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Assessment of Natural Gas Loss from the Well-to-Tank Supply Chain of Natural Gas Based Transportation Fuels

Prof. Ofira Ayalon
Dr. Miriam Lev-On
Dr. Perry Lev-On
Naama Shapira

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למחקר מדיניות לאומית

סקר היתכנות - אומדן הפחת של גז טבעי בשרשרת האספקה מהבאר לרכב עבור דלקים מבוססי גז

Assessment of Natural Gas Loss from the Well-to-Tank Supply Chain of Natural Gas Based Transportation Fuels

דו"ח סופי

עורכי המסמך:

פרופ' אופירה אילון – מוסד שמואל נאמן

ד"ר מרים לב און – מוסד שמואל נאמן

ד"ר פרי לב און – מוסד שמואל נאמן

נעמה שפירא – מוסד שמואל נאמן

מוגש למשרד המדענית הראשית – המשרד להגנת הסביבה

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EXTENDED ABSTRACT & SUMMARY (HEBREW)

גז טבעי, שהינו דלק פוסילי נקי יותר מדלקים פוסיליים אחרים, הוא מקור דלק חשוב המוביל לקראת צריכת אנרגיה נקייה יותר. גז טבעי מוכר גם כ"דלק מגשר" וכמפתח פוטנציאלי לעתיד דל פחמן, שכן מעבר לגז טבעי מפחם או מדלקים פוסיליים נוזליים תורם להפחתת פליטת פחמן דו חמצני (פד"ח - CO_2) ליחידת אנרגיה ומפחית את הצורך בטכנולוגיות ללכידת פחמן.

המתאן (CH_4) הוא המרכיב העיקרי של הגז הטבעי והינו גז החממה השני בהיקף פליטת גזי החממה, ובו מתמקדים כיום - יחד עם עוד גזי חממה קצרי-חיים - המאמצים לצמצום פוטנציאל ההתחממות הגלובלית של האטמוספירה. המתאן, כתורם לאפקט החממה, מאופיין במקדם פוטנציאל התחממות גלובלית מעל לפי 25 בהשוואה ל-CO_2[1]. בנוסף, המתאן נוטל חלק בתהליכים אטמוספריים ותורם להיווצרות ערפיח פוטו-כימי ולכן ישנה התמקדות מוגברת על פליטותיו מצד רגולטורים, אמצעי תקשורת, תעשייה וארגונים סביבתיים.

מגוון רחב של מקורות לאורך שרשרת אספקת הנפט והגז הטבעי תורמים לפליטות המתאן. אלה כוללים פליטות ממקורות ייצור קונבנציונלי ובלתי קונבנציונלי, מאיסוף ועיבוד של גז, כמו גם מהולכתו וחלוקתו לצרכני הקצה. פליטות מסוימות הן מקריות, למשל עקב איטום פגום או בגלל שסתום דולף, בעוד שאחרות הן מכוונות ומבוצעות מטעמי בטיחות או בשל העיצוב והייעוד של המתקן או הציוד.

הגז הטבעי הוא תורם חשוב לכלכלת ישראל, הן בהיבט כלכלי והן בהיבט סביבתי. הגז הטבעי המופק ממקורות ישראליים מקדם עצמאות אנרגטית והשימוש בו מפחית את פליטת גזי החממה משום שהשימוש בו גורם לפליטה נמוכה יותר של פחמן ליחידת אנרגיה בהשוואה לדלקים פוסיליים אחרים.

מחקר זה מתמקד בהערכת אובדן גז טבעי ופליטת גזי חממה (CO_2 ו-CH_4 בלבד) בשרשרת האספקה מה"באר למיכל" (well-to-tank) עבור מספר נתיבי הפקת דלקים המבוססים על גז טבעי, כולל: גז טבעי דחוס (CNG), מתנול מעורב בדלק בנזין והפיכת גז לדלק נוזלי (GTL). כמו כן, בעקבות הצגת התוכנית האסטרטגית החדשה לשנת 2030, על ידי משרד האנרגיה, כללנו גם הערכות ראשוניות של אובדנים כתוצאה מייצור חשמל באמצעות גז טבעי לצורך טעינת כלי רכב חשמליים.

מטרות ספציפיות של המחקר:

- סקירת הספרות והנתונים העדכניים ביותר לגבי שיעורי אובדן הגז הטבעי ממגזרי שרשרת האספקה של הגז הטבעי;
- הערכת שיעור פליטת גזי המתאן עקב שריפה בלפיד, נישוב ודליפה בתהליכי ההפקה, העיבוד, וההולכה של הגז הטבעי;

[1] פוטנציאל התחממות גלובלית (GWP) הינו מדד לכמות החום היחסית הנלכדת על ידי מסה של גז חממה מסוים לעומת מסה זהה של פד"ח לאופק זמן נתון. הערכת המדדים האלה השתפרה עם השנים והמדד עבור מתאן לאופק זמן של 100 שנים השתנה מ-21 (המיושם במצאי הפליטות של מדינת ישראל) לעומת 25 (המיושם במצאי הפליטות של מדינות אמנת האקלים) ו-34 שהינו המדד העדכני מדו"חות ההערכה של ה-IPCC.

- השוואת נתונים ממדינות נבחרות לפליטות הקשורות במעלה ובמורד הזרם לייצור דלקים מבוססי גז טבעי לתחבורה בישראל;
- המלצה על אמצעי מדיניות אופציונליים לצמצום אובדן הגז הטבעי ופליטת גזי חממה.

הסקירה המדעית והניתוח המופיעים במחקר זה מוגבלים, משום שהם מבוססים על נתונים הזמינים רק ממספר מדינות נבחרות, בעיקר מארה"ב. כמו כן, יש נתונים פומביים מעטים ולא מפורטים דיים מפעילות משק הגז הטבעי בישראל. בנוסף, בשל הנפקת מידע עסקי סודי ומגבלות תקציביות, לא ניתן היה לבצע איסוף נתונים נרחב כדי לאפיין את הענף בישראל.

ממצאים עיקריים:

1. **אומדן פליטות גלובליות**

- ארגון IEA מעריך כי הממוצע בעולם של פליטות מרשת אספקת הגז הטבעי (שעמד על 42 Mt בשנת 2015) עומד על 1.7% - זהו האחוז הממוצע מהגז המופק שאבד והשתחרר לאטמוספרה, לפני שהגיע לצרכן.
- אחוזי האובדן בפועל הם ייחודיים לכל מדינה, ויש לחשבם מנתוני ייצור ושיווק מקומיים מפורטים, יחד עם מצאי פליטה רלוונטי.
- אומדן פליטת CO_2, על סמך נתוני מאקרו, כגון איכות הדלק, כמותו ותכולת הפחמן, הינם פשוטים יחסית. עם זאת, אמידת פליטת CH_4 מורכבת יותר משום שנדרשת הערכה של מספר גדול מאד של מקורות פליטה ותהליכים הנדסיים. נתוני מצאי הפליטה ברחבי העולם הם באיכות משתנה ולמדינות רבות עדיין אין דיוק בנתוני פליטות מתאן.
- הלקחים שנלמדו מסקר הספרות לשיפור כימות הפליטות כוללים: עדכון מקדמי פליטה תוך העדפת קטגוריות של מקורות הפליטה העיקריים; איסוף נתונים תוך הבטחת הלימות וייצוגיות הנתונים עבור פעילות המגזר המקומי; הערכת השונות ואי הוודאות של הנתונים כאשר משתמשים במקדמי פליטה מקומיים לעומת מקדמים גנריים. **המלצות אלה חלות על חישוב כל מלאי הפליטה הארצי המסתמך כיום בעיקר על מקדמי פליטה גנריים**.

2. **עצימות הפליטות**

- טווח עצימות פליטות גזי החממה המוערך על פני שרשרת האספקה הוא רחב מאוד ונע בין 2 ל-42 גרם CO_2e/MJ;
- עצימות הפליטה עבור שרשרת האספקה **היבשתית** של גז טבעי בארה"ב מוערכת ב-0.29 גרם CH_4/MJ של גז טבעי משווק, או 9.9 גרם CO_2e/MJ (בהנחת מקדם התחממות גלובלית של 34 עבור CH_4 לאופק זמן של 100 שנים). ערך זה שווה לשיעור פליטת מתאן של 1.7% (טווח של 1.3-2.2% עם רווח סמך של 95%). עבור כלל פליטות גזי החממה (CH_4-ו CO_2) ושימוש במקדמי

התחממות גלובלית לאופקי זמן של 100 שנה ו-20 שנה, עצימות הפליטה היא 13.8 גרם CO_2e/MJ ו-28.6 גרם CO_2e/MJ, בהתאמה.

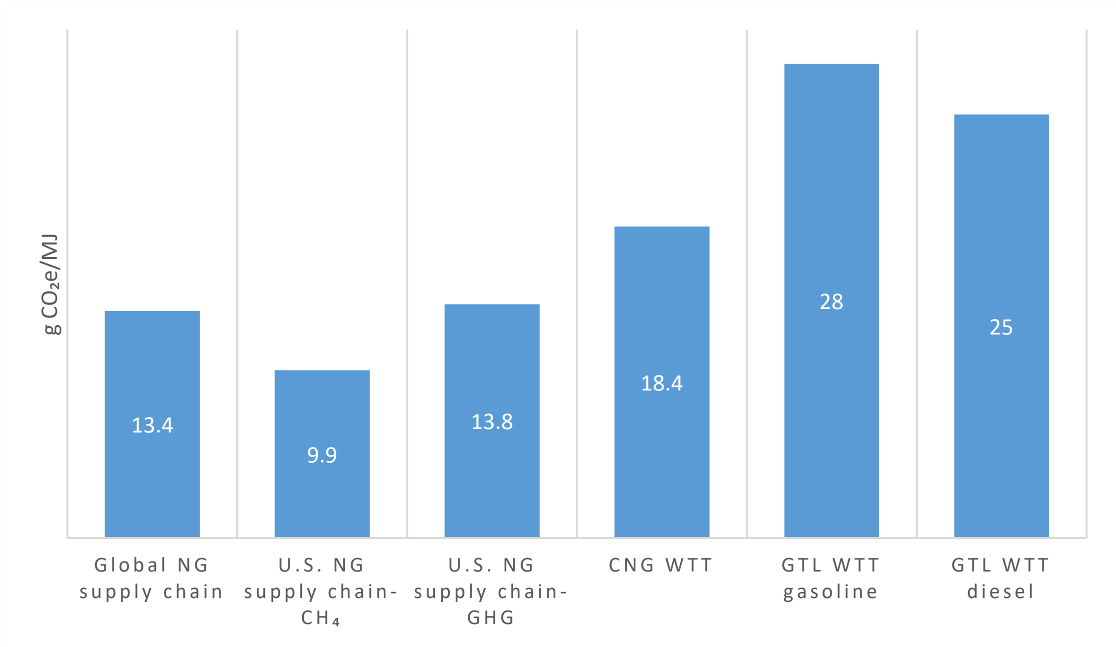
- אומדני עצימות הפליטה של CH_4 בלבד נעים בין 0.2% ל-10% מכלל כמות המתאן בגז הטבעי המיוצר, אשר ניתן לביטוי כ-1-58 גרם CO_2e/MJ, כאשר רוב האומדנים נעים בין 0.5% ל-3% מהמתאן בגז המיוצר;
- עבור אספקת הגז הטבעי במעלה הזרם, החציון המוערך של פליטת גזי חממה הוא 13.4 גרם CO_2e/MJ, אם נעשה שימוש בציוד מודרני עם משטרי תפעול ותחזוקה מתאימים.

מהנתונים בולט שישנם פערי מידע על פרטי הפליטות בהפקת גז טבעי בים, וכן בצנרת של מקטעי ההולכה והחלוקה.

3. ניתוח מחזור חיים

- בניתוח שרשרת האספקה מהבאר למיכל (WTT) עבור **CNG** באיחוד האירופי נמצא, על בסיס אנרגטי, שעצימות הפליטות היא בטווח שבין 13.75 ל-19.8 גרם CO_2e/MJ עבור פליטות הנובעות מאספקת גז טבעי מאזורים שונים; עצימות הפליטה עבור פד"ח, מתאן ו-N_2O עומדת על 9.9, 3.74 ו-0.11 גרם CO_2e/MJ, בהתאמה. עצימות הפליטה בשימוש במודל GREET עבור מסלול CNG היא 18.4 גרם CO_2e/MJ.
- עצימות הפליטה הקשורה לייצור **מתנול** מגז טבעי משתנה בין המתקנים השונים בשל מקור הגז הטבעי והטכנולוגיה בה משתמשים. עצימות הפליטה במקרים השונים שנבדקו נמצאה בטווח שבין 0.3 ל-0.9 $tCO_2e/tMeOH$. הפליטה הכוללת לכל MJ של דלק מיוצר תהיה תלויה באחוז המתנול המעורבב עם הבנזין, המהווה את השימוש העיקרי של מתנול כדלק תחבורה.
- בניתוח WTT של ייצור **GTL** נמצאה עצימות בטווח 28-90 גרם CO_2e/MJ עבור הפיכת גז לבנזין, או 25-191 גרם CO_2e/MJ עבור הפיכת גז לסולר. עבור GTL, גבולות ההערכה צריכים לכלול שינוע של המוצר - שינוע הדלק ממתקן ההמרה לתחנת התדלוק, אחסון באתר וכן פליטות בעת התדלוק.

באיור א' מוצג סיכום של עצימות פליטות של נתיבי השימוש בגז טבעי יחד עם העצימות המשוערת של שרשרת אספקת הגז הטבעי בטרם הפיכתו לדלק.



איור א' - השוואה של עצימות פליטות עבור מסלולים נבחרים של גז טבעי במונחים של גרם CO_2e/MJ

שלבי העיבוד הנוספים הנדרשים לייצור דלקים מבוססי גז טבעי, גורמים להגדלת פליטות גזי חממה מעבר לפליטות בשרשרת האספקה במעלה הזרם. תהליכים אלה מובילים להגדלת צריכת אנרגיה - עם עלייה בפליטות פד"ח במקביל – וכן לעליה של פליטות מתאן כתוצאה מדליפות ונישוב הקשורים לתהליכים השונים.

4. הערכת פליטות בישראל

- **פליטות במעלה הזרם -** נתוני הפליטות מרשת אספקת הגז הטבעי בישראל הזמינים לציבור מוגבלים למידע שדווח למפל"ס, וזאת לפי דיווחים מהאתרים של חברות הגז הטבעי לשנים 2014-2017. חישוב פליטות מתאן, תוך שימוש במקדמי IPCC של Tier 1 (על בסיס נפח הגז המופק), מניב ערכים גבוהים יותר, כפי שניתן לראות בטבלה א'.

טבלה א' - הערכת פליטות מתאן בשרשרת האספקה של גז טבעי בישראל

	2014	2015	2016	2017	Units
Domestic Natural Gas Supply [(a)]	7,550	8,280	9,300	9,830	MCM
IPCC Tier 1 Estimate [(b)]					
Production and Processing	6.9	7.6	8.5	9.0	kt CH_4/year
Transmission and Storage	7.7	8.5	9.5	10.1	kt CH_4/year
Distribution	8.3	9.1	10.2	10.8	kt CH_4/year
Total Supply Chain	23.0	25.2	28.3	29.9	kt CH_4/year
IL-PRTR Reporting [(c)]					
Production/Processing	4.4	4.6	4.0	4.3	kt CH_4/year
Difference (PRTR-IPCC)/IPCC	**-36%**	**-39%**	**-53%**	**-52%**	

[a] *Source: NGA, 2018.*
[b] *Emissions based on IPCC Tier 1 factors as exhibited in Table 3-1*
[c] http://www.sviva.gov.il/PRTRIsrael/Pages/default.aspx

- בישראל אין נתונים ספציפיים המאפשרים אפיון פליטות גזי חממה (CO_2 ו-CH_4) הצפויות בעת המרת גז טבעי לדלקים מבוססי גז.
- בהתבסס על ההנחות שבטיוטת התוכנית האסטרטגית של משרד האנרגיה לשנת 2030 (MOE, 2018) פליטות CO_2 עקיפות מכלי רכב חשמליים בתחנות ייצור החשמל הנוכחיות נאמדות בכ-92.8 גרם פד"ח לק"מ וצפויות להצטמצם עד כדי 56.9 גרם פד"ח לק"מ בשנת 2030, אם אכן יושג תמהיל הדלקים לייצור חשמל בהתאם לתוכנית זו. פליטות פד"ח עקיפות מאוטובוסים חשמליים תחת תמהיל ייצור החשמל הנוכחי מוערך בכ-721.6 גרם לק"מ והוא צפוי להיות בשיעור של כ-442.5 גרם לק"מ בשנת 2030, בהתאם לתוכנית.
- פליטות מתאן עקיפות הקשורות לכלי רכב חשמליים צפויות להיות פחות מ-1% מפליטות הפד"ח לק"מ, גם כאשר מתייחסים לפליטות הלא מוקדיות הנוספות מרשת אספקת הגז הטבעי.

5. הפחתת פליטות

- מאגר המידע של גז הטבעי של ה-EPA כולל כ-70 טכנולוגיות וטכניקות להפחתת פליטות מתאן בקטעי הייצור, העיבוד, ההולכה וההפצה של הגז הטבעי.
- ניתוח שבוצע על ידי צוות תוכנית הגז הטבעי Natural Gas STAR מצא כי עלויות ליישום טכנולוגיות הפחתה במתקנים הרחוקים מהחוף (off shore) צפויות להיות גבוהות באופן משמעותי ממתקנים יבשתיים.

- ארבעה סוגים של אמצעי הפחתה מהווים את רוב האמצעים עם עלות אפס נטו (או אפילו נמוכה יותר): איתור ותיקון דליפות (Leak Detection and Repair - LDAR) ממקורות של פליטות לא מוקדיות; לכידת גז למניעת נישובו לאטמוספירה והחזרתו לשימוש בתפעול האסדה; החלפת ווסתים פנאומטיים המונעים על ידי גז טבעי להפעלה באוויר למיכשור (instrument air); והחלפת משאבות המופעלות בגז (Kimray) במשאבות חשמליות.

6. המלצות ליישום בישראל

המסקנה העיקרית של מחקר זה היא הצורך בקבלת נתוני פליטות אמיתיים מתעשיית הגז על מנת שלא להסתמך על הערכות גנריות של IPCC. לנושא זה יש חשיבות מירבית בכדי לאפשר לישראל לשדרג את מצאי הפליטות השנתי ומערך הדיווח לאו"ם במסגרת "ספר החוקים" ליישום הסכם פריז לאמנת שינוי האקלים שלפיו תצטרך מדינת ישראל לדווח לאו"ם על פליטות גזי החממה בישראל מדי שנה.

ישראל הצטרפה ב-2018 למיזם בינלאומי – Global Methane Initiative (GMI)[2]. בעת הצטרפותה למיזם הודיעה ישראל כי היא מאמינה שקיימות בישראל אפשרויות להפחתה ולכידה של מתאן בעיקר בתחום הגז הטבעי, פסולת מוצקה וחקלאות. תוך הכרה ששותפות ב-GMI מהווה הזדמנות ללמוד מניסיונן של מדינות אחרות.

המלצות לפעילות הממשלה:

- לפתח תקני פליטה והיתרי פליטה מחמירים להגבלת שיעור פליטת המתאן בתעשיית הגז הישראלית;
- לבצע (או לדרוש מהתעשייה לבצע) סקר דליפה פיזי שנתי לניטור פליטות המתאן באמצעות שילוב של טכנולוגיות, לרבות מצלמות אינפרא-אדום או התקני חישה מרחוק;
- לבצע סקירה תקופתית (אחת ל-3-5 שנים) של פעילות תעשיית הגז הטבעי, לרבות ספירת ציוד, הרכב גז טבעי ואפיון המתקנים ומצבי ההפעלה שלהם;
- לקבוע דרישת דיווח שנתית של פליטות גזי החממה עבור פד"ח ומתאן, בשילוב הנחיות מורחבות המפרטות את רשימת מקורות הפליטה ואת מתודולוגיית האמידה הספציפית;
- לפרסם אסטרטגיה לאומית להפחתת פליטות מתאן כחלק מהשיפורים הצפויים ולהעמיק את ההתחייבות שנתנה ישראל לאו"ם.

המלצות לפעילות בתעשייה:

- להיערך לתקנות עתידיות ולהיתרי הפליטה, על ידי קביעת נהלי ממשל תאגידי לטיפול בסיכוני מתאן;

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[2] https://www.globalmethane.org/partners/index.aspx

- להיערך ולתכנן מכשור וטכנולוגיות (במיוחד עבור בניית צנרת) על מנת להבטיח צמצום פליטות גז טבעי כתוצאה מתהליכי אוורור ודליפות מרכיבי ציוד;
- לאמץ שיטות ניהול וטכנולוגיות מומלצות בעלות תועלת מרבית כדי למזער וללכוד מתאן במתקנים מתאימים;
- לדווח באופן תדיר על ההיקף והמתודולוגיה של בדיקות שבוצעו עבור תוכניות הפחתת פליטות וולונטריות, כגון בדיקה ישירה, תחזוקה וכן גילוי דליפה ותיקון.

EXTENDED ABSTRACT & SUMMARY (ENGLISH)

Natural Gas, which is a cleaner burning fuel than solid or liquid fossil fuels, is an important fuel source leading towards a cleaner energy future. Natural gas is also well recognized as a potential 'Bridge' fuel to a low-carbon future, since substitution of natural gas for coal or liquid fossil fuels leads to reduced generation of carbon dioxide (CO_2) when natural gas is combusted, in comparison to other fossil fuels, and is reducing the need for carbon capture technologies.

Methane (CH_4) is the primary constituent of natural gas and the second most abundant GHG, focusing global efforts on the need to reduce the global warming potential of the atmosphere by reducing CH_4 emissions, amongst other short-lived climate pollutants. As an atmospheric constituent with radiative forcing upwards of 25 times[3] that of CO_2, and with its contribution to the formation of photochemical smog, CH_4 is gaining increased attention from regulators, media, industry, and environmental organizations.

A wide variety of sources along the oil and natural gas supply chain contribute to CH_4 emissions. These are comprised of sources from conventional and unconventional production, from the collection and processing of gas, as well as from its transmission and distribution to end-use consumers. Some emissions are accidental, for example because of a faulty seal or leaking valve, while others are deliberate, often carried out for safety reasons or due to the design of the facility or equipment.

Natural Gas is emerging as an important contributor to the Israeli economy from both the economic and environmental perspectives. Natural gas sourced from Israeli operations leads to energy independence and its utilization promotes decreased greenhouse gas (GHG) emissions since it has lower carbon per unit of energy than other fossil fuels.

This study focusses on the assessment of natural gas loss and (**only**) energy related GHG emissions (CO_2 and CH_4) in the **well-to-tank supply chain** for several pathways of natural gas-based transportation fuels, including: compressed natural gas (CNG), methanol blended gasoline fuels and Gas-to-Liquid (GTL) fuels. Due to the introduction of the new strategic plan to 2030, by the Ministry

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[3] Global Warming Potential (GWP) is a relative measure of how much heat greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide over a certain time horizon. The values of the GWPs have evolved through the years. For CH_4 at the 100-year time horizon the value changed from 21 (which is still used in the Israeli GHG inventory) to 25 (which is used in the GHG inventories of Annex 1 countries), and more recently to 34 based on the latest IPCC assessment.

of Energy, we have included also preliminary assessments of the impact of the fuel mix for electricity generation for charging electric vehicles.

Specific goals of the study:

- Survey of the most recent literature and data on natural gas loss rates from various natural gas supply chain segments;
- Assessment of natural gas GHG emission, especially those of CH_4, due to venting, flaring and equipment leakage;
- Comparing data from select countries to upstream and fuel pathways related emissions and their relevance for Israel;
- Recommendation of optional policy considerations for minimizing natural gas loss and CH_4 emissions.

The scientific overview and analysis presented in this research is limited since it is based on data that is available only from a few select countries, primarily the U.S. There is sparse availability of publicly disclosed data from operations of the natural gas sector in Israel. Moreover, due to issue of confidential business information and budget limitations it was not feasible to undertake extensive data collection to characterize the industry sector in Israel.

Main findings

1. **Global Emissions Estimate**

- IEA estimates that - when averaged globally - emissions from the natural gas supply chain (42 Mt in 2015) is equivalent to an emission intensity of 1.7% – that is the average percentage of gas produced that is lost to the atmosphere before it reaches the consumer.
- The actual shrinkage and loss percentages are country specific and ought to be determined from detailed local production and marketing data along with applicable emission inventories.

- Estimation of CO_2 emissions from macro data such as fuel quality and quantity and carbon content are straightforward. However, estimation of CH_4 emissions are more complex since they entail assessment of a myriad of emission sources and engineered processes. Emission inventories around the globe are of varying quality and many countries have yet to address CH_4 data accuracy.

- **The lessons learned from the literature survey to improve the quantification of emissions** include: updating emission factors focusing on high priority emissions sources categories; collecting new measurements data to customize emission factors to represent local sector operations; utilization of robust sampling design and sample size for measurements to ensure data representativeness; and assessment of emission variability and uncertainty while using emission factors metrics. **These recommendations are applicable to all national emission inventories which currently rely mainly on generic emission factors.**

2. Emissions Intensity

- The range of estimated GHG emissions across the supply chain is vast: varying between 2 and 42 g CO_2e/MJ;
- U.S. onshore natural gas supply chain is estimated to emit 0.29 g CH_4/MJ of delivered natural gas, or 9.9 g CO_2e/MJ when assuming a GWP of 34 for CH_4. This is equivalent to a CH_4 emission rate of 1.7%, (with a 95% confidence interval from 1.3% to 2.2%). The full lifecycle GHG emissions (accounting for both CH_4 and CO_2) and using 100-year and 20-year GWPs is 13.8 g CO_2e/MJ and 28.6 g CO_2e/MJ, respectively;
- Methane-only emission intensity estimates range from 0.2% to 10% of the CH_4 content of the produced natural gas, which can be expressed as 1 to 58 g CO_2e/MJ, with most estimates between 0.5% and 3% of produced CH_4;
- For the Upstream natural gas supply chain GHG emissions the median estimated intensity is 13.4 g CO_2e/MJ, if modern equipment with appropriate operation and maintenance regimes were used.

Data gaps are notable primarily for offshore natural gas extraction as well as transmission and distribution pipelines.

3. Life cycle assessment

- Well-to-Tank analysis for **CNG** in the EU is found, on an energy basis, to range from 13.75–19.8 g CO_2e/MJ due to emissions associated with natural gas supply from different regions; the emission intensity rates for CO_2, CH_4, and N_2O amount to 9.9, 3.74 and 0.11 g CO_2e/MJ, respectively. The emission intensity used in the GREET model for the CNG pathway is 18.4 g CO_2e/MJ.
- The emissions intensity associated with the manufacture of **methanol** from natural gas vary between plants due to their design technology and source of the natural gas. The emission intensities for the various cases reviewed are shown to range from 0.3 to 0.9 tCO_2e/tMeOH. The ultimate emission per MJ of fuel produced would depend on the percent of methanol blended into gasoline, which is the primary use of methanol as a transportation fuel.
- For production of **GTL** the Well-to-Tank emissions intensities are shown to range from 28 to 90 g CO_2e/MJ of gasoline, or from 25 to 91 g CO_2e/MJ of diesel. For GTL, the assessment boundaries should include product transport. This consists of movement of fuel from the conversion facility to the refueling station, on-site storage, and dispensing of the fuel into a vehicle.

A summary of the target fuels pathway intensity, along with estimated intensity of the natural gas supply chain prior to fuel conversion, is presented in Figure A.

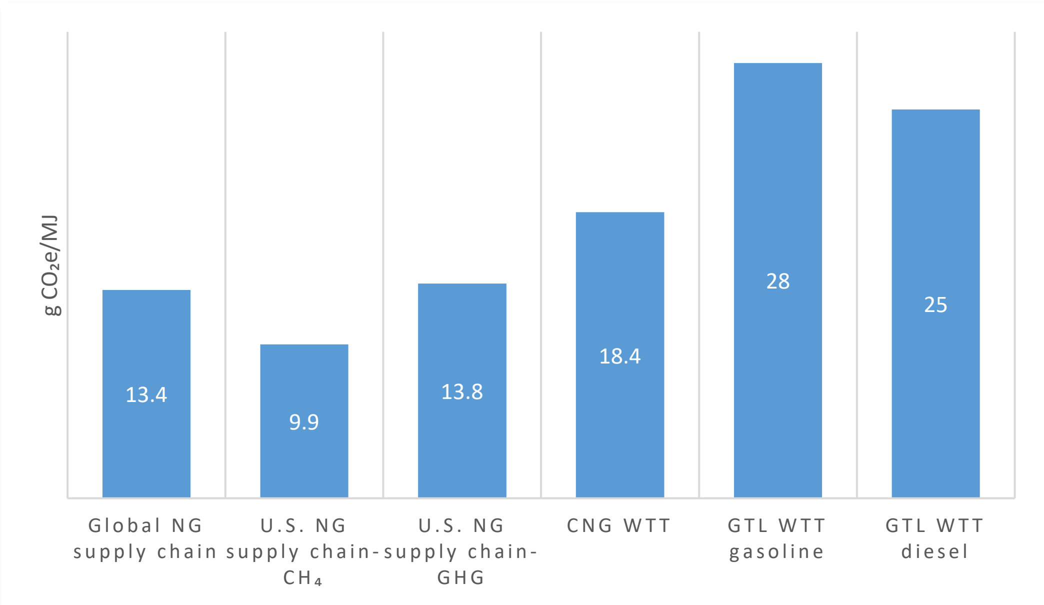

Figure A > Comparison of emissions intensity for select fuel pathways in terms of g CO_2e/MJ

- Additional processing required to produce natural gas-based fuels will result in more GHG emission as compared to those from the upstream supply chain alone. Such processes lead to incremental energy consumption – with corresponding CO_2 emissions - as well as additional leaking and venting of CH_4.

4. Israel Emissions Estimate

- **Up- stream gas production**. Publicly available emissions data from the natural gas supply chain in Israel is limited to information reported to the IL-PRTR for natural gas systems operations for the years 2014–2017. Calculating CH_4 emissions, using Tier 1 IPCC factors (based on volume of gas produced) yields higher values as seen in Table A.

Table A > Israel Estimated Natural Gas CH_4 Emissions

	2014	2015	2016	2017	Units
Domestic Natural Gas Supply [(a)]	7,550	8,280	9,300	9,830	MCM
IPCC Tier 1 Estimate [(b)]					
Production and Processing	6.9	7.6	8.5	9.0	kt CH_4/year
Transmission and Storage	7.7	8.5	9.5	10.1	kt CH_4/year
Distribution	8.3	9.1	10.2	10.8	kt CH_4/year
Total Supply Chain	23.0	25.2	28.3	29.9	kt CH_4/year
IL-PRTR Reporting [(c)]					
Production/Processing	4.4	4.6	4.0	4.3	kt CH_4/year
Difference (PRTR-IPCC)/IPCC	**-36%**	**-39%**	**-53%**	**-52%**	

[a] *Source: NGA, 2018.*
[b] *Emissions based on IPCC Tier 1 factors as exhibited in Table 3-1*
[c] *http://www.sviva.gov.il/PRTRIsrael/Pages/default.aspx*

- No Israeli specific data is available to enable characterization of the GHG (CO_2 and CH_4) emissions that are expected to be associated with the conversion of natural gas to gas-based transportation fuels.

- Based on the assumptions in the Draft Strategic Plan to 2030 (MOE, 2018) indirect CO_2 emissions from electric passenger vehicles under the current electricity generation mix is estimated as 92.8 gr/km and it is expected to be reduced to 56.9 gr/km in 2030 if the new fuel mix is attained in 2030 and beyond. Indirect CO_2 emissions from electric buses under the current electricity generation mix is estimated as 721.6 gr/km and is expected to be reduced to 442.5 gr/km in 2030 if the new fuel mix is attained.
- Indirect CH_4 emissions associated with electric vehicles are expected to be less than 1% of the CO_2 emissions per km from electricity generation even when accounting for the additional fugitive emissions from the natural gas supply chain.

5. Emissions mitigation

- EPA's Natural Gas STAR data base consists of around 70 technologies and practices to cut CH_4 emissions in the Production, Gathering and Boosting, Processing, Transmission and Distribution segments of the industry.
- Analysis performed by the Natural Gas STAR program staff found that costs for applying the same reduction technologies/practices offshore can be significantly higher than for an onshore application. General factors that contribute to higher costs offshore include higher Capital, installation, operating and maintenance costs**.**
- Four types of abatement measures account for most measures with net zero cost (or even lower): **Leak detection and repair (LDAR) of sources of fugitive emissions; Capturing vented gas; Replacing high-bleed pneumatic devices with low- bleed pneumatics; and Replacing Kimray pumps (i.e., gas-powered) with electric pumps.**

6. Recommendations for Implementation in Israel

The main conclusion from this study is the need for local emissions and activity data (so as not to rely on generic IPCC assessments). This issue is of great importance in order to enable Israel to upgrade its annual emissions inventory and reporting system to the United Nations within the framework of the "Rulebook" for the implementation of the Paris Agreement of the Climate Change Convention, according to which the State of Israel will have to start reporting GHG emissions annually.

In 2018, Israel joined the Global Methane Initiative (GMI)[4]. At the time of joining the project, Israel announced that it believes that there are possibilities in Israel for the reduction and recovery of methane, mainly in the field of natural gas, solid waste and agriculture. Recognizing that the GMI partnership provides an opportunity to learn from the experience of other countries.

Recommendations for Government Action

- Develop national technology and performance standards for CH_4 emission rates for key emission sources and incorporate them in operating permits and track compliance;
- Perform (or require Industry to undertake) an annual physical leak survey to monitor CH_4 emissions using a combination of technologies including infrared cameras or remote sensing devices;
- Perform a periodic census (once every 3-5 years) of natural gas industry activities including equipment counts, natural gas composition, and characterization of devices and their operating modes;
- Establish annual GHG reporting requirement for both CO_2 and CH_4, with expanded guidelines specifying the list of emission sources and specific estimation methodology;
- Publish a national CH_4 mitigation strategy as part of the anticipated enhancements to the nationally determined contribution which would extend Israel's contribution to climate change mitigation to 2030.

Recommendations for Industry Action

- Prepare for upcoming regulations by establishing corporate governance practices to address CH_4 risks;
- Assess current devices design and construction material (specifically for pipeline construction) to ensure minimization of venting and leaking emissions;

[4] https://www.globalmethane.org/partners/index.aspx

- Adopt cost-effective best management practices and technologies to mitigate and capture CH_4 from applicable installations;
- Report frequency, scope and methodology, of inspections performed for regulatory and voluntary emission mitigation programs such as direct inspection and maintenance and/or leak detection and repair.

KEYWORDS

Alternative fuels

Natural gas- based transportation fuels

CNG

GTL

Methanol

Greenhouse gas emissions

Methane leakage rate

Natural gas supply chain

Natural gas venting and flaring

Fugitive Emissions

Natural Gas Loss Rate

Natural Gas Fuel Cycle

PLANNING VS EXECUTION

Month	Assignments	Execution
April 2017	Natural gas loss literature survey	Completed
May 2017	Natural gas loss literature survey	Completed
June 2017	Natural gas loss literature survey	Completed
July 2017	Upstream natural gas comparative data analysis	Completed
August 2017	Upstream natural gas comparative data analysis	Completed
September 2017	Upstream natural gas comparative data analysis	Completed
October 2017	Natural gas-based transportation fuels review	Completed
November 2017	Natural gas-based transportation fuels review	Completed
December 2017	Natural gas-based transportation fuels review	Completed
January 2018	Integration of natural gas-based fuels pathways analysis	Completed
February 2018	Integration of natural gas-based fuels pathways analysis	Completed
March 2018	Integration of natural gas-based fuels pathways analysis Submission of phase 1 report (Sections 1-3)	Completed
April 2018	Integration of natural gas-based fuels pathways analysis	Completed
May 2018	Prioritization of core emission sources and policy measures	Completed
June 2018	Summary of cost-effectiveness studies Revisions submitted by MoEP	Completed
July 2018	Reviewed comments received from MoEP on Sections 1-3	Completed - Integrated into final report
August 2018	Collected data on oil and gas emissions sources in Israel	Completed
September 2018	Assembling data, calculations and writing final report	Completed
October 2018	Assembling data, calculations and writing final report	Completed
November 2018	Writing final report	Completed
December 2018	Submitted final report to MoEP	Completed

ACRONYMS

BCM - Billion Cubic Meters

Btu - British Thermal Units

CCAC - Climate and Clean Air Coalition

CCS - Carbon Capture and Sequestration

CH_3OH - Methanol

CH_4 - Methane

CNG - Compressed Natural Gas

CO_2 - Carbon dioxide

CO_2e - CO_2 equivalents. Weighted sum of greenhouse gases amounts by their respective global warming potentials is used to derive a CO_2 emissions equivalent value. This allows us to compare between different greenhouse gases on the same scale.

CTL - Coal-to-Liquids

DI&M - Directed Inspection and Maintenance

EPA - Environmental Protection Agency

FFV - Flex Fuel Vehicle

FT - Fischer-Tropsch synthesis (LTFT - Low-temperature FT; HTFT - High-temperature FT)

GHG - Greenhouse Gas

GHGRP - GHG Reporting Program

GMI - Global Methane Initiative

GREET - The Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model

GTL - Gas-to-Liquids

GWP - Global Warming Potential

H_2 - Hydrogen

IEA - International Energy Agency

IEO - International Energy Outlook

IL-CBS - Israel Central Bureau of Statistics

IL-PRTR - Israel Pollutant Release and Transfer Register

IPCC - Intergovernmental Panel on Climate Change

LDAR - Leak Detection and Repair

LNG - Liquefied Natural Gas

MCM - Million Cubic Meters

MMBtu - Million Btu

MMT - Million Metric Tonnes

MoEP - Ministry of Environmental Protection

M15 - Blends of 15% methanol and 85% gasoline and correspondingly - M85, M100

NDC - National Determined Contribution

NGV - Natural Gas Vehicle

O&M - Operating and Maintenance

OECD - Organization for Economic Co-operation and Development

OGMP - Oil & Gas Methane Partnership

RECs - Reduced Emission Completions

Syngas – "Synthesis" natural gas

Tcf - Trillion cubic feet

VRU - Vapor Recovery Unit

WEO – World Energy Outlook

WTT - Well to Tank

WTW - Well to Wheel

1 INTRODUCTION

Natural Gas, which is a cleaner burning fuel than solid or liquid fossil fuels, is an important fuel source leading towards a cleaner energy future (MIT, 2011). Natural gas is also well recognized as a potential 'Bridge' fuel to a low-carbon future (Moniz et al., 2010) since substitution of natural gas for coal or liquid fossil fuels leads to reduced generation of carbon dioxide (CO_2) when natural gas is combusted in comparison to other fossil fuels, and is reducing the need for carbon capture technologies (Zhang et al., 2016).

Methane (CH_4) is the primary constituent of natural gas and the second most abundant greenhouse gas (GHG), focusing global efforts on the need to reduce CH_4 emissions, amongst other short-lived climate pollutants. As an atmospheric constituent with radiative forcing upwards of 25 times that of CO_2, and with its contribution to the formation of photochemical smog, CH_4 emissions are gaining increased attention from regulators, media, industry, and environmental organizations. Understanding potential natural gas losses and emissions from the operating segments that make up the “natural gas supply chain” and the conversion of natural gas to transportation fuels is the focus of this study. Such losses may be due to its field utilization; flaring, venting and leakage; as well as processing for conversion to transportation fuels.

Minimizing losses and emissions are essential to planning for the increased use of natural gas. In the U.S. for example, the Energy Information Administration (EIA, 2012) estimated that in 2012 the total loss of natural gas was about 10 - 14% of the gross natural gas produced. These losses are due to use of gas in field operations; removal of non-hydrocarbon gas during processing; and fugitive emissions of CO_2 and CH_4 to the atmosphere. Fugitive emissions along the natural gas supply chain consist of component equipment leaks; flaring and venting of gas that is not captured; release of naturally occurring CO_2 when processing raw natural gas; and CO_2 and CH_4 emissions that are the result of natural gas combustion to control volatile compounds emissions from operations.

Methane, as an energy resource can substitute coal and oil derivatives (fuel oil and diesel) for electricity production, fuel oil and diesel for heat production and gasoline and diesel for transportation. Natural gas emits 50 to 60 percent less CO_2 when combusted in a new, efficient natural gas power plant compared with emissions from a typical new coal plant (NETL, 2010). Considering only tailpipe emissions, natural gas also emits 15 to 20 percent lower GHGs than gasoline when burned in today's typical vehicle[5]. However, CH_4 emissions associated with natural gas may negate all or part of these advantages. Studies in the U.S. suggest that substitution of new coal-fired power plants with new natural gas plants would result in short-term climate benefits only if the total net atmospheric CH_4 emission rate would be less than 3-4 percent of the natural gas produced, while the introduction of Compressed Natural Gas (CNG) as a transportation fuel would necessitate a CH_4 loss rate lower than 1.6 percent (Alvarez et al., 2012; Schweitzke et al., 2014).

Natural Gas in Israel

Natural gas is emerging as an important contributor to the Israeli economy from both the economic and environmental perspectives. Natural gas that is sourced from Israeli operations leads to energy independence and its utilization promotes decreased GHG emissions since it has a lower carbon intensity - per unit of energy produced - than other fossil fuels. With the increased importance of natural gas in the Israeli domestic market, it is essential to evaluate its economic benefits, along with the potential of losses and atmospheric emissions from the various segments of the natural gas supply chain. In addition to the economic penalty due to the loss of a valuable resource, such losses may contribute to atmospheric emissions of CH_4 (and other volatile organic compounds) that would affect both local air quality and global climate change. As Israel is developing its national natural gas strategy it is important to assess which sectors of the economy, in addition to electricity generation that could also be used for charging electric vehicles, would benefit from the introduction of natural gas. Various recent studies have focused on the use of natural gas in the industrial and transportation sectors including both gaseous fuels and natural gas- based liquid fuels (Ben Zion, 2014).

On February 7, 2010, the government of Israel passed a resolution stating that it "sees research, development, and implementation of technologies that reduce global oil use in transportation as a national mission that requires harnessing national resources" and set this goal as a top priority, advancing strategic national interest, environmental considerations, and economic potential (resolution no. 1354).

[5] Based on: FuelEconomy.gov. 2013. "Find a car: Compare side-by-side". U.S. Department of Energy. Argonne National Laboratory. GREET 2 2012 rev1. U.S. Department of Energy. https://www.fueleconomy.gov/feg/Find.do?action=sbs&id=33504&id=33503&id=33324

The Fuel Choices and Smart Mobility Initiative[6], Israel's national program for alternative fuels and means of transportation, was launched in the following year as an intergovernmental effort headed by the Prime Minister's Office. The Initiative aims to establish Israel as a center of know-how and industry in alternative fuels and smart mobility, serving as a showcase to the world.

A strategic plan containing "clean energy" goals to 2030 was released recently by the Ministry of Energy (MOE, 2018). The plan foresees that 80% of electricity generation in Israel would be based on domestic natural gas and 20% on renewables. For the transport sector it foresees a gradual transition to electric vehicles, with no imports of fossil fueled passenger vehicles permitted after 2030, and heavy-duty transport (trucks and buses) transitioning to CNG.

Study Goals

The study presented here investigates the emission implications of the use of natural gas-based transportation fuels. This report summarizes the literature review performed focusing on the assessment of natural gas loss and the corresponding GHG emissions in the well-to-tank (WTT) supply chain for natural gas-based transportation fuels. The study consists of assembling the latest information on CH_4 emissions from the natural gas supply chain and the integration of global data for use in the Israeli context. The data will be augmented with local information about natural gas-based transportation fuels (Rapoport, 2013) that were already shown to be economically viable options.

This study assembled the latest information on CH_4 emissions from the natural gas supply chain and the integration of global data for use in the Israeli context, with specific goals:

- Survey of the most recent literature and data on natural gas loss rates from various natural gas supply chain segments;
- Assessment of natural gas GHG emission, especially those of CH_4, due to venting, flaring and equipment leakage;
- Comparing data from select countries to upstream and fuel pathways related emissions and their relevance for Israel;
- Recommendation of optional policy considerations for minimizing natural gas loss and CH_4 emissions.

[6] http://www.fuelchoicesinitiative.com/our-mission/

This study aims to contribute to the development of a national policy in Israel regarding the use of natural gas-based fuels for the transportation sector. The study was initially planned to focus on natural gas-based fuels such as CNG, methanol and GTL. However, due to the latest developments regarding the anticipated penetration of electric vehicles (EV) to Israel, the study has been expanded to include some preliminary considerations related to the impact on CO_2 and CH_4 emissions caused by the additional load on the grid that is needed to fuel the expanded EV fleet.

The next five sections, which constitute the bulk of this report, include:

Section 2 describes the natural gas sector including global trends for energy, transportation and GHG emissions;

Section 3 discusses the scientific background for characterization of GHG emissions from the natural gas supply chain including emissions associated with manufacturing of natural gas-based fuels such as CNG, methanol and GTL;

Section 4 provides a summary of results for the carbon intensity of the natural gas supply chain globally and in Israel with some preliminary considerations of the impact of introduction of EVs on incremental emissions from electricity generation;

Section 5 addresses recommended mitigation technologies and policy measures for the reduction of CO_2 and CH_4 emissions; and

Section 6 brings forward conclusions and recommendations.

Additionally, four appendices provide supplemental technical information for the natural based fuels reviewed.

2 OVERVIEW OF NATURAL GAS SECTOR

2.1 Global energy trends

The International Energy Outlook 2016 (IEO2016) (EIA, 2016a) shows rising levels of energy demand over the next three decades, led by strong increases in countries outside of the OECD. In the IEO2016 Reference case, total world energy consumption is expected to increase by 48% by 2040. Most of the world's energy growth will occur in the non-OECD nations, where energy consumption is estimated to increase by 71% between 2012 and 2040 as compared with an increase of 18% in OECD nations. The difference is due to the OECD nations more mature economies and slow or declining population growth trends. To meet the rising natural gas demand projected in the IEO2016 Reference case, the world's natural gas producers are estimated to increase supplies by nearly 69% from 2012 to 2040. The largest increases in natural gas production during that period is expected to occur in non-OECD Asia (18.7 trillion cubic feet (Tcf)), the Middle East (16.6 Tcf), and the OECD Americas (15.5 Tcf).

Even though consumption of non-fossil fuels (renewables and nuclear power) is expected to grow faster than consumption of fossil fuels, fossil fuels will still account for 78% of energy use in 2040. Natural gas is projected to be the fastest-growing fossil fuel according to the IEO2016 and global natural gas consumption is expected to increase by 1.9% per year. Worldwide natural gas consumption is projected to increase from 120 Tcf in 2012 to 203 Tcf in 2040 according to the IEO2016 Reference case (Figure 2-1).

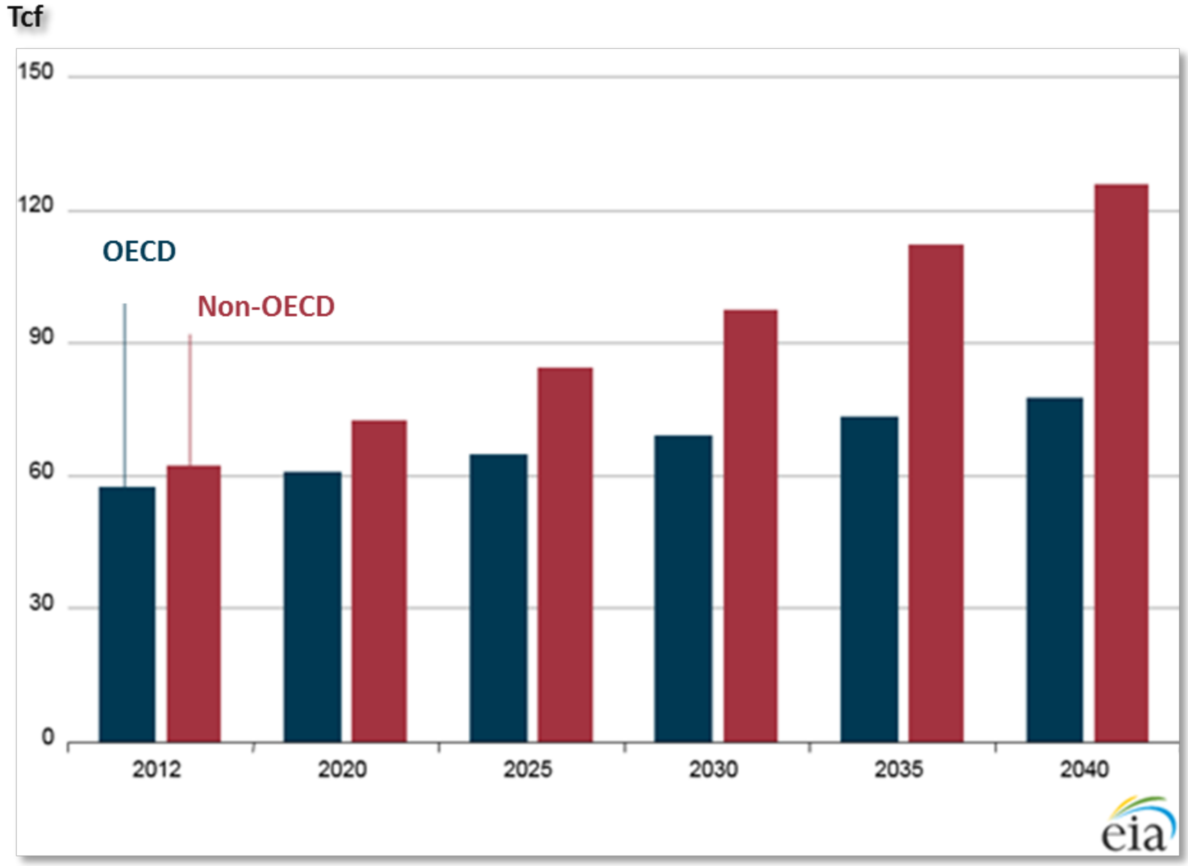

Figure 2-1 > World natural gas consumption 2012-2040

(Source: EIA, 2016a; Figure 3-1)

The world energy outlook 2016 (WEO-2016), developed by the International Energy Agency (IEA), expects a similar trend with 1.5% annual rate of growth in natural gas demand to 2040 (IEA, 2016). According to the WEO-2016 natural gas consumption in the OECD Europe[7] region is expected to grow by 1.3% per year on average, with natural gas accounting for the largest increase in world primary energy consumption. Natural gas is expected to remain a key fuel in both the electric power and the industrial sectors. The industrial and electric power sectors together account for 73% of the total increase in world natural gas consumption, and they are expected to account for about 74% of total natural gas consumption through 2040. Since natural gas burns cleaner than coal or petroleum products, and as more governments begin implementing national or regional plans to reduce CO_2 emissions, they may encourage the use of natural gas to displace more carbon-intensive coal and liquid fuels.

[7] Note: Israel is included in OECD Europe for statistical purposes

2.2 Global transportation sector energy trends

Energy use in the transportation sector includes the energy consumed in moving people and goods by road, rail, air, water, and pipeline. The transportation sector accounted for 25% of the total world energy consumption in 2012, and transportation energy use is expected to increase at an annual average rate of 1.4% to 2040. Direct global GHG emissions for the transport sector consist primarily of CO_2 from the burning of fossil fuels. Relatively small amounts of CH_4 and nitrous oxide (N_2O) are also emitted during fuel combustion. In addition, a small amount of hydrofluorocarbon (HFC) emissions are also attributed to the transportation sector. These emissions result from the use of mobile air conditioners and refrigerated transport. Indirect emissions for the transportation sector include emissions associated with fuel production, processing and refining.

Worldwide, liquid fuels (including natural gas plant liquids, biofuels, GTL, and coal-to-liquids (CTL)) are expected to remain the dominant source of transportation energy consumption, although their share of total transportation energy may decline somewhat over the projection period, from 96% in 2012 to 88% in 2040. Global transportation energy consumption is dominated by two fuels: motor gasoline (including ethanol blends) and diesel (including biodiesel blends). Together, these two fuels accounted for 75% of total delivered transportation energy use in 2012. Motor gasoline is used primarily for the movement of people, especially by light-duty vehicles. Diesel fuel is used primarily for the movement of goods, especially by heavy-duty trucks.

Motor gasoline remains the largest transportation fuel, but its share of total transportation energy consumption is expected to decline from 39% in 2012 to 33% in 2040. The share of natural gas as a transportation fuel is expected to grow from 3% in 2012 to 11% in 2040. Figure 2-2 depicts the expected trends of world transportation sector energy consumption by fuel for the period 2010-2040.

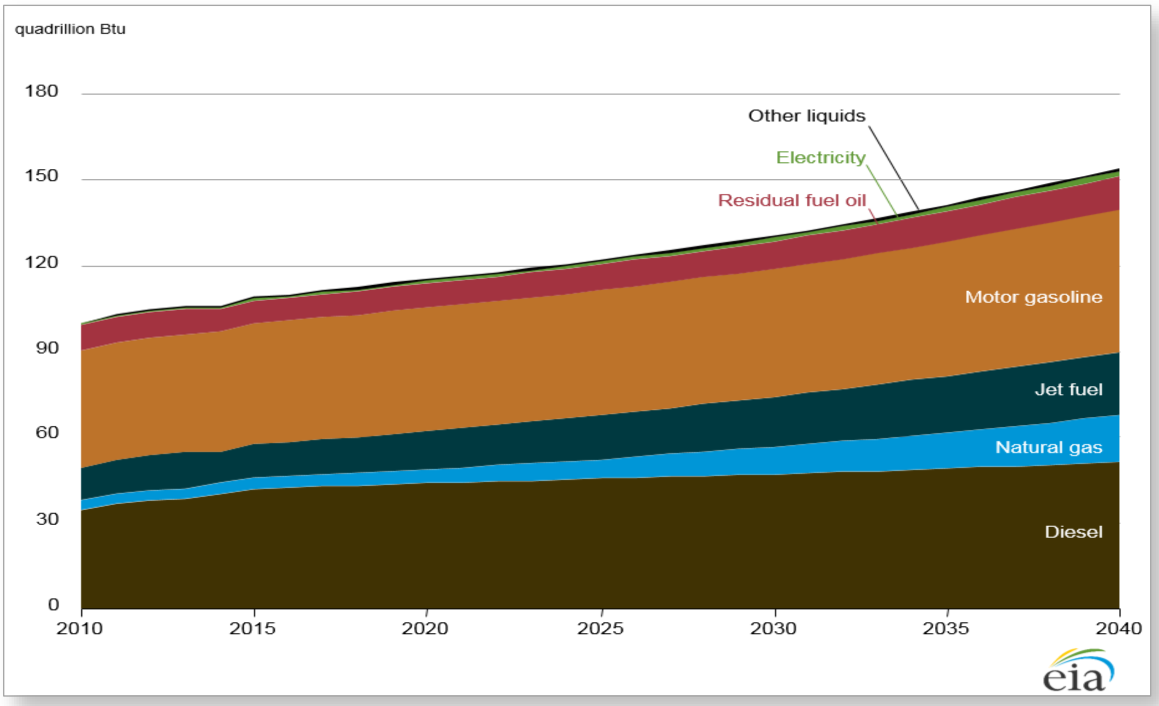

Figure 2-2 > Actual and projected world transportation sector energy consumption by fuel (2010 -2040)

(Source: EIA, 2016a; Figure 8-2)

The transportation sector comprises both passenger and freight modes. The passenger modes include light-duty cars and trucks, buses, 2- and 3-wheel vehicles, airplanes, and passenger trains. The freight modes, which are used in the movement of raw, intermediate, and finished goods to consumers, include trucks (heavy-, medium-, and light-duty), marine vessels (international and domestic), rail, and pipelines.

Passenger or personal mobility-related fuel consumption accounted for 61% of total world transportation energy consumption in 2012. Among the personal mobility modes of transport, light-duty vehicles accounted for 44% of total world transportation energy use, followed by aircraft at 11%. Buses, 2- and 3-wheel vehicles, and rail accounted together for 6% of total world transportation energy use. Freight modes accounted for the other 39% of total world transportation energy consumption. Freight trucks made up by far the largest share (23%) of total transportation energy use followed by marine vessels (12%) and rail and pipelines (a combined 4%).

In 2012, pipelines accounted for 66% of transportation sector natural gas use, light-duty vehicles 28%, and buses 4%. As a result of favorable fuel economics, a strong increase is projected for the natural gas share of total energy use by large trucks according to the IEO2016 Reference case; from

1% in 2012 to 15% in 2040. In addition, 50% of bus energy consumption is projected to be natural gas in 2040, as well as 17% of freight rail, 7% of light-duty vehicles, and 6% of domestic marine vessels.

In 2009, only 3% of transportation fuel worldwide consisted of natural gas and 2.1% of this was used in five countries: Pakistan, Argentina, Iran, Brazil and India (IEA, 2013). By November 2016, there were approximately 23 million natural gas vehicles (NGVs) operating in more than 85 countries worldwide, most of them in Asia-pacific (Figure 2-3).

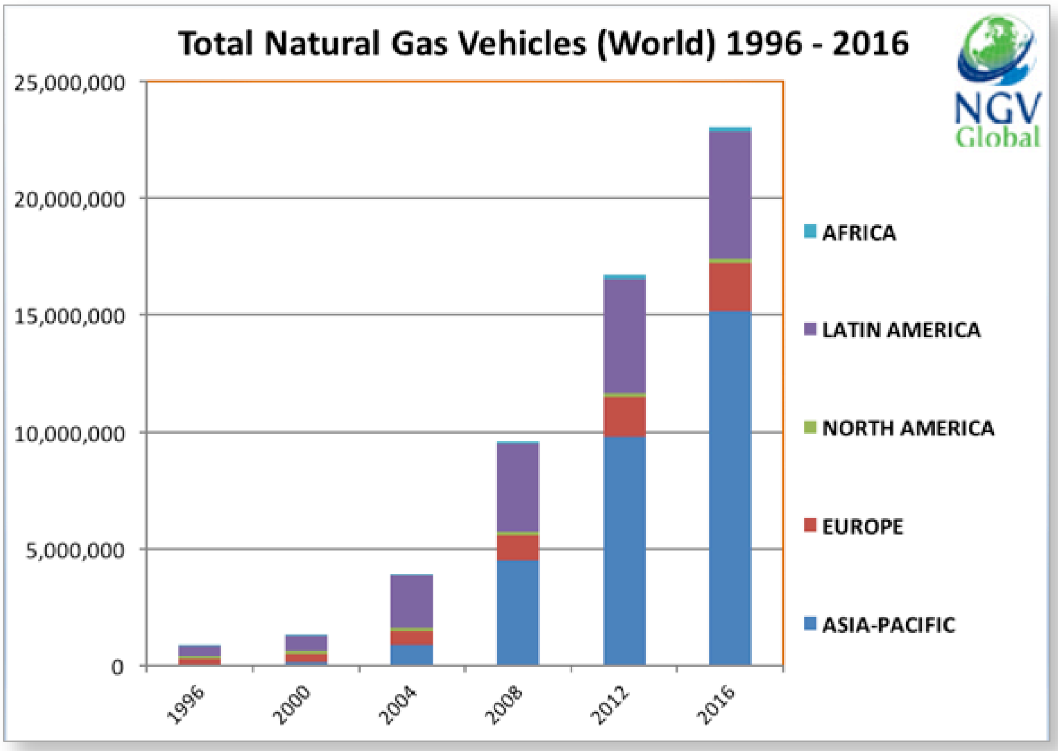

Figure 2-3 > Trend in total natural gas vehicles in different regions of the world

(Source: NGV Global, 2017a)

Despite the general trend of an increase in the number of NGVs, there seems to be a decrease in the rate of the addition of NGVs relative to the previous period. That trend is less pronounced in North America where the number of NGVs is less than 1% of world total NGVs (Figure 2-4).

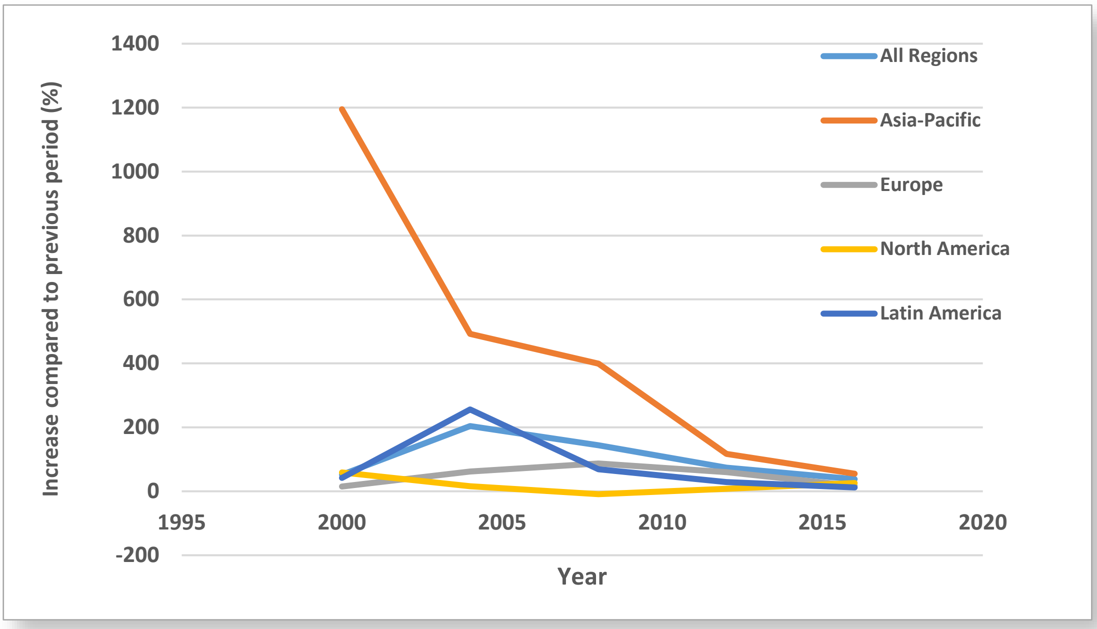

Figure 2-4 > Global and regional change in NGVs compared to previous period (%)

(Source: based on data from NGV Global, 2017a)

As of June 2017, there were over 24 million NGVs in the world with over 29,000 fueling stations (NGV Global, 2017b). Table 2-1 presents the top 10 countries around the globe in number of NGVs, which together comprise over 88% of total NGVs worldwide.

Table 2-1 > Top 10 countries by Natural Gas Vehicle numbers

COUNTRY	NGV Numbers	% all NGVs in world
China	5,000,000	20.6%
Iran	4,000,000	16.5%
India	3,045,268	12.5%
Pakistan	3,000,000	12.3%
Argentina	2,295,000	9.4%
Brazil	1,781,102	7.3%
Italy	883,190	3.6%
Colombia	556,548	2.3%
Thailand	474,486	2.0%
Uzbekistan	450,000	1.9%

(Source: NGV Global, 2017b)

2.3 Global energy related CO_2 emission trends

World energy-related CO_2 emissions, which are defined as emissions related to the combustion of fossil fuels (liquid fuels, natural gas and coal) are expected to rise from 32.2 billion metric tons in 2012 to 35.6 and 43.2 billion metric tons in 2020 and 2040, respectively based on the IEO2016 Reference case. The increase is expected to occur for all fuels with the relative contributions of the individual fuels shifting over time (Figure 2-5).

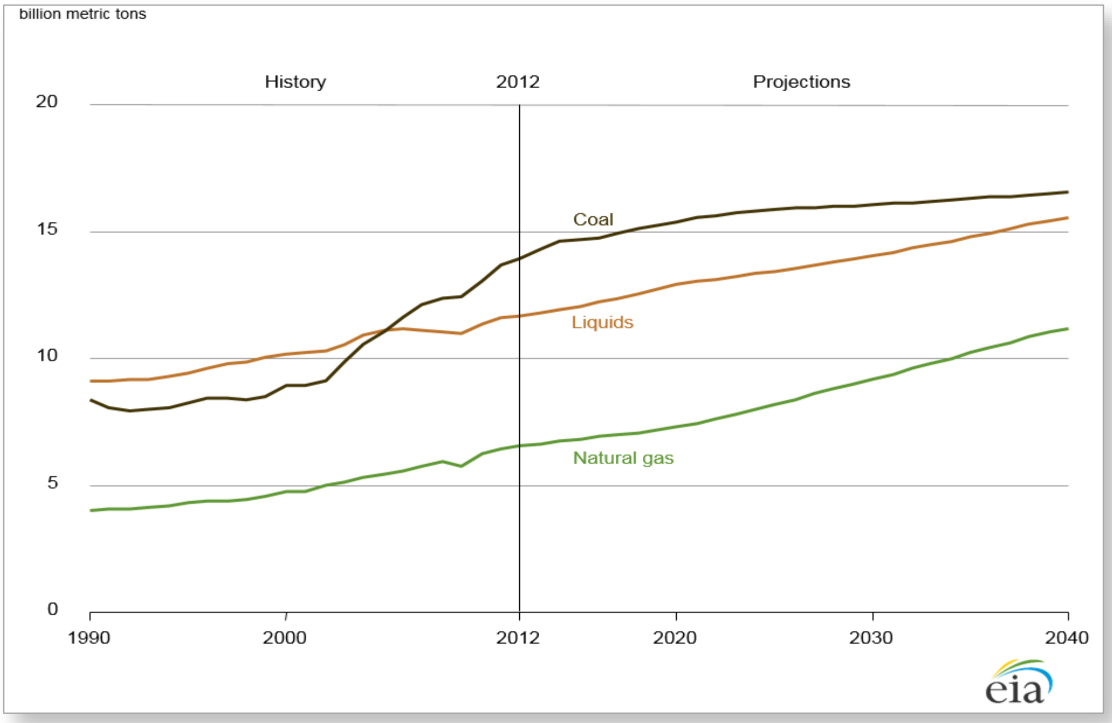

Figure 2-5 > World energy-related CO_2 emissions (billion metric tons) by fuel type (1990-2040)

(Source: EIA, 2016a; Figure 9-3)

In 2012, CO_2 emissions associated with the consumption of liquid fuels fell to 36% of total emissions (compared to 43% in 1990) and are projected to remain at that level through 2040 in the IEO2016 Reference case. The natural gas share of energy related CO_2 emissions was 19% in 1990 and 20% in 2012, and is expected to increase to 26% in 2040. The historical trends and the projection of energy related CO_2 emissions by fossil fuel type for OECD and non-OECD countries are shown in Figure 2-6.

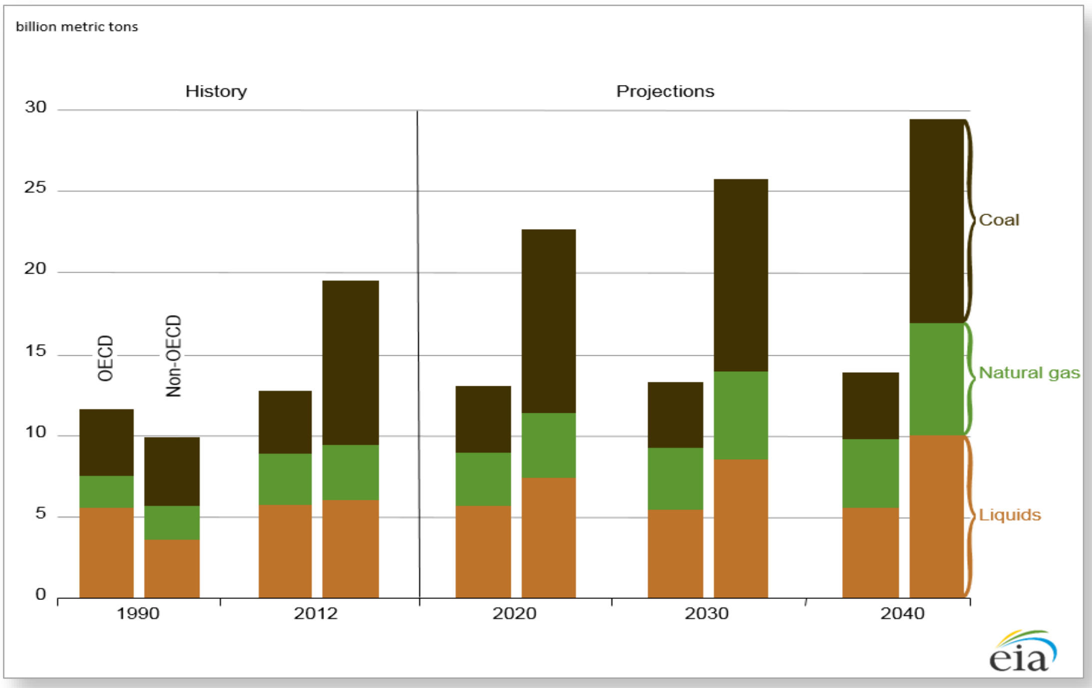

Figure 2-6 > Energy related CO_2 emissions by fuel type for OECD and non-OECD countries for 1990-2040 (Source: EIA, 2016a; Figure 9-4)

With the projected increase in renewable and nuclear energy, the share of fossil fuels consumption is expected to decrease to 78% of the total with changes in the mix of those fossil fuels in the period of 2012 to 2040. The coal share of total energy use is expected to fall from 28% to 22%. Over the same period, liquid fuels share is expected to fall from 33% to 30%, while the natural gas share is forecasted to rise from 23% to 26%. The net result of the reduced share of fossil-fuel in worldwide energy consumption and the shift in the fossil-fuel mix is that projected energy-related CO_2 emissions in 2040 are expected to be 10% lower than they would have been without these changes. Nonetheless, natural gas is the largest contributor to CO_2 emissions growth in both the OECD and non-OECD economies, accounting for 100% and 35%, respectively, of the projected CO_2 emissions increases in the two clusters.

2.4 Global CH_4 emission trends

Global anthropogenic CH_4 emissions by 2020 are estimated to be 9,390 MMT in units of CO_2 equivalent (CO_2e) (EPA, 2012). Most of the emissions are attributable to five sources: agriculture, coal mines, municipal solid waste, oil (petroleum) and natural gas systems, and wastewater (see Figure 2-7).

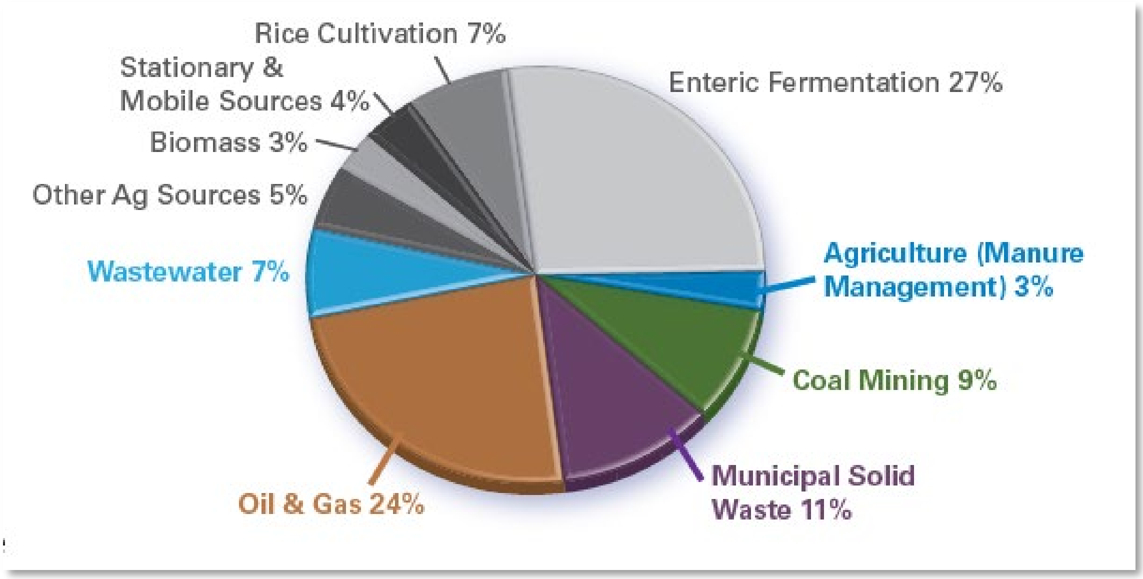

Figure 2-7 > Estimated global anthropogenic methane emissions by sector for 2020

(Source: GMI, 2015)

The IEA indicates (IEA, 2015) that global CH_4 emission estimates vary widely – due to lack of country-specific data and inconsistent measurement and assessment methods for fugitive emissions. Nonetheless, global anthropogenic CH_4 emissions are projected to increase by nearly 9% to 10,220 MMT of CO_2e by 2030 (GMI, 2015). From 2020 to 2030, the relative contributions of the agriculture, coal mining, and wastewater sectors remained relatively constant. Methane emissions increased by nearly 11%, and 17% from petroleum and natural gas and coal mines, respectively, from 2020 to 2030 (Figure 2-8).

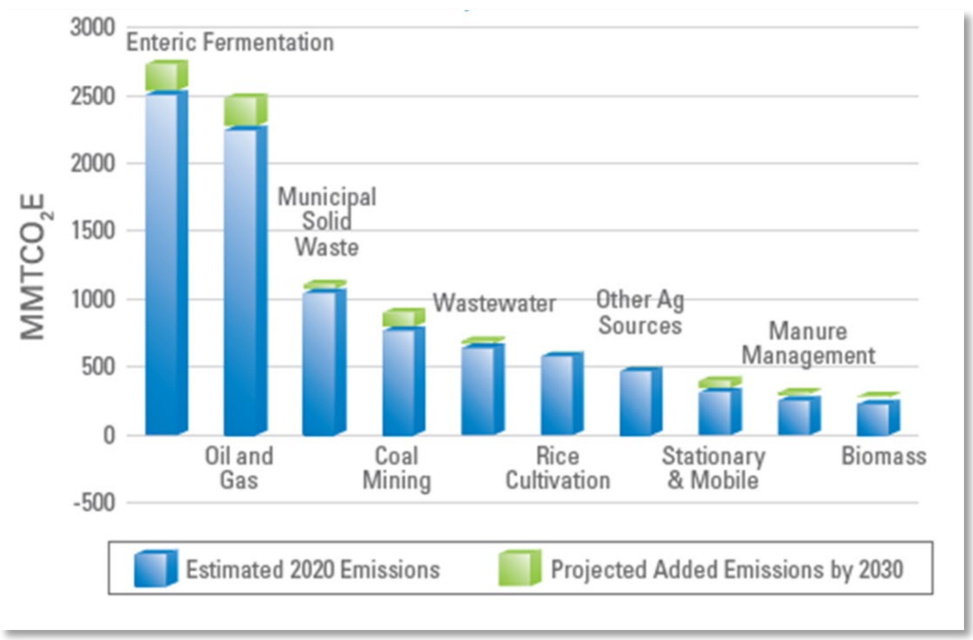

Figure 2-8 >Estimated and projected anthropogenic global methane emissions by source, 2020 and 2030 (Source: GMI, 2015)

2.5 Development of Israel's Natural Gas Sector

Israel, like many countries around the world, is encouraging a transition to natural gas as the primary energy source, with the many advantages it offers the consumer, the economy and the environment: reduced cost of electricity generation and of industrial products, less air pollution and GHG emissions, greater market competition and promotion of exports, and strengthening of Israel's economy, etc.

In recent years the Israeli economy has undergone significant changes in terms of the mix of the fuels consumed. Within the space of a few years, natural gas has become the primary, preferred fuel for electricity generation as well as for major industries.

Since the introduction of natural gas to the Israeli economy, in 2004, and until 2010, the amount of natural gas consumed has increased consistently from year to year. Due to political upheaval in Egypt during 2011, the supply of natural gas was curtailed until the final cessation of the flow of natural gas from Egypt in 2012. This has changed in 2013 when natural gas from the Israel's offshore field known as Tamar has been brought on line and domestic natural gas has risen to 7 billion cubic meters (BCM) in 2013. The growth trend has continued in subsequent years and in 2017 it amounted to 10.35 BCM, which represents a 7% increase as compared to 2016 (Figure 2-9).

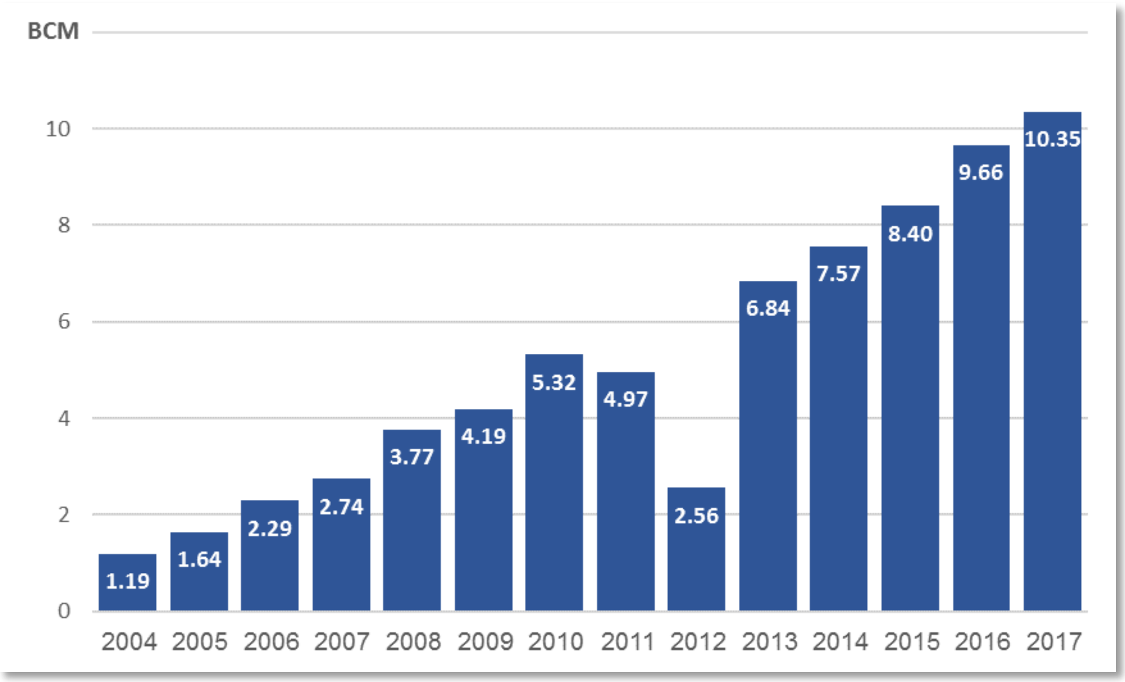

Figure 2-9 > Natural Gas Consumption in Israel for the period 2004-2017 (BCM)

(Adopted from: NGA, 2018)

The electricity sector is the main source of demand for natural gas in the Israeli economy. Israel's largest electricity producer is the Israel Electric Corporation, which consumed more than 30 BCM of natural gas from 2004 until the end of 2013, representing 87% of the amount of natural gas consumed up to that period in Israel. In 2010, Israel consumed 5.3 BCM of natural gas, of which 90% went to electricity generation, and accounted for 40% of electricity generation in Israel. In 2013, independent power providers (IPPs) entered the electricity market in Israel and by 2017 the rate of natural gas use for electricity generation in Israel has risen to 64%, accounting for 83% of the total demand for natural gas in the Israeli economy (8.54 BCM).

The demand for natural gas in the industrial sector is also on the rise and in recent years there is a massive conversion from the use of refined oil in industry to natural gas. The demand for natural gas in the industrial sector in 2017 amounted to 1.81 BCM, which represents a 11% increase as compared to 2016. Future demand for natural gas is expected to grow in the transportation and petrochemical sectors as well.

Accelerated growth in the use of natural gas in Israel is expected to continue in the coming years, increasing from 5.3 BCM in 2010, to 12.5 BCM in 2020, and to 18 BCM by 2030, of which 85% is expected to be used for electricity generation and industry. The forecast for natural gas demand from 2011 to 2040 is a total of 494 BCM, of which 39 BCM could be associated with the transportation sector and methanol (Figure 2-10).

The Natural Gas Authority at the Ministry of Energy has based its demand forecast largely on the following assumptions:

- a continued rise in electricity consumption at a multi-annual average of 3.1%;
- minimal use of heavy fuel oil;
- continued reliance on coal power generation at the same extent as currently;
- gradual adoption of renewable energy sources to reach a level of 10% in 2030;
- transition to natural gas as the primary fuel for electricity generation, which started in 2014, and reaching 60% in 2027 and 68% in 2040.

Additionally, the projections for natural gas consumption also assume a gradual conversion of the transportation sector to natural gas-based fuels, and domestic production of methanol and ammonia in the petrochemical industry, amounting to 0.7 BCM per year.

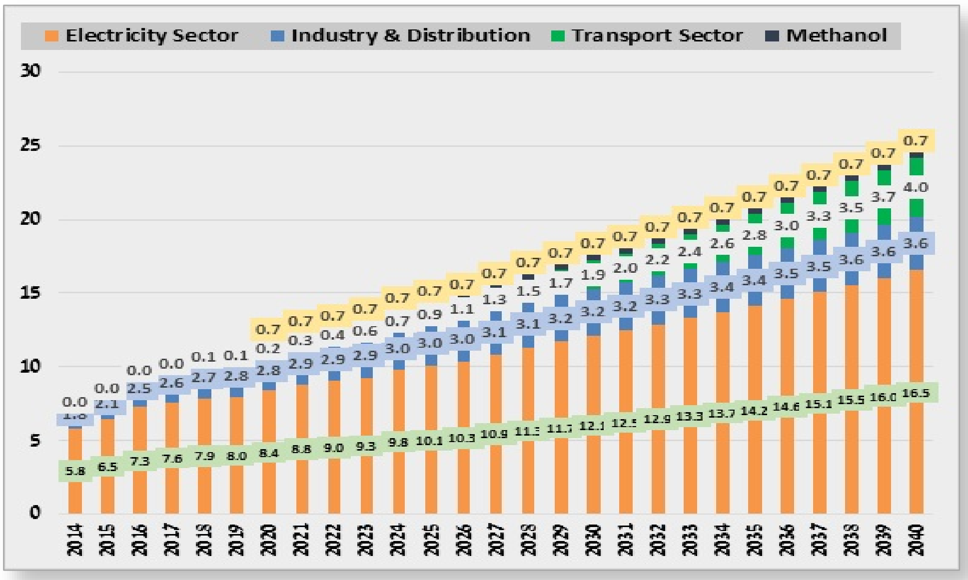

Figure 2-10 > Projected trends of natural gas consumption in Israel for the years 2014 - 2040 (Source: MOE, 2017)

The ministry of energy has released in October 2018 a Draft strategic plan for “clean energy” by 2030. The plan is open now for public review and comment (MOE, 2018) . The plan consists of eight scenarios that – on average – are consistent with the data provided in Figure 2-10 below, including the incremental use of natural gas for the transport sector in Israel[8].

Government Resolution 5327 (January 2013) seeks to promote the transition of the transportation sector in Israel between 2013 to 2025 to alternative sources of energy, rather than oil, and to reduce the share of oil in Israel's transportation sector by about 30% by 2020 and by 60% in 2025.

Figure 2-11 below presents the expected penetration rates for alternative fuels in the Israeli transportation sector, as introduced by the Fuel Choices and Smart Mobility Initiative. The preliminary analysis shown has focused on natural gas-based fuels, renewable biofuels and electrical mobility.

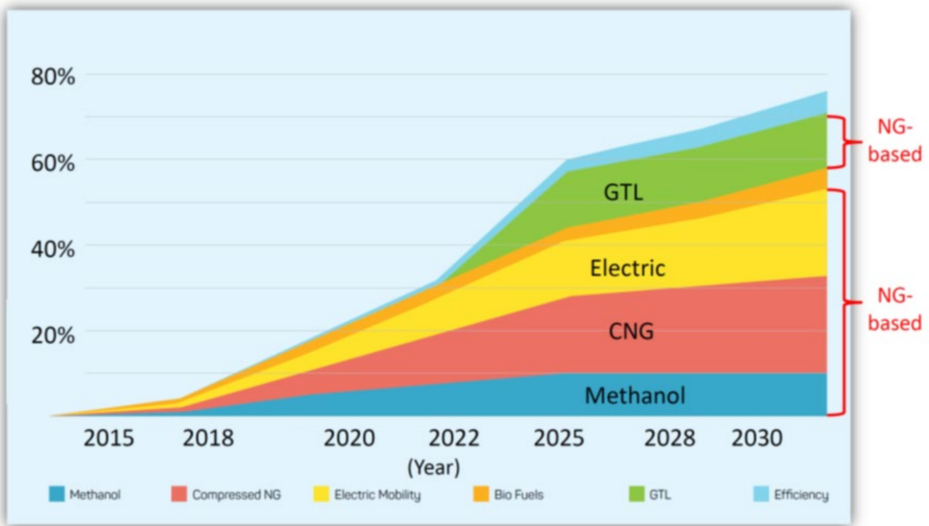

Figure 2-11 > Expected penetration rate for alternative fuels in Israel

(Source: FCI, 2016)

[8] https://www.gov.il/BlobFolder/rfp/ng_160718/he/ng_presentation.pdf

3 SCIENTIFIC BACKGROUND

Methane is the second most abundant anthropogenic GHG after CO_2, accounting for about 20 percent of global emissions. Methane is more potent than CO_2 in trapping heat in the atmosphere. Over the last two centuries, CH_4 concentrations in the atmosphere have more than doubled, largely due to human-related activities. Because CH_4 is a powerful GHG, and is short-lived compared to CO_2, achieving significant reductions would have a rapid and significant effect on atmospheric warming potential.

Expanded discussions of climate policy are increasingly focusing on short-lived climate pollutants (SLCP) including CH_4 emissions from oil & gas industry operations (CCAC, 2015) and as such it plays a role in emerging global and national climate strategies. With the increased use of natural gas globally, including in Israel, it is important to assess the loss, leakage and atmospheric emission rates of its prime constituent, CH_4, in order to assess net lifecycle benefits of switching to this lower carbon fuel in all sectors of the economy. Understanding CH_4 emissions from the entire fuel supply chain is critical to promulgating robust policies and mitigation strategies.

3.1 Natural gas fuel cycles losses

Understanding the leaks and losses of natural gas in the fuel supply pathways is essential to evaluating the GHG impact of the increased use of natural gas-based fuels. The focus of the following analysis is on the well-to-tank (WTT) segments of the fuel cycle, which is also referred to as the well-to wheel (WTW) fuel pathway. The WTT portrays the resource production emissions, including T&D (transmission and distribution) pathways. It extends from the point of fuel feedstock extraction through initial processing and transmission all the way to natural gas conversion to vehicle fuel and the point where the fuel is transferred to a vehicle (Figure 3-1). The GHG intensity of natural gas-based fuels comprises the CO_2 and CH_4 emissions from operations performed in bringing these fuels to the market relative to the amount of fuel produced.

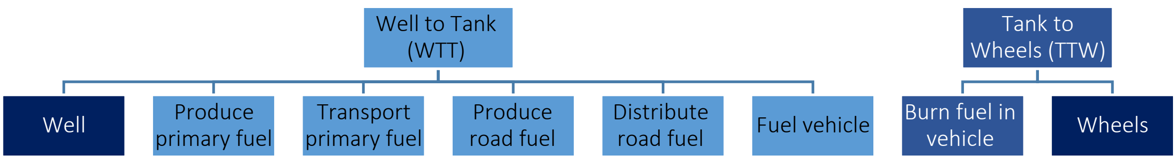

Figure 3-1 > Schematics representation of the WTW fuel pathways (Adopted from: EU, 2016)

The stages of importance for the WTT analysis are:

1. **Production and conditioning** – includes the operations required to extract, capture or process the primary energy source, i.e. natural gas. In most cases, the extracted natural gas is gathered and processed prior to it being transmitted to end-users.
2. **Transformation (or conversion)** – applies to operations that include either compression or an industrial process to produce the natural-gas based transportation fuel (e.g. methanol or GTL plants).
3. **Transportation/transmission** – is relevant to energy carriers or blending compounds that are transported over long distances under high pressure.
4. **Conditioning and distribution** – relates to the final stages required to distribute the finished fuels from the point of production (or import) to the individual refueling points (e.g. road transport) and available to the vehicle tank (e.g. compression in the case of CNG).

The focus of this study is on accounting for the non-combustion emissions of CO_2 and CH_4 associated with natural gas production, its conversion to transportation fuels, and the transmission and distribution of the finished fuels to the respective users, be it power producers or vehicle tanks.

3.1.1 Relevant concepts for the natural gas fuel cycle

Processes in each of the WTT stages discussed above are characterized by some shrinkage or loss of natural gas along with CO_2 and CH_4 emissions to the atmosphere. The 'loss' is the difference between the amounts of natural gas produced (withdrawn) at the wellhead and the dry natural gas that is available for supplying to customers. For this study the relevant emissions include:

1. Wellhead operation;
2. Amount of gas being vented and flared as part of routine operations or during operational emergencies;
3. Emissions of CO_2 and CH_4 emissions from condensate and plant liquids extraction processes;
4. Gas shrinkage during its transportation including GHG emissions from compressors;
5. Losses and GHG emissions associated with conversion of natural gas to transportation fuels.

Natural gas is lost at many points throughout the natural gas supply chain; however, not all losses are leaks or result in emissions to the atmosphere (Littlefield et al., 2016). Consumptive losses result from the use of natural gas for heat or energy generation by processing equipment or compressors. Non-consumptive losses include unintentional, intentional, and fugitive emissions. Unintentional emissions are from sources that are frequently augmented with vapor recovery equipment that send captured gas to flares (flares combust CH_4 and other hydrocarbons in the natural gas to CO_2, reducing its climate impact, but a small amount of un-combusted CH_4 passes through flares).

Intentional venting and emissions may arise from one-time or periodic events, such as gas well completions or venting for liquids unloading, for which recovery equipment and flaring are increasingly being used. Natural gas driven pneumatic devices are also sources of intentional emissions since they must vent gas as part of normal operation[9]. Fugitive emissions are released through valve stems, flanges, and other connections or storage tanks and are the only type of loss that can be accurately described as “leaks”. Figure 3-2 shows the natural gas pathways that result in CH_4 emissions.

There are other processes in the natural gas supply chain that emit GHGs but are not considered natural gas losses or WTT emissions. These may include, for example, construction and installation of wells and pipelines; treatment of produced water before it is discharged; and production of electricity on-site. All these activities may combust fuels and emit GHGs but are not necessarily based on using produced natural gas and thus are not accounted in this study as natural gas losses and atmospheric emissions.

[9] For the offshore platforms in Israel, pneumatic controllers are actuated by ‘instrument air’ so no natural gas is emitted or lost.

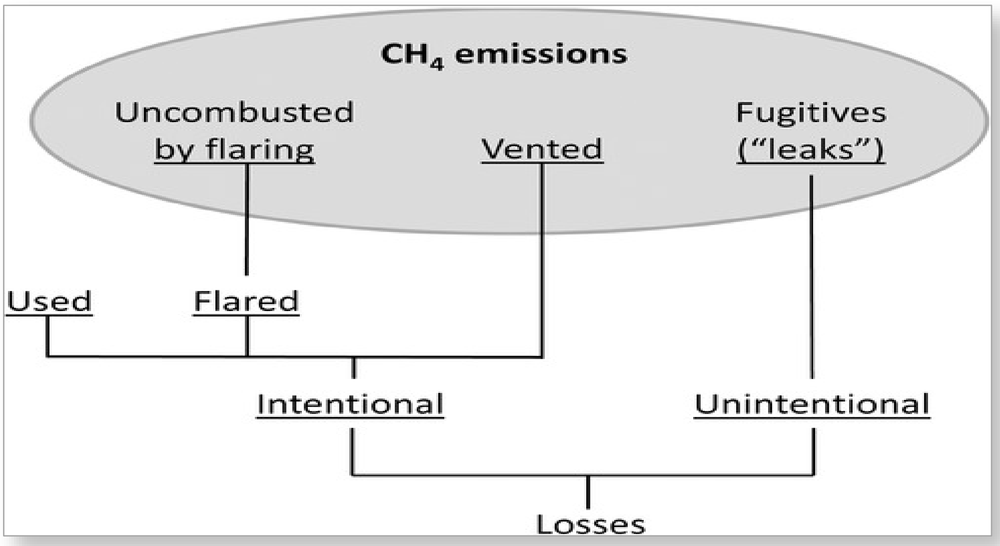

Figure 3-2 > Hierarchy of CH_4 pathways in the natural gas supply chain
(Source: Littlefield et al., 2016)

Natural Gas Flow Balance

Gross gas withdrawals: *refers to the full well stream volume from both gas wells and associated gas oil wells. It includes natural gas plant liquids and nonhydrocarbon gases after oil, lease condensate, and water have been removed. It includes production quantities that are delivered as royalty payments and quantities of 'fuel gas' used to run the operations.*

Marketed production: *refers to gross withdrawals less natural gas used for re-pressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations and includes all quantities of gas used in field and processing plant operations.*

Dry natural gas production: *refers to the marketed production reduced by processing or extraction losses that comprise of:*

- *Nonhydrocarbon gases (e.g., water vapor, CO_2, helium, hydrogen sulfide, and nitrogen) removed from the gas stream; and*
- *Natural gas converted to liquid form, such as lease condensate and plant liquids. Volumes of dry gas withdrawn from gas storage reservoirs are not considered part of production.*

Example: U.S. Gas Flow Balance

Figure 3-3 provides the U.S. natural gas flow for calendar year 2015 depicting its national balance, which provides an example of the detailed data needed at the national level in order to fully characterize emissions and losses from domestic natural gas flow. The diagram presents a schematic of the natural gas shrinkage from the gross withdrawals to marketing and dry gas production all the way to consumption by the various sectors of the economy.

The data in this example indicate that out of the 32.96 Tcf of gross withdrawals, 28.81 Tcf (87%) end up as marketed production. The 13% shrinkage is due to the use of about 10.5% for fuel gas and re-pressuring the formations, a loss of about 1.25% is due to water and other non-hydrocarbons removal, and about 1.25% are vented and flared. Out of the 28.81 Tcf of marketed natural gas about 27.09 Tcf (94%) are the actual dry natural gas production for the year 2015. The remainder 6% comprises the extracted natural gas plant liquids (NGPL), including constituents such as ethane, propane, butane, and pentanes.

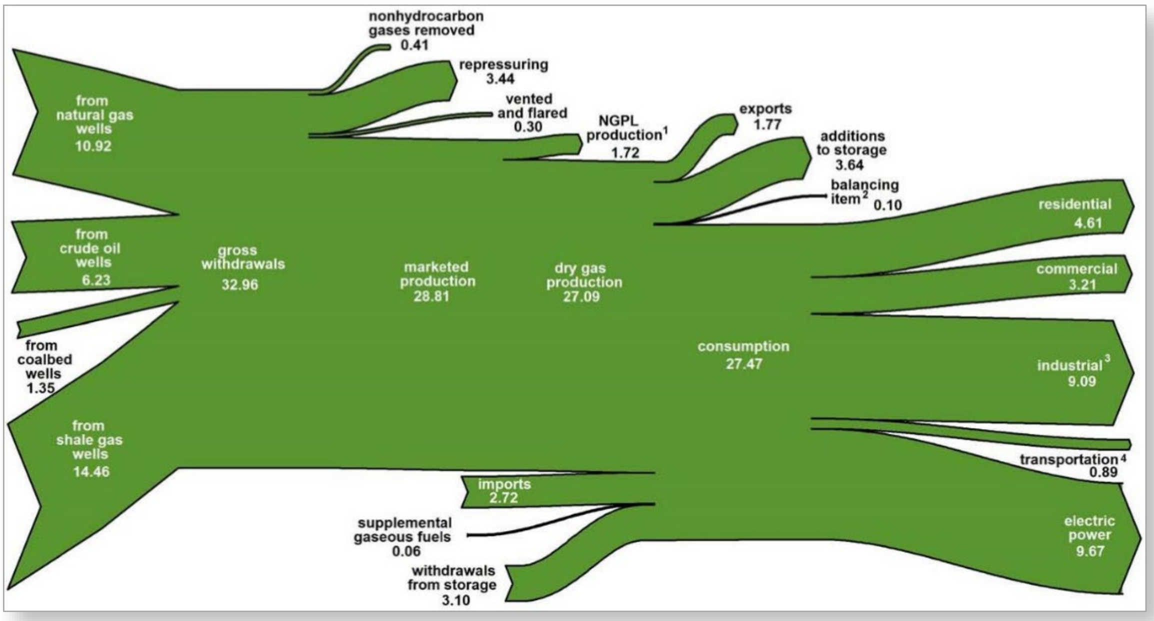

Figure 3-3 > U.S. Natural Gas Flow 2015 (Tcf)

(Source: EIA, 2016b)

The shrinkage and loss percentage provided above are unique for calendar year 2015 in the U.S. and are discussed here merely as an example and do not intend to provide a precise determination of what such losses may be in other countries. The actual natural gas flow and its balance varies from country to country based on whether it is a producer, importer and/or exporter of natural gas and on the type of formations and the quality and quantity of the natural gas produced from the exploited reservoirs. Natural gas withdrawal in the U.S. is comprised of four categories of formations: natural gas wells; coal-bed methane wells; shale gas wells; and associated gas from crude oil wells. Each of these categories of producing wells, and their associated infrastructure, have different emissions and loss profiles. Such details are missing in Israel, where multiple data gaps do not allow completing an accurate assessment of natural gas flow, losses and emissions.

3.2 GHG Emissions from Upstream Natural Gas Operations

Figure 3-4 presents a schematic of the natural gas infrastructure system for the supply chain from the wellhead to the consumer (EPA, 2014a). The complexity of natural gas operations varies in different parts of the world but the main broad segments shown in Figure 3-4 are common to all. Natural gas systems are often divided into three broad segments which serve specific functions (even if some functions are not present in certain regions) for the purpose of estimating direct GHG emissions from operations.

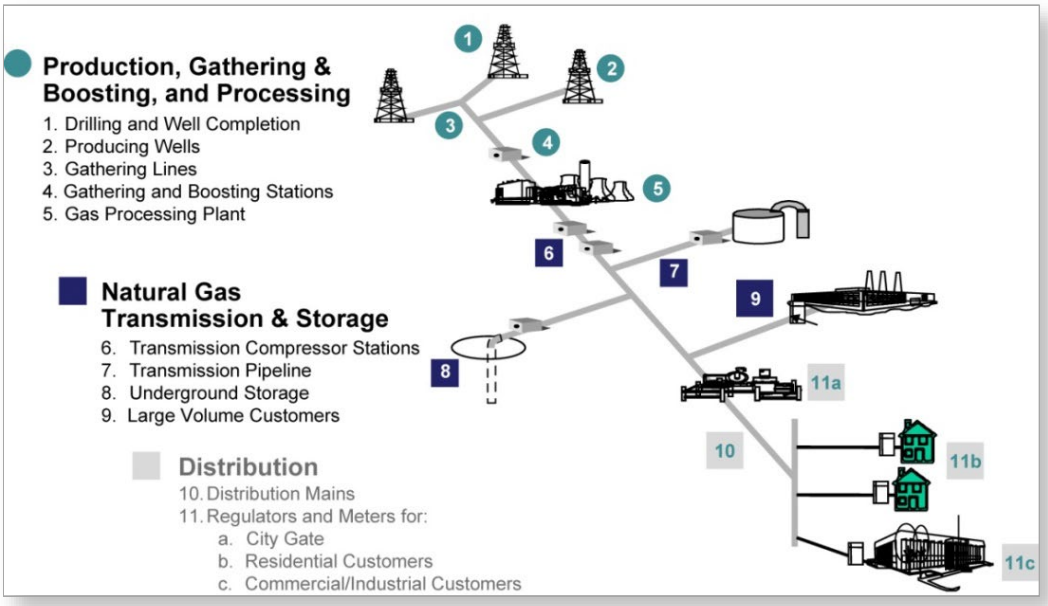

Figure 3-4 > Stages of the natural gas supply chain and main emission sources (Source: EPA, 2014a)

The segments of the natural gas supply chain and the major operations associated with each of them include:

1. **Drilling, production, gathering & boosting, and processing** – includes on-shore and off-shore production of natural gas from wellheads or fields, encompassing the emissions associated with drilling, well completions and workovers. The produced natural gas is delivered through gathering and boosting (compression) operations to processing plants to extract natural gas liquids and remove impurities from the natural gas stream, as well as compress the natural gas to transmission line pressure.
2. **Transmission and storage** – entails transmission of natural gas through long-distance pipelines from the producing area to market areas via large-diameter and high-pressure pipes and compressors. Transmission can also include (temporary) storage of natural gas for future use, direct high- pressure delivery to large customers such as power generators along with infrastructure for liquefied natural gas (LNG) storage.
3. **Distribution** – consists of metering and regulators for distribution of natural gas to residential, industrial and commercial customers, via smaller diameter low-pressure pipelines, which may include natural gas compression and refueling stations.

The GHG emitted from the supply chain sources are primarily CO_2 and CH_4, which are emitted during the combustion, flaring, venting or leakage of gases associated with natural gas operations:

- **Emissions of CO_2** are contributed primarily by onshore and offshore drilling, production & gathering; natural gas transmission; and natural gas processing operations due to combustion and flaring.
- **Emissions of CH_4** are associated primarily with fugitive emissions that result from equipment leaks and process venting, including in exploration and natural gas transmission and distribution.

It is important to note that emissions from venting and flaring are mostly due to the engineering design of petroleum and natural gas systems infrastructure and are designed to allow for controlling process cycles, or for emergency pressure relief or equipment malfunction.

In order to address the myriad of issues associated with quantifying CO_2 and CH_4 emissions from the petroleum and natural gas sector we provide different perspectives on the current state of knowledge and emerging information:

Section 3.2.1 provides an example of typical GHG emissions data that are characteristics of the U.S. industry which is based on data reported under the U.S. mandatory GHG Reporting Program (GHGRP).

Section 3.2.2 describes the current Intergovernmental Panel on Climate Change (IPCC) endorsed methodology which relies on using generic emission factors when more detailed data are not available. These generic factors are linked to overall petroleum and natural gas production, processing and distribution amounts and have high uncertainty bounds associated with them.

Section 3.2.3 provides an overview of recent studies and assessments that aim to improve understanding of CH_4 emissions from industry segments and includes recommendations for improvement of the knowledge base.

3.2.1 Example: Petroleum and Natural Gas Systems data from the U.S. GHGRP

Figure 3-5 presents an example of the contribution of the U.S. natural gas segments to CO_2 and CH_4 emissions. The data summarizes GHG emissions reported for calendar year 2015 by over 2,400 petroleum and natural gas facilities that have reporting obligations under the U.S. EPA mandatory GHG reporting program (GHGRP). Only facilities exceeding the 25,000 tonnes of the CO_2e emissions threshold are mandated to report (EPA, 2010). Data for the petroleum and natural gas sector is reported to the EPA annually since 2011 and the coverage of the segments included is expanding.

The data is publicly disclosed after internal data verification by EPA experts (EPA, 2017a). See text box below for a summary of the verification process[10].

The U.S. Verification Process for GHGRP Data

Pre-submittal *checks highlight potential errors before the report is certified and submitted so that the reporter has the option to address the errors before submitting the report. Pre-submittal checks typically highlight missing data fields and values that fall outside of an expected range.*

Post-submittal *checks are applied after a report is certified and submitted to EPA, where report complexity checks were not included in the pre-submission checks. These types of checks include:*

- *Range checks are used to determine if a respondent's data are within the expected range.*

[10] https://www.epa.gov/sites/production/files/2017-12/documents/ghgrp_verification_factsheet.pdf

- *Statistical checks are used to evaluate all the data from all similar facilities and identify data that might be outliers.*

- *Algorithm checks consider the relationships between different pieces of entered information and compare them to an expected value.*

- *Outside data checks are used to compare facility level details to other datasets not in the GHGRP.*

- *Year-to-year checks are used to determine if variations occur in the same reported data element between reporting years.*

***Record retention** is required for at least 3 years. These records include a monitoring plan describing where and when samples were collected, methods used to analyze samples, and the procedures used for quality assurance and quality control. These records must be readily available for inspection and review.*

In this example, the total emissions from all segments combined amounted to 231 MMT of CO_2e with CO_2 accounting for 161 MMT CO_2e, or 70% of the reported emissions, and CH_4 for 70 MMT CO_2e, or 30% of reported emissions. This comparison is provided in units of CO_2e using a 25 times multiplier for the global warming potential (GWP) of CH_4 compared to CO_2.

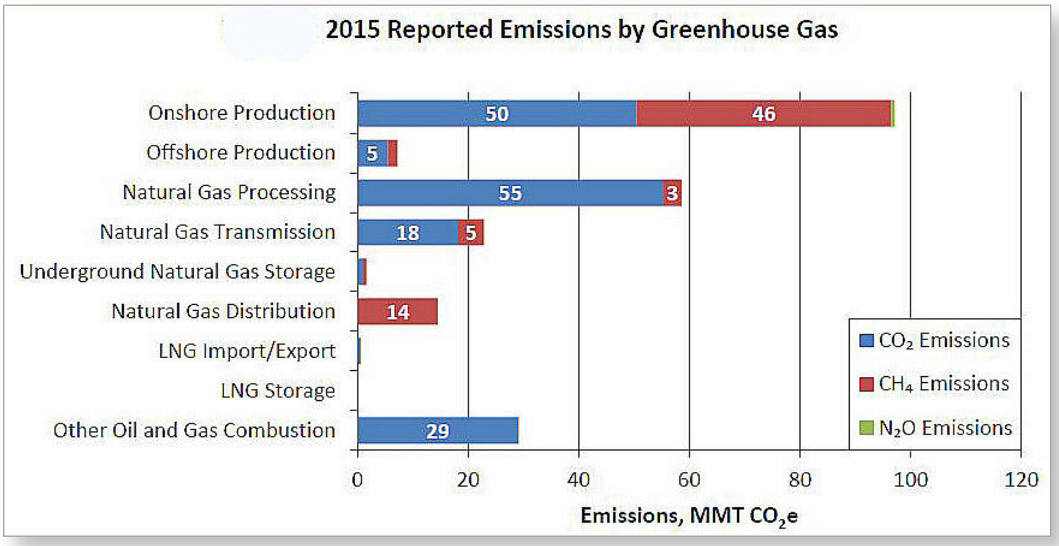

Figure 3-5 > Petroleum and Natural Gas Systems 2015 Reported Emissions by GHG

(Source: EPA, 2016)

Each segment of Petroleum and Natural Gas Systems has unique emission sources. Emissions may result from the combustion of fossil fuels or from process sources as discussed above. Most CO_2 emissions are from combustion emissions from natural gas processing, onshore production, other oil and gas combustion, and natural gas transmission as shown in Figure 3-5. The figure also shows that emissions from offshore production emissions are much lower than those from onshore production. Onshore and offshore production encompass both petroleum and natural gas production.

Non-combustion CH_4 emissions are due to onshore production (20% of the reported emissions), natural gas processing (1.3% of the reported emissions), natural gas transmission and distribution (2% and 6% of the reported emissions, respectively). Process emissions may be further classified as vented emissions, equipment leaks, and flaring. Vented emissions in onshore production are primarily CH_4 while vented emissions in natural gas processing are primarily CO_2. Equipment leaks emissions are primarily CH_4, while flaring emissions are primarily CO_2.

EPA estimates that although the GHGRP covers only about half of the number of wells nationwide, it accounts for 80% of the emissions since the mandatory reporting covers all the larger facilities. Therefore, the information collected under the GHGRP provide an excellent source of data for developing new national emission factors to improve the U.S. national GHG Inventory that is submitted annually by the U.S. - along with other signatories – to the United Nations (UNFCCC, 2017). A study conducted by the Joint Institute for Strategic Energy Analysis (JISEA) is recommending multiple improvements to the U.S. GHG Inventory for improved characterization of CH_4 emissions from the natural gas supply chain (Heath et al., 2015).

Potential improvements may include:

- Update emission factors focusing on high priority emissions sources categories,
- Collect new measurements data to ensure robust sample size, strong sampling design to capture source variability and minimization of self-selection bias,
- Explore how to characterize emission variability while using emission factors metrics.

These recommendations for improvements are applicable to other national emission inventories which currently rely mainly on generic emission factors.

3.2.2 Natural gas systems emissions in national emission inventories

Energy systems GHG emissions, in most economies, are largely driven by the combustion of fossil fuels. During combustion the carbon and hydrogen (H_2) of the fossil fuels are converted mainly into CO_2 and water, releasing the chemical energy in the fuel as heat. The energy sector is usually the most important contributing sector to GHG emission inventories, typically accounting for over 90% of the CO_2 emissions and 75% of the total GHG emissions in developed countries.

The non-combustion energy sector emissions inventory is constructed around the following main source categories (IPCC, 2006a):

- Exploration and exploitation of primary energy sources,
- Conversion of primary energy sources into more useable energy forms in refineries and power plants,
- Transmission and distribution of fuels
- Use of fuels in stationary and mobile applications.

A lower percentage of the energy sector emissions arise from non-combustion processes including fugitive emissions from extraction, transformation and transportation of primary energy carriers. The contributions of CH_4 emissions from non-combustion processes to the national total depend on regional circumstances and are more significant for countries that produce or transport significant quantities of natural gas.

The sources of fugitive emissions from petroleum and gas systems include, but are not limited to, equipment leaks, evaporation and flashing losses, venting, flaring, incineration and accidental releases (e.g., pipeline dig-ins, well blow-outs and spills). Fugitive emissions are a direct source of GHG due to the release of CH_4 – the primary constituent of natural gas - and formation CO_2 (i.e., CO_2 present in the produced petroleum and natural gas when it leaves the reservoir). While some of these emission sources are engineered or intentional (e.g., tank seals, process vents and flare systems), the quantity and composition of these emissions are generally subject to significant uncertainty. This is due, in part, to the wide range of flows and variations in composition that may occur. Even though some of these losses or flows are tracked as part of routine production accounting procedures, there are often inconsistencies in the activities that get accounted for and whether they are based on engineering estimates or measurements.

Due to the diversity of the petroleum and natural gas industry with its large number and variety of potential emission sources, the IPCC has devised a tiered approach for estimating emissions in national inventories (IPCC, 2006a) to maximize the use of available data. A 'Tier 1' emissions estimate comprises the application of appropriate default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a country's petroleum and natural gas industry. The use of simple production-based emission factors introduces large uncertainty to the resultant emissions, though in many instances it may be the only data available to develop a national inventory. Moving to higher tiers ('Tier 2' and 'Tier 3') improves the accuracy of the inventory and reduces uncertainty, but the complexity and resources required for conducting inventories also increases for higher tiers.

IPCC Tiered Approach

Tier 1 *employs the default emission factors and other generic parameters provided by the IPCC.*

Tier 2 *generally uses the same methodological approach as Tier 1 but applies emission factors and other parameters which are specific to the country. More highly stratified activity data may be needed in Tier 2 to correspond with country-specific emission factors and parameters for specific regions.*

Tier 3 *consists of higher-order more detailed methods that are based on engineering emission models and can utilize more complex approaches. However, it should be compatible with lower tiers.*

Table 3-1 provides a listing of the petroleum and natural gas segments recommended by the IPCC for inclusion in national inventories of developed countries along with applicable generic emission factors to be used for estimating Tier 1 CH_4 emissions. Detailed reporting formats and tables are also provided separately by the IPCC (IPCC, 2006b).

The emission factors in Table 3-1 are related to throughput, because production, imports and exports are the only national petroleum and natural gas statistics that are consistently available in many countries. Despite a reasonably broad relationship between the level of production and the extent of infrastructure, such a relationship does not hold for each individual facility due to variability of design and operating practices.

Clearly not all segments will necessarily apply to all countries. For example, countries that only import natural gas, but do not produce any, will probably only have to account for emissions associated with gas transmission and distribution. Countries, such as Israel, that produce and distribute their domestic natural gas may use its country specific data on gas production, raw feed gas to processing plants, amount of marketable gas and condensate, with the respective emission factors from Table 3-1, to estimate its Tier 1 CH_4 emissions.

The choice of using the emission factors for sweet gas or sour gas plants for natural gas processing depends on the CO_2 and H_2S content of the produced gas[11].

For current production in Israel, the gas produced from the Tamar and Mary B formations is sweet gas.

Table 3-1 > Emission Factors (IPCC, Tier 1) for CH_4 Emissions from Oil & Natural Gas Operations

Category	Subcategory	Emission Source	IPCC Code	Emission Factor	Uncertainty (% of Value)	Units of Measure
Well drilling	All	Flaring & Venting	1.B.2.a.ii or 1.B.2.b.ii	3.3.E-05	± 100%	Gg per MCM of gas production
Well testing	All	Flaring & Venting	1.B.2.a.ii or 1.B.2.b.ii	5.1E-05	± 50%	Gg per MCM of gas production
Well Servicing	All	Flaring & Venting	1.B.2.a.ii or 1.B.2.b.ii	1.1E-04	± 50%	Gg per MCM of gas production
Gas Production	All	Fugitives	1.B.2.b.iii.2	3.8E-04 to 2.3E-03	±100%	Gg per MCM gas production
Gas Production	All	Flaring	1.B.2.b.ii	7.60E-07	±25%	Gg per MCM of gas production
Gas Processing	Sweet Gas Plants	Fugitives	1.B.2.b.iii.3	4.8E-04 to 10.3E-04	± 100%	Gg per MCM of raw gas feed
Gas Processing	Sweet Gas Plants	Flaring	1.B.2.b.ii	1.2E-06	± 25%	Gg per MCM of raw gas feed

[11] Sweet gas is defined as gas that contains low amounts of H_2S and CO_2, whereas standard specifications for sour gas is gas that contains over 3% of CO_2 or 4PPM of H_2S or both.

Category	Subcategory	Emission Source	IPCC Code	Emission Factor	Uncertainty (% of Value)	Units of Measure
Gas Processing	Sour Gas Plant	Fugitives	1.B.2.b.iii.3	9.7E-05	± 100%	Gg per MCM of raw gas feed
Gas Processing	Sour Gas Plant	Flaring	1.B.2.b.ii	2.4E-06	± 25%	Gg per MCM of raw gas feed
Gas Processing	Deep Cut Extraction Plant	Fugitives	1.B.2.b.iii.3	1.1E-05	± 100%	Gg per MCM of raw gas feed
Gas Processing	Deep Cut Extraction Plant	Flaring	1.B.2.b.ii	7.2E-08	± 25%	Gg per MCM of raw gas feed
Gas Processing	Default Weighted Total	Fugitives	1.B.2.b.iii.3	1.5E-04 to 10.3E-04	± 100%	Gg per MCM of gas production
Gas Processing	Default Weighted Total	Flaring	1.B.2.b.ii	2.0E-06	± 25%	Gg per MCM of gas production
Gas Transmission & Storage	Transmission	Fugitives	1.B.2.b.iii.4	6.6E-05 to 4.8E-04	± 100%	Gg per MCM of marketable
Gas Transmission & Storage	Transmission	Venting	1.B.2.b.i	4.4E-05 to 3.2E-04	± 75%	Gg per MCM of marketable gas
Gas Transmission & Storage	Storage	All	1.B.2.b.iii.4	2.5E-05	-20 to +500%	Gg per MCM of marketable gas
Gas Distribution	All	All	1.B.2.b.iii.5	1.1E-03	-20 to +500%	Gg per MCM of utility intake
Natural Gas Liquids Transport	Condensate	All	1.B.2.b.iii.5	1.1E-04	± 100%	Gg per MCM of condensate and Pentanes plus

(Extracted from: IPCC, 2006b; Table 4.2.4 of Tier 1 Fugitive Emission Factors from Oil and Gas Operations in Developed Countries)

3.2.3 Review of CH_4 emissions data from the natural gas supply chain

Natural gas may be appealing from a climate change mitigation perspective as electricity generation from natural gas typically emits less CO_2 per unit of electricity generated than coal-sourced electricity. The majority of upstream GHG emissions from natural gas comprise of CH_4. The balance of GHG emissions is CO_2 from combustion or flaring, negligible amounts of naturally occurring CO_2 in vented natural gas, and negligible amounts of nitrous oxides from combustion.

Increased use of natural gas, which is primarily CH_4, and the high uncertainty associated with its emission rates across all segments of the natural gas supply chain, have led to the performance of multiple studies and analyses in the past few years (Sevenster & Croezen, 2006). Many of the studies have indicated that CH_4 emissions are higher than previously estimated and as such national emission inventories tend to underestimate such emissions. As a consequence, many countries are now joining initiatives to improve CH_4 emission estimates and collaborate with major oil and gas companies to collect more data to improve their emission estimation methods and applicable factors (CCAC, 2017), see further details in Section 5.

In a review performed by Bradbury et al. (2013) they have noted that differences among studies are primarily due to inconsistent estimation of the magnitude and range of CH_4 emissions across the natural gas supply chain, the methods and data assumptions used to estimate these emissions, and the 'global warming potential' of CH_4 compared to CO_2 including the timescale over which it should be considered.

The variability in reported CH_4 emissions has also been demonstrated by Brandt et al. (2014), who have compiled 20 years of literature data on CH_4 emission rates and show that reported CH_4 emissions vary by 10 orders of magnitude. These extremes are bounded on the low end by device-level measurements at the emission source, and on the high end by continental measurements after atmospheric mixing. Brandt et al. (2014) conclude that the two data collection approaches, i.e. bottom-up and top-down measurements, are key drivers of the variability observed in reported CH_4 emission rates.

Clearly, many top-down CH_4 emission measurements have been conducted which involve measuring or inferring the concentration of CH_4 in the atmosphere within a region, and subsequently allocating the detected emissions to specific emission sources within that region. These estimates are useful in attempting to validate point source emission estimates and to identify whether bottom-up estimates may be underestimating emissions. However, they provide little detail in terms of detecting where such underestimates may occur. Bottom-up point source measurement in combination with local leak detection operations could help to prevent missing unknown emission sources.

Other methodological assumptions within life-cycle assessment studies of the natural gas supply chain also vary significantly across the literature and can have a major effect on the estimated emissions. Important divergent assumptions include (Balcombe et al., 2015):

- the assumed global warming potential of CH_4;
- the assumed total production volume of a well;
- the allocation of emissions to other co-products such as natural gas liquids;
- different boundary limits across different life cycle studies; and
- the assumed CH_4 content of the extracted natural gas.

As a result of lifecycle assessment studies performed by the National Environmental Technology Laboratory (NETL) the authors conclude that the boundary differences between the various studies account for a large portion of the result variability amongst many of the studies (Littlefield et al., 2016).

3.3 GHG Emissions due to Conversion of Natural Gas to Transportation Fuels

With increased availability of low-cost natural gas, a question arises regarding the optimal use of natural gas as a transportation fuel. The issues to consider are whether for minimizing GHG emissions and total energy use, is it more efficient to use natural gas generate electricity for charging electric vehicles, or to compress natural gas for onboard combustion in vehicles, or to reform natural gas into a denser transportation fuel?

Many studies have investigated the well-to-wheels energy use and GHG emissions from various natural gas-to-transportation fuel pathways and compared the results to conventional gasoline vehicles and electric vehicles. When comparing natural gas vehicles running on CNG to electric vehicles charged with natural gas produced electricity (e.g., Curran et al., 2014), the conclusions from such studies differ widely due to inconsistent assumptions about emissions from the upstream segments of the natural gas supply chain, as discussed in Section 3.2 above.

Clearly, the use of natural gas for transportation requires compressing, liquefying, or conversion, where each of the steps may lead to natural gas loss and GHG emissions. A comparative analysis of different natural gas-based fuel products will assist in the determination of the best use of natural gas as a transportation fuel.

3.3.1 Compressed Natural Gas

In order to be used directly in a vehicle, natural gas needs to be brought to a refueling station and pressurized into the vehicle tank[12]. Natural gas sent down the pipelines may contain some light hydrocarbons and some inert compounds so that its composition varies between producing formations and regions. The differences in composition result in a range of volumetric heating values as well as significant differences in combustion characteristics as measured by the CH_4 or octane number[13].

3.3.2 Natural gas-based Methanol blended fuels

In the last few decades, methanol was brought into use as an ingredient in fuel (mainly mixed with gasoline) in different percentages around the world. This section provides a review of the use of pure methanol and its gasoline blends as a transportation fuel. Additional information on methanol production and properties can be found in Appendix A.

In the **United States**, the use of methanol as transportation fuel began in racecars, since 1965, and eventually in regular cars. Initial interest in methanol was not in its role as a sustainable fuel, but as an octane booster when lead in gasoline was banned in 1976. Interest in alternative fuels, including methanol, was also raised after the first and second oil crisis (1973 and 1979, respectively).

An experimental program in California during 1980 to 1990 used blends of 85% methanol with 15% gasoline (M85). Gasoline vehicles were also converted to dedicated methanol vehicles, for use with high methanol blends. Limitations of the distribution system (small number of refueling stations; maintenance of these stations; poor locations) resulted in operator dissatisfaction, while vehicle operation was either comparable or superior to the gasoline counterpart. The implications of the

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[12] The operational parameters for CNG fueled vehicles include an initial compression of the natural gas to a pressure of 276 bar (272.4 atmospheres) to allow for pressure losses caused by cooling during vehicle refueling of the tank which is typically at 248 bar (244.8 atmospheres). The key assumptions are that the compressors are located at the refueling station and have efficiencies in the range of 91.7% and 97.9% with an average of 93.1% (Curran et al., 2014).

[13] Octane number is a figure indicating the antiknock properties of a fuel, based on a comparison with a mixture of isooctane and heptane. Premium gasoline has an octane number of 91, while natural gas has an octane rating of approximately 130. This higher octane allows for increased engine compression and combustion efficiency.

limited distribution infrastructure resulted in the decision to implement flex-fuel vehicles (FFV) in subsequent programs (Acurex, 1987).

M85 FFV vehicles in the U.S. peaked in 1997 at just over 21,000 with approximately 15,000 of these in California, which had over 100 public and private refueling stations. However, in 2005 California stopped the use of methanol after 25 years and 200,000,000 miles of operation (Bromberg & Cheng, 2010). The failure of methanol in becoming a substantial transportation fuel component in U.S. may be attributed to the following factors:

- Methanol was introduced in a period of rapidly falling petroleum fuel prices; therefore, there has been no economic incentive for continuing the methanol program.
- There was no strong advocacy for methanol as a transportation fuel, unlike the Agricultural lobby which promotes the use of ethanol, which displaced methanol as the choice oxygenate for gasoline blends.
- There is limited advocacy for generating methanol from biomass, as a renewable pathway, despite it being a well-developed technology. Instead, crop-based ethanol has been promoted by the U.S. federal government (through tax incentives and fuel quality regulations) as the transition fuel towards cellulosic bio-fuel production.

China is currently the largest user of methanol for transportation fuel in the world. Interest in China in the use of methanol as a transportation fuel is high (but local) as there is an abundance of readily available feedstocks (coal, natural gas, biomass) from which methanol can be produced (Chen et al., 2014.), and the interest is mainly economic (methanol is cheaper than gasoline by volume as well as by energy). Chinese use of direct blending of methanol into the country's gasoline pool has seen an average annual growth rate of 25% from 2000 to 2015, resulting in gasoline blending becoming the third largest demand segment for methanol by 2015. Nonetheless, out of 69.8 million metric tons of methanol consumed in 2015 worldwide, only 14% was used as fuel (MI, 2018).

In Europe, implementation of methanol fuels has been limited to light blends. The European interest in Alternative Fuels is driven mostly by desire to curtail CO_2 emissions.

3.3.3 Gas to Liquid fuel alternatives

GTL process technologies enable the conversion of natural gas into high-quality liquid fuel products that would otherwise be made from crude oil. These products include transportation fuels, motor oils and the feedstock for everyday necessities like plastics, detergents and cosmetics. GTL products are colorless and odorless, and contain almost none of the impurities – sulphur, aromatics and nitrogen – that are found in crude oil. Additional information on GTL technology can be found in Appendix B.

Utilization of GTL technology is an effective tool for increasing a producing country's energy security, by increasing the supply of secure domestic transportation fuels without relying on additional oil imports. Additionally, GTL could mitigate some environmental concerns by displacing higher-sulfur fuels derived from petroleum with essentially sulfur-free fuels (Goellner et al., 2013). Another advantage of such synthetic fuels is that they could provide a "drop-in" replacement of crude oil-based fuels without having to change any infrastructure and with no (in most cases) engine modifications. They do not require different types of infrastructure for transmission, storage, and refueling and most vehicles can be fueled by GTL directly, in accordance with the vehicles original fuel specifications (Ha et al., 2010).

Natural gas is a very valuable feedstock to produce liquid fuels due to the high hydrogen-to-carbon ratio within a CH_4-rich feed. This will ultimately increase the overall yield of carbon in the liquid products, decrease the capital investment required to generate liquid products, and reduce the amount of CO_2 that is produced (Baliban et al., 2013).

Today, only a handful of projects are operational around the world, as can be seen in Table 3-2, while other projects are in different phases of development in countries like Mozambique, Niger and Canada.

Table 3-2 > GTL operations worldwide

Plant	Country	Owner	Liquids capacity (bbl/d)	Start operation
Mosel Bay	South Africa	PetroSA (Sasol technology)	36,000	1992
Bintulu	Malaysia	Shell, Mitsubishi, Petronas, Sarawak state Gvt.	14,700	1993
Oryx	Qatar	Qatar Petroleum (QP) and Sasol	34,000	2007
Pearl	Qatar	QP and Shell	140,000	2011
Escravos GTL	Nigeria	Chevron, Nigerian National Petroleum Corporation (Sasol technology)	33,000	2014
Novokuybyshevsky	Russia	Rosneft	100,000	Scheduled in 2018
Oltin Yo'l GTL	Uzbekistan	Sasol, Uzbekneftegaz, Petronas	37,000	Under construction

(Adopted from: Enerdata, 2014; Shaw, 2012)

In addition, there are a few companies that have been investing in small scale GTL technologies (around 2,000 bbl/d), that can be deployed in small modular units to process associated gas from petroleum production (instead of flaring or reinjection) and where the main synthetic crude oil is exported to a conventional refinery for further processing (Enerdata, 2014; Wood et al., 2008).

Most of the already developed and planned GTL plants target the production of diesel fuels (C_{14}-C_{20}) together with some kerosene/jet fuel (C_{10}-C_{13}), naphtha (C_5-C_{10}), lubricants (>C_{50}) and a little LPG (C_3-C_4). By adjusting operating conditions in the Fischer-Tropsch (FT) reactor, the mix of products can be altered. In most applications it is the middle distillate diesel fuels and jet fuels that represent the highest-value bulk products with lubricants offering high-margin products for more limited volume markets (Rahmim, 2005).

GTL diesel has a high cetane number (at least 70 compared with a 45 to 55 rating of most diesels), low sulphur (less than five parts per million), low aromatics (less than 1%) (Buchanan, 2006), which ensure a more efficient and cleaner-burning combustion environment, affording a substantial reduction in engine wear and exhaust emissions. For suitably optimized engines, emission reductions are expected to be 30% in particulate matter, 45% in nitrogen oxides, 85% in carbon monoxide (CO), and 60% in hydrocarbons. GTL diesel may offer a substantial additional reduction of particulate matter emissions with the installation of diesel particulate filters that are enabled by the extremely low sulphur content of the fuel. These fundamental superior physical properties extend to all GTL products, which can result in a downstream GHG emissions benefit relative to petroleum-derived analogous products (Forman et al., 2011).

4 SUMMARY OF RESULTS

The results presented in this section are summarized in terms of CO_2 and CH_4 as follows: Section 4.1 presents an overview of natural gas supply chain emissions and loss, Section 4.2 addresses emissions associated with natural gas-based transportation fuel and Section 4.3 includes the estimate of emissions and losses for the natural gas supply chain in Israel including scenarios of converting natural gas to transportation fuels.

4.1 Natural Gas Supply Chain Operations Emissions

The concentration of CH_4 in the atmosphere is currently over twice as much as during pre-industrial levels, with global CH_4 emissions estimated to be around 570 million tonnes (Mt) in 2012. The emissions consist of around 40% from natural sources, and 60% from anthropogenic sources. The largest source of anthropogenic CH_4 emissions is agriculture, closely followed by the energy sector, which includes emissions from coal, oil, natural gas and biofuels (GCP, 2016; Sanouis et al., 2016).

The IEA estimated in the 2017 World Energy Outlook (WEO-2017) that 76 Mt CH_4 emissions (around 13% of global) were contributed by oil gas operations in 2015 (IEA, 2017). The WEO-2017 estimated that the large oil and gas-producing areas of Eurasia and the Middle East are the highest emitting regions, accounting for nearly half of the total emissions globally, followed by North America. **IEA estimates that when averaged globally emissions from the natural gas supply chain (42 Mt in 2015) is equivalent to an emission intensity of 1.7% – that is the average percentage of gas produced that is emitted to the atmosphere before it reaches the consumer.**

The results presented below are based on recent literature reviews that aimed to synthesize the current state of knowledge of CH_4 and CO_2 emissions associated with the global natural gas supply chain (Balcombe et al., 2015); field measurements data for the U.S. onshore natural gas supply chain (Littlefield et al., 2017), and the revised fuels cycle data summarized in the 2018 update of the GHG, Regulated Emissions and Energy Used in Transportation (GREET) model (Burnham, 2018).

4.1.1 Key Global Findings

The analysis performed by the Sustainable Gas Institute (SGI) at the Imperial College in London is asserting the following (Balcombe et al., 2015)[14]:

[14] Assuming a GWP of 34 for CH_4 that is based on the IPCC 5th Assessment Report (AR5).

- The range of estimated GHG emissions across the supply chain is vast: between 2 and 42 g CO_2e/MJ[15].
- If the gas were to be used for electricity generation, these supply chain emissions would be equivalent to 14–302 g CO_2e/kWh electricity generated. A small number of studies estimate even higher emissions from specific supply chain stages or facilities, especially from well completions (for unconventional gas) and liquids unloading processes.
- **Methane-only emission estimates range from 0.2% to 10% of the CH_4 content of the produced natural gas, which is equivalent to 1 to 58 g CO_2e/MJ. Most of the estimates lie between 0.5% and 3% of produced CH_4, which is equivalent to 2.9 to 17 g CO_2e/MJ. These values represent a wide range of extraction, processing and transport routes, reservoir conditions, regional regulations and estimation methodologies**.
- The total supply chain emissions is estimated to lie within the range of 2.7–32.8 g CO_2e/MJ with a central (median) estimate of 13.4 g CO_2e/MJ, if modern equipment with appropriate operation and maintenance regimes were used.

The key emission sources identified from the literature reviewed point to the importance of CH_4 emissions associated with well completions; liquids unloading; natural gas driven pneumatic devices, and compressors.

a. In the U.S., for example, it is now mandatory to capture emissions during well completions by using Reduced Emission Completions (RECs) equipment, which reduces CH_4 emissions significantly and removes the main difference in emissions characteristics between conventional and unconventional natural gas production.
b. Estimates of liquids unloading emissions are also highly variable and may represent a large emissions source for wet gas production. Current understanding of the distribution of emissions across the global well population is extremely poor within the literature and further research is required to detail and quantify the factors affecting unloading emissions such as well age, reservoir properties, equipment used and operational strategies.

[15] The emission factors in this section are defined as weight per unit of energy, where the energy is provided on Higher Heating Value (HHV) basis. HHV (also known as gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity of fuel (at 25°C) being combusted and the products returning to a temperature of 25°C. This definition takes into account the latent heat of vaporization of water in the combustion products

‘Super emitters’[16] is the designation of the small number of high-emitting sources and/or facilities that are skewing the emissions profile at every stage. ‘Super emitters’ have been found at various facilities across the whole supply chain including well completions, liquids unloading, leaking pipework, pneumatic devices and compressors. These large emissions are likely to occur due to the use of ineffective process equipment and poor operational and maintenance strategies. **Specifically, more data is required for offshore natural gas extraction, coal bed methane extraction, liquids unloading, well completions with RECs and transmission and distribution pipelines.**

4.1.2 Key Findings from U.S. Field Studies Data Synthesis

The data analysis performed by NETL (Littlefield et al., 2017) was enabled by new field measurement data from a series of campaigns that measured CH_4 emissions at component and facility levels. These data represent the four stages of the natural gas supply chain: production, gathering and processing (G&P), transmission and storage (T&S), and distribution[17].

- The U.S. natural gas supply chain is estimated to emit 0.29 g CH_4/MJ of delivered natural gas, or 9.9 g CO_2e/MJ[18]. **This is equivalent to a CH_4 emission rate of 1.7%,** (with a 95% confidence interval from 1.3% to 2.2%). The contribution of each of the natural gas segments is presented in Figure 4-1.
- The full lifecycle CO_2e emissions (accounting for both CH_4 and CO_2) and using 100-year and 20-year time horizons for the GWPs are 13.8 g CO_2e/MJ and 28.6 g CO_2e/MJ, respectively.

[16] Super-emitters are emissions sources within a sector, subsector or a site that account for the existence of abnormal process conditions and result in high, unintended emissions, which contribute a disproportionate portion of measured or estimated emissions from the respective sources.
[17] The new field measurements data was augmented to provide a more complete emission profile by adding emissions from EPA’s national GHG Inventory and the mandatory GHG reporting program for: produced water storage tanks, compressor packing, compressor exhaust, and dehydrator vents.
[18] Assuming a GWP of 34 for CH_4 for the 100-years time horizon

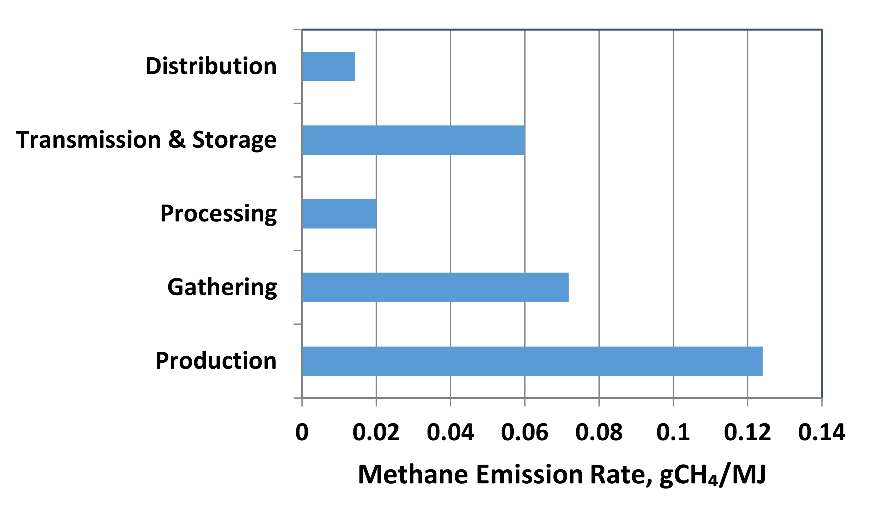

Figure 4-1 > Upstream Natural Gas CH_4 emissions for the U.S. Data Synthesis

(Based on Littlefield et al., 2017)[19]

- When accounting for the total natural gas delivered in the U.S., the NETL results are equivalent to an annual inventory value of 7,349 Gg CH_4/yr, which is 9.4% higher than EPA's most recent national GHG inventory value for 2012 - 6,716 Gg CH_4/yr. The difference may be due to inclusion of 'unassigned emissions' in the NETL synthesis to represent the difference between remote field observations of total site-level emissions and the sum of known component emissions that is the basis of the EPA's national GHG Inventory.
- On a 100-year CO_2e basis, CH_4 accounts for 76% of the GHG impact from the natural gas supply chain. On a 20-year CO_2e basis, CH_4 accounts for 88% of the GHG impact from the natural gas supply chain.
- The top three sources contributing to the NETL derived emissions, and which are also those contributing to the difference with the EPA estimate - are gathering systems, natural gas driven production pneumatics, and so called 'unassigned emissions'.
- The emissions from gathering stations and production pneumatics, which are 22% and 10% of supply chain CH_4 emissions, respectively, should be the top priorities for emission reduction opportunities.

[19] Data is expressed on a unit of delivered Natural Gas and scaled to an annual inventory basis

- Future data collection and analysis might better clarify the specific sources that make up the 'unassigned emissions' (19% of CH_4 emissions) and may shift the ranked contributions from production emission sources.

Figure 4-2 provides a summary of results for the CH_4 emission rates for the U.S. natural gas supply chain.

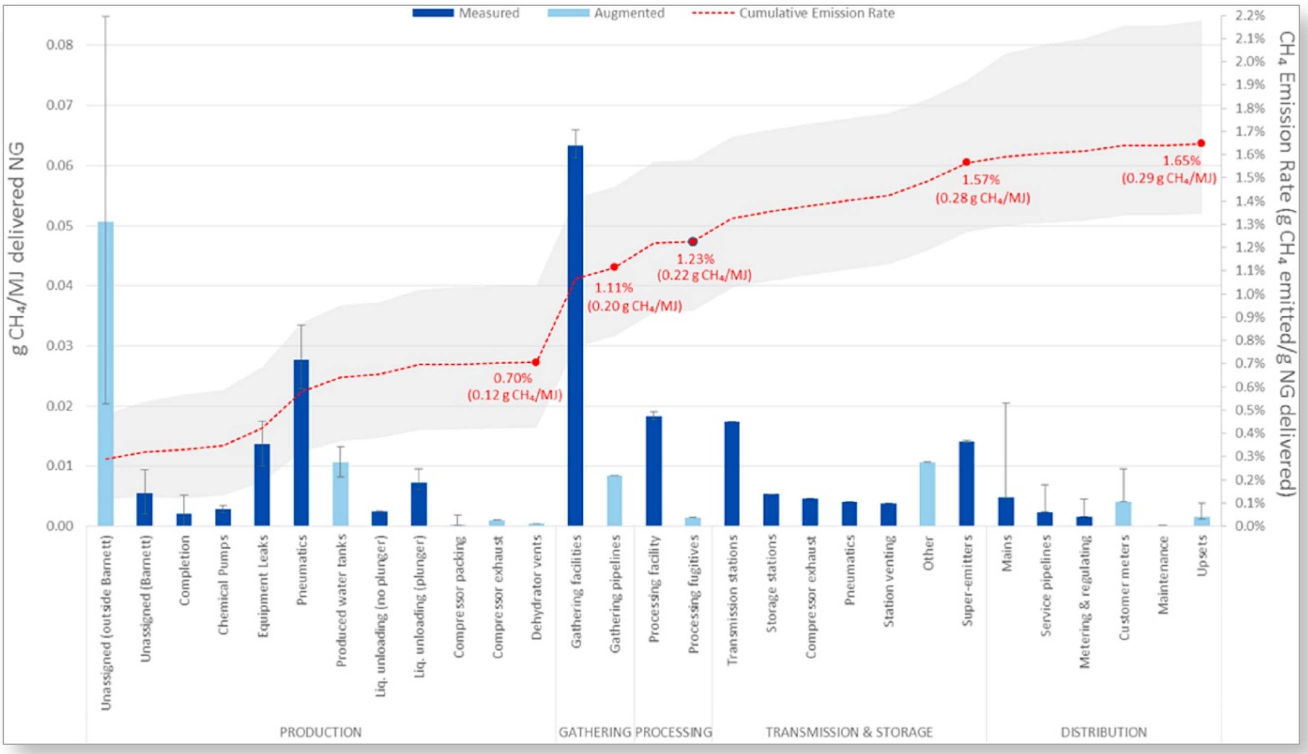

Figure 4-2 > CH_4 emissions from the natural gas supply chain

(Source: Littlefield et al., 2017)

[Bars represent emissions in terms of g CH_4/MJ delivered natural gas. The cumulative emission rates (g CH_4/g Natural Gas delivered) and CH_4 emissions (g CH_4/MJ natural gas delivered) are marked with red dots at key supply chain stages. Error bars on the blue bars and the gray shading around the dashed trend line represent 90% confidence intervals.]

4.1.3 Transportation Emissions Model Update

The U.S. model of WTW emissions is based on the approach used by the Argonne National Laboratory (ANL) - the GREET Model. This model is now used globally – with applicable adjustments – to estimate fuel cycle emissions from transportation fuels. For the 2017 GREET update ANL has summarized CH_4 emissions as a percentage of the volumetric Natural Gas throughput by stage for both conventional and shale natural gas supply chains (Cai et al., 2017). The overall natural gas supply chain leakage of a unit of natural gas throughput is calculated based on the leakage rate of each supply chain stage (Burnham et al., 2015). A new update was provided in 2018 which accounts for the EPA updates in the national GHG inventory, accounting for CH_4 leakage rates from gathering and boosting operations that were not considered in previous EPA GHG inventories. Table 4-1 summarizes the CH_4 fugitive emission for both shale and conventional natural gas in GREET1_2018 (Burnham, 2018). The results are an overall CH_4 leakage rate of 1.32% and 1.34%, respectively, though distribution to customers for the conventional and shale gas supply chain.

Table 4-1 > Summary of CH_4 emissions per natural gas throughput for GREET1_2018

Sector	Process	Conventional Gas ($g\ CH_4$ /MMBtu)	Shale Gas ($g\ CH_4$ /MMBtu)
Exploration & Production	Completion	0.5	3.3
Exploration & Production	Workover	0.0	0.7
Exploration & Production	Liquid Unloading	4.4	4.4
Exploration & Production	Well Equipment	132.2	132.2
Processing	Processing	5.9	5.9
Transmission	Transmission and Storage	43.6	43.6
Distribution	Distribution	29.2	29.2
Distribution	Distribution (station pathway)	19.4	19.4
Total		**215.9**	**219.4**
Total (station pathway)		**206.1**	**209.5**

(Source: Burnham, 2018; Table 4)

As shown in Table 4-1 above slightly lower leakage rates are expected for distribution directly to fueling stations rather than to the ‘city gate’ for low pressure delivery to customers.

Table 4-2 presents the parameters use to model leakage from CNG stations. These data are based on information provided by Clark et al. (2016).

Table 4-2 > Summary of methane emissions from compressed natural gas fueling stations

Source	CNG station (gCH_4/MMBtu)
CNG Compressor	9.0
Fueling nozzle	2.2
Total	**11.2**

(Source: Burnham, 2017; Table 4)

4.1.4 Reported Methane Emissions for Select Countries

The Sustainable Gas Institute (Balcombe et al., 2015) highlighted a wide range of approaches to data collection and publication, and many apparent anomalies. This is an issue in producing countries when data is absent or highly aggregated. Differences between countries in terms of data quality may be due to the country's status under the UN Framework Convention on Climate Change (UNFCCC). Only Annex 1 countries are required to report emissions on an annual basis separated by source, while non-Annex 1 countries report much less frequently with significant lags in data and according to older guidance (IPCC, 1996).

Table 4-3 provides a compilation of reported CH_4 emissions data from the oil and gas sector of oil and gas producing countries that are both Annex 1 and non-Annex 1 countries with the reporting year listed (Oxford, 2017). The listed countries account for at least 60% of global CH_4 emissions from oil and gas production – and approximately 55% of oil and gas production.

Table 4-3 > Estimate of CH_4 emissions from the oil and gas sector as reported by major producing countries

	CH_4 emissions (Tg)	Reporting Year	Oil and gas production (Mtoe)*	CH_4 emissions rate (%)**
Russia	25.29	2015	1058.3	2.4%
USA	8.09	2015	1272.0	0.6%
Canada	1.72	2015	349.8	0.5%
India	1.56	2010	85.6	1.8%
Mexico	1.53	2013	194.2	0.8%
Ukraine	1.15	2012	35.0	3.3%
Turkmenistan	0.95	2010	48.9	1.9%
Azerbaijan	0.55	2012	57.4	1.0%

(Sources: UNFCCC, 2018; BP, 2017)

** Oil and gas production is for the reporting year shown*

*** percent of CH_4 emissions as a function of mass (tons of oil equivalent) of produced natural gas*

The data in Table 4-3 indicates that the percent of CH_4 leakage from the petroleum and natural gas supply chain, as a function of oil & gas production (in terms of tons of oil equivalent), ranges from 0.5% – 3.3%, with North American countries (Canada, Mexico and U.S.) have leakage rates that are lower than 1%.

Tables 4-4 highlights the range of emissions for the natural gas supply chain segments of selected Annex 1 countries reporting under the UNFCCC. Comparison of country data may be difficult due to differences in methods used among countries for estimating emissions. Some of the countries use country specific emission factors, or direct measurements (Tier 2 or Tier 3 methodology) whilst others use UNFCCC recommended emission factors (Tier 1) as part of the reporting process.

Table 4-4 > Methane emissions from the natural gas sector in selected Annex 1 countries in 2015

	Exploration & Production (Gg of CH_4)	**Transmission** (Gg of CH_4)	**Distribution** (Gg of CH_4)	**Other** (Gg of CH_4)	**Total** (Gg of CH_4)	**Rate***
Australia	42	12	172	0	226	0.2%
Canada	104	46	38	295	483	0.2%
France	0	24	20		44	0.1%
Germany	1	76	89	27	193	0.2%
Italy	9	31	142	-	182	0.2%
Netherlands	0	7	6	-	13	neg
Poland	16	6	13	-	35	0.1%
Romania	138	7	20	20	185	1.2%
Russia	1,164	3,715	497		5,376	0.6%
Spain	0	2	24		26	0.1%
Turkey	2	24	54		80	0.1%
Ukraine	75	54	433	575	1,137	1.4%
UK	3	2	149		154	0.1%
USA	4,709	1,349	439		6,497	0.5%

(Sources: UNFCCC, 2018; BP, 2017)
**Note: The rate is the level of reported emissions as a percentage of either the country's reported 2012 natural gas production or consumption, whichever is greater*

Variability in reported data stems also from the age and design of oil and gas infrastructure and local emission control requirements. The section below presents an example for three countries: Norway, United Kingdom and Germany, where Norway is a large domestic producer which exports most of its natural gas to the UK and Germany.

Norway

Norway is the second largest gas supplier to Europe, after Russia, and followed by Algeria, Qatar, Nigeria and Libya (EC, 2016). In 2012 Norway GHG emissions (without accounting for land use changes and sequestration) amounted to 52,757.2 Gg CO_2e of which 44,123.2 Gg CO_2e (or 83.5%) were due to CO_2 emissions and 16.5% to non-CO_2 GHGs; CH_4 emissions were 8% of total Norway emissions in 2012 (UNFCCC, 2015).

The 2016 Statoil Study investigated emissions from natural gas produced at the Norwegian Continental Shelf, processed at onshore facilities in Norway, transported by subsea pipelines and distributed to customers in the UK and Germany (Statoil, 2016). Table 4-5 presents the CH_4 emission ratios in the Statoil study for the different segments of the natural gas supply chain, from production to delivery to customers.

Table 4-5 > Methane emission ratio along the gas supply chain

Ratio of Methane Emission	Norwegian gas to UK/Germany
Exploration / Production	0.012
Processing / Transport / Terminals	0.006
UPSTREAM + MIDSTREAM	**0.017**
Transmission / Storage / Distribution	0.209
DOWNSTREAM	**0.209**
TOTAL	**0.226**

(Source: Statoil, 2016)

One of the main outcomes from the Statoil study is that the CH_4 emissions in the upstream and midstream sectors are considerably lower for Norwegian gas than for other gas streams to Europe. This can be explained by several factors, a high focus on limiting CH_4 emissions at offshore installations due to safety risk and the extremely low gas leakage rate for subsea pipelines already mentioned from Norway to the UK and Germany. For Statoil's gas supply chain, from production in Norway to delivery to customers in the UK and Germany, the upstream and midstream sectors CH_4 emissions represent less than 10% of the total Norwegian CH_4. Overall, CH_4 contributes to less than 4% of the total GHG emissions in the upstream and midstream Norwegian gas sector.

Finally, the level of total CH_4 emission levels along the gas supply chain largely confirms a significant climate benefit of natural gas compared to coal. For Norwegian gas delivered to customers in the UK and Germany, emission rates are below 0.3% of the CH_4 content of the gas produced.

United Kingdom

UK government statistics (BEIS, 2018) show that CH_4 represents most of the non-CO_2 GHG emissions. About 20% of CH_4 emissions are largely attributed to the energy sector including fugitive emissions which arise from natural gas leakage, operational and closed coal mines, and solid fuel transformation. Emissions from the energy sector have fallen due to the reduction in coal mining and the replacement of old metallic mains in the gas distribution network. CH_4 emissions amounted to 41,200 tonnes during 2015, where venting accounted for 53% of this amount with a further 34% due to unburned gas during flaring operations. A key source of leakage is the natural gas pipeline system including transmission and distribution network, where leakage is due both to UK produced natural gas as well as gas imported from Norway.

A recent study investigated CH_4 emissions from the UK high-pressure pipeline system (National Transmission System - NTS) for natural gas pipelines with maximum operating pressure of 85 bar (Boothroyd et al., 2018). Methane fluxes from control routes were statistically significantly lower than the fluxes measured on pipeline routes, with an overall pipeline flux of 627 (241–1,123 interquartile range) tonnes CH_4/km/yr. Soil gas CH_4 measurements indicated a total flux of 62,600 tonnes CH_4/yr, which equates to 2.9% of total annual CH_4 emissions in the UK.

Germany

The energy sector in Germany is the second largest CH_4 emission source after agriculture, and the third largest in Europe, after agriculture and waste management (IASS, 2016). The German UNFCCC 2016 inventory (for reporting year 2014) stipulates that total CH_4 emissions from the oil and gas sector amount to 194 Gg CH_4. The largest contribution comes from the distribution segment, which is responsible for about half of the total emission (88.5 Gg CH_4), followed by transmission lines emissions (76.3 Gg CH_4). These two segments account for close to 90% of total CH_4 emission from natural gas systems in Germany. Natural gas Production and Processing segments contributed slightly over 1% of total emissions due to the small amount of gas produced and processed domestically (i.e., 9.2 BCM in 2014).

4.2 Emissions from Natural Gas Based Transportation Fuels

As discussed above the major sources of CH_4 emissions are natural gas production, transmission, distribution and use. In order to use natural gas as a transportation fuel there is a need to compress it (compressed natural gas or CNG), to liquefy it (liquefied natural gas or LNG), or else manufacture other alternative liquid fuels including methanol or GTL. The sections below address the technology and GHG emissions considerations for the introduction of CNG, methanol, or GTL fuels.

4.2.1 High pressure compression and fueling with Compressed Natural Gas

The European Commission Directorate-General for Energy (EC DG ENER) has undertaken a study to determine the breakdown of the carbon intensity (CI) of natural gas pathways by supply chain stage, and EU region (EC, 2015). The analysis of average CI values for CNG supply in each region and for the EU is presented in Table 4-6. The differences of the CI in the different regions are due to the origin of the natural gas. Highest intensity is found in the South East EU region that imports high upstream emissions gas from North Africa along with gas from Russia via long transmission pipeline having high midstream emissions.

Table 4-6 > Average Carbon Intensities of Natural Gas for the considered EU Regions

Reference scenario	**EU average** (gCO_2e/MJ)	**EU North** (gCO_2e/MJ)	**EU Central** (gCO_2e/MJ)	**EU South East** (gCO_2e/MJ)	**EU South West** (gCO_2e/MJ)
Fuel dispensing	3.82	3.52	4.11	4.22	2.79
Gas distribution, transmission and storage	2.96	1.25	2.80	6.62	1.16
Feedstock transportation (pipeline, LNG)	6.63	2.44	8.29	9.12	5.14
Fuel production and recovery	5.40	4.82	3.35	7.86	9.56
CO_2, H_2S removed from Natural Gas (gas processing)	0.37	0.24	0.20	0.77	0.52
Total	**19.18**	**12.26**	**18.76**	**28.58**	**19.17**

(Adapted from: EC, 2015)

The current European natural gas grid has a high enough Octane Index which is sufficient to allow the use of dedicated CNG vehicles with a higher compression ratio in the EU distribution network and that would be available for use as road fuel.

In the U.S. the modelling approach used by the ANL for the GREET Model for CNG assumes that the natural gas pipeline is fed directly into a refueling compressor station (see Table 4-7).

Table 4-7 > Key emission parameters for CNG fuels pathways

	Efficiency	CH_4 Leakage rate (gCH_4/MJ)	Carbon Intensity * (gCO_2e/MJ)
Natural Gas Transmission	99.60%	0.084	13.3
Natural Gas Distribution	99.70%	0.061	15.2
Natural Gas Compression	97.90%	**	18.4

(Source: Wang & Elgowainy, 2014)
** Note: Includes all 'Upstream' emissions.*
*** Data is available only in terms of CO_2e.*

The operational parameters for CNG fueled vehicles include an initial compression of the natural gas to a pressure of 276 bar (272.4 atmospheres) to allow for pressure losses caused by cooling during vehicle refueling of the tank which is typically at 248 bar (244.8 atmospheres). The key assumptions are that the compressors are located at the refueling station and have efficiencies in the range of 91.7% and 97.9% with an average of 93.1% (Curran et al., 2014).

Although we are not investigating here the full WTW energy and GHG emissions for natural gas fueled vehicles, it is interesting to note the impact of compressor efficiency on overall energy efficiency and GHG emissions, as depicted in Figure 4-3.

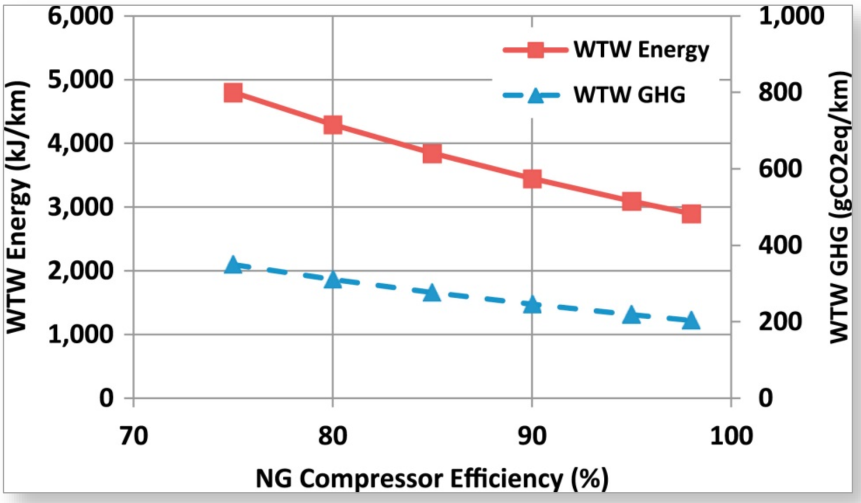

Figure 4-3 > Natural gas compressor efficiency impact on WTW energy and GHG emissions (Source: Curran et al., 2014)

In addition to the impact of compressor efficiency, the GHG benefits of NGVs are influenced by fuel economy. The relative fuel economy of NGVs is affected by natural gas tank weight, vehicle performance, engine technology and design.

A recent investigation commissioned by the Natural & bio Gas Vehicle Association (NGVA) in Europe included an industry-wide GHG intensity analysis of supplying and using Natural Gas at the European level. The analysis focused on the overall chain of operations for road transportation (Well-to-Wheel), with an analysis of the WTT portion of the natural gas fuel pathway (thinkstep, 2017). The report provides a complete analysis of the current natural gas supply and use scenarios based on the most recent data, provided through the NGVA members with data up to 2015.

For the Well-to-Tank supply chain, the NGVA study shows that the EU total carbon footprint for CNG is 13.75 g CO_2e/MJ[20], which consist of 9.9, 3.74 and 0.11 gCO_2e/MJ, respectively, for CO_2, CH_4, and N_2O.

Like prior studies, this study also identified large variations (±30%) for the CNG supply chains among the four defined EU regions (North, Central, South East, South West) used for calculating a weighted average total EU value. Major reasons for this variation include different transmission energy intensities and related CH_4 emissions; different Natural Gas countries of origin with different supply routes and technologies and consequently different GHG intensities; and different GHG intensity of production and processing.

The contribution of the various supply chain segments to CH_4 emissions is:

- Production, processing and liquefaction (45%)
- Gas transmission, storage and distribution (32%)
- Long distance transportation (15%)
- Dispensing (8%)

4.2.2 Conversion of natural gas to methanol

Methanol that is produced from natural gas could be blended into transportation fuels to lower their carbon intensity. The impact of the use of methanol on GHGs emissions is dependent on the source of the methanol, as indicated in Table 4-8, which describes the Life Cycle Carbon Intensity, including indirect Land-Use Change (ILUC) of various fuels:

[20] On an HHV basis

Table 4-8 > Life cycle Carbon Intensity of various fuel sources

Fuel	Well-To-Wheel (g/MJ fuel)	ILUC (g/MJ fuel)
Conventional gasoline	96	n/a*
Ethanol (corn)	68	30
CNG	68	n/a
Biodiesel (soy)	21	62
Methanol (natural gas)	88	n/a
Methanol (natural gas) in dedicated vehicles	67	
Methanol (coal)	190	n/a
Methanol (coal with CCS)	89	n/a
Biomethanol (renewable)	5	unknown

(Adapted from: Bromberg & Cheng, 2010)
** Not applicable*

Methanol from natural gas can slightly decrease the carbon intensity compared to the baseline gasoline case because of the increased hydrogen content of the natural gas (lower carbon intensity of CH_4).

Renewable methanol is fully miscible with conventional methanol and offers a highly scalable renewable liquid fuel pathway without the risk of indirect land use change, fertilizer overuse, and top soil erosion risks associated with conventional corn ethanol.

In another study of the life cycle energy use and GHG emissions of methanol pathways was conducted by Wang & Lee (2017) using the GREET 2016 model. The study concludes that natural gas- based methanol has GHGs emissions that are similar to gasoline. The research also notes that efficient vehicle technology such as FCVs (Fuel Cell Vehicle) can further increase energy and emission benefits of methanol.

The emissions associated with the manufacture of methanol vary between plants due to their design and source of the natural gas. Table 4-9 provides a comparison of the facility capacity and emissions parameters for the various plants to better understand the variability of GHG impact among such projects due to technology selection and the project boundaries included in the assessment. Appendix C provides further details of the technology and emission boundaries, for the four methanol production projects.

Table 4-9 > Comparison of the GHG Emissions Intensity for select methanol production plants

Methanol Plant	Location	MeOH Capacity (tons per year)	Technology	GHG Emissions (ton CO_2e/year)	Emissions Intensity (tCO_2e/ tMeOH)
Australian Methanol Co. PTY	Burrup Peninsula, Perth, Australia	1,050,000	Lurgi combined reformer	451,600	0.43
YCI Methanol Plant	Louisiana, USA	1,820,000	Lurgi MegaMethanol®	1,620,000	0.89
Northwest Innovation Work, LLC	Kalama, Washington, USA	3,600,000			
			Combined reformer: alternative 1	1,570,000	0.63
			Ultra-Low Emissions: alternative 2	1,181,000	0.33
Israel case study	Desktop assessment	500,000	Generic	137,000	0.27

4.2.3 Gas to Liquid fuel alternatives

GTL technology converts natural gas into high-quality liquid products that would otherwise be made from crude oil. These products include transportation fuels, motor oils and feedstocks to the manufacture of plastics, detergents and cosmetics. GTL products are colorless and odorless and contain almost none of the impurities – sulphur, aromatics and nitrogen – that are found in crude oil.

As of late 2014 there were only four full scale plants operating in the world that range in liquids capacity from 14,000 to 140,000 Bbl/day with a products slate that include all or some of the following: naphtha, kerosene, diesel, paraffins, lubricants and waxes. Six more GTL plants were in various stages of planning and were expected to be commissioned by 2018 (Entrada, 2014). More recently there seems to be a growing emphasis on small scale GTL plants to utilize gas that would otherwise be vented or flared. For example, three such plants are slated to start operation in the

2016-2018 timeframe and range in capacity from 1,100 to 2,800 Bbl/Day. These plants include one in offshore, Brazil (to eliminate Petrobras flaring), and two in the USA in Lake Charles, Louisiana, and Ashtabula, Ohio.

GTL Life Cycle Assessment

Several studies over the past decade have presented results of life cycle assessments (LCA) of GTL. The analysis of the GTL process typically addresses five stages in the fuel production:

1. Raw Material Acquisition (RMA) includes the extraction and processing of natural gas.
2. Raw Material Transport (RMT) from the site of acquisition to the liquid fuels production facility, i.e. domestic natural gas via pipeline.
3. GTL plant - The Energy Conversion Facility (ECF) converts raw materials to liquid fuels. May include Carbon Capture and Sequestration (CCS) operations.
4. Product Transport (PT) moves fuel from the ECF to the refueling station, on-site storage, and dispensing of the fuel into a vehicle.
5. Use of fuel in a passenger vehicle.

In this section of the current study we will focus mainly on the emissions of GHG, especially CH_4, from stages 3 and 4, by extracting the relevant data, when possible. Stage 5 is out of the scope of this study while stages 1 and 2 were reviewed in the previous section above (Section 4.1).

Table 4-10 presents a compilation of results from studies surveyed. Additional details provided in Appendix D.

Table 4-10 > Compilation of select WTT carbon intensity results for natural gas based GTL

Study reference	WTT Carbon Intensity (gCO_2e/MJ) Gasoline	WTT Carbon Intensity (gCO_2e/MJ) Diesel	Notes
Jaramillo et al. (2008)	28-32		FT process only
Forman et al. (2011)		88.7	WTT
Goellner et al. (2013)	89.4	90.6	WTT
Khraisheh (2013)		59.7	Diesel production only
JRC (2014)		89	WTT
JRC (2014)		25	NG processing/transport
Peng et al. (2017)		71.3	WTT

The literature reviewed confirms that making synthetic diesel is an energy-intensive endeavor. The combination of steam reforming, partial oxidation and Fischer-Tropsch synthesis result in overall efficiencies within a broad range of 45 to 65% depending mostly on the feedstock and to a lesser extent the process scheme. The GTL (natural gas to liquids) processes are the most efficient with figures in the 60-65% range due to the relative ease of producing a syngas from natural gas. In the best case syndiesel fuel production from natural gas requires about 3 times as much total energy as conventional diesel fuel (JRC, 2014).

For a case study analysis in China the assumed that the energy conversion efficiency for GTL is in the range of 46-55% and the total GHG emissions for GTL were calculated to be 143.9 g CO_2e/MJ. The emissions seem to be equal in the WTT and TTW phases of the analysis, with almost half attributed to upstream processes (49.53%) and the remainder to the fuel use phase (50.47%) (Peng et al., 2017).

A previous study which evaluated the environmental effects of a GTL facility in Israel (Rapoport, 2013), did not specify CH_4 emissions from facility operations, but noted CO_2 emissions of 2.1 Million ton per year, for a 45,000 Barrels/day (2M ton/year) facility. The study also presents data on emissions during products' transport, based on Greet model, as detailed in Table 4-11 below:

Table 4-11 > Emissions during products' transport

Segment	Emission component	Amount	Units
Natural gas transport to the GTL facility	CH_4	42	Mg/ton/km pipe
Natural gas transport to the GTL facility	CO_2	16	Gram/ton/km pipe
From the facility to a close refinery plant	CH_4	3.7	Mg/ton/km pipe
From the facility to a close refinery plant	CO_2	6.8	Gram/ton/km pipe
Transfer of product in road tanker	CH_4	-	Microgram/ton/km pipe
Transfer of product in road tanker	CO_2	110	Gram/ton/km pipe

(Adopted from: Rapoport, 2013)

4.3 Estimating CH_4 Loss from the Natural Gas Supply Chain in Israel

According to the Israeli Natural Gas Authority, over the decade of 2005-2014, there has been a 358% increase in the amount of natural gas extracted in Israel, from 1.64 BCM in 2005 to 7.51 BCM in 2014 and over 10 BCM in 2017 (NGA, 2018). Concurrently, natural gas imports have substantially dropped. After increasing from 0.32 BCM in 2008 to 2.10 BCM in 2010, imports dropped to just 0.06 BCM in 2014, as Israel became more reliant on domestically-produced gas. The uptake in the power production and industrial sectors has been immediate, with these two sectors consuming 7.5 BCM of natural gas in 2014, and reaching 10.35 BCM in 2017.

During the period of 2008-2010, and later in 2012, there were several major natural gas discoveries in Israeli offshore waters (including it its Exclusive Economic Zone):

- Dalit reservoir – off the Hadera coast – contains about 14 BCM;
- Tamar reservoir – off the Haifa coast – contains about 240 BCM;
- Leviathan reservoir – off the central coast at Dor - contains about 540 BCM;
- Karish/Tanin reservoir – off the Haifa coast – contains about 31 BCM.

In 2013, the Tamar field began producing natural gas for Israeli consumption and use of gas increased; enabling Israel to nearly eliminate the use of fuel oil for electricity generation.

Currently, CH_4 as reported in the national GHG inventory in Israel accounts only for CH_4 emissions from fuel combustion and waste disposal. In this section we aim to try and fill the information gap by comparing various data sources from which we estimate CH_4 emissions including fugitive emissions, venting and flaring from the natural gas supply chain in Israel.

Section 4.3.1 provides a comparison of estimated natural gas CH_4 emissions and emission intensities, in select countries, with an emphasis on the extent of domestic natural gas production and import. Section 4.3.2 presents an analysis of data that has become available over the last few years through the Israel Pollutant Release and Transfer Register (IL-PRTR)[21], and includes an overview of the excess CO_2 and CH_4 emissions expected from the anticipated deployment of electric vehicles in Israel.

Clearly, Israel needs to update its emission inventory to account for the expansion of natural gas operations in the country which contributes to higher CH_4 emissions as well as overall GHG

[21] http://www.sviva.gov.il/English/env_topics/IndustryAndBusinessLicensing/PRTR/Pages/default.aspx

emissions. These higher CH_4 emissions would contribute to climate change and may detract from Israel's ability to meet its national climate change action plan and attain its target emission reductions.

Section 5 will address CH_4 emissions controls and mitigation technologies and policies which should be considered when Israel updates its National Determined Contribution (NDC) as part of the Paris Agreement periodic update process.

There are typically several methodological tiers for determining fugitive emissions and venting and flaring emissions from natural gas systems (IPCC, 2006a). The specific methodology selected for use for any given emissions inventory is based on data and resource availability. Note that it may be appropriate to apply different methodological tiers to different parts of the natural gas supply chain.

4.3.1 Comparison of reported emissions for select countries

According to the IPCC guidance[22], the term 'fugitive emissions' refers to the sum of emissions from equipment leaks, vented sources and flaring emissions. In accordance with the guidance, reporting for this industry sector encompasses emissions from all segments, including production, gathering, processing, transmissions, and distribution of natural gas. For each segment a distinction should be made between the primary types of emissions source, namely: venting, flaring, equipment leaks and miscellaneous sources.

The IPCC defines the sectors as follows:

1 B 2 **Oil and Natural Gas** - fugitive emissions from all oil and natural gas activities. The primary sources of these emissions may include fugitive equipment leaks, evaporation losses, venting, flaring and accidental releases:

- ***1 B 2 a*** **Oil** - emissions from venting, flaring and all other fugitive sources associated with the exploration, production, transportation (including oil pipelines), upgrading, and refining of crude oil and distribution of crude oil products.
- ***1 B 2 b*** **Natural Gas** - emissions from venting, flaring and all other fugitive sources associated with the exploration, production, processing, transmission, storage and distribution of natural gas (including both associated and non-associated gas).

[22] IPCC Subcategory 1.B.2 of the energy sector: https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_4_Ch4_Fugitive_Emissions.pdf

Table 4-12 below presents a comparison of the CH_4 emissions reported to the UNFCCC for Calendar Year (CY) 2015 for select Annex I countries under IPCC national emissions inventory guidelines for category 1.B.2.b - natural gas systems. It also includes an estimate for Israel CH_4 emissions for CY2015 based on IPCC Tier 1 factors, as will be further discussed in Section 4.3.2 below.

Table 4-12 > Comparison of absolute emissions and emission intensity for select countries

2015 Data	units	Australia [a] UNFCCC Data Interface	U.S. UNFCCC Data Interface	Russia UNFCCC Data Interface	U.K. UNFCCC Data Interface	Italy UNFCCC Data Interface	Germany UNFCCC Data Interface	Norway UNFCCC Data Interface
Natural Gas Emissions	kt CH_4	6,735.1	6,497	11,984	195	185	193	23 [b]
IEA Natural Gas Statistics								
Domestic Production	MCM	53,132	768,935	584,400	41,201	6,773	8,392	120,589
Imported Natural gas	MCM	7,279	76,969	0	44,833	61,200	141,640	14
Domestic + Imported	MCM	60,411	845,904	584,400	86,034	67,973	150,032	120,603
Emissions Intensity								
Relative to Domestic Production	kt CH_4/MCM	0.13	0.008	0.02	0.005	0.03	0.02	0.002
	Wt.% [c]	20.3%	1.4%	3.3%	0.8%	4.4%	3.7%	0.03%
Relative to Domestic Production + Imported	kt CH_4/MCM	0.11	0.008	0.02	0.002	0.003	0.001	0.002
	Wt. % [d]	17.9%	1.2%	3.3%	0.4%	0.4%	0.2%	0.03%

[a] Australia reports exceedingly high emissions from natural gas distribution.
[b] Note: estimated total emissions from Norwegian natural gas operations – including offshore - is 560 kt CH_4 in 2015.
[c] Wt.% assumes 93% CH_4 in natural gas.

The data in Table 4-12 are presented both in terms of absolute emissions and as emission intensity indicators. Two indicators are used, the first one relative to '**domestic production**' and the second one relative to '**domestic production + imported**', based on data provided by the IEA Natural Gas monthly gas statistics (IEA, 2018). The table also presents the respective emission intensity in terms of % loss rates derived from CH_4 emissions relative to the CH_4 weight of the natural gas (assuming an average of 93% by weight for all countries). **The data is indicative of the wide range of emission intensities and % loss (leakage) associated with information provided in national emission inventories. The divergence between countries may be due to real difference in the national natural gas systems but may also be indicative of gaps and data inconsistencies. It should be viewed in the context of the IEA (IEA, 2017) assessment for a global loss rate of 1.7% (by weight) for natural gas systems.**

In reviewing the details of the data provided through the UNFCCC data interface[23], which is the basis of the summary presented in Table 4-12, we observe several interesting features:

- **Australia** is shown to have very high emission intensity consistent with its reporting of an exceedingly high emission for their natural gas distribution network. This data is not very well understood.
- Though **Russia's** domestic natural gas production is only 75% compared with that of the U.S., its emission intensity is more than twice as high due to large amounts of gas reported as either vented or flared.
- For the **U.K., Italy and Germany** a larger fraction of the natural gas consumed is imported rather than domestically produced. The derived emission intensities relative to production are only higher than those derived by normalizing the data relative to 'domestic production + import'.
- For **Norway** the CH_4 emissions accounted for in the national GHG inventory are from its onshore and territorial offshore waters only. The IEA production statistics accounts also for all the exported natural gas. Accounting for all the emissions from Norwegian operations would possibly increase the emission intensity by a factor of 25 (to 0.7%).

Israel is not an Annex 1 country, so it has not been reporting annually as the other countries listed above. The estimate for CH_4 emissions from natural gas operations in Israel is based on an IPCC Tier

[23] https://unfccc.int/process/transparency-and-reporting/reporting-and-review-under-the-convention/greenhouse-gas-inventories/submissions-of-annual-greenhouse-gas-inventories-for-2017

1 methodology from the 1996 guidelines, which provide the guidance for non-Annex 1 countries that are signatories to the UNFCCC (IPCC, 1996). Further discussion of the Israeli data follows in Section 4.3.2 below.

4.3.2 Estimated CO_2 and CH_4 emissions from the natural gas supply chain in Israel

The IL-PRTR is a database that archives mandatory reports submitted by large facilities that are required to report their releases to air, water and land, when exceeding a specified emissions threshold for listed pollutants. This regulatory scheme has been established under the 2012 Environmental Protection Law: 'Emissions and Transfers to the Environments – Reporting and Register Obligations' (MoEP, 2012). The data is reported to the Ministry of Environmental Protection (MoEP) by March 31st of the following calendar year and is publicly released by the MoEP six months afterwards – in September of the respective year. This database is providing valuable information for many sectors of the economy including petroleum and natural gas operations.

The regulation mandates reporting air emissions for 89 listed pollutants including CO_2 and CH_4. The reporting threshold for CO_2 is 1,000 metric tons (1 million Kg), and for CH_4 it is 10 metric tons (10,000 Kg). To note – these thresholds are 100-fold lower (more stringent) for CO_2 and 10-fold lower (more stringent) for CH_4 when compared to the EU-PRTR[24].

Table 4-13 provides the details of the data reported to the IL-PRTR for natural gas systems operations for the years 2014-2017. The data is presented in terms of metric tons per year for CH_4 and CO_2 as reported under the regulation **without** summing it up in terms of CO_2e[25]. For the period 2014-2017 the operations that were above the reporting threshold included the mature Mary B platform, the newer Tamar platform (started operations in 2013) and the Yam Tetis shore receiving unit.

[24] Reporting obligation for: E-PRTR data reporting; https://rod.eionet.europa.eu/obligations/538
[25] The IL-CBS reports national data in terms of CO_2-equivalent where the GWP_{CH4} = 21, per the IPCC 1996 guidelines.

Table 4-13 > Trends of CH_4 and CO_2 emissions reported to the IL-PRTR for natural gas operations

	2017 CH_4 (t/year)	2016 CH_4 (t/year)	2015 CH_4 (t/year)	2014 CH_4 (t/year)	2017 CO_2 (t/year)	2016 CO_2 (t/year)	2015 CO_2 (t/year)	2014 CO_2 (t/year)
Tamar Platform	3,950	3,597	4,218	4,088	57,952	37,637	57,410	35,389
Yam Tetis	114	228	290	226	1,065	18,689	3,550	[a]
Mary B platform	211	170	105	101	2,462	2,215	2,633	6,453
Offshore production & processing	**4,276**	**3,995**	**4,613**	**4,415**	**61,479**	**58,541**	**63,592**	**41,842**

[a] *Below the reporting threshold*

A review of the data in Table 4-13 indicates that CH_4 emission estimate are about 4,400, 4,600, 4,000 and 4,300 t/year for calendar years 2014, 2015, 2016 and 2017, respectively. Figures 4-4 and 4-5 present the 2014-2017 time series for CH_4 and CO_2 emissions, respectively, from the three major natural gas facilities that report to the IL-PRTR. Analyzing the trend shown in Figure 4-4 we note that CH_4 emissions exhibit about a 50% decrease from 2016 to 2017 for the Yam Tetis shore receiving unit, and a 10% and 24% increase in the emissions from the Tamar Platform and the Mary B platform, respectively.

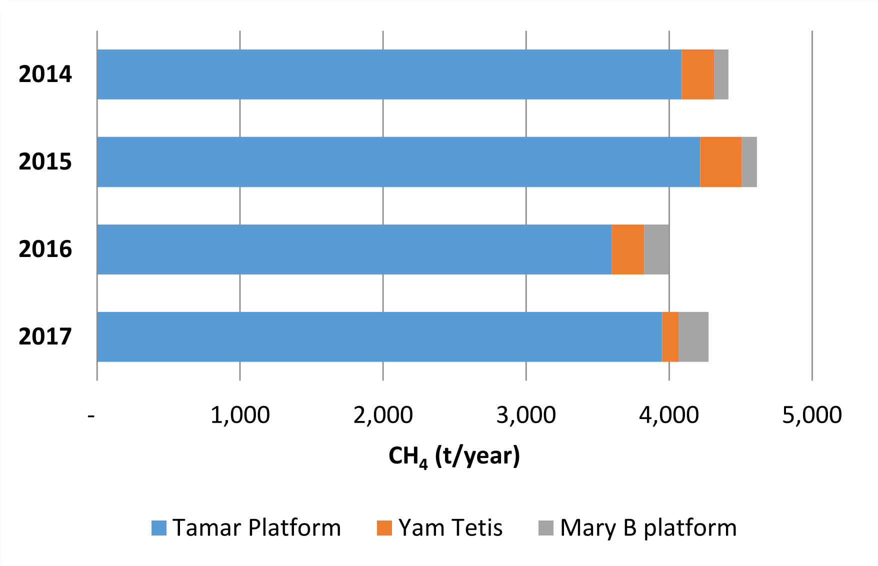

Figure 4-4 > Emissions of CH_4 as reported to the IL-PRTR database for the years 2014-2017

For CO_2 we note (Figure 4-5) a 95% decrease for the Yam Tetis shore receiving unit from 2016 to 2017, while the CO_2 emissions from the Tamar Platform and the Mary B platform increased by 50% and 10% between the same two years, respectively.

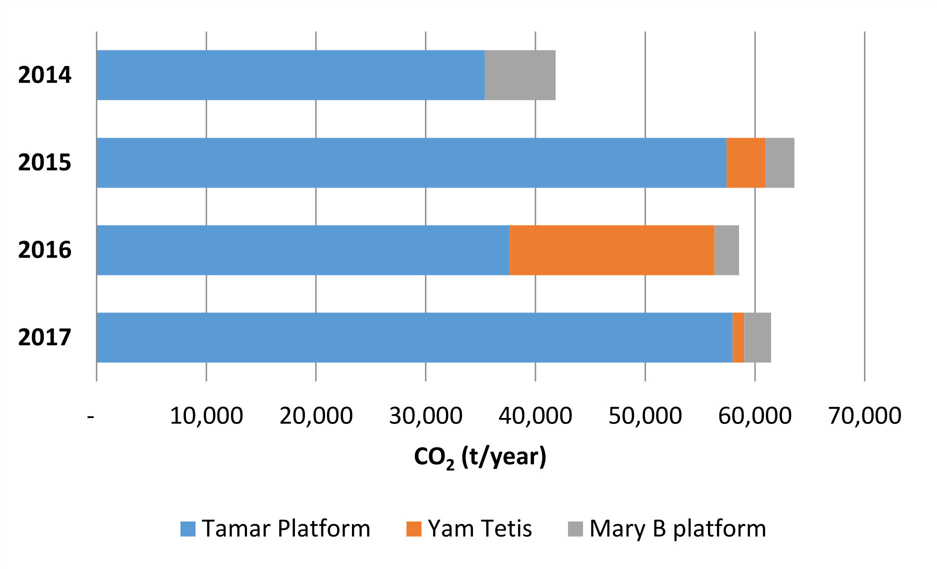

Figure 4-5 > Emissions of CO_2 as reported to the IL-PRTR database for the years 2014-2017

As part of the data review process undertaken by the MoEP the emissions data reported by Nobel Energy Mediterranean, the operator of the Tamar and Mary B platforms, has been updated for 2016 in accordance with the results of new emission testing that was conducted.

As an alternative approach we have assessed the CH_4 emissions that would be derived from using the IPCC Tier 1 emission factors for the different sources in the natural gas supply chain (Table 4-14). The IPCC factors cover all the segments of the natural gas supply chain including: production and processing; transmission and storage; and distribution. This is different from the IL-PRTR data that pertains only to production and processing segment. When comparing the estimate for the production and processing segment we note that the IL-PRTR data is lower by 30% to 50% as compared to that derived using the more conservative IPCC emission factors.

Table 4-14 > Estimated Israel CH_4 fugitive emissions from the natural gas supply chain

				2014	2015	2016	2017	Units
Natural Gas Supply [a]				7,550	8,280	9,300	9,830	MCM
IPCC Tier 1 Category [b]	**Subcategory**	**Emission Source**	**Emission Factor**					
Well drilling	All	Flaring & Venting	3.30E-05	0.25	0.27	0.31	0.32	kt CH_4/year
Well testing	All	Flaring & Venting	5.10E-05	0.39	0.42	0.47	0.50	kt CH_4/year
Well Servicing	All	Flaring & Venting	1.10E-04	0.83	0.91	1.02	1.08	kt CH_4/year
Gas Production	All	Fugitives	1.30E-04	0.98	1.08	1.21	1.28	kt CH_4/year
Gas Production	All	Flaring	7.60E-07	0.01	0.01	0.01	0.01	kt CH_4/year
Gas Processing	Default Weighted Total	Fugitives	5.90E-04	4.45	4.89	5.49	5.80	kt CH_4/year
Gas Processing	Default Weighted Total	Flaring	2.00E-06	0.02	0.02	0.02	0.02	kt CH_4/year
Production & Processing				**6.92**	**7.59**	**8.53**	**9.01**	**kt CH_4/year**
Gas Transmission & Storage	Transmission	Fugitives	2.70E-04	2.039	2.236	2.511	2.654	kt CH_4/year
Gas Transmission & Storage	Transmission	Venting	7.30E-04	5.5	6.0	6.8	7.2	kt CH_4/year
Gas Transmission & Storage	Storage	All	2.50E-05	0.2	0.2	0.2	0.2	kt CH_4/year
Gas Transmission & Storage				**7.7**	**8.5**	**9.5**	**10.1**	**kt CH_4/year**
Gas Distribution	All	All	1.10E-03	**8.3**	**9.1**	**10.2**	**10.8**	**kt CH_4/year**
Total Estimated Emissions				**23.0**	**25.2**	**28.3**	**29.9**	**kt CH_4/year**

[a] Source: NGA, 2018.

[b] Emissions based on IPCC Tier 1 factors as exhibited in Table 3-1

Use of the IPCC emissions estimates noted above is justified in view of on-going assessment of the quality of reported data and since the IL-PRTR does not capture all the emissions from the natural gas supply chain in Israel, especially emissions associated with the transmissions, storage and distribution of natural gas. However, since the IPCC estimate is based on generic production-based factors, it leads to an estimate of linear emission increases with increasing production without taking into account local efforts to mitigate or reduce emissions via retrofits and new designs of operating equipment.

In the Energy segment of the official Israeli GHG emissions inventory, the CO_2 and CH_4 emissions reported are due to fuel combustion only for all sectors, including energy industries and transportation. The inventory segment that pertains to “fugitive emissions from fuels” is blank and no official data is provided through the calendar year 2016 inventory. As such the reported emissions are not relevant to our assessment of WTT emissions for natural gas-based transportation fuels. However, the fugitive emissions of CH_4 estimated with the IPCC Tier 1 factors could fill this gap for fugitive emissions associated with the natural gas supply chain through production, processing, transmission and distribution. Neither the IPCC Tier 1 emission factors nor the IL-PRTR data account for the emissions associated with natural gas conversion to transportation fuels.

The discussion in section 4.2 provides an overview of the supply chain emissions associated with the conversion of natural gas to CNG, methanol (for gasoline blends) and GTL. No equivalent data is available for Israel.

Expected emissions associated with the introduction of electric vehicles in Israel

With the aim of reducing GHG emissions associated with the transportation sector, decision makers at all levels are supporting a multitude of policy measures to increase adoption of light-duty electric vehicles (DOE, 2015; Zhou et al., 2015). The actual emission-reduction benefits associated with plug-in electric vehicles (PEVs) or battery electric vehicles (BEV) in a specific location are dependent on multiple factors, such as the electricity generation fuel mix, the time of day charging, and the vehicle type (EPA, 2014b). Ultimately, the emissions associated with electric vehicles, rely on consideration of vehicle types (battery electric or plug-in hybrids), the carbon intensity of the grid, and the charging infrastructures and patterns employed (NREL, 2016).

To address these issues in Israel, the Ministry of Energy has released a draft strategic plan (MOE, 2018) for the stepwise introduction of low - or zero - carbon energy sources to the Israeli market by 2030. The draft has been released for public review and comments and it is based on increasing the use of "clean fuels" in the Israeli power market including more renewable energy and phasing down the use of fossil fuels for transportation by 2030. For the transport sector, the plan relies on gradual transition to electric passenger vehicles and switching heavy duty trucks to operate on natural gas, and hinges on a total ban of importing diesel or gasoline fueled vehicles after 2030.

The envisioned implementation stages include:

- **Passenger vehicles** – phasing-in the sale of electric vehicles, with 5% in 2022, 23% in 2025, and 61% in 2028;
- **Trucks** – 60% of heavy-duty trucks (over 3.5 tons), and 20% of light-duty trucks (less than 3.5 tons) sold, will be fueled by CNG by 2030, with the rest of the trucks fueled by electricity;
- **Buses** – Preliminary penetration target of 25% fueled by CNG by 2030 with the rest of the buses driven by electricity.

Electric vehicles do not emit air pollutants and GHG directly during on-road travel but have emissions associated with the electricity produced to charge the vehicles. The draft strategic 'clean energy' plan assumes that the fuel mix for electricity generation will change in stages to about 80% natural gas and 17% renewables by 2030. Based on these assumptions the indirect CO_2 emissions from electric passenger vehicles and electric buses are expected to be:

- **Electric passenger vehicles** – Indirect CO_2 emissions under the current electricity generation mix is estimated as 92.8 gr/km. It is expected to be reduced to 56.9 gr/km in 2030 if the new fuel mix is attained.
- **Electric Buses** – Indirect CO_2 emissions under the current electricity generation mix is estimated as 721.6 gr/km. It is expected to be reduced to 442.5 gr/km in 2030 if the new fuel mix attained.

Indirect CH_4 emissions associated with electric vehicles are expected to be less than 1% of the CO_2 emissions per km from electricity generation even when accounting for the additional fugitive emissions from the natural gas supply chain.

5 METHANE EMISSION MITIGATION AND POLICY MEASURES

Methane emissions from the oil and gas sector has been identified as one of the world's most significant opportunities for climate change mitigation, along with health and safety benefits (CCAC, 2017; IEA, 2015). The actions required to tackle the issue of CH_4 emissions need ultimately to accomplish two goals: measure and abate. Although there are uncertainties and gaps in CH_4 emissions estimates, the overall data trends illustrate both the need, and opportunity, for CH_4 emissions reduction. The technologies that can reduce CH_4 emissions are well documented, well understood and, for the most part, widely available.

There is substantial evidence that oil and gas CH_4 emissions are highly variable across regions, supply chain routes, processes and equipment (Balcombe et al., 2017; Brandt et al., 2016). While the majority of possible emissions sources exhibit low emission rates, a relatively small number of sources have frequently been found to cause the majority of emissions. The top 10% of emitting sources on average contribute around 70% of total emission (IEA, 2017). This causes a highly skewed or "heavy tailed" distribution of emissions from key sources. These so called "super-emitters" have a disproportionate influence on overall emissions, which cannot be explained by variation in routine operating conditions. It may nevertheless be possible to minimize their occurrence and duration length through preventative maintenance, effective operational strategies to minimize errors, and regular leak detection and repair programs. There would be great benefit in doing so, and it has been suggested that successfully reducing emissions from super-emitters to "normally expected" levels could reduce emissions by around 65-85% (Zavala-Araiza et al., 2015).

5.1 Global Outlook

To fully understand the costs and benefits of action on CH_4 emissions, the IEA (IEA, 2017) constructed a global picture which describe in detail the emissions reductions and monetary costs (and savings) that can result from the use of different abatement technology options. Since natural gas is a valuable product, the CH_4 that is recovered can often be sold. This means that deploying certain abatement technologies can result in overall savings if the value received for the CH_4 sold is greater than the cost of the technology.

The IEA (IEA, 2017) estimates global oil and gas CH_4 emissions in 2015 to be around 76 Mt, and some 55% of which are from natural gas operations. The 42 Mt emissions from natural gas correspond to a global average emission intensity of just over 1.7%. Just under 60% of total oil and gas emissions are vented (i.e. are intentional releases), 35% are fugitive (i.e. are unintentional releases) and the remainder are from the incomplete combustion of Flares.

The IEA (IEA, 2017) concludes that for 19 emissions sources identified in the outlook, and with around 50 different known abatement technology options, it is technically possible to reduce global oil- and gas-related CH_4 emissions by 58 Mt, a 75% drop from levels today. Emissions of 38 Mt (50%) can be mitigated using measures with positive net present values, based on 2015 gas prices. Further reductions would start to rely on technologies or approaches that would cost money rather than saving it, either because the gas cannot be monetized (if it is flared for example) or because capital and operating costs are larger than the revenue that would be received from selling the gas recovered. However, the analysis is quite sensitive to prevailing natural gas prices, if 2016 prices were to be used, the level of possible emissions reduction globally with measures that have positive net present values would drop from 50% to 40%.

There are differences between the level of mitigation technically possible for oil and for gas, assuming 2015 gas prices (IEA, 2017):

- Oil - over 80% of CH_4 emissions can be avoided globally and over 60% of CH_4 emissions can be avoided with measures that have positive net present values
- Gas - less than 75% of CH_4 emissions can be avoided globally and 40% of CH_4 emissions can be avoided with measures that have positive net present values

For fugitive emissions from both oil and gas, a maximum of 85% can be captured by introducing monthly Leak Detection and Repair (LDAR) programs. Upstream (and downstream oil) fugitive emissions are much more concentrated in discrete facilities and it is generally quicker and less expensive to inspect and repair these than is the case for downstream gas. The abatement potential for vented emissions from the downstream gas sector is much lower – here it is technically possible only to avoid 25% of vented emissions.

The cost of mitigation is generally lowest in developing countries in Asia and the Middle East, and generally highest in areas that have low wellhead gas prices. in North America, for example, around 20% of total oil- and gas-related CH_4 emissions could be eliminated using technologies with negative or no overall costs.

5.2 Public Private Methane Abatement Partnership Programs

Increased attention to CH_4 emissions has led to the formation of several national and international public private partnerships under the auspices of either the U.S. EPA or the global Climate and Clean Air Coalition (CCAC). Many of these initiatives focus on best practices and on promoting awareness and sharing information on the use of abatement technologies. Some set specific emission reduction goals and establish a timeframe for implementation with relevant milestones.

(a) U.S. EPA voluntary oil and gas methane programs (including Natural Gas STAR, Natural Gas STAR International, and Methane Challenge)

This family of initiatives comprise of oil and natural gas companies operating both domestically in the U.S. and abroad. The programs consist of companies sharing information about their experiences with implementing varied technologies and compilation of "lesson learned" case studies that provide detailed information to other potential users. The Natural Gas Star website outlines recommended technologies to reduce oil and gas CH_4 emissions[26]. The listing includes around 70 technologies and practices to cut CH_4 emissions in the Production, Gathering and Boosting, Processing, Transmission and Distribution segments. The programs' Lessons Learned Studies and Fact Sheets present analysis of emissions reduction/mitigation that devices and sources,

- Compressors/Engines,
- Dehydrators,
- Pipelines,
- Pneumatics devices and controllers,
- Storage Tanks,
- Valves,
- Gas Wells, and
- Recommended practices for Directed Inspection and Maintenance (DI&M).

For each of the devices/sources several mitigation options are included including data on the estimated implementation cost and incremental operating cost. The costs presented range from less than $1,000 to more than $50,000 with estimated payback periods of a few months to few years (depending on natural gas prices). The use of these technologies and practices helped to yield

[26] Natural Gas STAR Program, *Recommended Technologies to Reduce Methane Emissions*; https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions

a near 30% reduction in the overall emission intensity of natural gas in the United States between 2005 and 2015 (EPA, 2017b).

According to Bylin et al. (2010) the Natural Gas STAR Program technical documents are generally applicable to onshore installations. Costs for applying the same reduction technologies/practices offshore can be significantly higher than for an onshore application. General factors that contribute to higher costs offshore include:

- Capital costs could increase as the equipment may need to be more robust to tolerate marine and harsh weather conditions or reduced in size to conserve limited deck space.
- Installation costs can be much higher due to the transport of people and equipment offshore, lifting the equipment up to the platform deck, and moving existing equipment to accommodate new installations.
- Operating and maintenance costs are higher due to transportation of maintenance materials and personnel offshore and more frequent maintenance requirements in an adverse operating environment.

The analysis of 15 representative offshore platforms with combined oil and gas emissions used in Bylin et al. analysis (2010) uses data from the 2005 Gulfwide Offshore Activities Data System (GOADS-2005) that was created to collect monthly emissions activity data from platform sources in the Gulf of Mexico. The data indicate that CH_4 emissions reductions of 40% to 85% can be achieved cost-effectively, demonstrating that CH_4 emission reduction projects can be successfully implemented economically at offshore production facilities despite the increased costs and unique challenges of offshore operations.

Table 5-1 shows the mitigation option cost and saving for CH_4 emissions reduction from offshore platform.

Table 5-1 > Mitigation option for methane emissions reduction from offshore platforms

Technological Options	Capital Cost	Installation Cost	New Equipment Delta O&M Cost	Reduction Efficiency (%)	Condition of Application for costs
Install vapor recovery unit (VRU)	$178,215	$178,215	$21,891	95%	500 MCF per day VRU
Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrators	$56,382	$0	$17,082	90%	Horizontal flash tank for 450 gallons/hour TEG circulation rate
Pipe Glycol Dehydrator to VRU	$26,250	$26,250	$0	95%	250 feet length of pipe
Recover Gas from Pipeline Pigging Operations	$26,250	$26,250	$0	95%	250 feet length of pipe
Replace Wet Seal with Dry Seals	$486,000	$486,000	-$114,790	94%	6-inch shaft beam type compressor, 2 wet seals
Reducing Emissions When Taking Compressors Off-Line	$5,064	$5,064	$0	90%	Cost corresponds to option of connecting blowdown vent to fuel gas system
DI&M	$50,000	$0	$0	70%	One-time costs for a third-party contractor
Reducing Methane	$4,860	$4,860	$0	65%	Teflon or moly-based 8 to 10 cup

Technological Options	Capital Cost	Installation Cost	New Equipment Delta O&M Cost	Reduction Efficiency (%)	Condition of Application for costs
Emissions from Compressor Rod Packing Systems					ring set for a 3-inch rod; including cups and cases
Convert Gas-Driven Chemical Pumps to Instrument Air	$30,000	$30,000	$1,300	100%	Gas-assisted glycol pump sized for a gas dehydration unit that processes 10 MMCF of wet gas per day
Convert Gas Pneumatic Controls to Instrument Air	$209,469	$209,469	$42,705	100%	Screw-type air compressor with a capacity of 350 CFM of air. Volume tank of 1,000 gallons of air, and alumina bed desiccant dryer with an air volume capacity of 350 CFM
Replace High Bleed with Low Bleed Devices	$5,427	$5,427	-$47	75%	Replacing high-bleed pressure controller to low-bleed (average costs for Fisher brand pneumatic controller installed)

(Adopted from: Bylin et al., 2010)

(b) The Global Methane Initiative (GMI)

The GMI was launched in 2004[27] as a voluntary international public-private initiative that emerged from the US Natural Gas Star. It advances cost-effective, near-term CH_4 abatement and recovery and use of CH_4 as a clean energy source in three sectors: biogas (including agriculture, municipal solid waste, and wastewater), coal mines, and oil and gas systems. The GMI partners collaborate with other international organizations, such as the United Nations Economic Commission for Europe (UNECE) and the CCAC to reduce global CH_4 emissions.

GMI has created an international network of partner governments (including the government of Israel), private sector members, development banks, universities and non-governmental organizations to conduct assessments, build capacity, create partnerships, and share information to facilitate project development for CH_4 reduction in GMI Partner Countries.

The GMI has created a Project Network with more than 1,000 public and private sector organizations and have helped the program to leverage, by 2015, nearly $600 million in investment from private companies and financial institutions (GMI, 2015).

It is estimated that by 2020 CH_4 emissions from normal operations, routine maintenance, and system disruptions in the oil and natural gas industry would reach 2,276 MMT CO_2e. Similar to the Lessons Learned from the US Natural Gas Star, it is anticipated that CH_4 mitigation will be based on technologies or equipment upgrades that reduce emissions or eliminate equipment venting or fugitive emissions. Additional emission reductions are anticipated from enhanced best management practices that take advantage of improved measurements or emission reduction technology.

GMI Partner Countries account for approximately 70 percent of global manmade methane emissions, and they are encouraged to develop action planning documents to identify the overall vision for their participation in the GMI, outline key country activities and priorities, and provide a mechanism to advance cooperation among partners by identifying needs and opportunities. Israel has joined the GMI in 2018 looking to learn from the experience of other countries to reduce and capture CH_4 not only from its emerging natural gas sector but also from solid waste management and in the agriculture sector.

[27] https://www.globalmethane.org/about/index.aspx

Examples of a few studies performed at GMI partner countries include:

- **2018 O&G: Measurement Study at Cairn Facilities (India)**
  The EPA team travelled to India to conduct a field CH_4 measurement study at Cairn India's Ravva and Suvali oil and gas production and processing facilities (GMI, 2018). During the measurement study, the team conducted CH_4 emissions detection using an infrared camera to scan for leaks and vented emissions and then used a Hi-Flow Sampler© and a thermal mass flow meter to quantify emissions and verify the sources. The EPA team also conducted CCAC Oil & Gas Methane Partnership (OGMP) asset surveys for each of the facilities, in order to determine how many OGMP "core sources" were at the two facilities, and whether they were mitigated or unmitigated.

- **2017 Site Survey at KU-Maloob-Zaap Offshore Production Platform (Mexico)**
  The activity consisted of an annual site survey that was conducted at the KU-Maloob-Zaap Offshore Production Platform (GMI, 2017). The facility is an offshore oil and associated gas production platform complex with four platforms connected by walkways; well receiving and gas/oil separation platform, gas compression platform, flare platform, and "hotel" platform. Sources identified as present during the 2017 site survey included only fugitive emissions; all compressors were dry seal centrifugal compressors. Several recommendations were provided to mitigate CH_4 emissions:

    - The facility has a FLIR® leak imaging camera and performs leak surveys four times per year on each platform. The leaks detected and repaired are recorded in a log, therefore this source is considered mitigated.

    - The type of component found leaking and repaired was not recorded in the log. It was recommended that recording the component type would allow the facility to estimate CH_4 emission reductions using applicable emission factors from a Technical Guidance Document.

- **2014 Field Study at Pertamina Facility (Indonesia)**

  The U.S. EPA conducted a field CH_4 emissions measurement study with the Indonesian partner, Pertamina, at the Tambun and Subang oil and gas production facilities (GMI, 2014). These facilities produce and treat crude oil, natural gas, and condensate. The EPA team was accompanied by individuals from Pertamina that was represented by individuals from the operations, maintenance, and fire departments from each of the facilities studied. The team conducted CH_4 emissions detection using an infrared camera to scan for leaks and vented emissions and then used a Hi-Flow Sampler© and a gas sampler to quantify emissions. In addition to finding and measuring CH_4 emissions at Pertamina's operational facilities in Tambun, this study also provided hands-on experience to Pertamina staff on the value of having leak detection and measurement equipment. This joint study will lay the foundation for future Pertamina projects to recover and utilize CH_4 that might otherwise be lost to the atmosphere.

(c) The Climate and Clean Air Coalition (CCAC) – including the Oil & Gas Methane Partnership (OGMP)

This CCAC[28] was convened in 2011 as a voluntary partnership of governments, intergovernmental organizations, businesses, scientific institutions and civil society organizations committed to address climate change and air quality issue by the reduction of short-lived climate pollutants. The global network includes 120 state and non-state partners (including the state of Israel), along with hundreds of local participants that are active across economic sectors.

As part of the CCAC, the Oil & Gas Initiative focuses on reducing emissions from oil & gas industry operations, with a focus on emissions of CH_4 – also known as the Oil & Gas Methane Partnership (OGMP). The OGMP has a goal of improving CH_4 management practices and fostering an industrywide culture of performance excellence[29]. There are potentially several hundreds of CH_4 emission sources throughout oil & gas operations, and the OGMP helps companies to better understand and prioritize how to best reduce their CH_4 emissions. The partnership requires companies to do the following in their participating assets (CCAC, 2017):

- Survey emissions for nine "core" sources that account for a large fraction of CH_4 emissions in typical upstream and midstream operations;
- Evaluate cost-effective technology options to address emission reductions for uncontrolled sources;

[28] The Climate and Clean Air Coalition; http://ccacoalition.org/en
[29] The CCAC OGMP serves as a forum for knowledge-sharing between industry partners and representatives of prominent national/international CH_4 reduction programs, including the Environmental Defense Fund, the U.S. EPA (Natural Gas STAR Program and Global Methane Initiative), and the World Bank's Global Gas Flaring Reduction Program.

- Report progress on surveys, project evaluations and project implementation in a transparent and credible manner that demonstrates results.

The OGMP works to improve data collection through systematic surveys to determine where emissions exist and share best practices to minimize them. Companies are also encouraged to investigate and report on additional sources beyond the core sources.

It should be noted that “100 percent mitigated” does not necessarily mean zero emissions, but that all sources of a type are using best practice to minimize CH_4 emissions as defined in the Technical Guidance Documents (TGDs) published by the CCAC.

CCAC “Core” Sources

The OGMP is initially focusing its efforts on a group of nine of the largest (“core”) sources of CH_4 emissions based on relative contribution of these sources to upstream oil and gas CH_4 emissions, along with the availability of cost-effective options to mitigate them. Further information on the various sources, is presented in Appendix E:

1. *Natural Gas-Driven Pneumatic Controllers and Pumps*
2. *Fugitive Component and Equipment Leaks*
3. *Centrifugal Compressors with “Wet” (Oil) Seals*
4. *Reciprocating compressors rod seal/packing vents*
5. *Glycol dehydrators*
6. *Unstabilized Hydrocarbon Liquid Storage Tanks*

There are a couple additional sources identified as major source for CH_4 emissions in the oil and gas sector, however they are less relevant for our study since they refer to gas flow decline in depleted reservoir, hydraulically fracturing unconventional natural gas reservoirs and venting from associated gas in oil wells production.

The OGMP encourages companies to adopt best operating practice by implementing appropriate measures to identify malfunctioning devices in a timely manner. As part of such practices, it is recommended that all equipment should be subject to either a regulatory LDAR program, or a voluntary DI&M programs[30]. These programs, despite their differences, could help to identify and repair leaks and confirm that the equipment is operating per design specifications. A DI&M plan should include the identification and quantification of leaks, development of record for the baseline leak data (so that future surveys can focus on the most significant leaking components), and a defined schedule for future surveys (at an annual frequency, at minimum).

To ensure consistent annual quantification of CH_4 emissions and comparable evaluation of mitigation options, the CCAC OGMP recommends that operators use one of the following quantification methodologies:

- direct measurement (by calibrated vent bag, high-volume sampler, Vane anemometer, Hotwire anemometer, turbine meter, acoustic leak detector, hi-flow sampler, etc.)
- lab analysis or engineering calculation with software
- emission factor calculation

In principle, direct measurement is the most accurate method for quantifying CH_4 emissions and documenting costs and benefits of mitigation efforts (i.e., value of gas saved). As such, measurement is highly encouraged whenever possible (CCAC, 2017).

5.3 Economic Considerations for implementing methane mitigation options

Both voluntary initiatives and emission control regulations rely on using technically feasible and cost-effective solutions for addressing the many sources of CH_4 emissions from oil and gas operations. Clearly, the economics and cost effectiveness of measures vary from site to site, even within the same country, depending on the technical concept considered and operating conditions. For each project the operational conditions, as well as logistical, safety and cost considerations, must be evaluated on a case-by-case basis.

When determining the associated costs related to equipment maintenance/replacement, it should include: equipment and installation costs, operating and maintenance (O&M) costs, avoided maintenance costs for an older equipment, energy costs associated with the new practice, and costs associated with production stops, if such stops are required to carry out the maintenance/replacement.

[30] In some countries, for regulatory compliance, operators are required to implement a LDAR Program. DI&M and LDAR are significantly different while the objective is the same: reduction of fugitive emissions. The DI&M practice is based on cost-effective CH_4 emission reduction, whereas LDAR defines leaks that must be repaired, even when not economical. LDAR regulations are very prescriptive and inflexible, with considerable records-keeping and retention, and potential penalties for non-compliance. DI&M is strictly voluntary best practice of CH_4 fugitive emissions reduction.

The payback period of any opportunity will vary depending on the expected leak reduction value (volume of gas that will be saved) multiplied by the gas price, if there is beneficial use for the saved gas (for sale and/or use as fuel gas).
Once operators have determined which device can be cost-effectively replaced or retrofitted, they should develop a strategy for implementing the project (e.g., during the next site visit or during the next planned maintenance shutdown). Equipment replacement can help minimize labor/installation costs and shutdown time and should be considered along with applicable maintenance and/or equipment upgrade.

The results of a survey of the potential cost-effective opportunities for CH_4 emission abatement is shown in Figure 5-1. The figure presents results of the marginal abatement costs for each of the operating segments of the natural gas supply chain in the US (JISEA, 2015). The marginal abetment cost curves (MACCs) illustrate the relative benefits and costs of opportunities to reduce CH_4 emissions based on an assumed resale value of the captured natural gas that would otherwise be lost. The curves show emission reduction opportunities from all segments of the natural gas supply chain, including opportunities downstream of production.

The report concludes that four types of abatement measures within the natural gas supply chain account for a majority of those at net zero cost or lower:

- LDAR of sources of fugitive emissions
- Capturing vented gas
- Replacing high-bleed pneumatic devices with low- bleed pneumatics
- Replacing Kimray pumps (i.e., gas-powered) with electric pumps

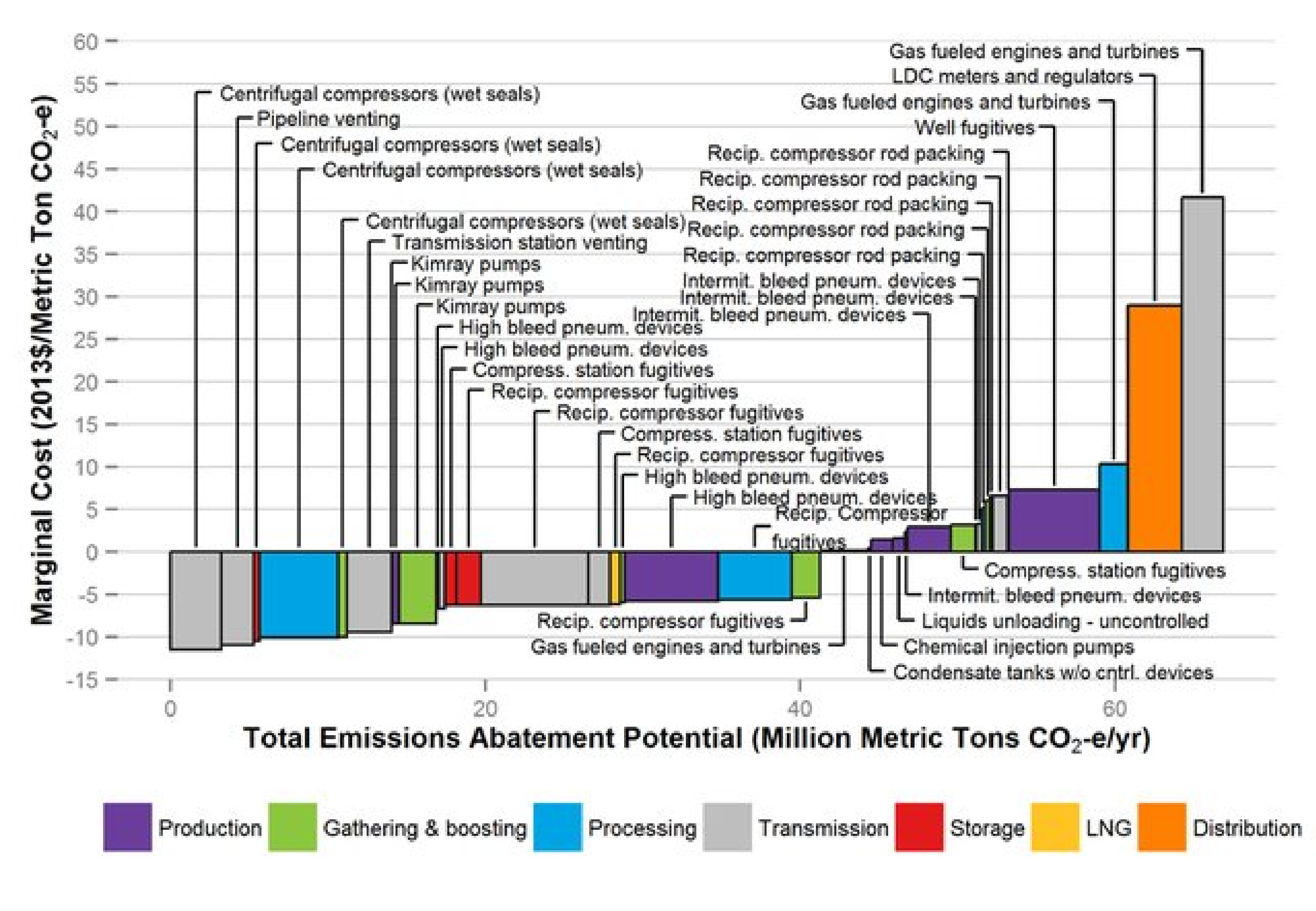

Figure 5-1 > Natural gas MACC separated by source and supply chain segment for the full revenue scenario in the U.S. in 2013

(Source: JISEA, 2015)

Labels indicate the emission source. Acronyms: intermittent (intermit.), pneumatic (pneum.), local distribution company (LDC), liquid natural gas (LNG), reciprocating (recip.).

As discussed, costs and CH_4 emissions abatement potential from actual projects are highly variable and site-specific. The data presented in Figure 5-1 reflects only estimated U.S. national average CH_4 emission abatement potential and abatement costs for each emission reduction opportunity. The data used to develop these estimates do not capture the large range and variability of reported CH_4 emission reduction costs and performances documented by the primary data source (i.e., NG STAR) (EPA, 2014c). Marginal costs developed from EPA reports assume representativeness of the data collected from NG STAR and similar sources for the estimation of national averages. However, reported data may not rely on representative emission rates or project costs. Additionally, the results do not fully consider externalities such as wider macroeconomic benefits of capturing natural gas for use, or environmental co-benefits of abating CH_4 emissions.

5.4 Policy Measures

While the voluntary programs have yielded important emissions reductions, some data (EPA, 2015) suggest that their impact is not even global and its impact has started to stall though it got reinvigorated by a spur of new activities following the Paris Agreement. Many of the voluntary actions are focused on implementing measures that are low-hanging abatement fruit, which raises the question of whether broader implementation of emissions reductions measures may require regulatory intervention, to ensure desirable results from a public policy perspective. In addition to the environmental and safety aspects, governments, as well as industry operators, may have an economic incentive to reduce emissions, as this means increasing revenues from avoiding natural gas losses and government collecting increased royalties' payments for the incremental gas sold. For example, the US Bureau of Land Management (USBLM) estimated that its 2016 rule would generate \$3–\$10 million each year in additional government royalties from the captured gas (USBLM, 2016). Yet despite incentives for action, few companies or countries have set hard targets for fugitive CH_4 reduction (Hendrick et al., 2017; Konschnik & Jordaan, 2018). A notable exception is the Oil and Gas Climate Initiative (OGCI)[31], which is a voluntary CEO-led initiative taking practical actions on climate change. OGCI members leverage their collective strength to lower carbon footprints of energy, industry, transportation value chains via engagements, policies, investments and deployment. The initiative has three primary objectives:

1. Influence the broader energy industry to reduce its carbon footprint.
2. Accelerate the policy agenda by deepening engagement with governments at all levels and with coordinating organizations such as the United Nations.
3. Link closely with the sustainable development goals by setting clear long-term pathways with measurable milestones and commitments.

[31] https://oilandgasclimateinitiative.com/

The text-box below is based on the CEOs' Foreword in the OGCI 2018 report (OGCI, 2018a). Where the CH_4 emission intensity reduction commitment, which was updated in September 2018[32], is calculated in accordance with specified methodology (OGCI, 2018b).

The OGCI declaration on Methane Intensity Reduction Commitments:

1. *OGCI (ten-member companies) produce a total of 41 million barrels of oil equivalent per day representing 25% of global oil and gas production.*

2. *OGCI companies directly emit a total of 600 million tons of CO_2e per year, or 1.8% of total global direct energy related GHG emissions, with an emissions intensity baseline of 0.32% in 2017.*

3. *They have announced a target (September 2018) of collectively reducing the average CH_4 intensity - of their aggregated upstream gas and oil operations - to below 0.25% by 2025, with the ambition to achieve 0.20%.*

4. *Reaching the 0.20% target would translate into greatly reducing the collective CH_4 emissions by more than one-third – approximately 600,000 tonnes of CH_4 annually – by the end of 2025.*

The CH_4 intensity refers to the CH_4 that gets lost in the atmosphere when producing oil and gas, as a percentage of the gas sold. This effort represents a significant milestone in tackling a key issue in the fight against climate change and underlines OGCI's stance in working together to support the goals of the Paris Agreement.

A common element across many regulatory systems is a reporting requirement. However, measurement needs to be distinguished from detection and monitoring. While it may be common for the industry to monitor CH_4 emissions levels for safety reasons, it is much less common for emissions to be quantified in a rigorous way on a continuous basis at low detection thresholds. Typically, when leaks are detected, the focus is on repairing the leak rather than assessing how much CH_4 may have been emitted. Policies that govern CH_4 emission reduction require regulations to support the policy goals. The regulations need to ensure that robust measurements are undertaken, and that their results are reported publicly to enable tracking of emission reductions.

[32] OGCI member companies: BP plc, Chevron Corporation*, China National Petroleum (CNPC), Eni S.p.A., Equinor ASA, ExxonMobil*, Occidental Petroleum (OXY)*, Petróleos Mexicanos (PEMEX), Petroleo Brasileiro SA (BR), Repsol S.A., Royal Dutch Shell plc, Saudi Aramco, Total S.A (* New members joined in September 2018 and all their data is not yet fully implemented in the commitments).

Governments may ensure compliance by conducting announced and unannounced desk-top audits or site visits to verify reported emission levels. Governments may impose fines for failing to report or under-reporting, while they could also impose an emission fee (or tax) on the emissions reported.

Methane emissions can be regulated either via operational safety and/or environmental requirements. Depending on the regulatory framework for a given country, CH_4 emissions could be controlled as part of air quality management, such as for VOCs[33], or through GHG mitigation policies. Some examples of regulatory regimes that control CH_4 include:

(a) **In the US**, following the Obama's Climate Action Plan, the Obama administration expressed a policy commitment to act to reduce CH_4 emissions from the oil and gas industry by 40-45% from 2012 emission levels by 2025 through a variety of regulatory and non-regulatory actions. Federal regulatory efforts aimed at reducing emissions from oil and natural gas operations include the Department of Interior's Bureau of Land Management's (BLM) proposed standard to reduce emission from oil/gas wells on public lands, the Department of Transportation (Pipeline and Hazardous Materials Safety Administration) new research into pipeline safety (including better detection of leaks/ CH_4 fugitives), and the Department of Energy's (DOE) research and support for emissions reduction from transportation and distribution infrastructure. However, the primary regulatory focus is through regulation by the EPA.
Under the Clean Air Act, the U.S. EPA is responsible for establishing air quality standards, including emission standards known as New Source Performance Standards (NSPS). In recent years, the EPA has used these provisions to indirectly and directly regulate CH_4 emissions from the natural gas industry.

The New Source Performance Standards (NSPS) subpart OOOO (2012)[34] was finalized to regulate VOCs and sulfur dioxide emissions from the oil and natural gas industry (for new and modified emission sources in the production, transmission and distribution segments), without directly regulating CH_4. However, CH_4 emissions are reduced as a co-benefit of the VOC reductions resulting from this regulation. In 2015 the EPA has finalized NSPS Subpart OOOOa[35],

[33] Methane is usually excluded from air quality regulations (often phrased as "non-methane VOCs"), but because CH_4 emissions tend to be accompanied by emissions of other VOCs, regulating VOCs can lead to reductions in CH_4 emissions.
[34] https://www.law.cornell.edu/cfr/text/40/part-60/subpart-OOOO
[35] https://www.law.cornell.edu/cfr/text/40/part-60/subpart-OOOOa

which would regulate CH_4 directly as a pollutant, however, the final rule from 2016 does not apply to offshore operations. In 2016, the EPA announced its intent to regulate CH_4 emissions also from existing facilities in the oil and gas industries. This would be accomplished under section 111(d) of the Clean Air Act NSPS provisions.

The rule known as New Emission Standards for Hazardous Air Pollutants (NESHAP) subpart HH (2012)[36] includes emission reduction targets for compounds classified as hazardous air pollutants (HAPs), including benzene, toluene, mixed xylenes, ethylbenzene, from oil and natural gas production, transmission and storage facilities. As with NSPS OOOO, the NESHAP regulations do not directly regulate CH_4 emissions, though there could be a similar co-benefit reduction in CH_4 emissions.

In addition to federal policy, several states have issued regulations and/or guidance on CH_4 emissions from oil and gas operations*:* **Colorado** became the first state to regulate CH_4 emissions in the upstream parts of the industry directly as a GHG[37], **Pennsylvania** has regulated CH_4 emissions from compressor stations[38], and **California** has finalized it Oil & Gas Law effective October 1, 2017[39]. **Massachusetts** has developed specific regulations for reducing CH_4 emissions from natural gas distribution[40].

(b) Since April 2018, **Canada**'s upstream oil and gas industry will be subject to new regulations that are designed to ensure that the sector's CH_4 emissions are reduced by 40 to 45 percent by 2025, relative to 2012 emissions[41].

5.4.1 Policy Options

Four categories of policies are typically identified to affect emission reduction:

- voluntary initiatives (as discussed above),
- technology standards,
- performance standards, and

[36] https://www.law.cornell.edu/cfr/text/40/part-63/subpart-HH
[37] Under Colorado Department of Public Health and Environment's Regulation Number 7, "Control of Ozone Via Ozone Precursors And Control of Hydrocarbons Via Oil and Gas Emissions". https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf
[38] Through the revised General Permit 5 (GP-5).
[39] https://www.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm
[40] http://www.mass.gov/eea/docs/dep/air/climate/3dfs-methane.pdf
[41] https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/proposed-methane-regulations-additional-information.html

- market-based policies.

Market-based policies (such as taxes and trading programs) have not been widely discussed in the context of CH_4 emissions. One reason for this is that, from an administrative point of view, it seems impossible to craft a classic carbon tax or emissions trading system (ETS) for CH_4, given that governments do not have accurate and publicly available robust inventories of CH_4 emissions levels.

Voluntary initiatives have been shown to be implemented either by application of existing technologies or by accelerating the development of new ones. Due to the uncertainties associated with the characterization of CH_4 levels, policies should evolve and should be perfected as more information becomes available. Below is a list of several optional policies (Munnings & Krupnick, 2017):

1. **Technology-Based Equipment Standards** - technology standards prescribe a certain technology that polluters must use to achieve the desired regulatory emissions goal
2. **Performance–Based Equipment Standards** - performance standards might require equipment operators to reduce emissions from certain types of equipment, either below a pre-defined baseline emission levels or below a maximum emission rate, while giving the operator a discretion regarding how reductions are achieved.
3. **Leak Detection and Repair Programs** - programs prescribe detection threshold, monitoring frequency and require that a leak be corrected within a given period. In addition, such policies may also specify the required performance for the monitoring technology being used.
4. **Performance Standards for Facilities or Firms** - a performance standard could require an individual facility or an aggregate of facilities in a firm to keep emissions at or below a certain maximum emissions cap of emissions rate, from all that firm's equipment and processes. Such a performance standard could alternative require that a facility or a firm reduce emissions to a certain percentage below its baseline levels.
5. **Tradable Performance Standard** - the regulator assigns a natural gas segment an emissions rate goal and allocates it tradable credits. A firm within this segment that could economically reduce its emissions below the emissions rate goal may sell its extra credits to another firm that emits above the subsector rate and count them toward compliance. In this way, individual firms can be above or below the overall emissions rate for the subsector so long as the subsector meets its emissions rate goal in aggregate.

6. **Tax with Default Leakage Rates** – a firm would be taxed for each ton of CH_4 emissions, based on estimates that rely on prescribed emissions factors and activity factors. A firm that believes that the default emission and activity factors overestimate its CH_4 emissions could conduct an emission survey, using approved methodologies, and petition the certify these lower emissions if the firm's evidence can be verified.

Table 5-2 describes how each policy performs according to three fundamental criteria: Administrative costs, Economic efficiency and Environmental effectiveness.

Table 5-2 > Policy performs under fundamental criteria

Policy	Administrative costs	Economic efficiency	Environmental effectiveness
Technology-Based Equipment Standards	Need to ensure that firms have installed and are using these technologies and enforcing penalties against firms that are in noncompliance. Since number of emissions sources at Oil & Gas facilities is very large, this could be a massive undertaking	Provide little if any flexibility to regulated entities regarding which technologies to use to reduce emissions. Therefore, technology standards are inefficient, meaning costs to reduce emissions are likely higher than they need to be.	Depends on the cause of the emissions and the relative share of emissions from different categories. If emissions originate from equipment malfunctions and human operating error, technology standards will miss at least some opportunities for abatement. In addition. Technology standards do not encourage regulators or regulated entities to improve their emissions inventories.
Performance-Based Equipment Standards	Necessitate estimating baseline emissions levels. Monitoring and enforcement for a vast number of sources that use different technologies could be a massive undertaking. If firms are required to estimate their emissions levels, those need to be periodically verified by the government.	Give operators more flexibility in choosing which technologies or practices they use to reduce emissions, which improves the cost-effectiveness of abatement. However, performance standards apply to all pieces of equipment, which precludes the ability to prioritize abatement at super-emitting equipment.	If they are rate based, an increase in the number of devices of a given type will raise emissions even if the standards are met. if episodic or stochastic emissions explain a significant portion of the emissions, then performance standards will miss at least some opportunities for abatement
Leak Detection and Repair Programs	while the governmental costs of monitoring installations are quite low (transferred to regulated entities), enforcement costs might be high,	Depend on four cost elements: type of monitoring equipment, frequency of monitoring, costs of fixing the detected problems, and costs of	Agnostic regarding the cause of an emissions source, however, the probability that episodic, and stochastic emitters would be detected

Policy	Administrative costs	Economic efficiency	Environmental effectiveness
	since regulators must ensure that regulated entities are regularly and thoroughly searching for leaks, and repairing them when required	proving that the repair work was performed.	depends on a variety of factors, including, the methods used to detect leaks and the survey frequency.
Performance Standards on Facilities or Firms	The regulator must estimate not only CH_4 emissions from a firm but also CH_4 throughput, the data collection of which would come with additional costs.	Allows for a type of averaging that affords regulated polluters the flexibility to choose the technologies providing improved cost-effectiveness.	The performance standard on firms might pick up and encourage the abatement of more emissions than a performance standard on equipment, if the regulator measures CH_4 emissions in a way that also captures leaks from episodic and stochastic emitters. In addition, performance standards do not directly improve emissions inventories.
Tradable Performance Standard	The costs are like those for a performance standard on firms. However, there is an additional cost: regulators must oversee a pollution rights market, since credits would need to be issued, tracked, and retired across firms.	A tradable performance standard improves on the efficiency of a performance standard on firms or facilities by broadening the averaging or trading horizon across operators and possibly across states and across firms in other stages of the natural gas supply chain. However, reporting and monitoring burdens are higher than for a performance standard without the trading.	The tradable performance standard might pick up and encourage the abatement of more emissions than a performance standard on equipment, if the regulator measures CH_4 emissions in a way that also captures leaks from episodic and stochastic emitters. However, tradable performance standards do not directly improve emissions inventories.
Tax with Default	Monitoring and enforcement costs	Firms can reduce emissions which	The environmental effectiveness of

Policy	Administrative costs	Economic efficiency	Environmental effectiveness
Emission Rates	could be relatively low, but it will increase as the number of firms petitioned for lower factor values increase. At the same time, the tax generates revenues, which could be used to offset such costs. This approach is much simpler in terms of reporting and tracking than a tradable performance standard.	reduces compliance costs. However, if a firm's calculated emissions levels are much lower than its actual emissions levels, then economic efficiency would be compromised, since only a portion of emissions is effectively taxed. May incentivize firms to invest in research and development for monitoring technologies.	this approach is only as good as its default emissions rates. If these rates are assigned using current inventories, underestimation of emissions is likely, which would essentially allow firms to pay too low a tax and provide too little incentive to fix leaks.

(adapted from: Munnings & Krupnick, 2017)

Policy and regulation for CH_4 emissions mitigation should consider the following principles (IEA, 2017; Ravikumar & Brandt, 2017):

- **Emphasize data gathering**: one option would be to include a regulatory obligation to detect, monitor and quantify CH_4 emissions from a sufficiently large representative sample of operations.
- **Set an overall emission abatement goal.**
- **Foster innovation**: the need for technology innovation that delivers reliable measurement of emissions at low cost is a key technology gap and needs to be a focus both for public support and private initiatives.
- **Maximize transparency**: measurement and analysis protocols (including existing datasets) could be shared among industry and regulators to facilitate consistent approaches to quantification and abatement and to help spur implementation. Measurement data should be made available publicly. It can help allay public concern over potential risk and provides strong encouragement for operators to reduce emissions.
- **Ensure widespread engagement** during the design of regulations with as broad a stakeholder group as possible.
- **Incentivize collaboration**: industry partnerships between international and national oil and gas companies, and collaboration between different regulatory bodies, including those in other countries.
- **Establish enough enforcement**: effective enforcement means deciding how oversight and regulation should be carried out, establishing which institution is to be charged with regulation or enforcement, providing leadership and resources for that institution, and working out the penalties for non-compliance.
- **Incorporate flexibility into measurement and abatement policies**: allow adjustments to overall goals over time if interim milestones are exceeded or not met.
- **Focus on outcomes**: technological flexibility would allow operators to develop the most cost-effective means to achieve the target. One area to focus on is the timely detection and elimination of high-emitting sources, resulting in large marginal abatement benefits. The incentive structures should reward emissions mitigation that exceeds targets, while simultaneously penalizing non-compliance.

- **Coordination with other emission mitigation policies**, reducing GHG emissions from different sectors of the economy, will be crucial to prevent unintended emissions spill-over effects. Studies have shown that increased CH_4 leakage in the natural gas sector can potentially erode the benefits of switching high-emitting coal-based power plants with low-emitting natural gas plants. In addition, there is evidence that mitigating all GHGs simultaneously as opposed to focusing on just CO_2 will be more cost-effective.
- **Encourage new corporate thinking** on CH_4 emissions reduction: dialogue, policies and regulatory frameworks may be able to help to change views and help to mobilize the financing necessary to achieve emissions reductions.

6 CONCLUSIONS and RECOMMENDATIONS FOR IMPLEMENTATION IN ISRAEL

Losses and fugitive emissions of CH_4 - the primary constituent of natural gas – and its unchecked atmospheric emissions threaten to erode the climatic benefit that natural gas holds when switching fuel for energy systems operations. The focus of this study was to understand potential natural gas losses and GHG emissions, especially CH_4, from the operating segments that make up the "natural gas supply chain" and from the conversion of natural gas to transportation fuels. Such losses may be due to field utilization of natural gas; flaring, venting and leakage from operations; as well as from processing to convert natural gas to transportation fuels. Minimizing losses and emissions are essential to planning for the increased use of natural gas.

This study assembled the latest information on GHG emissions, with emphasis on CH_4, from the natural gas supply chain. Due to the lack of Israeli specific data we have relied on the integration of global data for use in the Israeli context. Specific goals included:

- Survey of the most recent literature and data on natural gas loss rates from various natural gas supply chain segments;
- Assessment of natural gas GHG emission, especially those of CH_4, due to venting, flaring and equipment leakage;
- Comparing data from select countries to upstream and fuel pathways related emissions and their relevance for Israel;
- Recommendation of optional policy considerations for minimizing natural gas loss and CH_4 emissions.

6.1 Research Findings

The concentration of CH_4 in the atmosphere is currently over twice as much as during pre-industrial levels, with global CH_4 emissions estimated to be around 570 million tonnes (Mt) in 2012. The emissions consist of around 40% from natural sources, and 60% from anthropogenic sources. The largest source of anthropogenic CH_4 emissions is agriculture, closely followed by the energy sector, which includes emissions from coal, oil, natural gas and biofuels.

Emissions estimate

The IEA estimated in the 2017 World Energy Outlook (WEO-2017) that 76 Mt CH_4 emissions (around 13% of global) were contributed by oil and gas operations in 2015 (IEA, 2017). The WEO-2017 estimated that the large oil and gas-producing areas of Eurasia and the Middle East are the highest emitting regions, accounting for nearly half of the total emissions globally, followed by North America. **IEA estimates that when averaged globally emissions from the natural gas supply chain (42 Mt in 2015) is equivalent to an emission intensity of 1.7% – that is the average percentage of gas produced that is lost to the atmosphere before it reaches the consumer.**

Natural gas is lost, and CH_4 may be emitted, at many points throughout the natural gas supply chain. Consumptive losses result from the use of natural gas for heat or energy generation by processing equipment or compressors. Non-consumptive losses include unintentional, intentional, and fugitive emissions. Unintentional emissions are from sources that are frequently augmented with vapor recovery equipment that send captured gas to flares. Flares combust CH_4 and other hydrocarbons in the natural gas to CO_2, reducing its climate impact, though a small amount of un-combusted CH_4 passes through flares.

For example, in the U.S. the natural gas flow balance for calendar year 2015 indicates that out of the 32.96 Tcf of gross withdrawals, 28.81 Tcf (87%) are designated for marketed production. The 13% shrinkage is due to the use of about 10.5% for fuel gas and re-pressuring the formations, a loss of about 1.25% is due to water and non-hydrocarbons removal, and about 1.25% are vented and flared. Out of the 28.81 Tcf of marketed natural gas about 27.09 Tcf (94%) are the actual dry natural gas production for the year 2015. The remainder 6% comprises the extracted natural gas plant liquids (NGPL), including constituents such as ethane, propane, butane, and pentanes.

The actual shrinkage and loss percentages are country specific and ought to be determined from detailed local production and marketing data along with applicable emission inventories.

Estimation of CO_2 emissions from macro data such as fuel quality and carbon content are straightforward. However, estimation of CH_4 emissions are more complex since they entail assessment of a myriad of emission sources and engineered processes. Emission inventories around the globe are of varying quality and many countries have yet to address CH_4 data accuracy. Recommended enhancements include:

- Update of emission factors focusing on high priority emissions sources categories;
- Collection of new measurements data to customize emission factors to represent local sector operations;

- Utilization of robust sampling design and sample size for measurements to ensure data representativeness;
- Assessment of emission variability and uncertainty while using emission factors metrics.

These recommendations for improvements are applicable to all national emission inventories which currently rely mainly on generic emission factors.

Emissions Intensity

As shown in Section 4.1.1 key global findings for emissions intensity of the natural gas supply chain (expressed as g CO_2e relative to the energy content of the natural gas) are[42] (Balcombe et al., 2015):

- The range of estimated GHG emissions across the supply chain is vast: varying between 2 and 42 g CO_2e/MJ;
- Methane-only emission intensity estimates range from 0.2% to 10% of the CH_4 content of the produced natural gas, or expressed as 1 to 58 g CO_2e/MJ, with most estimates between 0.5% and 3% of produced CH_4;
- For the Upstream natural gas supply chain GHG emissions the median estimated intensity is 13.4 g CO_2e/MJ, if modern equipment with appropriate operation and maintenance regimes were used.

Data gaps are notable for offshore natural gas extraction, coal bed methane extraction, gas wells liquids unloading, well completions with RECs, and transmission and distribution pipelines.

A synthesis report (Littlefield et al., 2017), discussed in Section 4.1.2, is based on new field measurements of CH_4 emissions from U.S. onshore production, gathering and processing (G&P), transmission and storage (T&S), and distribution. Key findings for U.S. onshore operations include:

- The U.S. natural gas supply chain is estimated to emit 0.29 g CH_4/MJ of delivered natural gas, or 9.9 g CO_2e/MJ when assuming a GWP of 34 for CH_4. **This is equivalent to a CH_4 emission rate of 1.7%, (with a 95% confidence interval from 1.3% to 2.2%).**

[42] GWP (CH_4) = 34 (100-yr time horizon)

- The full lifecycle GHG emissions (accounting for both CH_4 and CO_2) and using 100-year and 20-year GWPs is 13.8 g CO_2e/MJ and 28.6 g CO_2e/MJ, respectively.

Life cycle assessment

With increased availability of low-cost natural gas, a question arises regarding the optimal use of natural gas as a transportation fuel. The issues to consider are whether for minimizing GHG emissions and total energy use, it is more efficient to use natural gas to generate electricity for charging electric vehicles, to compress natural gas for onboard combustion in vehicles, or to reform natural gas into a denser transportation fuel.

Many studies have investigated the 'Well-to-Wheel' energy use and GHG emissions from various natural gas-to-transportation fuel pathways and compared the results to conventional gasoline vehicles and electric vehicles (charged electricity produced with natural gas). The conclusions from such studies differ widely due to inconsistent assumptions about emissions from the upstream segments of the natural gas supply chain, and the divergence of methodological assumptions about the operational boundaries of the 'Well- to-Tank' supply chain.
Important divergent assumptions include:

- the range of values used to represent global warming potential of CH_4;
- the uncertainty associated with total production volume of a well;
- the allocation of emissions to other co-products such as natural gas liquids;
- the utilization of different boundary limits across life cycle studies;
- the assumed CH_4 content of the extracted natural gas.

Well-to-Tank analysis for **CNG** in the EU finds the following:

- EU total carbon footprint for CNG, on an energy basis, is estimated to range from 13.75-19.8 g CO_2e/MJ due to emissions associated with natural gas supply from different regions;
- The emission intensity rates amount to 9.9, 3.74 and 0.11 for CO_2, CH_4, and N_2O, g CO_2e/MJ, respectively;
- The emission intensity used in the GREET model for the CNG pathway is 18.4 g CO_2e/MJ.

The emissions intensity associated with the manufacture of **methanol** from natural gas vary between plants due to their design technology and source of the natural gas. The emission intensities for the various cases reviewed are shown to range from 0.3 to 0.9 t CO_2e/tMeOH. The ultimate emission per MJ of fuel produced would depend on the percent of methanol blended into gasoline, which is the primary use of methanol as a transportation fuel.

For production of **GTL** the Well-to-Tank emissions intensities are shown to range from 28 to 90 g CO_2e/MJ of gasoline, or from 25 to 91 g CO_2e/MJ of diesel. For GTL, the assessment boundaries should include product transport. This consists of movement of fuel from the conversion facility to the refueling station, on-site storage, and dispensing of the fuel into a vehicle.

Figure 6-1 provides a summary of the fuel pathway intensity. It compares the average results obtained from global and U.S. data synthesis studies (Balcombe et al., 2015; Littlefield et al., 2017) to three different WTT for fuel conversion pathways to produce CNG, GTL (gasoline) and GTL (diesel), respectively.

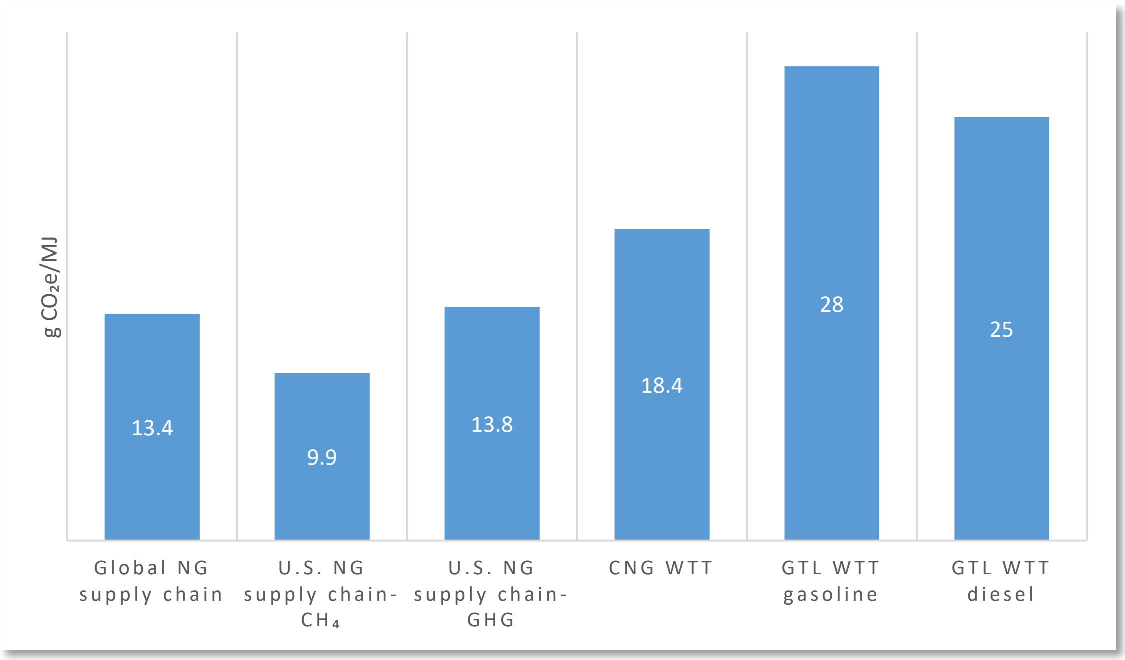

Figure 6-1 > Comparison of emissions intensity for select fuel pathways in terms of g CO_2e/MJ

Clearly the additional processing required to produce natural gas-based fuels will result in more GHG emission as compared to those from the upstream supply chain alone. Such processes lead to incremental energy consumption – with corresponding CO_2 emissions - as well as additional leaking and venting of CH_4.

Israel Emissions Assessment

Publicly available emissions data from the natural gas supply chain in Israel is limited to information reported to the IL-PRTR for natural gas systems operations for the years 2014-2017. For the four years specified the only operations that were above the reporting threshold included the mature Mary B platform, the newer Tamar platform (started operations in 2013) and the Yam Tetis shore receiving unit. The CH_4 data is shown in Table 6-1 below, which is a summary of the detailed data provided in Table 4-13 and Figures 4-4 and 4-5 Section 4 above.

Table 6-1 > Israel Estimated Natural Gas CH_4 Emissions

	2014	2015	2016	2017	Units
Domestic Natural Gas Supply [a]	7,550	8,280	9,300	9,830	MCM
IPCC Tier 1 Estimate [b]					
Production and Processing	6.9	7.6	8.5	9.0	kt CH_4/year
Transmission and Storage	7.7	8.5	9.5	10.1	kt CH_4/year
Distribution	8.3	9.1	10.2	10.8	kt CH_4/year
Total Supply Chain	23.0	25.2	28.3	29.9	kt CH_4/year
IL-PRTR Reporting [c]					
Production/Processing	4.4	4.6	4.0	4.3	kt CH_4/year
Difference (PRTR-IPCC)/IPCC	**-36%**	**-39%**	**-53%**	**-52%**	

[a] *Source: NGA, 2018.*
[b] *Emissions based on IPCC Tier 1 factors as exhibited in Table 3-1*
[c] *http://www.sviva.gov.il/PRTRIsrael/Pages/default.aspx*

Table 6-1 also presents the assessed CH_4 emissions data for Israel based on the IPCC Tier 1 emissions factors (see Table 3-1). The data indicate that the IL-PRTR data is lower by 36% to 53% from that computed with the IPCC factors, which is a more conservative estimate.

The IPCC factors enable assessment of emissions from the various segments of the natural gas supply chain, as shown in Figure 6-2. **The disadvantage of using the IPCC Tier 1 factors is that they trend upwards with natural gas production rates and do not account for any operational improvements or mitigation measures undertaken by the operators.**

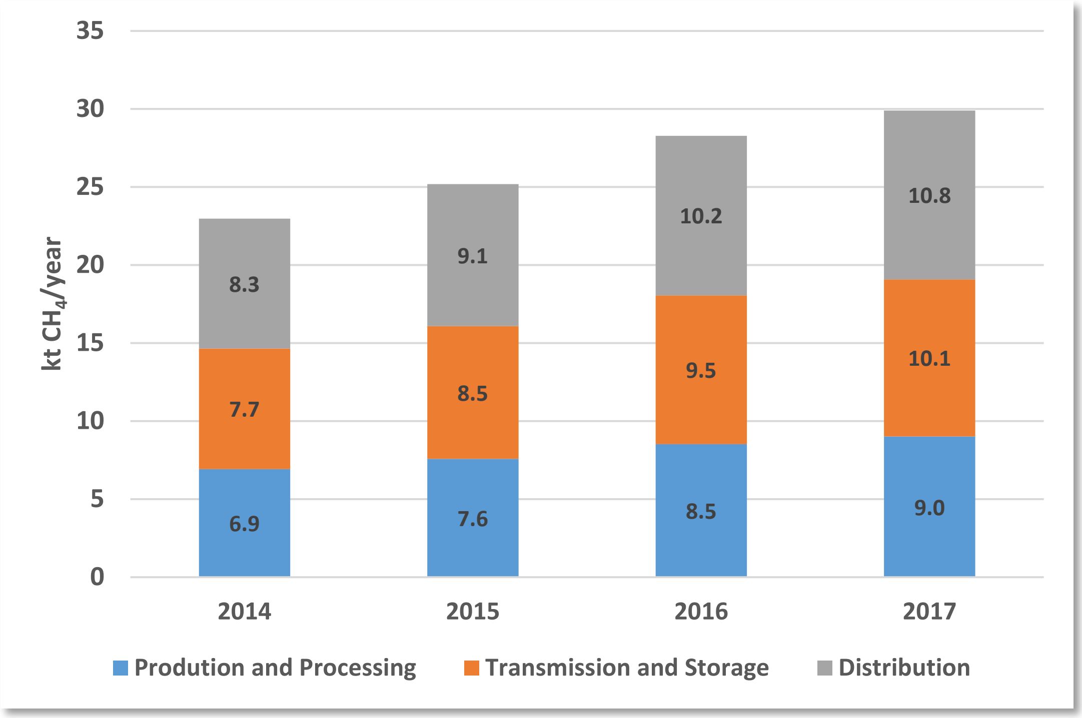

Figure 6-2 > Estimate of Israel CH_4 emissions from the natural gas supply chain segments (Based on IPCC Tier 1 Emission Factors)

No Israeli specific data is available to enable characterization of the GHG (CO_2 and CH_4) emissions that are expected to be associated with the conversion of natural gas to gas-based transportation fuels.

When addressing the introduction of electric vehicles in Israel, clearly no direct air pollutant and GHGs are emitted during road travel. However, they contribute to indirect emissions from the electricity produced to charge the vehicles. Based on the assumptions in the Draft Strategic Plan to 2030 (MOE, 2018) indirect CO_2 emissions from electric passenger vehicles and electric buses are expected to be:

- **Electric passenger vehicles** – Indirect CO_2 emissions under the current electricity generation mix is estimated as 92.8 gr/km. It is expected to be reduced to 56.9 gr/km in 2030 if the new fuel mix is attained[43].

[43] Current electricity generation mix: 68% Natural gas, 4% Renewables, 28% Coal. New fuel mix: 83% Natural gas, 17% Renewables.

- **Electric Buses** – Indirect CO_2 emissions under the current electricity generation mix is estimated as 721.6 gr/km. It is expected to be reduced to 442.5 gr/km in 2030 if the new fuel mix attained.

Indirect CH_4 emissions associated with electric vehicles are expected to be less than 1% of the CO_2 emissions per km from electricity generation even when accounting for the additional fugitive emissions from the natural gas supply chain.

Emissions mitigation

Most existing sources of CH_4 emissions in the natural gas sector are only sparsely regulated for CH_4 emissions. This is due in part to concerns that policies to mitigate these emissions would entail overseeing many sources and impose significant administrative and compliance costs. A suite of prototypical policies to reduce CH_4 emissions from the natural gas sector would consist of voluntary initiative, technology standards, performance standards for installations, and several types of leak detection and repair or direct inspection and maintenance programs.

Section 5 provides a detailed listing of technologies and their associated costs based on information compiled by the U.S. EPA Natural Gas STAR program. EPA's Natural Gas STAR data base consists of around 70 technologies and practices to cut CH_4 emissions in the Production, Gathering and Boosting, Processing, Transmission and Distribution segments of the industry. It also provides short 'Lessons Learned' and 'Fact Sheets' documents that present analysis of emissions reduction/mitigation for specific devices and sources in on-shore operations focusing on: Compressors/Engines; Dehydrators; Pipelines; Pneumatics devices and controllers; Storage Tanks; Valves; Gas Wells; and recommended practices for DI&M.

The data presented in Figure 5-1 is U.S. specific though it may provide an indication to the cost effectiveness of various mitigation measures. It shows that capturing or minimizing emissions from compressor vents and equipment leaks have negative costs (result in positive return). On the other hand, attempts to capture the emissions from natural gas fired engines or turbines is not cost effective due to the high in cost of implementing such technology and small amount of CH_4 that would be captured.

A separate analysis was performed by the Natural Gas STAR program staff to assess the applicability of these technologies to offshore operations. The key findings are that costs for **applying the same** reduction technologies/practices offshore can be significantly higher than for an onshore application. General factors that contribute to higher costs offshore include:

- **Capital costs** could increase as the equipment may need to be more robust to tolerate marine and harsh weather conditions or reduced in size to conserve limited deck space.
- **Installation costs** can be much higher due to the transport of people and equipment offshore, lifting the equipment up to the platform deck, and moving existing equipment to accommodate new installations.
- **Operating and maintenance costs** are higher due to transportation of maintenance materials and personnel offshore and more frequent maintenance requirements in an adverse operating environment.

Studies (i.e. IEA, 2017; JISEA, 2015) assessing the costs associated with CH_4 mitigation within the natural gas supply chain conclude that four types of abatement measures account for a majority of those with net zero cost or lower (benefits – of depicted as negative costs):

- **Leak detection and repair (LDAR) of sources of fugitive emissions;**
- **Capturing vented gas;**
- **Replacing high-bleed pneumatic devices with low- bleed pneumatics;**
- **Replacing Kimray pumps (i.e., gas-powered) with electric pumps.**

Yet, cost-benefit analysis of methane emissions mitigation requires in-depth and specific work, since each platform, each receiving station and each natural gas conversion facility has unique conditions, in addition, potential emissions abatement means include diverse and complex technologies and practices. The economic viability for implementing methane mitigation program is calculated by the facility's owner, which consider the gas loss as income loss (assuming resale value of the captured natural gas), however, **the national perspective is different – the state's utility related to methane emissions' externalities**. Hence, the benefits are calculated as the reduction's estimates multiply by the external cost of methane (25 factor[44] X 131 NIS per ton of CO_2[45]).

6.2 Research Limitations

The scientific overview and analysis presented in this research is limited since it is based on data that is available only from a few select countries, primarily the U.S. There is sparse availability of

[44] 25 times multiplier for the GWP of CH_4 compared to CO_2
[45] MOEP, Air pollution externalities. http://www.sviva.gov.il/subjectsEnv/SvivaAir/Pages/AirExternalCost.aspx

publicly disclosed data from operations of the natural gas sector in Israel. Moreover, due to issue of confidential business information and budget limitations it was not feasible to undertake extensive data collection to characterize the industry sector in Israel. Main data gaps are due to:

- Lack of detailed data on equipment and activity factors for the offshore installations in Israel;
- Lack of data on natural gas composition and CH_4 content throughout the Israeli natural gas supply chain;
- Lack of information on activities related to natural gas dehydration, natural gas liquids separation, gas capture and reinjection prior to transmission;
- Lack of information on onshore transmission and distribution operations in terms of pipeline construction material, use of dehydrators and compressors along the pipeline routes, and leak prevention activities;
- Lack of robust information on specific technologies adopted, and GHG emissions associated with, the conversion of natural gas to methanol or the production of GTL.

It is anticipated that air permits being negotiated between the Ministry of Environmental Protection and natural gas operators, will establish a compliance process that will comprise of annual reporting of emissions and compliance with permit terms. The annual public disclosure of data will make that information more accessible to researchers for further assessments.

6.3 Recommendations for Implementation in Israel

Our recommendation for implementation of best CH_4 management practices in Israel emphasize both government action along with companies' strategies. The main conclusion from this study is the need for local emissions and activity data so as not to rely on generic IPCC assessments. This will become even more urgent starting in 2020 with the entry to force of the Paris Accord with its new transparency requirements. Under that regime countries will be expected to submit enhanced emission inventories to document progress towards national goals.

To that affect we are recommending the following:

Government Action

- Develop national technology and performance standards for CH_4 emission rates for key emission sources and incorporate them in operating permits and track compliance;

- Perform (or require Industry to undertake) an annual physical leak survey to monitor CH_4 emissions using a combination of technologies including infrared cameras or remote sensing devices;
- Perform a periodic census (once every 3-5 years) of natural gas industry activities including equipment counts, natural gas composition, and characterization of devices and their operating modes;
- Establish annual GHG reporting requirement for both CO_2 and CH_4, with expanded guidelines specifying the list of emission sources and specific estimation methodology;
- Publish a national CH_4 mitigation strategy as part of the anticipated enhancements to the nationally determined contribution which would extend Israel contribution to climate change mitigation to 2030.

Industry Action

- Prepare for upcoming regulations by establishing corporate governance practices to address CH_4 risks;
- Assess current devices design and construction material (specifically for pipeline construction) to ensure minimization of venting and leaking emissions;
- Adopt cost-effective best management practices and technologies to mitigate and capture CH_4 from applicable installations;
- Report frequency, scope and methodology, of inspections performed for regulatory and voluntary emission mitigation programs such as direct inspection and maintenance and/or leak detection and repair.

6.4 Future studies

As new data will become available from public reporting in Israel it would be beneficial to undertake a cost-benefit analysis comparing different CH_4 mitigation options in the Israeli context.

Additionally, current emission estimation methodologies rely primarily on U.S. onshore measurements and the emission factors derived from these studies. Israel would benefit from developing and testing efficient measurement methods for CH_4 emissions and its impact on the local ambient atmosphere.

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APPENDICES:

Appendix A: Methanol production and properties

Methanol (CH_3OH), also known as methyl alcohol is a chemical compound that is water soluble and readily biodegradable, and it has been widely used in industry since the 19th century, as an essential ingredient in chemical and manufacturing process for products, including paint, particle board, plastics, carpets, pharmaceuticals, etc. Worldwide, over 90 methanol plants have a combined production capacity of about 110 million metric tons a year (MI, 2018a).

Natural Gas is the most common raw material used to produce methanol in the western world, however, it can be produced from coal (35% of installed global capacity, mostly in China (MI, 2018b)) or renewable sources such as biomass (forest biomass, crop residues etc.) or biogas from waste feedstocks (landfilled solid waste, manure, wastewater treatment plant sludge, etc.).

Methanol is produced in a number of different ways, but the primary method is through the synthesis of natural gas, as illustrated in Figure A-1.

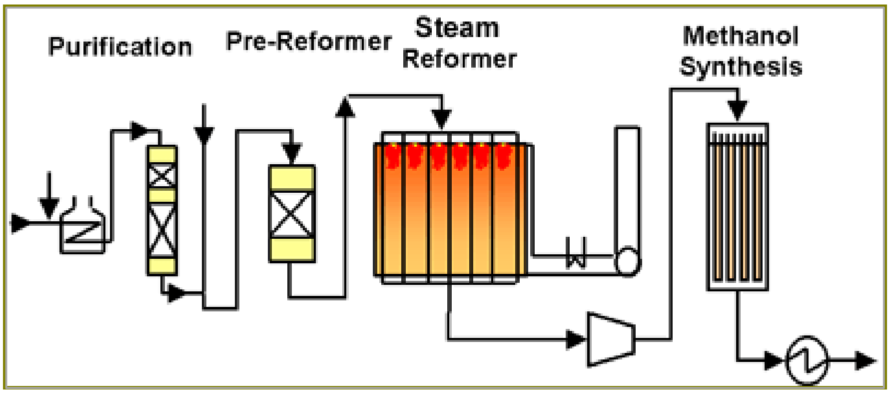

Figure A-1 > Methanol production

(Source: MI, 2018c)

The gas is first compressed and then purified by removing sulfur compounds. The purified natural gas is saturated with heated water. The mixed natural gas and water vapor then goes to the reformer to be partially converted to "synthesis gas" (syngas), a mixture of CO_2, CO and H_2, as described in Equation (1) (partial oxidation is another possible route).

Equation 1: $2CH_4 + 3H_2O \rightarrow CO + CO_2 + 7H_2$

The syngas from the reformer is then compressed, and the compressed syngas enters the catalytic converter reactor and the synthesis reaction occurs, as summarized in Equation (2):

Equation 2: $CO + CO_2 + 7H_2 \rightarrow 2CH_3OH + 2H_2 + H_2O$

Distillation removes water and organic impurities, producing methanol with a purity of 99.5%.

Methanol fuel-blend properties:

The use of methanol as a component in gasoline blends has been restricted in the past to a volume of 3-5% because of the sensitivity of carbureted engines in dealing with oxygenates. Today, in the advanced fuel injection era, experience from around the world shows that it is possible to use methanol blends up to M15 (15% of methanol) in vehicles from 1995 or later. The transition needs to be gradual in order to prevent dissolving of sediments in the fuel system and clogging of different parts. With the introduction of FFV's to the market, mainly for use with ethanol in the US and Brazil, these vehicles were used for methanol as well with high-proportion blends such as M85-M100. Technology is also being commercialized to use methanol as a diesel substitute.

Methanol has attractive features for use in transportation (Bromberg & Cheng, 2010):

- It is a liquid fuel which can be blended with gasoline and ethanol and can be used with today's vehicle technology at minimal incremental costs.
- It is a high-octane fuel with combustion characteristics that allow engines specifically designed for methanol fuel to match the best efficiencies of diesels while meeting current pollutant emission regulations.
- It is a safe fuel. The toxicity (mortality) is comparable to or better than gasoline. It also biodegrades quickly (compared to petroleum fuels) in case of a spill.

Some potential issues with the use of methanol fuel blends include:

- The energy content of methanol is less than that of gasoline (8540 Btu/lb vs 19,080 Btu/lb) so that higher fuel consumption would be theoretically predicted for blends of methanol and gasoline than for straight gasoline.
- The presence of very small amounts of water can cause methanol/gasoline mixtures to separate into gasoline and water-alcohol phases. These separate phases are vastly different in their combustion properties.

- The automotive fuel system has been developed for the use of Petroleum distillates and the substitution of blends of methanol for fuels opens the possibility of corrosion of fuel system parts. The gasket materials and elastomer seals used in the automotive fuel system must also be examined for compatibility with methanol fuel blends.

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Appendix B: GTL technology

GTL and CTL technologies were pioneered in Germany during the 1920s, using a process, which came to be known as Fischer-Tropsch (FT) synthesis, when Germany found itself short of petroleum but with ample reserves of coal (Heng & Idrus, 2004).

Although a technical success, the FT process could not compete economically with the refining of crude oil and consequently, early applications were limited to fulfil supply shortage where economic competitiveness was less relevant (e.g. during World War II in Germany and during oil embargoes imposed upon South Africa during its apartheid era). For the past several decades there has been renewed interest in FT synthesis in the form of GTL, using low-temperature FT conversion of natural gas primarily into middle distillates. This was prompted by the abundant supply of economically-priced stranded gas and recent prospects for shale gas production, which helped reduce the delivered cost of natural gas. It is also driven by restricted access to crude oil supplies and the global desire for higher-quality transportation fuels and the need to improve local air quality in many cities around the World (Baliban et al., 2013; Heng & Idrus, 2004; Wood et al., 2012).

Although there are other GTL technologies currently in use, most of the capital investment in GTL remains focused on the FT technologies. Large scale FT GTL processing facilities built to date are based on technologies held by just two companies: SASOL GTL plants with the three-step slurry phase distillate (SPD) GTL process, and Shell GTL plants, which use the Shell Middle Distillate Synthesis (SMDS) process. Both companies have recently cancelled planned projects in Louisiana (United States). The Sasol project was viewed as uneconomical, mainly due to a low oil price environment, and the Shell project did not pass the feasibility phase. These cancellations do not necessarily indicate the level of activity in the field in other parts of the world. However, the GTL industry faces a number of challenges and risks, including: high capital costs; efficiency and reliability of complex process sequences; volatile natural gas, crude oil and petroleum product markets; integration of upstream and downstream projects; and access to technology (Wood et al., 2012).

Figure A-2 shows the three main steps in a GTL process (Knottenbelt, 2002; Wood et al., 2012; Zhang et al., 2015):

- Syngas generation through CH_4 reforming - The carbon and hydrogen are initially separated from the CH_4 molecule and reconfigured by steam reforming and/or partial oxidation (requires air separation units to remove the nitrogen from air to yield an oxygen-based atmosphere for the reaction)[46]. The syngas produced, consists primarily of CO and H_2.
- Syngas conversion via FT synthesis - The syngas is processed in FT reactors creating a wide range of paraffinic hydrocarbons product (synthetic crude, or syncrude), particularly those with long-chain molecules (e.g. as many as 100 carbons in the molecule).

  Product upgrading by catalytic hydrocracking - The syncrude is refined using conventional refinery cracking processes (Agee, 2005). By starting with very long chain molecules the cracking processes can be adjusted to an extent in order to produce more of the products in demand by the market at any given time.

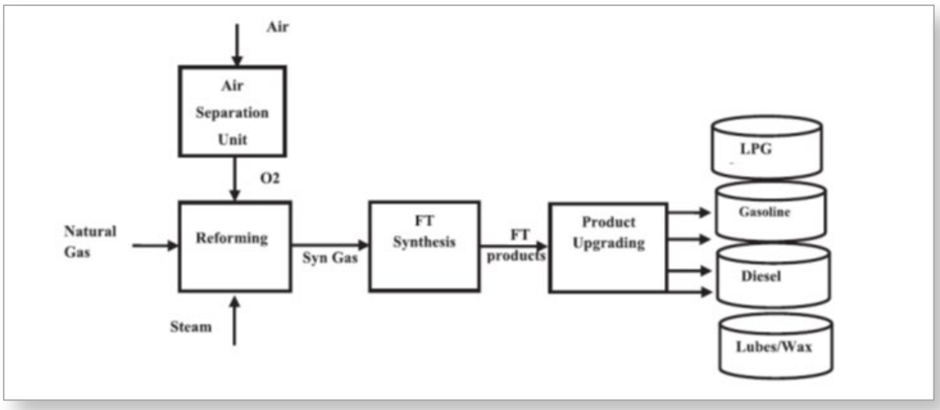

Figure A-2 > A typical GTL train block flow diagram

(Source: Al-Sobhi & Elkamel, 2015)

The FT synthesis step is the key step in the GTL process, because its conversion and selectivity have vital effects on the energy efficiency of the GTL process (Steynberg et al., 2004).

There are two major categories of natural gas-based FT process technology (Wood et al., 2012; Guettel et al., 2008; Steynberg et al., 2004):

- **High-temperature FT (HTFT)** - Performed under the conditions of 320-350 °C and pressures of approximately 2.5 MPa[47]. The syncrude produced includes a high percentage of short

[46] In Auto-Thermal Reformer (ATR) the syngas production process combines steam reforming with partial oxidation.
[47] MPa stands for Megapascal - one million pascal unit – or 10 Bars

chain (i.e., <10 carbon atoms) with significant amounts of propane and butane mixed with olefins (Minnie et al., 2005). Conversion in HTFT can be >85% efficient (De Klerk, 2012), but not all the products are readily usable or capable of producing high quality transportation fuels. HTFT processes tend to be conducted in either circulating fluidized bed reactors or fluidized bed reactors (Velasco et al., 2010).

- **Low-temperature FT (LTFT)** - Typical process operation conditions are temperatures of approximately 220-240 °C and pressures of approximately 2.0-2.5 MPa. This is a cobalt-catalyst-based process, either in slurry-phase bubble-column reactors (e.g. Sasol) or in multi-tubular fixed-bed reactors (e.g. Shell). LTFT produces a synthetic fraction of diesel. Conversion in LTFT is typically only about 60% with recycle or the reactors operating in series to limit catalyst deactivation (De Klerk, 2012).

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Appendix C: Methanol plants – features and emissions

Listed below examples of features and emissions from three methanol plants, and details about Israeli case study presented in previous study:

a) **Australian Methanol Co Pty** Ltd intends to construct and operate a methanol plant of 1.05 million tonnes per annum (Mt/a) nominal capacity, at the Burrup Peninsula near Perth (Western Australia), which includes infrastructure for the export of product through the Port of Dampier. The plant will convert natural gas to methanol using the proven, proprietary Combined Reforming Technology of Lurgi Oel-Gas-Chemie GmbH (Lurgi). The energy efficiency of the proposal is estimated as 34 Gigajoules per tonne (GJ/t) of methanol. In the EPA's report and recommendations for the Minister for the Environment and Heritage on the environmental factors relevant to the proposal an emissions assessment is described, as detailed in Table A-1.

Table A-1 > Summary of GHG emission estimates

	Kg CO_2e per hour	Tonnes CO_2e per year
Carbon dioxide	50,520	442,550
Methane	10	92
Nitrous Oxide	1,023	8,960
TOTAL	51,550	451,600

(Adopted from: EPA, 2002)

It is proposed to minimize natural gas consumption through the adoption of energy saving measures and thus minimize GHG emissions. Specific “no regrets” measures that will be included in the plant design include:

- efficient reforming process;
- recovery of waste heat;
- no fugitive emissions or flaring;
- steam turbine drives;
- power recovery turbines; and
- self-contained utilities systems.

b) **YCI methanol plant** in Louisiana is designed to produce approximately 5,000 metric tons per day of refined Grade AA methanol from natural gas using Air Liquide's Lurgi MegaMethanol® technology. The methanol production process consists of three main steps: synthesis gas (syngas) production, crude methanol synthesis and methanol distillation.

A summary of GHG emissions from June 2016, which was submitted to the Louisiana department of environmental quality for Air permit modification, include the following information, as described in Table A-2.

Table A-2 > GHG emissions for YCI methanol plant

Source Description	CO_2e [a] (US tons/yr)	CO_2 (US tons/yr)	CH_4 (US tons/yr)	N_2O (US tons/yr)
Steam Methane Reformer	1,338,863	1,338,226.16	11.62	1.16
Auxiliary boiler	269,929	269,650.03	5.08	0.51
Flare	11,022	11,010.64	0.205	0.021
Emergency generator	234			
Firewater Pump No. 1	34			
Firewater Pump No. 2	34			
Cooling Tower	-			
Fugitives	35 [b]	1	1.74	
Ammonia Tank	-			
Transfer and Storage Cap	-			
Methanol Scrubber	-			
Wastewater	-			
TOTAL (tpy)	1,620,151			

(Adopted from: Ramboll Environ, 2016a)

[a] *GWP: CO_2=1; CH_4=25; N_2O=298*

[b] *Include VOC emissions*

c) **Northwest Innovations Works LLC** (NWIW) propose to construct a methanol production facility at the port of Kalama in Washington state, US. The facility will have the capacity to produce up to 10,000 metric tons of AA grade methanol per day (2 units), and annual methanol production capacity will be approximately 3.6 million metric tons per year (mtpy). Natural gas feedstock will be provided via pipeline, and is first treated to remove sulfur compounds and then combined with steam and heat to produce syngas, this is a two stage reforming process: the first stage partially reforms water-rich natural gas using heat and steam, and the second stage completes the reforming process with oxygen using an auto-thermal reformer (ATR), to produces a syngas with the optimum composition for methanol production. The syngas is then exposed to a catalyst, resulting in a crude methanol liquid mixture. Crude methanol is distilled to yield a mixture composed of 99.9% pure methanol and 0.1% water. The finished methanol will be stored on site prior to shipment to global markets. Figure A-3 below presents the process flow diagram:

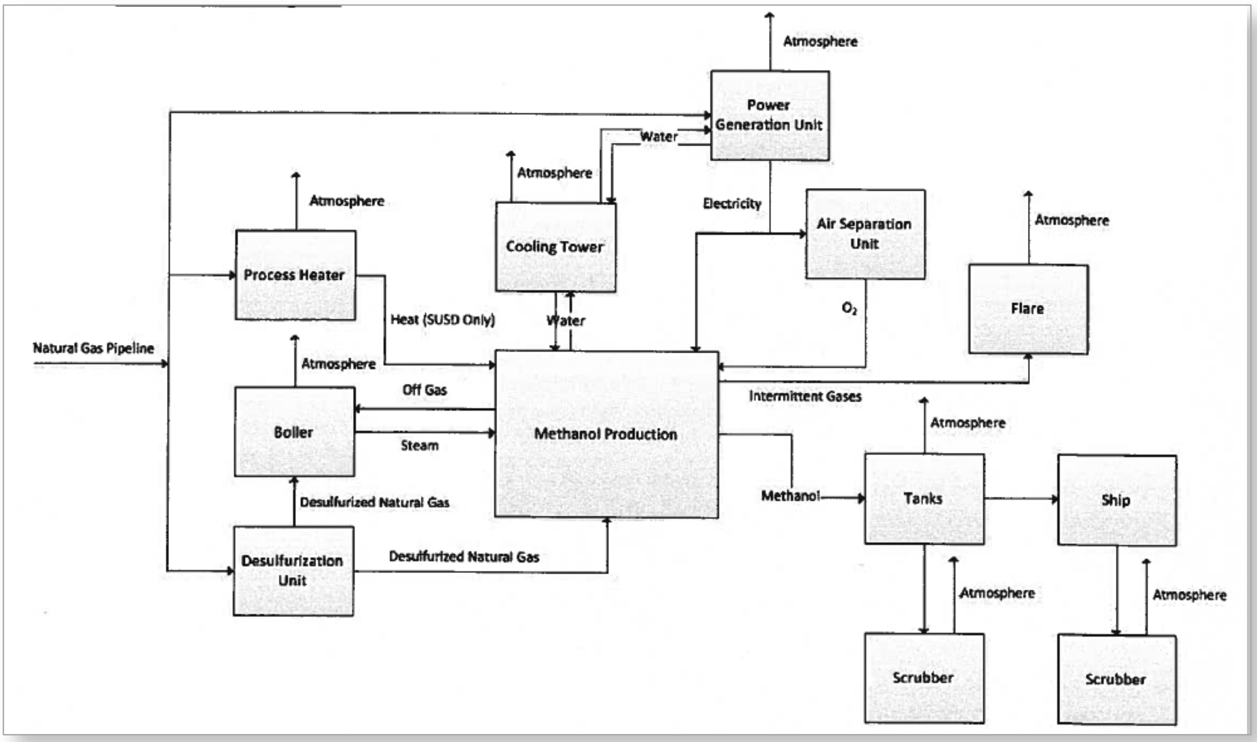

Figure A-3 > Process flow diagram

(Source: SWCAA, 2017a)

In the plan's Air discharge permit (ADP) (SWCAA, 2017b) the limitation for combined GHG emissions from approved emission units is set to 1,076,000 tons of $C0_2e$ per calendar year. This requirement is consistent with the emission estimates in the Environmental Impact Statement (EIS) report under the Ultra-low emission alternative (Ramboll Environ, 2016b). The report (which is open to public's comments until 1 March 2018) considered two methanol production technology alternatives:

- Combined Reformer (CR) Alternative – where the proposed methanol manufacturing facility would use combined reforming technology, which employs a combination of a steam-methane reformer (SMR) and an ATR.
- Ultra-low Emission (ULE) Alternative – where the proposed methanol manufacturing facility would use ULE reforming technology, which employs a gas-heated reformer (GHR) and an ATR.

The project as originally proposed and publicly announced by NWIW was based on the CR Alternative technology. During the preliminary engineering for the facility, NWIW explored other technologies that would mitigate the GHG and other emissions that would result from the CR technology. This exploration led to consideration of the ULE technology. ULE technology has been used to produce other chemicals from natural gas, but is a new technology for methanol production. The technology was developed in Australia at a small methanol plant, but it has not been applied at any full-scale methanol production facility. NWIW conducted a detailed engineering evaluation and feasibility analysis of the ULE technology in 2015. The Total Annual Emissions from Normal Facility Operations for the CR alternative are 1,570,000 tons per year GHG (CO_2e), where the two main sources of emission are reformer heaters (1,280,000 tpy) and boilers (280,000). Whilst the annual emissions on the ULE alternative are 1,076,000 tpy, and the main emitters are boilers (605,000 tpy) and on-site combustion turbines (465,000). Based on the favorable conclusions from that analysis, NWIW determined to change the proposed technology for the project from CR to ULE for the purpose of mitigating air quality impacts.

The ADP's technical support document (SWCAA, 2017a) detailed the emissions determination from the equipment/operations as proposed in ADP application, in terms of CO_2e (emission factor: 117 lb/MMBtu, exclude emissions from diesel engines which use emission factor of 163.6 (lb/MMbtu) - according to 40 CFR 98, subpart C), as describes in Table A-3 below:

Table A-3 > Emissions determination from the equipment/operations (in terms of CO_2e)

Process	Lb/hr	tpy	**Combined emissions** (tpy)
Boilers (Nat Gas)	62,010	270,963	541,926
Boilers (process)	6,963	30,500	61,000
Power generation unit	65,309	286,055	572,110
Heaters	8,705	772	1,544
Flare pilot	39	171	171
Flare		3,777	3,777
Startup	68,562		
Shutdown	153,036		
Upset	37,089		
Emergency Shutdown	207,909		
Storage tank Fugitives	0.007	0.032	0.063
Equipment component fugitives	2.63	11.5	11.5
Storage tank scrubber	1.42	6.22	6.22
Diesel engines – 2 emergency generators	5,784	150	301
Diesel engines – fire pump	1,772	50	50
Emissions summary			**1,180,897**

(Adopted from: SWCAA, 2017a)

d) Israeli case study was previously studied to evaluate the environmental effects of alternative fuels for transportation in Israel (Rapoport, 2013). That study presents data on emissions during facility operation and products' transport, for a 500,000 ton/year methanol facility, which will provide 2.8% of the fuel sources for transportation, as detailed in Table A-4 below:

Table A-4 > Emissions associated with the operation of a 500,000 ton/year methanol facility

Segment	CH_4	CO_2	Units
Natural gas (273,000 ton/year) transport to the Methanol production (90 km pipeline)	1	393	kg/year
Methanol production	5	125,000	ton/year
Desalinated water consumption (5 cubic meters per hour)	0.08	4,300	kg/year
Transfer of product in road tanker (100 km)	0	5,500	ton/year
TOTAL	**5**	**136,000**	**ton/year**

(Adopted from: Rapoport, 2013)

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Appendix D: GTL Processes GHG Emissions Assessment

Fuels properties represent only one aspect of the GTL process in the fuels' Life Cycle Assessment (LCA), hence, several studies seek to explore the broad environmental impacts of the process, including pollutants and GHG emissions.

LCA Studies Surveyed

Goellner et al. (2013) model a Low-Temperature Fischer-Tropsch (LTFT) GTL system that produces 50,000 bbl/day of fuel (with one-third gasoline and two-thirds diesel). The LCA results of their analysis are restricted to GHG emissions, expressed as CO_2e using IPCC 2007 100-yr GWP (i.e. GWP CH_4 = 25). Scenarios for diesel and gasoline were assessed, using 1 MJ of combusted fuel as the functional unit (the basis of comparison). Results were generated for current practices in the natural gas industry in the U.S. and the life cycle GHG emissions for GTL based diesel and gasoline are 90.6 g CO_2e/MJ and 89.4 g CO_2e/MJ, respectively. These results are 0.6% higher for diesel and 2.1% lower for gasoline when comparing to the NETL petroleum baseline values for petroleum-based fuels, which are 90.0 and 91.3 g CO_2e/MJ for diesel and gasoline, respectively. Most of the emissions (80-94%) are attributed to the combustion of fuels in the vehicles (mainly CO_2 emissions), however, most of the CH_4 emissions come from upstream and midstream operations. Combustion emissions are greater when using diesel, but CH_4 emissions from GTL based gasoline are more than double, since 1 kg of gasoline requires twice as much natural gas, as a raw material, as compared to diesel.

The GTL plant contributes only a few percentage points to total emissions since in the GTL process CO_2 is separated (“captured”) from other process gases as part of normal plant operations. The purpose of the CO_2 removal at a GTL plant is to reduce the circulation of non-reactive gases that would otherwise build up in the FT recycle loop. CO_2 removal also minimizes equipment sizes and costs. In this analysis, the CO_2 capture system removes 93% of the CO_2 from the synthesis gas stream. If this captured CO_2 is sequestered instead of vented, it could reduce the CO_2 emissions of the GTL plant at a similar percentage, as shown in Table A-5 below.

Table A-5 > Unit process flows for GTL operation

	Diesel Reference flow	**Gasoline Reference flow**	**Units**
Input Flow*			
Natural Gas	2.03	4.8	Kg
Output Flow*			
Diesel (co-product)	1	2.4	Kg
Gasoline (co-product)	0.42	1	Kg
Carbon dioxide (Air Emission)	0.07	0.17	Kg
Carbon dioxide (Captured)	1.22	2.90	Kg

(Adopted from: Goellner et al. 2013, Exhibit 7-16)

** All flows are expressed on the basis of 1 kg of Fischer-Tropsch diesel production*

The GTL pathway model evaluated in Forman et al. (2011) is based on global current or imminent GTL production, and represents an industrially relevant average of the GTL process[48]. Nevertheless, since only a single product slate from raw gas was considered in the study[49], a different mix of GTL products could produce different GHG emissions. For the GTL simulations carried out in that study, the total WTW GHG emissions for GTL diesel is 88.7 g CO_2e/MJ. Again, the majority of emissions come from fuel's combustion (81%), and upstream operations (17%), while the fuel production is characterized by net emissions that are close to zero. This can be rationalized by the relative carbon-balancing effect of coproduct credits resulting from the superior physical properties of GTL products relative to petroleum-derived analogues. Without the credit, the emissions related to the GTL plant are up by 35.1 g CO_2e/MJ.

Jaramillo et al. (2008) reflect a similar trend for the segments' emissions, referring to two scenarios:

- In the high-emissions scenario which uses the former U.S. fuel mix for electricity generation[50] and does not consider CCS for the FT plants, and when domestic natural gas

[48] In this study it is assumed that conventional natural gas is extracted offshore and processed onshore at a gas processing facility.
[49] LPG; 8.4%, condensate; 17.8%, GTL Naphtha; 23.1%, GTL diesel; 40.7%, GTL normal paraffin; 2.4%, GTL lubricant base oils; 7.5%
[50] 50% coal, 20% natural gas, and 30% low-carbon sources (DOE, 2005)

were used to produce gasoline, GHG emissions would have increased by 20-25% compare to petroleum based fuels, most of it due to the GTL plant, about 1 kg CO_2e/liter, or in the range of 28 to 32 g CO_2e/MJ.

- In the low-emissions scenario, were all FT plants use CCS and a low-carbon source of electricity (such as nuclear energy or renewables) is considered, slight reductions (less than 4%) in emissions was observed when producing gasoline from domestic natural gas. In the case of diesel, the use of domestic natural gas could result in a slight increase of less than 5% in GHG emissions compared to petroleum-based diesel.

Assessments of GHG Emissions from different Fischer-Tropsch (FT) processes

The Center for Transportation Research at Argonne National Laboratory conducted a WTW assessment of FT diesel compared with conventional motor fuels (i.e., petroleum diesel), using the Argonne's GREEET model (Wang, 2001).

The analysis uses information provided to the Department of Energy (DOE) by three companies, in their petitions to designate FT diesel as an alternative fuel. The information by Mossgas, Rentech and Syntroleum includes the energy and carbon conversion efficiency of their FT processes and facilities, which is distinctly different due to the company's technology, facility design, energy feedstock inputs, and product slate.

- The Mossgas facility product slate is 47% gasoline, 40% diesel fuel, 5% LPG blending components, and 8% of other energy products. Of the total energy feedstock inputs, 82% is natural gas, 15% is condensates, and 3% is electricity.

- The Rentech design uses natural gas as the only energy feedstock input and produces diesel fuel and naphtha. On the volumetric basis, the Rentech design was presented to produce 71% diesel and 29% naphtha.

- The Syntroleum design uses natural gas as the only energy feedstock input and produces diesel fuel and naphtha. On the energy basis, the Syntroleum design may produce 70% diesel fuel and 30% naphtha.

The study combines emissions of the three GHGs with their GWPs (1 for CO_2, 21 for CH_4, and 310 for N_2O) to derive CO_2-equivalent GHG emissions.

Table A-6 presents CO_2 emissions as well as aggregated emissions for WTT FT diesel plant, with probability distributions of 10%, 50%, and 90% (statistically, P50 values represent average values), and the information by the individual companies.

Table A-6 > WTT GHGs emissions from FT plants

	Facility energy efficiency	**CO_2** *(g/MJ of Fuel Delivered)*	**GHGs - CO_2e** *(g/MJ of Fuel Delivered)*
FT diesel, standalone plant – 10% probability	54%	23.67	25.8
FT diesel, standalone plant – 50% probability	61%	32.48	34.6
FT diesel, standalone plant – 90% probability	68%	41.79	43.92
Mossgas	62%	30.12	32.38
Rentech	54%	38.75	40.88
Syntroleum	49%	38.88	41.01

(Adopted from: Wang, 2001)

Khraisheh (2013) investigate the LCA of a GTL plant that produces 34,000 bbl/d, mostly (70-75%) GTL diesel, and the rest being naphtha and LPG. The analysis expresses GHG emissions of CO_2, CH_4 and N_2O in units of CO_2-equivalents, and the total GHG emissions for GTL diesel production is 59.7 kg CO_2e per kg diesel produced. The majority of the GHGs are due to CO_2, which is more than 90% of total GHG generated.

Controlling GHG Emissions from GTL Processes

Hao et al. (2010) report higher GHG emissions from GTL diesel, where the study examines GTL's large range (reported 54–70%) of synthesis efficiency, as the key factor in determining energy consumption and GHG emissions within the GTL fuel supply chain. For the probable case (GTL synthesis efficiency: 65%), the life cycle GHG emissions of GTL fuel are 12.6% higher than that of crude oil-based diesel. If the efficiency of the GTL synthesis process is improved to 75%, then the GHG emissions level of the GTL fuel supply chain can be reduced to the same level as the diesel fuel supply chain. Although at a cradle to gate level GTL diesel offers larger GHG emissions than biodiesel, studies (Economides, 2005) suggest that GTL diesel offers a significant reduction of GHG emissions at a cradle to grave level, this is because fewer emissions were generated during the GTL diesel utilization phase.

The IEA GHG R&D Programme (IEAGHG, 2000) explores the options for CO_2 abatement in a GTL plant. The analysis assumed a medium-sized GTL facility which produces 10,000 bbl/d of liquid product (6,000 bbl/d of diesel and 4,000 bbl/d naphtha), with approximately 55% thermal efficiency. Three FT technologies are evaluated (each with and without CO_2 abatement):

- Slurry reactor - A SPD process (Sasol-type technology)
- Fixed-bed reactor - The SMDS (Shell process)
- Fix-bed reactor - A process in which the syngas is produced using air rather than oxygen (Syntroleum-type)

The process performances are presented in Table A-7 below:

Table A-7 > Amount of Carbon emitted to the atmosphere due to FT synthesis plants operation with and without CO_2 abatement

FT process	**Without CO_2 abatement** (t/h)	**With CO_2 abatement** (t/h)
Sasol-type	20.2	6.0
Shell-type	19.7	1.9
Syntroleum-type	21.0	8.9

(Adopted from: IEAGHG, 2000)

Approximately 2/3 of the carbon feed remains in the product, without CO_2 abatement, approximately 600,000 tonnes/year of CO_2 would be emitted to the atmosphere by the conversion process. By using existing technology, approximately 25% of the carbon entering the process can be captured as CO_2, i.e. about 450,000 tonnes CO_2/year for 10,000 bbl/d facility.

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Appendix E: Synopsis of Mitigation Options for the CCAC "CORE" sources:

1. Natural Gas-Driven Pneumatic Controllers and Pumps (CCAC, 2017a)

Controllers and pumps may be powered by compressed air or utility-supplied electricity. At remote production, gathering, and gas transmission facilities, compressed air or electricity may not be available and economical. In such cases, operators may use the available inherent energy of pressurized natural gas to power these devices.

A major component of remote, automated control of natural gas and petroleum industry facilities is the operation of control valves, which are often powered and actuated by natural gas through pneumatic controllers, in practice, most pneumatic controllers in oil and gas production are designed to vent gas as part of normal operation. In addition, there are natural gas-powered pumps used for injecting chemicals and other purposes. Several types of these equipment release or "bleed" natural gas to the atmosphere by design. In addition to emissions by design, pneumatic controller loops and pneumatic pumps can also emit gas because they have a defect or a maintenance issue. In fact, recent field measurement studies (Allen et al., 2014) have pointed out that a large fraction of total emissions from pneumatic devices in the production segment are a result of devices that are not operating as designed (due to a defect or maintenance issue).

Mitigation options include:

- Retrofit pneumatic high-bleed gas controllers with low-/intermittent-bleed controllers to reduce gas emitted.
- Ensure intermittent bleed controller only vents/emits during the de-actuation portion of a control cycle with no emission when the valve is in a stationery position.
- Install instrument air system for pneumatic gas supply/use.
- Routing natural gas-driven pump emissions to an existing combustion device or VRU.
- Replace pneumatic pumps with electric pumps, including solar electric pumps for smaller applications such as chemical and methanol injection.

2. Fugitive Component and Equipment Leaks (CCAC, 2017b)

Fugitive emissions arise from unintentional leaks from equipment used in oil and gas operations. Potential components or sources of leaks from this equipment include flanges, screw and compression fittings, stem packing in valves, pump seals, compressor components, through-valve leaks in pressure relief devices that vent to the atmosphere, hatches, meters, open-ended lines and improperly operated storage tanks, however, emissions from equipment designed to vent as part of normal operations are not considered leaks.

Methane (CH_4) leaks are typically caused by poor construction, corrosion or wear of mechanical joints, seals, and rotating surfaces over time. Fugitive emissions can also occur from devices that are not operating properly such as intermittent pneumatic devices that are malfunctioning and continuously bleeding gas, or stuck dump valves on separators.

Due to the high number of valves, instruments, piping and tubing connections, pumps, and other components within oil and gas operations, fugitive emissions – even if individually small – can collectively become a substantial fraction of a site CH_4 emissions inventory. Component and equipment leaks are unintended and random, and therefore require dedicated study with specialized equipment to find and repair the associated emissions.

Fugitive emissions can be identified through one or more leak screening techniques, as listed below:

- Optical gas Imaging, such as an infrared leak imaging camera (designed to visually identify hydrocarbon emissions).
- Remote CH_4 Leak Detector (handheld device which uses tunable diode laser absorption spectroscopy for detection of CH_4).
- Soap bubble screening.
- Leak sensors such as a Flame Ionization Detector (FID), an Organic Vapor Analyzer (OVA) or a Toxic Vapor Analyzer (TVA) equipped with both Photo Ionization Detector (PID) and FID.
- Acoustic Leak Detection.

For reference, experience shows that a majority of fugitive emissions from upstream facilities derive from valves, connectors, flanges and compressor seals (EPA, 2016a). Other emissions occur primarily from open-ended lines, crankcase vents, pressure relief devices that vent to the atmosphere, pump seals, and scrubber/vessel dump valves passing gas with liquid to separators or tanks. Experience indicates that the majority of emissions from leaking equipment and process components typically come from a relatively small percentage of leaking components.

Mitigation Option consists of periodic DI&M surveys in which specialized equipment is used to detect and repair leaks**.** Studies by the Natural Gas STAR program indicate that a DI&M program can profitably repair 78 to 92 percent of equipment leaks, with a 6 to 12 month payback.

3. Centrifugal Compressors with “Wet” (Oil) Seals (CCAC, 2017c)

Centrifugal compressors have seals on the rotating shafts that prevent the high-pressure natural gas from escaping the compressor casing. These seals can be high-pressure oil ("wet”) seals or mechanical gas (“dry”) seals, which act as barriers against escaping gas. The wet seal centrifugal compressors circulate oil under high pressure between rings around the compressor shaft, forming a barrier against the compressed gas to prevent its escape to the atmosphere.

Operators should evaluate the system regularly to ensure that it is functioning properly and minimizing CH_4 emission levels as can be observed by inspecting flare ignition and/or atmospheric vents from the seal oil sump or the seal face of a dry seal using an infrared leak imaging camera. Possible equipment failures resulting from improperly functioning systems include an intermediate degassing system malfunction, dry seal malfunction or an extinguished flare.
Mitigation options include:

- The gas released from the seal oil by an intermediate pressure seal oil/gas separation system is routed to a pressurized inlet such as compressor suction, fuel gas, or flare. Degassing the seal oil at intermediate - rather than atmospheric - pressure reduces emissions and allows pressurized gas to be captured and directed to beneficial use. This technology can reduce CH_4 emissions by an estimated 95 percent, and it is highly cost effective.
- The gas is separated from the seal oil at atmospheric pressure and is routed to a vapor recovery unit (VRU) for beneficial use or for flaring, which normally provides a better environmental solution than direct venting of seal gas[51]. This technology can reduce CH_4 emissions by an estimated 95 percent (EPA, 2016b), and its economics may be compelling, especially if the seal oil degassing vent lines are routed to an existing VRU which has sufficient capacity to handle an increase in throughput.
- Convert centrifugal compressor wet oil seals to mechanical dry seals – Dry seals are mechanically simpler than seal oil lubricating systems because there is no need for oil circulation and treatment equipment. Given that dry seals have fewer ancillary components, they generally consume less power and have higher overall reliability and less downtime. If wet seals were due to be replaced anyway, operators may find that the

[51] The operation should consider the overall GHG emission load associated with the additional electricity requirements to run the VRU against the base case (i.e., emissions from wet oil seal being directly vented to atmosphere).

cost of replacing wet seals with dry seals is not significantly more, and may select this option based on the additional operational and emission reduction benefits.

4. Reciprocating compressors rod seal/packing vents (CCAC, 2017d)

Reciprocating compressors in the oil and gas industry commonly emit natural gas (where CH_4 is the main component) during normal operation and during standby under pressure. These emissions can be vented from the rod packing and blowdowns or as fugitives from the various compressor components.

Experience indicates that fugitive leaks from these compressor types are minimal, and they are addressed under core source Number 2 (Fugitive Component and Equipment Leaks). Piston rod packing systems, however, typically emit the highest volume of gas for compressors in good repair. Reciprocating compressors can be found on offshore installations, however, compressors directly driven from turbines are far more common.

By design, rod packing systems emit small amounts of gas either into the distance piece or through a vent line connected to the packing case, or both. All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and amount of wear on the rings and rod shaft.

Leakage volumes/rates that are deemed to be significantly higher than what is typical for the design and operation of the compressor will be considered as “excessive”.

Possible malfunctions include improper sealing of rod packing, unexpected rod or ring wear, or an extinguished receiving flare.

Mitigation options include:

- Rod packing is vented to the atmosphere and operator conducts periodic (annual) checks to each rod seal for excessive seal/packing leakage and replace rings/rods on seals/packing found to be excessively leaking - the maximum replacement frequency accepted as a best practice mitigation is the typical number of engine hours at which an engine overhaul is required. Any time-based rod packing replacement shorter than this period, 26,000 operating hours (three years), is considered mitigated. Operating a rod packing beyond this period would require periodic inspection and measurement of the rod packing system to enable operators to identify when it is economical to replace the rings only, rings and cups, and piston rods, based on cost and the value of gas saved by replacement. It is important to note that this mitigation option is most appropriate for compressors which are spared, and thereby not deemed as critical (i.e., they can easily be stopped without affecting production). For unspared compressors that cannot easily be stopped for extended periods (to conduct maintenance), operators should evaluate routing leaked gas to recovery or flares until the next scheduled shutdown.

- Route reciprocating compressor “distance piece” or packing case vents (point where rod packing leakage exits the compressor) to useful outlet or flare. operators can expect to reduce CH_4 emissions by up to 95 percent from reciprocating compressor venting when routing rod packing emission to a VRU (the operating factor of a VRU) and by up to 99 percent when implementing a flare connection (assuming 99 percent flare efficiency). Assuming a facility has an existing useful outlet such as a VRU, the low capital cost and high CH_4 reduction value, could quickly benefit most facilities. However, routing gas that leaks from rod packing to a flare will not result in a direct economic benefit, but rather suggest indirect benefits (e.g., safety benefits, reputational risk mitigation).

5. Glycol dehydrators (CCAC, 2017e)

Glycol dehydrators remove water from an incoming wet gas stream using monoethylene glycol, diethylene glycol, or, most commonly, triethylene glycol (TEG). “Lean,” or dry, glycol is pumped via a pneumatic or electric pump to a gas contactor where it mixes with the natural gas stream. The glycol absorbs water from the gas stream, in addition to lesser amounts of CH_4, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs), producing dry gas and “rich,” or wet, glycol. Dehydrators can have a variety of configurations, which affect CH_4 emission levels.
Possible equipment failures resulting from improperly functioning systems include a venting system malfunction or an extinguished flare. Moreover, operators should evaluate gases from glycol dehydrator that are routed to a flare (flow rate, composition) to estimate CH_4 emissions resulting from the flare combustion efficiency.
Mitigation options include:

- Route flash tank (if present) and dehydrator regenerator vents to beneficial use, such as fuel gas (may require a VRU) **-** Recovering gas that is otherwise vented to the atmosphere may allow for substantial costs savings. Many dehydrators are reported to be operating at a glycol circulation rate that is higher than necessary to meet gas moisture specifications, which does little to improve the gas moisture quality but increases emissions. Therefore, operators should consider optimizing/reducing the glycol circulation rate and the stripping gas injection flow rate to reduce emissions at a negligible cost while meeting moisture specifications.

The flash tank captures approximately 90 percent of the CH_4 entrained by the TEG, thereby reducing emissions when that CH_4 is routed to beneficial use. When routing vents to a VRU, operators can expect to reduce their CH_4 emissions including those coming from the stripping gas by approximately 95 percent (or more) from regenerator vents.

- Route flash tank (if present) and dehydrator still overheads to flare/combustion device.
- Replace the gas assist lean glycol pump with an electric lean glycol pump.

6. Unstabilized Hydrocarbon Liquid Storage Tanks (CCAC, 2017f)

In offshore fields, storage tanks on production platforms, floating production, storage and offloading (FPSO) vessels and floating storage and offloading (FSO) vessels contain crude oil and/or condensate, produced from connected wells or coming from nearby platforms. Light hydrocarbons dissolved in the crude oil or condensate under pressure (i.e. unstabilized hydrocarbon liquids)—including CH_4 and other VOC, natural gas liquids (NGLs), HAPs, and some inert gases—will flash (vaporize) from the liquid stored in the tank and accumulate in the vapor space between the liquid surface, the walls and roof of the tank. Fixed roof tanks can not contain any significant pressure above atmospheric pressure, and therefore these vapors must be vented.

Emissions from storage vessels are a combination of flash, working, and standing losses. Flash losses (the most significant of the three) occur when a pressurized liquid with dissolved gases is transferred from a well or vessel at higher pressure to a fixed roof, atmospheric pressure tank. The pressure drop causes gas to rapidly evolve from the liquid and/or vaporize (i.e., flash). Working losses refer to vapors above the liquid surface pushed out by rising liquid levels and agitation of liquids in tanks associated with circulation of fresh liquid through them. Standing losses refer to vapors expanding and venting associated with daily and seasonal temperature and barometric pressure changes.

The volume of vapor emitted from a fixed-roof storage tank is dependent on several factors, most significantly the pressure in the gas/liquid separator and the oil or condensate flow rate from this separator into the tank. That is, the greater the differential in pressure between the separator and tank, the higher the flashing losses. Lighter crude oils (API gravity >36°) flash more hydrocarbon vapors than heavier crudes (API gravity <36°) at the same separator pressure. Additionally, in storage tanks where oil cycling is frequent and overall throughput is high, more working losses will occur than in tanks with low throughput and where oil is held for longer periods of time.

Mitigation options include:

- Tank vapors are recovered by routing to a VRU system and directing to productive use (e.g., fuel gas, compressor suction, gas lift) - two indicators of a potential VRU project are a regular and sufficient quantity of crude oil and/or condensate production and an economic outlet for collected products. In addition, a source of electricity is highly desired to power several of the VRU's components. Based on a VRU operating factor of 95 percent (allowing 5 percent yearly downtime of the VRU for maintenance), it can be expected to reduce CH_4 emissions from a storage tank by 95 percent after implementing this technology. The cost of a VRU is dependent on several design/operational factors, including gas throughput to the VRU, inlet and desired outlet temperatures and pressures for the system, and composition(s) of the gas being recovered. In addition, a VRU can recover other vented or flared gas streams at a facility. Installation costs can vary widely depending primarily on the location of a site and number of tanks being connected to the VRU system. Operation and maintenance costs vary depending on the location of the VRU system, the quality of the gas, electricity costs, and oil produced.
- Stabilization towers are installed ahead of tanks to reduce the amount of entrained gas and flash gas emitted from the tank(s) - In gas processing facilities, the purpose of stabilization towers is to separate, through distillation, heavier hydrocarbons and lighter fractions (C_1 to C_4) prior to transporting and storing crude oil and condensate. Stabilization removes virtually all CH_4 from the crude oil or condensate. Because stabilization towers are expensive, it is not anticipated that operators will install them as a retrofit for the sole purpose of controlling CH_4 emissions from tanks.
- Tank vapors are routed to a flare/combustion device, hence, reduces CH_4 emissions to the atmosphere through oxidative combustion of CH_4. Companies can expect to achieve a 98 percent reduction in CH_4 emissions from this option, assuming a properly operated flare. Routing storage tank vapors to an existing flare are associated with minimal capital costs. Though flaring achieves no economic benefit in terms of gas saved, a flare is an important operational/safety device at a natural gas installation.

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Samuel Neaman Institute
for National Policy Research

Tel. 972-4-8292329 | Fax. 97-4-8231889
Technion City, Haifa 3200003, Israel
www.neaman.org.il