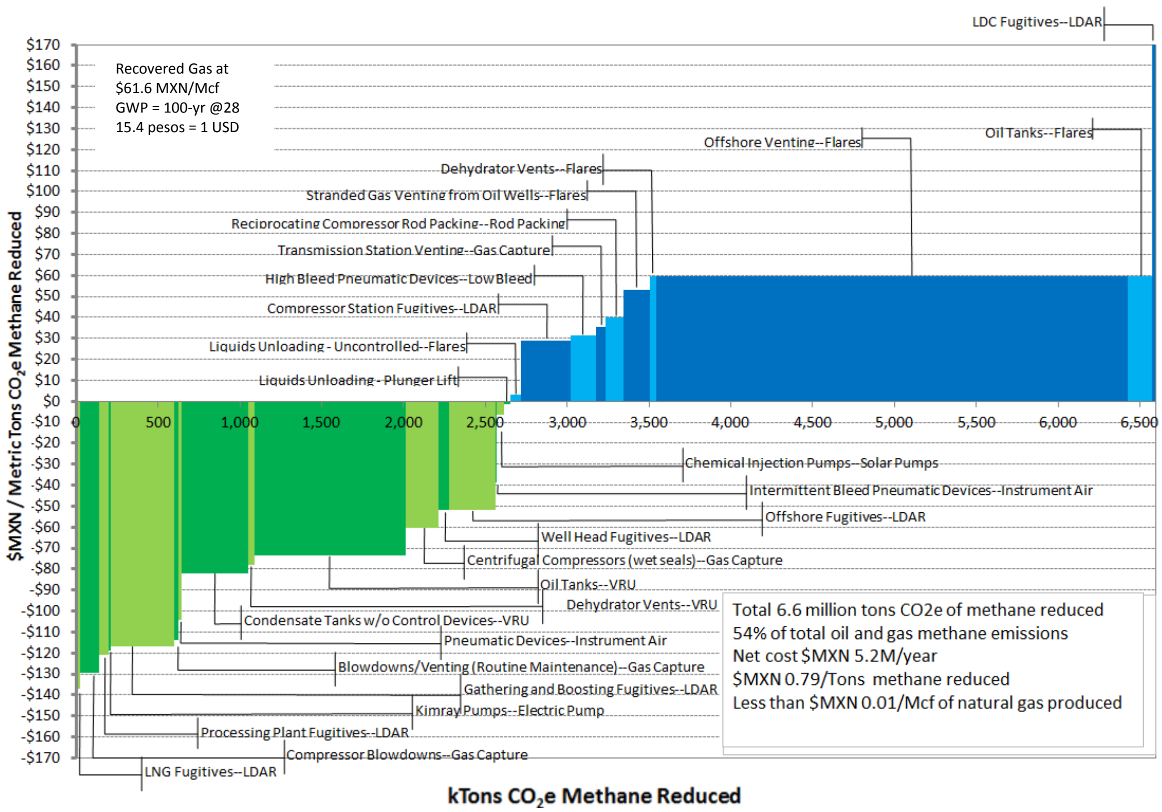
There are several caveats to the results:

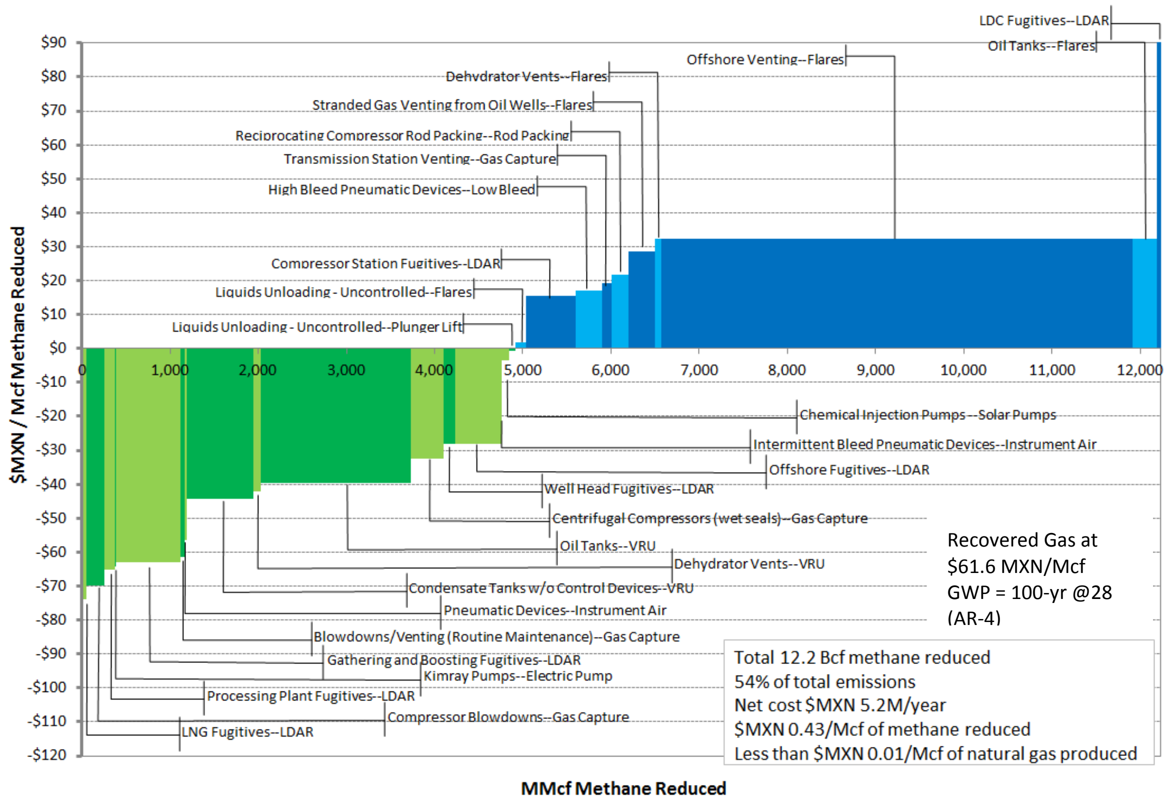
- Mexican data sources/reports and other U.S. sources are the best starting points for this analysis, but each is based on many assumptions and some older data sources. Although these reports and the inventory are improving with new data, aspects of the methodology are imperfect, especially at the detailed level, for a granular analysis of this type.
- Emission mitigation cost and performance are highly site-specific and variable. The values used here are estimated average values.
- The analysis presents a reasonable estimate of potential cost and magnitude of reductions within a range of uncertainty.

The base case assumption for the results in this section assumes a $62 MXN/Mcf price for recovered gas and a 10% discount rate/cost of capital for calculating the cost of control. Additional sensitivity and alternative cases are shown in Appendix C (e.g. segment emissions breakdowns).

Figure 4-2 shows the national aggregate MAC curve for the baseline technology assumptions by source category for both metric tons in CO2e followed by the same chart in Bcf. The Bcf curve is used for much of the analysis and breakdowns in this section. It shows the reductions achievable from each source with the relevant emission control measure. These results are aggregated across industry segments, so the "reciprocating compressor fugitives" block, for example, includes the cost and reductions from the source among all segments. The variations between regions and between segments for a given technology are averaged for each block.

Figure 4-2 – National Aggregate MAC Curve for Baseline Technology Assumptions





The total reductions are 12.2 Bcf of methane per year or 54% of the 2020 emissions from the oil and gas industries. The total annualized cost to achieve those reductions is $ MXN 5,220,000 /year or $ MXN 0.43/Mcf of methane reduced. This total annual cost is the net of the $ MXN 212 million annual savings (green bars below the axis) and $ MXN 217.2 million annual cost (blue bars above the axis). The chart shows which sources and technologies have the lowest cost-of-control (height - vertical axis) and the greatest reduction (width – horizontal axis). The results are also summarized in

Table 4-1. The cost ranges from -$ MXN 153.71/Mcf methane reduced for LDAR at LNG facilities to $ MXN 245.55/Mcf methane reduced for LDAR at LDCs. Credit for recovered gas accrues to all sectors except transmission and LDCs, which are limited by rate regulation from monetizing the emission reductions.

Table 4-1 also shows the estimated annualized costs in addition to reduction potential and cost per Mcf reduced of methane. This is a top-down estimate based on the projected reductions and the capital cost per measure so the costs are less certain than in a bottom-up costing, particularly with respect to differences between segments. The total capital cost is estimated at $ MXN 1,624 million.

Table 4-1 – Annualized Cost (in $ MXN), Reduction Potential, Cost/Mcf, and Initial Capital Cost

Source/Measure	Annualized Cost ($ million/yr)	MMcf Methane Reduced/yr	Cost $/ Mcf Methane Reduced	Initial Capital Cost ($ million)
LNG Fugitives--LDAR	-$3.54	47.1	-$74.1	$0.92
Compressor Blowdowns--Gas Capture	-$14.7	212.4	-$69.9	$6.6
Processing Plant Fugitives--LDAR	-$7.3	112.9	-$65.3	$2.0
Kimray Pumps--Electric Pump	-$1.3	20.4	-$64.2	$0.77
Blowdowns/Venting (Routine Maintenance)--Gas Capture	-$45.4	721.2	-$62.9	$6.6
Pneumatic Devices--Instrument Air	-$2.9	46.8	-$61.4	$1.54
Gathering and Boosting Fugitives--LDAR	-$1.8	31.7	-$56.3	$14.1
Condensate Tanks w/o Control Devices--VRU	-$33.2	754.0	-$44.2	$73.9
Dehydrator Vents--VRU	-$3.2	76.1	-$42.2	$6.47
Oil Tanks--VRU	-$67.6	1,707.1	-$39.5	$216.2
Centrifugal Compressors (wet seals)--Gas Capture	-$12.0	371.5	-$32.4	$14.0
Well Head Fugitives--LDAR	-$3.5	128.5	-$28.0	$8.32
Offshore Fugitives--LDAR	-$14.6	524.8	-$28.0	$36.6
Intermittent Bleed Pneumatic Devices--Instrument Air	-$0.2	8.1	-$29.9	$0.31
Chemical Injection Pumps--Solar Pumps	-$0.3	78.4	-$3.39	$32.9
Liquids Unloading - Uncontrolled--Plunger Lift	-$0.01	73.6	-$0.77	$20.1
Liquids Unloading - Uncontrolled--Flares	$0.2	126.6	$1.69	$0.77
Compressor Station Fugitives--LDAR	$8.8	559.4	$15.5	$10.2
High Bleed Pneumatic Devices--Low Bleed	$4.9	292.1	$16.9	$129.9
Transmission Station Venting--Gas Capture	$2.2	110.1	$19.1	$15.5
Reciprocating Compressor Rod Packing--Rod Packing	$4.3	197.1	$21.7	$25.5
Stranded Gas Venting from Oil Wells--Flares	$8.6	298.4	$28.6	$34.0
Dehydrator Vents--Flares	$2.3	73.3	$32.1	$12.4
Offshore Venting--Flares	$172.1	5,342.2	$32.1	$900.9
Oil Tanks--Flares	$8.7	274.5	$32.1	$47.1

Source/Measure	Annualized Cost ($ million/yr)	MMcf Methane Reduced/yr	Cost $/ Mcf Methane Reduced	Initial Capital Cost ($ million)
LDC Fugitives--LDAR	$5.3	45.2	$118.2	$6.1
Grand Total	**$5.2**	**12,234.6**	**$0.43**	**$1624.4**

Figure 4-3 shows the emission reductions by major category. Reducing of offshore venting emissions and oil tank emissions are some of the main opportunities for reduction. Other vented and fugitive sources of emissions make up the remaining amount and also have viable mitigation measures.

Figure 4-3 - Distribution of Emission Reduction Potential

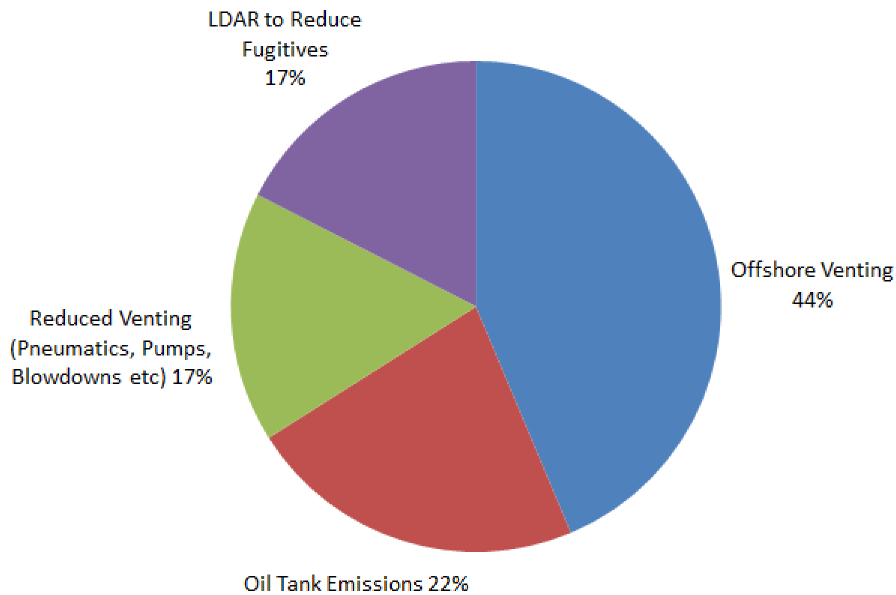


Figure 4-4 shows the reduction in methane emissions by industry segment for the same case. The transmission and distribution sectors are not able to monetize their reductions and therefore will always have a net positive cost. The LDC segment has only one measure and is the highest cost. The costs for the other sectors depend on the particular mitigation options available in each and their aggregate cost. The offshore oil, gas transmission and oil production segments account for more than 84% of the total reductions.

Figure 4-4 - Emission Reduction by Industry Segment (in $MXN)

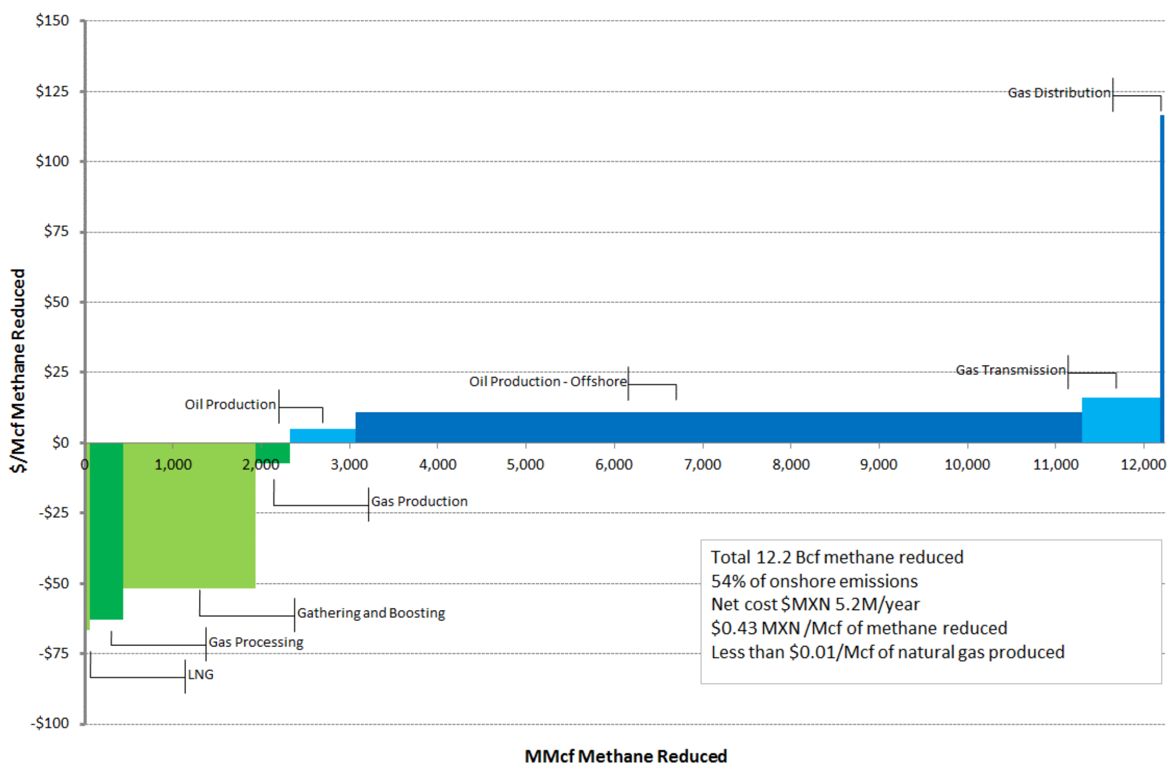


Figure 4-5 shows the breakdown of reduction options for the Offshore Oil Production segment. Offshore venting accounts for almost three quarters of the reductions and can be reduced at roughly $ MXN 32.19 per Mcf. Oil tanks, offshore fugitives, and condensate tanks are also significant sources at relatively low positive cost mitigation options. The total reduction opportunity is 8.2 Bcf with a net cost of $ MXN 10.93/Mcf of methane reduced.

Figure 4-5– Emission Reductions for the Offshore Oil Production Segment (in $MXN)

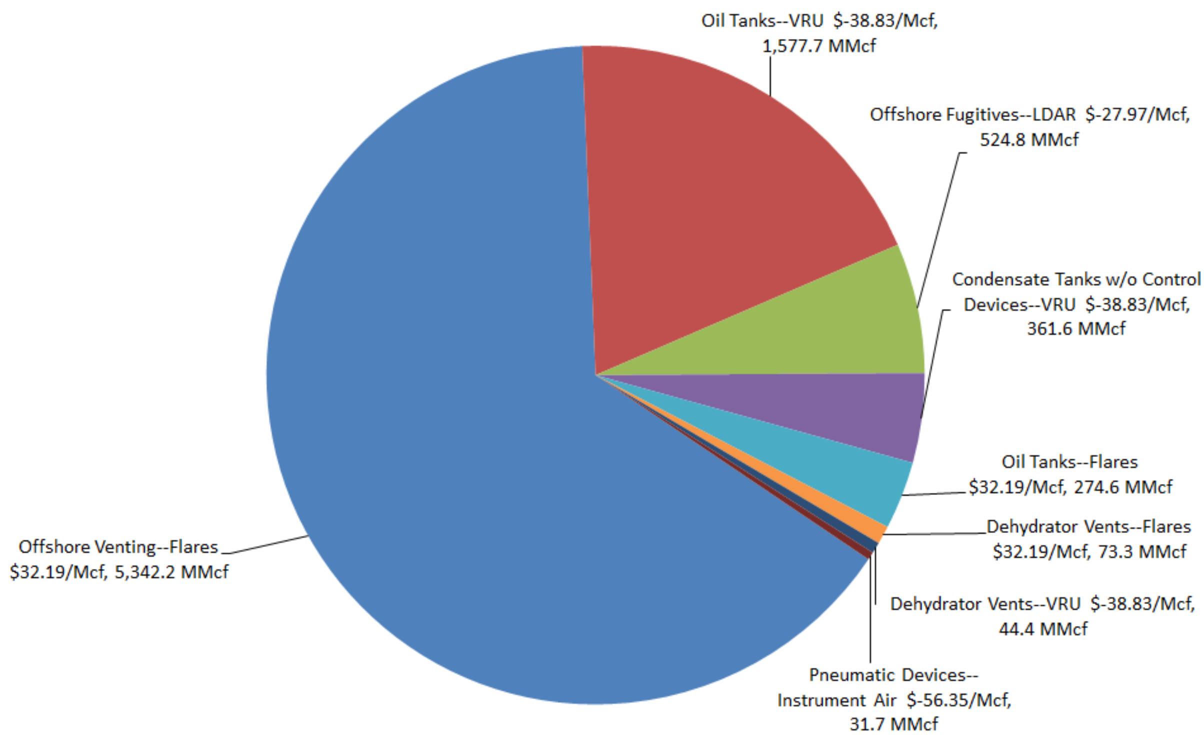


Figure 4-6 shows the breakdown of reduction options for the Gas Production segment. Liquids unloading accounts for roughly half of the reductions and can be reduced at roughly $ MXN 1.73 per Mcf or -$ MXN 0.76 per Mcf depending on the mitigation option. Chemical injection pumps, liquids unloading, and the replacement of high bleed pneumatics are also significant sources at relatively low positive cost mitigation options. The total reduction opportunity is 0.39 Bcf with a net cost of -$ MXN 7.24/Mcf of methane reduced.

Figure 4-6 – Emission Reductions for the Gas Production Segment (in $MXN)

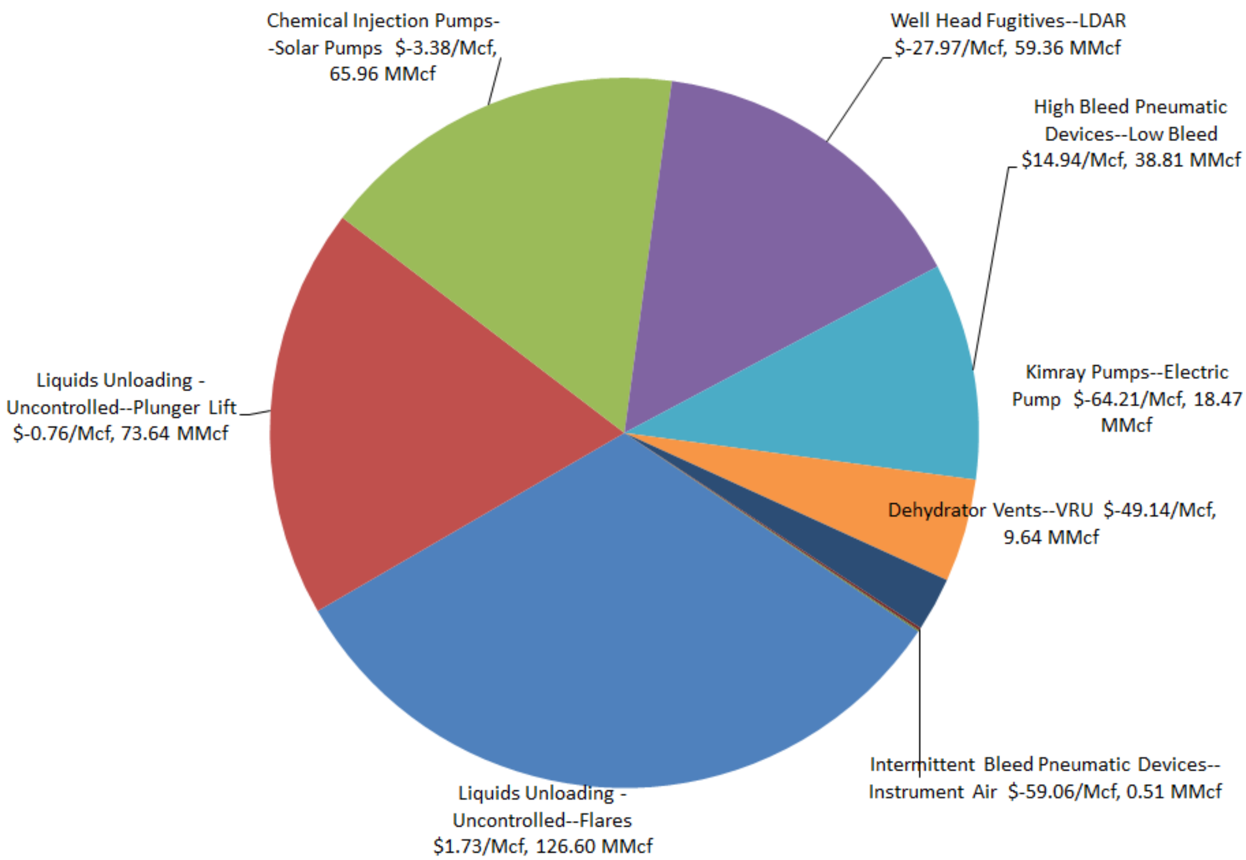


Figure 4-7 shows the reductions for the Oil Production segment. Stranded gas venting is by far the largest source, representing about 0.3 Bcf of reduction opportunity. Installation of VRU's on oil tanks in addition to the replacement of high bleed pneumatics are significant components as well, accounting for nearly half of the reductions. A handful of other emission sources round out the segment, with the total reduction across oil production being 0.75 Bcf at a cost of 4.78/Mcf of methane reduced.

Figure 4-7 - Emission Reductions for the Oil Production Segment (in $ MXN)

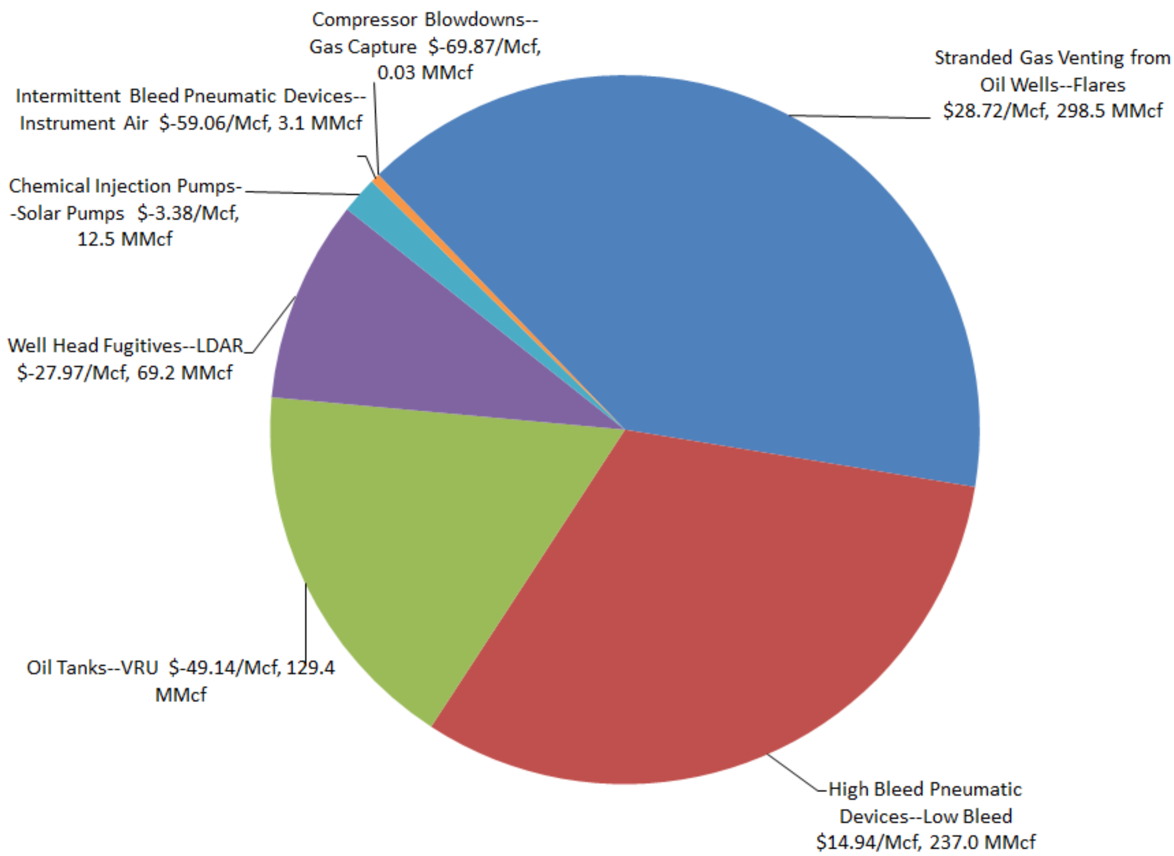


Figure 4-8 shows the reductions for Gathering and Boosting. LDAR to reduce fugitives at stations accounts for almost half of the reductions, while venting from condensate tanks, compressor blowdowns and reciprocating compressor rod packing almost account for the other half. The total reduction is opportunity 1.5 Bcf at a cost of -$ MXN 51.66/Mcf.

Figure 4-8 - Emission Reductions for the Gathering and Boosting Segment (in $ MXN)

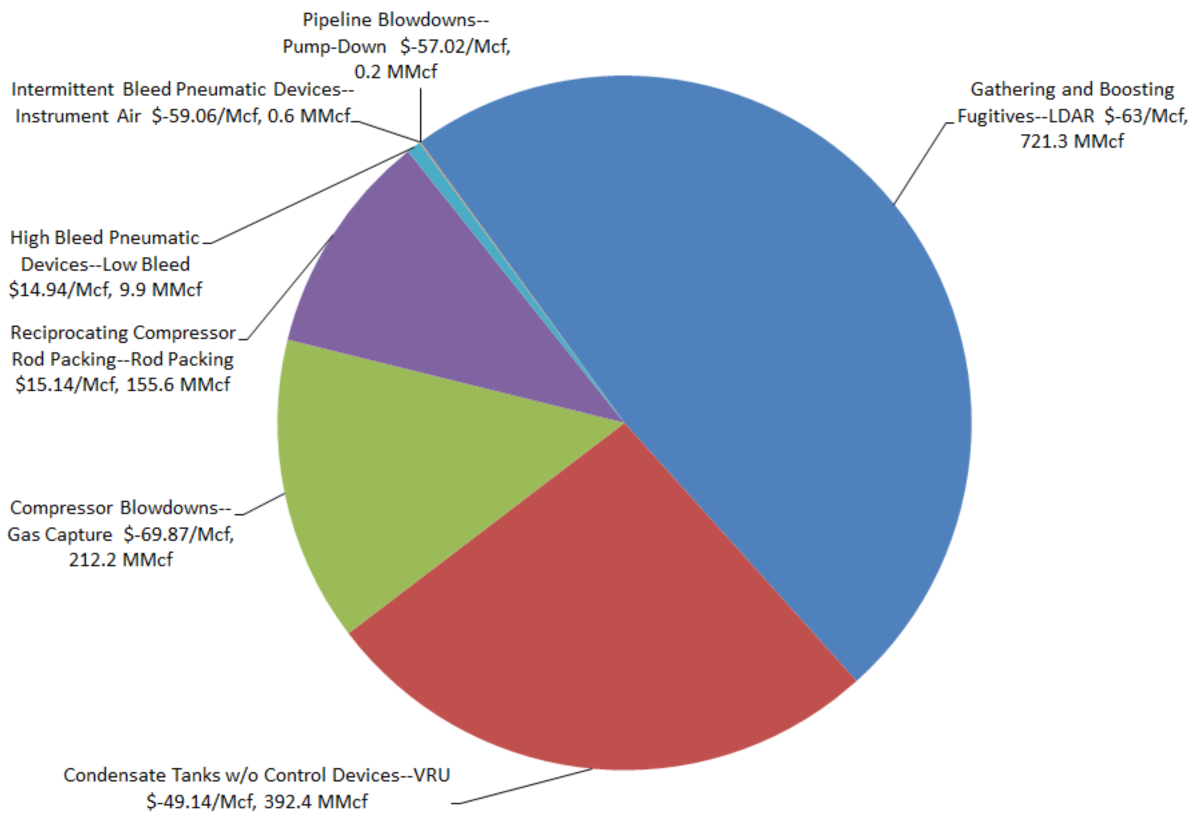


Figure 4-9 shows the reductions for the gas Transmission segment. LDAR reductions of fugitives from stations and compressors are the largest components. Capture of degassing emissions from wet seal centrifugal compressors and reduced station venting are the other significant measures. Due to regulatory limitations, transmission pipelines are not able to monetize emission reductions, so the cost of reductions is positive for all measures, $ MXN 16.02/Mcf of methane reduced for 0.89 Bcf of reductions.

Figure 4-9 - Emissions Reductions for the Gas Transmission Segment (in $ MXN)

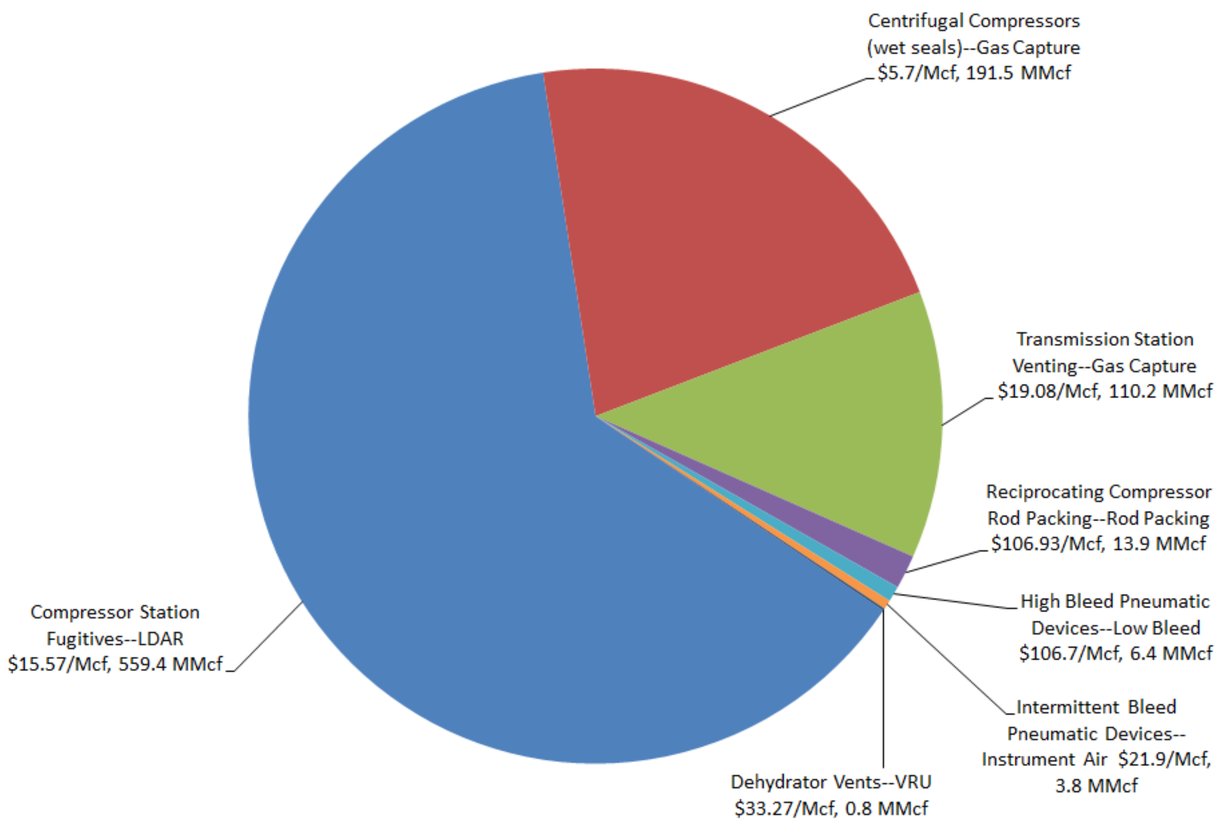
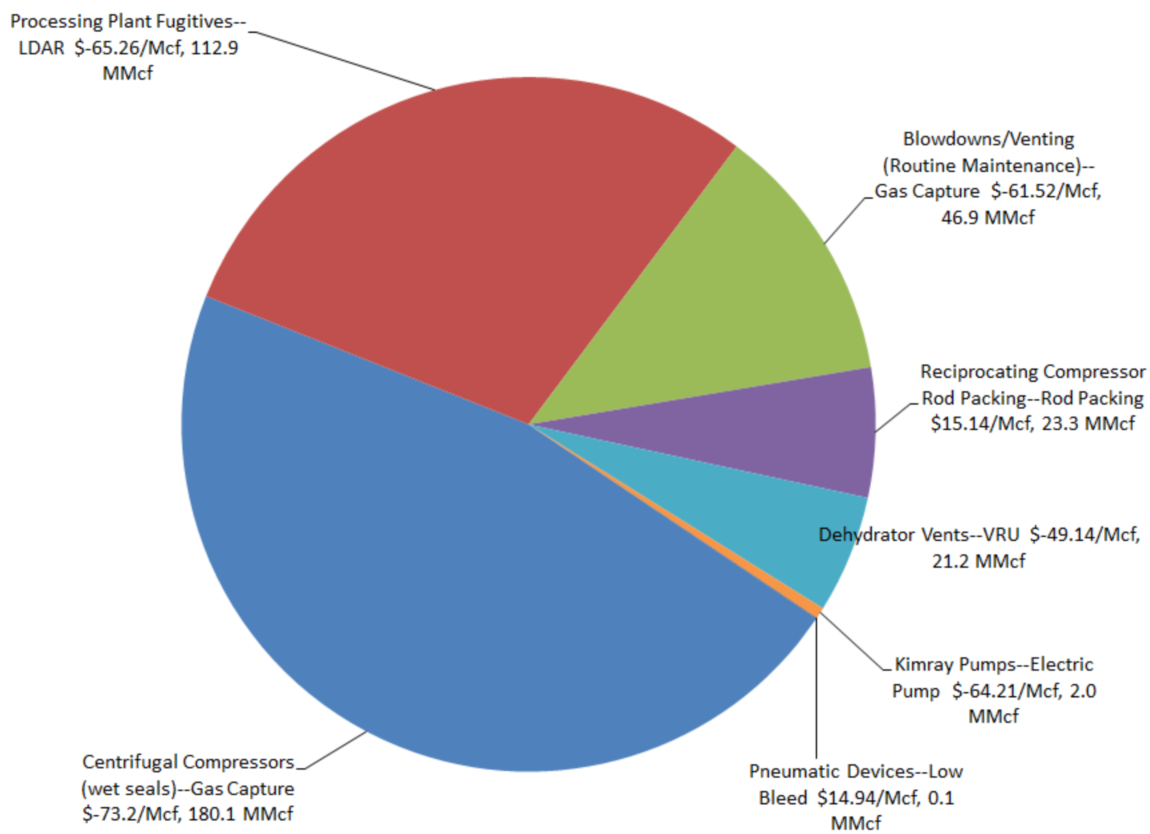


Figure 4-10 shows the reductions for the Gas Processing segment. Capture of degassing emissions from wet seal centrifugal compressors and fugitives from processing plants are the two largest sources, while routine blowdowns and venting from reciprocating compressor rod packing emissions are other significant sources. LDAR reduction opportunities exist for other sources, and having a comprehensive LDAR program that targets processing plants will benefit other emission sources as well. The cost of reductions for all measures is -$ MXN 62.73/Mcf of methane reduced for 0.38 Bcf of reductions.

Figure 4-10 - Emissions Reductions for the Gas Processing Segment (in $ MXN)



4.3. Co-Benefits

Measures that reduce gas emissions will also reduce the emissions of conventional pollutants - volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) - in the gas as well as methane. Most of these components are removed from the gas at the gas processing stage so the primary co-benefits are at or prior to that stage in the value chain. Although not quantified as part of this report due to a lack of data, it can be reasonably anticipated that a reduction of both VOCs and HAPs would result along with actions taken to reduce methane. If the co-benefit of reducing VOCs/HAPs were considered in conjunction with the cost of reducing methane emissions, the overall $/Mcf cost would decrease, essentially yielding a lower cost of control.

5. Conclusions

The key conclusions of the study include:

- **22.7 BCF of Emissions in 2020** - Methane emissions from oil and gas activities are projected to decrease from 14.6 million metric tons of CO_2e (27.05 Bcf) in 2013 to 12.2 million metric tons of CO_2e (22.7 Bcf) in 2020.
    - The opening up of Mexico's oil and gas sector to foreign companies was analyzed as part of this emissions analysis but not found to significantly affect emissions in 2020 as projects will not yet be online.
    - The majority of this emissions decrease is caused by the continued decline of Mexico's most prolific offshore producing field - Cantarell. Offshore fields such as Ku-Maloob-Zaap (KMZ) are also projected to decline from 2013 to 2020, contributing to an overall decrease in emissions.
    - Existing 2013 emissions sources account for over 90% of emissions in 2020.
- **Concentrated Reduction Opportunities** - 21 of the over 100 emission source categories account for over 80% of the 2020 emissions, primarily at existing facilities. Thus, reductions from these sources offer the opportunity for high overall reductions.
- **54% Onshore and Offshore Emissions Reduction Possible with Existing Technologies** – This 54% reduction of all oil and gas methane is equal to 6.6 million metric tons CO_2e (12.2 Bcf of methane) and is achievable with existing technologies and techniques. This reduction:
    - Comes at a net total cost of $0.43 MXN /Mcf reduced ($0.03 USD/Mcf reduced) or for less than $0.01 MXN /Mcf of gas produced nationwide, taking into account savings that accrue directly to companies implementing methane reduction measures.
    - Is equal to $0.79 MXN / metric tons CO_2e reduced. If the natural gas is valued at $62 MXN/Mcf ($4/Mcf), the methane reduction potential includes recovery of gas worth approximately $483.6 million MXN ($31.4 million USD) per year.
    - Is achievable at a net cost of over $5.2 million MXN per year ($313,546 USD) if the full economic value of recovered natural gas is taken into account and not including savings that do not directly accrue to companies implementing methane reduction measures. If the additional savings that do not accrue to companies are included, the 54% reduction is achievable at a net savings of $78 million MXN ($5 million USD).
    - Is in addition to regulations already in place as well as projected voluntary actions companies will take by 2020.
- Capital Cost – The initial capital cost of the measures is estimated to be approximately $1.6 billion MXN ($106 million USD).
- **Largest Abatement Opportunities -** In 2020, the Offshore segment makes up 54% of total oil and gas methane emissions, followed by Gathering and Boosting (19%) and Oil Production (11%). By

volume, the top five largest sources of on and offshore Mexican oil and gas methane emissions and reduction opportunities are:

- Offshore Venting – opportunity to reduce emissions by 78% by installing flares.
- Venting from Oil Tanks – opportunity to reduce emissions by 48% by installing vapor recovery units.
- Reciprocating compressor rod packing seals - opportunity to reduce emissions by 22% by replacing rod packing at a higher frequency.
- Stranded Gas Venting – opportunity to reduce emissions by 78% by installing flares.
- Venting from Condensate Tanks – opportunity to reduce emissions by 48% by installing vapor recovery units.

- **Co-Benefits Exist** – Reducing methane emissions will also reduce - at no extra cost - conventional pollutants that can harm public health and the environment. The methane reductions projected here would also result in a reduction in volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) associated with methane emissions from the oil and gas industry. This was not quantified in this study due to lack of data.

There are several caveats to the results:

- This study used as much Mexican-specific data as possible and modeled emissions by resource type and by using Mexico-specific activity data, where possible. Various assumptions across each segment were utilized in conjunction with Mexican-specific data (e.g. Secretaría De Energía (SENER), Petróleos Mexicanos (PEMEX), Instituto Nacional de Ecología y Cambio Climático (INECC), etc.) in order to develop equipment and segment-specific activity estimates for the Mexican oil and gas industry. Where no Mexican data existed, supplementary data from U.S. studies was used. Assumptions about site configurations are also U.S. based. Factors specific to Mexican oil and gas operations were also considered in the estimation of emissions, specifically the presence of sour gas and nitrogen injection in select oil production wells such as the Cantarell for enhanced oil recovery.
- IPCC guidelines for oil and gas methane reporting are split into three regions; U.S. and Canada, Western Europe, and other oil exporting countries. Mexico falls into the last region, which has higher emission factors, specifically for venting and flaring emissions. Mexico prepares its inventory using these IPCC emissions factors and reports it to the UNFCCC. Mexican emissions inventories are higher in comparison to this ICF study, in part, because of the higher IPCC emission factors. The more recent INECC study indicates a different approach to estimating emissions and is significantly lower than the previous UNFCCC reporting. However, if IPCC emission factors used by Mexico are directionally correct, this study provides a conservative estimate for potential reductions.
- This ICF study developed a bottoms up emissions estimate using specific activity and emissions factor data where applicable. Where no Mexican emission factors were available, this study used data from the Subpart W of the U.S. EPA GHG Reporting Rule (GHGRP) which was analyzed in conjunction with regional proxies (based on geology) to develop emission factors that apply to the

Mexican case. Source-specific emissions factors from U.S. data are not expected to be significantly different vs. Mexican operations. For example, a pneumatic device made by the same company can reasonably be assumed to operate the same in Mexico as it would in the U.S.

- Various assumptions across each segment were utilized in conjunction with available public reports (e.g. SENER, PEMEX, INECC, etc.) in order to develop equipment and facility information for Mexican segments, which is not otherwise available.
- Emission mitigation cost and performance are highly site-specific and variable. The values used here are estimated average values.

Appendix A. Development of the 2013 Baseline Inventory

A.1. Overview

The analysis of methane emission reduction potential uses Mexican-specific research reports from organization such as PEMEX, SENER, and other bodies such as CNH. The Mexican data is combined with the structure and emissions sources from the methane portion of the Natural Gas and Petroleum Systems section of EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012* as a basis. The baseline inventory represents a robust, comprehensive data set that utilizes various Mexican specific data resources and applies U.S. inventory methodology to estimate emissions.

A.2. H_2S Content – Sweet vs. Sour Splits

Oil and Gas activity was divided into two categories based on the presence of H_2S- sweet or sour. The determination on of whether or not to classify production as sweet or sour was made based on data extracted from various reports published by CNH and analyzed at the field level where applicable. If the measured H2S content was greater than 0.1%, the field and its associated production was assumed to be sour. The percentage of sweet vs. sour activity (e.g. gas production, gas processing throughput, etc.) across Mexico was calculated and used to segregate activity accordingly in the baseline inventory.

A.3. Natural Gas Inventory

The data structure and taxonomy from the U.S. EPA Inventory were used as a starting point to generate the list of sources for the natural gas portion of the baseline. A significant change to the structure of the natural gas segment in the 2013 Baseline was breaking out the Gathering and Boosting segment. This is the segment between onshore Production and either Gas Processing or Gas Transmission. This segment is included in the onshore production segment of the EPA Inventory based on the 1996 GRI measurement study rather than being fully broken out as a separate segment. In this study, some sources were moved from Production to the Gathering and Boosting segment in order to allow them to be analyzed separately for this segment and new emissions estimates, for some sources not represented in the 2013 EPA inventory, were added. For example, emissions from condensate tanks were moved from the Production segment to the Gathering and Boosting segment.

Although emissions were not segregated by Mexican region, a detailed analysis was undertaken to properly separate Mexico's onshore vs. offshore oil and gas operations for developing the baseline. For example, since most of Mexico's onshore non-associated gas production is focused in the norther region, this area became important when trying to identify a surrogate location in the U.S. A similar analysis was performed for Mexico's onshore southern region, which is mainly comprised of oil production.

Based on geological criteria, these surrogate locations were identified in the U.S. to help generate estimates for activity for select emissions sources when Mexican specific information was not available. Various source estimates (both activity and emissions factors) were driven using data (e.g. Subpart W data, well counts, miles of Transmission pipeline, etc.) from the regional proxies to eventually yield a Mexican specific value. The following analogs were identified:

- Onshore Northern Mexico– Gulf Coast
- Onshore Southern Mexico– Mid-continent

In subsequent sections, instances where *regional proxies* were used to estimate Mexican activity or emissions factors will be identified as such. It is important to note that these regional proxies and the associated analysis is performed at the emissions baseline inventory level. Once all emissions data was estimated, information was rolled up according to industry segment.

A.3.1. Gas Production

A.3.1.1. Natural Gas Well Counts

Well counts for natural gas-producing regions were obtained from data included in the PEMEX 2013 Annual Report[63]. These well counts drive the count of associated well equipment, such heaters, separators, and dehydrators (found in their respective sections below), as well as drive activity estimates for other sources.

A.3.1.2. Well Head Fugitives

Well head fugitive emissions are based on the activity of non-associated gas wells identified in section B.3.1.1 and an emission factor per well. Significant non-associated natural gas production in Mexico is based in the Burgos region, which is located in the northern portion of the country.

Emissions factors were generated for the northern region according to its U.S. proxy and work done by the University of Texas for EDF on fugitive emissions from well sites[64]. From this study, any identifiable well head emissions (i.e., emissions from the well itself, not the associated equipment) were grouped together and then divided by the well count at those sites to determine an overall per well emission factor. These emissions factors were then applied to the natural gas well counts identified.

A.3.1.3. Heaters, Separators, Dehydrators, and Meters/Piping (Well Fugitives)

Similar to the U.S. EPA Inventory, well counts drive these equipment activities by applying a standard ratio of equipment per well, according to U.S. region. Ratios generated for each U.S. region were applied to the Mexican northern region based on its proxy. An example for heaters in the northern region is:

$$HeaterActivity_{North} = \left(\frac{Heaters}{Well}\right)_{GulfCoast} \times Wells_{North}$$

The emission factor used here was provided by the EPA Inventory, and are applied according to the regional proxy specific to the northern Mexican region. Emission factors for heaters, separators, dehydrators, and meters/piping are also from the EPA Inventory.

A.3.1.4. Reciprocating Compressors

Small compressors were driven by an internal EDF Compressor memo that performed a compressor analysis in the U.S., which established a set ratio of compressors per wellsite. The count is then apportioned according to sweet and sour activity. Large reciprocating compressors and compressor stations have been allocated to Gathering and Boosting.

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[63] PEMEX 2013 Annual Report
http://www.pemex.com/acerca/informes_publicaciones/Documents/informes_art70/2013/Informe_Anual_PEMEX_2013.pdf

[64] Allen, David, et. al., "Measurements of Methane Emissions at Natural Gas Production Sites in the United States". 10.1073/pnas.1304880110

Emission factors were obtained from the EPA Inventory split according to the Mexican northern region and its regional proxy.

A.3.1.5. Gas Well Completions and Workovers

Gas well completions are broken out only for non-hydraulically fractured wells, with the activity factors for each of these sources developed using data from the 2013 PEMEX Annual Report.

Emission factors from the EPA Inventory are used for both completions and workovers.

A.3.1.6. Well Drilling

Total non-associated gas wells drilled were drawn from the PEMEX 2013 Annual Report, for example the Burgos and Veracruz production regions. The Gulf Coast emissions factor in the EPA Inventory was applied to this activity to calculate total emissions for this source.

A.3.1.7. Well Testing

This source was not included in the published EPA Inventory, but is included in subpart W of the GHGRP. The activity factor consists of an onshore well count, extracted from the 2013 PEMEX Annual Report. The emission factor was developed using total emissions reporting under subpart W for each region and the total well count in the U.S. from HPDI for each region. The regional subpart W factors were then applied to the Mexican regions according to their U.S. proxy.

A.3.1.8. Pneumatic Devices

Pneumatic devices in the published EPA Inventory are listed as a single category and use a single emission factor. However, pneumatic devices are reported in Subpart W under three categories: low bleed, intermittent bleed, and high bleed devices. In order to break out the devices into the respective categories, the 2013 emissions data in Subpart W was analyzed. From each device type's emissions, the count of each device type was back calculated using the prescribed standard emission factor in subpart W. This was done for each regional proxy and applied to estimate Mexican regional activity, as described further below. An example calculation for low bleed devices for the regional proxy Gulf Coast is:

$$LBD\ Activity_{GC} = \left(\frac{\sum RM\ LBD\ Emissions}{Emissions\ per\ device_{standard}}\right)_{SubpartW}$$

Where GC is Gulf Coast and LBD is low bleed device.

The "intermittent bleed" category covers a variety of different types of devices with different emission characteristics and is not well-characterized either in the subpart W data or other sources of emission data. Some of these, as characterized in the Subpart W emission factors, have a relatively high emission factor, while others are much lower. For this reason, the intermittent devices were further segregated into two categories: dump valves and non-dump valve intermittent devices. The dump valves represent devices that do not have a continuous bleed and generate emissions only when actuating. These types of devices are generally found as level controllers in separators. Assuming that approximately 75% of separators have a lower emitting intermittent bleed dump valve yielded an estimate that approximately 75% of the total intermittent bleed devices were dump valves. The percentage splits were based on SME input.

The activity factors for each type of device are calculated the same way according to regional proxy and well count data (both U.S. and Mexico). First, the sum of the total pneumatic device counts (for a particular device) is calculated from Subpart W according to regional proxy and divided by the total number of wells in that U.S. region. An example calculation follows for low bleed devices in the gulf coast region, utilizing the 'LBD Activity' calculation above.

$$LBD_{PneumaticRatioGC} = \frac{LBD\ Activity}{Total\ Well\ Count_{GC}}$$

The low bleed device example calculation above is further adjusted to account for wells not reported to Subpart W. Once the low bleed device ratio for the rocky mountain region has been calculated it is multiplied by the Northern gas well count to yield the low bleed device activity for the North as follows:

$$LBD_{North} = LBD_{PneumaticRatioGC} \times GasWellCount_{North}$$

Emissions factors were mainly sourced from a 2013 EDF study with the University of Texas[65]. In the report, bleed rates from low, high, and intermittent bleeds were measured and compiled from multiple sites.

Similar calculations are performed for each type of pneumatic device across the remaining Mexican regions.

A.3.1.9. Chemical Injection (Pneumatic) Pumps

The count of chemical injection pumps is derived using a subpart W factor of chemical injection pumps per well and applied across regional well counts in Mexico. The emission factor used for this source is from the U.S. EPA Inventory. Both the activity and emissions factors are applied according to the regional proxies.

A.3.1.10. Dehydrators and Kimray Pumps

Dehydrator counts in the Mexican inventory were estimated by multiplying regional well counts by standard ratios of the number of dehydrators per well according to the U.S. proxy. These ratios were obtained from the U.S. EPA inventory and broken down by region.

Kimray pump activity was estimated also by using the U.S. EPA Inventory methodology. Kimray pump activity was estimated by taking multiplying dehydrator activity above and EPA's value of average dehydrator throughput (2 million cubic feet per day) multiplied by a 45% capacity factor across an entire year. Finally a fraction of 0.891 is applied to account for the estimate of dehydrators with gas-driven Kimray pumps being present. An example calculation for Alberta is as follows:

$$KP\ Activity_{Alberta} = DehydratorActivity \times \frac{2MMscf}{day} \times 45\% \times 365\frac{days}{year} \times 0.891\frac{KimrayPumps}{Dehydrator}$$

Emissions factors were applied from the U.S. EPA Inventory according to regional proxy.

A.3.1.11. Dump Valve Venting

Activity was estimated by calculating a dump valve per well count according to subpart W data and reporting oil and gas wells. This ratio was then multiplied by regional gas well counts according to the regional proxy. Since this source was not included in the published EPA Inventory, but is included in subpart W reporting, the emission factor was also developed using Subpart W using total emissions. For production sites, an average emissions per device was calculated according to regional proxy and then

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[65] http://www.pnas.org/content/110/44/17768

applied to each region, respectively. An example for both activity and emissions factor in the North region is as follows:

$$DV\ Activity_{North} = \left(\frac{DV\ Device\ Count}{OilandGasWells}\right)_{GC} \times GasWells_{North}$$

Where DV is dump valves and GC is Gulf Coast.

$$DV\ EF_{North} = \left(\frac{\sum DV\ Emissions}{Device}\right)_{GC}$$

Where EF is emissions factor. The emissions factor for each region was supplemented with data on 'malfunctioning devices' from the previous EDF pneumatics device study. SME input determined that the 'malfunctioning devices' were stuck dump valves and the accompanying dump valve emissions factor was added to the Subpart W derived dump valve emissions factor.

A.3.1.12. Liquids Unloading (Gas Well Clean Ups)

Activity was estimated by calculating a liquids unloading value (both reporting unloadings with and without plunger lifts) per well count according to subpart W data and reporting oil and gas wells. This ratio was then multiplied by regional gas well counts according to the regional proxy. In a similar fashion, a specific regional subpart W emissions factor was calculated according to region and whether or not the well had a plunger lift present or not. Thus, for production sites, an average emissions per well reporting liquids unloading was calculated according to regional proxy and then applied to each region, respectively. Example calculations are below for both activity and emissions factors in the north region:

$$LUwoPlungerLiftActivity_{North} = \left(\frac{\#ofWellsUnloading_{woPlunger}}{OilandGasWells}\right)_{GC} \times GasWells_{North}$$

Where LU is liquids unloading and woPlunger is without plunger lifts.

$$LUwoPlungerLiftEF_{North} = \left(\frac{\sum Emissions_{woPlunger}}{WellsUnloading}\right)_{GC}$$

Where EF is emissions factor. Activity and emissions factors for wells with plunger lifts is calculated in a similar manner to wells without plunger lifts above.

A.3.1.13. Vessel Blowdowns, Compressor Blowdowns and Starts, and Pressure Relief Valves

Activity for compressor starts is equal to the number of small production compressors (a separate emissions source) estimated according to the methodology in 3.1.4. Activity for vessel blowdowns is assumed to be the summation of activity for heaters, separators, and dehydrators at well sites. The number of pressure relief valves was estimated by taking the ratio of pressure relief valves in the U.S. EPA inventory to total wells and then applying that ratio to regional gas well counts according to proxies.

All emissions factors for each emissions source are from the U.S. EPA Inventory according to regional proxy.

A.3.2. Gathering and Boosting

According to U.S. EPA Inventory methodology, the gathering and boosting segment was previously included as part of the Production sector, but has been broken out in this analysis so that it could be separately analyzed. This sector in the 2013 Mexico Baseline contains emissions from large reciprocating compressors, compressor stations, pneumatic devices, and pipelines, amongst other sources. Some other supporting equipment types were left in their respective segment, as found in the EPA Inventory and will be noted.

A.3.2.1. Condensate Tanks

Activity data for condensate tanks in Gathering and Boosting is based on lease condensate production specific to each region according to PEMEX's 2013 Annual report. Data reported to subpart W was used to update the U.S. EPA Inventory emission factors for condensate tank venting. The data pulled from Subpart W was on a regional basis and included average API gravity, separator pressure, and separator temperature. This data was then used to run simulations through API's E&P Tank™ software in order to develop new emission factors. The emission factors for each region were then applied to Mexican regions according to regional proxies. Based on SME input of Mexico operations, it was assumed that 10% of the tanks had control measures in place.

A.3.2.2. Compressors

The initial estimate of the compressor count comes from a ratio of compressors per gathering and boosting station[66] based on a previous internal EDF compressor memo. An average of 2.75 compressors per station was established from an analysis performed on the U.S. gathering and boosting system validated by and an EDF study of gathering systems, while a 45.2% operating factor was applied from the U.S. EPA inventory.

For this source and similar sources in other segments, there are two sources of reciprocating compressor emissions. Fugitive emissions (non-seal) from sources such as open-ended lines, flanges, and valves, in addition to vented rod packing seal emissions. To account for fugitive sources, the emission source was separated into blowdown valve operating, blowdown valve standby, and isolation valve activity. To drive the activity for each of these sources, the total compressor count was used since subsequent emissions take into account operating modes and % of time operating in those modes.

Emission factors for each fugitive source were derived from subpart W according to regional proxies, including data from both measured and non-measured compressors and applied across region. Vented emissions were calculated using total compressor count per reporting facility and subpart W derived emission factors, specific to rod packing.

In addition to splitting out fugitive sources on compressors, both seal and non-seal emission sources were further split between controlled and uncontrolled. Based on SME input, it was assumed that all compressor emissions were uncontrolled.

A.3.2.3. Scrubber Dump Valves

According to input from SMEs, the baseline inventory assumes one scrubber dump valve per compressor. The activity factor for scrubber dump valves is the sum of individual activity factors for controlled and uncontrolled reciprocating compressors. The emission factor was derived from subpart W data according to regional proxy and applied to each region.

[66] Two independent sources of data were used to determine the count of Gathering and Boosting Stations. 1) The Oilfield Atlas (Tenth Edition, 2014-2015), and 2) ST102: Facility List formerly Battery Codes and Facility Codes from the AER.

A.3.2.4. Compressor Exhaust (Gas Engines)

The exhaust from compressor engines and turbines contains some unburned methane. The activity factor for these two emissions sources in the derived from analysis of the EPA Inventory which has total horsepower hours of the equipment. Additionally, the U.S. EIA publishes the amount of natural gas used as "Lease Fuel," which is fuel burned at natural gas production sites. A new fuel volume was calculated for small reciprocating, gathering and boosting reciprocating, and gathering and boosting centrifugal compressors, respectively, according to typical horsepower ratings of each compressor type. This fuel volume was used as the new activity factor for compressor exhaust. The analysis assumed 70% of the lease fuel was consumed in engines and turbines and the breakdown between engines and turbines was determined to be 96% to 4%, respectively, using the breakdown of compressors according to count of U.S. compressors from the EDF Compressor Analysis report.

The emissions factors were updated using emissions factors from the EPA's manual of emission factors ("AP-42"). Since AP-42 lists 3 separate emission factors for engines (two stroke lean-burn, four stroke lean-burn, and four stroke rich-burn), a combined emission factor was developed based on the data obtained from U.S. state energy agencies. This data set, which contained nearly 10,500 compressors/engines across all sectors of the industry, was used to determine the breakout of engine types: 10% two stroke lean-burn, 34% four stroke lean-burn, and 56% four stroke rich-burn. These ratios were used to give an overall emission factor for engines. The emission factor for turbines, was listed directly in AP-42 and used as-is.

A.3.2.5. Gathering and Boosting Stations

Formally called "Large Compressor Stations" in the EPA Inventory, the count of stations was determined by utilizing data in an internal EDF compressor memo, whereby the total U.S. onshore count of gathering and boosting stations was divided by total U.S. onshore gas production. This yielded a ratio of compressor stations per unit of gas production. This ratio was then multiplied against Mexican onshore gas production in 2013 to estimate the count of gathering and boosting stations.

The emission factor for this source is derived from Subpart W data for transmission stations by taking the average emissions per station and applying it according to regional proxy in Mexico. An example calculation for the gathering and boosting station emissions factor is:

$$G\&BStationEF_{North} = \left(\frac{\sum Emissions_{TransmissionStation}}{\#ofTransmissionStations}\right)$$

A.3.2.6. Dehydrators and Kimray Pumps

Dehydrators and Kimray pumps were handled in a similar fashion as described in Gas Production (3.1.10)

A.3.2.7. Pneumatic Devices

The pneumatic device methodology is split in a similar to fashion as in Gas Production (3.1.8). The activity count is driven by an API/ANGA[67] ratio of device per gathering station multiplied by the ratios established in gas production according to the type of device (e.g. High-bleed, low-bleed, intermittent bleed, etc.). The emission factor methodology is the same as described in the Gas Production section.

[67] Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf

A.3.2.8. Pipeline Leaks, Pipeline Blowdowns, Compressor Starts, and Compressor Blowdowns

These emissions were moved from Production to Gathering and Boosting to better represent the breakout of emissions in the industry. Pipeline leaks and blowdowns are based on the ratio of gathering miles in the U.S.[68] divided by total gas production and then multiplied by total Mexican gas production. The units of pipeline blowdowns is also in miles and follows the same methodology.

For compressor starts, activity is based on the total number of compressors in the Gathering and Boosting segment as detailed in section 3.2.2. Since the units of activity for compressor blowdowns is "stations", the activity factor for compressor blowdowns is simply the count of gathering and boosting stations.

Emissions factors for pipeline leaks, pipeline blowdowns, and compressor starts are sourced from the U.S. EPA Inventory, while the emissions factor for compressor blowdowns was calculated using subpart W data. Specifically, emissions the subpart W table for transmission station venting was used as a proxy for compressor blowdowns in Gathering and Boosting and applied across each region.

A.3.3. Gas Processing

A.3.3.1. Gas Plant Fugitives

Activity for currently operating Gas Plants across Mexico was obtained from both the 2013 PEMEX annual report and their 2013 statistical report. These figures were cross checked with SENER data. The data sources provide a 2013 total list of gas processing facilities and whether the plant is considered a sweet or sour processing plant. The total plant count is not high, and in fact is only nine plants across Mexico. This count of plants drives much of the activity for the Processing segment. Due to the increased size of the Mexican gas processing facilities, the emissions factor for gas plant fugitives was obtained from Subpart W data driven by regional proxy and by analyzing emissions from U.S. plants of similar size.

A.3.3.2. Reciprocating and Centrifugal Compressors

Activity for Centrifugal compressors at gas processing facilities was obtained directly from PEMEX GMI publications, with the count being 67 compressors, split between 46 of the wet seal variety and 21 of the dry seal type. Since this number was known and not the total count of reciprocating compressors, Subpart W data was utilized in conjunction to provide the complete count of compressors in gas processing. An average compressor count at similarly sized facilities was determined from Subpart W data and was utilized to allocate the reciprocating compressor activity after taking into account the known centrifugal activity. This analysis yielded a total reciprocating activity of 78 compressors across gas plants.

The emissions factors for each of the sources are also mainly derived from Subpart W. For centrifugal compressors, Subpart W ratios of compressor emissions per compressor are used for blowdown

[68] Pipeline Annual Mileage
http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=78e4f5448a359310VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print&vgnextnoice=1

operating and isolation valve modes, while the EDF memo[69] on compressor seal emissions was used as the seal-only emissions factor. Reciprocating compressor emissions factors were strictly sourced from Subpart W analysis with minor supplements from the U.S. EPA Inventory. For example, subpart W provides emissions data on blowdown and isolation valves, which can produce regional emissions factors, but Subpart W does not have data on emissions from reciprocating compressor PRVs and miscellaneous components. The respective emissions factors from the U.S. EPA inventory are used here to supplement the emissions factor for completeness. Finally, all factors derived took into account the larger average size of Mexican gas processing facilities and thus analyzed data from similarly sized plants in Subpart W.

A.3.3.3. Scrubber Dump Valves

This emissions source followed a similar methodology as in gathering and booster, whereby it is assumed that there is one scrubber dump valve per compressor. The activity factor for scrubber dump valves is the sum of individual activity factors for controlled and uncontrolled reciprocating & centrifugal compressors. The emission factor was also derived from subpart W data according to regional proxy and applied to each region.

A.3.3.4. Gas Engine and Turbine Exhaust

The activity factor for these two emissions sources in the Mexican Baseline Inventory are driven by U.S. EIA published values for gas processing fuel consumption (the amount of natural gas used as "Plant Fuel") and total U.S. gas processing throughput. The total fuel volume from the EIA was used under the assumption that 80% of the fuel being consumed is for use in engines and turbines in a typical processing plant. Furthermore, fuel consumption splits between engines and turbines was assumed to be 46% to 54%, respectively, using the current horsepower-hour ratios in the published U.S. EPA Inventory. These estimates for both engines and turbines were divided by total U.S. gas processing throughput and apportioned according regional gas processing throughput. The final result of these calculations was a fuel consumption number by region in million standard cubic feet of natural gas burned.

The emissions factors were also updated and followed the same methodology as described in section B.3.2.4.

A.3.3.5. Dehydrators and Kimray Pumps

Dehydrators and Kimray Pumps followed a similar methodology as in Gas Production (3.1.10).

A.3.3.6. AGR Vents, Blowdowns/Venting and Pneumatic Devices

Activity for AGR vents is calculated by taking the 1992 ratio of AGR vents to gas processing plants in the U.S. EPA Inventory and multiplying the ratio by gas processing plants in Mexico. Pneumatic devices are not split into high, low, or intermittent bleed categories for this segment, but rather follow the U.S. EPA Inventory convention of having just one source. The unit of activity for pneumatics using this convention is simply the gas plant count, which is known from the methodology above for gas processing plants across Mexico. Blowdowns/venting also follow a similar methodology as pneumatics and also have gas plant count as its activity.

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[69] Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States
http://dept.ceer.utexas.edu/methane/study/

In all three sources, emissions factors from the U.S. EPA Inventory were used for each region according to their proxies.

A.3.4. Gas Transmission

A.3.4.1. Pipeline Leaks

Pipeline leak activity is driven by total mileage of transmission pipeline across Mexico. Data was obtained from a 2013 data published from SENER according to the Prospectiva de Gas Natural y Gas L.P. This information was summed up for the entire transmission segment across onshore Mexico and converted to miles. The emissions factor was obtained from the U.S. EPA Inventory.

A.3.4.2. Transmission Compressor Stations

Activity for transmission compressor stations was also obtained from SENER's Prospectiva according to the ESTACIONES DE COMPRESIÓN DE GAS NATURAL, 2013 section of the report. According to the report, there are approximately 20 compressor stations across Mexico of varying installed capacities.

The emissions factor for compressor stations was obtained from the U.S. EPA Inventory.

A.3.4.3. Reciprocating and Centrifugal Compressors

Activity factors for compressors were estimated in two distinct steps. First, a preliminary data cut was obtained from Pemex Transportation System Appendix (PTSA) to determine compressor counts at select compressor stations. Secondly, given data obtained in step 1, further SME input was used to allocate compressors across transmission stations according to installed capacities, standby requirements, etc. The resulting analysis produced a total count of 29 and 25 for centrifugal and reciprocating compressors, respectively. For centrifugal compressors, PEMEX GMI publications were utilized to determine splits between wet and dry seals. PEMEX's publicly reported percentage of wet seal compressors was obtained to be 70%. Similar steps were performed in terms of breaking out blowdown and isolation value activity consistent with the methodology found in gathering and boosting.

Emissions factors for both reciprocating and centrifugal compressors were also developed consistently with the Gathering and Boosting segment, namely sourced from Subpart W, the U.S. EPA Inventory, and the EDF compressor memo with data on centrifugal seal emissions.

A.3.4.4. Engine and Turbine Exhaust

Fuel consumption in engines and turbines in the transmission segment was also estimated in two distinct steps. First, as a driver, the ratio of total U.S. pipeline fuel consumption from the EIA to total U.S. transmission pipeline mileage was calculated and applied to the total miles of transmission pipeline across Mexico. Secondly, the fuel consumption was apportioned across engines and turbines according to the estimate of Mexico reciprocating and centrifugal compressors and the ratio of million horsepower-hour to reciprocating and centrifugal compressors, respectively, from the U.S. EPA Inventory. Assuming that that 90% of this fuel was used for compression, estimates for total engine and turbine exhaust were then able to be calculated. The emissions factors followed a similar methodology in other segments for engine exhaust.

A.3.4.5. Pneumatic Devices

Activity for high, low, and intermittent bleed devices were determined by taking Subpart W ratios of each device respectively to the count of reporting U.S. transmission stations. This ratio was then multiplied by the total transmission station count in Mexico for each device to arrive at its respective activity.

Emissions factors were applied according to similar methodology as described in other sections, mainly citing EDF studies on measuring device leakage rates.

A.3.4.6. Dump Valve Leakage

This emissions source followed a similar methodology as in Gathering and Booster, whereby it is assumed that there is one scrubber dump valve per compressor. The activity factor for scrubber dump valves is the sum of individual activity factors for controlled and uncontrolled reciprocating & centrifugal compressors. The emission factor was also derived from Subpart W data according to the transmission segment.

A.3.4.7. Pipeline Venting

Activity for pipeline venting was simply the total transmission pipeline mileage as calculated earlier in this segment. The emissions factor was obtained from the U.S. EPA inventory.

A.3.4.8. Transmission Station Venting

The total count of transmission stations from Mexico was used as the activity for transmission station venting. The emissions factor was obtained from Subpart W by calculating blowdown emissions and reporting station count from the transmission segment across 2011-2013 and averaging the resulting emissions factor. The resulting value was implemented as the emissions factor for transmissions station venting in Mexico.

A.3.5. Liquefied Natural Gas (Import/Export Terminals)

Besides import and storage terminals below, other sources LNG followed similar methodology as described in other segments of this appendix.

A.3.5.1. Import/Export Terminals

There is not significant activity across Mexico for LNG import/export terminals. However, there were three identified active import terminals according to research performed for the year 2013[70]. Emissions from these terminals were estimated using an emissions factor sourced from the U.S. EPA inventory.

A.3.5.2. Storage Terminals

This source was not considered as a significant emissions source for the Mexican emissions inventory.

A.3.6. Gas Distribution

Gas Distribution in the Mexican Baseline Inventory follows the U.S. EPA Inventory methodology with three key differences. First, each source is driven by residential gas consumption or mains mileage

[70] LNG Import Terminals
http://www.globallnginfo.com/world%20lng%20plants%20&%20terminals.pdf

specific to Mexico. Secondly, total distribution mileage was obtained from SENER[71], while residential gas consumption was also obtained from SENER. The final main difference between the Mexican methodology and the U.S. EPA Inventory was the implementation of emissions factors from an EDF study on leaks from distribution systems[72]. The resulting emissions factors from the EDF study are significantly lower than U.S. EPA Inventory values. It's important to note these factors applied to all sources except: Residential, Commercial/Industry, Pressure Relief Valves, Pipeline Blowdowns (Maintenance), and Mishaps (Dig-ins).

A.3.7. Oil Production - Onshore

A.3.7.1. Oil Tank Venting

Activity data for oil tanks is based on oil production specific to each region according to the 2013 PEMEX annual report. Additionally, data reported to subpart W was used to update the emission factors for condensate tank venting. The data pulled from subpart W was on a regional basis and included average API gravity, separator pressure, and separator temperature. This data was then used to run simulations through API's E&P Tank™ software in order to develop new emission factors. The emission factors for each region were then applied to Mexican regions according to their proxies. Based on SME input of Mexico operations, it was assumed that 10% of the tanks had control measures in place.

A.3.7.2. Oil Tank Dump Valve Venting

Activity and emissions factors for dump valve venting were estimated using a similar methodology as described in the Gathering and Boosting segment.

A.3.7.3. Pneumatic Devices

Activity and emissions factors for pneumatic devices (high, low, and intermittent bleed) were estimated using a similar methodology as described in the Gathering and Boosting segment. Data from the oil production segment of subpart W was used according to regional proxies.

A.3.7.4. Chemical Injection (Pneumatic) Pumps

Activity for chemical injection pumps in the oil production segment were sourced according to the U.S. Inventory Petroleum model, which is based on a 1999 Radian report[73]. The only difference is that a count of Mexican oil wells is used to drive chemical injection pump activity instead of U.S. oil well counts.

The emissions factor for chemical injection pumps come from the U.S. EPA Inventory.

A.3.7.5. Oil Well Completions

Activity on completions data was mainly sourced from the PEMEX 2013 Statistical Handbook and Annual report. Wells without hydraulic fracturing were evaluated as part of this emissions inventory. The data

[71] SENER Distribution Mileage.
http://www.energia.gob.mx/res/403/Elaboraci%C3%B3n%20de%20Gas.pdf

[72] Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.
http://pubs.acs.org/doi/abs/10.1021/es505116p

[73] Methane Emissions from the U.S. Petroleum Industry
http://www.epa.gov/climatechange/pdfs/radian-petroleum-1999.pdf

reported to subpart W was used to develop new emission factors use in Mexico for both emissions sources.

A.3.7.6. Oil Well Workovers

The same methodology for oil well completions was used to develop activity and an emissions factor for workovers.

A.3.7.7. Stranded Gas Flaring and Venting from Oil Wells

Flaring and Venting volumes were obtained at a high level (i.e. for both onshore and offshore) and then distributed across the various sources of flaring and venting. Values for flaring and venting from publicly available sources[74] in addition to direct contact and cross checking with PEMEX provided an estimate for both the split between flared and vented volumes in addition to the total volumes in each case. Once the total vented and flared volumes were obtained, the following steps were made to distribute the emissions across the appropriate sources:

- A flaring and venting estimate was calculated for Floating Production, Storage, and Offloading (FPSO) based on PEMEX published data on each of their FPSOs. Parameters such as max oil production, max gas capacity, and gas injection capacity were analyzed for PEMEX's major FPSO's and based on 2013 operations to obtain an estimate of flared and vented volumes.
- A flaring and venting estimate was then estimated for all of PEMEX's offshore platforms (e.g. Production, Drilling, Compression, etc.) based on data available from PEMEX and SENER[75]. When data was unavailable or missing for platforms, the overall floating and vented volumes were scaled up based on platform count.
- With flaring and vented volumes estimated from offshore operations, the balance of flaring and vented volumes were allocated to the onshore 'stranded gas flaring and venting from oil wells' emissions source.

The following equations represent the steps above:

$$Onshore_{Flaring} = TotalFlaring_{ReportedByPEMEX} - FPSO_{FlaringEstimate} - OffshorePlatforms_{FlaringEstimate}$$

$$Onshore_{Venting} = TotalVenting_{ReportedByPEMEX} - FPSO_{VentingEstimate} - OffshorePlatforms_{VentingEstimate}$$

In some areas nitrogen is injected into wells for enhanced oil recovery. The nitrogen content could affect the amount of methane in the vented gas.

A.3.7.8. Separators (Light and Heavy), Heater/Treaters, and Headers (Light and Heavy)

Activity for all sources were calculated according to the U.S. EPA Inventory for petroleum systems. Much of this activity follows the 1999 Radian report[76], which characterizes each of these emissions sources and drives activity based mainly on whether production is light (i.e. API gravity greater than 20°)

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[74] PEMEX SEC Vented and Flared Volumes
http://www.ri.pemex.com/files/content/Form%206-K%20as%20filed%20June%207,%202013_RR.pdf

[75] Examples of platform data sources include:
Abk-A Platform: http://www.cnh.gob.mx/_docs/InfoTrim2014/2014-1ER-TRIM-SPRMSO-APAPCH.pdf
Ku-M Platform: http://www.cnh.gob.mx/_docs/InfoTrim2010/2TerTtrim/AIKMZ.pdf

[76] Methane Emissions from the U.S. Petroleum Industry
http://www.epa.gov/climatechange/pdfs/radian-petroleum-1999.pdf

or heavy (API gravity less than 20°). This study obtained the light vs. heavy production % splits directly from the 2013 PEMEX Annual Report and statistical handbook. These percentages drive the light vs. heavy splits for separators and headers. Heater/treaters and headers are assumed to be present for both light and heavy crude wells, and activity is treated the same way as described for separators.

The emission factor for all three sources were originally sourced from the U.S. EPA Inventory and then were updated to the emission factors published in Subpart W.

A.3.8. Oil Production - Offshore

A.3.8.1. Condensate and Oil Tank Venting

Activity data for oil tanks is based on PEMEX reported data for offshore condensate and oil production according to the 2013 PEMEX annual report. The emissions factors for both tanks were assumed to be equal to the emissions factors for onshore tankage for condensate and oil tanks, respectively. Based on SME input of Mexico operations, it was assumed that 10% of the tanks had control measures in place.

A.3.8.2. Offshore Platforms

A published study[77] based on the Gulfwide Offshore Activities Data System (GOADS) describes the emissions inventory of oil and gas operations in the Outer Continental Shelf of U.S. Gulf of Mexico. This study provides the necessary structure and data to estimate both activity and emissions factors for offshore platforms by source. This study utilized the GOADS reported emissions data and updated emissions factors based on Subpart W published data. The GOADS report provides data on various platform types, and for the purposes of this study, it was assumed that all Mexican platforms were of the 'shallow water oil' variety, i.e. the platforms predominantly produce oil and are located in shallow waters. The following emissions sources were analyzed and included for shallow oil platforms:

- Amine Units
- Boilers/Heaters/Burners
- Diesel and Gasoline Engines
- Drilling Rigs
- Fugitives
- Glycol Dehydrators
- Loading Operations
- Losses from Flashing
- Mud Degassing
- Pneumatic Pumps
- Pressure/Level Controllers
- Flaring (MSCF/yr)
- Venting (MSCF/yr)
- Centrifugal (Wet Seal)

[77] Gulfwide Emission Inventory Study, Bureau of Ocean Energy Management, U.S. Department of the Interior http://www.boem.gov/Gulfwide-Offshore-Activity-Data-System-GOADS/

- Centrifugal (Dry Seal)
- Reciprocating Fugitives
- Reciprocating Rod Packing

For each of the emissions sources above, an ‘equipment schedule’ was established according to platform type. For example, production platforms were assumed to have more equipment present, and thus more fugitive emissions sources present in the equipment schedule. The allocation of equipment schedule was determined based on the processes that are typically located on each platform type. Once the equipment schedule was established for the platform type, total emissions (by platform type) were estimated by multiplying the equipment schedule by the appropriate source specific emissions factor. The methodology for estimating the count of platform type is discussed in the flaring and venting portion for the ‘Stranded Gas from Oil wells’ source, but is based on published data from PEMEX and their offshore operations.

Appendix B. Emission Projection to 2020

B.1. Mexico's Oil and Gas Production

B.1.1. Introduction

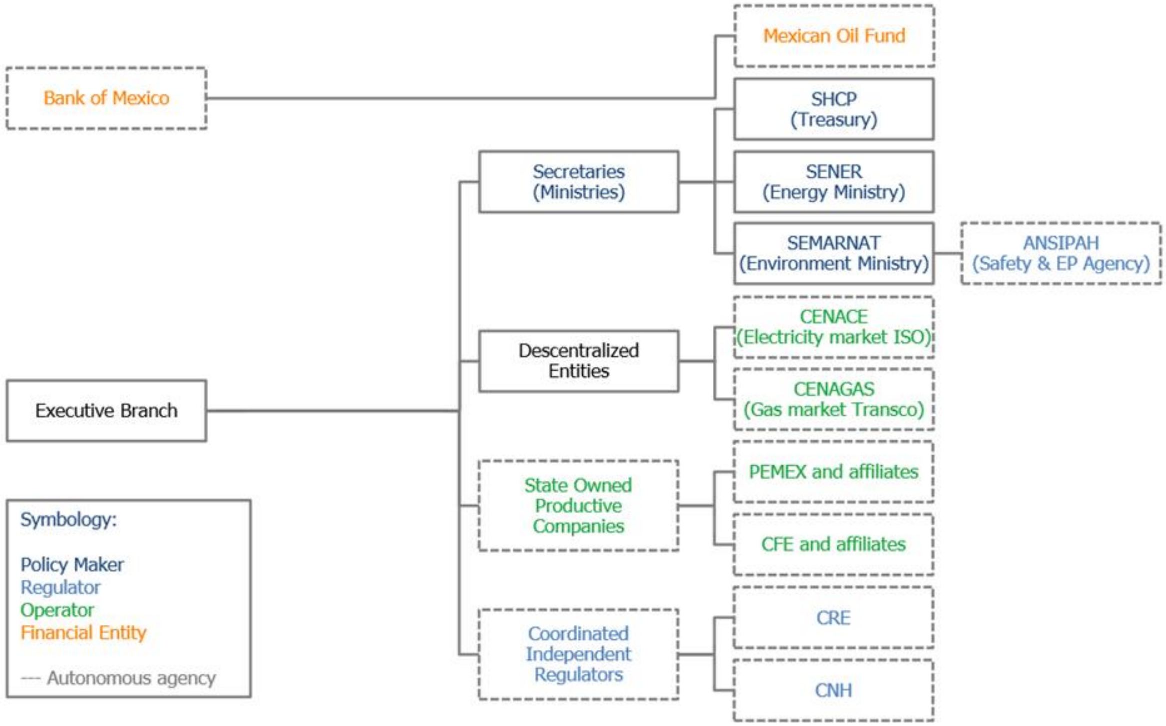
The Mexican energy industry has historically been dominated by state-run monopolies in both the oil and gas sectors, as well as in the power sector.

With the passage of a Constitutional Amendment in December 2013, substantive and historic changes in the structure of the Mexico oil and gas sector have been initiated that hold the potential to open exploration and production as well as power generation activities to greater international participation. To varying degrees, transportation, logistics, and retailing activities are also affected. A primary change is the role of state-owned companies that formerly operated with an exclusive mandate in energy sectors considered strategic. After the amendment, these organizations remain state-owned but must now compete with third party providers. In 2014, a number of secondary laws were passed by Congress creating a revised organizational framework and expanded set of participants in the Mexican energy sector. Notably, the secondary laws provided a more detailed roadmap of the transition, as well as important changes in a number of supporting activities.

The primary actors within the reformed Mexican Energy Sector now include the following.

- Policy Makers and Executive Level Government Agencies:
  - SENER or the Ministry of Energy is Mexico's approximate equivalent of the U.S. Department of Energy and develops the policies for energy markets broadly
  - SEMARNAT is Mexico's Ministry of Environment which develops policies related to natural resources and the environment.
- Regulators:
  - CRE is an independent body organized within SENER and is responsible to regulate the transmission and distribution of energy much like FERC in the U.S.
  - CNH is responsible for regulating the upstream sector.
  - ASEA (ANISPAH) is a new agency responsible for regulating safety and environmental compliance.
- Operators:
  - Petroleos Mexicanos or PEMEX is the state-run oil and gas conglomerate, which operates upstream, midstream, and downstream services.
  - Comision Federal de Electricidad or CFE is the state-run electric provider, which operates power plants, transmission and distribution systems.
  - CENACE is in the process of becoming the Independent System Operator for the national power grid, absorbing selected CFE activities and implementing new ones as well.
  - CENEGAS is in the process of becoming the integrated gas transportation system operator and will also acquire most of PEMEX's natural gas pipelines.

Figure B-1 – Mexican Energy Policy Overview



Source: CRE Presentation- Mexico Energy Reform[78]- Summer 2014

B.1.2. Major Observations

As a result of reforms and this study's analysis conducted, this study anticipates that oil and gas activities between 2015 and 2020 in Mexico are likely to be driven by several factors:

a) A focus on improved oil recovery on-shore and in shallow water targets along the eastern coast through partnerships with PEMEX (although in recent years oil and gas production in Eastern fields have been declining, especially in Cantarell);
b) Reliance in the near to medium term on imports of natural gas from the U.S.

Other development strategies are more uncertain, but worthy of note:

c) Continuing interest in longer term deep-water offshore production potential in Mexico, but with little impact on production during the 2015-2020 period. Continuing interest is driven in part by high oil prices over the past few years, and a general belief by stakeholders that current levels are not sustainable and high prices may reemerge. Given the long-term nature of deep-water infrastructure development, near-term activities may be slowed, but even if they continue, production impacts will be more likely beyond 2020.
d) Potential for increased unconventional shale oil and gas development in the North and Northeast regions (e.g. Chicontepec) possibly late in the 2015-2020 period allowing for modest displacement of eastern supplies, greater substitution for natural gas imports and reinforcing the potential for LNG exports from the Pacific Coast of Mexico. Timing and success of

[78] CRE Presentation
http://www.narucmeetings.org/Presentations/salazar%20energy%20reform%20in%20Mexico%20an%20overview.pdf

implementation will depend greatly on obtaining a better understanding of local geology, access to water, regional security, successful resolution of land issues, and effective oil field service staffing. Major production impacts appear more likely beyond 2020.

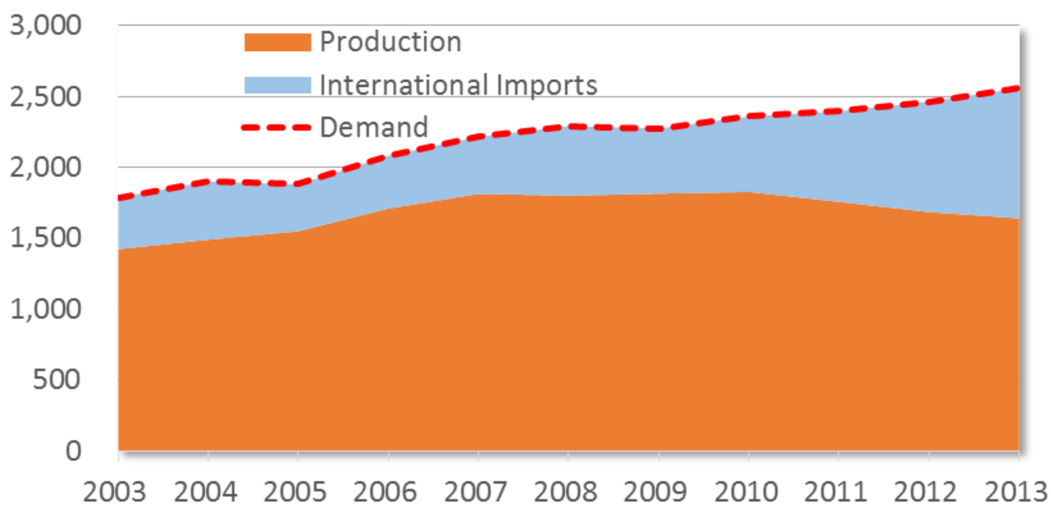
Many factors, especially the last two above, have been impacted by the recent drop in oil prices. Additionally, dramatic increases in gas and oil production in the U.S., from shale and tight oil/gas plays have occurred in recent years, especially in the Eagle Ford and Permian basins. All of these aspects were considered for the 2015-2020 outlook for Mexico.

This study began with a review of recent oil and gas supply and demand trends in Mexico.

B.2. Historical Market Overview

Figure B-2 below shows that Mexico's demand for natural gas has grown markedly from 2003 to 2013. Demand grew 43% between 2003 and 2013. Regional production met 80% of demand in 2003, grew up through 2007 and then began to decline in 2009. In 2013 only 65% of demand was met by domestic production, with the remaining balance met by international imports from the U.S.

Figure B-2 – Historical Mexican Natural Gas Supply/Demand Balance (Bcf/Year)



Source: SENER

Figure B-3 shows the regional breakdown of natural gas demand between 2003 and 2013. Regional demand in the South-Southeast was reduced over the period from 45% of total demand in 2003 to 37% in 2013. The Northeast region grew the most over the period from 26% of total demand in 2003 to 33% in 2013. The Central and Northwest regions both grew nominally over the 10 year period.

Figure B-3 – Historical Mexican Natural Gas Demand by Region (Bcf/Year)

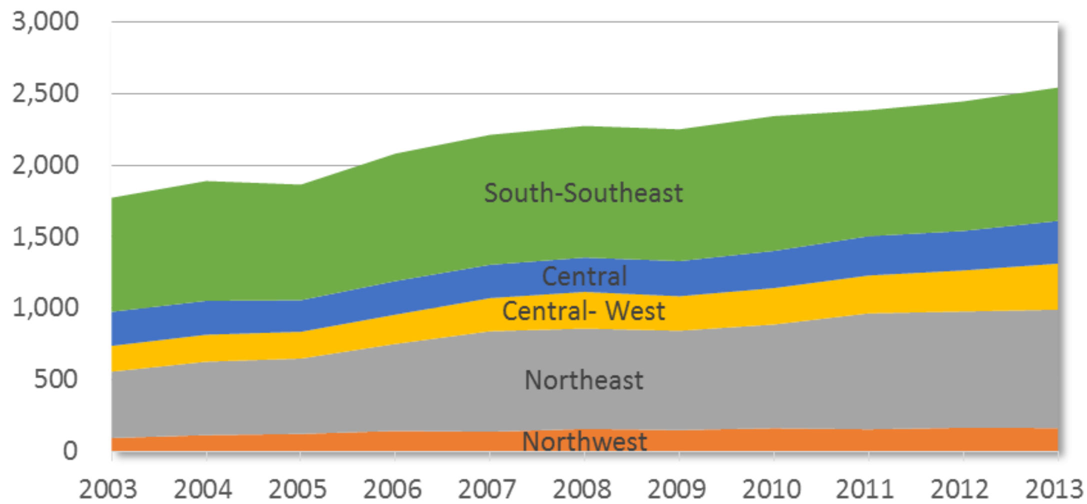


Figure B-4 below shows the regional breakdown of natural gas production between 2003 and 2013. Total domestic production grew 42% over the ten year period. Production grew sharply between 2003 and 2008, and began to decline slightly in 2010. All regions other than South- Onshore grew over the period, with ranges of 50% to 120% growth. The Southeast Coast- Offshore Region gained the greatest share of total production, growing from 13% of total domestic production in 2003 to 21% in 2013. The South-Onshore Region became less important to domestic production as a whole over the period, decreasing from 36% of total domestic production in 2003 to 25% in 2013. Most of the southern onshore gas production is associated gas.

Figure B-4 – Historical Mexican Natural Gas Production by Region (Bcf/Year)

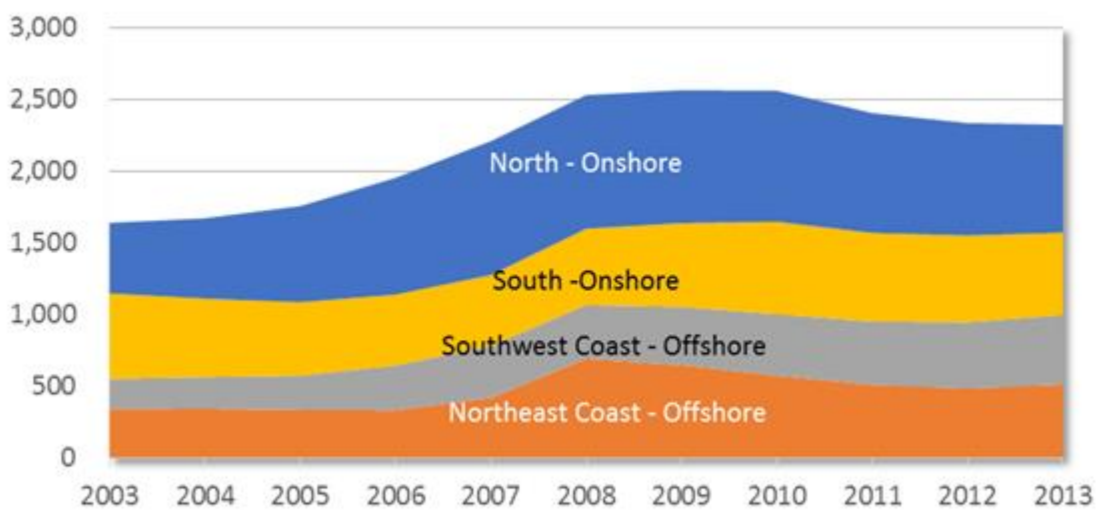
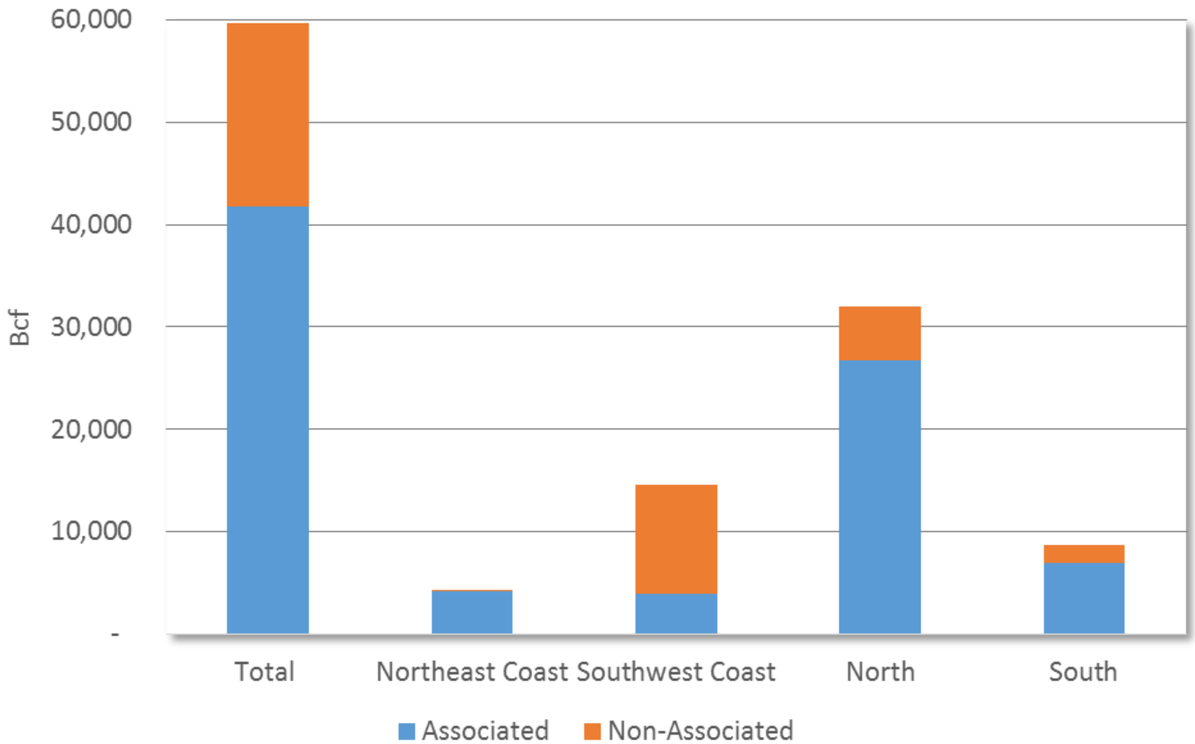


Figure B-5 shows the breakdown of Mexican natural gas reserves by region and type as of the end of 2014.

Figure B-4 – Breakdown of Natural Gas Reserves by Region & Type– As of end of 2014



B.3. Methodology

For this investigation, this study utilized data from a variety of publicly available sources. SENER reports provide annual historical data on a range of oil and gas statistics; PEMEX also makes public additional data. PEMEX data are primarily historical, and they provide information on oil and gas production by type and by region. The Sistema de Información Enerégtica (SIE) from SENER includes oil and gas production projections based on different scenarios developed by the Instituto Mexicano del Petróleo (IMP), with data from CFE, EIA, PEMEX, and SENER.

SENER oversees a process designed to develop a future outlook for the sector. As part of the Prospectiva process, forecasts are also prepared for future energy demand SENER releases a Prospectiva every year. The 2014 Prospectiva was finalized in the third quarter of 2014, and as a result projects announced more recently (as well as project delays) may have altered the outlook after the publication date. SENER develops expectations and scenarios related to domestic development (supply, domestic demand, and other variables especially US imports and international LNG imports).

This study reviewed these data in light of recent developments under the energy reform, and modified the resulting supply and demand balance in line with more recent developments. This study also developed a forecast of producing oil and gas wells needed to support the additions foreseen by SENER.

B.3.1. Assumptions

This study uses the following assumptions in order to create its forecasts of Mexican supply and demand.

- GDP (PIB) growth rate:
  - For Mexico in 2015 to 2020: Secretaría de Energía de México.
  - 4.9% per year.
  - Consistent with the Ministry's view that substantive GDP growth follows from lower energy costs and the view that current goods and services output does not fully satisfy demand.
- Electricity demand growth:
  - For Mexico in 2015 to 2020: Secretaría de Energía de México.
  - 4.4% per year.
  - Consistent with the Ministry's view that substantive electricity growth follows GDP growth and the view that current levels of energy consumption does not fully satisfy demand.
- Demographic trends are consistent with trends during the past 20 years.
- Projected weather -- consistent 20-year average seasonal patterns.
- Numerous clean energy efforts through legislative bill, none fully adopted.
- Renewable generation capacity increases modestly at rates similar to those under energy banking program.
- Adoption of DSM programs and conservation and efficiency measures continue, consistent with recent history.
- Nuclear plants are assumed to have a maximum lifespan of 60 years.
- Energy reforms implemented in line with Constitutional Amendment of Dec, 2013 and sub-law passage of Aug, 2014.
- Current oil price environment has modified the initial Round Zero/Round One process.
- Unconventional resource additions are focused primarily on reducing requirements to bid. Many interpret this to be supportive of greater participation of local firms.
- Economically recoverable natural gas reserves and resources in Mexico natural gas total roughly consistent with EIA and SENER estimates.
  - 1P, 2P and 3P categories
  - 3P – 2.046 Tcf
  - 545 Tcf technically recoverable resource base
- Gas supply development is expected to be consistent with recent levels.
  - Outlook considers short term price perspective of $45-60/barrel crude and long run price of $77/barrel (2014 USD).
  - Company operating efficiency consistent with SENER view.
  - No significant restrictions on permitting or hydraulic fracturing beyond current restrictions.
- Additional unconventional gas pipelines announcements are not included.
- No significant restrictions on well permitting and fracturing beyond restrictions that are currently in place.
- Gas demand – Consistent with SENER estimates including re-injection for existing field pressure maintenance.

- Offshore deepwater/unconventional supply - Consistent with SENER and PEMEX production estimates as to resource base.
- Pipeline capacity expansions over the next 4 to 5 years are consistent with announced projects.
    - In the long-term, pipeline capacity is expanded as announced.
    - CFE-stated goals examined separately from SENER National Infrastructure Plan.
- Some Mexico West and East Coast LNG terminals have contracts and project financing in place, and are currently operational as import facilities.
    - These are kept on-line consistent with SENER existing views.
- Recently, PEMEX has proposed a new West Coast LNG export facility.
    - This project will be viewed through a comparison with announced SENER study results.
- Gas to oil ratios are held constant at May 2015 values through 2020 for both North and South Onshore as well as Northeast and Southwest Marine.
- Oil projections were made for each region separately based on historical production trends
- Associated gas production was estimated based on oil projections and the region specific gas to oil ratio, with non-associated gas as the balance considering overall supply/demand trends and domestic production capabilities.
- Regional completions and retirement rates were evaluated to estimate the growth in producing wells for well count projections.

B.4. Model Results

The following tables show projections of oil and natural gas in 2013 and 2020. As noted in the methodology section these projections have been informed largely by SENER with this study's adjustments.

Table B-1 – Mexican Gas Production Outlook (Bcf/Year)

National Gas Balance (Bcf/Year)	2013	2020
National Domestic Production	**2,324**	**2,153**
Northeast Marine	515	565
Southwest Marine	484	581
South	573	382
North	752	625

Source: SENER and ICF International

Table B-2 – Mexican Oil Production Outlook (Mbbl/Year)

National Oil Balance (Mbbl/Year)	2013	2020
National Domestic Production	**920,577**	**788,648**
Northeast Marine	475,801	359,558
Southwest Marine	216,396	258,510
South	175,491	113,161
North	52,889	57,418

Source: SENER and ICF International

The total national gas production in Table B-1 is less than projected demand. This "balancing amount" must be met by either additional local production (through the Rondas or additional PEMEX activity) or from imports (largely from the U.S.). From a supply perspective, this study's view is that the balancing amount will likely be fully met from U.S. imports and not local production. ICF notes the 2020 total is consistent with this study's view of imports expected in 2017 and 2018. Also supporting the notion that it is unlikely that Mexican gas production will be able to satisfy local demand, ICF's Gas Markets Model (GMM) also predicts roughly a 3-fold increase in US gas pipeline exports to Mexico during the 2013 to 2020 period.

Table B-2 highlights an overall decrease in Mexican oil production from 2013 to 2020, with a significant portion coming from the northeast marine region, driven by the continued decline of the Cantarell field. Increased production will likely come from activity in the southwest marine and northern onshore regions, with the most notable region being Chicontepec. Although the Chicontepec region has been identified as holding vast proven reserves, history has shown that the region has significant challenges that have limited its production potential. This study's forecasts do not see significant changes in production in the Chicontepec region during the 2013 to 2020 period.

As for oil and gas well counts, Table B-3 below shows well counts projected to 2020 by region and type. Driven by continued attempts to find new production and the need to maintain marginal wells, the Mexico total well count is forecasted to grow by 19% from 2013 to 2020. More of this growth is projected in oil wells with a growth of roughly 24%, while gas wells are estimated to grow by 11%. SENER projections for wells drilled, and ultimately producing wells, from 2013 to 2020 are more aggressive than this study's estimates. Similar to the methodology and assumptions discussed above, this study believes some of this activity will be delayed and not achieved in the 2013 to 2020 period, especially considering historical well completions and retirement rate trends.

Table B-3 – Mexican Well Count Outlook (Qty)

Oil/Gas Production Well Count (Qty)		**2013**		**2020**	
		Oil	**Gas**	**Oil**	**Gas**
Region	Location				
Northeast Marine	Offshore	396	-	441	-
Southwest Marine	Offshore	163	-	207	-
South	Onshore	1,258	82	1,396	85
North	Onshore	4,692	3,245	6,010	3,601
Sub-Total		6,509	3,327	8,054	3,686
Total		***9,836***		***11,740***	

Source: ICF International, SENER

B.4.1. Observations

To better understand production in 2013 and the estimates in 2020, this study relied on SENER and PEMEX reports, as well as additional research and analysis to ensure that the projections match this study's expectations of demand growth and production growth in Mexico. The following observations are considered relevant:

Role of PEMEX

- The Prospectiva gas balance of supply and demand is developed with PEMEX continuing to play a major role in providing new supplies during the 2015 to 2020 timeframe.

- Additionally, the Prospectiva envisions substantive contributions to gas supply from early results of the Rondas (likely the additions to supply from new international participants) and the bidding/awards process is being initiated in 2015. These gas supply additions could be used in a variety of ways – to satisfy some portion of domestic demand or for exports.
- PEMEX has stated publicly that it expects to partner with international firms to improve its reserve and production profile. A number of agreements have been signed (just under 40) as of this writing.
- If these pending developments are carried forward, ICF expects that they will positively impact Round Zero fields that PEMEX continues to hold. Improved recovery holds potential to arrest the medium term decline in well productivity. Although not publicly stated by PEMEX or SENER, some industry participants believe that it is reasonable to consider production scenarios with per well additions at least holding at 2013 levels; others believe these efficiencies could increase in future years.

Role of the Rondas

- Considerable uncertainty surrounds the success of the Rondas and their potential impact on production and reserves. These processes open prospects to international participants more directly. The first proposals had a due date set in July, 2015.
- On-Shore and Shallow Water Resources: Overall, this study believes that these bidding rounds are likely to progress even with oil prices at lower levels. Extensive participation and successful awards to new entrants can lend some confidence to the supply additions foreseen by the Prospectiva if they materialize as expected in the 2015 to 2020 time period.
- Deep Water Resources: Conversations with industry participants indicate continuing interest in these blocks and rounds. However, this study's view is consistent with the Prospectiva's view of the impact of this component of the "Gran Proyectos" on PEMEX; that is, the impact of these Deep-Water activities will largely occur beyond 2020.
- Unconventional Resources: Due in part to the lower price of oil in 2H2014 and 1H2015, development of these unconventional resources (largely shale) has been modestly delayed compared with the initial schedule of development as well as changes in the scheduled offerings and the terms of the offerings. Based on conversations with industry participants, this study believes that production additions may be subject to delay due in part to questions about land access, water rights, and service company development, and deployment of trained staff. These factors seem likely to limit early contribution of these resources to the production profile between 2015 and 2020.

Well Counts

- Currently, there are limitations as to reliable well count projections given the structural changes already in place and pending. This study relied on historical PEMEX well-level data and additions and compared that information with similar U.S. plays. One limitation is that EURs were not readily available for Mexico. Thus, this extrapolation is based in part on a limited understanding of geology at the play level in addition to completions and retirement rate trends over time.
- Further, well data disaggregation into on and off-shore regions are limited. As a result, while projections of well counts are based on SENER projections and historical regional trends, there are a number of data limitations that impact the robustness of these estimates.

- The Prospectiva calls for substantive production and reserve increases from the Rondas and international participation. Conversations with industry participants as to the viability of increased production diverge widely.
- Well counts were prepared considering both associated and non-associated activities (in other words for both oil and gas recovery) and are reported as a composite number representative of what might be needed to meet the gas demand foreseen by the Prospectiva.

Gas Demand

- For the 2015 to 2020 period, this study relied on SENER historical data and projections, as well as this study's view on how the power demand for oil and gas will evolve over time. This study also reviewed announced and planned CFE projects, some of which are not fully recognized in the Prospectiva.
- While the level of overall gas demand growth is high by U.S. and Canadian standards, consumption is currently considered to be materially below demand, reinforcing the view of high growth.
- On balance, the overall demand growth level will likely vary depending on international macroeconomic conditions and prospects, but can reasonably be expected to outpace underlying U.S. and Canadian demand growth.

Gas Imports

- Given the potential for future CFE additions of midstream assets and power generation equipment (increasing end-use demand), Prospectiva demand projections may prove to be conservative.
- In June, 2015, CFE announced additional pipeline projects for the 2015-2018 period building on previously announced additions in 2013 and 2014. The major thrust of these additions is to facilitate power generation additions (through laterals) and to debottleneck imports during the 2015-2020 period.
- Some market participants are more aggressive in their views of imports than the most recent SENER Prospectiva; however, many of these differences appear in the 2020 to 2022 horizon.
- The Prospectiva projects that 2019-2020 imports are likely to fall relative to 2018 due to new local production brought on-line during that period. This study retains the SENER view through 2018, but notes that it is more likely now for local production additions (most likely from the Rondas) to be delayed into the 2019 or 2020 period. As a result, in this study's view, the shortfall in production is likely to be met by greater imports from the U.S. in 2019 and 2020.
- In general, the Prospectiva envisions increasing gas exports to the U.S. post-2020.
- Consequently, while this study notes the substantive and extensive hopes in the Prospectiva for domestic Mexico production increases late in the 2018-19 period associated with the Rondas, based on conversations and this study's view of local conditions, this study adopts the view that imports are more likely to continue into this period and defer some (or a majority) of these local production increases into the post 2020 period. This is supported by ICF's Gas Markets Model.

LNG Imports and Exports

- SENER, PEMEX, and CRE provide historical data on LNG imports. This study reviewed and analyzed these sources to develop a forward-looking view of these imports over the 2015-2020 period, and compared these analyses to the SENER Prospectiva projections.
- In general, this study follows the SENER expectations and balance. These are generally expensive imports and are likely to be under pressure (and potentially very low) due to price competition with U.S. gas imports and expected increases in U.S. deliverability beginning in 2017.
- Nevertheless, LNG imports can be required by the electricity system to balance power output in years of low hydro, so a single year's imports can be at variance from planning expectations.
- On balance though, this study retains the SENER forecast recognizing that future hydro and weather can push needs for Mexico to temporarily receive LNG cargos.
- PEMEX has publicly indicated that they have plans to develop an LNG export facility. This study believes other private sector entities may also be interested in doing so as well.
- Currently, however, these plans are also likely to require additional pipeline debottlenecking, and are not advanced enough to be fully considered "firm builds" by this study. This study also notes that they are not included transparently by SENER in the 2014 Prospectiva.
- As a result, this study flags them as potential changes to the supply/demand balance, but given the current state of development, the earliest that this study would expect commercial operation might be in the 2019 or 2020 period. Following SENER, this study has not included these potential volumes in the supply/demand balance.

B.5. Summary, Tables, and Projection Charts for Mexico

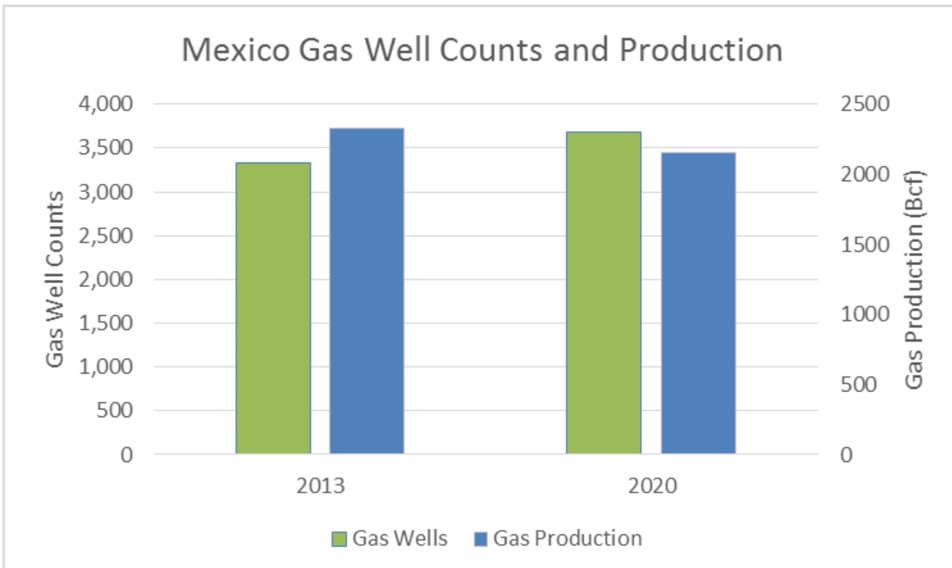
In summary, this study's analysis indicates that some project developments and delays primarily related to unconventional resources in Round 1 and subsequent round bidding processes for land announced during the latter part of 2014 and early 2015 call certain assumptions of the 2014 Prospectiva into question. It should also be noted that the 2014 Prospectiva was written before the significant drop in oil prices in 4Q2014.

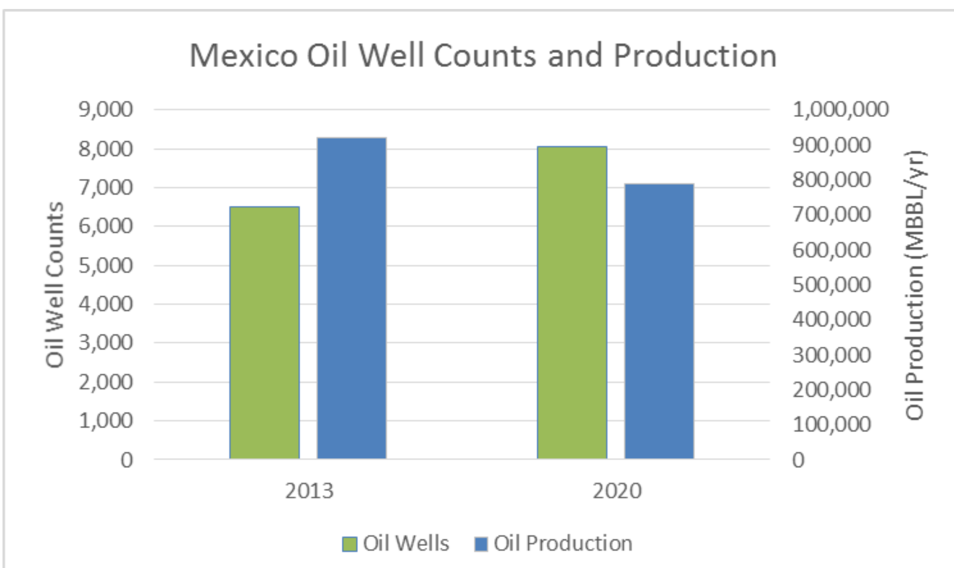
Principally this study believes that oil production will continue declining in Mexico in the near term future based on historical trends. On the gas side, this study agrees with SENER's projected gas demand profile through 2020, but disagrees with how that demand is most likely to be met. Due to delays in the land acquisition and bidding processes and the evolving nature of the reforms, this study believes that the exploration and production cycle will take longer than envisioned initially. As a result, new local production (supply) has the potential to be delayed later in the forecast cycle than foreseen by SENER. Thus, this study suggests that a greater share of 2019 and 2020 gas demand will likely be met by international imports, largely from the US. It is important to recognize that current public production projections for Mexico are very much limited by the expectations of how the country will develop its regulations, and how the private sector, PEMEX, and CFE will participate with international participants and new local competitors in the future.

<u>Tables and Charts</u>

Figures B-5 through B-11 describe this study's projections from Mexico in more detail at the regional level. Total gas wells in Mexico increase from about 3,330 wells in 2013 to roughly 3,690 wells in 2020. Gas production declines to nearly 2,153 Bcf/year due to decreases in associated gas from fields such as Cantarell and Ku-Maloob-Zaap. Roughly a 24% increase in conventional oil wells is exhibited from 6,500 in 2013 to 8,050 in 2020, with Mexican producers running out of sweet spots, facing lower oil well productivity, and holding onto marginal wells. Therefore, annual conventional oil production also is expected to decrease to approximately 788,650 Mbbl by 2020. Oil production is also impacted by lower oil prices, which reduces the incentives for growth in oil production.

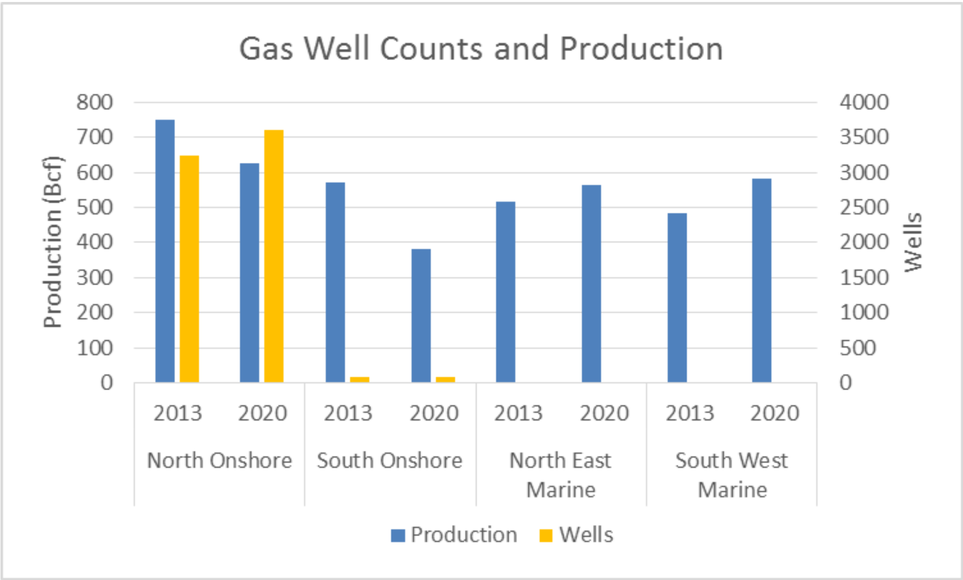
Figure B-5 – Mexico Oil and Gas Well Count and Production Projections





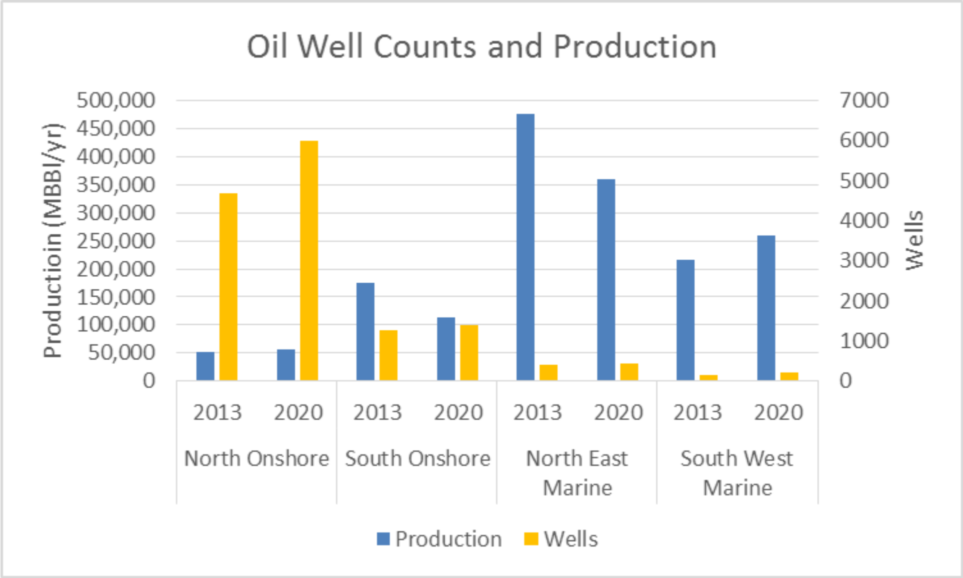
Source: SENER and ICF International

Figure B-6 – Regional Gas Well Counts and Production



Source: SENER and ICF International

Figure B-7 – Regional Oil Well Counts and Production

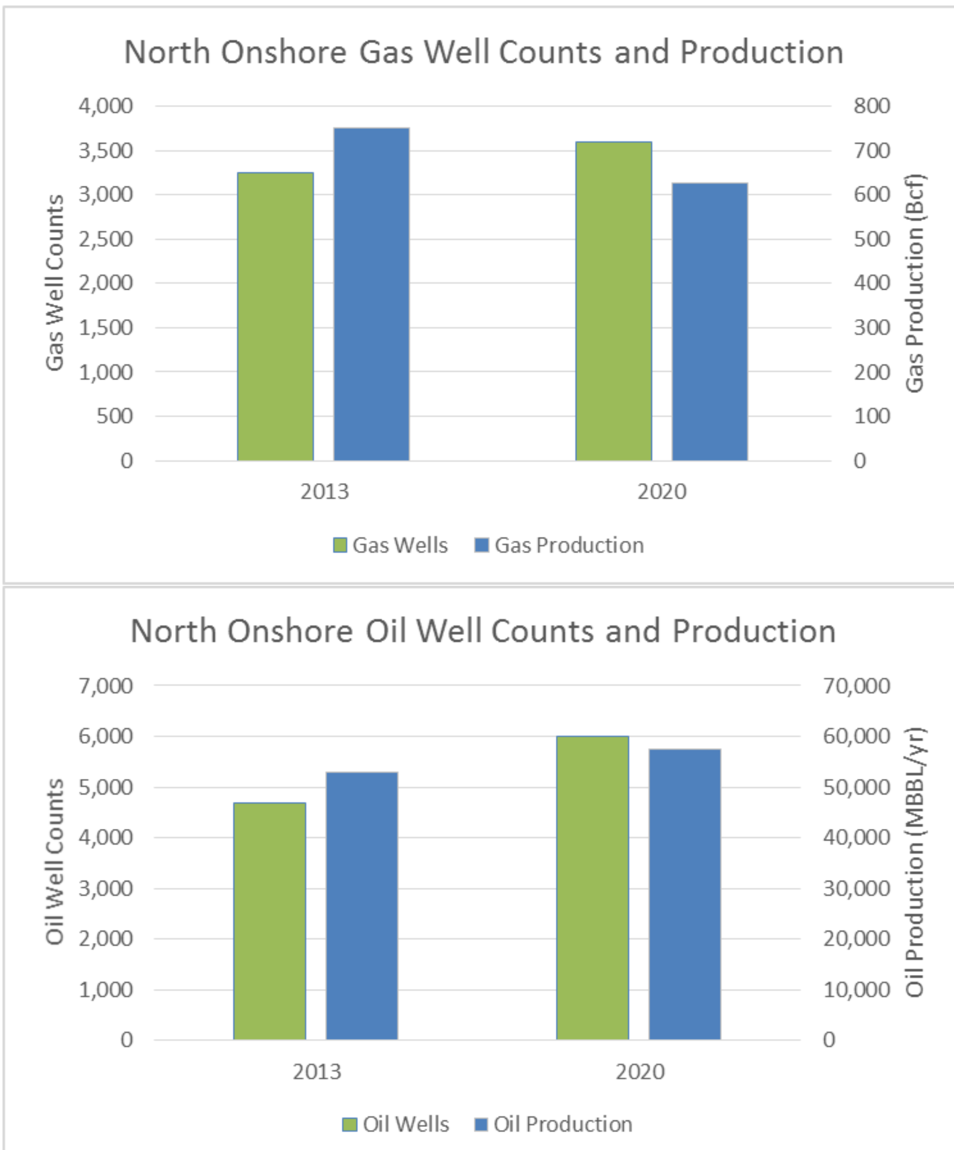


Source: SENER and ICF International

Onshore

The northern region of Mexico has the most non-associated gas production, namely from areas such as Burgos and Vera Cruz. However, gas production follows the decline in gas well count over the next 5 years. This study also does not anticipate significant changes in well productivity due to technology improvements. The northern region is expected to produce roughly 625 Bcf of gas by 2020, with gas well counts increasing to roughly 3,600 to try and make up for lost production. Conventional oil production is anticipated to increase conservatively to 57,400 Mbbl due to increased drilling activity in areas such as Chicontepec. The increased oil production activity helps improve associated gas production but is not enough to make up for the overall loss of non-associated gas activity in the area.

Figure B-8 – North Mexico Oil and Gas Well Count and Production Projections

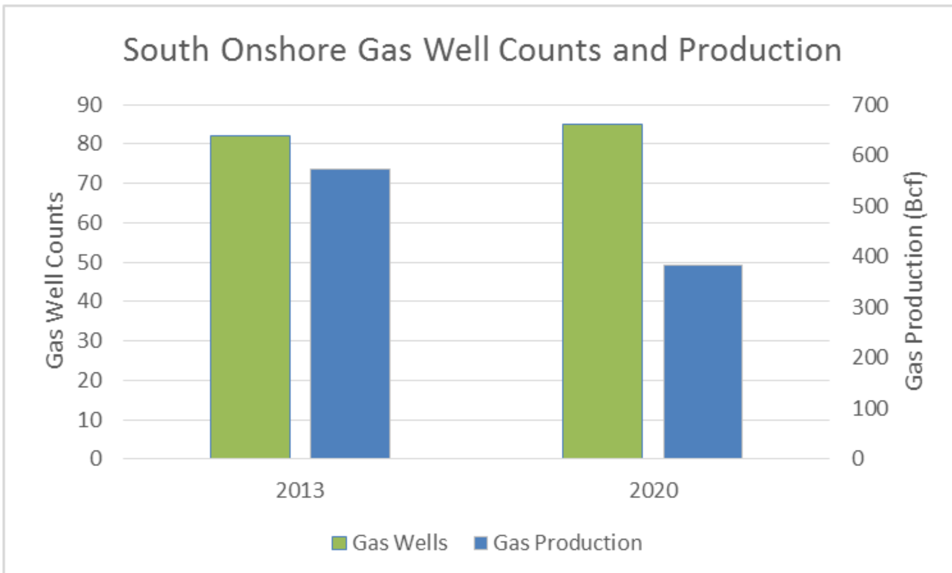


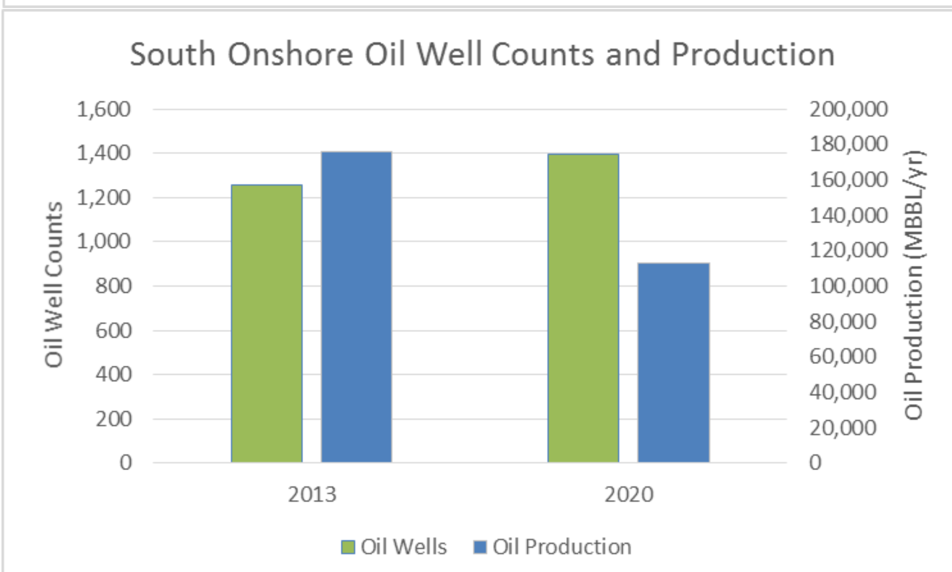
Source: SENER and ICF International

The southern region of Mexico is characterized more by conventional oil wells that produce associated gas. Non-associated gas wells do exist, but the number is quite small compared to the northern region.

Historically the crude production in the southern region has been in decline, and with this continued trend in productivity (i.e. decreased EUR), overall oil production is projected to decrease from 175,500 to 113,160 Mbbl from 2013 to 2020. Marginal wells will likely be kept online to bolster production along with increased well activity, leading to an increase of conventional producing oil wells of 1,400 wells by 2020. Driven mostly by associated gas, overall gas production will decrease to 382 BCF following the overall decline in oil production. Non-associated gas well counts are small to begin with and are forecast to increase slightly to about 85 wells.

Figure B-9 – South Mexico Oil and Gas Well Count and Production Projections





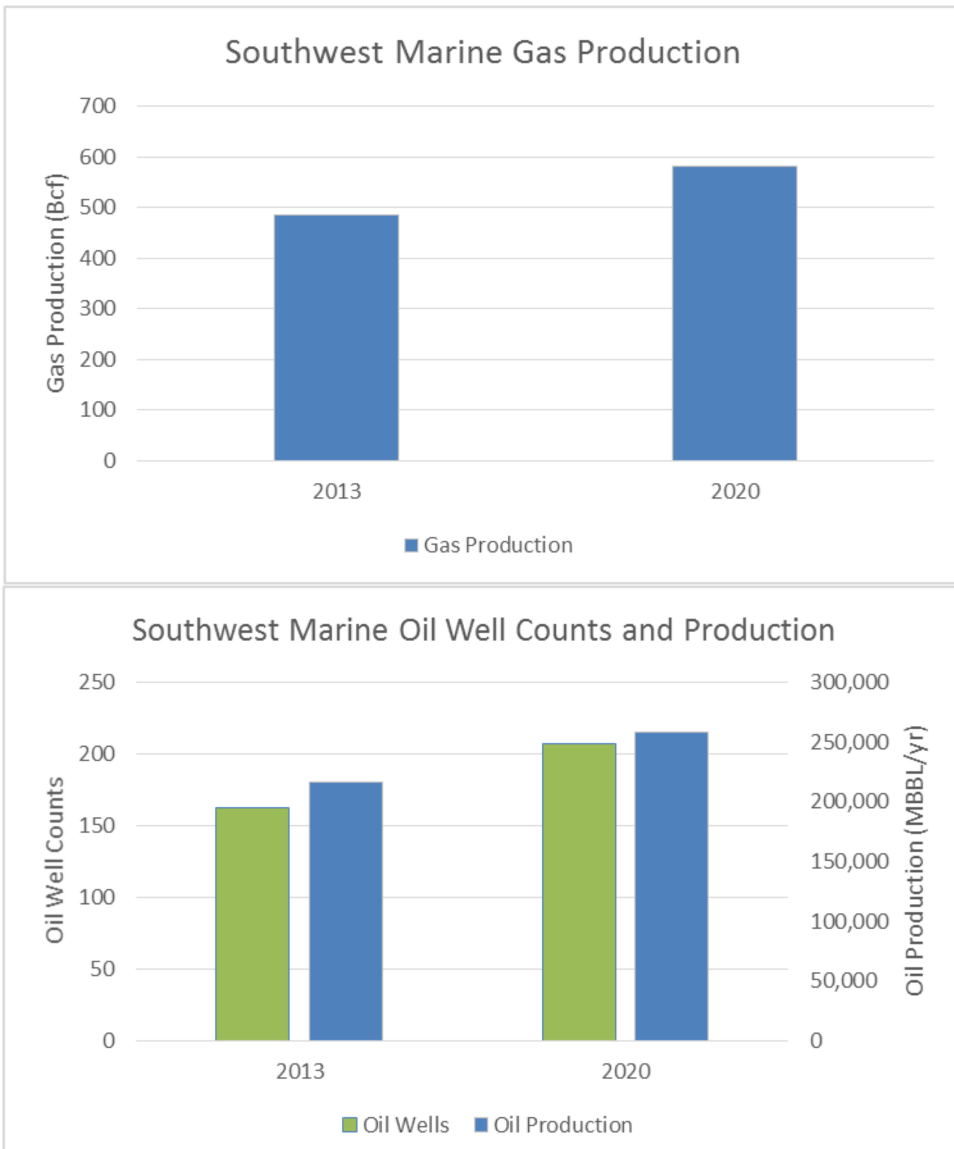
Source: SENER and ICF International

<u>Offshore</u>

The northeast and southwest marine regions of Mexico have conventional wells producing oil and associated gas, with both regions not having any non-associated gas wells. Given this fact, subsequent gas figures only display gas production values while oil figures present both well counts and production values.

Driven largely by increased gas to oil ratios in the northeast marine region, total gas production in Mexico's northeast marine region actually increases from 2013 to 2020 by almost 10%, even with the continuing decline of the Cantarell field. The Cantarell field has been experiencing a decline in recent years and that trend will continue to 2020. Similar trends have been observed for the other major field in the northeast marine region such as Ku-Maloop-Zaap, but an increasing oil to gas ratio is contributing to a large increase in associated gas even with depressed oil production. Conventional oil production from the region is forecasted to decrease from 475,800 to 359,560 Mbbl from 2013 to 2020.

Figure B-11 – Southwest Marine Oil and Gas Well Count and Production Projections



Source: SENER and ICF International

Appendix C. Additional Tables and Figures

Additional sensitivity MAC curves for Mexico are developed below. All MAC curves reflect baseline MAC parameters unless otherwise specified. For example, baseline MAC parameters are in Mexican Pesos and are set at $62 MXN / Mcf ($4 USD/Mcf) natural gas price and 100-yr GWP at 25. It can also be assumed that a ton is equivalent to 'metric ton'.

Figure C-1 – Total Mexican MAC Curve with 20-Yr GWP in CO_2e

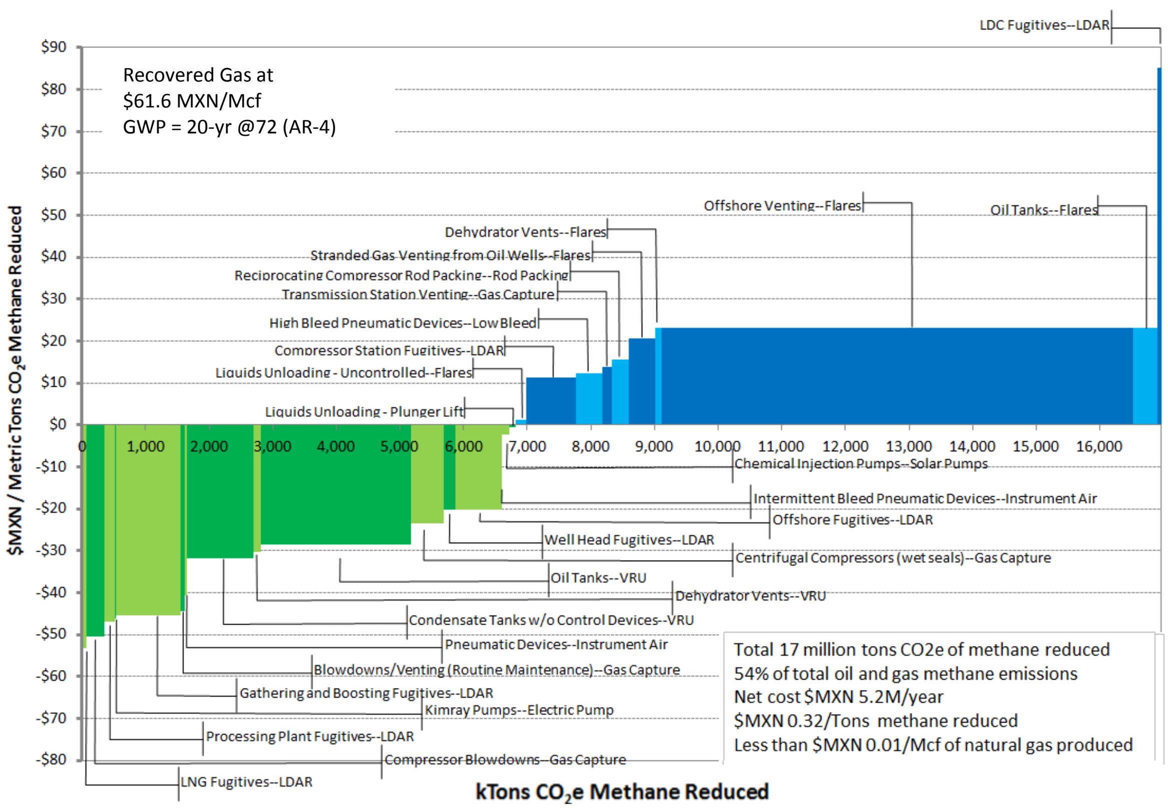


Figure C-2 – Total Mexican MAC Curve with 100-Yr GWP and $3 USD/Mcf in BCF

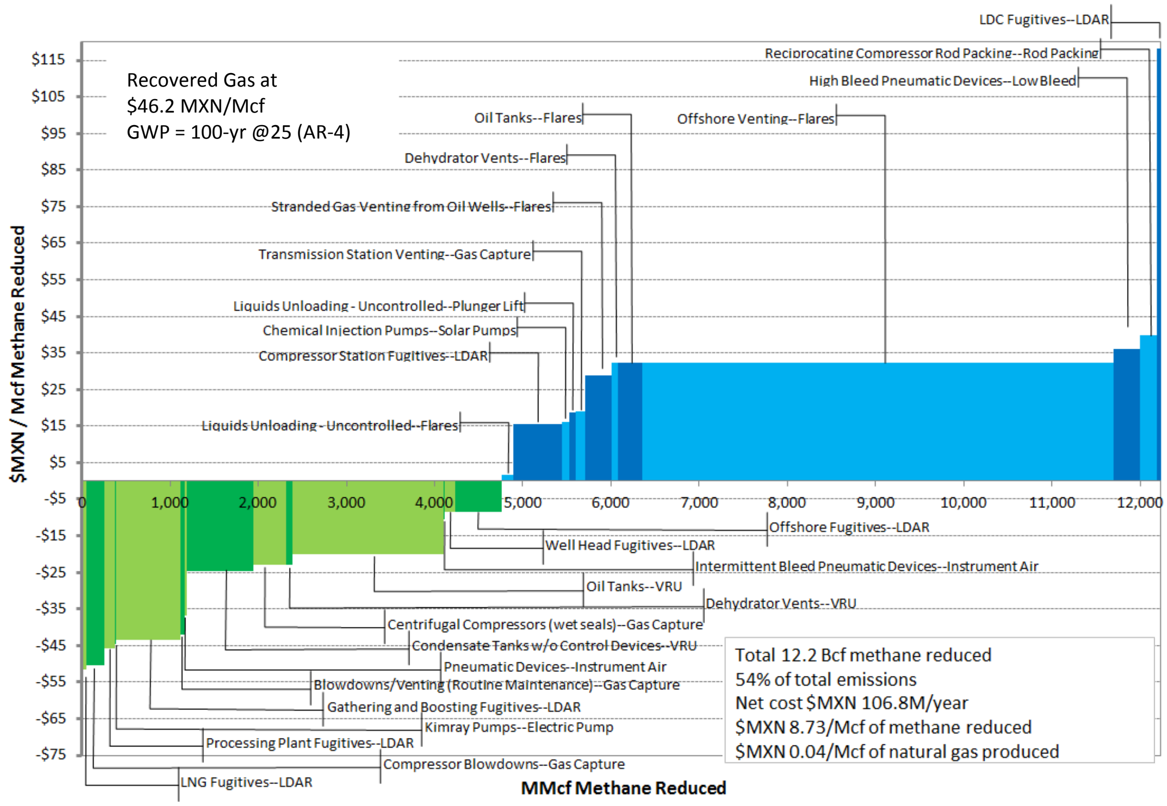


Figure C-3 – Total Mexican MAC Curve with 100-Yr GWP and $5 USD/Mcf in BCF

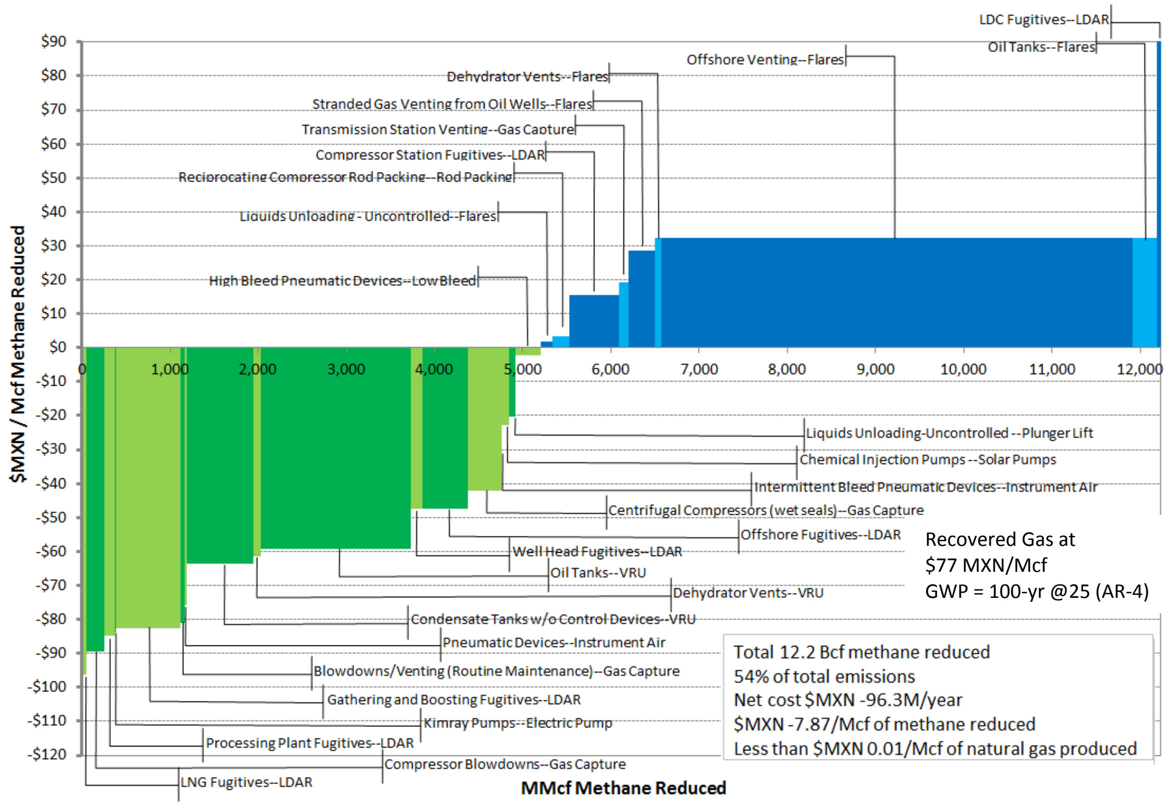


Figure C-4 – Total Mexican MAC Curve with 100-Yr GWP and $4 USD/Mcf in BCF

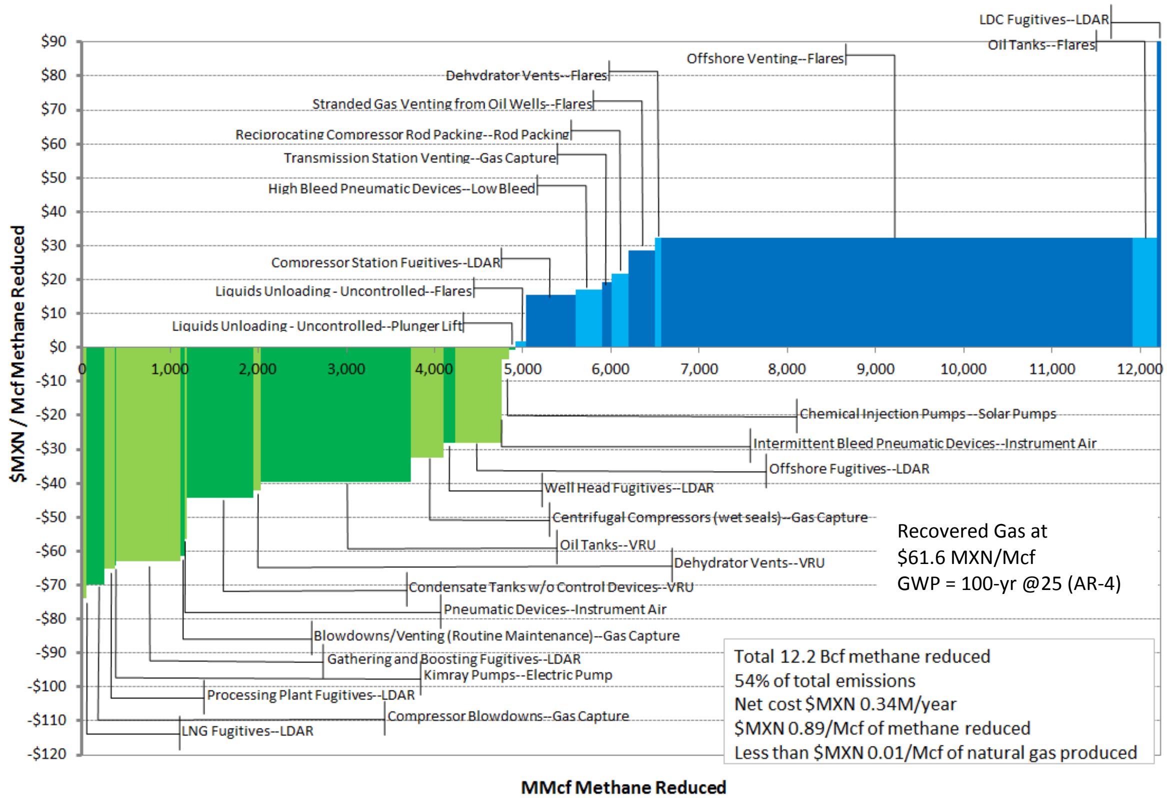


Table C-5 – Baseline Inventory Simple Payback Table for Select Mitigation Technologies

Mitigation Technology	Simple Payback Period[79]
Early replacement of high-bleed devices with low-bleed devices	6.6
Replacement of Reciprocating Compressor Rod Packing Systems	3.4
Install Flares-Stranded Gas Venting	2.6
Install Flares-Portable	0.1
Install Plunger Lift Systems in Gas Wells	6.0
Install Vapor Recovery Units	1.3
LDAR Wells	5.4
LDAR Gathering	11.2
LDAR Processing	0.9
LDAR Transmission	0.3
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	5.9
Replace Kimray Pumps with Electric Pumps	0.5
Wet Seal Degassing Recovery System for Centrifugal Compressors	0.1
Wet Seal Retrofit to Dry Seal Compressor	0.6
Blowdown Capture and Route to Fuel System (per Compressor)	2.6
Blowdown Capture and Route to Fuel System (per Plant)	1.0
Replace with Instrument Air Systems - Intermittent	2.1
Replace with Instrument Air Systems - High Bleed	0.8

[79] Simple Payback Calculated as: Taking the initial investment costs dividing by the annual cash flow (cost). The payback period is measured in years and represents the time to recover the initial investment.

Appendix D. Emissions Calculations with GWP Sensitivities

Based on the literature cited in this study, Table D-1 below contains the global warming potentials for methane according to the AR-4/AR-5 report and whether it is on a 20 year or a 100 year basis.

Table D-1- Methane Global Warming Potentials

Assessment Report #	20-yr Basis GWP	100-yr Basis GWP
AR-4	72	25
AR-5	86	34

As indicated in the main report, the 2020 Mexican Emissions Baseline value of 125 Bcf translates to approximately 60.2 million metric tons CO_2e when using an AR-4 100-yr GWP. Table D-2 demonstrates the GWP sensitivity and recalculates the million metric tons of CO_2e depending on what GWP is used. Table D-3 performs the same calculation but for the total 2020 Mexican reduction opportunity of 56 Bcf. This means that if the AR-5 20 year GWP was used instead of the 100 year, 93 MMTCO2e of reductions could be achieved from the technologies and practices identified in this report.

Table D-2- 2020 Canadian Baseline Emissions with GWP Sensitivity

Assessment Report # Used in Calculation	Emissions (MMTCO2e) w/20-yr Basis GWP	Emissions (MMTCO2e) w/100-yr Basis GWP
AR-4	173.3	60.2
AR-5	207.0	81.9

Table D-3- 2020 Reduction Opportunity with GWP Sensitivity

Assessment Report # Used in Calculation	Emissions (MMTCO2e) w/20-yr Basis GWP	Emissions (MMTCO2e) w/100-yr Basis GWP
AR-4	77.7	27.0
AR-5	92.8	36.7